Arnold Schwarzenegger
Governor

VALUE OF DISTRIBUTION AUTOMATION APPLICATIONS

PIER FINAL PROJECT REPORT

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission) conducts public interest research, development, and demonstration (RD&D) projects to benefit the electricity and natural gas ratepayers in California. The Energy Commission awards up to $62.5 million annually in electricity-related RD&D, and up to $18 million annually for natural gas RD&D.

The PIER program strives to conduct the most promising public interest energy research by partnering with RD&D organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Environmentally Preferred Advanced Generation
- Energy-Related Environmental Research
- Energy Systems Integration
- Transportation

Preliminary Assessment: Value of Distribution Automation is the final report for contract number 500-01-006 WA 60-P-05 conducted by Energy and Environmental Economics, Inc. and EPRI Solutions, Inc. for the Distribution Research Program. The information from this project contributes to PIER's Energy Systems Integration program area.

For more information on the PIER Program, please visit the Energy Commission's Web site at www.energy.ca.gov/pier or contact the Energy Commission at (916) 654-5164.

Table of Contents

Preface ii
List of Tables v
List of Figures v
Abstract vii
Abstract vii
Executive Summary 1
1.0 Introduction 6
1.1 Background 6
1.2 Objectives 7
1.3 Report Organization 7
2.0 Distribution Automation Applications and Technologies 9
2.1 Background and Definition of Distribution Automation Functions 9
2.1.1 Automated Grid: Delivering Energy and Information 9
2.1.2 Distribution Automation Functions 10
2.1.3 Distribution Automation Technology Categories 11
2.1.4 New Distribution System Technologies 13
2.2 AMI Applications and Status 15
2.2.1 AMI Investments in California 15
2.2.2 AMI Benefits 16
2.3 Survey Results 19
2.3.1 Summary of Utility Distribution Automation Activities and Plans 20
2.3.2 Summary of Individual Utility Systems and Plans 28
2.3.3 Summary of Distribution Automation Technologies and Development Activities 44
2.3.4 Summary of Recommendations for Development 46
2.3.5 Summary of Distribution Automation Value Assessment Considerations 48
2.4 Summary - Categorization of DA Technologies and Applications 48
2.4.1 Applications 48
2.4.2 Technologies 51
3.0 Business Case Components – Categorizing the Applications and the Value Matrix 55
3.1 Valuation Methodology – Customer Perspective 55
3.2 Categorizing the Applications and the Value Matrix 56
3.3 Characterization of Value Streams 57
3.3.1 Reliability improvement 58
3.3.2 Power quality improvement 63
3.3.3 Energy savings 64
3.3.4 Distribution operation and capital savings 65
3.3.5 Early problem detection, maintenance and emergency repair cost savings 67
3.3.6 Outage detection, location, and accelerated repair time 68
3.3.7 Energy security 68
3.3.8 Public and employee safety 68
3.3.9 Value of Flexibility 69
4.0 High Value Applications - Business Case Highlights 71
4.1 Routine Operational Efficiency 71
4.1.1 Voltage Control 72
4.1.2 Loss Reduction 73
4.1.3 Equipment Diagnostics 76
4.1.4 PQ Improvement 76
4.1.5 Advanced Metering 76
4.2 Management of Peak Loads 79

4.2.1 System Reliability ... 80
4.2.2 Maintaining System Reliability ... 82
4.2.3 Increasing System Reliability ... 85
4.2.4 Distribution Level Load Control ... 86
4.2.5 Targeted Conservation Voltage Reduction ... 89
4.2.6 Automated Dispatch of DER ... 90
4.2.7 Integrating Distributed Generation into Distribution Planning ... 96
4.3 Prediction of Equipment Failure ... 100
4.4 System Restoration After Failure ... 105
4.4.1 Automated Switching ... 105
4.4.2 Outage Detection and Location ... 113
5.0 Conclusion ... 114
5.1 High Value Distribution Applications ... 114
5.2 Research and Development Needs ... 115
5.3 Next Steps: A Use Case Framework ... 116
Appendix A: Survey Background and Questions ... 118
Appendix B: Detailed Survey Results ... 118

List of Tables

Table 1: Categorization of Automation Applications with Selected Examples 3
Table 2: Top Applications from Each DA Category 4
Table 3: Stages of DA Development - Concept to Deployment 7
Table 4: Summary of automation functions defined as part of the Intelligrid Architecture use cases 11
Table 5: Proposed AMI Deployment Cost and Benefits for the Three California IOUs 16
Table 6: Survey participants 20
Table 7: Summary of existing DA implementation from the survey results 21
Table 8: Summary of planned distribution automation implementations and research initiatives from the survey results 24
Table 9: Economic Benefits as a Function of Substation Automation Functions 41
Table 10: Differences between DA and Active Network Management 44
Table 11: Recommendations by Surveyed Utilities for Research in Advanced DA Systems 46
Table 12: Summary of DA Applications 49
Table 13: Summary of DA Technologies 51
Table 14: Value Matrix of Distribution Applications 57
Table 15: Reliability Metrics for a Variety of Applications 59
Table 16: Range of VOS Estimates 60
Table 17: Residential Customer Outage Cost in 2004 $/kWh Unserved in California 61
Table 18: Residential Customer Outage Costs Estimates in 2004 $ per Outage Event 61
Table 19: California Nonresidential Customer Outage Cost in 2004 $/kWh Unserved 62
Table 20: California Nonresidential Customer Costs in 2004 $ per Outage Event 62
Table 21: Implied VOS based on PG&E Reliability Shareholder Mechanism 63
Table 22: Effect of Design Features on the Operation, Capital Cost, and Reliability of Standard Distribution System 67
Table 23: Proposed AMI Deployment Benefit Projections for the Three California IOUs 77
Table 24: Energy Storage Example – Utility Parameters 93
Table 25: Energy Storage Example - Storage Device Parameters 94
Table 26: Illustrative example of failure prediction in capital budgeting process 104
Table 27: Relationship of Outage Isolation Capability to Number of Switches 108
Table 28: Top Applications in Each Category 114

List of Figures

Figure 1: Summary of Existing and Planned DA Applications for Utilities Surveyed 1
Figure 2: Categories of Benefits used to Justify Automation 2
Figure 3: The flexible electrical architecture and open communication are interrelated components of an automated distribution system 10
Figure 4: Illustration of Typical RCS Arrangement 30
Figure 5: Summary of Existing and Planned DA Applications for Utilities Surveyed 45
Figure 6: Existing and Planned Communication Technologies for Utilities Surveyed 45
Figure 7: Benefits Identified for Automation Investment Justification by Surveyed Utilities 48
Figure 8: Levelized Energy Value by Hour and Month 64
Figure 9: Long-run Forecast of Annual Average Energy Value 65
Figure 10: Radial Distribution System 66
Figure 11: Illustrative Results to Show Value of Flexibility across a Range of Scenarios 69
Figure 12: “As Found” Voltage Profiles at Silicon Valley Power (SVP) 72
Figure 13: Feeder Losses without SEP Generator operating and with SEP Generator Operating According to the Measured Output for the Time Period 74

Figure 14: Feeder Losses without SEP Generator Operating and with SEP Generator Operating at Maximum Output for the Time Period 74
Figure 15: Distribution System Losses by Time of Use Period 75
Figure 16: Example Distribution System Topology 80
Figure 17: Illustration of a 6 State Markov Chain Analysis 81
Figure 18: Example Reliability Curve and Peak Load 81
Figure 19: Illustration of Shift in Peak Load 83
Figure 20: Increase in Feeder Line Capacity to Serving New Peak Load 84
Figure 21: Addition of DG Sources and Coordination with DA to Serve New Peak Load 84
Figure 22: Distribution Automation Applications to Reduce Peak Load and Increase Reliability 86
Figure 23: SCE Summer Discount Program for Customer Load Control 87
Figure 24: Illustration of System Load Sorted Priority of Interruption for Each End-Use 88
Figure 25: Reduction of Peak System Load based on Priority of Interruption 89
Figure 26: DG with No Capacity Benefits 91
Figure 27: Capacity Benefits Shared 50% Participants and 50% Non-participants 92
Figure 28: Variation of Wholesale Energy Prices over Year 93
Figure 29: Utility Benefits of Storage Devices with and without DA coordination 95
Figure 30: Side-by-Side Comparison of CPAU Load Contour and assumed Solar PV Output Contour 97
Figure 31: CPAU Contour Load for Single Feeder Line 98
Figure 32: Hourly output of PV System based on orientation with 2pm to 6pm highlighted 99
Figure 33: Illustrative Curve to Compute Probability of Failure in Each Year 102
Figure 34: Expected Cost by Year of Three Different Replacement Strategies 103
Figure 35: Least Cost Replacement Age by Estimated Equipment Failure Probability and Outage Cost 103
Figure 36: Typical RCS Arrangement Illustration from SCE's 2006 GRC 106
Figure 37: Example RCS Arrangement with 2 Switches and 4 Sections 107
Figure 38: Example RCS Arrangement with 4 Switches and 6 Sections 107
Figure 39: Example RCS Arrangement with 6 Switches and 8 Sections 108
Figure 40: Illustration of Fault on Circuit with 4 Switches and 6 Sections 110
Figure 41: Potential Reduction in SAFI by Number of Additional Switches 111
Figure 42: Potential Reduction in SAIDI by Number of Additional Switches 112

Abstract

This report presents a preliminary assessment of high value distribution applications in California in order to guide future research by the Public Interest Energy Research (PIER) Distribution Research Program. The report is presented in three sections.

1. A survey of national and international utilities, vendors, and research organizations of existing and planned investments in distribution automation (DA) technologies.

2. Categorization of the applications made possible by these technologies into four main categories with similar approaches for valuation. These four categories include:

- Routine Operational Efficiency
- Management of Peak Loads
- Prediction of Equipment Failure
- System Restoration After Failure

3. Description and illustrative results of approaches to value applications in each category. These results were developed with easily available public data, and drawing on past PIER research efforts. Future research that would support or improve the value assessment is provided.

The main purpose of this report is to identify areas for future research of the PIER program. To facilitate discussion, a specific high value application is identified in each category based on the survey and valuation results.

Keywords:

OMS – Operations Management System

Executive Summary

The Distribution Research Program has recently been developed within the Energy System Integration Program area of PIER and the California Energy Commission. The new program will focus on research, development and demonstration opportunities that support improvements of distribution system adequacy, efficiency, flexibility, reliability and cost. In addition, the program will support the integration of Distributed Energy Resources (DER) into utility operations and planning.

In this report, the project team of Energy and Environmental Economics, Inc. (E3) and EPRI Solutions, Inc. presents results from a national and international survey of 20 organizations active in distribution automation (DA), categorizes distribution applications into 4 main drivers of value, and then investigates approaches, and where possible presents initial results, on methodologies to value applications in each category.

Information from this study will be used to develop appropriate and relevant public interest research focusing on those areas where the value for California is the greatest. As this research program is started, the Energy System Integration Program Area is also highly interested in other research activities underway and coordination to produce the greatest value from research funding.

Survey

While a large variety of applications of distribution automation and technologies were mentioned by survey respondents, certain applications were frequently referenced. The figure below lists the most commonly cited existing and planned distribution automation applications for the utilities that were surveyed, and shows the percentage of respondents that cited those applications.

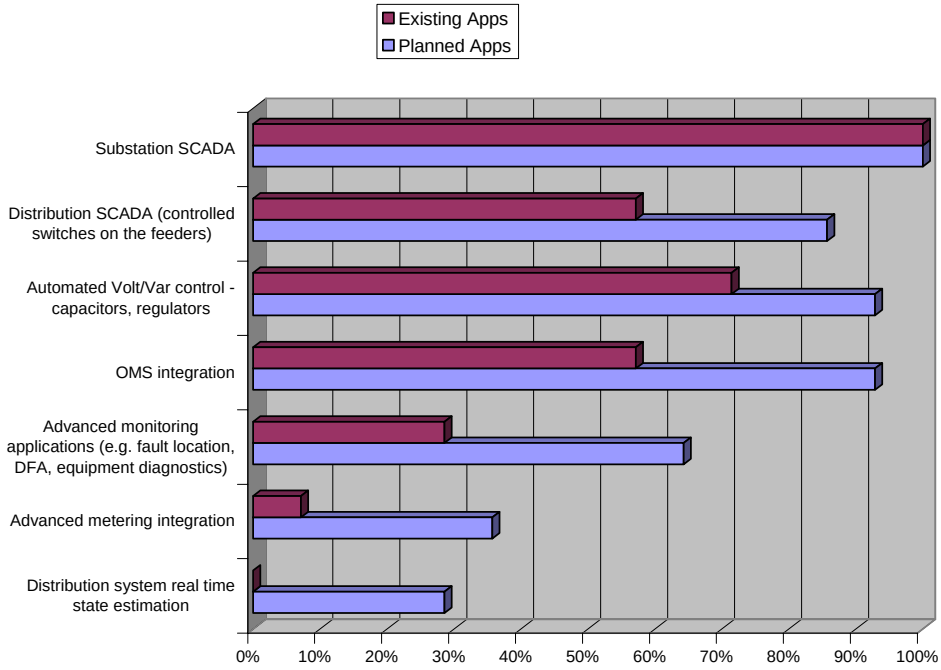


Figure 1: Summary of Existing and Planned DA Applications for Utilities Surveyed

The survey for this project also requested utilities to identify value streams they used to justify and gain approval for investments in automation. The value streams that survey participants most often associated with DA applications are listed in Figure 2 below.

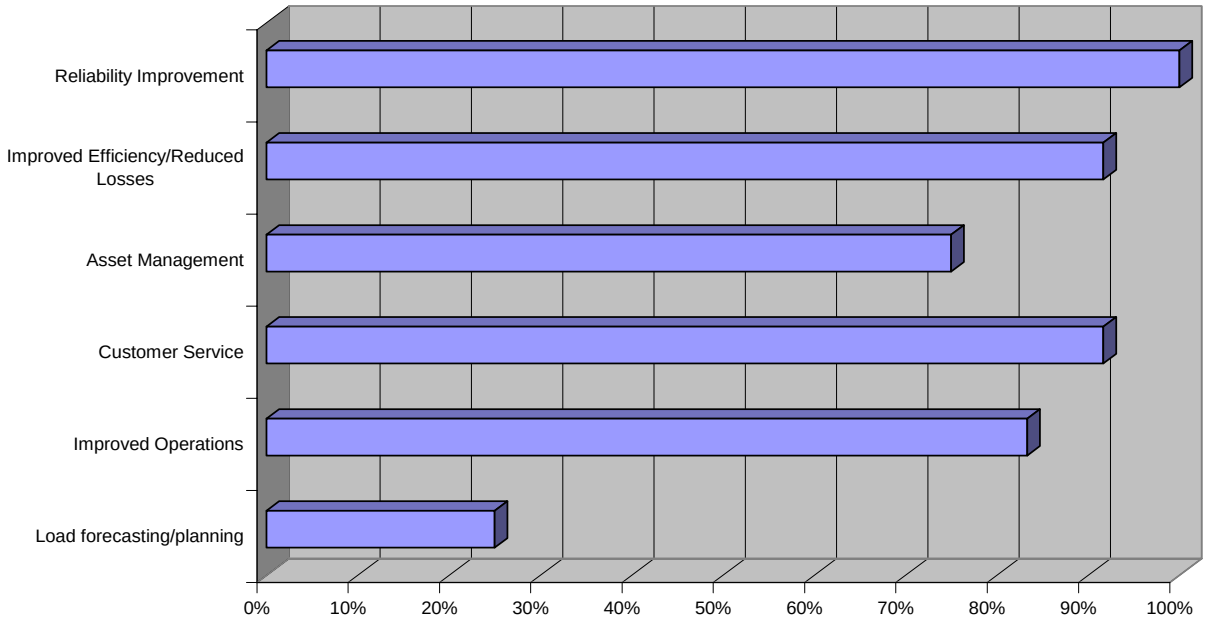


Figure 2: Categories of Benefits used to Justify Automation

Categorization

The survey of utilities and manufacturers provided a broad range of DA applications, each supported by a number of different types of technologies. To approach the valuation of these applications, we grouped these applications in to four main categories based on their approach for improving the distribution system. While the specific application and available technology to implement each approach depends on a number of factors that will vary by utility, these four categories (Routine Operational Efficiency, Management of Peak Loads, Prediction of Equipment Failure, and System Restoration after Failure Occurs) represent the main types of applications identified in the survey. Within each category, DA applications identified in the survey and literature are grouped in each category in Table 1.

Table 1: Categorization of Automation Applications with Selected Examples

1. Routine Operational Efficiency
Integration of SCADA and remote switching of capacitors to optimize voltage and var conditions
Voltage control at individual customer facilities (e.g. MicroPlanet)
Coordinated control of voltage regulators with substation tap changers, static var compensators, statcoms, intelligent universal transformers (IUT)
Equipment diagnostics for capacitors, regulators, switchgear; incipient fault detection (and location)
Integration of data from monitors and sensors throughout the system into common database platforms
Identification of other system problems – harmonic resonance, voltage variations, unbalance, repetitive faults, galloping conductors, etc.
Optimized power quality management system - harmonic control coordinated with volt/var control systems
Detection of losses, including non-technical losses through processing of monitoring data
Smart metering with automated connect/disconnect

2. Management of Peak Loads
Automated switching for dynamic reconfiguration (to reduce losses, prevent overloading/outages)
Conservation voltage reduction (CVR) during constrained hours to meet peak demand
Coordinated load control and demand response for distribution operations support
Load control through dynamic pricing to coordinate with circuit loading conditions
Control of distributed generation resources and energy storage to meet T&D as well as system-level capacity constraints
Coordination of Distributed Generation (DG), energy storage and Demand Response (DR) for improved voltage control, reduced losses, or improved reliability in microgrid
Selection of location for PVroofs / DG for optimal coincidence with distribution circuit loads
Power quality and reliability management using distributed generation and storage (including microgrid applications as appropriate)

3. Prediction of Equipment Failure
Advanced asset management systems
Advanced methods to determine remaining lifetime of equipment (e.g., machine learning techniques such as those being developed at Con Edison)
Advanced testing techniques (on line and off line) to support asset condition assessments
Incorporation of equipment condition information into decision making tools for system configuration and management.
Real time state estimation (to support dynamic reconfiguration, reliability management, asset management, load control, etc.)
Real time power flow simulation of distribution system based on sensors around the system
Real time state estimation integrated with advanced metering (information from virtually all customers as basis for real time state estimation)

4. System Restoration after Failure Occurs
Advanced fault detection and location
Automated switching for isolating faults during contingency
Automated switching for restoring loads after fault condition is cleared, etc.
Monitoring and control of substation breakers (Substation SCADA), and remote breakers and reclosers on the distribution system (Feeder SCADA)
Advanced OMS integration with advanced metering for accurate determination of faulted sections
OMS integration with automatic circuit reconfiguration systems
OMS integrated with advanced monitoring fault location applications (substation monitoring or frame fault indicators)

Valuation Methodology

For each category of distribution application, a valuation model was developed and illustrative value assessments were made with existing information where possible. In each case, the value assessment is based on providing the best value to California's customers. This perspective is consistent with PIER's mission statement and provides the strongest regulatory argument for funding investment in advanced technology. When refined with benefits confirmed through field testing, and costs developed through competitive procurement process, a credible case can be made to change the existing standard practice distribution system design to include investments in distribution automation.

Top Applications in Each Category

Based on the results of the valuation, a top application was selected in each category. The selection process was intended to test the valuation approach and offer specific ideas for discussion. For this preliminary assessment, the process to identify high value applications discussed in the report is more important than the results themselves.

Table 2: Top Applications from Each DA Category

Category	**Preliminary Assessment of Top Applications**
1. Routine Operational Efficiency	(a) Improve voltage / var control along feeders to reduce losses through switched capacitors and voltage regulators. (b) Install 'self-reporting' sensors to improve equipment maintenance (c) Develop distribution efficiency standards based on the cost and value of reducing losses
2. Management of Peak Loads	Automatically reduce loads when distribution system contingencies occur during the local peak.
3.Prediction of Equipment Failure	Develop condition-based probability assessment of underground cable failure to justify early replacement in urban areas.
4.System Restoration After Failure	Install automated switching on feeders and enhance existing outage management systems (OMS) to more precisely locate faults.

Conclusions

Distribution Automation technologies are commercially available for wide scale utility deployment. The key is identifying and unlocking the values which provide the best return on investment in ways that can be measured by utilities. Applications which may have greatest potential are operations and efficiency, Management of peak loads, predictive technologies and communications for equipment, and system restoration technologies.

Further work associating the value of DA relative to state and federal energy policy goals such as the integration of renewable distributed generation, prioritization of energy efficiency, and reduction of greenhouse gasses in electricity generation, will be beneficial in making DA technologies more widely deployed in the most suitable applications. It is possible that utility customers may desire a certain service or action from utilities that can be facilitated by a DA application, but that regulatory mechanisms are not in place to encourage the utility to meet this need. Effective selection of research funding for particular

DA applications to fund requires developing a greater understanding of the needs and desires of California customers.

1.0 Introduction

1.1 Background

The Distribution Research Program has recently completed a comprehensive Research Assessment and Gap Analysis. The new program will focus on research, development and demonstration opportunities that support improvements of distribution system adequacy, efficiency, flexibility, reliability and cost, while supporting the integration of Distributed Energy Resources (DER) into utility operations and planning. Assessing the value of automation and possible business cases based on current practices that address utility investment in automation, DER, and system upgrades were identified as high priority research initiatives that the program would pursue in 2006.

The Energy and Environmental Economics, Inc. (E3) and EPRI Solutions, Inc. research team has been asked, on behalf of the program, to study and begin collecting information on (a) whether distribution automation offers compelling value for California, and if so, (b) what research will help deliver this value to Californians. Information from this study will be used to develop appropriate and relevant public interest research focusing on those areas where the value for California is the greatest.

As the surveys of researchers in this report demonstrate, there are many DA applications and advanced technologies being considered across the nation and abroad. Each application is designed to address a specific problem or take advantage of the capabilities of a new technology. In addition, even within California, there are many different distribution system designs of different vintages that serve urban, suburban, and rural parts of the State. The challenge is to sort through all of these applications and find those that can provide the greatest value, and then to identify the appropriate PIER research that would be most helpful in supporting these applications.

Through a structured approach, identification of the best opportunities is possible. Surveys provide context for applications other researchers believe have the most promise. Surveys also help the PIER program identify opportunities to coordinate with other researchers and leverage available research funding.

Additionally, the current energy challenges confronting California, the policy foundation developed by the State's Governor, legislature, and Energy Commission, and our existing system design and distribution infrastructure provide context for identifying high value applications. In particular, we note the following conditions that assist in selecting applications;

- Aging infrastructure, particularly in established urban areas
- Electric system supply constraints
- Loading order of resources established through the California Energy Action Plan
- Commitment towards reducing greenhouse gas emissions
- Increasing need for highly reliable electric service

Finally, for many distribution applications, a great deal of research has been completed in California, and by out-of-state researchers and utilities. Therefore, a considerable body of knowledge and notable success stories are available to help identify high value applications.

With this background, we develop approaches to assess the value of different distribution automation technologies. For those applications that look promising, our research team and the Program Advisory Committee (PAC) identify research opportunities that can move the applications closer to system-wide deployment. To assess the development stage of different technologies, the project team has used a

simplified research process structure that identifies the stages of DA evaluation from concept to system-wide deployment. In this context, the most helpful research is that which moves high value applications closer to full-scale deployment. Table 3, below, illustrates the conceptual development process.

Table 3: Stages of DA Development - Concept to Deployment

	Development Stage	Value Proposition	Resources Committed	Timeline
1	**Concept and approach**	High level value assessment	Very small	Year 1
2	**Small-scale Test** Designed to confirm technical success	Refined based on findings of technical performance in the field	Small ($500k to $2M)	Year 2 to 3
3	**Field Verification Test** Confirm specific technology specification and performance and procurement costs	Refined performance and proven technology costs allows regulatory level filing, broad stakeholder review	Modest ($1M to $10M)	Year 3 to 5
4	**System-wide Deployment**	Tracked and verified during deployment	Very Large ($10M to Billions)	Year 5 +

1.2 Objectives

This project will assess whether distribution automation offers compelling value for California through the following activities:

1. Survey distribution research efforts that are focusing on utilization of distribution automation and other technologies for improvements in reliability. Research includes innovative ways to more fully utilize distribution technology and infrastructure improvements to capture value for both the customer and utility.
2. Research the business and regulatory case for new distribution planning and automation approaches.
3. Characterize the value that improvements to the existing standard practice of distribution planning and automation practices can provide to California.

1.3 Report Organization

The remainder of this report is organized as follows.

Chapter 2 describes the range of distribution automation technologies, presents results from our survey of existing and planned distribution automation applications, and concludes with the list of distribution automation applications and technologies considered. It also contains a discussion of the relationship of advanced metering infrastructure to DA and a description of recent investments in DA by California investor-owned utilities (IOUs) based on their general rate case (GRC) documents.

Chapter 3 categorizes the DA applications into four categories based on the valuation approach necessary to appropriately consider them, and identifies the main value streams that each application provides.

Chapter 4 documents the valuation approach and presents examples from each category of value. For each category a preliminary assessment of the most promising application is highlighted for discussion. The tools, data, and necessary research required to improve the valuation analysis is identified.

The report concludes with a summary of the selected high value applications, and rationale for their selection. Gaps in available information and methodologies for computing value streams are identified.

2.0 Distribution Automation Applications and Technologies

This chapter characterizes the broad range of distribution automation (DA) applications and technologies, presents a survey of leading researchers on their existing and planned applications, and develops a comprehensive list of DA applications to consider for valuation.

2.1 Background and Definition of Distribution Automation Functions

Advanced information technology, databases, communication and controls are increasingly making a vast array of new distribution applications possible. To the extent they are economic and/or promote other policy goals, California has the ability to build these technologies into its distribution systems. While many of the DA applications apply to a broad range of systems, it is important to recognize that there are a number of different types of distribution systems that have different characteristics. Applications that provide positive value in some part of the system may not be applicable or have positive economics in other parts of the system. The major categories of system types are the following;

Urban networks. These systems supply high density loads that may be a combination of commercial facilities, residential, and light industrial loads. They will typically be underground systems and may already be network configurations.

Suburban systems. These systems are characterized by moderate load density and a variety of load types. They may be a combination of overhead and underground systems with a general trend towards increasing the penetration of underground distribution. They are typically radial primary systems that may have open tie points between feeders.

Rural systems. These systems will typically be overhead, radial circuits that are less likely to have open tie points to other feeder circuits. They may be very long primary distribution systems (e.g. 20 miles and more).

Special systems. Special systems may supply premium power parks, office parks, or other special groups of loads. Special designs (e.g. microgrids) and technologies (e.g. custom power technologies) may be justified for these systems based on the needs of the end users supplied. There may be special contracts associated with the customers on these systems.

2.1.1 Automated Grid: Delivering Energy and Information

Traditional distribution systems were designed to perform one function, to distribute electrical energy to end-users. Increasingly, distribution systems are delivering electrical energy AND information between participants, system operators, and system components. As demand response and other Distributed Energy Resources (DER) penetration of the grid increases, the lines between electricity supplier and consumer blur because many of participants will assume both roles. Similarly, the exchange of information is multi-directional and will facilitate system operation and potentially enable decisions on whether to “supply” or “use” electrical energy based on dynamic rather than static prices.

To exchange electricity and information, the automated grid will contain two interrelated components:

1. A communication architecture to facilitate the system monitoring and control functions of the automated system. Ideally, this will be migrating to open systems that will allow integration of technologies and components from multiple vendors.
2. New electrical architectures and protection systems that enable an interoperable network of components.

These two components are synergistic and inter-related with each other, and together they comprise the automated distribution system, see Figure 3. The communication and information protocols required by

the automated grid comprise a good number of the DA applications identified in this research. These are also the focus of a number of research efforts such as IntelliGrid, Gridwise, and others.

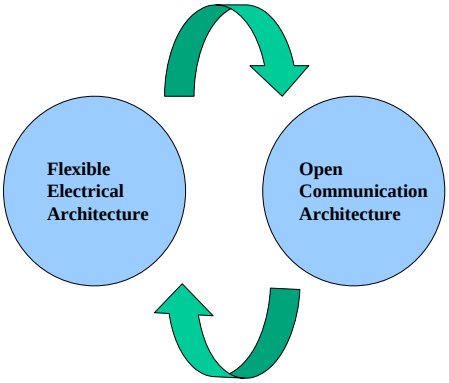


Figure 3: The flexible electrical architecture and open communication are interrelated components of an automated distribution system.

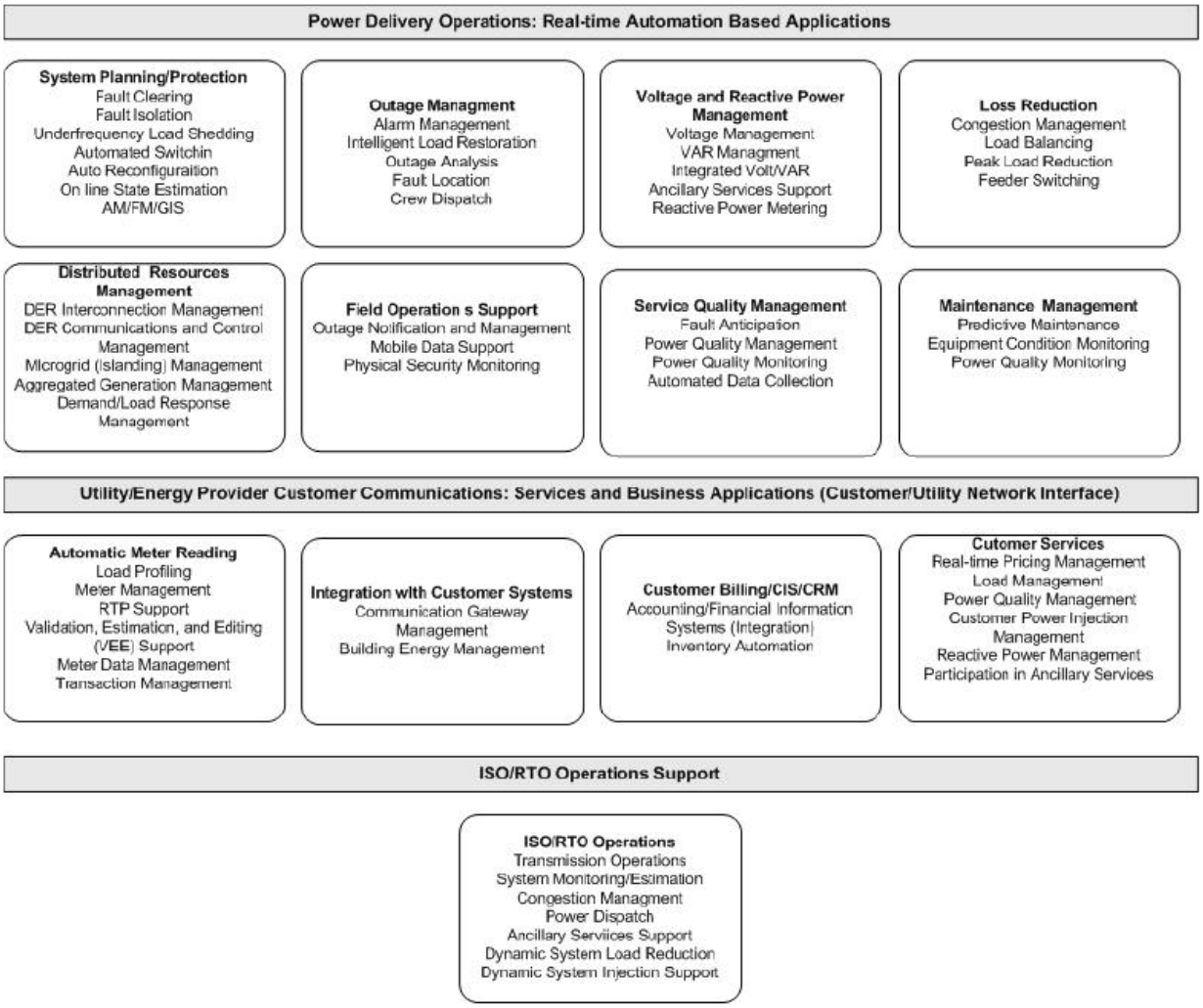
2.1.2 Distribution Automation Functions

Many individual functions that can be included in the overall category of distribution automation are facilitated by the exchange of information. This section describes a few of the important functions briefly to provide a background for the survey and basis for the valuation development. The major functions are categorized by their value in Chapter 4.

Table 4 summarizes automation functions that were identified as part of the Intelligrid Architecture project[1].

[1] For more information about Intelligrid, see http://www.epri.com/IntelliGrid/

Table 4: Summary of automation functions defined as part of the Intelligrid Architecture use cases



2.1.3 Distribution Automation Technology Categories

A number of different technologies that fall within Distribution Automation are available or are being developed to achieve these functions. The major categories for each technology are briefly described.

2.1.3.1 Substation SCADA

Substation SCADA systems are usually considered part of substation automation rather than distribution automation. Monitoring and control of breakers and equipment in distribution substations is widespread. Probably 80% of substations in the US have some level of remote monitoring and control. However, significant opportunities exist to improve the substation applications and to integrate these applications with technologies applied on the actual distribution circuits.

An example of an important new benefit of substation monitoring systems is automated fault location. Detailed monitoring information from substation monitors can be used in conjunction with an understanding of the electrical topology to identify possible fault locations on the distribution system.

This type of capability can be used in conjunction with outage management systems (OMS) to significantly improve fault response times and repair times.

2.1.3.2 Distribution SCADA (monitoring and controlling the switches on the distribution circuits)

This is an area of significant investment in the industry as the concept of substation automation migrates to the distribution circuits. Substantial benefits in terms of reliability improvements can result from having remote control of switches on the distribution circuits, especially if the switches can operate automatically to reconfigure circuits and limit the extent of outages.

2.1.3.3 Automated Volt/Var Control Systems and Power Quality Management

These systems involve monitoring and control of capacitor banks and/or voltage regulators on distribution circuits to provide improved voltage control and to minimize losses on distribution circuits. It is often possible to justify investment in these systems based on the loss reduction benefits alone. In the future, integration with more extensive monitoring, two-way communications, and application of power electronics technologies for better reactive power control will all provide opportunities for improved volt/var control systems.

Future extensions of volt/var control systems will look at a broader range of power quality characteristics on the distribution system. These characteristics could include harmonic distortion, unbalance, and voltage fluctuations (flicker, sag performance, and stray voltage conditions).

2.1.3.4 Outage Management Systems (OMS)

Outage management systems are software systems that integrate geographical information systems, electrical topology, and customer information systems to predict portions of distribution circuits that are interrupted (usually based on customer calls) and manage the response to these interruptions. They can include coordination of work crews and management of all reliability data for reliability reporting. Outage management systems are not technically part of distribution automation, but it is critical that automated systems for distribution be coordinated closely with outage management systems.

2.1.3.5 Advanced Metering Systems (AMI)

Advanced Metering Infrastructures (AMI) are the next generation of metering systems to facilitate a wide range of technologies for both the customer and the overall power system operation. Most utilities have some type of automated meter reading (AMR) systems, at least for portions of their customer base. However, AMI involves a much higher level of automation and two way communication to enable advanced applications, like automated demand response, load control systems, customer information systems, and information systems to support distribution automation. This last function can become an integral part of distribution information systems to support automation in the future. This chapter discusses AMI applications and current AMI activities by the three California IOUs in more detail in Section 2.2.

2.1.3.6 Advanced Monitoring Systems and Intelligent Applications

Many utilities have power quality monitoring systems, monitoring systems for distribution SCADA, and other types of monitoring equipment. The application of intelligent electronic devices (IEDs) such as intelligent relays, reclosers, capacitor controllers, smart switches, etc. is becoming increasingly widespread. The availability of this vast amount of monitoring information creates opportunities for new intelligent applications that can be integrated with automation systems. Applications include automated fault location and equipment diagnostics.

2.1.3.7 Distribution System Real Time State Estimation and Control

Future distribution control systems will incorporate systems that can process data from monitoring throughout the distribution system to continuously assess the state of the system, identify opportunities for improved efficiency, and implement configurations to minimize the risk of outages. These systems will integrate advanced metering systems with more traditional monitoring systems and real time models of the distribution system. While this type of technology is used throughout transmission systems, it is not yet applied for distribution.

2.1.3.8 Integration of Distributed Resources

Automated distribution systems will permit more effective integration of distributed resources and higher levels of penetration on distribution systems than is current feasible. These integrated systems will take advantage of the real time system control and two way communication capabilities to improve system reliability and provide new options for improved efficiency and system operation.

2.1.3.9 Asset Management Applications

Automated distribution systems will have the capability to track the performance of distribution assets (cables, transformers, breakers, reclosers, sectionalizers, capacitors, regulators, arresters, etc) in a much more detailed manner than they are now tracked. Loading information, operation history, and disturbance characteristics can all provide information about the condition of assets. This condition information can be used to make more intelligent decisions about maintenance programs and asset replacement strategies.

2.1.4 New Distribution System Technologies

New technologies are becoming available that will shape the distribution system of the future. These technologies will become integral parts of automated distribution systems. It is important to consider the technologies when planning future systems and ways to integrate these technologies with existing systems.

2.1.4.1 Electrical and Electronic Technologies

- Distributed energy resources (distributed generation and storage)
- New sensor technologies that will allow collection of electrical and performance information from devices and components throughout the system
- Monitoring and analysis technologies for identifying system and equipment problems before actual failures (e.g. distribution fault anticipator, capacitor problem identification, regulator problem identification, etc.)
- Power quality enhancement technologies for the distribution system (e.g. DVR, Statcom)
- Solid state breakers and switches for fast fault clearing, system reconfiguration, and transient-free switching (e.g. capacitors)
- Load management technologies (end user systems that must be coordinated with ADA)
- Power quality enhancement technologies for end user facilities that should be coordinated with ADA
- Advanced metering capabilities that will allow intelligent applications to be coordinated with detailed characteristics of end user systems
- Advanced electrical system configurations, such as intentional islanding (including microgrids), dc ring buses, looped secondary systems, and advanced distribution networks

- Automatic switching systems to reconfigure the system for disturbances (e.g. faults), load conditions, DER conditions, quality and reliability requirements, etc.
- Intelligent universal transformer (a multi-functional, solid-state replacement for distribution transformers)

2.1.4.2 Communications Characteristics and Technologies

The link between customers, smart devices on the grid, and system operators lies in the communication infrastructure. As the complexity of these communications grows and the time-frame decreases, the demands on the communications infrastructure to provide faster exchange of data (high bandwidth) increases. Also, as more critical functions are automated, heightened security of information becomes more and more important. Finally, to promote inter-operability of many different devices manufactured by many different vendors, common protocols and open architecture will be desired.

Communication technology projects include:

- Open, standardized communication architecture
- Advanced, secure communication media (including wireless, PLC, satellite, etc.)
- Open information exchange model for work process management
- Consumer Portal and Advanced Metering systems
- Sensing and monitoring devices implementing features of new communications architecture and with integrated intelligent applications that become an integral part of overall system control schemes
- Real time state estimation and predictive systems (including fault simulation modeling) to continuously assess the overall state of the distribution system and predict future conditions, providing the basis for system optimization
- Advanced control systems to optimize performance of the entire distribution system for efficiency, asset management, reliability, quality, and security
- Load management and real time pricing systems that integrate with end user and DER systems to optimize overall system performance and efficiency
- Asset management and work management systems that integrate with intelligent monitoring systems, customer information systems, and forecasting tools to optimize investments and maintenance based on the specific requirements of individual systems

General requirements for the communications architecture are described below.

2.1.4.2.1 Scalability

Scalability refers to the ability of the technology to be scaled up if the number of applications or sites grows. Often scalability issues are addressed by creating a distributed system – that is a system where computing resources are physically separated.

2.1.4.2.2 Reliability

Reliability refers to the ability of a system to operate continuously over an extended period of time. To achieve this, the system must be constructed using robust technology and able to deal with failure gracefully. Any part of a distributed system can fail. Any ADA communications architecture must

incorporate the ability to provide backup components and seamless failover. In as much as failure cannot be completely compensated for, its effect must be kept local and not allowed to affect the reliability of the system as a whole.

2.1.4.2.3 Federation

Federation refers to the ability to monitor and control assets autonomously owned and managed. This is a particularly important consideration when addressing the issue of interfacing with a wide variety of end user communication and control systems.

2.1.4.2.4 Interoperability

Interoperability is the ability of the technology to interconnect different systems, technologies, and vendor implementations. Interoperability is, of course, the goal of communications standards in general. However, the sheer scope and variety of those in use across the entire industry will place particular challenges on the technologies chosen for the final architecture.

2.1.4.2.5 Adaptability

Adaptability is the ability of the technology to support change and accommodate new information and business requirements. Currently, power utility communications systems are actually quite adaptable, but the means of adaptation is almost always a manual, labor-intensive (and capital-intensive) process. The technologies that will be successful in the new architecture will be those that can adapt quickly and automatically, with as little human intervention as possible.

2.1.4.2.6 Securability

Securability is the ability of the technology to support secure communication, safe from attack from within or outside a utility. Some of the major forces affecting the development of utility communications technologies have been integration: integration of SCADA and protection departments, integration of automation departments into corporate IT domains, integration of entire utilities into a deregulated market, sharing automation information. ADA systems will also require integration with customer operations. With each level of integration comes another level of danger from attack. Successful utility communications technologies must therefore be secure.

2.2 AMI Applications and Status

As described section 2.1.3.5, Advanced Metering Infrastructures (AMI) are the next generation of metering systems to facilitate a wide range of technologies for both the customer and the overall power system operation. AMI is also complementary to other DA technologies, in that AMI serves an important role in enabling utilities to get the maximum possible from many types of other automation applications. Due to the role AMI plays both as a technology and as a system context for the application of other technologies, it is useful to understand the status of AMI implementation in service areas considering further DA investments.

2.2.1 AMI Investments in California

This section briefly summarizes the business cases put forth by the three California IOU's regarding the deployment of AMI. The CPUC initiated R. 02-06-001 in June 2002 to establish policies and practices for advanced metering, demand response and dynamic pricing. As part of that proceeding, ALJ Cooke directed California's three IOUs to file applications by March 2005 seeking approval for each utility's advanced metering infrastructure deployment strategy, including detailed analyses regarding the timing, costs and benefits of AMI investments. The analyses filed in March 2005 by the three IOUs have, in some cases, been updated as the utilities proceed with their respective proposals.

SCE argues that currently available AMI technology is neither sufficiently integrated nor developed to be cost effective. SCE instead proposes to engage in a "deliberate, yet fast-paced effort" to design and develop a new advanced integrated meter (AIM) with improved integration and functionality at the same or lower cost as existing solutions. In December 2005 the CPUC approved a settlement agreement establishing $12 in funding for Phase I of SCE's AIM development effort, which focuses on defining the requirements of an AIM system and meter and performing due diligence to determine whether such a product is available in the market (D. 05-12-011, A 05-03-026).

PG&E and SDG&E argue that AMI may be cost effectively deployed using existing technology with net benefits to ratepayers and the state. PG&E and SDG&E propose to deploy AMI throughout their service territories over five years at a present value revenue requirement of $2.2 billion and $719 million respectively.

PG&E received final approval to proceed with AMI deployment in July 2006 (D. 06-07-027, A. 05-06-028). Rebuttal testimony was filed in September 2006 in SDG&E's proceeding, a final decision has not yet been scheduled (A. 05-03-015). Although SCE did not propose to implement AMI, the utility was nevertheless required to analyze the cost and benefits of AMI under several scenarios along with PG&E and SDG&E. The estimated costs and benefits proposed by each utility are shown in Table 5

Table 5: Proposed AMI Deployment Cost and Benefits for the Three California IOUs

Utility	Meters	Total Cost	Total Benefit	NPV
PG&E[2]	9.2 million	$2,258	$2,472[3]	$214
SDG&E[4]	2.3 million	$719	$783	$64
SCE[4]	4.5 million	$1,298	$808	($481)

PG&E proposes that operational benefits ($2 billion or 91% of the total cost) will offset the bulk of the deployment costs. PG&E evaluates a number of voluntary or "Opt-In" demand response program scenarios and found that the expected benefits under most cases offset the remaining costs. PG&E's base case for Demand Response estimated a benefit $448 million (20% of total costs) in its decision authorizing PG&E to deploy AMI. Together, the benefits total $2.4 billion for a NPV of $214 million.

SDG&E also finds that operational cost savings provide most of AMI's quantifiable benefits ($548 million/76% of total costs). SDG&E, however, finds that avoided energy and capacity costs associated with demand response ($235 million/33% of total costs) will provide a greater percentage of the total benefits as compared to PG&E.

SCE estimates operational benefits of $438 million (34% of total costs) and demand response benefits of $370 million (29% of total costs). SCE's analysis finds that the total benefits of $808 million do not outweigh the costs of AMI deployment, resulting in an NPV of negative $481 million.

2.2.2 AMI Benefits

The benefits of AMI deployment articulated by the three utilities are summarized below. The benefits calculated by the utilities are shown in section 4.1.5.

[2] Present Value Revenue Requirement
[3] Operational Benefits of $2,024 plus $448 in Demand Response from Scenario 1(e) (D. 06-07-027) ($million)
[4] Present Value Total Costs

2.2.2.1 Meter Reading

Meter Reading – Costs associated with the retrieval, collection and collation of the meter billing reads will be either eliminated or drastically reduced. AMI meters are expected to be more accurate and require less testing and maintenance than existing meters. Both PG&E and SDG&E gained union support for their AMI proposals in part by emphasizing that attrition, redeployment and retraining will minimize or prevent layoffs as meter reading jobs are phased out.

Employee Safety – Meter readers and other customer field personnel have the highest accident rate of any classification in the utility due to their driving and walking exposure. The reduction of the reader workforce reduces corporate exposure to workers compensation claims, employee medical and legal costs, and customer property claims resulting from employee accidents.

Meter Standardization and Reprogramming Costs – Advanced meter data could be obtained directly from the advanced metering system and could eliminate the need for complex Time-of-Use ("TOU") , demand and lo..ad research meters and the high level of meter maintenance now required for such meters. Utilities will also avoid the periodic replacement of electronic meter reading devices and associated software that is currently required. With standardization, the capital and inventory costs associated with maintaining and replacing a variety of conventional, TOU and load research meters can be eliminated.

2.2.2.2 Billing

Billing Adjustments – Billing adjustments are usually a result of a customer requested re-read, inaccessible meter, or inaccurate meter read. With AMI, billing will be more accurate and timely, requiring fewer estimated bills and bill adjustments. Billing adjustments are costly, involving a back office investigation, manual update of the CIS system and the re-issuance of bills. The process also often results in poor customer relations.

Revenue Protection – The system provides tampering information on a real-time basis to indicate that someone is tampering with the meter or turning it upside-down. This will both discourage and allow for earlier detection of energy theft, reducing associated revenue losses.

Immediate Identification of Stopped/Dead Meters – Currently, the discovery of stopped or dead meters occur during the monthly meter read activity. With this initiative, the daily collection of data allows them to be quickly discovered and corrected, resulting in better customer service. The revenue that would have otherwise gone unregistered for some extended period of time can then be properly measured and billed. No estimate and resulting negotiation with the customer need occur.

Improved Cash Flow – Summary bills provided for multi-premise accounts are not issued until after the read date of the last meter read, causing a lag in billing for many of the premises. AMI will allow all meters linked to summary billed accounts to be read on the same date. Similarly, with fewer "exceptions" (delayed bills, estimated bills, inaccessible or inaccurate meter reads, manual input error), delays in revenue collection associated with exceptions processing, estimated bills and bill adjustments will be reduced.

2.2.2.3 Transmission and Distribution Benefits

Customer Load Research – Load research activities are used for transmission and distribution planning, rate design, utility commission rate case requirements, and internal data gathering. These activities traditionally have required expensive solid-state data recorders that must be connected via phone lines or manually retrieved. The system would facilitate the gathering of load research data without the need for specialized meters and software.

More Efficient Asset Utilization and Investment – Distribution system modeling and load forecasting are expected to become more accurate and geographically precise with AMI. Readily available real-time load data for specific customers, customer classes, and feeder lines will also allow for specifically targeted capital improvements, education campaigns and demand response programs. With daily as opposed to monthly data on gas use vs. temperature, critical peak use can be forecasted more accurately, increasing the precision in engineering the gas transmission and distribution system to meet peak demand.

More Efficient Outage Restoration – With the availability of immediate and location specific load data, the utilities anticipate more a more timely and efficient response to outages and a reduction in the duration of outages. Crews can be more efficiently dispatched and verification of restoration can be made while crews are still in the field.

2.2.2.4 Field and Customer Services

Move In/Move Out – With AMI, meters can easily be read on the actual date that service at an account starts or stops. Currently the process involves either estimated bills between meter reads or a special trip by a meter reader.

Service Connect/Disconnect – An available disconnect collar installed at the meter can be used to perform service disconnect without requiring a field visit for those cases where frequent activity occurs. This service saves the time and expense of installing and removing boots from the meter, minimizes the revenue lost due to the time lag between the decision to disconnect a customer and the activity being undertaken, and ensures the most rapid customer service reconnection.

Avoided Dispatch to "No Power" Calls – AMI will eliminate the dispatching of crews to no power calls when the problem is on the customer-side of the meter. Instead AMI meters can indicate whether there is power on the PG&E side of the meter.

Call Center Savings – Utilities receive calls concerning high energy costs, delayed bills, estimated bills and meter reading complaints. With AMI, the calls associated with these complaints could be greatly reduced. In addition, those calls that come in can usually be resolved with the first call due to the quantity and quality of the data that will be available to the CSR 's. Multiple customer calls due to outage events would also be reduced. Since these types of calls are part of the base workload of the call centers, their reduction results in reduced personnel requirements, improved call-handling metrics due to faster call processing, and better customer service levels.

Improved Pricing and Tariff Flexibility – The system provides the ability to quickly implement new rate structures to respond to utility commission directives and/or market conditions. Consumption only customers can be changed to demand, time-of-use or critical peak pricing schemes in short periods of time as opposed to the current scenario, which requires meter procurement and exchanges.

Customer Energy Use Information – An AMI system facilitates the collection and storage of customer use information that can then be posted to an internet server for customer viewing and examination. Traditional meter reading paradigms resulted in only a single monthly consumption value, which did not support web data presentation, but fixed network systems can provide daily consumption, demand or finer resolution information. This information can be posted on the day following the usage thus allowing customers to view consumption patterns in a timely fashion. This information format can be used to communicate rate offerings or other utility programs.

2.2.2.5 Advanced Tariffs

All three utilities propose that AMI will support the implementation of the loading order articulated in California's Energy Action Plan (EAP). The loading order identifies energy efficiency and demand response as California's preferred means of meeting growing energy needs. The utilities propose that AMI is an "enabling technology", supporting more aggressive and targeted implementation of energy efficiency, demand response and dynamic pricing programs. The technology will further provide state policy and decision makers with the flexibility to adopt a variety programs tailored to as yet unknown future circumstances. PG&E argues that only with AMI will the utility be able to enroll residential customers in demand response and dynamic pricing programs at the levels necessary to meet the goals set out by the EAP and CPUC.

The utilities also argue that dynamic pricing will provide societal benefits through more efficient pricing. By providing rates more closely aligned with marginal energy costs, dynamic pricing will reduce over-consumption of electricity during periods when typical retail rates are below marginal supply costs.

2.2.2.6 Demand Response

Reduced energy and capacity costs through demand response and dynamic pricing is the second largest category of benefits quantified by the utilities. The utilities evaluated a range of potential scenarios in developing their savings estimates. The utilities list the following benefits associated with reduced energy and capacity requirements:

- Reduced short-term energy purchases
- Reduced long-term capacity costs
- Lower market clearing energy prices
- Incremental reliability benefits
- Reduced transmission and distribution capacity expenditures

2.3 Survey Results

Given the range of distribution automation functions and technology categories, the project team developed a survey to understand which applications and technologies are actively being studied and tested in California and elsewhere in the country. One of the project objectives was to characterize existing research efforts and specific utility plans and valuation methodologies for distribution automation projects.

The survey was designed to include the following components:

1. Distribution automation activities and plans for California utilities
2. Distribution automation activities and plans of other leading electric utilities (including international perspective)
3. Manufacturer perspective for distribution automation research needs and valuation methodologies.
4. Important research initiatives in DA (including IEEE activities and other research organizations)

The questionnaire developed to facilitate the survey is provided in Appendix A. The detailed survey results are included in Appendix B. There have been 20 participants in the survey so far, each is listed in Table 6, below

Table 6: Survey participants

Utilities	Manufacturers, Integrators, Consultants
Southern California Edison	S&C Electric
Pacific Gas & Electric	Schweitzer Engineering Labs
San Diego Gas & Electric	Natis Communications
LADWP	Cannon Technologies
TXU Electric Delivery	ABB
American Electric Power	Enernex
Southern Company	
Consolidated Edison	
Progress Energy	
We Energies (DV2010)	
MidAmerican Energy	
Hydro-Québec	
EDF	
UK Research Initiaitves	

The following section summarizes important results of the survey and the implications for ongoing distribution automation research needs and values.

2.3.1 Summary of Utility Distribution Automation Activities and Plans

2.3.1.1 Existing Distribution Automation Technologies and Implementation

The table below summarizes important distribution automation activities that define the current state-of-the-art for existing automation implementations.

- Most utilities have SCADA systems that provide information and control down to the substation level (60-80% penetration of substation automation).
- The next generation of systems is expanding to automation and reconfiguration of distribution circuits for reliability improvement. Many utilities have at least trials or demonstrations of this technology.
- Automation of capacitors and coordination with regulators for voltage control and var support is also relatively common with a variety of different approaches, mostly radio-based.
- Power quality monitoring systems with advanced applications are starting to be integrated with distribution operations (e.g. fault location) – Con Edison, SDG&E, Progress Energy.

Table 7: Summary of existing DA implementation from the survey results

Utility	Existing Applications
Southern California Edison	- 2400 distribution switches automated on 1330 of the 4000 distribution circuits - 960 automated remote automatic reclosers - 7500 capacitor banks automated of the total 9000 switched banks - Misc. automation of devices such as Remote Fault Indicators, Voltage Regulators, Fault Interrupters and Auto Transfer Switches - About 200,000 A/C cycling switches - Large customer load interruption program (I-6 rate)
Pacific Gas & Electric	- Substation SCADA throughout system - Extensive capacitor control system - Extensive application of reclosers for automated system reconfiguration following a fault. PG&E is in the process of configuring these reclosers for remote monitoring and control.
San Diego Gas & Electric	- Substation SCADA to all substations - Limited automation beyond the substation - Increasing percentage of system is underground (58% - 9,000 circuit miles) - Extensive power quality monitoring system that characterizes power quality performance at many of the substations
LADWP	- Widespread Substation Automation
TXU Electric Delivery	- Substation automation throughout system - Initial demos of controlled switches for reconfiguration - Automation of capacitors for voltage and var control
AEP	- Substation automation (goal of 100% coverage within 5 years) - 3-4 small pilots of automated circuit reconfiguration
Southern Company	- Extensive distribution SCADA (switches, reclosers, capacitors, monitoring points, fault detectors)
Con Edison	- Extensive underground network system that is inherently automated and allows 2 feeders to be out of service without customers losing power. - 100% substation automation and control. - Transformer monitoring system that tracks loading and conditions of all network transformers with a power line carrier-based system. - Power quality monitoring system on network and at substations with fault location capability being implemented.

Progress Energy (Carolina)	- One of the first utilities to implement distribution automation on a significant scale. - Automated monitoring and control of all distribution feeder breakers on the entire system (approximately 1000 feeder circuits) - $14M investment in 1990s. - RTUs that have much more capability than traditional RTUs – track a variety of power quality characteristics and can record voltage and current waveforms for any disturbance at the substation. - Automated fault location based on capabilities of RTUs. - Other functions that take advantage of the detailed monitoring information - problem identification, equipment problems, fault characteristics, conductor problems, etc. - Automated capacitor control throughout the system (radio)
MidAmerican Energy Company	- Extensive substation automation system based on detailed economic assessment of benefits
We Energies (and DV2010)	- Founder of the Distribution Vision 2010 (DV 2010) consortium looking at advanced distribution automation technologies with the goal of improving reliability and quality of distribution systems. - First utility to demonstrate DV2010 concepts and have continued to provide leadership for the consortium. - PeerCommTM Communications System (Cooper Industries) – allows continuous communication between reclosers for fast isolation of faults - Enhancements to the Cooper Form 6 Recloser Control with enhanced overcurrent protection functions - Reverse Vacuum Fault Interruptor (RVFI) – supplies a reduced cost high speed transfer capability. - DA Master from NovaTech – distribution system automatic reconfiguration controller.
Hydro-Québec	- Substation SCADA - Detailed roadmap for automation of distribution circuits for reliability improvement and other benefits
EDF	- Controlled switches (90,000 or 3.5 per feeder) - sectionalizers, reclosers (a few) - control of capacitors and regulators at substations for voltage control

2.3.1.2 Planned Distribution Automation Technologies and Development Projects

Table 8 summarizes important distribution automation activities that are planned or are the basis of research projects from the utilities surveyed.

- Automation of circuit reconfiguration has the most significant direct impact on reliability and is the focus of many demonstration projects, trials, and automation expansion plans.
- Finding and repairing faults faster is a critical need. Fault indicators with communications and continued advanced monitoring system enhancements are planned to provide this functionality (Hydro-Québec, Progress Energy, Con Edison, SDG&E, TXU, Southern Company)
- Fast communication systems to enable many distribution automation and control functions are being evaluated and implemented by many utilities (TXU, SCE, DV2010, Hydro-Québec).

- Integration of advanced metering with automation systems. This makes integration of customer load control and load response possible (TXU, SCE).
- New topologies and advanced protection schemes and designs for more automated operation and increased reliability (EDF, UK, Con Edison, SCE, DV2010, Hydro-Québec).
- Automation to facilitate integration of DG is a priority (SCE, EDF, UK, Hydro-Québec).
- Improving cable performance, fault identification, decision making related to replacement strategies is critical (PG&E, Con Edison)
- Asset management integrated with automation will provide benefits in terms of improved equipment performance and maintenance (AEP, Con Edison, SDG&E, Hydro-Québec).

Table 8: Summary of planned distribution automation implementations and research initiatives from the survey results

Utility	Planned Applications	Research Projects
Southern California Edison	1. Continue with installation of 250 distribution switches annually on worst performing circuits 2. All new devices (reclosers, capacitor controls) come automated from vendors 3. Automating Network Protectors in Long Beach network area 4. Expanding use of Automated Fault Interrupters 5. Installing Smart Fault Indicators 6. Planning implementation of Advanced Metering Infrastructure that will provide meter reading and load management for all customers with loads less than 200 kW	1. Advanced Protection schemes (DOE Advanced Protection project). 2. Integration with Substation automation and Energy Management System 3. Automatic Power Restoration 4. Distribution circuit fault current limiter test and demonstration 5. Customer A/C stalling testing, modeling, and solutions (proposed funding from CEC's transmission program) 6. Aggregation of multiple distributed generation units over the Internet for central control and future bidding of DG into market (Connected Energy/ DOE project) 7. Control of A/C cycling switches (demand response) as a group for spinning reserve capability (LBNL/CEC project)
Pacific Gas & Electric	1. Conducting a study to evaluate future philosophy for distribution automation enhancements and investments (Distribution Automation Roadmap) 2. Advanced Metering investment is justified largely based on operational benefits that will be realized (These include improved outage response, targeted T&D investements, and enabling demand response and dynamic pricing)	1. Distribution Area Automation Pilot projects that integrate automatic load restoration and dynamic circuit monitoring and switching to prevent overloads and optimize voltage 3. Participating in multiple research initiatives related to understanding cable fault issues, reducing the number of cable faults, and developing strategies for cable management

San Diego Gas & Electric	1. Implementing a trial automated fault location capability using Substation monitoring information integrated with distribution electrical models 2. Increasing Substation monitoring capability with IEDs and application of SATEC meters on feeder circuits that have waveform recording capability- this will provide additional information for automated fault location 3. SDG&E is designing their advanced metering system to implement demand response and distribution operations benefits are being considered	1. Implementation of SAIDET index for more customer-focused characterization of system performance 2. Improved asset management replacement strategies using analysis of historical performance on circuit by circuit basis with Root cause analysis 3. Fault location demonstration project that builds on existing power quality monitoring system
LADWP	Looking at technologies and methods for improved asset management and system operating procedures.	
TXU Electric Delivery	1. Extensive rollout of BPL system with supporting fiber optic and network system that will support to communication to Distribution devices and meters. 2. Distribution fault anticipator demonstration project - two next generation units to be installed at substations	1. Next generation DFA 2. Advanced metering information integration

AEP	1. 3-6 additional small pilots of automated circuit reconfiguration 2. One larger pilot with approximately 40 smart switches 3. Pilot of automated capacitor controls 4. Advanced monitoring of assets for condition assessment, improving reliability, etc. Several projects planned or under way.	1. Enhanced distribution system monitoring project - mesh network radios for system and asset monitoring, control. 2. EHV transformer health monitoring (similar concepts could be applied for assets at distribution substations and systems). 3. Microgrid integration study (AEP is demonstration site) with CERTS and CEC 4. Energy storage for asset deferral, islanding for reliability, PQ and load leveling 5. Superconductivity medium voltage cable installation 6. Fast fault detection and automatic disturbance detection 7. Phasor technology - development of planning tools 8. Participating in DOE/EPRI Solutions Advanced Monitoring project for advanced applications of monitoring data – interested in fault location applications
Southern Company	DFA Demonstration - integration with DA	1. DFA Demonstration - next generation technology integrated with DA 2. Advanced sensor applications (optical sensors) 3. Integration of information systems with common user interface (DOE Project with Areva)

Con Edison	1. Development of plan for third generation (G3) network design - sent engineers around the world to benchmark distribution network designs and pick best approaches for G3 design. 2. Characteristics of the G3 design will include the ability for flexible configuration of the network to achieve the highest possible levels of reliability, information integration for convenient development of new advanced applications, and new communications infrastructures to facilitate real time monitoring and state estimation. 3. Worked with EDF to develop the specifications for the Intelligrid Distribution Fast Simulation and Modeling system that can be the basis for distribution real time monitoring and control in the future.	1. One of the most important issues facing Con Edison (maybe the most important issue for distribution systems) is the management of aging cables (91,000 miles of underground cable) and deciding when to replace cables. Con Edison has been working on a system based on machine learning that predicts the most likely cable sections to fail based on a large database of characteristics associated with each cable section (historical performance, type, manufacturer, splices, disturbances, etc.). 2. G3 Network design and demonstration. Features of the next generation systems will include new distribution topologies, super-fast simulations, advanced visualization tools, enhanced communication and information systems, adaptive sense and respond systems, new protection and control paradigms, advanced technologies such as power electronics. 3. Working with Infotility to apply some of the GridAgent technology that has been developed for DOE to the G3 system design (DOE project).
Progress Energy (Carolina)	1. Continued advancement of fault location system with implementation of additional capabilities and deployment in Florida. 2. Further integration of systems with OMS, GIS, etc.	Participating in DOE Advanced Monitoring Project
We Energies (and DV2010)		DV 2010 has a goal of developing a new primary network design tied to multiple source buses and using directional overcurrent protection, distribution automation, high speed communications, and automated real-time system analysis to reduce annual outage times experienced by customers by a factor of 10. Technical development for the DV 2010 technologies continues. Important areas of development include fast communication technologies, wide area control technologies, and demonstration of concepts.

Hydro-Québec	10 year roadmap for extensive distribution automation investment	1. Automated reconfiguration through automation of switches, breakers, reclosers throughout the distribution system 2. Volt/var control 3. Fault Location 4. Integration with monitoring systems 5. Information systems integration
EDF	1. Automation at the control centre (first deployment in 2007) 1a. Automation analysis of alarms coming from subs 1b. Automatic collection of fault indicator data 1c. Automation execution of restoration strategy (directed by operator) 1d. Automatic restoration of healthy feeder sections (2008) 2. Monitoring of wind energy production 3. Volt/var control with dispersed generation - coordinated voltage control on distribution system with DER spread around system (substation caps, tap changers, and reactive power from DER) - 2009	1. Automation at the control center 2. Preparation and monitoring at renewable energy sources 3. AURA research project in UK for automated network operation 4. Various EU initiatives in microgrids and smart distribution systems
UK Distribution Companies		1. Supergen Project - Distribution automation to support distributed generation integration. 2. AURA Project (Active Network Management) 3. Incentives to innovations in the distribution system - • Distributed Generation Incentive: 1.5£/kW/yr for all additional DG connected • Registered Power Zones (RPZ): additional 3£/kW/yr for innovative solutions to DG connection • Innovation Funding Incentive (IFI): 0.5% of revenue for technological development and demonstration • Active Network Management is a key area of distribution company plans for innovation expenditure

2.3.2 Summary of Individual Utility Systems and Plans

This section provides a short description of the important activities at each of the utilities in the survey.

2.3.2.1 Southern California Edison

Southern California Edison has invested heavily in automation already and continues to look at new ways to get value from automation investments. They have a significant initiative to evaluate new distribution technologies as part of the SCE "Circuit of the Future". This project involves a prototype distribution system that is currently under construction and can be a test bed for new automation and communication technologies. This test bed is also being used for two projects that are being funded by DOE - new protection technologies for distribution automation and aggregation of distributed generators.

Southern California Edison is also in the process of developing requirements for an extensive advanced metering system that will likely involve a completely new infrastructure and replacement of all meters with intelligent meters. This infrastructure could have very important benefits for the distribution system as well, and those benefits are being evaluated as part of the AMI requirements development process.

SCE has also been involved in updating its distribution network in a number of ways described in its General Rate Case proceedings (GRC). SCE plans for further modifications that include implementation of technologies promoting distribution automation.

In the opening statement of its 2006 GRC, "SCE requested funding for six specific RD&D program areas".[5] The ORA allowed only $1.6 million of the total $4.2 million in RD&D funds requested by SCE. The program areas for which SCE's request was made are:[6]

1. Improving Existing T&D Asset Utilization
2. Advanced T&D Technology
3. Advanced Communication systems
4. Distributed Generation;
5. Environmental and T&D Impacts
6. End-Use Technologies and Load Impacts.

In addition to spending on RD&D related to distribution, SCE included plans for capital spending from 2004 to 2008 on DA equipment in three major categories:[7]

1. Circuit Automation, ($30 million total, approximately $6 million per year)
2. Capacitor Automation ($6 million total, approximately $1.2 million per year)
3. Distribution System Efficiency Enhancement Project, ($30 million total, approximately $6 million per year)

SCE believes that these investments to automate distribution circuits will "…improve overall system performance, helping [SCE] to maintain a high level of reliability."[8] In SCE's 2006 GRC, the CPUC allowed "$12.1 million, approximately 90% of the requested funding in distribution automation of $13.4 million."[9]

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[5] p. 64 opening briefs, volume 1
[6] p. 80 from 56444 final decision body DA RD&D.pdf/ Summary of SCE Distribution Automation Document Review
[7] Volume 3: Part 3 – Capital Expenditures by Allen Thiel, SCE; Overview & chart p. 63
[8] Ibid, p. 63
[9] D.04-12-014, pp. 249-251

Circuit Automation

SCE states that the "… purpose of [its] circuit automation program is to restore power to customers more quickly, thereby, reducing customer minutes of interruption (CMI) on those automated circuits while maintaining overall system reliability."[10] Circuit automation technology has allowed SCE switching centers to control and monitor circuits remotely, helping to "quickly isolate trouble and remotely restore power to the system."[11] If power cannot be restored remotely, the automation devices also help locate outages and better direct dispatch crews to deal with problems.

Since 1999, the use of circuit automation successfully helped to lower the time to restore power to customers on automated circuits by 42 minutes on average and to reduce the total customer minutes of interruption by 20,800 per interruption.[12] By selecting to implement automation on the "worst performing circuits", SCE has attempted to maximize the benefit of each circuit upgrade to its distribution system. Roll out of circuit automation targets "worst performing" circuits first.[13]

Remote Control Switches (RCS) are often arranged on a circuit in a manner that allows the system "to automatically sectionalize and restore portions of the circuit."[14] As illustrated in the diagram below, a mid-point RCS is placed on each circuit at a point where 40-60 percent of the load or customers are on either side of the mid-point RCS, and a tie point RCS is placed where one circuit connects to another, allowing feeding of customers from a different source.

Figure II-24
Typical RCS Arrangement

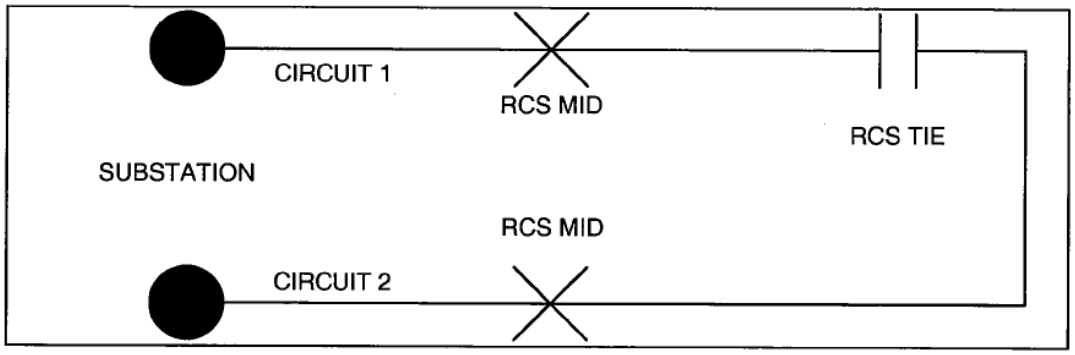

Figure 4: Illustration of Typical RCS Arrangement

This configuration improves reliability because "the mid-point switch will automatically open when power is lost due to a fault on a circuit. If the fault on the circuit is beyond the mid-point switch, power to about one-half the customers is automatically restored in less than a minute. If the fault is located before the mid-point switch, a switching center operator can remotely close the tie-point switch, restoring power to about one-half of the customers within a few minutes rather than the 40 to 50 minutes now required for a crew to be dispatched."[15]

[10] Volume 3: Part 3 – Capital Expenditures by Allen Thiel, SCE; p. 63
[11] Ibid, p. 63.
[12] Ibid, p. 64.
[13] Ibid, p. 64.
[14] Ibid, p. 68.
[15] Ibid, p. 69.

Capacitor Automation

Capacitor banks are used on a distribution system to "provide voltage and VAR support", which prevents low or high voltages at a customer's meter, and they are typically switched open or closed based on voltage, time, of day, day of week, and season.[16] More advanced, "radio controlled programmable capacitor controls (PCC) are installed on capacitor banks to provide remote control" override functions and to allow remote monitoring and inspection of the capacitor banks. While approximately 5,900 of SCE's 9,000 switched-capacitor banks currently have PCCs installed, by 2008, SCE plans to have automated "all existing switched capacitor banks."[17]

Distribution System Efficiency Enhancement Project (Project #4017)

The final area of SCE's equipment spending plan, the distribution system efficiency enhancement projects, consists of "two major elements: (1) circuit and automatic recloser lockout alarms [CARLA]; and, (2) the NETCOMM radio system."[18]

CARLA, battery operated radios that are used "to monitor circuit and automatic reclosers for circuit outages", help to "dispatch crews directly to circuit outage locations" and reduce outage time.[19] Due to the strong emphasis on automating circuits in SCE's plans for 2004 to 2008, SCE will install very few CARLA radios (fewer than 10 per year), and only on non-automated circuits and automatic reclosers [ARs].

The NETCOMM radio system, a "wireless wide area packet radio communications network" with wireless routers, is a "radio infrastructure to remotely monitor and control" DA devices on a network. Each DA device "requires one radio installation as part of the automation package."[20]

2.3.2.2 Pacific Gas & Electric

Pacific Gas & Electric is in the process of working on a roadmap for distribution automation applications. They are also in the process of a large investment in automated meter reading but the system has relatively low bandwidth for most distribution management applications. Reliability improvement is the main driver for investments in automation – both the number and the duration of outages are important considerations.

In its General Rate Case (GRC) for 2007, PG&E made moderately-sized funding requests for investment in distribution automation. PG&E's Phase 1 filing for the GRC was submitted in December 2005, and the decision, which is still pending, is expected in December 2006.[21] PG&E's DA funding requests were split between distribution line automation expenditures and costs associated with distribution automation at the distribution substation level.

PG&E's distribution automation line requested investments consist of four categories:[22]

1. Replacing line Primary Distribution Alarm and Control (PDAC) devices that are becoming obsolete and need to be converted to SCADA systems (Cost: $150,000 per year; 5 sites per year at $30,000 each). This work also establishes new communications links via PG&E's radio

[16] Ibid, p. 69.
[17] Ibid, p. 66.
[18] Ibid, p. 73.
[19] Ibid, p. 73.
[20] Ibid, p. 74.
[21] PG&E, http://pcg.client.shareholder.com/investors/financial_reports/EdgarDetail.cfm?CompanyID=PCG&CIK=1004980&FID=1004980-06-134&SID=06-00&filings=PGE&formchoose=insider
[22] PG&E 2007 GRC Filings – Phase 1, Chapter 8, pp. 8-34 to 8-36.

communications systems so that failure of a single wire center will not interfere with control of a large number of line devices, such as line reclosers, line switches, and interrupters.

2. Converting existing reclosers for SCADA operation (Cost: $200,000 per year; 5 sites per year at $40,000 each). This conversion increases recloser performance, allows the reclosers to operate remotely, and provides load reads and indications of line faults.

3. Replacing and/or upgrading communications equipment (Total cost: $6.6 million from 2006 to 2009). These updates are necessary to allow the communications systems to accommodate the greater volume of information provided by SCADA devices, to replace obsolete communications equipment that is not functional or maintainable, and to convert expensive leased line communications to radio or other more cost-effective mediums such as fiber optic or cellular.

4. Distribution area automation pilot (Cost: $500,000 in 2005; 2 circuits at $250,000 each). These two pilot projects aim to investigate an emerging approach to distribution automation systems "that integrate advanced features such as automatic load restoration and dynamic circuit monitoring/switching to prevent overloads and optimize voltage . . . using technology and industry standard protocol so future enhancements are more easily adapted for system expansion."

For the distribution pilot projects, PG&E "contracted with KEMA consulting to perform a business case study with emphasis on reliability improvement." The changes include "modifying or installing 'intelligent' switches, substation feeder breaker automation and associated communication infrastructure such as leased line, radio, pilot optic, or cellular technology, depending on" the availability of these mediums near the required locations. Assuming the pilot is successful, PG&E plans to implement these technologies in other circuits between 2007 and 2009. [23]

The technology PG&E plans to use in its automation pilot projects has proved successful during a similar installation for a utility in Alberta, Canada. That project, initiated by ENMAX Power Corp. in the Calgary area, began in 2002 with a study, also done by KEMA Consulting, to determine the effect DA would have on system reliability.[24] The original KEMA study determined that the DA investments for the project would be "economically viable when customer outage cost savings were considered." Indeed, by November 2004, Phase I of the project, completed in March 2004 and focused on 19 feeds of ENMAX's 25-kv distribution system, "had averted an estimated 862,000 customer outage minutes and 6,800 customer outages," which represents "an 8.6 reduction in SAIDI and a SAIFI reduction of 1.7 percent," a particularly significant improvement given that only 16 percent of ENMAX's customers were affected by the Phase 1 installations.

The ENMAX project, the recipient of the 2004 T&D Automation Project of the Year Award, uses "distributed intelligence and peer-to-peer communications to constantly monitor the power system. When a fault occurs on the line, the system sectionalizes the line to isolate the faulted section, and then restores serves to all unfaulted line sections." The system, which "maximizes the probability that a restoration solution can be found" through use of multiple circuit ties, also "uses distributed intelligence to prevent line overloads-enabling ENMAX to apply automation on circuits that would have otherwise been unsuitable for the task."

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[23] Ibid, p. 8-36.
[24] "2004 Automation Project of the Year Awards: ENMAX DA Project Achieving Impressive Results", (http://uaelp.pennnet.com/Articles/Article_Display.cfm?Section=ARCHI&ARTICLE_ID=223760&VERSION_NUM=2)

In the area of electric distribution automation relating to electric distribution operations and distribution substations, PG&E's 2007 capital expenditures focus on replacing and upgrading distribution control center SCADA master stations. The stations, which consist of computer servers with software necessary to run the SCADA system, are physically located at the distribution control centers.[25] Forecasted annual expenditures of $100,000 for four years will replace four $25,000 units in each year. Additionally, PG&E requests funds for leased line costs and master station distribution maintenance of approximately $1 million per year and $1.3 million, respectively, which PG&E views as necessary "to support the reliable operation of PG&E's SCADA systems."

2.3.2.3 San Diego Gas & Electric

SDG&E was the first utility in the United States that had true performance-based rates. This type of regulatory structure provides an inherent justification for technologies that can improve reliability. As a result, reliability is the most important factor in automation investment decisions. However, SDG&E has expanded the concept of reliability to provide a more customer-focused assessment of system performance. They use an index called SAIDET that represents the duration of interruptions that have exceeded some threshold value that is determined to be important to customers.

SDG&E has also had a major focus on customer power quality. They have an extensive power quality monitoring system that provides information about steady state power quality and voltage sag performance throughout the system. Voltage sags are analyzed just like interruptions to provide root cause information so that improvement measures can be prioritized. The power quality monitoring system is currently being expanded to implement automated fault location to further improve reliability. This will be integrated with new monitoring investments (SATEC meters on feeder circuits) and technologies (intelligent relays).

Cable replacement strategies are critical for SDG&E as they continue to make more and more of their system underground and ageing cables are a major cause of outages. Sophisticated tools for prioritizing cable replacement are being implemented and used.

As discussed in its 2004 cost of service study, SDG&E has initiated a number of investments related to distribution automation, most notably those targeted at remote control and data analysis. The wide-spread application of a SCADA system has improved SDG&E's monitoring and control of its distribution infrastructure. Additional benefits have related to improved use of load curtailment and other forms of demand response by SDG&E during hours that are critical for its system.[26]

As of December 2002, SCADA has been implemented into over half of SDG&E's electric distribution infrastructure, "comprising 56 substations, 490 circuits and approximately 700 strategically located switches and service restorers."[27] This represents a quadrupling in size and coverage during an eight-year period.

SDG&E noted that the SCADA produced a number of benefits, including:[28]

1. Improving efficiency in circuitry's response during rolling blackouts.
2. Reducing outage restoration time, through SCADA's prompt reporting of system problems and, in some cases, identification of the cause and location of the problem.

[25] PG&E 2007 GRC Filings – Phase 1, Chapter 11, pp. 11-10 to 11-14.
[26] SDG&E Applications for authority to update its gas and electric revenue requirement and base rates (U 902-M). Direct Testimony of David Geier on Behalf of San Diego Gas & Electric (SDG&E 2004 Cost of Service Application – Phase 1), p. DLG 15.
[27] Ibid, p. DLG 23.
[28] Ibid, p. DLG 23.

3. Helping to implement the Load Curtailment program, which is able to drop considerable load within 5 minutes and contributed to SDG&E success in riding "through the hardship of the energy crisis of 2001."
4. Improving prioritization of cost-effective improvements to the distribution network.

In conjunction with SCADA, SDG&E has begun to use a new reliability engineering method and predictive analysis, know as Predictive Circuit Reliability Analysis (PCRA), which has improved SDG&E's identification of cost-effective improvements to its distribution system. This method models alternatives for improving the distribution system and compares them "for optimal reliability benefit and cost."[29]

PCRA has provided numerous benefits to Nashville Electric Services (NES), which with the help of ABB Consulting recently implemented predictive reliability software to analyze 10% of its distribution feeders.[30] RELINET, the software used by NES, "models improvements and evaluates reliability alternatives", enabling NES to "easily quantify the percent improvement of a reliability index after making a reliability improvement." For example, on "a typical NES feeder, the addition of one recloser and one fuse" created a 15 percent improvement in SAIDI and improved the feeder's SAIFI by 20%. The RELINET analysis allows NES to identify and prioritize such opportunities for system reliability improvements, making PCRA a valuable tool in the planning process.

At the time of its 2004 cost of service study, SDG&E has a number of other on-going projects related to Distribution Automation. Six notable such projects are:

- Sustainable Community Energy Systems (Project 02264) provides funds of $10 million over 2002–2004 "for the engineering, design, materials, installation, testing, and maintenance of the following items:
    - Community based energy reliability and efficiency strategies
    - State-of-the-art generation and storage technologies, such as solar photo-voltaics, fuel cells, advanced flow battery energy storage, combined heat and power, etc.
    - Advanced metering, control, and interconnection, such as time-of-use metering, automated meter reading, and web-based or remote monitoring and control".[31]
- Distribution Automation and Control System (Project 94245) provides funds of $1.6 million in 2002 and $4.2 million in both 2003 and 2004 for the "installation, upgrading, and expansion of SDG&E's Supervisory control and Data Acquisition (SCADA) system and other associated Distribution Automation systems. A variety of SDG&E and Sempra Energy Divisions/Depts./Sections utilize and benefit from distribution automation systems."[32]
- Distribution SCADA/OMS Interface System Upgrades (Project 856) uses approximately $80,000 in 2002 to upgrade the new Outage Management System (OMS II) and to improve the integration of data from the OMS II and the SCADA system, resulting in increase efficiency and reduced time required to identify and restore and outage.[33]
- Distribution SCADA System Redundancy (Project 01832), a 2002 project estimated to cost $1.1 million, "will expand the capabilities, reliability, functionality and redundancy of the

[29] Ibid, p. DLG 146.
[30] http://tdworld.com/mag/power_nes_tackles_circuit/index.html
[31] SDG&E 2004 Cost of Service Application – Phase 1, pp. DLG 181-182.
[32] Ibid, p. DLG 184.
[33] Ibid, p. DLG 187.

SCADA system utilized in Electric Distribution Operations to support the expansion of remote control and data acquisition from substations and field devices."[34]

- Distribution SCADA System Infrastructure Upgrades (Project 01833) uses approximately $1.1 million between 2002 and 2003 "to replace obsolete components and subsystems before failure and to expand the Distribution SCADA system and external associated systems." These upgrades add functionality and maintain high system reliability levels.[35]
- Outage Management System II – Implementation (Project 99821), estimated to cost $14 million per year from 2002 to 2004, replaces the "existing Outage Management System (OMS) which consists of numerous computer-based systems, standard practices/procedures, and automate manual functions utilized within Distribution Operations." The new system improves communication with external customers through tracking of calls and web-based information for users about outages, as well as "increasing the timeliness and accuracy of outage status reporting", which is used for management evaluation of the system.[36]

2.3.2.4 Los Angeles Department of Water and Power

LADWP recently invested in one of the most advanced substation automation systems in the country. The system allows monitoring and control down to the feeder breaker level throughout the LADWP system. This provides tremendous operational benefits for responding to system problems and improving the steady state performance of the system.

However, LADWP has recently experienced a number of significant outages affecting large numbers of customers. This has resulted in an internal assessment of operations, technology, asset management practices, and maintenance practices. The results of these internal investigations could identify additional needs for automation and technologies that could improve the understanding of performance throughout the system and provide the capability to avoid outages affecting significant parts of the system.

2.3.2.5 TXU Electric Delivery

TXU Electric Delivery has a number of major projects that are related to reliability improvement and improved operation of the distribution system.

- Advanced Metering Initiative. TXU has a multi-year plan to make implement advanced metering to 100% of their customers (3 million meters). As part of this deployment, TXU announced the investment in Current Technologies and an arrangement for Current Technologies to deploy a widespread broadband over power line communication system on the TXU distribution network. This system will be used for advanced metering communications and will also support distribution operation enhancements. The system will also involve a large deployment of optical fiber communications to the BPL injection points and this fiber communications infrastructure will directly benefit distribution operations. The system will employ a variety of different communication technologies for different parts of the system.
- One of the key requirements to achieving the planned benefits of AMI and other automation initiatives is effective data integration so that information from the various systems is available on a common platform. TXU is using a third party system to provide the data integration but wants to migrate to the Common Information Model (CIM) as the general approach for implementing a common platform.

[34] Ibid, p. DLG 191.
[35] Ibid, p. DLG 192.
[36] Ibid, p. DLG 195.

- Distribution automation initiatives. TXU has trial applications of automated distribution circuit reconfiguration systems with smart switches and associated communication systems. These can be the basis for more widespread application for reliability improvement.
- TXU has been a major funder and trial site for the Distribution Fault Anticipator (DFA) technology. This technology employs advanced monitoring and diagnostics to identify system and equipment problems. As an extension to this effort, TXU is a partner in the DOE/EPRI Solutions Advanced Monitoring project and is the coordinator of the DFA Focus Group in that project to help define the requirements for a commercial DFA product. They will be deploying next generation DFA systems at two substations as part of the project.
- TXU is actively evaluating new technologies for automation and sees a variety of technologies on the horizon that will become important for improving the reliability and performance of the distribution system.

2.3.2.6 American Electric Power

AEP has numerous initiatives under way related to distribution automation and improved distribution operations. In general, they are related to reliability improvement initiatives. Important areas of research include advanced monitoring (part of Doe project), feeder automation (a number of pilot projects), and advanced communication techniques (developing peer-to-peer communications system for distribution applications.

2.3.2.7 Southern Company

Southern Company has an extensive distribution automation infrastructure already in place with RTUs at both substations and throughout the distribution system. They are one of the few utilities that monitors all three phases at remote distribution RTU locations. They have found that the three phase information is very valuable in identifying capacitor problems, regulator problems and other system conditions. Controls that are only based on one phase of the voltage and current can sometimes operate incorrectly or not identify an equipment problem.

Applications of the distribution automation system include:

- Distribution line monitoring (RTU monitors at Southern Company monitor all three phases and include the ability to track harmonics up to the 15th harmonic)
- Integrated volt/var control (switched capacitor banks)
- Remote control of distribution switches for system reconfiguration, distribution line switch automation
- Automated pole mounted reclosers, automated sectionalizing schemes
- Automated transfer pad-mounted switchgear, automated transfer switching schemes
- Standby generator connected to distribution
- Fault detection and fault location
- Identification of problems with distribution equipment

Southern Company is always looking at ways to improve and enhance the existing infrastructure, as well as evaluating new technologies that can become important. They have a radio-based communication system for their existing RTUs. Other communication technologies may be considered in the future.

Southern Company is actively looking at improved sensor options. With the number of monitoring locations throughout the system, this is a primary need. New technologies like optical sensors are being considered and Southern Company is also looking at the detailed specifications for new sensor technologies

Southern Company is one of the main partners in the development and deployment of the Distribution Fault Anticipator (DFA) technology. As part of their participation in the DOE/EPRI Solutions project, they will be looking at deploying next generation DFA technology integrated with their distribution automation system. These units will go out on distribution systems rather than at substations, allowing better identification of equipment problems and possible future fault conditions.

Southern Company also has an extensive multi-year effort to integrate the various databases and information systems that are part of their overall distribution management system (Distribution Automation - DA, Geographic Information Systems – GIS, Outage Management Systems – OMS, etc.). This project is being funded by Southern Company and DOE and they are working with Areva on the implementation of the integrated system. This need for integration of the different distribution management applications is one facing all utilities. Southern Company feels that they can justify the investment in the integrated system based on reduced losses alone (includes lost power sales during outages).

2.3.2.8 Consolidated Edison

The Con Edison distribution network is already one of the most reliable in the world. The network configuration results in the ability to lose as many as 2 distribution primary feeders without loss of service to customers. Recent events in the summer of 2006 illustrate that, even with this robust design, overloads and equipment failures can occasionally exceed the capacity of the network, resulting in significant customer outages.

Con Edison maintains an extensive monitoring system that tracks the loading and voltage at every network transformer on the system. This system uses a narrow-band power line carrier communication technology to collect the information. In addition, Con Edison has power quality monitors throughout the distribution network and is installing additional power quality monitors at substations. A recent development project has implemented fault location using the power quality monitors at the substation. This capability is currently being expanded to include all substations and will also integrate data from intelligent relays. The fault location significantly reduces the time required to locate faults and allows the feeders to be put back in service much faster.

Con Edison has sent engineers around the world to benchmark distribution network designs and provide the basis for their third generation (G3) network design. Characteristics of the G3 design will include the ability for flexible configuration of the network to achieve the highest possible levels of reliability, information integration for convenient development of new advanced applications, and new communications infrastructures to facilitate real time monitoring and state estimation. Features of the next generation systems will include:

- New design that:
  - Maintains reliability
  - Installs less copper
  - Lowers costs
- Advanced Distribution Automation

- New distribution system topologies
    - Super-fast simulations
    - Advanced visualization tools
    - Enhanced communication and information systems
    - Adaptive sense and respond systems
    - New protection and control paradigms
    - Advanced technologies such as power electronics

Con Edison worked with EDF to develop the specifications for the Intelligrid Distribution Fast Simulation and Modeling system that can be the basis for distribution real time monitoring and control in the future. This specification is being incorporated into the G3 system design.

Con Edison is working with Infotility to apply some of the GridAgent technology that has been developed for DOE to the G3 system design. The project will result in deployment of agent-based control for a portion of the Fulton network that is currently being designed.

One of the most important issues facing Con Edison (maybe the most important issue for distribution systems) is the management of aging cables (91,000 miles of underground cable) and deciding when to replace cables. Con Edison has been working on a system based on machine learning that predicts the most likely cable sections to fail based on a large database of characteristics associated with each cable section (historical performance, type, manufacturer, splices, disturbances, etc.). Con Edison sees the machine learning approach as being appropriate for a wide variety of decision support tools related to distribution asset management.

2.3.2.9 Progress Energy

Carolina Power & Light (Progress Energy Carolina) was one of the first utilities to implement distribution automation on a significant scale. In the 1990s, Progress Energy invested $14M to provide automated monitoring and control of all distribution feeder breakers on the entire system (approximately 1000 feeder circuits). In addition, the decision was made to implement RTUs that have much more capability than traditional RTUs – these track a variety of power quality characteristics and can record voltage and current waveforms for any disturbance at the substation.

One of the most important applications that Progress Energy has implemented with this system is automated fault location. The fault location technology has been developed over a number of years and is now capability of accurately locating faults a high percentage of the time, even for the very long rural circuits that are typical of the Carolina service territory. However, the actual fault location capability is only a small part of the implementation problem – the integration with outage management and GIS is equally critical so that operators can actually use the system.

Once the fault location function is operational, a number of other benefits can be derived from the system. Capabilities that have been implemented by Progress Energy include:

- Identification of galloping conductors
- Identification of locations on the system that are experiencing multiple faults in a defined period of time
- Identification of incipient arrester failures and cable splice failures

- Trending fault events over time
- Tracking momentary faults as well as permanent faults

Progress Energy uses the monitoring system to calculate a new index for each feeder – faults per feeder mile. They have found that this index correlates better with customer expectations and customer satisfaction than traditional indices like SAIDI and SAIFI. The faults per feeder mile index includes all faults that occur on the circuits (both momentary and permanent).

2.3.2.10 We Energies and DV 2010 Consortium

We Energies is the founder of the Distribution Vision 2010 (DV 2010) consortium looking at advanced distribution automation technologies with the goal of improving reliability and quality of distribution systems. They were the first utility to demonstrate some of the concepts and have continued to provide leadership for the consortium. BC Hydro now has a similar demonstration under way. Important objectives of the demonstrations include:

- Demonstrate enhanced high-speed communication-based distribution protection schemes to provide reliable and secure fault isolation on complex branching network feeder designs within 3-5 cycles.
- Demonstrate instant reconfiguration of the system once a fault has been isolated.
- Demonstrate management of the system configuration in real time with high speed communication and integration with an Energy Management System.
- Demonstrate real time voltage monitoring and control.

The research includes a number of important developments and deliverables that will be demonstrated as part of the project:

- PeerCommTM Communications System (Cooper Industries) – allows continuous communication between reclosers for fast isolation of faults
- Enhancements to the Cooper Form 6 Recloser Control with enhanced overcurrent protection functions
- Reverse Vacuum Fault Interruptor (RVFI) – supplies a reduced cost high speed transfer capability.
- DA Master from NovaTech – distribution system automatic reconfiguration controller.
- Real time distribution system analyzer for wide area voltage control and system operation management.
- New fault locating algorithms – University of Wisconsin.

DV 2010 has a goal of developing a new primary network design tied to multiple source buses and using directional overcurrent protection, distribution automation, high speed communications, and automated real-time system analysis to reduce annual outage times experienced by customers by a factor of 10.

Some of the important concepts introduced by DV 2010 include:

- Premium Operating District (POD). This is a concept where the reliability provided to a customer is determined by the reliability of the POD. By adding automation equipment to reduce the size of the POD, the customer reliability can be improved. The limiting case of an

individual customer being a POD maximizes the reliability for the customer and introduces the possibility of premium power services.

- Tiers of control
  - Tier 1 – Autonomous Control – inherent functionality using local sensors, no communication required
  - Tier 2 – Distributed control – high speed communications plus logic in the line device control can supercede autonomous protection, can provide 3-5 cycle fault isolation.
  - Tier 3 – Local Area Control – multiple substation control hubs evaluate the state of the system after the initial isolation, coordinate and control automatic switches to refine isolation and restore service.
  - Tier 4 – Wide Area Control – Coordinate individual local area controllers to control LTCs, regulators, DG, and capacitors to optimize system performance.

Different levels of reliability improvement can be achieved by reducing the size of individual PODs. This allows tailoring the investment to the level of reliability that is desired.

Technical development for the DV 2010 technologies continues. Important areas of development include fast communication technologies, wide area control technologies, and demonstration of concepts.

2.3.2.11 MidAmerican Energy Company – Cost/Benefit Analysis of Substation Automation

The MidAmerican Energy example involves substation automation, rather than distribution automation. Substation automation is becoming very widespread as mentioned previously. MidAmerican Energy is also looking at additional automation functions, including fault location, DFA, and the Intelligent Universal Transformer. However, this discussion focuses on the cost justification process for substation automation because similar approaches can be used to assess and justify investments in other automation functions and technologies.

The project involved an integrated approach for implementing substation automation (SA) systems so that the wealth of information available in IEDs could be fully exploited in a cost effective manner. The overall objective of the study was to determine what additional functionality changes, if any, to MidAmerican's current standard approach to substation monitoring and control architecture are economically justified.

The two major tasks associated with accomplishing the objective were:

1. Identify additional SA functions that produce significant operational benefits
2. Determine the economic justification for implementing some or all of these functions using benefit-cost analysis

One of the most important results of the management interviews was a list of business "drivers" to be addressed in the SA business case. MidAmerican's key business drivers pertaining to SA are:

- Reliability and quality of service
- Customer loyalty
- Cost of service

- Deliverance of information to the enterprise
- Proactive response to industry developments

A list of "candidate SA functions" was derived from the results of the interviews. These candidates are the SA functions that appear to provide solutions to MidAmerican's business problems and needs.

A benefit-cost analysis was then performed to determine which of the candidate SA functions identified during the information-exchange process is economically justified. The candidates believed to be most economically suitable for MidAmerican and their corresponding benefits are tabulated below.

Table 9: Economic Benefits as a Function of Substation Automation Functions

SA Function	Anticipated Benefit
Online Equipment Condition Monitoring	Fewer routine inspections (transformers, circuit breakers), Fewer catastrophic failures (15% reduction in circuit breakers and 20% reduction in substation transformers), Equipment life extension (1 year for breakers and transformers)
Dynamic Equipment Ratings	Gain additional capacity from existing equipment during peak load periods. This, in turn, will allow MidAmerican to defer capital expenditures and, in some extreme cases, can help avoid load shedding
Adaptive Relay Settings	This application function will enable MidAmerican to change normal feeder protective-relay settings to fuse-saving settings under conditions (such as storms) when numerous momentary faults are likely to occur. Fuse saving will prevent feeder branch line fuses from blowing for momentary faults, thus avoiding unnecessary extended outages for some customers at the expense of numerous momentary outages for all customers on the feeder.
Power System Disturbance Data	Having more convenient access to the power system disturbance data contained in IEDs (relay targets, fault location and magnitude, etc.) will assist field crews in investigating and locating the fault and thereby reduce both investigation time and feeder patrol time. This reduces the average customer outage duration, which in turn results in a significant reliability improvement benefit.
Automatic Load Restoration	This SA system candidate function will enable MidAmerican to automatically restore power to customers whose service has been interrupted due to a high-voltage supply-line or substation transformer failure (no high side circuit breakers). A significant reliability improvement benefit can be attributed to this SA system candidate function.

2.3.2.12 Hydro-Québec

Hydro-Québec put together a detailed roadmap for distribution automation implementation and developed a cost justification for the entire system. The approach was approved by the regulator and Hydro-Québec is now in the initial stages of system implementation.

Benefits of the system were developed in six categories:

- Service Continuity
- Energy Efficiency
- Information Management
- Carryforward Investment
- Social Costs

- Reduction in Labor Costs

The argument to the regulator included an assessment of historical reliability and the relationship to investment in maintenance and operations. The findings were supported by positive results from field testing of the proposed investments. Goals of the network investments are to improve SAIDI and also to reduce the disparity of reliability levels for different customers that pay the same rate. Several alternative approaches were presented in the regulatory filing from traditional methods of improving reliability to investment in distribution automation using a detailed cost/benefit approach. The conclusion was that investments in an automated distribution system would provide the most value for customers and society. As a result, the regulator approved a six year program to automate 3750 switches and breakers on the Hydro-Québec system at a cost of $188M Canadian.

Hydro-Québec's commitment with respect to the automation investment includes:

- The percentage of customers with a reliability index above 4 hrs is about 15 % (500 000 customers) and it shall drop to 8 %.
- SAIDI shall be reduced by 15 min per customer, per year, on average
- Labor costs shall be reduced significantly
- Total amount of customer claims shall be cut by about 20 %

Hydro-Québec realized that they needed a more integrated plan for taking advantage of this investment and making the automation an integral part of their future distribution system. As a result, they developed a 10 year roadmap for the automation program that involves participation with research and development efforts and implementing important new technologies and communications capabilities as they are developed.

2.3.2.13 EDF

EDF is participating in many different advanced distribution R&D initiatives. Ivan Bell of EDF was the project manager for the development of the distribution fast simulation and modeling requirements and framework document (along with Con Edison). This document is a framework for a real time state estimation capability that is currently being developed by EDF.

Reliability improvement is the primary justification for investments in DA at EDF. EDF has already implemented remote control of 90,000 switches throughout their MV system (3.5 switches per distribution feeder). This has significantly reduced SAIDI (now 35 minutes at the MV level and 55 minutes at the LV level).

An overall plan for migration to a more intelligent distribution system is being developed. This will apply to one of the largest systems in the world:

- 2,200 distribution substations
- MV network : 570,000 km (35% underground)
- 650,000 MV/LV sub-stations (350,000 pole mounted, 300,000 in cabin, 200,000 with MV breakers)
- LV grid: 630,000 km (40% underground) -29 million customers

Typical grid architecture:

- Double feeder for each MV/LV substation in Paris
- Ring Main Unit in other urban areas
- radial in rural areas

MV equipment used for grid automation:

- Remotely controlled switches: 93,000 (3.7 per feeder), usually equipped with a fault indicator,
- A few reclosers and a few sectionalizers

Experimentation of 3 new automation functions assisting the operator in:

- FonSYNT: Synthesize alarms coming form sub-stations (20 alarms are summarized in one line)
- FonLOC: Automated localization functions (calls up fault indicators and localizes the faulted segment)
- FonREP: identifies the remote actions to reconfigure (algorithm can adapt to any grid situation)

2.3.2.14 UK Research Initiatives

There are a number of important research initiatives and demonstration projects related to advancing distribution automation and management. Much of the research being performed by a group of UK universities in conjunction with utilities and manufacturers involves next generation network topologies and management structures. Graham Ault (University of Strathclyde) uses the term Active Network Management as compared to the traditional direction of Distribution Automation. The distinction is summarized in Table 10.

The regulator is directly involved in helping promote the results of the research. Technical working groups are set up by the regulator (Ofgem) in conjunction with the Department of Trade and Industry (DTI) who provides funding for the research. Best Practice guides and Engineering Technical Reports (ETRs) are published to promote the ANM solutions. The Distribution Network Operators (DNOs) are encouraged to consider these options in DG connection planning.

The Electrical Engineering organization in the UK (IEE) is also involved. They are committed to undertake research and development work to address future power system needs addressing the issues:

- Distributed Energy Resources
- Asset Renewal
- Liberalised Market Frameworks
- Lower Carbon Energy Systems
- Efficient, Cost Effective Solutions

This will result in network development strategies facilitating the efficient planning, connection and operation of:

- Current and future generation technologies
- Static and responsive demand
- Energy storage devices
- Network auxiliary plant and equipment

Table 10: Differences between DA and Active Network Management

Distribution Automation	Active Network Management
Takes existing network automation further	Focused on the economic integration of distributed and renewable resources into distribution networks
Main focus is on system reliability	Focused on secondary system solutions
Addresses key utility drivers in the US and UK: > Distribution Reliability > Capital and operating cost control > Customer Focused Operation > Connection of distributed and renewable generation > primary and secondary system solutions	Seeks to overcome barriers to generation connection: > Power flows > Voltage control > Fault level
	Real-time control of generation, load, storage and network devices based on real-time measurements, communications and control

There are significant incentives for both DG integration and for research and demonstration of new technologies for distribution network management. The most important programs include:

- Distributed Generation Incentive: 1.5£/kW/yr for all additional DG connected
- Registered Power Zones (RPZ): additional 3£/kW/yr for innovative solutions to DG connection
- Innovation Funding Incentive (IFI): 0.5% of revenue for technological development and demonstration
- Active Network Management is a key area of distribution company plans for innovation expenditure

2.3.3 Summary of Distribution Automation Technologies and Development Activities

2.3.3.1 Automation Technologies

The results of the survey were compiled to identify any trends among those interviewed. The following charts illustrate the percentage of surveyed utilities that have existing or planned activities in each of distribution automation technologies surveyed. Note that these utilities are some of the most advanced in the industry. Therefore, these summaries should not be considered representative of the entire industry but instead show where the leaders are headed with automation applications. Additionally, a utility is counted as having an existing application even if the application is installed on some, but not all, of the utility's distribution circuits.

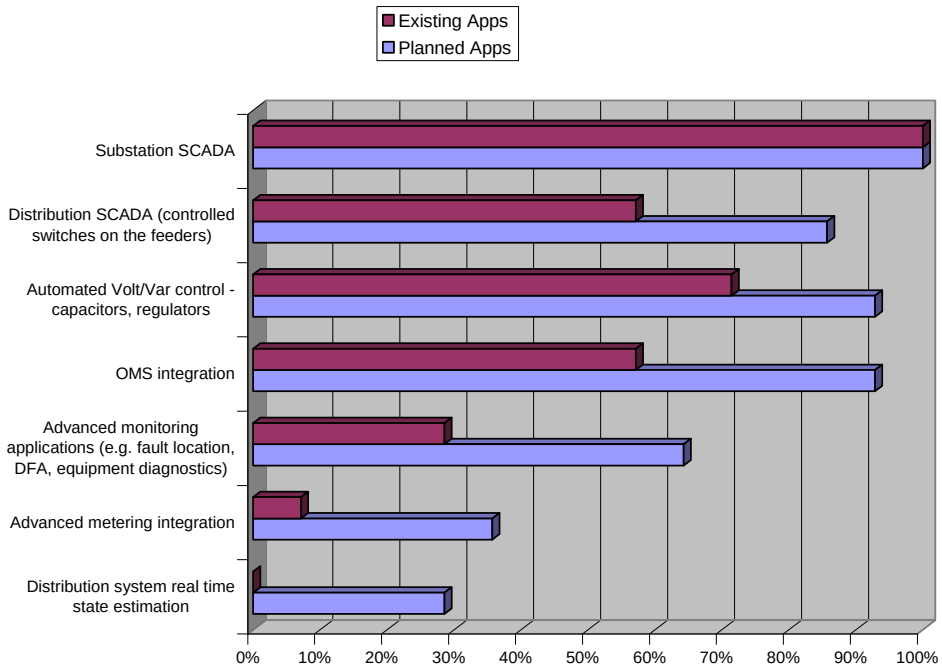


Figure 5: Summary of Existing and Planned DA Applications for Utilities Surveyed

2.3.3.2 Communication Technologies

What communication technologies are being used for automation and control functions on distribution systems? The following chart summarizes the basic technologies currently being used and planned (note that trial projects, such as BPL trials, were put in the category of planned applications).

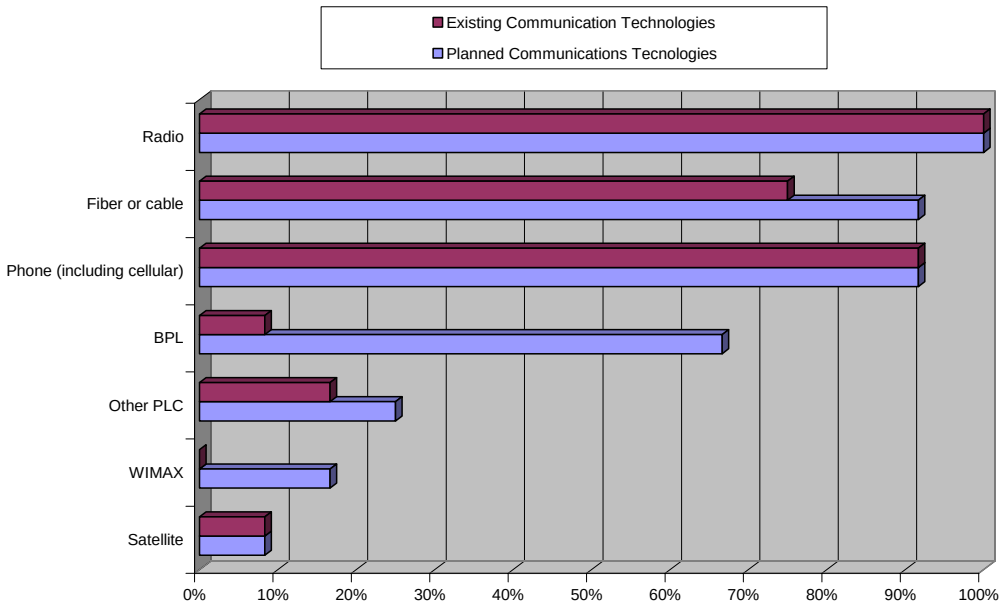


Figure 6: Existing and Planned Communication Technologies for Utilities Surveyed

2.3.4 Summary of Recommendations for Development

As part of the interview process, each of the organizations was asked for to recommend areas of research that would most benefit advanced distribution systems. Table 11 summarizes the recommendations that were received for development efforts. This list compiles recommendations from all respondents, utilities, vendors, consultants and other researchers.

Table 11: Recommendations by Surveyed Utilities for Research in Advanced DA Systems

Category	Research Recommendations
Monitoring and control equipment and technologies	Lower cost sensors
	Small and easy-to-install power sources for automation equipment, "battery-less" automation devices
	Smarter and inexpensive fault indicators
	Fault location technologies
	Distribution fault anticipator technology integration with distribution devices, applications that help identify asset condition.
	Automatic analysis of protection system performance from real time monitoring systems
	Consumer portal integration with distribution operations to enable optimization to include load response
	Integrating syncrophasors into the control center
Distribution Equipment Technologies	Fault current limiters for distribution
	Intelligent Universal Transformer
	Solid state switch (economical) for fast clearing and reconfiguration
	Advanced power electronics for improved DG interfaces
	Superconducting technologies - reduced losses, fault current limiting
Communication Technologies	WiMax communications for DA/DSM/EE
	Integration of different communication media to create robust communications platform for DA/DSM/EE
	Integration of multiple applications (DA/DSM/EE) on one communication channel/platform
	Integration of fast communications with protection systems to allow extremely fast fault clearing and circuit reconfiguration
	IEC 61850 extended to distribution systems (from substations)

	Integrating with existing public and semi–public networks and utilizing existing security technology standards and equipment to protect the communications.
	Low cost methods to communicate to more devices – even fuses for example
Information Systems	Information system integration
	Common application platforms, advancements in Common Information Model
	Information models for DA devices
	Integration of Advanced Metering with overall information systems to maximize benefits
Analysis and Modeling Tools, Optimization Functions	Feeder modeling tools that can improve the assessment of different reliability improvement options and technologies importance of HAVING a GOOD MODEL and DATABASE (Root causes of outages)
	Improved asset replacement strategies based on reliability impacts and objectives
	Understanding of harmonic levels, causes of harmonic distortion levels, and best methods for controlling harmonics
	DA for load optimization between feeders, stations, transmission system
	Impact of DG on automation functions (volt/var control, fault locating, restoration), advanced networks and control strategies for DG integration
	Advanced simulation and visualization functions (real-time state estimation)
	Machine learning techniques to optimize asset management and other decisions
	Energy efficiency and reliability improvements through microgrids development
	Load shed and generation shed remedial action schemes
	Standardized algorithms
	Local, autonomous decision making
	Strategies for implementing ADA algorithms that take communication latency and failures into account
	Simulation of power systems that include ADA hardware and communications elements
Economics	Value proposition and justification for automation technologies

2.3.5 Summary of Distribution Automation Value Assessment Considerations

Utilities cite a variety of benefits that are used to justify automation investments. Some of the most important ones were identified in the survey and are summarized below. While utilities mention a variety of benefits, reliability improvement is virtually always the main driver for the investments. Figure 7 summarizes the survey results of the value streams each utility identified as a justification for their distribution automation activities.

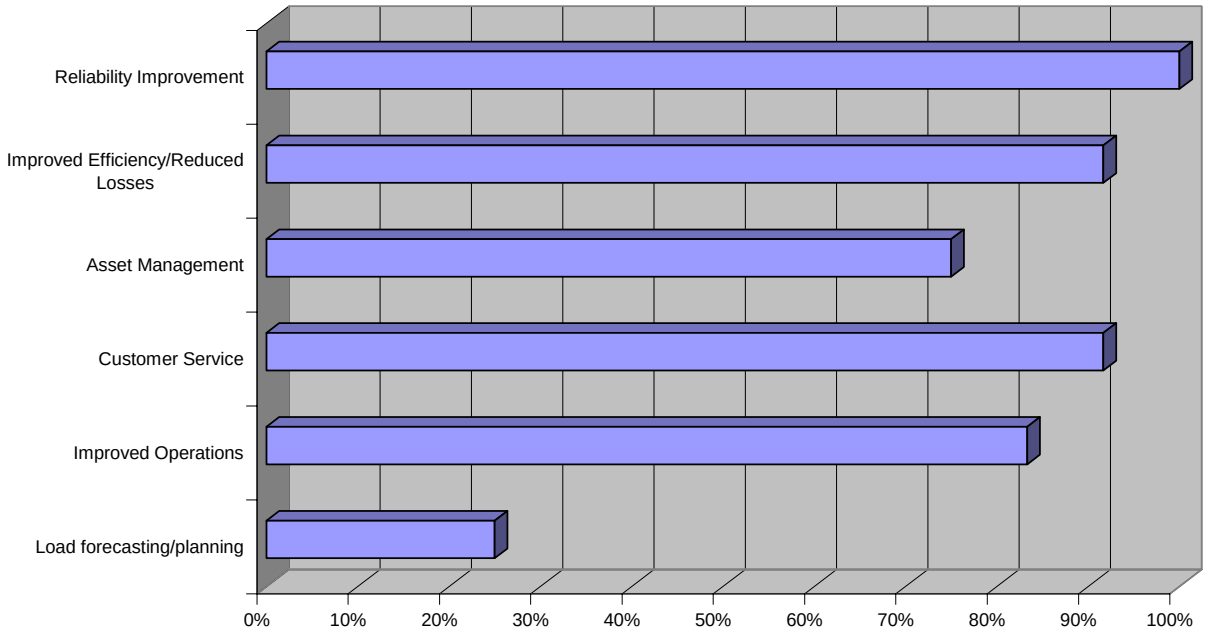


Figure 7: Benefits Identified for Automation Investment Justification by Surveyed Utilities

2.4 Summary - Categorization of DA Technologies and Applications

Based on the interviews with leading researchers, the survey results, and ongoing efforts at major research organizations, the project team has identified a comprehensive list of specific DA applications and technologies to address when developing the valuation approaches.

The distinction between applications and technologies is subtle, but is often important. A technology by itself does not provide any specific value; rather, it is how that technology is used to make changes to the way the grid operates that provides value. Therefore, for assessment of the value of DA we focus on applications, recognizing that there may be one or more technologies that enable that application to be implemented. This is not to say that the technology that is chosen does affect the overall value proposition. Different technologies have different costs and individual technology performance characteristics may affect the type of application that can be developed. Therefore, we summarize this chapter by describing both the applications and the technologies that make them possible.

2.4.1 Applications

Applications mentioned in the survey related to distribution automation are listed by application area in Table 12. Within each area, the applications have been sorted in approximate stage of development, with the first application.

Table 12: Summary of DA Applications

Application Area	Applications
SCADA applications	Monitoring and control of substation breakers (Substation SCADA)
	Monitoring and control of remote breakers and reclosers on the distribution (Feeder (SCADA)
	Monitoring and control of remote capacitor banks and voltage regulators (SCADA for volt/var control)
Advanced monitoring applications	Integration of data from monitors and sensors throughout the system into common database platforms
	Fault location
	Incipient fault detection (and location)
	Identification of other system problems – harmonic resonance, voltage variations, unbalance, repetitive faults, galloping conductors, etc.
	Equipment diagnostics (identifying equipment problems before they cause failures – capacitors, regulators, switchgear)
	Asset management applications (using monitoring to support condition-based maintenance applications
	Detecting losses, including non-technical losses through processing of monitoring data (real time data from throughout the system – advanced metering)
Automatic system reconfiguration	Automated switching for isolating faults during contingency
	Automated switching for dynamic reconfiguration (e.g., improved efficiency, reduced losses, prevent overloading, lower probability of outage, etc.)
Coordinated voltage and var control	Remote switching of capacitors to optimize var and voltage conditions (including sensor requirements)
	Coordinated control of voltage regulators and substation tap changers
	Coordination with advanced technologies like static var compensators, statcoms
	Coordination with var compensation available from loads and distributed generation (effect of significant solar penetration)
	Coordination with var control from intelligent universal transformer (IUT)
Conservation voltage reduction	CVR managed from substation but controlled based on sensors around system
	CVR coordinated with control of capacitor banks and regulators throughout system
	CVR coordinated with voltage control at individual customer facilities (e.g. MicroPlanet)
	CVR coordinated with advanced metering to provide information to customer facilities and distributed generation
Coordinated load control and demand response for	Direct load control to prevent distribution system overload
	Direct load control to coordinate with circuit reconfiguration

distribution operations support	Load control through dynamic pricing to coordinate with circuit loading conditions (improve reliability, prevent equipment overloading, delay investment requirements for system reinforcements)
	Monitoring and verification of response (AMI)
Advanced Outage Management Systems (OMS)	OMS integration with advanced metering for accurate determination of faulted sections
	OMS integration with automatic circuit reconfiguration systems
	OMS integrated with advanced monitoring fault location applications (from substation monitoring or from fault indicators throughout distribution system)
	Consolidation or relocation of service centers
Advanced Asset Management Systems	Advanced equipment diagnostics based on monitoring to characterize the condition of equipment on the distribution system
	Advanced methods to determine remaining lifetime of equipment based on many factors (machine learning techniques such as being developed at Con Edison)
	Advanced testing techniques (on line and off line) to support asset condition assessments: Cables, transformers, breakers, capacitors, regulators, arresters, Advanced technologies (solid state equipment, etc.)
	Using high frequency signals, such as BPL, to identify equipment problems and condition
	Incorporation of equipment condition information into decision making tools for system configuration and management.
Real time state estimation	(This is an application that supports various applications above – dynamic reconfiguration, reliability management, asset management, conservation voltage reduction, load control, etc.)
	Real time management of the power system configuration information and electrical model
	Real time power flow simulation of distribution system based on sensors around the distribution system
	Real time state estimation integrated with advanced metering (information from virtually all customers as basis for real time state estimation)
Optimized power quality management system	Harmonic control coordinated with volt/var control systems (integration of filters as needed)
	Integration of advanced technologies for var and harmonic control (active filters)
	Localized power quality improvement with DVR, UPS, etc.
	Localized power quality improvement with DVR, UPS, etc.
	Power quality and reliability management with distributed generation and storage (including microgrids as appropriate)
Traditional methods of	Undergrounding circuits

reliability improvement (for comparison with advanced applications)	Tree trimming (maintenance)
	Early replacement of assets (cable transformers, etc.)

2.4.2 Technologies

The applications listed in the previous section are each supported by a number of different technologies. Because many technologies also support a variety of different applications, mapping the correspondence of technologies to applications it enables would be somewhat speculative and overly lengthy for this portion of the report. Instead, technologies are listed by general category in the table below.

Table 13: Summary of DA Technologies

Technology Area	Specific Technologies
Communications (communications is a foundation for virtually all the applications and consists of high speed two-way communications throughout the distribution system and to individual customers)	Radio technologies
	Wimax
	Peer-to-peer systems (e.g., zigbee for local systems like substation)
	BPLC (Broadband over Powerline Communications)
	Fiber optic applications on the distribution system
	Network connectivity
	Technologies to use public communication infrastructures for automation and metering applications with required security and reliability.
Sensors (the next basic requirement for virtually all the applications)	Integration of sensors in the substation for monitoring applications
	Advanced sensors for the distribution system • Fault indicators • Optical sensors (voltage and current) • Other low cost sensor options • Widely distributed low cost sensors • Sensors with integrated communications (wireless)
	Using advanced metering as the sensors for distribution applications
Monitoring devices and technologies	Monitoring technologies integrated with distribution equipment (relays, regulators, capacitor controls, reclosers, etc)
	Special purpose monitoring technologies
	Special monitoring applications (special processing for decision making, e.g., DFA) • High frequency signal characteristics • Wavelet processing • Harmonic processing • Detecting arcing conditions • Fault location • Detecting incipient faults

Monitoring data integration	IEC 61850 models for all distribution substation equipment
	Extension of IEC 61850 throughout the distribution system
	Extension of information models to distributed generation and storage technologies
	Extension of information models to new technologies (static compensators, IUT, etc.)
	Integration of data with Common Information Model (CIM) to facilitate use of information in a wide variety of applications from real time state estimation to asset management.
	Standard database designs for distribution information management
Conventional switchgear advancements	Controllable vacuum breaker and SF6 breaker for fast switching applications and controlled zero crossing applications
	Integration of monitoring and communications with breaker for distribution information management
Solid state switch	Solid state switch for fast fault clearing
	Solid state switch for reduced transients during capacitor switching
	Solid state switch for fast system reconfiguration
	Solid state switch to facilitate microgrids
Advanced meters	Meters that can provide gateway to load control and load management through pricing information
	Meters that can provide interface for direct load control in times of emergency and during system reconfiguration efforts
	Meters that integrate with OMS
	Meters that can integrate with distribution information systems (e.g. for real time state estimation)
Advanced protection systems	Advanced reclosers for integration with automatic reconfiguration systems
	Adaptive protection systems that can be coordinated with changing system configurations and conditions
	Adaptive protection systems that can be controlled based on environmental conditions (e.g. storms)
	Protection systems that provide integrated monitoring information for overall distribution management systems

	Advanced expulsion and current limiting fuses for fast clearing of faults with integrated sensors and communications
Distribution equipment advanced technologies	Transformers • High efficiency • Integrated sensors and communications for loading, hotspots, condition assessment
	Capacitors • Integrated sensors and communications • Integrated protection
	Regulators • Improved switching for fast voltage control • Integration with monitoring and control systems • Intelligent algorithms for coordination with distributed generation
	Arresters • Integrated monitoring and communications to identify problems • Dynamic arrester characteristics for control of different types of transients and overvoltages
Conductors	Advancements in underground cable design, installation, and reliability to improve overall system reliability
	Integration of sensors and communications with underground cables
	Advanced conductors for improved reliability with animals and trees
	Advanced conductors with sensors to detect loading, arcing, etc.
	Superconducting cables
Advanced power electronic technologies	Static var systems
	Statcom
	Integration of var control with local var sources (local generation, local capacitors, local technologies like statcoms that also provide power quality improvement)
	Active filters (integrated harmonic control)
	Intelligent universal transformer (including support of dc supply options for facilities)
	Advanced CVR technology for local voltage sag ride through
	Advanced UPS for local reliability improvement and possible integration with microgrids

Power quality improvement technologies	Harmonic filters on the distribution system
	Static var systems and statcoms for fast voltage control
	DVR for local voltage sag ride through support
	Advanced UPS for local reliability improvement (and also can provide var support)
Distributed generation advancements	Integration of local generation with distribution control • Fuel cells • Microturbines • Diesel and gas generators • Local CHP
	Plug-in hybrid vehicle as a device for local generation and storage that can be integrated with the distribution system
New energy storage technologies	New technologies for energy storage at the distribution level (e.g. substation)
	New technologies for energy storage at the customer level that can be integrated at the distribution level
Overall system control technologies	Optimizing for energy efficiency and losses with dynamic configuration capability, load control, and flexible var control
	Optimizing local and system generation for reliability, power quality, and losses
	Managing system configuration and monitoring information – real time state estimation
	Distributed agents to improve reliability, information flows, security etc.
	Optimum system management with microgrid capability

3.0 Business Case Components – Categorizing the Applications and the Value Matrix

To approach the valuation of a broad range of DA applications, we recognize that most of the DA applications can be categorized into four main approaches for improving the distribution system. The specific application and available technology to implement each approach depends on a number of factors that will vary by utility. The four categories are:

1. Routine Operational Efficiency
2. Management of Peak Loads
3. Prediction of Equipment Failure
4. System Restoration After Failure

In this chapter we categorize the range of applications cited in Chapter 2 and identify the major value streams associated with each application. We then describe how each value stream it is typically measured or addressed when trying to estimate a particular value. Ranges of value are provided, as well as references to source data in some cases.

3.1 Valuation Methodology – Customer Perspective

For each category of distribution application, we characterize the main value streams (Chapter 3) and develop a methodology to quantify the main values (Chapter 4). In each case, the value assessment is based on providing the best value to California's customers. This perspective is consistent with PIER's stated goals of affordability, reliability, and sustainability, and it provides the strongest regulatory argument for utilities looking to fund investment in distribution automation.

Depending on the type of application, a portion of the 'customers' may be further characterized as 'participants' who engage directly in the performance of the distribution system. For example, a customer may volunteer load to be automatically reduced by the distribution automation system in the event of an emergency. The remaining group of customers can be solely characterized as 'ratepayers' who do not participate directly in distribution automation, but are affected by reliability of their service, costs included in their rates, environmental impacts or benefits, and other value streams defined in the Section 3.2.

For a 'participant' the value proposition is relatively straight-forward. The net benefits can be calculated as the sum of benefits less the sum of costs that the customer faces as a participant. An example for a customer with backup natural gas generation that can be dispatched for local and system emergencies through the distribution automation system is included in Chapter 4. If the payback on any investment required by the customer to participate is attractive enough, the customer is likely to proceed.

Most of the distribution automation applications do not involve or require specific 'participating' customers. In fact, most customers won't know that their utility has invested in distribution automation except through the results of improved performance of the system, such as shorter restoration times and lower bills. We capture the cost savings to 'ratepayers' as a reduction in revenue requirement of the utility. Although not immediate, we assume that revenue requirement reductions of the utility will ultimately be passed to customers at the next rate case or rate setting process. We capture reliability improvements as improvements to system reliability indices – the appropriate reliability indices for a customer perspective are discussed in section 3.3.1.

3.2 Categorizing the Applications and the Value Matrix

To best manage the large number of potential distribution applications, we categorize each into one of four categories that describes the approach taken to improve the distribution system. Each of the categories has a similar approach for evaluating the value proposition. The four categories used to categorize advanced distribution applications are defined as follows.

Routine Operational Efficiency applications include those that reduce losses, improve voltage profiles, identify equipment that is not operating as well as it should, make the system easier for system operators to manage, and reduce labor costs. The operations-based applications do not include applications associated with faults, or equipment failure.

Management of Peak Loads applications include those designed to reduce peak loads on the system. These applications include those that coordinate with customer equipment to reduce loads, balance loads between available distribution substations and feeders.

Prediction of Equipment Failure applications include those that are designed anticipate problems on the distribution system before they occur. These applications include both real-time monitoring applications that can identify specific distribution components that are about to fail as well as techniques designed to estimate the probability of equipment failure based on equipment type, history of loading, and other factors.

System Restoration After Failure applications include those that are designed to improve restoration of the grid and service loss to customers in the event of equipment failure. These applications include switching applications to reconfigure the grid, and advanced outage management systems to identify where problems have occurred.

The following 'value matrix' organizes the distribution applications identified in Chapter 2 according to the approach they take to improve the distribution system. For each application, the major value streams for that application are identified with a check-mark. The value matrix provides a high-level approach to understanding the major categories of benefits that should be considered when developing the value proposition for that application. In the next section, each value stream is described in more detail. The value proposition is put together for applications in each category in Chapter 4.

Table 14: Value Matrix of Distribution Applications

	Application	Value Stream: Reliability improvement	Power quality improvement	Energy savings	Distribution and Transmission capital savings	Early Problem Detection, Maintenance & Emergency repair cost savings	Outage detection, accelerated repair time	Energy security	Public & Employee Safety	Flexibility
Routine Operational Efficiency	Optimization of Volt/Var Conditions		✓						✓	
	Coordinated Control of Voltage Regulators		✓							
	Equipment Diagnostics for Fault Detection					✓				
	Data Integration	✓	✓		✓	✓	✓	✓		
	Identification of Other System Problems	✓				✓	✓		✓	
	Optimized Power Quality Management System		✓						✓	
	Detection of Losses		✓	✓						
Management of Peak Loads	Automated Switching for Dynamic Reconfiguration	✓			✓					✓
	Conservation Voltage Reduction	✓		✓	✓					✓
	Coordinated Load Control	✓		✓	✓					✓
	Load Control Through Dynamic Pricing	✓		✓	✓					✓
	Control of Distributed Generation Resources	✓			✓			✓		✓
	Coordination of Energy Storage	✓			✓			✓		✓
	Selection of Location for PV/DG	✓			✓			✓		✓
	Power Quality and Reliability Management	✓	✓							✓
Prediction of Equipment Failure	Advanced Asset Management				✓	✓				✓
	Methods to Determine Remaining Equipment Lifetime				✓	✓				
	Advanced Testing Techniques				✓	✓				
	Incorporation of Equipement Condition Info				✓	✓				
	Real Time State Estimation				✓	✓				✓
	Real Time Power Flow Simulation				✓	✓				✓
	Real Time State Estimation Integrated w/AM				✓	✓				
System Restoration After Failure Occurs	Advanced Fault Detection						✓		✓	✓
	Automated Switching for Fault Isolation	✓					✓			✓
	Automated Switching for Restoring Loads	✓					✓		✓	✓
	Monitoring and Control of Substation Breakers	✓					✓			✓
	Advanced OMS Integration	✓					✓			
	OMS Integration with Auto Circuit Reconfiguration	✓					✓			
	OMS Integrated w/Advanced Monitoring	✓					✓			

3.3 Characterization of Value Streams

As illustrated in the value matrix, for each of the distribution applications considered, there are a number of value streams that the application provides. This section defines each of the major benefit streams and

describes the major considerations for each value. When available, details on past studies of these value streams and the actual values are presented. The major benefits streams are:

- Reliability improvement
- Power quality improvement
- Energy and system capacity savings
- Distribution and Transmission capital savings
- Maintenance cost savings
- Emergency repair cost savings
- Early problem detection
- Outage detection, location, and accelerated repair time
- Energy security
- Public and employee safety
- Flexibility

This is not an exhaustive list of the benefits that can accrue from the various high value distribution applications, but does comprise the highest value streams that can reasonably be quantified. In addition to this list, there are also applications that promote stated public policy goals. For example, facilitated interconnection of renewable energy technology, or other technologies that encourage resources in the established preferred load order such as demand response. These policy preferences are addressed in Chapter 4.

3.3.1 Reliability improvement

Service Reliability is the most common distribution system performance metric for Utility Distribution Companies (UDCs). Reducing the duration and frequency of customer outages is a priority for distribution system planners. Many distribution automation applications provide reliability benefit streams through their ability to reduce the duration and/or frequency of customer electricity outages. All of the surveyed organizations cited improved reliability as one of their goals of distribution automation.

There are several approaches to valuing reliability. The three main choices are summarized in Table 15, below. The choice of metric depends on the type of application and the perspective. One approach is the use of IEEE-defined performance metrics for utility reliability performance evaluation (IEEE Standard 1366). These metrics are based on measured historical performance of the distribution system from outage data and customer records. Since they can be calculated directly from measured data, they are considered very accurate.

A few utilities including SDG&E are using and developing tools to predict changes in the IEEE metrics to make distribution planning choices, rather than use historical data. This approach is discussed in detail in Chapter 4 for ‘System Restoration After Failure’ applications.

The third approach is to use monetary estimates of customer costs from energy service interruptions which are proxies for the customer value of increased service reliability. This approach is commonly referred to as Value of Service (VOS). The disadvantage of VOS approaches is that it is difficult to know how customers actually value increased reliability. There are numerous studies, but results routinely show a wide variation from customer to customer and between customer classes (residential, commercial,

and industrial). The California investor-owned utilities regularly update their VOS estimates for ratemaking purposes.. From a perspective of promoting applications that provide the greatest value from California, the Value of Service approach is ideal as long as we can be reasonably certain that we are accurately estimating the value of reliability improvements.

Table 15: Reliability Metrics for a Variety of Applications

Application	Perspective	Metrics
Benchmarking Utilities, Shareholder Incentives	Measurement of historical performance of a utility	SAIDI, SAIFI, CAIDI based on historical performance, adjusted for storms
Planning	Prediction of change in performance metrics	Prediction of future SAIDI, SAIFI, CAIDI, MAIFI
Planning	Value for Ratepayers	Net Benefits based on Momentary Outages, kWh unserved, and Value of Service

3.3.1.1 Interruption Indices

The most common metrics used to evaluate utility reliability performance are CMI, SAIFI, SAIDI, and CAIDI. CMI measures the number of minutes all of the customers are without service, SAIFI measures how often a customer can expect to experience an outage, SAIDI measures average outage duration per customer, and CAIDI measures average outage duration if an outage is experienced, or average restoration time.

Each of these measures is defined as follows.

- Customer Interruptions (CI) = Total number of outage events occurring longer than 5 minutes for all customers served by the utility.

$$CI = \sum_{customers} OutageEvents(Duration \geq 5\min)$$

- Customer Minutes of Interruption (CMI): The total minutes of interruption for all outage events qualifying as Customer Interruption (CI).

$$CMI = \sum_{CI} OutageDuration(\min)$$

- System Average Interruption Frequency Index (SAIFI):

$$SAIFI = \frac{CI}{NumberofCustomersServed}$$

- System Average Interruption Duration Index (SAIDI):

$$SAIDI = \frac{CMI}{NumberofCustomersServed}$$

- Customer Average Interruption Duration Index (CAIDI):

$$CAIDI = \frac{CMI}{CI}$$

These metrics are commonly used to report the average frequency and duration of sustained outages. They are defined over a fixed time period, usually a month or a year. The indices can be measured over the entire electric distribution system or over smaller portions of the system, such as an operating area or individual circuit.

In addition to these commonly used metrics of utility performance, other indices exist such as MAIFI (Momentary Average Interruption Frequency Index). The difference between the SAIFI and MAIFI index is that SAIFI only counts service interruptions if they occur for more than 5 minutes, while MAIFI counts all service interruptions regardless of their duration. Typically, utility performance is not evaluated based on MAIFI since utilities have less control over the occurrence of outages than the restoration time.

Additionally, some utilities have recently introduced two new reliability metrics that help focus the utility on improving reliability most strongly correlated with customer satisfaction surveys. **CEMI 6** (Customers Experiencing Multiple Interruptions) measures the proportion of customers who have experienced six or more interruptions per year. **CELID 4** (Customers Experiencing Longest Interruption Duration) measures the number of customers whose longest outage was four or more hours.

3.3.1.2 Customer Value of Service

Utility customers incur economic losses from electricity service interruptions. The estimate of economic losses from service interruptions is commonly referred to as Value of Service (VOS). VOS varies significantly between customers and between different customer classes. For example, a large production plant may suffer heavy productivity losses from a service interruption, while a residential customer may suffer little from having their electricity shut off unexpectedly. The typical estimation of VOS is measured in $ per kWh unserved, based on outage duration and customer load, and $ per outage based on the number of outages experienced. The actual VOS values are difficult to quantify but have been studied extensively using customer survey and revealed preference estimation techniques. Table 16 summarizes ranges for VOS values based on a recent literature review.[37]

Table 16: Range of VOS Estimates

Customer Class	$/kWh Unserved	$/outage
Residential	$2.19 - $5.71	$2.41 - $6.27

[37] *Scoping Study on Trends in the Economic Value of Electricity Reliability to the U.S. Economy*, J. Eto at al, Energy Analysis Department, LBNL, 2001. ** U.S. Utilities only.

Commercial & Industrial	$4.19 - $703.20	$1,533 - $45,926

These VOS estimates vary by day of week and by hour of day. E3 compiled VOS statistics from PG&E and SCE and from other relevant literature in a report for the Energy Commission regarding the cost of outages caused by wildlife.[38] These estimates shown in dollars per kWh unserved and dollars per outage event for both residential and non-residential customers are reproduced in the four tables below.

Table 17: Residential Customer Outage Cost in 2004 $/kWh Unserved in California

Outage type[39]	SCE estimates based on SCE 1999[40] (Exhibit 1999)		PG&E estimates based on PG&E 2000[41] (p.22)	PG&E estimates based on Woo and Pupp 1992[42] (Table 2)	
	Willingness-to-pay (WTP)	Willingness-to-accept (WTA)	Direct cost (DC)	Willingness-to-pay (WTP)	Direct cost (DC)
Summer weekday afternoon: 1-hour	N.A.	N.A.	5.10	3.80	8.50
Summer weekday evening: 1-hour	4.60	9.70	N.A.	N.A.	N.A.
Summer weekday afternoon: 4-hour	1.50	3.10	5.00	2.00	7.40
Summer weekend afternoon: 4-hour	1.40	2.90	N.A.	N.A.	N.A.
Summer weekday morning: 8-hour	1.60	3.80	N.A.	N.A.	N.A.
Summer weekday afternoon: 12-hour	N.A.	N.A.	N.A.	1.50	6.60
Winter weekday afternoon: 4-hour	N.A.	N.A.	7.20	2.30	9.40
Winter weekday afternoon: 8-hour	1.60	4.40	N.A.	N.A.	N.A.
Winter weekday morning: 12-hour	N.A.	N.A.	N.A.	1.60	7.20

Table 18: Residential Customer Outage Costs Estimates in 2004 $ per Outage Event

Outage type	Lawton et al. 2003b[43] (p.46)	SCE 1999 (p.60)		PG&E 2000 (p.13)	Woo and Pupp 1992 (p.116)	
	WTP	WTP	WTA	DC	WTP	DC
Summer afternoon: 1-hour	2.9	4.7	9.9	4.4	1.85	4.1
Summer afternoon: 8-hour	7.2	8.2	20.1	N.A.	N.A.	N.A.

[38] Energy and Environmental Economics, Inc. 2005. *The Cost of Wildlife-Caused Power Outages to California's Economy. California Energy Commission*, PIER Energy-Related Environmental Research. CEC-500-2005-030.
[39] All figures exclude momentary outages.
[40] SCE. 1999. *Customer Value of Service Reliability Study*. Rosemead, California.
[41] PG&E. 2000. *Value of Service (VOS) Studies: Presentation to ISO Grid Planning Standards Subcommittee*. San Francisco, California.
[42] Woo, C. K., and R. L. Pupp. 1992. "Costs of service disruptions to electricity consumers." *Energy* 17(2): 109–126.
[43] Lawton L. et al. 2003b. *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*. Report LBNL-54365. Lawrence Berkeley National Laboratory. Berkeley, California.

Winter afternoon: 1-hour	3.3	N.A.	N.A.	N.A.	3.33	12.1
Winter afternoon: 8-hour	8.3	8.3	22.4	N.A.	N.A.	N.A.

Table 19: California Nonresidential Customer Outage Cost in 2004 $/kWh Unserved

Outage type	SCE estimates (based on SCE 1999, Exhibit 5.5a)				PG&E estimates (based on PG&E 2000, p.22)		
	Commercial / Industrial willingness-to-pay (WTP)	Commercial / Industrial direct cost (DC)			Commercial direct cost (DC)	Industrial direct cost (DC)	Agricultural direct cost (DC)
		Lost product	Idle input	Total			
Summer weekday afternoon: 1-hour	10.00	158.90	90.00	248.90	68.20	24.80	11.50
Summer weekday evening: 1-hour	9.60	308.50	110.20	418.70	N.A.	N.A.	N.A.
Summer weekday afternoon: 4-hour	N.A.	N.A.	N.A.	N.A.	40.60	12.70	11.70
Summer weekday: 12-hour	3.00	75.20	41.80	116.90	N.A.	N.A.	N.A.
Winter weekday afternoon: 4-hour	15.90	114.90	60.90	175.80	51.90	16.00	N.A.

Table 20: California Nonresidential Customer Costs in 2004 $ per Outage Event

Outage type	Lawton et al. 2003b (p.46)		SCE 1999 (p. 66)		PG&E 2000 (p.21)	
	Small C/I	Large C/I	Lost sales	Idle factor	Commercial	Industrial
Summer afternoon: 1-hour	$1,200	$8,200	$1,599	$872	$537	$22,400

Another approach to assessing the value of reliability is to look at the shareholder incentive mechanisms put in place by the California Public Utility Commission (CPUC) and other state's regulators. These estimates provide another assessment, adopted by the regulators with stakeholder comment, on the value of customer to improve reliability. Of course, the amount paid to shareholders for reliability improvement is not necessarily the total value of that reliability, but rather it is a sharing mechanism. Therefore, the 'implied VOS' through shareholder incentive mechanisms tends to provide a lower estimate of VOS relative to the survey approach.

Confounding this tendency of downward bias, however, is the presence of "deadband" and "liveband" ranges in some incentive mechanisms. PG&E, for instance, has a reliability mechanism based on its SAIDI and SAIFI performance relative to a benchmarked score. In the latest version of its incentive mechanism,[44] PG&E experiences neither a positive nor negative SAIDI-based incentive for if its SAIDI is within 10 minutes of its benchmark. Beyond that range, PG&E is rewarded or penalized (depending on whether reliability performance is above or below the benchmark) $759,494 for each minute change in SAIDI up to 25.8 minutes above or below the SAIDI target, with a maximum SAIDI based incentive of +/- $12 million.

[44] PG&E 2007 GRC Testimony, Chapter 3: Electric Distribution Reliability and Outage Information Performance Metrics (PG&E-11).

Additionally, PG&E has a SAIFI-based incentive that depends on its performance relative to a benchmark. The SAIFI incentive has a deadband of +/- 0.1 from the benchmark, after which every 0.01 change in SAIFI yields an $800,000 incentive or penalty. This incentive extends to the end of the positive or negative live band, with a maximum incentive or penalty of $12 million for a SAIFI of +/- 0.25 from the benchmark.

Using a few simplifying assumptions, and based on the size of PG&E in 2005 (5.02 million total customer accounts, 81.75 million MWh served)[45], the incentives within the liveband can be translated to a incentive per change in customer outage incidence or per change in kWh unserved. These values are depicted in Table 21. The VOS amounts implied by these incentives do indeed have a higher value that those from the studies shown above, but these values are for the liveband only. Within the deadband near the benchmark, or outside of the liveband, the implied VOS is zero, so the liveband incentives are amplified to compensate.

Table 21: Implied VOS based on PG&E Reliability Shareholder Mechanism

Measure	Implied VOS
SAIDI-Based incentive per change in kWh unserved	$4.88
SAIFI-based incentive per change in outage incidence	$15.93
Total incentive per average-length customer outage	$25.42
Total incentive per kWh unserved during average length customer outage	$13.07

3.3.2 Power quality improvement

Utility distribution companies plan and operate their distribution systems to meet a set of defined power quality service standards. For the vast majority of customers, power quality within design standards will not cause any problems. Electric appliances and fixtures are designed to operate through the range of power quality. Sensitive electric loads such as electronics or sensitive manufacturing processes are generally protected from common power quality problems. There are sensitive loads that power quality problems will cause problems, but these are the exception rather than the rule.

The following list highlights common power quality problems.

<u>Common Power Quality problems</u>

- Low or high voltage
- Poor power factor
- Voltage sags and interruptions
- Surges
- Frequency deviation
- Harmonic distortion

[45] Total Residential, Commercial, and Industrial sales and customer accounts from PG&E's 2005 FERC Form No. 1, p. 304.4. The calculations in the table assume that each customer has a equal share of the load and that load is evenly distributed across each hour of the year.

With respect to energy savings, correcting high voltage and poor power factor create the most value for most customers. These applications are addressed in Chapter 4. In fact, the purchase of capacitors for power factor correction may be one of the few investments that can be justified on loss reduction alone when needed. Protecting against voltage sags and interruptions has the most value for industrial and commercial customers, although the value for residential customers may be very low.

3.3.3 Energy savings

Energy savings are a well-defined benefit stream that can result from improvements to the distribution system. There is a well-developed wholesale electricity market that provides energy prices, and long-term forecasts of the value of energy savings are routinely developed by the California Energy Commission for the Integrated Energy Policy Report, the Title 24 Building Energy Standard, and other applications. A range of distribution applications can result in energy savings, either through lower voltage levels as discussed in the power quality section, or through more efficient equipment, or more efficient distribution system design (e.g. shorter feeders or higher voltages).

Energy costs faced by utilities vary over the course of the year with the highest prices by far occurring during California's hottest summer, weekday afternoons. Therefore, energy savings are highest during the peak. This is the same time that losses are highest on the system. Figure 8 and Figure 9 illustrate the most recent energy forecast from the CEC Title 24 Building Energy standards process for the 2008 program cycle. The levelized value of energy exceeds $140/MWh ($0.14/kWh) in the afternoon in July and August. Current prices are in the $65 to $70/MWh range and forecasted to increase.

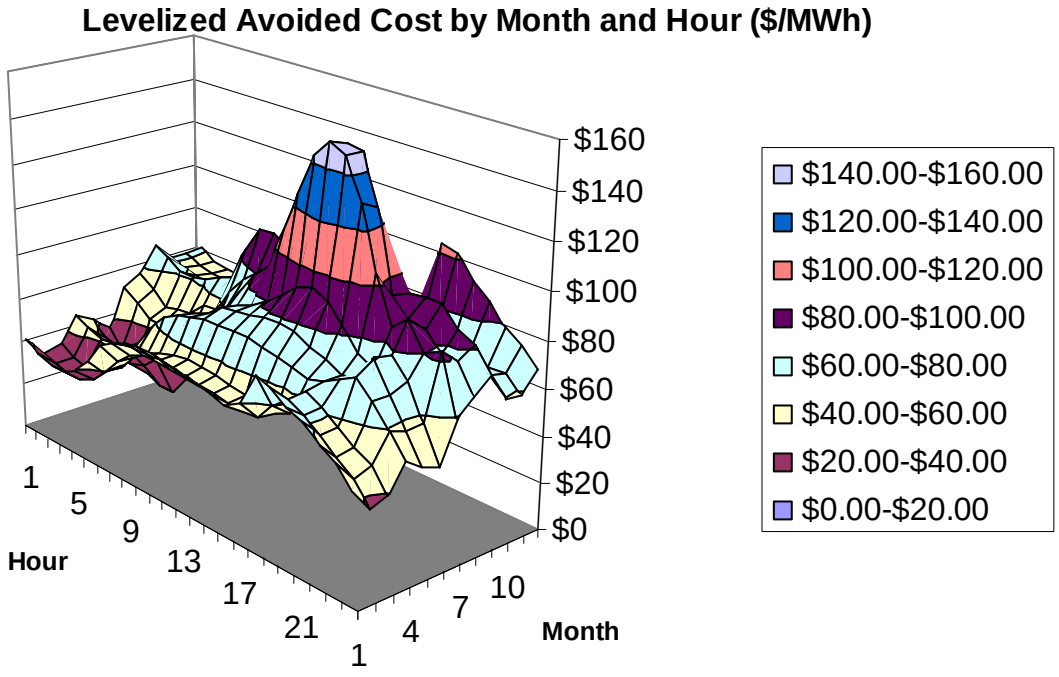


Figure 8: Levelized Energy Value by Hour and Month

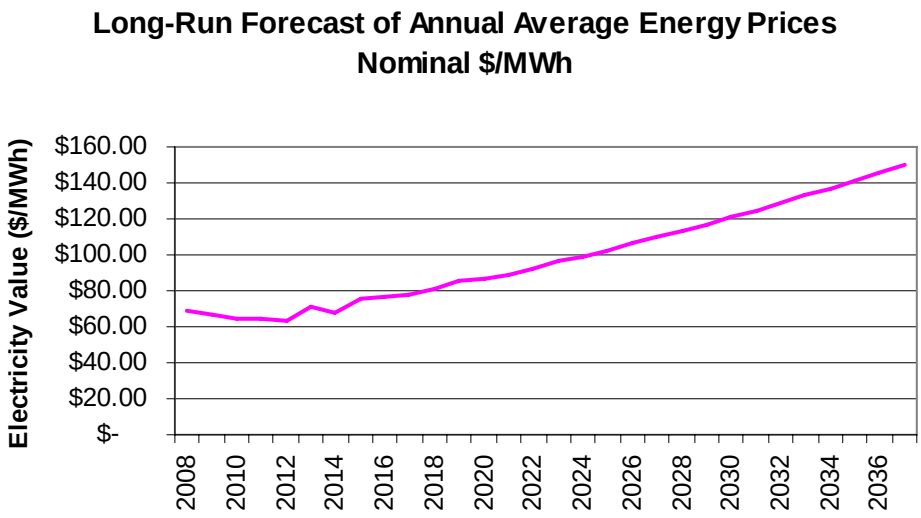


Figure 9: Long-run Forecast of Annual Average Energy Value

In addition to the direct market value of energy savings, a number of other additional benefits have been monetized in research at the CEC and California Public Utility Commission (CPUC) associated with the value of energy efficiency. These benefits are listed below, and detailed financial estimates for each can be found on the CPUC, CEC, and E3 websites[46].

- Reduced air emissions
- Reduced ancillary services
- Reduced wholesale market prices during periods of supply constraints
- Reduced system capacity purchases for savings during peak periods

3.3.4 Distribution operation and capital savings

Distribution planners strive to simultaneously meet capacity needs, maintain or improve reliability, meet service standards and minimize costs. To evaluate potential savings in this process, it is useful to consider the distribution planning process. Each year, a long-term list (5- or 10-year plan typically) of capital projects is refined, and projects to be built in the upcoming year are identified and prioritized based on assessment of project need, and availability of capital budget and construction crews. For each project, the preferred project is selected from competing alternatives. The alternatives for comparison are typically developed from alternative configurations of a standard system design that can solve an identified problem.

The available capital budget to expand the system at the California utilities is similar to the vast majority of states. There is not enough budget to complete every project that has been identified. Therefore, the extent that distribution automation allows utility planners to find solutions in areas with a smaller budget, more areas that need projects can be addressed in each planning cycle. Alternatively, distribution automation, built into a system as it is upgraded, may provide greater reliability with a similar budget as the standard distribution design. Whether the use of DA technologies is intended to provide better

[46] See CPUC avoided costs, CEC Title 24 Building Standards TDV Values, and related E3 website pages. (http://ethree.com/cpuc_avoidedcosts.html, http://ethree.com/cpuc_cee_tools.html, http://www.energy.ca.gov/title24/2008standards/documents/E3/index.html,.

reliability at the same cost, or to maintain reliability at low cost, the choice ultimately requires a theoretical framework that allows the explicit trade-off between cost and customer value. This framework is addressed in Chapter 4.

The configuration and design of a distribution system have important implications for the application and distribution cost savings potential of high value distribution applications. A few of the more important design considerations include configuration (radial or network), whether or not the system is underground, the interconnecting voltage, and substation design.

Utility distribution systems in the U.S. are broadly categorized as radial or network systems. In a radial system, primary distribution lines (or feeders) and their connected loads are supplied by only one substation source at a given time. A network distribution system is more similar to the transmission system, where lines and loads are interconnected as grids with more than one primary supply.

Since consideration of many of the DA applications requires an understanding of the typical distribution system, we present a simplified model of a typical distribution system design. The distribution lines in a radial system are analogous to the spokes of a wheel; they emanate from a single hub without interconnection with one another. Most distribution systems are radial because of the lower cost of protection, operation and maintenance. Radial systems are especially prominent in rural areas, where geography makes the cost of providing redundant supply sources prohibitively high. Figure 10 illustrates an area served by a radial distribution system. The transformer, bus and two breakers in Substation A supply power to Feeders A-1 and A-2. Customer loads are represented by the gray boxes, and are distributed along both the primary feeder lines and the laterals that branch off. For illustrative purposes, a small section of the nearby Substation B is shown with Feeder B-1 extending out towards Feeder A-2.

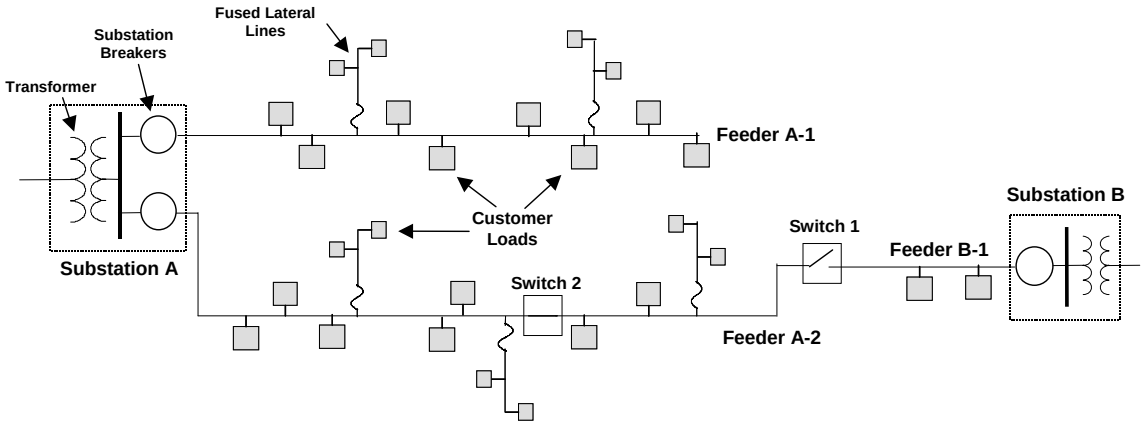


Figure 10: Radial Distribution System

There is no direct connection between any of the three feeders shown in the figure. However, switches along feeders can be opened and closed to shift line segments to a different source. For example, the system is shown with two switches. Switch 1 is normally open and Switch 2 is normally closed, therefore the loads between the switches are normally served by Substation A. If Substation A is overloaded, system operators have the ability to shift the intermediate customers to Substation B, by closing Switch 1 and opening Switch 2. System protection practices prohibit the operation of the system with both switches closed.

There are a number of design features of existing systems that have implications on the operation, capital cost, and reliability of the standard distribution system design.

Table 22: Effect of Design Features on the Operation, Capital Cost, and Reliability of Standard Distribution System

Design Feature	Effect on Operation & Capital Cost and Reliability
Density of distribution substations and feeder length	Shorter feeders and more substations increases redundancy and reduces losses
Number of switches or feeder sections	More switches allows faults to be isolated more precisely
Voltage levels	Higher voltage levels reduces losses
Overhead or underground	Underground systems reduce some types of faults such as trees, wildlife, and auto collisions, but cost more and take longer to repair in the event of a failure
Transformer design, size, and level of redundancy	Affects cost, redundancy of losses
Protection scheme	Affects the ability of DER to interconnect, choice between fuses, breakers, and reclosure scheme affects service reliability
Conductor type and size	Affects losses

From this perspective, one can see how the potential distribution costs are highly dependent on the standard distribution system design, equipment type and size levels, and configuration. The addition of the range of different distribution automation applications further increases the possibilities. Therefore, system-wide deployment of many distribution automation technologies can be done in conjunction with an update to the standard system design that explicitly considers the cost and reliability trade-offs.

3.3.5 Early problem detection, maintenance and emergency repair cost savings

Through vigilance, the normal maintenance of the distribution system, or customer reports, utilities can sometimes identify equipment on the distribution system that is not working correctly and schedule replacement before outright failure. A number of distribution automation monitoring applications can greatly enhance the ability to detect problems before they lead to outages, and in some cases before there are any obvious signs of trouble through monitoring harmonics or other power quality (PQ) signatures of different failure types. At least one utility in the US, Consolidated Edison, has implemented an approach to identify equipment that is likely to fail without any signatures other than the history of the equipment (loading history, type of equipment, vintage and a number of other factors) and comparison to the life of equipment with similar history on the system.

The primary benefit stream from these applications arises from the utility's ability to detect equipment problems and repair them before they lead to power outages. While early problem detection clearly provides reliability benefits by reducing outage occurrences, it also reduces equipment maintenance and repair costs by giving the utility flexibility when it dispatches repair crews and reducing overtime. Being able to decide ahead of time when repairs will occur rather than reacting to emergency repair situations

gives the utility the ability to more efficiently allocate staff and repair equipment resources. Another benefit stream associated with these systems is periphery equipment repair costs. Equipment failures can also damage nearby functioning distribution equipment. By detecting deterioration and repairing equipment prior to failure, the utility is able to avoid maintenance or replacement costs for additional equipment damaged by the failure incident.

Therefore, the core value stream is the cost difference between scheduled replacement of equipment, reduction of any customer outages failure would cause, and any damage on adjacent equipment. In addition, any reduction in maintenance costs for early replacement would be a benefit. For equipment that is still operating, but is aging or is likely to fail, the 'early replacement' of equipment depends on the ability to predict the probability the equipment will fail and the subsequent damages. This value proposition is illustrated in Chapter 4. Other applications in this category focus on reducing maintenance costs, such as 'self-reporting' sensors which can potentially reduce the equipment testing and replacement costs and reduce crew time.

3.3.6 Outage detection, location, and accelerated repair time

When utility equipment does fail and there are customer outages, the utility endeavors to restore service as fast as possible. There are a number of DA technologies that assist the utility in reducing restoration times. There are four general steps in restoring service quickly. DA can accelerate the time to complete the first three, and distribution system design, geography, availability of spare components, and other factors influence the fourth.

1. Identify that an outage has occurred
2. Identify the precise location and equipment that has failed
3. Isolate the outage to as few customers as possible
4. Repair the system as rapidly as possible

The types of DA applications can assist are advanced Outage Management Systems, which assist with (1) and (2) by augmenting identifying and locating problems, and switching (either remotely controlled through SCADA, or automated), which can assist with (3). All of the California utilities have OMS systems and some level of switching capability, however, the increased use of automation can reduce times and improve system restoration. This benefit stream can be valued as a combination or reduced repair times and reduced outage times. The value for this benefit stream can leverage values developed for reliability (Section 4.2.1) and outage repair costs (Section 4.2.3).

3.3.7 Energy security

Energy security has long been a consideration of utility system designers and since the events of September 11, 2001 this issue is gaining more and more attention. In the event of a terrorist attack on our electricity infrastructure, distribution automation approaches may help reduce the impact to our customers. If the attack were on a part of the distribution system ('small grid attack'), the management and restoration of the problem looks much like the management of equipment failure at a substation. In this case, many of the distribution automation components (advanced OMS, automated switching) would reduce the impact. If the attack is on the high voltage transmission system ('big grid attack') and power service is lost to distribution networks, applications designed to operate portions of the distribution system as islands ('microgrids') could significantly mitigate the impact of the outage.

3.3.8 Public and employee safety

Public and utility worker safety is a priority for distribution planners. The safety of the public and utility workers can be compromised by many aspects of a poorly functioning distribution system. The safety of the public can sometimes rely on electricity service such as cooling on an extremely hot day or lighting in

hazardous areas. In these situations, electricity service outages can endanger the public. In addition, when electricity service outages occur due to damaged power lines, those downed power lines can pose serious dangers to the public. The same applications that provide early outage detection, fault isolation, location and accelerated repair time can reduce the probability of injuries.

A recent example is the estimate of up to 139 deaths related to heat storms in California during this past summer of 2006.[47] In addition, there were presumably injuries and stress felt by survivors that were left in bad situations with the outages. It is difficult to include financial assessment of expected reduction in deaths or injury, but these benefits, where applicable, should not be forgotten or discounted either.

3.3.9 Value of Flexibility

Most cost / benefit analyses use expected future costs and benefits streams. For example, the expected future value of electricity is used to compute the benefits of loss reductions. However, there is actually a range of potential future benefits and costs. Some investment decisions will perform better if energy prices are higher than expected (e.g., energy efficiency improvements to the distribution system), and others will perform worse. To compare decisions that have different outcomes across the range of potential future scenarios, it is important to consider a range of scenarios. The results will be a more robust analysis than cost-effectiveness on an expected basis. Investment decisions that have a high expected net benefit, but have a wide range of outcomes may not be the best choice.

Figure 11, below, illustrates the approach to uncertainty into the decision-making process. For example, consider three potential plans and the resulting net cash flow of the outcomes. Plan 2 has the highest expected cash flow, but also the greatest risk of a bad outcome. On the other hand, Plan 3 has a lower cash flow, but the least risk. Plan 1 is somewhere between the two. If a utility must choose one of these plans to serve an area, the 'best' choice will depend upon the consequences of the bad outcome and the risk trade-off of the utility.

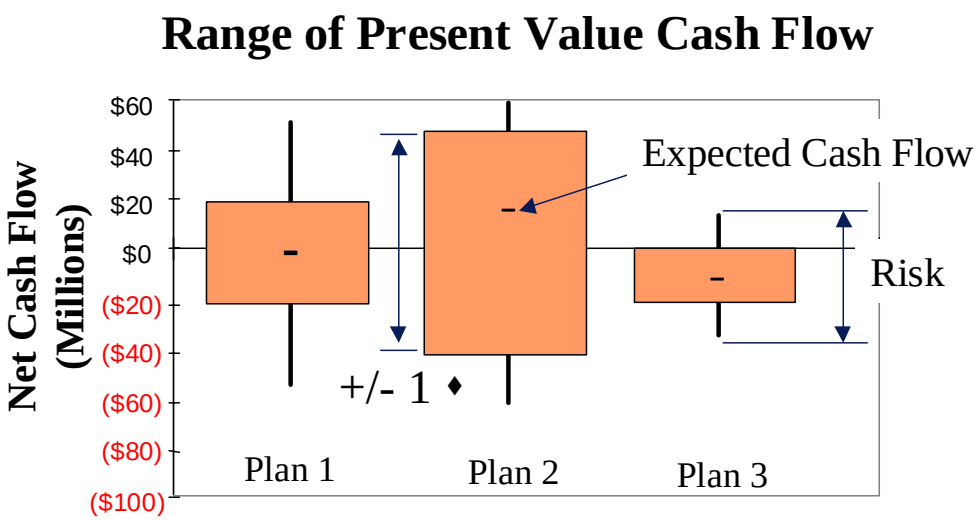


Figure 11: Illustrative Results to Show Value of Flexibility across a Range of Scenarios

[47] http://www.msnbc.msn.com/id/14073968/, *MSNBC*, July 28, 2006. http://www.nytimes.com/2006/07/28/us/28heat.html?pagewanted=1&ei=5070&en=0e5d3cc64fae7c8d&ex=1160107200, *New York Times*, July 28, 2006.

There are several DA applications where it is important to consider the range of scenarios to fully understand the benefits. Depending on the application, introduction of DA can allow the integration and control of local resources, increase the possible number of configurations of the system, and/or improve the ability to balance load across the existing distribution system. Taken together, these alternatives add flexibility to the system because the utility planners and engineers have more options to respond to higher or lower load growth in different areas, to outages that occur from a storm or fallen trees, and other events. Analysis of the value of flexibility is only possible by considering a range of potential future scenarios. There are many forms of flexibility for these types of systems. The following types of flexibility should be considered along with DA applications.

1. More system configurations through automated switching and load balancing mean that the range of customer outage durations will be reduced.

2. The ability to dispatch local generation and load reduction through distribution automation means that the system operator has more options when loads near the available capacity.

3. The ability to control local generation and other demand-side resources in smaller increments means that the planners are able to better match capacity to expected peak loads.

4.0 High Value Applications - Business Case Highlights

In this chapter we develop numerical examples of approaches to capture the value of distribution automation applications for each of the four categories. Where possible we use the California context to show the magnitude of benefits, but use information from out-of-state utilities when necessary or illustrative data to show the approaches. Also, it should be noted that some technology investments can be used for several applications and categories of benefits. The goal in each example is to (a) illustrate a methodology to evaluate a particular category of distribution automation application, and perhaps more importantly (b) identify research that can further the development and integration of high value distribution applications in California.

The four sections in this report that describe valuation approaches are the following:

4.1 Routine Operational Efficiency

4.2 Management of Peak Loads

4.3 Prediction of Equipment Failure

4.4 System Restoration After Failure

4.1 Routine Operational Efficiency

Applications	Automated capacitor switching, dynamic voltage / var control, advanced metering, equipment diagnostics
Value Streams	Energy savings, Voltage / Var control, PQ improvement, reduced theft, equipment diagnostics (blown fuses, bad capacitors, and other equipment)

Distribution automation applications in the category of 'routine operational efficiecy' reduce costs and improve efficiency of the day-to-day operation of the distribution system. The leading examples in common practice are (1) substation SCADA systems, and (2) switched capacitors. Substation SCADA allows system operators to perform distribution substation switching and load data collection from control centers. At this point, most of the California investor-owned utility distribution substations have SCADA at the substation level. The benefits include reduced substation crews, better system coordination, and better load balancing and asset management. New distribution automation applications offer other operational benefits including dynamic voltage and var control, reduced losses, load balancing, equipment diagnostics, power quality improvement, and smart metering to reduce metering costs, improve customer service and reduce theft.

The engineering tools largely exist to quantify system operation benefits such as better voltage / var control, and loss savings through the course of a year, or the equipment's life, although they are not routinely needed in existing distribution planning practice. Tools used for feeder load studies have the capability, but are typically used for peak planning and operate on a 'snapshot' of the forecasted load in the peak load hour. An EPRI tool, the Distribution System Simulator (DSS), has the ability to quickly evaluate a year of data on a distribution system and compare operational characteristics of the system for different system configurations and control schemes. Other vendors standard distribution design packages may also offer this ability even if it isn't commonly used. Using a series of load data, it is possible to sum operational benefits through the course of the year. For example, simulate a system with and without automated capacitors and sum annual loss savings. Other applications such as with and without photovoltaics, demand response dispatched during peak periods, or different equipment type (transformers, conductor, etc) is possible. The results are difficult to generalize; therefore, we draw on other examples completed under PIER research to illustrate the approach.

4.1.1 Voltage Control

One of the operational characteristics of the distribution system that can be managed through distribution automation is the voltage profile along the feeder. Since loads are dynamic and the amount of current affects the voltage drop along the feeder, using voltage monitoring and dynamic switching of capacitors and regulators it is possible to improve the voltage profile. A California Energy Commission study based at Silicon Valley Power illustrates the existing use of the distribution system[48]. This study shows that among other things, voltage profiles along distribution feeders can vary significantly above or below the design voltage. Figure 12 shows the range of voltage along a series of feeders "as found" without adjustment over five 'snapshots' in time, Summer Peak, "Knee" Peak (Fall and Spring), Winter Peak, and Light Load. The vertical axis is the variation in voltage level along a feeder, with 1.0 equivalent to the circuits rated voltage. The horizontal axis is geographic distance with all of the utility circuits shown back to back in sequence. Note that these results are based on simulation of the distribution system, not on measured voltages. Note that these results are based on simulation of the distribution system, not on measured voltages.

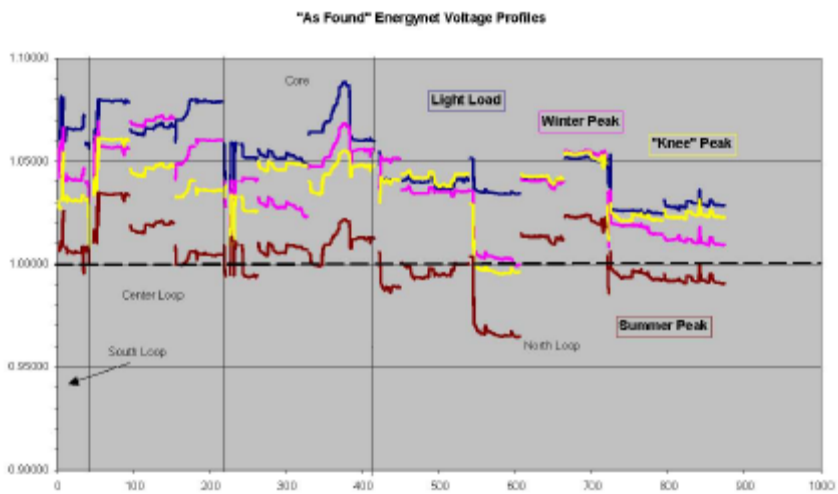


Figure 12: "As Found" Voltage Profiles at Silicon Valley Power (SVP)

In standard distribution system practice, voltage of delivered electricity is controlled to be within a tolerance band around the desired voltage levels. To meet these targets, voltage is measured at the substation breaker and modeled with simulation to identify the likely voltage profile. The distribution system components are then adjusted to maintain voltage within an allowable range of operation. Once set, the utility has limited tools to adjust the voltage profile of the feeder in response to loading conditions on the line. These are predominantly tap changers at the distribution substation and capacitors along the feeders. Distribution automation allows the utility to dynamically adjust these elements through automated voltage regulation at the substation, automatically switched capacitors, and other dynamic elements in response to changes of load.

As long as voltage delivered to customers is within tolerance (typically 120V +/- 6V at the customer), adjustments to the voltage does not have value on its own. However, reducing voltage at the customer can also reduce load and lead to energy savings. This concept is discussed further in targeted conservation voltage reduction in applications designed for 'Management of Peak Loads.' Good voltage

[48] Evans, Peter B. 2005. *Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet*. California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-2005-096.

control also improves customer power quality which benefits sensitive customers, and makes it less likely that the delivered voltage will fall outside of the desired band around 120V.

The energy savings from reduced voltage depends on the type of loads being served. Voltage reduction basically reduces demand (kW). Whether on not it saves energy (kWh) depends on how the load is controlled with respect to time. For 'resistive' loads, which include incandescent lighting, electric water heaters, and clothes dryers, one would expect the kW demand to drop by a square relationship as the voltage is reduced.

For 'inductive' loads, which typically consist of induction motors primarily, the demand reduction is less clear. The active power part (kW) of the load would be relatively constant, while the reactive power part (kvar) would ideally decline as the voltage is reduced. This would reduce losses in the system. However, if the voltage drops too low for heavily loaded motors, the reactive power consumed may actually increase, also increasing energy losses.

An amount of energy savings commensurate with the voltage reduction would be expected from, for example, lighting loads that are energized the same amount of time each day. These savings could be substantial. However, energy savings would likely be insubstantial from thermostatically-controlled loads that require a certain amount of energy to perform their task (e.g., electric water heaters). It is also possible that reducing the voltage on some loads reduces their efficiency to the point there is a negative savings.

Voltage Management at the Customer's Meter
To take advantage of CVR's potential for energy savings, the manufacturer Microplanet offers a product that adjusts the voltage at the customer meter to be just high enough to operate appliances (~114V for most homes). Advantages of this product include reductions in the customer bill. Utility pilots have been testing the installation of using customer voltage regulation such as the Microplanet[49].

4.1.2 Loss Reduction

A direct operational benefit that can be achieved with voltage and var control is loss reduction. Again, this benefit is difficult to generalize and we use a specific example from a CEC PIER research project as illustration. In this case we show simulation results from EPRI DSS for a distribution feeder in San Francisco that serves the San Francisco Southeast Wastewater Treatment Plant (SEP) with and without the SEP 2MW waste-gas cogeneration. Figure 13 and Figure 14 show comparisons of the hourly feeder losses without the SEP generator operating and with the SEP generator operating according to the measured output and at maximum output for the time period. In each instance, the reduction in feeder losses is represented by the blue areas (losses for the "No Generator" scenario) that show through the yellow areas (losses for the "With Generator" scenario). In Figure 13, because the generator output varies according to the measured data, we can clearly see the periods where the generator actually operated and where the generator did not operate.

[49] For example, see Northwest Energy Efficiency Alliance, http://www.nwalliance.org/projects/projectdetail.asp?PID=75

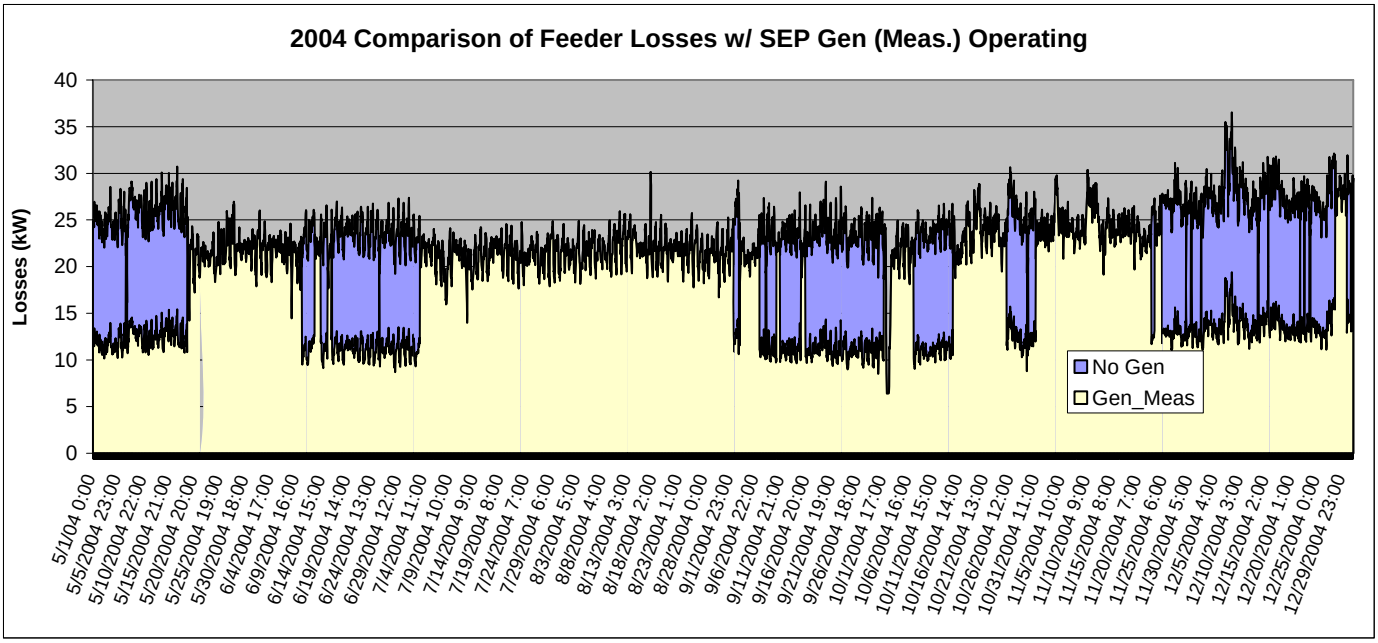


Figure 13: Feeder Losses without SEP Generator operating and with SEP Generator Operating According to the Measured Output for the Time Period

Figure 14 shows a constant reduction in losses as the generator output for this scenario is set constant at the maximum output of the generator. This would represent the loss savings if the cogenerator were always in operation.

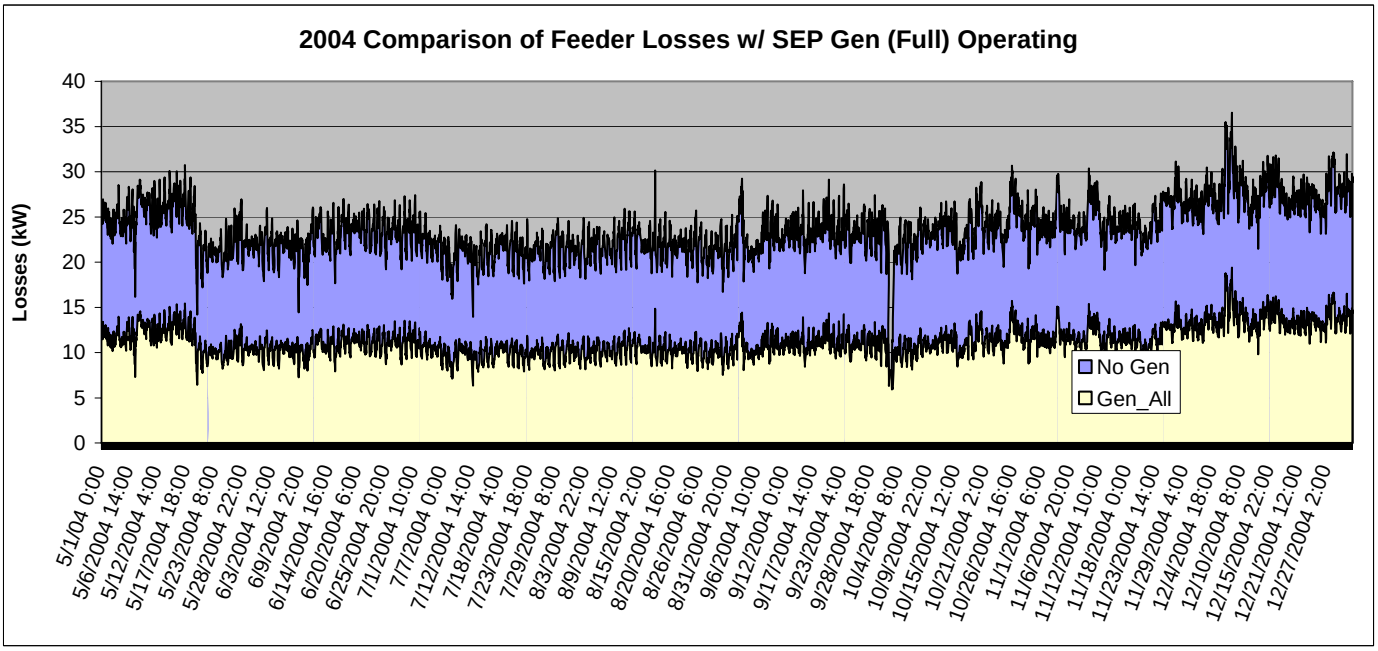


Figure 14: Feeder Losses without SEP Generator Operating and with SEP Generator Operating at Maximum Output for the Time Period

The net results of the SEP analysis shows a loss reduction on the feeder approaching 50%, which translates to an energy savings of approximately 0.6% of the total energy needed to be generated to serve SEP.

California Example

Even though the percentage improvements may be small, the economic impact of statewide deployment of distribution applications that can improve losses can be significant. Of the statewide average losses of 7 to 8%, approximately 3.5% of the losses occur on the distribution system on average. If a 0.5% reduction in losses can be achieved (e..g. movement to 3% average losses rather than 3.5%), this equates to approximately $50 million per year in value for the State (assuming $60/MWh market price of electricity). Using an estimated carrying cost of 12%, this could justify an investment of approximately $425 million per year in capital expenditure. This level of energy savings would also eliminate approximately 500,000 tons of CO2 per year[50]. A recent study at Hydro-Québec (publication pending) found approximately 2 TWh of energy savings per year is possible through improved voltage control in the province[51].

Because of the physics of electric distribution, losses are higher during the peak hours of the year than they are at other times. Figure 15, below, shows the average losses for the investor-owned utilities on the distribution system by time-of-use period (does not include losses on the subtransmission and transmission system).[52] In addition, the value of energy savings is significantly higher during the peak periods.

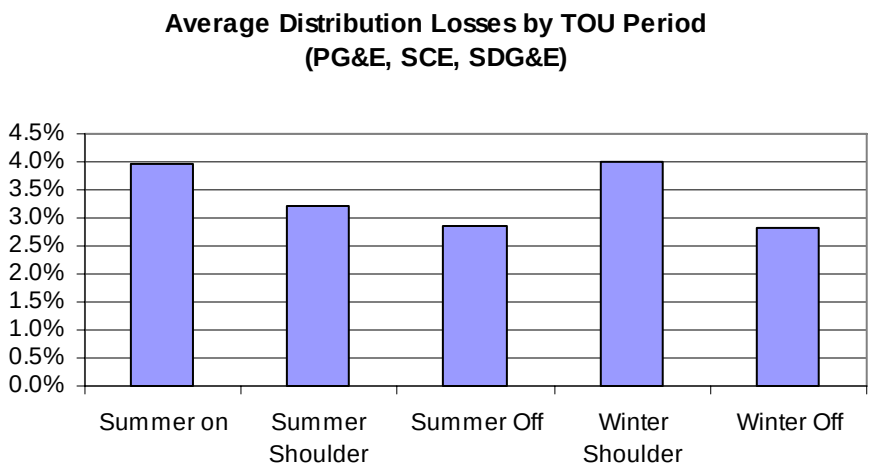


Figure 15: Distribution System Losses by Time of Use Period

Therefore, for many distribution applications focused on efficiency of distribution, if losses can be reduced on average 0.5% for the year, they will likely save on even higher percentage during the peak and of a greater throughput. Saving of losses on peak has more value because the costs of energy are higher and the emissions of on-peak generation are highest. Also, saving of peak losses also provides system and

[50] Estimate made using 1000lbs CO2 per MWh saved which is approximately the emissions rate of a new combined-cycle gas turbine.
[51] Presentation by Georges Simard of Hydro Quebec at EPRI Advanced Distribution Automation workshop in Montreal, Quebec – October 22 – 25th, 2006
[52] Loss data from CPUC R.04-04-025. SDG&E Winter Peak period is averaged into the Winter Shoulder period.

local capacity benefits. The approaches to reduce energy usage on the distribution system that are likely to increase peak savings include;

- Installing more efficient equipment (for example, conductors and transformers)
- Load balancing
- Eliminating malfunctioning equipment
- Reduction in theft (since most consumption is on-peak)

As seen in the Silicon Valley Power (SVP) example above, the voltage is highest during low load hours and stands to gain the most during this period. This is due to the fact that the system is designed to prevent under-voltages during the peak load and when load decreases voltage will tend to increase. However, this is the period with the lowest amount of energy delivered, no capacity concerns, and the fewest emissions. Therefore, while it would still be helpful to improve voltage profiles throughout the year, most of the value will likely be gained on peak. The targeted conservation voltage reduction (CVR) application discussed in the Managing Peak Loads applications is focused on exactly this application.

4.1.3 Equipment Diagnostics

Another operational benefit of distribution automation is in detecting equipment that is malfunctioning. A common problem, for example, is detection of a blown fuse on one phase of a capacitor bank on the distribution feeder. Through problem detection, these problems can be fixed which will also improve power quality, reduce losses, and save line crew time spent investigating and correcting line trouble.

4.1.4 PQ Improvement

For the majority of customers, the existing power quality of the system is adequate and there are not significant gains available from power quality improvement. For some sensitive customers, however, power quality is a significant concern. Distribution system monitoring applications can contribute significantly to monitoring and correcting power quality problems.

4.1.5 Advanced Metering

As noted in section 2.2 of this report, the California investor-owned utilities have recently made the business case for system-wide deployment of Advanced Metering Infrastructure (AMI). AMI provides significant operational benefits in metering costs and other operational value. These benefits offset the majority of the costs of implementing AMI in most utility scenarios. By integrating information from the AMI system with other distribution automation applications we can leverage the investment in AMI to provide additional value. For example, certain AMI technologies can enable the utility system to dispatch demand response for local load relief when needed for local system control. This example is discussed in detail under applications for ‘Management of Peak Loads.’

The major benefit categories reported by the three utilities and their percentage of the total cost reported for AMI deployment are shown in Table 23. Note that the utilities are not entirely consistent in allocating specific benefits to each category. Some of the benefit calculations for specific benefits are described in the sections below, when available.

Table 23: Proposed AMI Deployment Benefit Projections for the Three California IOUs

Benefit Type	PG&E		SDG&E		SCE	
Meter Reading O&M	$1,074	48%	$455	72%	$271	21%
Labor Overhead	221	10%				
Meter Operations	103	5%			4	0%
Meter Capital			8	1%	118	9%
Meter Reading	1,399	62%	463	73%	393	30%
Billing	215	10%	188		21	2%
T & D	189	8%	32	5%		
Service Start & Stops	102	5%			29	2%
Call Center Savings	40	2%			3	0%
Customer and Field Service	142	6%			32	2%
Demand Response	448	20%	351	55%	370	29%

4.1.5.1 Meter Reading

Meter reading cost savings is by far the largest benefit claimed by the three utilities ranging from 30% of AMI deployment costs for SCE to 59% for SDG&E. The avoided labor, capital and overhead costs from not having to maintain a meter reading staff are the primary savings. PG&E expects to eliminate 970 FTE positions at an annual savings of $86 million and total NPV of $1,085 million. SDG&E estimates average annual savings of $11.5 million for a total NPV benefit of $334 million.

SCE estimates that 80% of their 570 meter readers and 80 management and support personnel would be eliminated with total NPV savings of $271 million. Decommissioning 80% of its hand-held meter reading devices will save an additional $1.2 million. SCE believes that the benefits of carrying fewer types of meters will be offset by the higher failure rate and shorter useful life of AMI meters. However, the avoided cost of replacing 72,000 conventional meters each year is $118 million over the period analyzed (through 2021). The utilities also believe the costs associated with injuries, accidents and third party claims will be significantly reduced, as meter readers have relatively high injury rates.

4.1.5.2 Billing

PG&E estimates that AMI will result in an average decrease in the billing cycle of 15 days for summary billed accounts, resulting in a cash flow savings of $6.7 million per year. Reduced billing exceptions will require 55 fewer billing employees at an annual savings of $4 million.

SCE does not include any savings for more timely customer billing, believing the cost of rescheduling billing dates for all summary billed accounts would involve significant costs. Similarly, SCE asserts that savings associated with reduced “idle usage episodes”, periods when a meter should be turned off but is using energy, would be minimal. SCE anticipates total savings of $5.4 million in avoided estimated bills associated with inaccessible or inaccurate meter reads.

These benefits are somewhat offset by the increased IT and processing costs associated with the significantly increased volume of data and complexity of bill calculations utilizing the 15 minute interval data provided by AMI. The CPUC stated than an AMI system should support customer understanding of hourly usage patterns, hourly energy costs and access to personal usage data. Developing and

implementing the software and web applications to process AMI data and comply with the CPUC directive represents an additional as yet unspecified cost.

4.1.5.3 Transmission & Distribution

PG&E cites the experience of Ameren in estimating T&D engineering and planning benefits. Ameren asserts that AMI has allowed the company to improve its transformer utilization and purchasing, saving 20 percent of its annual costs through better sizing. A CapGemeni study estimates cost savings of 4-19 percent for system and equipment life-cycle management and 15-25 percent for system design optimization.[53]

PG&E cites several studies in estimating outage restoration benefits. Pennsylvania Power and Light claimed a reduction in restoration labor costs and a six-hour reduction in total restoration time during Hurricane Isabel as a result of AMI.[54] CapGemeni estimates a cost savings of 3-8 percent of annual costs for outage restoration for utilities using AMI. PG&E estimates outage restoration benefits of $7.2 million.

Transmission and distribution planning and capital costs can also be reduced. Readily available real-time load data for specific customers, customer classes, and feeder lines will also allow for specifically targeted education campaigns, demand response programs, and capital improvements. The availability of such data also eliminates the need for specialized load research studies. The combination of more accurate modeling and targeted programs will enable utilities to defer or avoid capital investments.

4.1.5.4 Field and Customer Service

PG&E anticipates a reduction in the number and length of customer calls related to energy costs, delayed bills, estimated bills and meter reading concerns and an annual savings of $2.7 million. SCE calculates that 3,376 billing inquiry calls will be avoided each year at an NPV savings of $3.4 million. SCE estimates an average cost of $15 per site visit to turn meters on and off. Such visits could be virtually eliminated at a savings of $29 million (through 2021).

4.1.5.5 Demand Response

PG&E's base case assumes 15% participation in an opt-in CPP program, estimating net benefits at $488 million. SDG&E predices 204 MW of demand response at a savings of $235 million. The SCE base case assumes that 80% of eligible customers are defaulted to CPP rates, providing total NPV benefits of $367 million. The above figures represent base case assumptions. Each utility analyzed demand response under a several scenarios, resulting in a wide range of potential participation levels and impacts. The key sensitivities driving the level of estimated benefits include:

- Future value of energy and capacity
- Customer loads, load profiles and growth rates
- Customer participation and response rates
- Elasticity of demand
- Rate levels and rate design (Real Time Pricing, Critical Peak Pricing, Peak Time Rebates)
- Opt-in versus opt-out requirement

[53] CapGemini PowerPoint presentation on "Advanced Metering Infrastructure Discussion" dated June 2, 2004.
[54] PPL 'white paper' on "how TWACS Successfully Supported power Restoration During Isabel" and PowerPoint presentation on "Outage Assessment Using AMR" distributed by PPL for the Chartwell Audio conference on Outage Management on May 25, 2005.

4.2 Management of Peak Loads

Applications	Distribution targeted load control, conservation voltage reduction, energy storage, facilitated Distributed Energy Resource (DER) interconnection
Value Streams	Improved reliability, energy savings, Distribution and Transmission operation and capital savings

Distribution automation applications in the category of 'Management of Peak Loads' help reduce overloads on distribution system equipment. This set of applications is similar to demand response measures currently in place to manage system peak, but targeted in a local area for relief on the distribution system. Peak load control in select areas of the distribution system is increasingly valuable to the distribution system as illustrated by the summer of 2006 in California, where many (possibly thousands) of line transformers were overloaded and needed to be replaced.

The following two news clippings illustrate the extent of the problem.

> *Pacific Gas and Electric Company is continuing its efforts to restore its customers affected by the heat wave. With historically high temperatures in California, PG&E has experienced record high levels of energy use throughout its service area, an increase of at least 15 percent.*
>
> *Due to prolonged heat conditions, system equipment has not had an opportunity to cool down. Starting yesterday, truckloads of transformers arrived at the company's materials center in Fremont to replace the many hundred units of overheated equipment damaged in the current heat storm. Over 900 repair crews dispatched into the field to address problems at over 1000 locations to restore power to the remaining 10 percent of the customers affected since the heat wave struck on Friday. PG&E's restoration efforts have been concentrated in the South and East Bay, the areas hardest hit by the heat storm. As of Tuesday afternoon at 4:00pm, 27,331 customers remain without power.*
>
> - *PRNewswire-First Call, July 25th, 2006*

> *Portland, Ore.-based PacifiCorp has agreed to send work crews to assist Southern California Edison (SCE) with the work of restoring power to the approximately 9,300 SCE customers still without power Tuesday due to a prolonged heat wave.*
>
> *SCE requested mutual aid from neighboring utilities on Sunday evening when trends clearly indicated some customers could be out for several days. Only PacifiCorp could respond and the number of workers is still being finalized. Utilities throughout the Western U.S. are all coping with the effects of a lingering heat wave.*
>
> *The workers are expected to begin arriving sometime Tuesday and will begin work immediately on the isolated power outages plaguing the Southland, many of them weather-related--either failed transformers or overhead electric wires down due to high temperatures, high winds or lighting strikes.*
>
> *- Businesswire, July 25th, 2006*

4.2.1 System Reliability

The primary benefit of the management of peak loads is increased distribution system reliability. To illustrate the relationship between load and reliability the project team developed a framework to assess the probability of being able to serve load at different load levels based on the probability of equipment failure, its load-carrying capacity, and restoration time when the component fails. This framework is used in the following sections to value the following peak load applications;

(a) automated operation of DR for local system conditions
(b) value of energy storage
(c) interconnection of renewable DG such as rooftop photovoltaics

The framework is implemented in Excel with simplified input assumptions, but could be done as a module for existing planning tools.

As an example of distribution system reliability analysis, we draw on an analysis E3 completed for a utility serving a major metropolitan area (names and numbers have been changed). This type of analysis is also possible on a radial distribution system network. The load area is served by 5 transmission lines each with a capacity of approximately 200 MW. Power delivery from the main transmission voltage substation is accomplished by means of five parallel circuits, each consisting of a single 345/138 kV autotransformer, and three 138/13 kV step-down transformers (one at each location). The design rating for this system is approximately 667 MW.

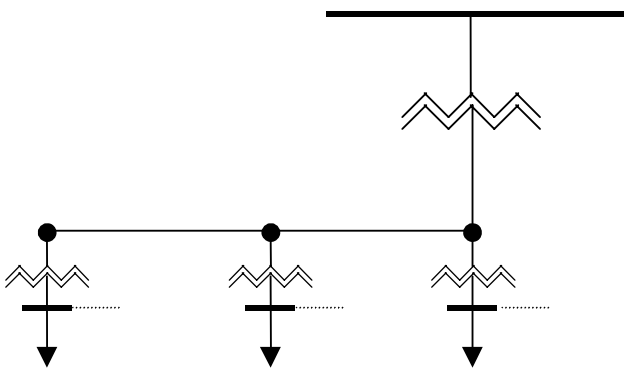


Figure 16: Example Distribution System Topology

With the system topology in place, we develop a reliability estimate at each load level for this system based on equipment failure and repair rates for the feeders. In this example historical failure rates for individual components on each feeder that are in series were combined (combination of cable, autotransformer, and sub-transformer failure rates). The resulting reliability expectation is 2.94 failures per year, and repair times of 2.74 days per feeder. Once elements in series are combined, a Markov chain analysis is used to determine the combined probability of the overall system being in each state. As shown in Figure 16, the system has 6 possible states ranging from 0-5 operational feeders. If State 1 is all of the feeders are working, then the failure rate determines the probability of moving to State 2, and if another feeder fails to State 3, and so on. The restoration time is used to determine the time to put a

feeder back in service. With this approach and the feeder failure and repair rates, the probability of the overall system being in each of the 6 states can be calculated.

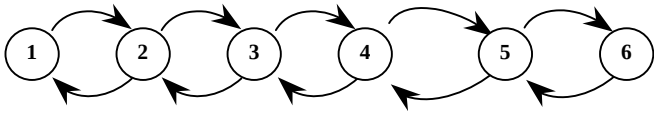


Figure 17: Illustration of a 6 State Markov Chain Analysis

Once the state probabilities have been calculated, they can be matched with the load serving ability in each state (i.e., the number of operational transformers) to determine the reliability curve for the system. If system peak demand is 663 MW then the system will be able to serve the peak demand 99.99% of the time because peak demand can be served by as little as 3 operational feeders, and the long term probability of 3 or more transformers being operational in the system is 99.99%. The reliability curve and peak load for this example is illustrated in Figure 18below.

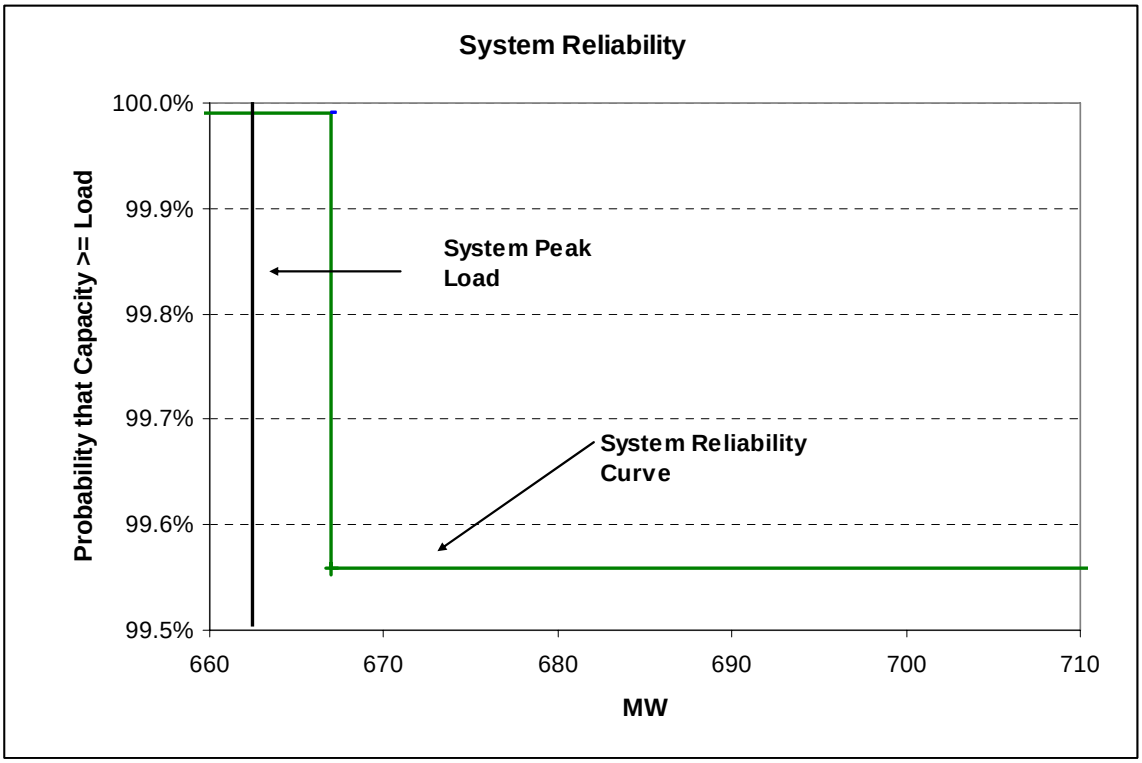


Figure 18: Example Reliability Curve and Peak Load

Based on transformer equipment failure rates the system will be able to serve loads up to 667 MW 99.99% of the time. This high availability at the lower demand levels can be attributed to the ability of the system to serve the 667 MW load level with less than full equipment operation of 3 or more transformers. So even if one or two transformers fail, a system load of 667 MW can still be served by the remaining operational transformers.

This is a specific example of how to calculate the reliability curve of a distribution system with 5 feeder lines, but given the appropriate configuration and information a similar curve can be formulated for any

distribution system. The following metrics are needed to calculate the shape of the reliability curve for general distribution systems:

- System configuration and topology, including:
  - Number of transformers and capability
  - Number of circuits and configuration
  - Number of switches, location, normal position, switching time
  - Other system capacity sources (energy storage, DG, etc)
- Rated or historical transformer outage frequency
- Rated or historic transformer repair times
- Rated DG outage frequencies (if available)

These metrics can then be used to develop the possible configurations of the system at any given time, and the probabilities of the system being in those configurations. Once all the system configurations and their associated long-term probabilities are calculated, the system reliability curve can be developed by plotting the load level available in each configuration against the configurations availability.

4.2.2 Maintaining System Reliability

As illustrated by the distribution system reliability analysis, as load levels increase, the likelihood of being able to serve the load decreases. In areas of the system that have been built, load growth through new customers and 'in-fill' necessitates adding capacity to the system. For an urban area, this can require expensive upgrades including purchase of new right-of-ways and substation property, high voltage underground cable, and involve contentious proceedings with the local community. In these cases, it might be easier and less intrusive to the community, to invest in distribution automation.

The system was able to meet the original system peak load with 99.99% reliability but the increase in peak load from 663 MW to 680 MW reduced the system peak reliability to 99.87%. This effect is illustrated in Figure 19 below, where the grey vertical line representing peak load is shifted to the right.

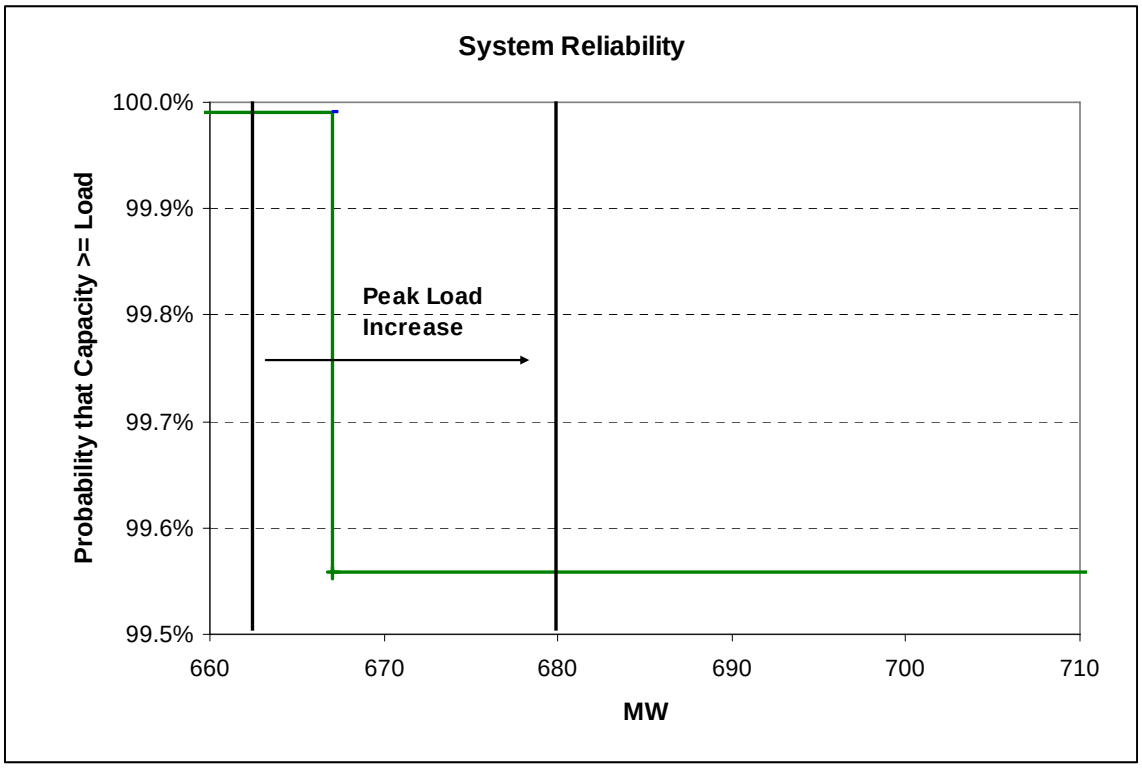


Figure 19: Illustration of Shift in Peak Load

There are two approaches to maintaining system reliability in the face of peak load increases. The first approach is to inject load resources into the system. These load resources include building increased transmission entrance points, increasing the import capabilities of existing transmission points, or adding distributed generation sources to increase the amount of energy available to the system. The effect of these sources is to shift the reliability curve to the right as another resource with its own availability is added to the system. One example of this approach is to increase the capacity of existing transmission feeder lines into the system to increase system load. In our example this can be accomplished by increasing the transmission capability of each feeder line by 10 MW. This would provide 700 MW of load capacity from 3 transformers and would once again allow the system to serve its peak load with 3 or more transformers and with 99.99% reliability. This increase in reliability of the system from the new transmission line capacities can be seen by the rightward shift in the reliability curve Figure 20.

An alternative approach to increasing load serving capabilities of the system in the face of peak demand increases is to add distributed generation (DG) sources to the system and use distribution automation to automatically dispatch the devices if needed. These distributed generation sources would provide back-up capacity if one or more of the existing feeder lines fail. In this example 10 2-MW distributed generation sites were built on the distribution system. The effect of this addition is again to shift the reliability curve to the right and restore system reliability levels back to 99.99% at the new peak load level. The effect is illustrated in Figure 21.[55] Multiple DG units combined with the existing distribution system can deliver a high level of reliability even though an individual DG unit has relatively low availability (95%) because there are a number of units and they are only required if a component of the highly reliable distribution system fails.

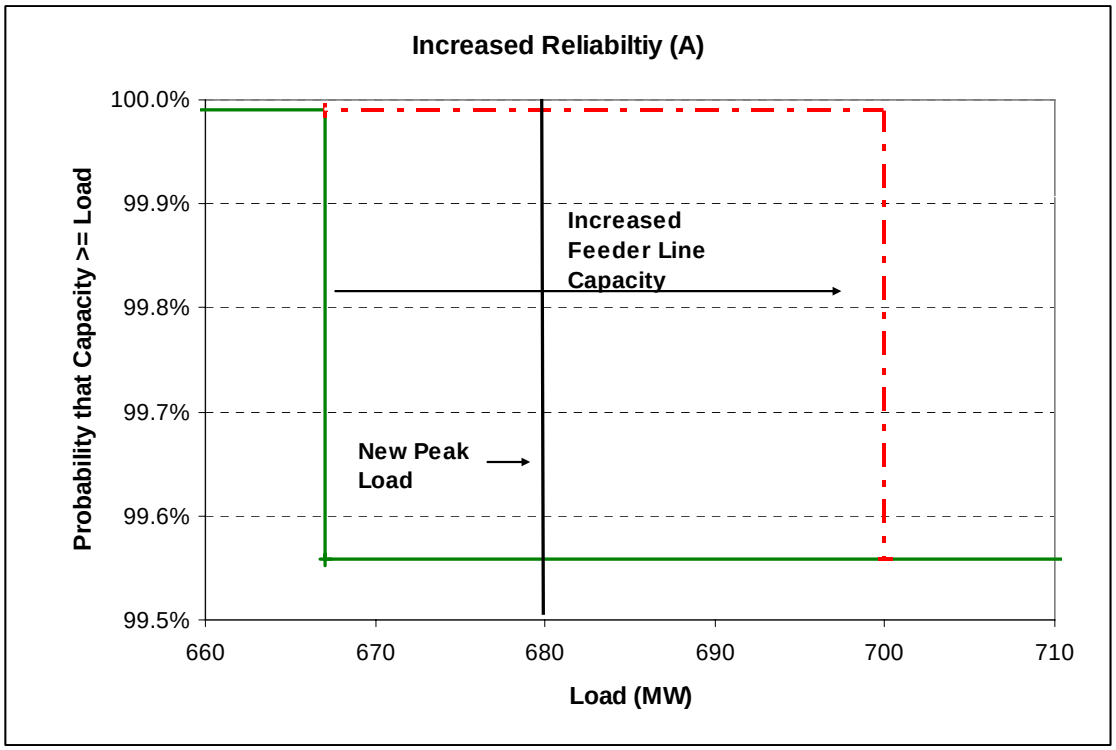


Figure 20: Increase in Feeder Line Capacity to Serving New Peak Load

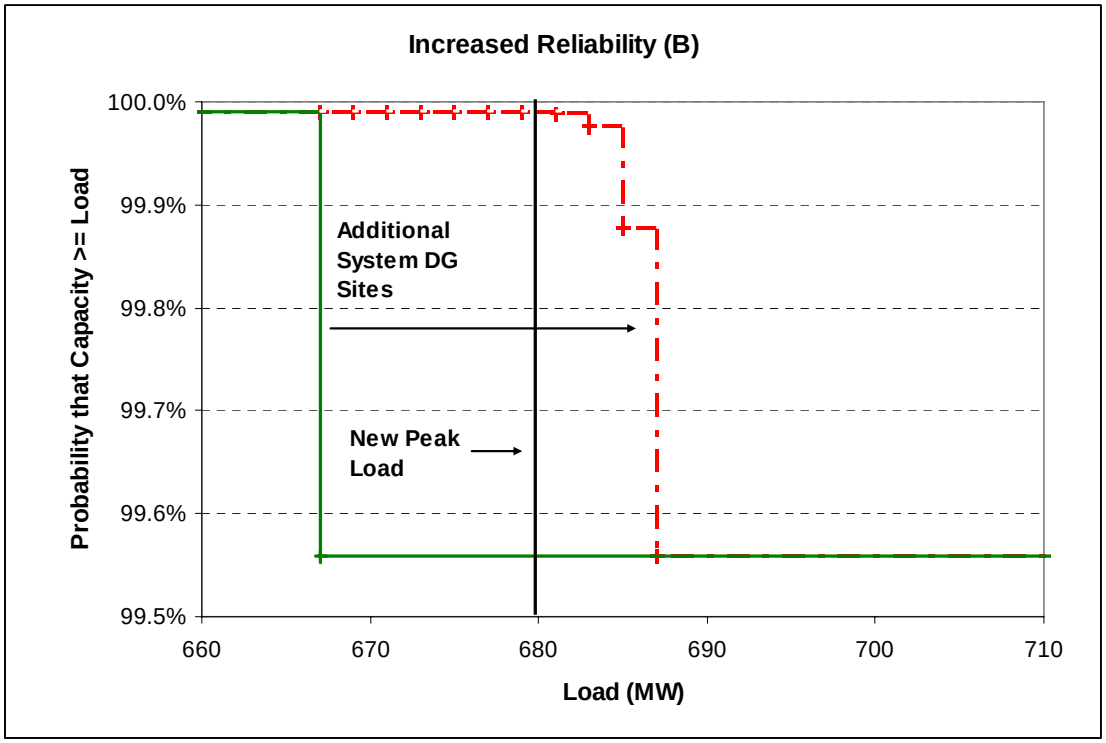


Figure 21: Addition of DG Sources and Coordination with DA to Serve New Peak Load

The second approach to maintaining system reliability involves the utilization of distribution automation to automatically dispatch demand response applications to shift the peak demand below 663 MW. Since the peak load occurs relatively few hours, and typically load reduction is only needed during a contingency on the peak, these demand response dispatch signals would be expected to operate very few hours. This application is discussed in more detail below.

4.2.2.1 Value of Distribution Applications for Maintaining System Reliability

The value of using distribution automation as a tool to maintain distribution system reliability is based on its cost relative to load resource acquisition alternatives. Clearly DA applications are only valuable for system reliability maintenance if they have higher net benefits than other supply side options.

DA Net Benefit = Present Value Savings of Deferring Traditional Investment + System Capacity Value of Load Resource – Load Resource Acquisition Cost

The cost of the DA technology will encompass any equipment and operation costs as well as any necessary payments made to customers for load reductions that occur from DA application. The previous equation, for DA net benefits, is only appropriate if it is a cost comparison between technologies with equal reliability performance characteristics. That is if both the load resource acquisition technology and DA application provide the same level of reliability to the system.

4.2.3 Increasing System Reliability

Distribution automation applications that reduce peak load can also be used to increased system reliability in non-growth areas rather than simply maintain the reliability in the face of increased peak loads. This effect is illustrated in Figure 22 below. If for example the original peak load on the system was 680 MW and the system had a corresponding 99.87% reliability level then the ability to dispatch a peak load reduction of 17 MW from DA applications could improve system reliability to 99.99%.

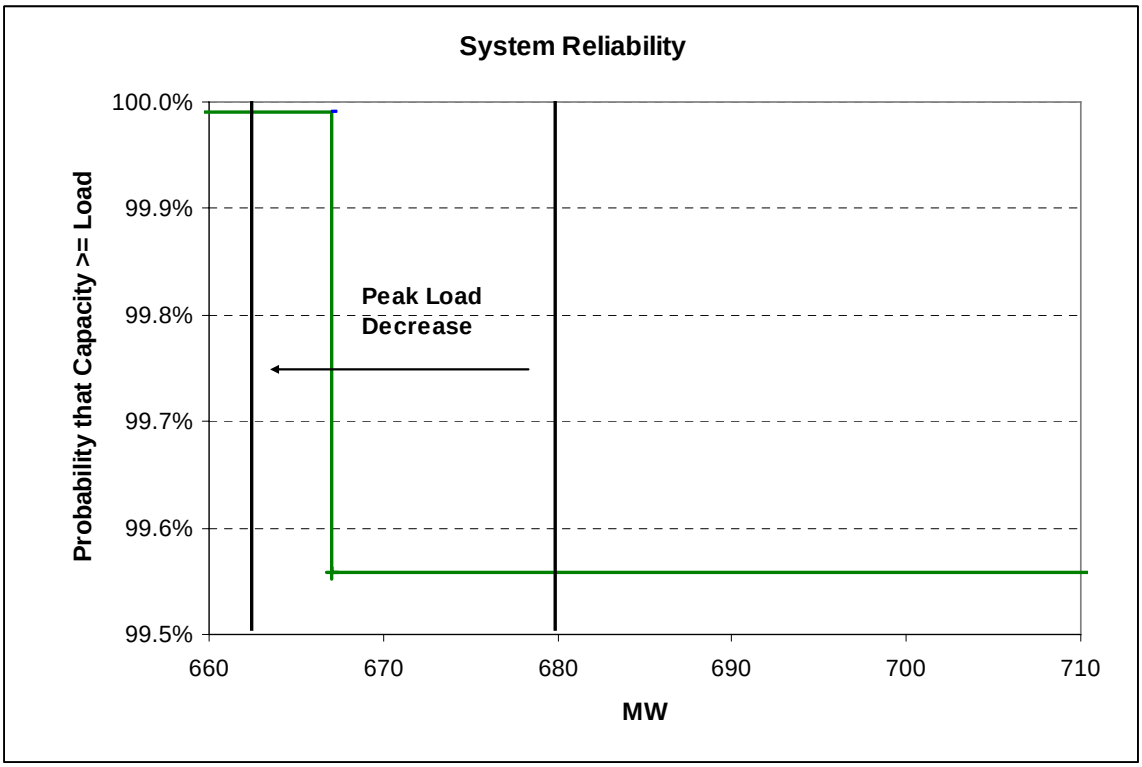


Figure 22: Distribution Automation Applications to Reduce Peak Load and Increase Reliability

4.2.3.1 Value of Distribution Application for Increasing System Reliability

The formulation of the net benefit stream of DA applications that change the reliability level must also consider the change in customer reliability. This benefit can be valued based on reliability metrics such as a predicted change in SAIDI, SAIFI, or CAIFI. The reliability benefit can be measured by customer outage costs or Value of Service (VOS) metrics. If VOS values are known then the equation for reliability benefits from the DA application can be calculated as follows.

DA Net Benefit = Present Value Savings of Deferring Traditional Investment + System Capacity Value of Load Resource + (VOS1* ΔHR + VOS2* ΔO) - Load Resource Acquisition Cost

Where VOS1 = Customer value of service $ per kWh unserved
VOS2 = Customer value of service $ per outage event
ΔHR = Change in outage hours from DA application
ΔO = Change in outage occurrence from DA application

4.2.4 Distribution Level Load Control

The major California utilities are already implementing a variety of demand response programs to provide bulk system capacity. The utilities offer customers incentive payments in return for customers dropping

some portion of their load upon request. Figure 23 is from the website for a program offered by SCE of the type of incentive the utility will offer a customer for their load control program[56].

SUMMER DISCOUNT PLAN	MAXIMUM SAVINGS	GOOD VALUE	MAXIMUM COMFORT
	off for up to **6 hours a day**	off for up to **4 hours a day**	off for up to **3 hours a day**
Unlimited (any # of interruptions)	**$200***	$100*	$50*
Limited (up to 15 interruptions)	$100*	$50*	$25*

Figure 23: SCE Summer Discount Program for Customer Load Control

Giving utilities control of demand response at the distribution level will allow them to more accurately maintain the reliability and service costs at each distribution system. The major California utilities have already invested significant resources in Advanced Metering Infrastructure (AMI) and programmable communicating thermostats (PCTs) are likely to be included in new construction and major retrofits beginning in 2008 (if adopted in the current Title 24 process). These technologies enable utilities to communicate with customers and selectively reduce load for participating customers. Automated local dispatch would be the final piece in this system by allowing the utility to automate the control when emergencies occur on the distribution level.

Because the AMI technology for distribution targeted load control for wide-scale deployment in California is already in place in many areas, the primary cost of load control programs at both the system and distribution level is the cost to customers of reduced energy usage. On any given distribution system there will typically some end-uses of some customers who are able to reduce load without undergoing significant economic burden as well as customers who will face significant economic burden from any level of energy loss. A program that allows customers to opt-in certain end-uses at different incentive levels so that the AMI system can control them when needed can be designed so that available load available is known to the distribution operator in a priority order of dispatch with the least costly energy needs interrupted first. This effect is illustrated for our example in the figure below. The initial reductions from DA from the distribution system peak load of 683 MW would be relatively inexpensive, but as more and more load needed to the load reduction becomes increasingly expensive.

[56]http://www.sce.com/RebatesandSavings/Residential/SummerDiscountPlan.

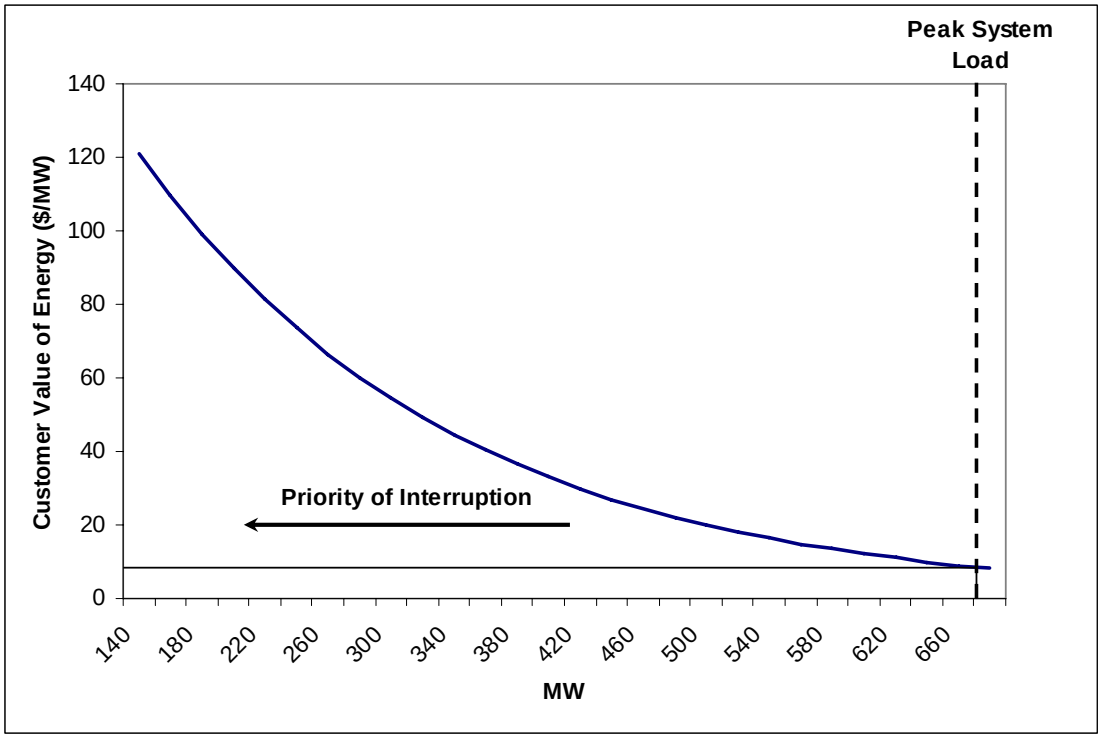


Figure 24: Illustration of System Load Sorted Priority of Interruption for Each End-Use

In our example, the total cost of a DA application that reduced load by 43 MW from 683 MW to 640 MW would be the area under the cost curve between those two peak load levels. This is illustrated as the shaded region in Figure 25 below.

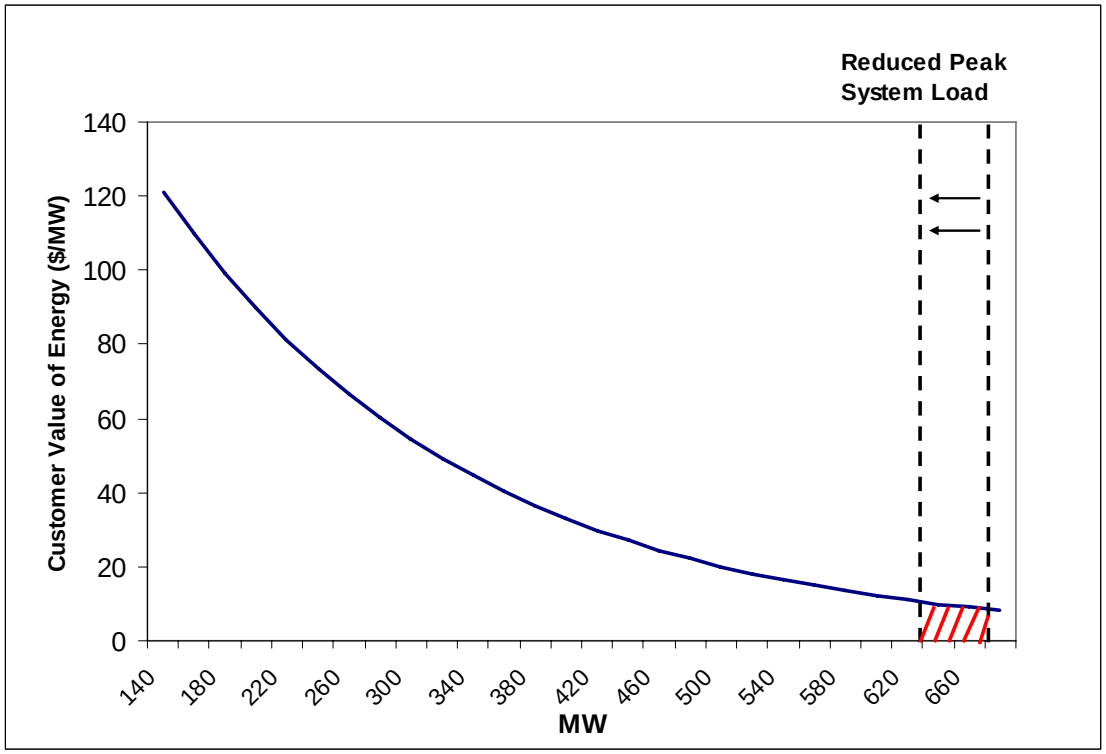


Figure 25: Reduction of Peak System Load based on Priority of Interruption

4.2.5 Targeted Conservation Voltage Reduction

'Targeted' conservation voltage reduction (CVR) allows distribution operators to reduce the overall voltage in an individual distribution area. Applied on a system level, reducing the voltage of has the effect of reducing the electricity demand in systems that are predominantly resistive loads (have constant resistance).[57] In a typical system with a combination of resistive and inductive loads, it is estimated that voltage reduction can reduce the use of energy by a factor of approximately 0.8, implying that an average utility that reduces its system's voltage by 1% could expect energy used to drop by 0.8%.[58] A typical system operator may have the flexibility to reduce voltage by up to 3%, corresponding to an estimated energy use savings of 2.4%.

The 'targeted' approach is similar to CVR approaches developed for system-wide voltage reduction, but localized to a distribution system that needs a small amount of load relief. CVR has the potential to be used by distribution system operators to avoid system overloads. It should be noted, however, that CVR is not appropriate for all distribution systems. The associated voltage reduction from CVR practices can have costly side-effects on equipment that can be damaged by sagging voltage levels.[59] CVR should therefore only be considered a high value application if it can be implemented at levels that do not affect power service quality to customers. By reducing system peak demand, CVR provides the same reliability

[57] Basic system energy demand D (in watts) can be calculated as $D = V^2/R$ where V is voltage level and R is resistance. Therefore assuming R remains constant, reductions in V will result in reductions in system demand D.
[58] This 0.8 amount is described as the "CVR Factor" in "Distribution Efficiency Initiative: Market Progress Evaluation Report, No. 1, Executive Summary" (report #E05-139), prepared by Global Energy Partners, LLC, for the Northwest Energy Efficiency Alliance, May 2005.
[59] For a complete discussion on the costs and benefits of CVR see, "The Power Quality Implications of Conservation Voltage Reduction", EPRI Report, December 2001.

benefits as load control programs, but unlike those programs, the CVR DA application does not have any significant associated costs other than the controls necessary to adjust voltage levels and monitor results.

4.2.6 Automated Dispatch of DER

4.2.6.1 Distributed Generation

Distribution automation in California could also enable the coordinated integration of distributed energy resources (both distributed generation and energy storage) to meet and manage peak loads on the distribution system. By coordinating a distributed generation system with feeder line data from SCADA, distribution automation could allow the DG system to be utilized to meet load that would otherwise need to be served by a constrained feeder line during peak hours.

This reduction and management of the peak load in a constrained service area creates financial benefits for the utility by enabling the deferral of investments in transmission and distribution capacity upgrade that would have been required of utilities not using coordinated distributed generation. Further benefits also accrue for the reduced losses associated with operating the distribution and transmission lines at lower capacity levels, in addition to the value of system generation capacity provided.

The size of T&D capacity benefits depends on the value of transmission capacity and distribution capacity for the location of the storage device. These amounts represent the potential value to the utility from the deferral of traditional transmission or distribution capacity investments as a result of being about to dispatch the DG resource to meet peak loads. These values can be calculated using the present worth (PW) method, as the difference between the present value of revenue requirement of a planned distribution investment that can be postponed if DG is located in the constrained area and dispatched to provide peak load reductions. The value of transmission capacity can be calculated similarly.

To illustrate the potential value of automated DG dispatch, we completed an analysis using the CEC DG Cost-effectiveness tool developed for the 2005 Integrated Energy Policy Report (IEPR).

For simplicity, we assume that the DG application is a dispatchable, gas-fired reciprocating engine. However, the principle can apply to any dispatchable resource such as other DG technologies, energy storage devices, or automated demand response.

For this example (shown in Figure 26), assume a 300kW commercial customer with moderate value of backup reliability of approximately $50,000 per year. At this level, installing a backup generator has a net negative present value to the customer (longer than desired payback period) given the assumptions of capital cost ($1,726 per kW) and financing (15 years at a weighted average cost of 8%). This application will not go forward.

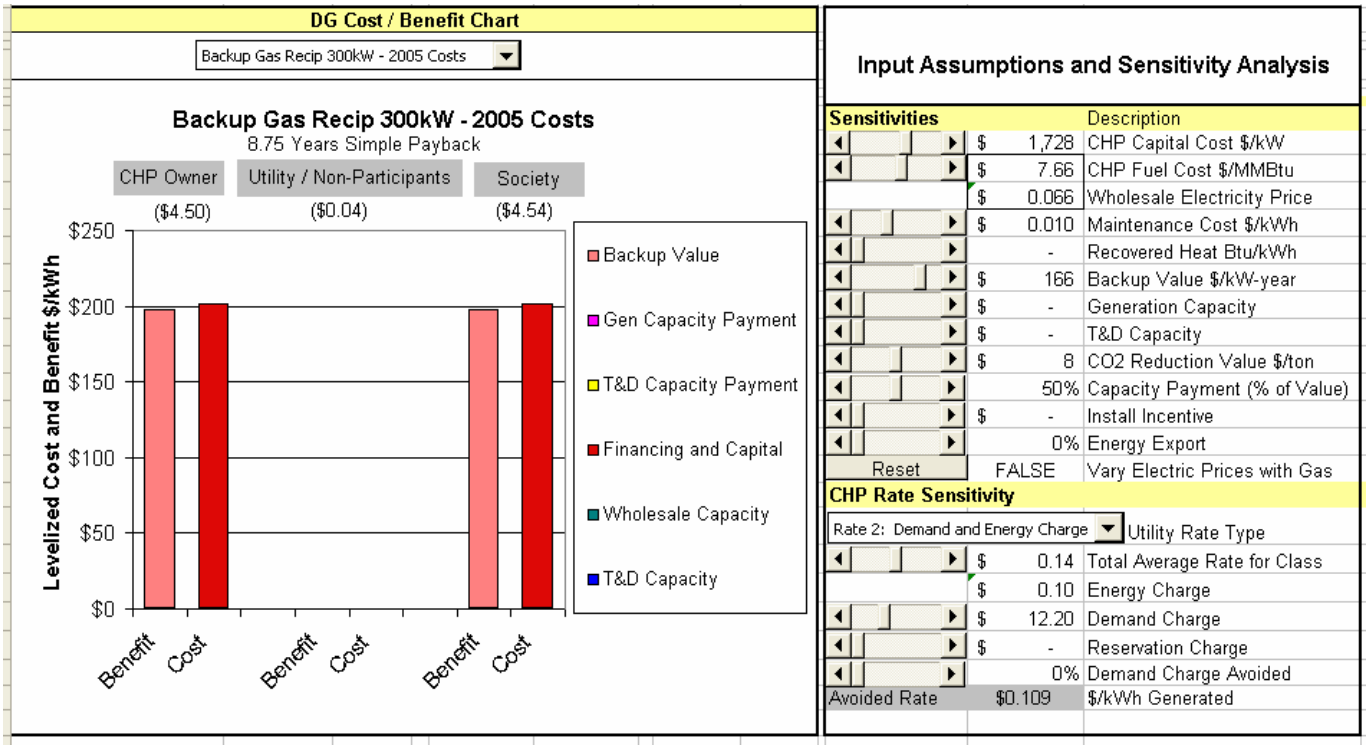


Figure 26: DG with No Capacity Benefits

Alternatively, consider the ability for the customer to participate in the state capacity market, and to make the backup generator available for utility dispatch when needed for local system conditions dispatched through SCADA. In this case, in addition to the backup value, the customer receives payments for making the generator available. For this example we assume a system capacity value of $40/kW-year, a T&D value of $40/kW-year, and a payment to the customer of 50% of the value of system and local T&D benefits. In this case, illustrated in Figure 27, the project looks significantly better economically, allowing the investment to go forward.

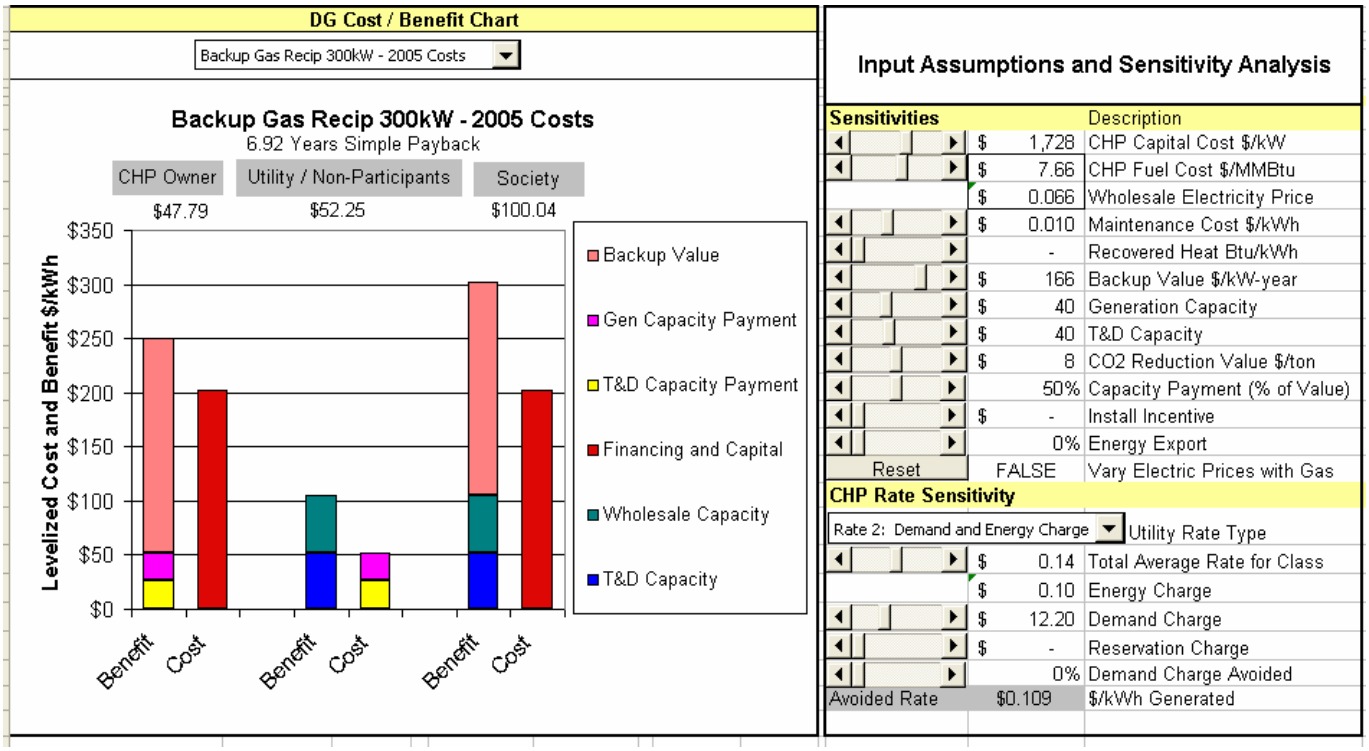


Figure 27: Capacity Benefits Shared 50% Participants and 50% Non-participants

While this analysis is just one stylized example, it clearly illustrates that the ability to dispatch customer-owned resources to manage system and local peak loads can provide an additional value stream to encourage more cost-effective DER projects. Reliability of the response is improved through automatic dispatch of the DG without direct customer action.

4.2.6.2 Energy Storage

Distribution automation can similarly be utilized to coordinate the use of energy storage. The use of large scale energy storage systems, such as pumped hydro, can help utilities manage peak system loads by allowing the utility to charge the device in off-peak hours when generation capacity is not constrained and wholesale energy is relatively inexpensive, and later to dispatch the stored energy during peak hours to meet demand that otherwise would have had to be met using constrained generation resources or costly wholesale purchases.

Distribution automation augments those system-wide storage benefits with distribution and transmission capacity benefits if it provides control of energy storage located on the distribution system. For example, by coordinating a smaller-scale device located on the distribution system with feeder loads through SCADA, distribution automation could cause the storage device to be charged and dispatched to offset load that would otherwise need to be served by the constrained feeder line during peak hours.

This reduction and management of the peak load in a constrained service area creates financial benefits for the utility by enabling the deferral of investments in transmission and distribution capacity that would have been required of utilities not using coordinated energy storage. There are also benefits from the differential in energy value during the charge and discharge periods net of the roundtrip efficiency of the storage device.

Using an EPRI Energy Storage Valuation tool (for which the CEC is a beta-tester), E3 has created an example valuation of the the net benefits energy storage based on a set of basic input parameters. This model contains a dispatch algorithm to optimally charge and discharge a battery storage device to maximize utility benefits based on assumptions of the energy and generation, transmission, and distribution value. Distribution automation is used to control the charging and dispatch of the energy storage to get the most value from the system.

For example, a utility with DA and energy storage may forecast the following price curve based on past market prices, or by using a production simulation model as illustrated for an example utility in Figure 28 below.

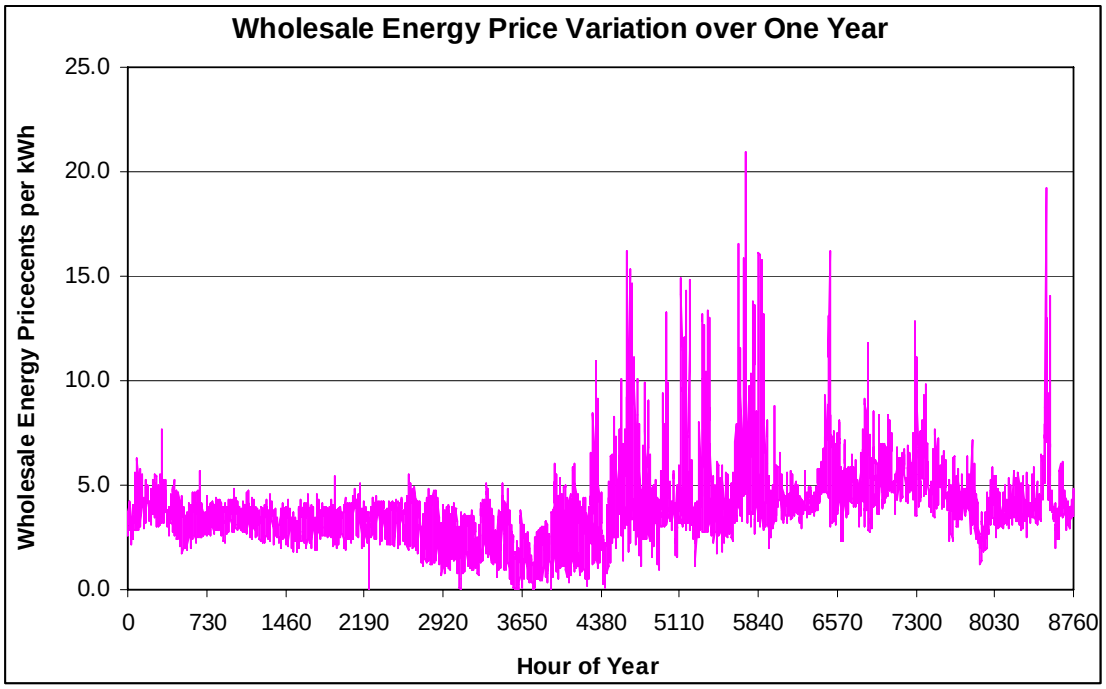


Figure 28: Variation of Wholesale Energy Prices over Year

In addition to energy prices, the utility may estimate other avoided system costs. Illustrative assumptions used in this example are shown in the Table 24 below.

Table 24: Energy Storage Example – Utility Parameters

Utility Parameter	Value
Average Energy Value	$0.040/kWh
Generation Capacity Value	$60/kW-year
Generation Value Assignment	100 hours/year
Marginal system losses during charging	4.0%
Marginal system losses during discharging	8.0%
Utility Weighted Average Cost of Capital	8.0%

Finally, some performance characteristics based on the type of energy storage technology must also be developed. The performance characteristics used in this example are shown in Table 25.

Table 25: Energy Storage Example - Storage Device Parameters

Storage Device Parameter	Value
Charge time	8 hours
Dispatch capacity	2 kW
Active storage capacity	4 kWh/kW
Average depth of discharge	90%
Maximum cycles per life	800 cycles
Maximum storage life	20 years
Number of cycles/year	80 cycles
Charge and discharge efficiency	80%
O&M costs	$0.05/kWh of energy stored plus $5/kW-year

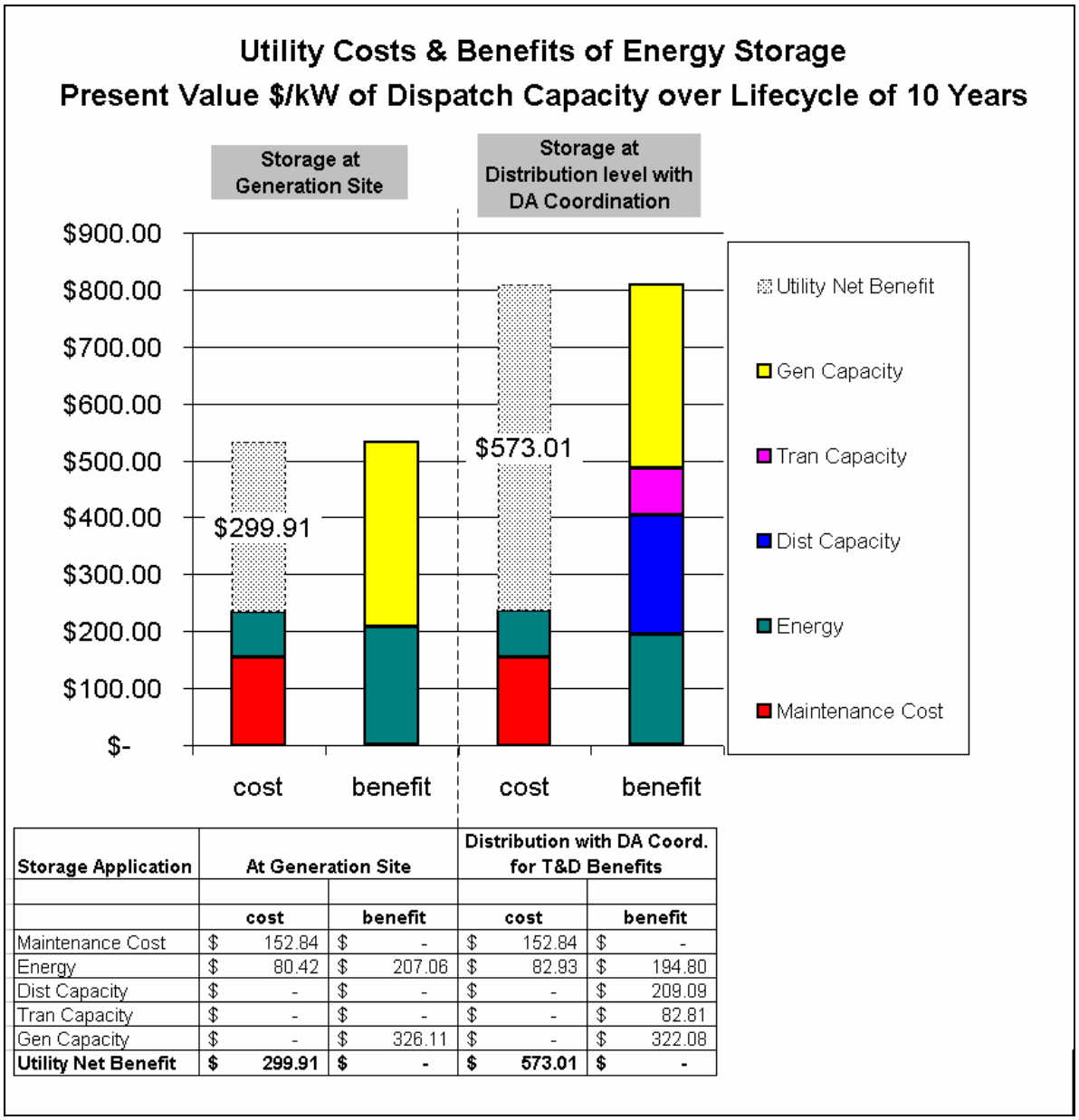
With these costs and performance characteristics we develop a cost-effectiveness example with and without the benefit of distribution automation. In the first case, the energy storage device is used for system capacity and can only capture energy and system capacity benefits. In the second case with DA, the energy storage device can capture energy, system capacity, transmission capacity, and distribution capacity benefits. The resulting net benefits, given the utility cost and energy storage performance characteristics, is $299.91 per kW of dispatch capacity without DA, and $573.01 per kW with DA. Coordination of the energy storage device with the needs of the local and the system benefits significantly increases the value of the distributed resource. The individual costs and benefits are illustrated in the first two columns of Figure 29 below.

Case 1: Energy Storage device without coordination with T&D system

The present value of the total maintenance costs for the device would be $152.84 per kW of the device's dispatch capacity. Energy that the utility uses to charge the device would cost a total of PV$80.42 per kW of dispatch capacity, but dispatching the device would create a benefit of $207.06 per kW of dispatch capacity for the utility by offsetting high-cost energy that would otherwise be required during peak hours. Additionally, the storage device would provide generation capacity benefits to the utility of PV$326.11 per kW. In total, the storage device would create a net benefit of $299.91 per kW for the utility, less the price of the device itself. This net benefit means that the utility could pay up to $299.91 per kW for the storage device and still receive a positive net benefit from the investment. These costs and benefits are illustrated in the first two columns of Figure 29 below.

Case 2: Energy Storage device with coordination with the T&D system

Using information provided by SCADA and other sensors, distribution automation could increase the value of a storage device by coordinating the charging and dispatch of the storage device based on information regarding transmission and distribution capacity constraints for the device's location. For instance, assume the same utility described above uses the same storage device, but locates it at the distribution level, where the transmission capacity value is $13.50 per kW-year and the distribution capacity value equals $38.50 per kW-year. If information provided by DA on the specific hours in which transmission and distribution capacity are constrained were incorporated into the utility's dispatch decisions for the storage device, then the storage device would also provide a transmission capacity benefit of $82.81 per kW of device dispatch capacity, and would provide a distribution capacity benefit of $322.08 per kW of dispatch capacity, as shown in the two right-most columns of Figure 29.



Storage Application	At Generation Site		Distribution with DA Coord. for T&D Benefits	
	cost	benefit	cost	benefit
Maintenance Cost	$ 152.84	$ -	$ 152.84	$ -
Energy	$ 80.42	$ 207.06	$ 82.93	$ 194.80
Dist Capacity	$ -	$ -	$ -	$ 209.09
Tran Capacity	$ -	$ -	$ -	$ 82.81
Gen Capacity	$ -	$ 326.11	$ -	$ 322.08
Utility Net Benefit	**$ 299.91**	**$ -**	**$ 573.01**	**$ -**

Figure 29: Utility Benefits of Storage Devices with and without DA coordination

The additional T&D capacity benefit of the storage device would boost the total net benefit of the storage device to the utility in this example to $573.10 per kW of dispatch capacity. Depending on the price point of the storage device, it is possible that an investment in energy storage would not be cost-effective if a utility only considered the generation and wholesale energy price benefits of the device, but that combining those benefits with the value from deferral of transmission and distribution capacity upgrades would justify investments in energy storage. Such conditions highlight the complementary nature of energy storage and distribution automation.

4.2.6.3 Plug In Hybrid Electric Vehicles (PHEVs)

If located on a customer site, energy storage may have added benefits of serving as a backup source of power during outages, in addition to the benefit of cost savings from capacity investment deferrals as

described in the example above. At current price levels for most batteries technologies, however, these benefits together are unable to justify the high price of energy storage. In next few years, however, plug in hybrid electric vehicles (PHEVs) may offer an opportunity to obtain the distribution system benefits of local energy storage without having to purchase equipment solely for that purpose.

PHEVs, unlike current hybrid electric vehicles, have larger battery storage capacity and a plug for connecting to an electricity outlet, allowing owners to charge the vehicle with power from the electricity grid that can run the car for a medium range distance, after which the vehicle can run on gasoline like traditional vehicles. While not currently in large scale production, after-market conversions are offered to make a standard hybrid electric vehicle plug in capable, and PHEVs are being researched by some major auto manufacturers such as Toyota.[60]

When plugged in to the grid, PHEVs or other electric vehicles with sufficient energy storage capacities could be used as a source of back up power to a home during an outage. Alternatively, they could be used to supply power to the grid in times of peak loads at either the system or distribution level. These types of applications (referred to as "Vehicle to Grid" or V2G), would be auxiliary benefits of the customer purchasing the vehicle for transportation, and therefore would not need to be the sole basis for the customer's purchase decision.

This type of usage would require DA applications to permit communications between the SCADA system on the grid and the vehicle's system regarding demands on the grid to determine when would be a necessary time to draw power from the vehicle's battery. Additionally, owners of PHEVs may wish to charge their vehicle away from their homes, such as at the office parking garage or at a friend's house. This activity could create challenges in determining whom to bill for the electricity used, or require metering within the car itself. If the owner of the vehicle wished to pay for the electricity, DA applications allowing greater levels of communication may need to be created to record the amount of energy used to charge the vehicle's battery and to charge the vehicle owner directly.

Though the requirements and potential distribution system benefits of PHEV usage in California are still years away and not yet a certainty, current investments in long-lived electricity distribution equipment should be made with some level of anticipation of the types of emerging services California customers may desire during the lifetime of that equipment. With PHEVs' potential to improve Californian's transportation expenses and create local and global environmental benefits, these applications at least merit consideration.

4.2.7 Integrating Distributed Generation into Distribution Planning

Information gathered from distribution automation devices can also leverage the value of distributed generation (DG) investments by incorporating distribution capacity values into the DG planning process. For example, data generated by SCADA regarding feeder line usage could enable utilities to more optimally select the locations and tilt orientations for solar photovoltaic (PV) systems to coincide with loads shapes in the area. As a result, if the PV energy output coincides sufficiently with the load on its circuit, installation of the PV system may be able to help the utility manage peak load on the feeder line and substitute for distribution capacity upgrades.

A CEC PIER project on Renewable DG Assessment completed in 2004 by E3 and conducted in conjunction with the City of Palo Alto Utilities (CPAU)[61] evaluated the local load shapes and compared

[60] http://www.toyota.co.jp/en/news/06/0613.html
[61] Price, Snuller, et al. 2004. *Load and Resource Analysis Report*. City of Palo Alto Project 3.1: DG Assessment Project, Contract #500-01-042.

them to the output shapes of potential resources for distribution generation. In the project, the CPAU system load was simulated for an entire year based on data from the year 2002-2003. For each hour of each month in the simulated year (e.g., the hour of 3: 00 p.m. – 4:00 p.m. in July), the highest hourly system load value is plotted. This load shape by hour and month are compared in the study to the shape of metered output of a photovoltaic installation in Palo Alto. The load and output shares are shown below, with the weeks of the year shown across each horizontal axis, the hour of day listed along the vertical axis, and the color of each square representing the relative size of the load or output in that hour.

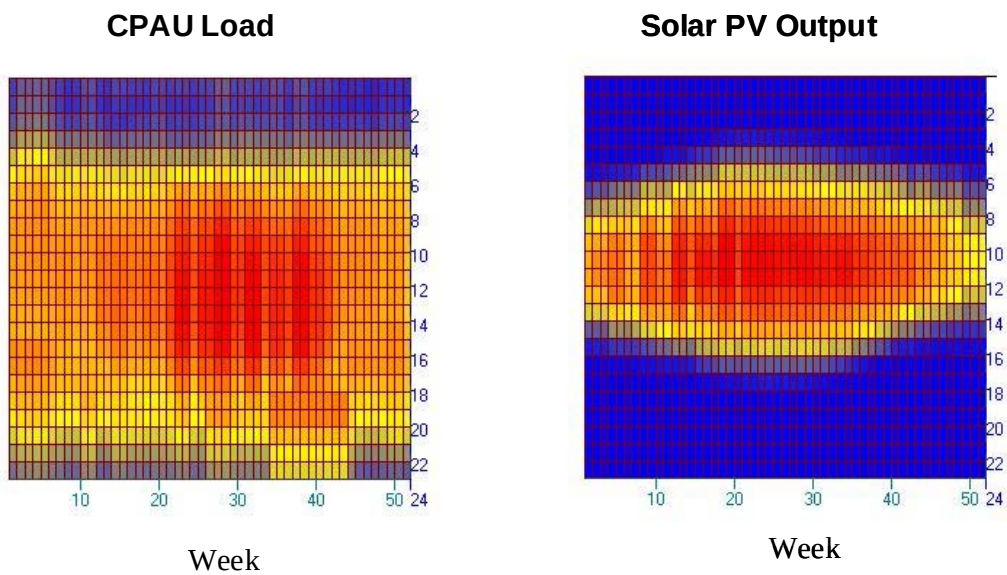


Figure 30: Side-by-Side Comparison of CPAU Load Contour and assumed Solar PV Output Contour

The system load peak for Palo Alto has a much longer duration than the PV output of a flat solar system without energy storage. While summer month output of the PV system begins to decline by 2:00 p.m., Palo Alto's load continues at a high level until past 6:00p.m. As a result, large additions of PV generation without energy storage would be unable to significantly reduce the summer month system peak in Palo Alto.

Comparison of PV output with the CPAU system, however, does not tell the whole story. An evaluation of the shape of loads on individual feeder lines made available by substation SCADA, however, indicates that specific areas within Palo Alto have a load profile that matches the output much better than that of the overall system. Figure 31 shows one such feeder (PB-23), which serves primarily commercial customers.

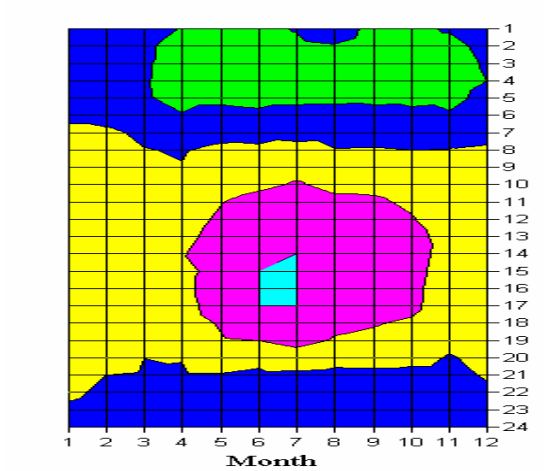


Figure 31: CPAU Contour Load for Single Feeder Line

The load profile for this feeder exhibits a profile that drops off faster in the late afternoon and early evening than the load of the entire system, and, as a result, could be served more directly through the output of a PV installation. This analysis indicated that information about capacity constraints on the distribution system should be incorporated into the planning decisions when determining where best to locate PV installations, because the output of the PV generation could have greater distribution capacity benefits if installed on a feeder line with earlier peak in daily load.

Additionally, data on the load shape and times of constrained capacity could be to choose the optimal tilt for a PV array so that the system's energy output best coincides with feeder line loads in the area. Figure 32 below, created using the PVFORM simulation software created for Sandia National Laboratories, compares the hourly energy output of a 1-kW (nameplate capacity) solar PV array on a perfectly horizontal roof with the output of an array of the same size that is on a 2-axis tracking system allowing the solar cells to have and optimal orientation throughout the day and year. The 2-axis tracking system represents the best possible orientation to match the peak load since the panel is directly facing the sun at all times.

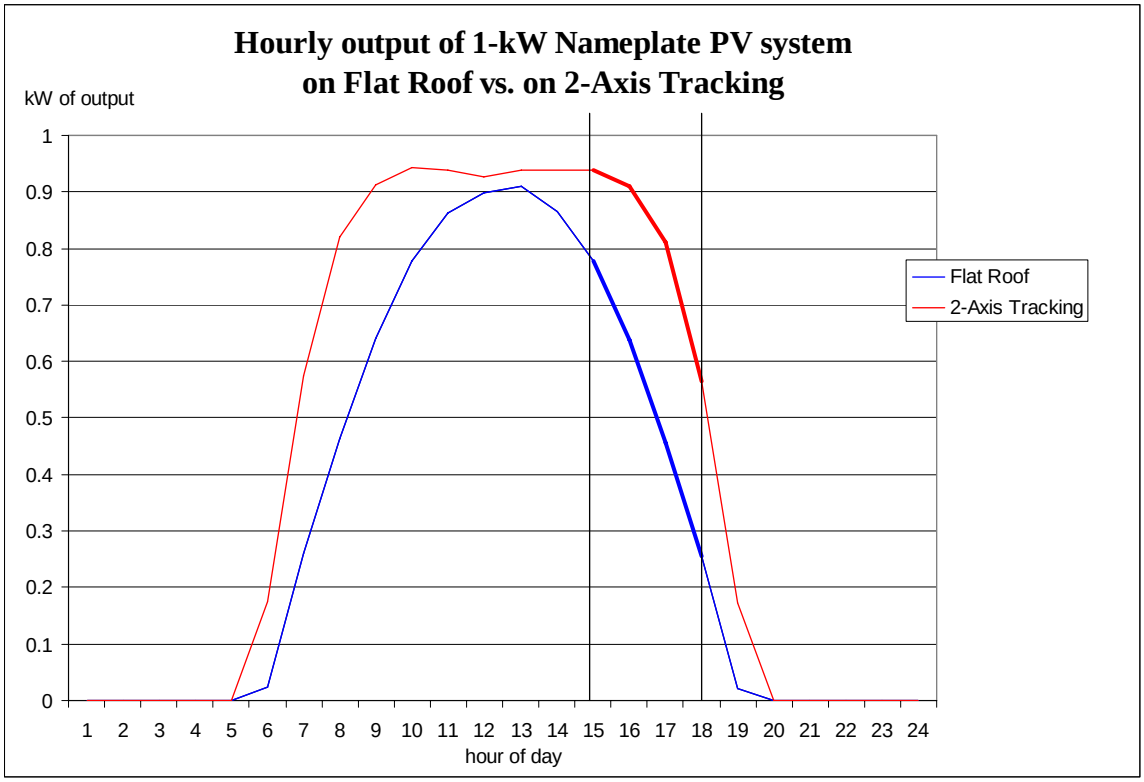


Figure 32: Hourly output of PV System based on orientation with 2pm to 6pm highlighted

The figure is based on a typical sunny summer day for a PV system at 35 degrees of latitude, such as a location in the California Central Valley. A comparison of the two series demonstrates how the optimally-tilted 2-axis tracking system, while producing only a small increase in the maximum output of the PV system at mid-day, has a considerable impact on extending a high level of output from the system to a larger number of hours.

In particular, during the hours of 2pm to 6pm, when residential area loads typically remain high, changing the tilt of the PV system significantly boosts hourly output, as highlighted by the space between the two vertical lines in the figure. By 6pm, the flat roof PV's output would have fallen to 0.25 kW (or 25% of nameplate capacity of the system), while the 2-axis tracking system's output remains at 0.55 kW (55% of nameplate capacity), more than double the output of the flat-roof system. Evaluated from a different perspective, the 2-axis tracking feature extends the output of the PV system at over 0.8 kW for 2 additional hours compared to the flat roof system, and the tracking system's output remains above 0.6 kW for 1.5 hours later than a PV system on a flat roof. Depending on the hourly load profile of the feeder line, this extension of PV system output could make a non-trivial difference in relieving capacity constraints on the local distribution system and positively contribute to the utility company's value derived from the PV installation.

Though placing PV arrays on tracking devices will likely add to the overall cost of the system and may affect its aesthetic appeal relative to PV panels that are flush to a rooftop, utilities may also consider encouraging fixed placement of PV arrays on westward-facing roofs. A westerly tilted PV system would likely capture some of the advantages of the tracking system during the 3pm to 6pm time range, especially during the summer months. Although a PV system titled to the west would sacrifice some output during the morning hours and may have a lower cumulative energy output than a flat roof system,

greater potential for coincidence with afternoon load profiles could potentially create distribution capacity benefits that outweigh the reductions in output of earlier hours. 'Performance' incentives for PV that offered greater incentives to orientations that provided the most system capacity could be used to encourage customers to install their PV systems in such a manner.

Large investments in PV installation are likely to occur in the next few years in California in response to recent "Million Solar Roofs" (California SB1) legislation. Encouraging these systems to be (1) in the right location on the distribution system, and (2) at the best orientation based on data collected from SCADA and other distribution automation investments can increase the benefit that these DG resources will be able to provide to Californians.

4.3 Prediction of Equipment Failure

Applications	Power quality monitoring to detect signatures of problem equipment, correlation of equipment type and history to high probability failures
Value Streams	Reliability, Reduced emergency repair costs

Distribution automation applications in the category of 'Prediction of Equipment Failure' improve the ability of the utility system operators to identify which equipment is most likely to fail before failure. There are two main applications in the category, the first application is in practice at Consolidated Edison and involves collecting information on distribution equipment (age, vintage, technology, past peak loading, and numerous other factors) and correlating those attributes with similar equipment that has failed to determine which types of equipment are like those that have already failed. As more information is gained, the predictive power increases in a process called 'machine learning.' The second application is to use power quality monitoring data and look for signatures that might indicate that a piece of equipment is likely to fail.

Prediction of failure is valuable because it allows the utility to replace equipment in a scheduled manner and without customer outages. Ideally, aging-equipment would be replaced the moment before it would otherwise fail, but that level of predictive precision would be difficult or impossible to achieve. Consolidated Edison, which uses machine learning, reports that approximately 80% of failures occur in the top 20% of their prioritized list.

In this section, we develop a methodology to prioritize capital projects based on prediction of failure. While it is possible to prioritize simply by probability, the costs of emergency replacement and customer outage costs are included to identify those likely failures that have the highest expected customer costs (both revenue requirement for emergency replacement and outage costs). The term 'expected' is used in the specific meaning of 'probability adjusted' likelihood of an outage. For example, if the chance of failure in a year is 20%, and the consequences of the failure is $1 million, the 'expected' cost is $200,000. In order to prioritize investments, the cost of replacing the equipment before failure is compared to the expected outage cost to estimate the expected net benefit of early replacement. After which, investment can be prioritized by greatest net benefit of replacement.

The formulation of the net benefit to customers of replacing a piece of equipment can be expressed as the following equation:

Expected NPV Net Benefit of Replacement	=	Expected PVRR of Emergency Replacement	+	Expected Cost of Customer Outage Costs	-	PVRR of Early Replacement Costs

This formula can also be written as the following:

Expected NPV Net Benefit of Replacement	=	NPV [Prob. Failure(y) * (Emergency Replacement + Outage Costs)]
		- NPV (Revenue Requirement of Replacement)

Where:
NPV = Net Present Value, PVRR = Present Value Revenue Requirement, y = Years in planning horizon

We use this relationship and proxy data to illustrate: (1) the value of good failure predictions that can be achieved with DA, and (2) an approach to prioritize capital budget replacement using information from DA. The DA approaches described are used to identify the probability of failure which is a critical input into the expected benefit of early replacement.

Illustrative Probability of Failure

To begin, we develop a proxy failure probability curve for a type of equipment (e.g. cable section) with an average expected useful life of 30 years. A base case curve shows the probability of failure in each year as the cable ages.[62] A high and a low case are added to illustrate that without better information, we do not know which represents the actual curve. DA monitoring and a machine learning based on equipment history may provide this information. So, for example, in the illustrative curve, a 20-year old cable section has about a 2% probability of failure in the base case. In a high failure case, which could correspond to heavy loading history on the line or other factors, the probability is 3%.

[62] The example failure probability curve was based on a quadratic function for which the Prob(f) in the final year of the expected useful life of the device is equal to (1/the expected life of the device). For this case of a device with a 30-year life, the Prob(f) in Year 30 is 1/30, or 3.3%. This Prob(f) increases for later years.

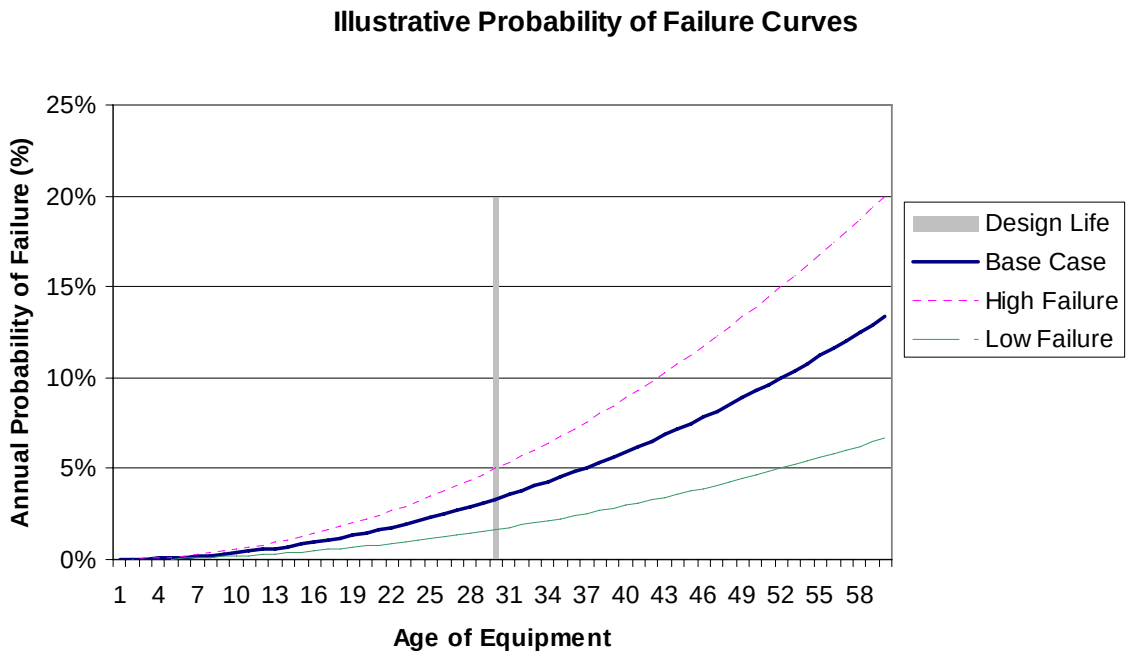


Figure 33: Illustrative Curve to Compute Probability of Failure in Each Year

Strategies for Replacement

Assuming that there is some probability of failure, consider a 25-year old cable section. Should it be replaced? If we assume that our predicted probability of failure is correct, we can compute the expected net benefit of replacement based on the expected costs of emergency replacement and customer outages, compared to the cost of replacement and calculate which choice results in the minimum expected cost to customers (and highest net benefit). To demonstrate the approach, Figure 34 shows the expected annual costs of three basic strategies: (1) Run to failure, (2) Scheduled replacement, and (3) Replacement based on probability of failure. In the run to failure approach, we assume the cable is kept in service until it fails. In the scheduled replacement approach, we assume that the equipment is replaced at the end of its design life of 30 years. In the replacement based on failure we assume that the cable is replaced when the expected cost of failure exceeds the replacement cost. Each case shows the age of the equipment, and the annual expected cost of the strategy in each year. As the probability of failure increases with time, the expected outage cost increases. However, there is a large cost for the capital replacement when the replacement is made. In each chart, the net present value of expected cost is compared with each approach. Over the 20 year planning horizon, replacement on failure has the highest expected cost, the scheduled replacement has the second highest, and the replacement based on minimizing expected cost has the lowest (almost by definition since the replacement is timed to minimize the cost).

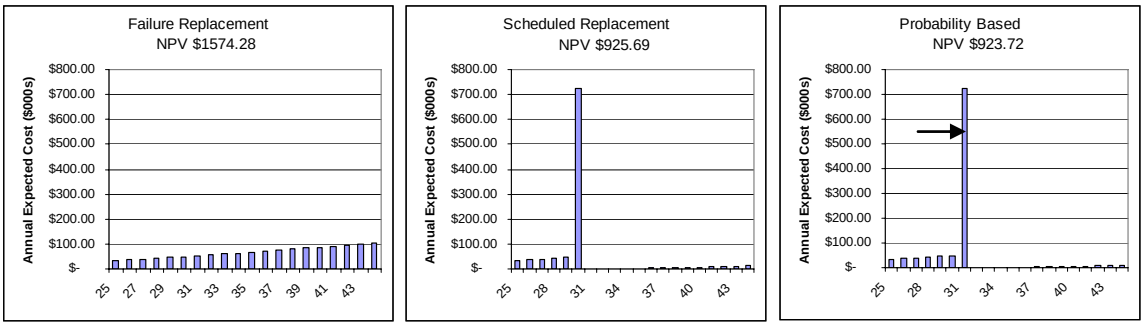


Figure 34: Expected Cost by Year of Three Different Replacement Strategies

Sensitivity Analysis

The results for this type of approach are sensitive to the inputs (probability curve, cost of outage, normal and emergency replacement costs). To show the variation we re-estimate the least cost replacement age for the base case, 'high failure', and 'low failure' probability curves and different estimates of the cost of customer outages. From the prior example, by using the probability based replacement, the least costs replacement timing was in year 31. Figure 35, below, shows the variation in the least cost replacement age for different estimates of equipment failure probability and outage cost. The base case assumed $0.50 per customer outage minute, as the outage cost increases, or the probability of failure is assumed to be higher, the ideal replacement age decreases. Similar sensitivity analysis of emergency failure costs show a similar relationship that as costs increase, the best lifecycle replacement age is earlier.

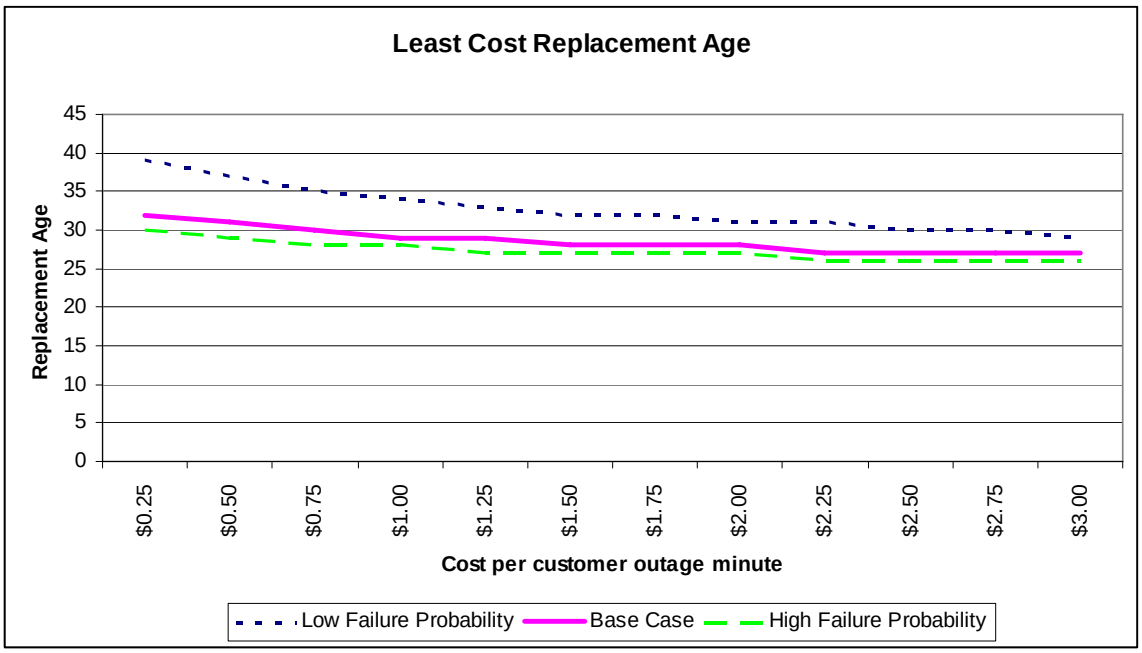


Figure 35: Least Cost Replacement Age by Estimated Equipment Failure Probability and Outage Cost

Capital Management Process

Thus far, we have considered the replacement of a single cable section; however, a utility is likely to have many cable sections with different replacement costs, probabilities of failure, and associated outage costs. Also, the perspective in the previous example is based on the minimum lifecycle cost of ownership over

20 years, which is different than a capital budget process that is looking at which investments to make over the next budget or rate case cycle (3 to 5 years). The results are very dependent on the planning horizon, and obviously on the available capital budget to spend on replacement of functioning equipment.

To illustrate an approach to determine which projects should be replaced in the next capital budget cycle (assumed to be a 5-year plan in this example), we repeat the analysis above with a 5-year horizon for all of the cable sections in service. Table 26, below, illustrates the capital budgeting problem. We assume there are 20 cable sections with different scheduled and emergency replacement costs and outage probabilities. We then compute the net benefit of early replacement as the difference between the expected cost of not replacing the equipment, and the value of deferring the investment until the next 5-year capital budget cycle. The projects are then sorted in priority based on net benefit of early replacement.

Table 26: Illustrative example of failure prediction in capital budgeting process

A	B	C	D	E	F	G = D*PV	H	I	J
Order	Age	Equipment Condition (Failure Probability)	Scheduled Replacement Capital Cost ($000)	Emergency Replacement Cost ($000)	Estimated Outage Cost ($000)	Probability of Failure in Planning Horizon	Present Value of Deferral for Delay 5 Years	Expected Cost of Failure over 5 Years	Savings for Replacement in Current Capital Budget Cycle	Required Capital Budget
1	28	Base	$ 1,500	$ 3,000	$ 35,000	16.7%	$ 454	$ 6,097	$ 5,643	$ 1,500
2	30	High	$ 1,000	$ 2,000	$ 10,000	28.5%	$ 302	$ 3,135	$ 2,833	$ 2,500
3	33	High	$ 1,500	$ 3,000	$ 5,000	34.1%	$ 454	$ 2,215	$ 1,762	$ 4,000
4	21	Base	$ 1,000	$ 2,000	$ 15,000	9.8%	$ 302	$ 1,573	$ 1,271	$ 5,000
5	24	Base	$ 1,250	$ 2,500	$ 5,000	12.6%	$ 378	$ 785	$ 407	$ 6,250
6	23	Base	$ 1,500	$ 3,000	$ 4,000	11.6%	$ 454	$ 639	$ 185	$ 7,750
7	23	Base	$ 1,000	$ 2,000	$ 3,000	11.6%	$ 302	$ 464	$ 162	$ 8,750
8	20	Base	$ 1,000	$ 2,000	$ 3,000	9.0%	$ 302	$ 360	$ 58	$ 9,750
9	31	Base	$ 1,500	$ 3,000	$ 1,000	20.2%	$ 454	$ 505	$ 51	$ 11,250
10	23	Base	$ 2,000	$ 4,000	$ 3,000	11.6%	$ 605	$ 581	$ (24)	$ 13,250
11	19	Base	$ 1,000	$ 2,000	$ 2,000	8.2%	$ 302	$ 246	$ (56)	$ 14,250
12	18	Base	$ 2,000	$ 4,000	$ 5,000	7.4%	$ 605	$ 521	$ (84)	$ 16,250
13	31	Base	$ 3,500	$ 7,000	$ 1,000	20.2%	$ 1,058	$ 909	$ (149)	$ 19,750
14	34	Low	$ 1,500	$ 3,000	$ 1,000	12.0%	$ 454	$ 300	$ (153)	$ 21,250
15	30	Base	$ 10,000	$ 20,000	$ 5,000	19.0%	$ 3,024	$ 2,850	$ (174)	$ 31,250
16	2	Base	$ 1,000	$ 2,000	$ 2,000	0.3%	$ 302	$ 10	$ (292)	$ 32,250
17	4	Base	$ 2,000	$ 4,000	$ 1,000	0.7%	$ 605	$ 21	$ (584)	$ 34,250
18	24	Low	$ 5,000	$ 10,000	$ 2,500	6.3%	$ 1,512	$ 471	$ (1,041)	$ 39,250
19	28	Low	$ 12,500	$ 25,000	$ 3,000	8.4%	$ 3,780	$ 1,295	$ (2,485)	$ 51,750
20	3	Base	$ 10,000	$ 20,000	$ 5,000	0.5%	$ 3,024	$ 75	$ (2,949)	$ 61,750

Savings from Deferral		Input Assumptions					
PV factor =	30%	inflation=	2.50%	WACC =	8%	Length =	5

Once the projects are sorted in order of priority, a capital budget can be estimated by totaling the known capital cost of replacements for all of those projects that have positive net benefits of early replacement. From the example, we see the common result of this exercise with the illustrative data: unless the probability of failure and/or the outage costs are very high, early replacement is difficult to justify. The equipment failures that are most likely to be in this category are underground cable sections that serve densely loaded areas with a high cost of customer interruption, such as an urban downtown network. With DA applications that can identify the equipment with high failure probability, the analysis will show that the projects to replace this equipment will move up in priority.

Another advantage of this approach is in transparency to the regulators of how projects are selected. The approach also allows the regulator to estimate the impact of capital budget increases or decreases if they ‘redraw’ the line on which projects are allowed in the capital budget.

4.4 System Restoration After Failure

Applications	Automated Switching, advanced Outage Management Systems that include precise outage location
Value Streams	Reliability (reduced scope of outage, accelerated repair time), Reduced emergency repair costs, energy security, public safety

Distribution automation applications in the category of 'System Restoration After Failure' are designed to limit the extent and cost of outages associated with distribution system problems such as failed equipment, fallen trees, or other issues.

4.4.1 Automated Switching

Line switches play a key role in service restoration following service outages. When outages occur, open switches can be closed and disconnected loads can be supplied other feeders through the switching process. This procedure can greatly reduce the number of customers who are without power while the actual distribution system fault is repaired. Because of the manual operation of distribution switches these customers, while not having to wait for line equipment repairs, still have to wait until utility crews can reach the switching site to restore their load. Automated switching for isolating faults during a contingency can greatly reduce the time needed for system reconfiguration and load recovery.

The primary benefit stream from automated switching for isolating faults during a contingency is reliability. This application does not reduce the number of momentary outage occurrences but can greatly reduce the duration of those outages for large groups of customers and possibly reduce the duration below the 5 minute SAIDI threshhold. As such, this value depends on the number of reduced outage hours it can provide.

The improvement in the reliability metrics (SAIDI, SAIFI, CAIDI) that occur as a result of automated switching for fault isolation will be used as performance metrics for the DA application. Once the improvement in reliability metrics is calculated, the monetary benefit of the application can be determined using value of service (VOS) estimates.

A model can be developed to predict reliability metric improvements from automated switching. It should be noted that this model assumes manual switches are already on a circuit and will be replaced one-for-one with automated switches, rather than adding additional automated switches to a system in addition to replacement of manual switches. Further benefits would accrue from automated switching applications that add automated switches to a system as well as replace manual switches. The model would have at a minimum, the following characteristics.

4.4.1.1 Inputs

The model would include the following inputs:

- Circuit configuration
- Number of switches per circuit
- Circuit load
- Number of customers on system
- Failure rate (faults per system)
- Non-automated service restoration times
- Non-automated fault isolation times
- Switching Times

The circuit configuration and the number of switches on a distribution system will determine the possible ways in which the system can be re-configured during outage events. An example of a simple system configuration can be seen in Figure 36.

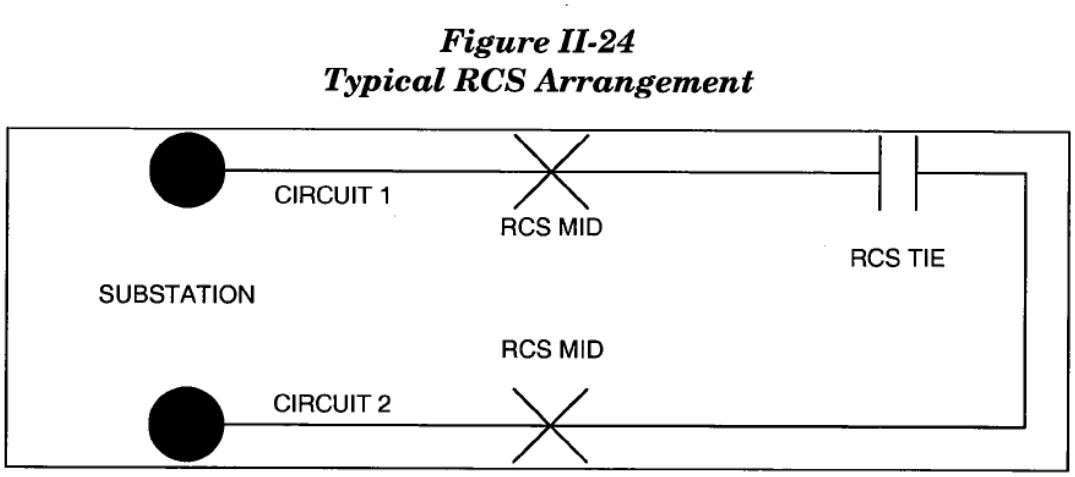


Figure 36: Typical RCS Arrangement Illustration from SCE's 2006 GRC

This configuration is from SCE's 2006 General Rate Case.[63] The dynamics of the system are described as follows:

"The mid-point switch will automatically open when power is lost due to a fault on a circuit. If the fault on the circuit is beyond the mid-point switch, power to about one-half the customers is automatically restored in less than a minute. If the fault is located before the mid-point switch, a switching center operator can remotely close the tie-point switch, restoring power to about one-half of the customers within a few minutes rather than the 40 to 50 minutes now required for a crew to be dispatched." [4]

This is an example of a simple distribution circuit system with 2 switches.[64] The ability of distribution systems to isolate faults during outages, and therefore the value of the DA automated switching system, will increase with the number of switches on each circuit. The following three figures illustrate the effect that increasing the number of switches on the distribution circuit has on the number and area of sections on the circuit.

[63] Southern California Edison 2006 General Rate Case: *Transmission & Distribution, Volume 3 – Capital Expenditures, Part III – Distribution Capital Replacements and Distribution Automation, page 69.*
[64] This can also be referred to as 2 ½ switches on each circuit as the RCS ties is counted as a half switch on each tie. For purposes of this report, this type of configuration will be referred to as having 2 switches.

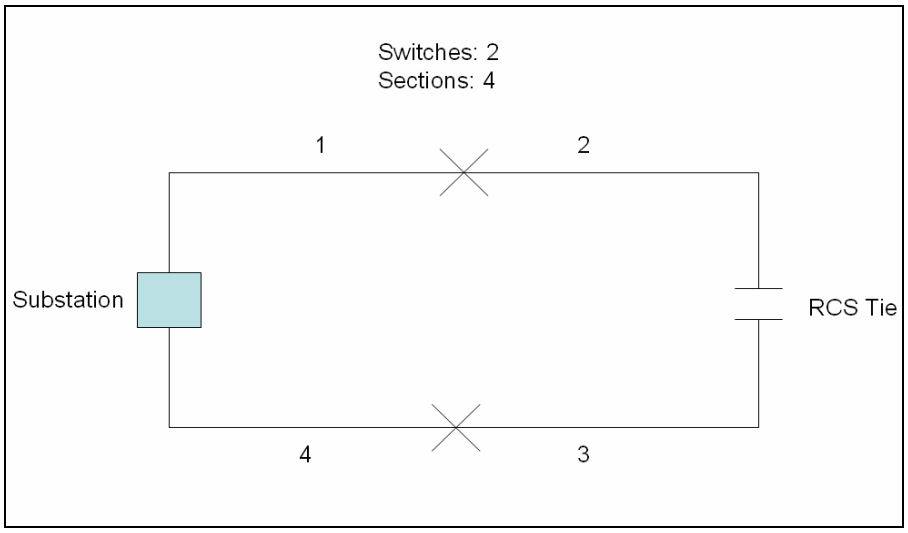


Figure 37: Example RCS Arrangement with 2 Switches and 4 Sections

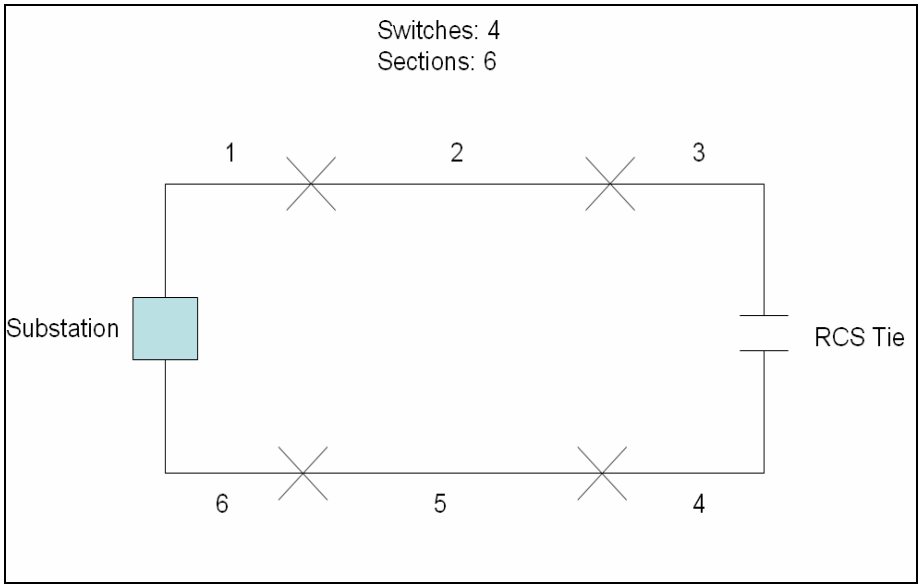


Figure 38: Example RCS Arrangement with 4 Switches and 6 Sections

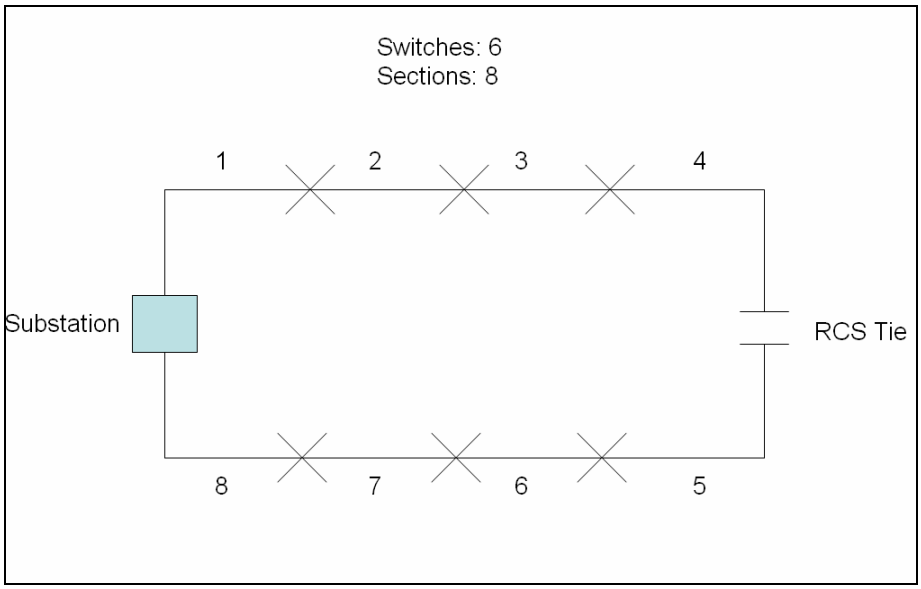


Figure 39: Example RCS Arrangement with 6 Switches and 8 Sections

The increase in the number of areas on the distribution circuit allows for greater fault isolation control for system operators. So if a fault occurs in section 1 of a system with no switches then half of the circuit will be without power until the fault is repaired, whereas is a fault occurs in section 1 of a system with 4 switches only 1/3 of the customers will be without power until the fault is repaired. With additional automation capabilities of the switches the number of customers without power for more than a couple minutes will be reduced to 1/3 as well. The relation of outage isolation to number of switches can be seen in the table below.

Table 27: Relationship of Outage Isolation Capability to Number of Switches

Number of Switches (Not including RPS Tie)	Number of Sections	Circuit Area Affected by Outage	Decrease in Outage (Compared to 0 automated switches)	Decrease in Outage (Compared to n-2 automated switches)
0	2	1/2	0	0
2	4	1/4	1/4	1/4
4	6	1/6	1/3	1/12
6	8	1/8	3/8	1/24
n	n+2	1 / (n+2)	n / (2n+4)	1 / (n+3)(n+2)

There are a few of simplifying assumptions in the affected outage area column. The first assumption is that either circuit of the substation can supply power to (n+1) / (n+2) sections of the two circuits. This may not be possible if the circuit is not rated to handle that much capacity. The second assumption is that each switch is evenly spaced along the circuit or spaced to maintain equal load/customer levels in each section. This is not an unreasonable assumption if system operators have control as to where switches are placed on the system with a great degree of accuracy, and can maximize automated switching benefits by ensuring that each section of the circuit serves an equal portion of the total circuit load. Finally, it is assumed that a failure of the switch itself is not the cause of outages.

Table 27 above can be used to determine what portion of the circuit can be restored within a couple of minutes by automated switching. Once this figure is known it can be applied to the total load for the system and the number of customers on the system to determine the number of customers who avoided the outage and the amount of load that was restored. These values, in combination with historical annual outage frequency on the circuit, can be used to determine the SAIFI improvements that result from DA.[65]

To determine SAIDI and kWh service improvements, additional inputs are needed for the historical manual switching times and outage repair times. Automated switching reduces the number of minutes customers are without power by the average manual switching time. The number of customers who receive this decrease in outage time will again be determined by the number of customers and number of switches on the system.

4.4.1.2 Outputs

Outputs of this model consist of:

- Reliability Index Change
  - SAIDI/SAIFI/CAIDI
  - MAIDI
- Cost Savings from Automated Switching Application
  - Customer Cost Savings
  - Utility cost savings
- Cost of DA application
  - Switch equipment, installation, and maintenance costs
  - Automated switching system operation costs

4.4.1.3 Reliability Index Change

One of the outputs for the model should be the change in reliability metrics from automated switching improvements, including SAIDI/SAIFI/CAIDI and possibly MAIFI. It is unclear whether distributed automation provides any MAIFI improvements. Based on the technology discussed here there are no MAIFI benefits from automated switching, given the technology restores power to customers within 1-2 minutes, but not instantaneously.

In addition to reliability metrics, the monetary value of reduced outages from customer perspectives can be valued based on customer Value of Service (VOS) estimates. Utility costs for transportation to switches and labor for manual operation of switches are reduced as well by automated switching applications.

The costs of automated switching, including switching and automation equipment should also be calculated in the model for comparison to benefit metrics.

4.4.1.4 Calculation Example

An example of the SAIFI, SAIDI, and VOS improvement from automated switching is as follows. Assume average manual switching times on a circuit are 42 minutes and repair times are 90 minutes, the

[65] A system outage greater than 5 minutes counts towards the SAIFI index for California IOU's. If Automated switching times are longer than 5 minutes they will not provide any improvement in SAIFI metrics.

system has 4 switches, and a fault occurs in section 3 as illustrated below.[66] Southern California Edison currently has an average reduction of 42 minutes for their switching time in systems in which they installed automated switching.[67]

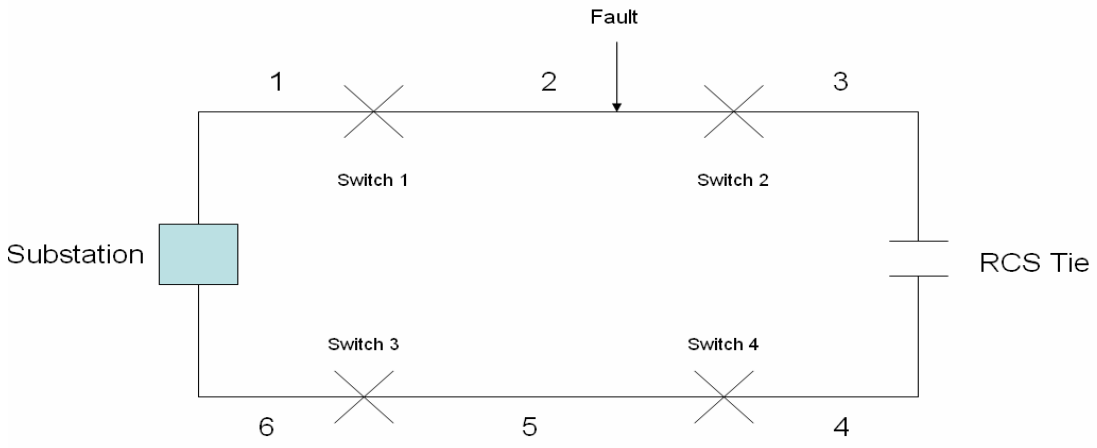


Figure 40: Illustration of Fault on Circuit with 4 Switches and 6 Sections

With automated switching when the fault occurs in section (2), switch 1 and 2 automatically open, restoring power to section 1 almost immediately. When the RCS Tie is closed power is restored to section (3) within a couple of minutes (here we will assume 1 minute). SAIFI for California IOU's is defined for outages that last over 5 minutes, so for calculation purposes automated switching avoids SAIFI defined outages for sections (1,3). Only section (2) is without power for on average 90 minutes until the fault can be fixed. Without automated switching, sections (1,2,3) will be without power for on average 42 minutes until switch 1 and 2 can me manually operated at which point power will be restored to (1,3), while section 2 will again be without power until the fault is repaired. In the case of manual switching all three sections will have SAIFI defined outages.

Automated switching in this example lowers the SAIFI index by 1/3 per outage. This is the difference between the portion of the system that is affected by the outage without automated switching and the portion of the system affected by the outage with automated switching (1/2 – 1/6 = 1/3). In general this value is n / (2n + 4) for n switches on the system. This value multiplied by the average number of outages annually will give you the annual SAIFI improvement from automated switching.

[66] As per the assumptions of the system, the actual fault location on the system will not change the reliability improvement metrics of automated switching.
[67] Southern California Edison 2006 General Rate Case: *Transmission & Distribution, Volume 3 – Capital Expenditures, Part III – Distribution Capital Replacements and Distribution Automation, page 69.*

Automated switching in this example lowers the SAIDI index by 25 minutes per outage or in general by:

$$n/(2n + 4) * [r1 + 2(r1-r2)/n]$$

where n = # of switches on the system
r1 = manual switching time
r2 = automated switching time

Manual switching keeps sections (1,3) without power for 42 minutes until the switch is reached and manually operated, while automated switching restores power to those customers within 1 minute.

SAIDI and SAIFI reductions increase as the number of switches increases however there is a diminishing effect on those reductions. This can be seen in the following two figures.

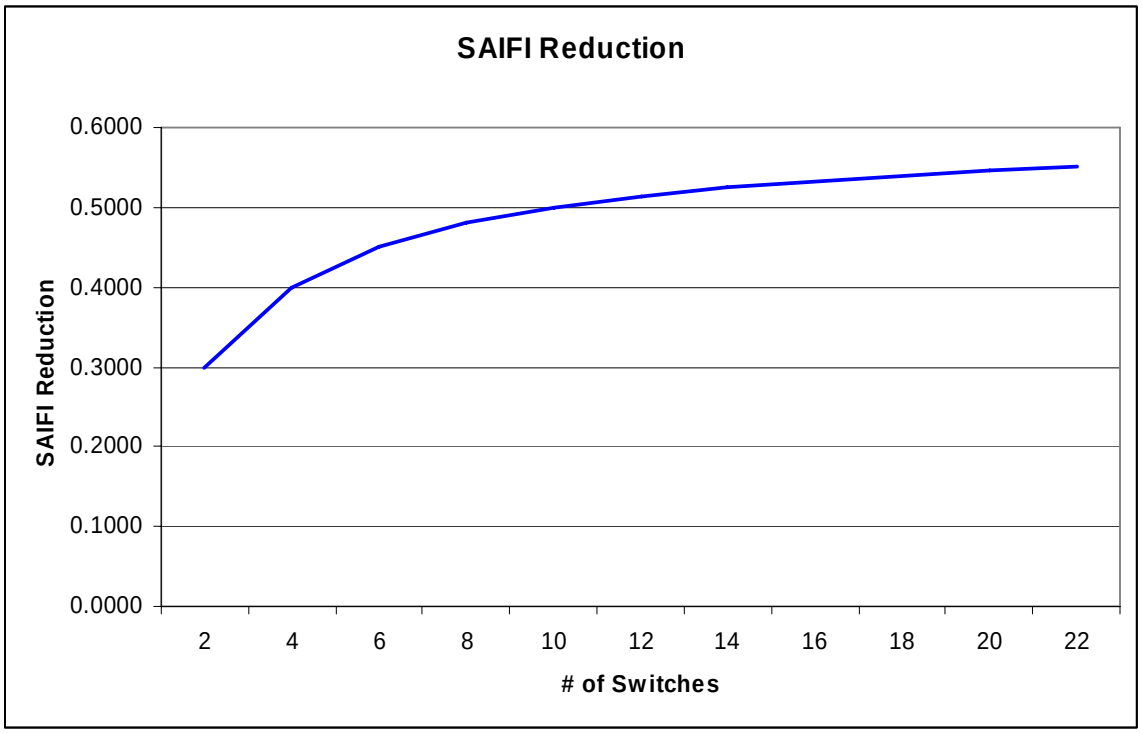


Figure 41: Potential Reduction in SAFI by Number of Additional Switches

Figure 42: Potential Reduction in SAIDI by Number of Additional Switches

Because of the diminishing returns on reliability metrics with switch number increases, distribution system planners will need to determine, based on switch and operation costs, the number of switches that can be added to a system before costs begin to exceed reliability benefits from the switches. This would require monetary valuation of SAIDI and SAIFI metrics using VOS values.

4.4.1.5 Cost Savings from Automated Switching Application

Also of interest in the valuation of DA automated switching is the customer cost savings from reduced outages and reduced outage hours. The customer value of reduced outage time can be calculated as follows:

Customer Value per Outage = OAR * [Load*MST*VOS1 + C*VOS2]

OAR = Outage Area Reduction
Load = Average Load on the Distribution system in kW
MST = Average Manual Switching Time – Automated Switching Time
VOS1 = Customer value of service $ per kWh unserved
VOS2 = Customer value of service $ per outage event
C = Number of customers on the system

VOS values are detailed in Chapter 3 and range from $1.40 to $8.50 per unserved kWh and a fixed value range of $1.85 to $22.4 per customer outage event for residential customers.[68] In this example if we

[68] Commercial and Industrial customers' VOS estimates are higher, ranging from $4.19 to $703.20/kWh unserved, and a fixed value of $537 to $22,400 per customer outage event.

assume VOS values of $1.84 per kWh and $20.00 per outage, then the value of the 4 automated switches on the circuit would be $68,578.

At the heart of this calculation is the issue of whether the SAIFI definition of outages over 5 minutes is accurate in determining whether to count the VOS per outage value for automated switching. Automated switching as envisioned does not avoid outages per the MAIFI definition and therefore would not provide customer $ per outage benefits if MAIFI outage metrics were used in lieu of SAIFI metrics. If this benefit were not counted then the customer value of the distributed automation technology in our example would be reduced by 38% to $41,911.

Utility cost savings from the automated switching technology accrue as reduced labor and transportation costs. Reduced costs from utility staff not having to travel to switching sites to manually operate switches. While not available for this report, these costs should be easy to estimate, and should be based on based on recorded utility switching costs.

4.4.1.6 Cost of DA Automated Switching Application

The costs of DA automated switching applications are two fold. The first cost is the actual equipment costs for the switches. Current estimates for these costs are $16,000 per switch for overhead lines and $32,000 per switch for underground lines.[69] The second cost for automated switching is the cost of equipment operation. This includes costs for computer software and communication devices for system operation.

4.4.2 Outage Detection and Location

When electricity service outages do occur it can be difficult for UDC staff to isolate the location of the fault, which increases outage durations and repair costs. DA applications can more accurately locate the point on the circuit where the fault occurred. The technology for this application is referred to as Supervisory Control and Data Acquisition (SCADA). SCADA applications are able to more quickly detect and locate electricity service outages that occur in distribution systems. This allows UDCs to more quickly restore energy to areas affected by the outage. This benefit stream can be valued as a combination of reduced repair times and their associated utility labor and equipment costs and reduced customer outage minutes.

The primary metrics for valuation of this application are historical outage detection times. These detection times should if possible be specific to individual distribution systems, as each system will have unique characteristics that facilitate or complicate outage detection. The difference in the average outage detection time with and without advanced Outage Management System technology can then be combined with outage frequency and customer outage levels to calculate the SAIDI metric improvement from this DA application.

If metrics are available for average outage repair crew search times, this value could be multiplied by outage repair labor costs to calculated the additional cost benefit of outage location from SCADA.

[69] SCE 2006 GRC Workpapers, p.171.

5.0 Conclusion

5.1 High Value Distribution Applications

This project identified a large number of different distribution automation applications that were identified in the survey, and through literature. The complete list represents something on the order of 40 distinct applications that are being evaluated. With such a broad scope of applications, we did not develop a complete value assessment for any single application. However, what we did accomplish, through categorization of these applications into categories with similar value propositions, assessment of the major value streams of each, and development of a methodology to value benefits in each category, was to identify applications that seem to represent the most near-term potential. In Table 28, we list the research team assessment of the top application in each category. These assessments should be considered preliminary since we did not do a complete value assessment on any single application.

Table 28: Top Applications in Each Category

Category	Preliminary Assessment of Top Application
1. Routine Operational Efficiency	(a) Improve voltage / var control along feeders to reduce losses through switched capacitors and voltage regulators. (b) Install 'self-reporting' sensors to improve equipment maintenance (c) Develop distribution efficiency standards based on the cost and value of reducing losses
2. Management of Peak Loads	Automatically reduce loads when distribution system contingencies occur during the local peak.
3.Prediction of Equipment Failure	Develop condition-based probability assessment of underground cable failure to justify early replacement in urban areas.
4.System Restoration After Failure	Install automated switching on feeders and enhance existing outage management systems (OMS) to more precisely locate faults.

The rationale for choosing each application is probably as important as the application itself.

For 'Routine Operational Efficiency', three applications were chosen as potentially high value. The 'best' application depends on the distribution system design and prior investments in DA and they are not in any particular order. The voltage / var control along feeders which can keep voltage above the minimum standard voltage for all customers, can significantly reduce energy consumption without any noticeable performance problems for most customers. A recent Hydro-Québec study estimates that such a strategy can save 2 TWh (2,000,000,000 kWh) per year. Voltage and var control may not yield the same benefits on the California system which has significant penetration of capacitors already. The 'self-reporting' sensors application can help crews locate equipment that is malfunctioning and speed up maintenance functions on the distribution system. Finally, the efficiency standards application was selected because from our analysis losses represent the greatest cost saving potential, and the amount of losses on the system depends mostly on the distribution system design. Voltage and var regulation, power quality improvement, and other operational factors do not seem to represent significant value streams for most customers. Over the years, utilities have made improvements to distribution systems that reduce losses. For example, many systems increased the voltage levels on distribution systems. Other distribution system design choices, such as the type of transformer and the length of feeders from the substation (e.g. number of substations and feeders per substation), also affect system losses. Ideally, the distribution design should balance total costs of building and maintaining the standard design and its operational efficiency.

For 'Management of Peak Loads,' automatically reducing loads during on-peak distribution system contingencies seemed to represent the best opportunity. Most distribution systems are built to serve the

peak load during a single contingency. However, in areas with fast or unexpected growth or if the utility has been capital constrained, peak loads can push past the ability to be served within normal equipment ratings under contingency. Reducing loads during this period therefore relieves overloads on the remaining equipment, and can keep the remaining customers in service. This approach can also give crews more time to repair equipment that might be operating in a 2-hour emergency limit to 8-hour or normal operating limit. Also, the combined probability of a contingency and the load being at the peak level of the year is small. Therefore, customer loads would not have to be reduced very often. Utilities are already increasing similar programs to manage system peaks and these programs could be dispatched for both local and system needs. Another advantage of this application is that California is investing heavily in the two technologies required to achieve the load reduction. The utilities are installing AMI which provides a link to the customer, and the proposed 2008 Building Efficiency codes include Programmable Communicating Thermostats (PCTs) which have the ability to set the temperature of the air conditioner (the predominant load on peak) by way of signal from the utility through AMI. The remaining piece that is not in place is the DA system that can sense a problem on the distribution system, and send a signal to the appropriate thermostats to help reduce any potential overloads.

For 'Prediction of Equipment Failure,' we found that it is difficult to justify the cost of 'early replacement' (e.g. replacing aging equipment while it is still working properly) unless (a) failure can be determined with a relatively high probability, and (b) failure results in significant costs and / or customer outages. In most cases, a lower cost strategy is 'run to failure' and subsequent management of the outages. Therefore, prediction of equipment failure is most valuable on underground cable sections since cable faults can result in sustained customer outages for long periods, and very expensive emergency replacements, particularly in urban areas. As California's infrastructure grows older, decisions will have to be made about when to replace cable sections, and distribution automation technologies that can help prioritize replacement will be especially valuable.

For 'Restoration After System Failure,' we found that the extent of customer outages can be significantly limited by installing automated switching to isolate faults. The theoretical result in our analysis is supported by the results SCE reported in support of the expenditure. SCE has targeted the worst performing feeders first. A benefit / cost analysis using customer outage cost may show that system-wide deployment would have positive net benefits to customers. Particularly, if the automated switches enabled additional monitoring capabilities that could be used for system operations applications or location of faults. Even with system-wide deployment of automated switching, there will still be customers without service. Therefore, there is still value in advanced Outage Management Systems (OMS) that can poll AMI meters and / or use system monitoring to precisely locate the failure and direct crews to the problem location. Interestingly, the more automated switching, the less overall benefit precise OMS systems will have since fewer customers will be without service.

5.2 Research and Development Needs

To develop the methodology in each valuation category, the team used many illustrative examples and approximations to estimate the range of benefits different applications could provide. Much of the data that was estimated (losses, load levels, system topology and equipment, etc.) is generally tracked by the utilities for their purposes. However, we also estimated or used proxies for data that is not commonly available at most utilities.

In particular, three types of data extremely helpful to value the range of distribution automation applicatoins are not generally available.

1. Equipment reliability data such as mean time to failure, mean restoration time. In the analysis, we used data from Consolidated Edison which has an extensive database of equipment failure. We are not aware of similar data for California-based utilities (and Consolidated Edison system and equipment is not representative of the equipment in California). Without equipment reliability data, the methodology developed to predict distribution system reliability at different

load levels would have to use proxy estimates and sensitivity analysis. This would not be nearly as meaningful if actual equipment data were applied.

2. Value of reducing a customer load. Customer value-of-service estimates are inherently difficult to estimate and apply with any certainty. The variations are significant between customers of the same type, and between interruptions at different times. Therefore, it is difficult to have a confidence in any single estimate. The data is even sparser on the value of interrupting a particular end-use rather than the whole customer. In the Management of Peak Loads applications, the approach presented interrupting individual end-uses from least value to most value to improve reliability, however, this is only an illustration and this type of data is not readily available beyond a few studies on the value of air conditioning. If this program were to be implemented, it would have to be designed so that customers select their own loads in order of priority at different price levels an this data would be available through self-selection.
3. Costs of distribution automation technologies. Most of the analysis completed in this study was done without consideration for the cost of the distribution automation technology itself. This is not because it isn't important, just that the research team did not have a reliable source of the cost to use. As with any emerging technology, the costs are likely to change as a particular technology becomes more widely used and manufacturers focus on developing lower cost, higher quality products. In the 'conceptual model' of DA development presented in the introduction, the third stage of 'Field Verification Test' includes competitive procurement of technology. This is likely the best and possible only way to get an accurate view of the current marketplace.

In addition to data that is not readily available, accurate valuation of some distribution automation technologies will require new methodology and tools to be developed.

One of those applications is to estimate energy savings or increases that can be expected from changes in voltage level. There may be modeling that makes this possible given an estimate of the type of loads on a particular system, but it was not readily apparent on how best to make this estimate accurately. This is probably best done through testing in the field.

More importantly, the team spent considerable time developing a framework to benchmark the expected reliability of a system and to then evaluate the trade-offs between changes in the reliability and cost. If implemented well, this framework can form the basis for numerous improvements in California's distribution system. Potential applications range from developing a new distribution system design standard with the 'right' level of reliability, exploring reliability differentiation between areas and premium power distribution systems or microgrids, revisiting the N-1 distribution system design standard and replacing it with a value based decision-making process, AND (of course) evaluating the value of a distribution automation application that improves reliability.

5.3 Next Steps: A Use Case Framework

On October 17th, a number of representatives from California and other utilities and from DA manufacturers attended a workshop to discuss this report, as well as other issues related to distribution automation. Of various suggestions for further research to come from the workshop, one that was most widely favored by participants was to analyze how DA applications could contribute to particular "use cases" in California.

The 'use case' is a characteristic distribution system scenario and provides more definition to the DA applications summarized in this report. For instance, peak loading that occurs on a rural radial circuit could be one use case, for which key decisions could involve evaluating options for managing the peaks or for expanding capacity to serve them. A separate use case may relate to peak loads on more urban, high density distribution networks. Other use cases could be developed for how storms affect various types of circuits. Additional use cases may be drawn from emerging issues, such as integration and use of rooftop PV, or facilitation of connections for plug-in hybrid electric vehicles (PHEV).

Developing a set of use cases that characterize some of the more common or most important situations relevant to the distribution system in California could serve as a starting point for further refining potential high value DA applications. Once a set of use cases is selected, each could be analyzed to determine the value propositions that involved with each case. These value propositions could be defined in terms of what problems are need to be solved, or what aspects of current utility practice for the use case situation could be improved. Similar to the exploration of value streams in Chapter 3 of this report, it would be important to define the goals related to each use case fundamentally and broadly enough to avoid being locked into a particular solution approach and thereby missing other, potentially more efficient, methods of achieving the actual goals.

After the use cases and applicable value streams have been developed, the range of DA applications can then be assessed for their potential ability to solve or improve the significant issue involved in the use case. For instance, in a use case involving outages on a rural, radial network, remote switches could be compared to fault interrupters on the basis of cost and how they would affect customer usage. Alternatively, as part of an aim to serve changing customers needs and to improve energy efficiency, utilities may need to consider ways to more easily facilitate interconnection of DG such as rooftop PV or CHP generation. Various DA applications and technologies could be evaluated for their ability to reconfigure the network to adapt to these new generation sources, or could be used to enable the DG to access additional value streams, such as enabling microgrids for security, or obtaining payments for their distribution capacity benefits.

After DA applications and technology options are evaluated for how they can address the value propositions related to particular use cases, particular applications can be selected for demonstration projects. This selection may be based on a number of criteria, such as:

- The DA application's alignment with the policy mandate of the CEC, which includes integration of renewable distributed generation, prioritization of energy efficiency, and reduction of greenhouse gasses in electricity generation,
- The economic significance of the issues in the use case that a DA application could address for California,
- The DA application's expected likelihood to address the issues in the use case in an effective and timely manner,
- The expected likelihood that a successful publicly-supported demonstration would lead to more widespread acceptance and use of the DA application and technology by IOUs or municipal utilities in California, and
- The probability that, if the DA application were not supported through publicly-funded demonstration projects, it would be overlooked or underutilized by the utilities.

This last element of the criteria could be related to situations in which the utilities incentives are not aligned in a manner to promote use of the DA solution. It is possible that customers involved may desire a certain service or action from utilities that can be facilitated by a DA application, but that regulatory mechanisms are not in place to encourage the utility to meet this need. Effective selection of research funding for particular DA applications to fund requires developing a greater understanding of the needs and desires of California customers.

Appendix A: Survey Background and Questions

[See separate file.]

Appendix B: Detailed Survey Results

[See separate file.]