Argonne NATIONAL LABORATORY

ANL/ESD-17/3

Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization

Business Case Calculations for DMS

Energy Systems Division

ANL/ESD-17/3

Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization

Business Case Calculations for DMS

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FOUNDATIONAL REPORT SERIES

DISTRIBUTION MANAGEMENT SYSTEMS FOR GRID MODERNIZATION

This is one of seven reports on distribution management systems (DMS), their functions, implementation, and importance for grid modernization.

The reports on DMS in this numbered series of Argonne reports are as follows:

1. Importance of DMS for Distribution Grid Modernization (ANL/ESD-15/16)
2. DMS Functions (ANL/ESD-15/17)
3. High-Level Use Cases for DMS (ANL/ESD-15/18)
4. Business Case Calculations for DMS (ANL/ESD-17/3)
5. Implementation Strategy for DMS (To Be Published)
6. DMS Integration of Microgrids and DER (To Be Published)
7. DMS Industry Survey (To Be Published)

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CONTENTS

CONTENTS (CONT.)

FIGURES

TABLES

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LIST OF ACRONYMS AND ABBREVIATIONS

AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
BCR	Benefit-to-Cost Ratio
CBM	Condition-based Maintenance
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DAC	Data Acquisition and Control
DCF	Discounted Cash Flow
DER	Distributed Energy Resources
DMS	Distributed Management System
DNP3.0	Distributed Network Protocol 3
DOE	U.S. Department of Energy
DR	Discount Rate
DSCADA	Distribution Supervisory Control and Data Acquisition
DTS	Distribution Training Simulator
DVVC	Dynamic Volt-VAR Control
EMS	Energy Management System
ESB	Enterprise Service Bus
FCI	Faulted Circuit Indicator
FLISR	Fault Location Isolation and Service Restoration
GUI	Graphical User Interface
ICE	DOE Interruption Cost Estimate Calculator
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
MW	Megawatt(s)
O&M	Operating and Maintenance
OMS	Outage Management System
ONR	Optimal Network Reconfiguration
PBR	Performance Based Rate
PER	IEEE Power and Energy Society
PFL	Predictive Fault Location

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDWG	IEEE Smart Distribution Working Group
SOM	Switch Order Management
SPG	Safety Protection Guarantees
TCO	Total Cost of Ownership
VAR	Volt Amps Reactive (Reactive Power)
VOLL	Value of Lost Load
VVO	Volt VAR Optimization

INTRODUCTION

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1 INTRODUCTION

Distribution Management System (DMS) applications require a substantial commitment of technical and financial resources. In order to proceed beyond limited-scale demonstration projects, utilities must have a clear understanding of the business case for committing these resources that recognizes the total cost of ownership.

Many of the benefits provided by investments in DMSs do not translate easily into monetary terms, making cost-benefit calculations difficult. For example, Fault Location Isolation and Service Restoration (FLISR) can significantly reduce customer outage duration and improve reliability. However, there is no well-established and universally-accepted procedure for converting these benefits into monetary terms that can be compared directly to investment costs. This report presents a methodology to analyze the benefits and costs of DMS applications as fundamental to the business case.

1.1 SCOPE

This report presents a methodology for computing the benefits and costs of DMS advanced applications, consistent with the Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization. It suggests an approach for monetizing the "functional" benefits, expressed in non-monetary terms, such as System Average Interruption Duration Index/System Average Interruption Frequency Index (SAIDI/SAIFI) reduction and improved efficiency, using commonly available technical and financial parameters. It offers a model for individual utilities to determine the estimated costs and benefits using their own specific data. Where actual utility-specific data is not available, industry default values are offered. The model uses discounted cash flow (DCF) analysis to evaluate the economic justification for an investment in DMS.

1.2 ORGANIZATION OF THE REPORT

This report sets forth the importance of DMS and makes suggestions for developing the business case (Chapter 2); explains the benefits and costs provided by common DMS applications (Chapter 3); describes a model to quantify and assess the benefits and costs of DMS through an objective and transparent methodology (Chapter 4); and concludes with some suggestions for future work (Chapter 5). Two major DMS functions, FLISR and Volt-Ampere Reactive (VAR) Optimization, are discussed at greater length in Annexes A and B, respectively. An evaluation model, DMS Value Calculator, and guidelines for its use are found in Annexes C and D.

Chapter 1 – Introduction. This chapter presents the objectives, scope, and organization of the report.

Chapter 2 – Developing a Business Case. This chapter provides a starting point for development of a business case for a DMS. General information about the DMS business case is provided, along with suggestions for dealing with some of the challenges that are inherent in the process, most importantly monetizing the benefits that are not readily quantifiable, and evaluating the costs and benefits over the expected lifetime of the system.

Chapter 3 – Benefits of DMS Applications. This chapter discusses the benefits and costs provided by DMS applications. It identifies the functional and monetary benefits of the DMS applications along with algorithms for computing the benefits and costs of each application.

Chapter 4 – DMS Value Calculator. This chapter describes DMS Value Calculator and a provides a sample business case that illustrates the key features of the model.

Chapter 5 –Conclusions and Future Work. This chapter draws conclusions from the findings in this report and makes recommendations for future work.

ANNEXES

A – Fault Location Isolation and Service Restoration. This Annex discusses the benefits and costs of deploying Fault Location Isolation and Service Restoration (FLISR). It includes an overview of FLISR operations, potential benefits, costs, and algorithms for computing the benefits.

B – Volt-Ampere Reactive (VAR) Optimization. This Annex discusses the benefits and costs of deploying Volt-VAR Optimization (VVO). It includes an overview of VVO operations, potential benefits, costs, and algorithms for computing the benefits.

C – DVCalc - DMS Benefit-Cost Analysis Tool

D – Distribution Management System Value Calculator and Guidelines. This Annex provides the evaluation model itself plus guidelines for entering inputs, executing the program, and viewing and interpreting the results.

DEVELOPING A BUSINESS CASE FOR DISTRIBUTION MANAGEMENT SYSTEMS

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2 DEVELOPING A BUSINESS CASE FOR DISTRIBUTION MANAGEMENT SYSTEMS

This chapter provides general information about developing a business case for electric utility Distribution Management Systems. General information about business cases is provided, along with best practices for addressing the challenges of business case development, including accurately monetizing benefits and costs, dealing with "soft" benefits, and evaluating the economic parameters over the expected lifetime of the system.

2.1 WHAT IS A BUSINESS CASE?

The purpose of a business case is to document the justification for undertaking a project. It is usually based on a comparison of the estimated cost of development and implementation with the anticipated business benefits to be gained, including due consideration of the risks associated with project deployment. The total cost of ownership may be much wider than just the project development costs.

A business case can be defined as a decision support and planning process that presents the likely financial results and business consequences of an investment decision. It presents the rationale for making an investment. The business case supports proposals and arguments that give decision makers the justification for proceeding with a project.

A business case is typically organized into two major parts:

1. A description of current or future business problems that are solved or mitigated by the proposed project, which includes the feasibility of the technology and solutions to be implemented as an investment
2. An economic analysis of the required investment, which includes monetized benefits versus the total cost of ownership over the life of the investment

2.2 NEED FOR A BUSINESS CASE

Many electric distribution utilities are considering deploying a DMS as part of their grid modernization strategy. Grid modernization includes power system improvements deployed to achieve specific business goals, such as improved reliability, safety, efficiency, asset utilization, and overall performance. However, before embarking on a major DMS project that requires a significant investment in resources, both technical and financial, management needs to know if the expected benefits outweigh the expected total cost of ownership.

Some asset monitoring and control systems are deemed essential for operating the power grid. For example, protective relays, required to protect circuits, equipment, etc., are an essential component of the distribution network itself, so the need for protective relays does not require economic justification. Similarly, Energy Management Systems (EMS), which provide visibility and control into transmission networks, are mission-critical for the operation of the bulk power system. The consequences of losing this visibility and control are so severe that transmission operators would never consider operating without an EMS, and the necessary investments would be made. Basic systems and technologies that are necessary for the operation of the distribution system do not require a business case to justify their acquisition.

The DMS has not yet reached the status of a mission-critical system. Nevertheless, it is likely to become one as the use of distributed energy resources (DER) located on the distribution system penetrate to a point where the lack of ability to manage these resources threatens the stability of the overall power grid. The DMS business case must anticipate the needs of the distribution utility when these penetration levels are reached. Presently, though, a business case that weighs the costs and benefits of the DMS is necessary. This report provides a methodology for developing the DMS business case.

2.3 GENERAL METHODOLOGY FOR DEVELOPING A BUSINESS CASE

This section outlines the general strategy for building a business case for DMS projects, which is illustrated in Figure 2-1:

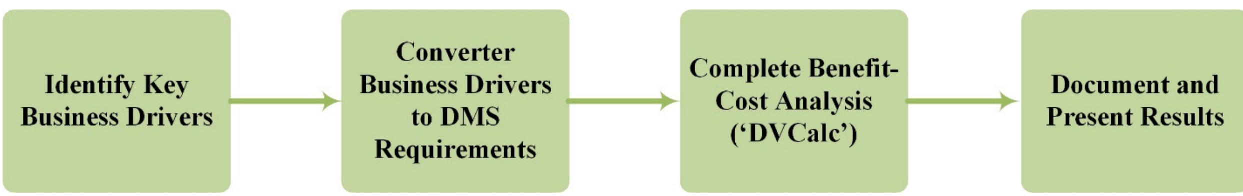

FIGURE 2-1 General Strategy for Developing the DMS Business Case

2.3.1 Identifying Key Business Drivers

DMS projects should support the business objectives and address the specific operational problems and needs facing the electric distribution utility. This is the foundation for success.

The process begins by developing a clear understanding of key business drivers and important business problems. The best way to identify the most important business issues and problems is to interview the persons who "own" them—senior-level management. These interviews should obtain information about current business drivers as well as issues the utility company will likely face in the near term (5 to10-year horizon). Providing a DMS solution that addresses the most pressing needs of senior management and supports the long range "vision" of company executives is key to gaining buy-in for the project and achieving long-term support. Top management backing from the executives who will fund the DMS project from operating budgets, oversee its implementation and deployment, and perform day-to-day maintenance and management is crucial for project success.

Although the specific business needs and objectives vary widely from utility to utility, those most relevant to a DMS project, as a starting point, can fall into one or more of the general categories listed below.

- Maintain safety of the workforce and public.
- Maintain a high level of customer satisfaction.
- Provide a quality of service that meets or exceeds industry or peer group standards.
- Achieve lowest possible cost of service.
- Maintain a highly productive workforce under normal and emergency conditions.
- Improve the overall efficiency and reliability of the power delivery system.
- Maximize utilization of the existing distribution assets.
- Accommodate high penetrations of distributed energy resources.

In addition to soliciting information from senior level managers on present and future business drivers, interviewing first line managers who are responsible for the day-to-day operation of the electric distribution system is imperative. First line managers will be the major users of the DMS and, in order to meet their needs, it is essential to obtain a thorough understanding of the challenges and problems they face daily and to identify ways to overcome them.

Concerns and issues vary widely from utility to utility, but typically include:

- Provide training programs to prepare new personnel to replace an aging workforce.
- Prepare workforce for new hardware, software, and communication technologies.
- Implement measures to guard against and recover from cyber and physical attacks.
- Eliminate inefficient manual, paper-driven business processes so that workforce can focus on increasingly complex operating problems.
- Maintain safety of the workforce as higher levels of automation are introduced.
- Improve visibility of operating conditions on complex systems.
- Implement measures to respond effectively during widespread emergencies.

2.3.2 Converting Business Needs to DMS Applications

Once a utility's business objectives and needs have been identified (as described in the previous section), the next step to develop the business case is to relate these objectives and needs to the specific DMS applications that addresses these issues.

The DMS application suite includes two major types of applications: “enabling” functions and “specific purpose” functions.

2.3.2.1 Enabling Functions

Enabling functions, shown in TABLE 2-1, perform elementary functions that support specific purpose functions. These enabling functions provide the foundation upon which almost every DMS is based. They are the minimum set of application functions required in every DMS. Without these enabling functions, the specific purpose application functions would not be possible. In addition to supporting (enabling) the specific purpose applications, some of the enabling functions provide value by themselves. For example, “Data Acquisition and Control” provides measurements that allow the dispatcher to view measured electrical conditions on feeders and execute supervisory and automatic control of devices; “On Line Distribution Power Flow” enables the dispatcher to view electrical conditions at locations that are not equipped with sensors.

TABLE 2-1 DMS Enabling Functions

DMS "Enabling" Functions
Data Acquisition & Control
State Estimation
Graphical User Interface
Historical Information System
Distribution System Model
Load Models
Topology Processor
On-Line Distribution Power Flow

2.3.2.2 Specific Purpose Functions

Specific purpose DMS functions address utility company-specific business objectives. The DMS Opportunity Matrix, shown in TABLE 2-2, cross references DMS applications to specific business objectives.

TABLE 2-2 DMS Opportunity Matrix

DMS "Specific Purpose" Apps	Safety	Reliability	Asset protection	Efficiency	Peak shaving	Asset Utilization	Manage DERs	Manage Evs
Intelligent Alarm Processing		✓	✓			✓		
Tagging, Permits and Clearances	✓	✓	✓	✓				
Short Circuit Analysis		✓	✓					
Switch Order Management	✓	✓	✓			✓		
Volt-VAR Optimization				✓	✓	✓	✓	
FLISR	✓	✓						
Predictive Fault Location		✓						
Optimal Network Reconfiguration		✓		✓	✓	✓		
Short Term Load Forecasting		✓		✓	✓		✓	✓
Dynamic Equipment Rating			✓			✓		
DMS Control of Protection Settings		✓	✓					
DER Management		✓	✓	✓	✓		✓	
Demand Response Management		✓			✓			
Emergency Load Shedding					✓			
EV Charging					✓			✓
Dispatcher Training Simulator	✓	✓	✓	✓	✓	✓	✓	✓

The utility company can use the Opportunity Matrix to determine the application functions that should be included in its DMS. For example, the checkmarks in the column headed "Reliability," identify the applications that improve Reliability:

- Intelligent Alarm Processing
- Tagging, Permits, and Clearances
- Short Circuit Analysis
- Switch Order Management
- Fault Location Isolation and Service Restoration (FLISR)
- Predictive Fault Location
- Optimal Network Configuration
- Short Term Load Forecasting
- DMS Control of Protection Settings
- DER Management
- Demand Response Management
- Dispatcher Training Simulator

Therefore, if "Reliability Improvement" is one of the business objectives, then some or all of these applications, depending on the criticality of their impact, should be included in the suite of applications for the proposed DMS.

2.3.3 Benefit Cost Analysis with DVCalc

A major part of developing a business case is evaluating the proposed DMS investment by comparing the associated benefits and costs to determine if it is economically justified. The overall process for conducting the Benefit Cost Analysis (BCA) is shown in Figure 2-2. The DVCalc model (described in Chapter 4) performs the benefit and cost calculations, as well as the analysis of revenue requirements.

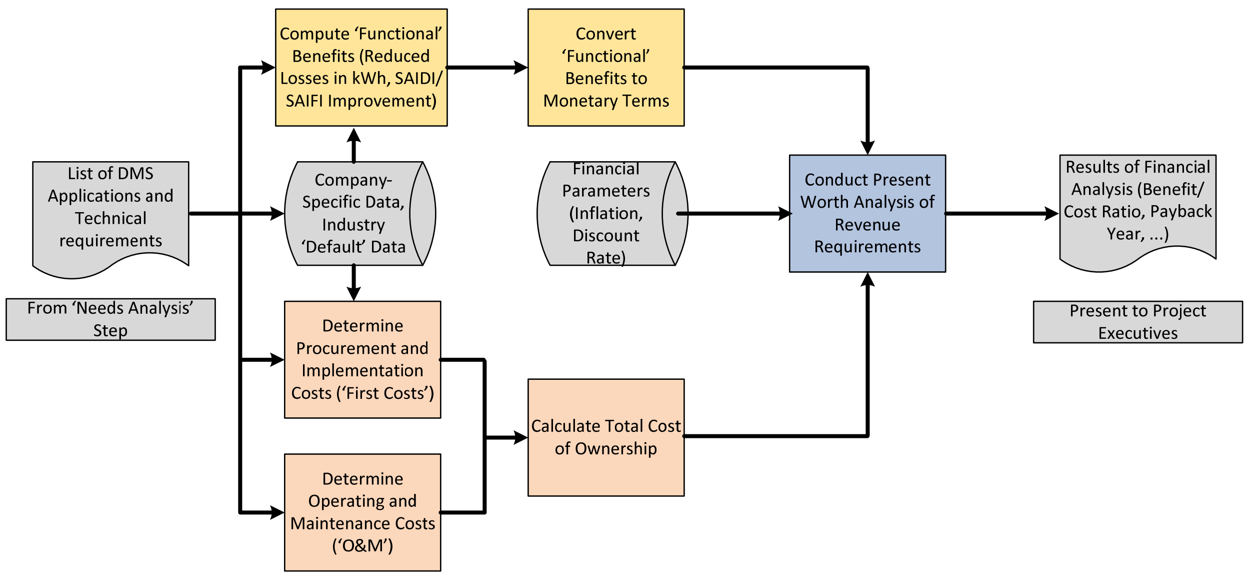

FIGURE 2-2 Methodology for Benefit Cost Analysis

It should be noted that the BCA described in this section is usually done at least twice. Early in the project, a "high-level" BCA is prepared to determine if the DMS appears to have sufficient merit to justify resource commitments for planning studies, needs analysis, procurement activities, and other "up front" tasks. Later, a more detailed BCA is done using actual costs for DMS-specific hardware, software, and services from vendor proposals. An overview of each of the major steps in the BCA is provided in the following sections.

2.3.3.1 Benefit Calculations

Computing the predicted DMS benefits is a two-step process. The first step is to calculate the benefits in "functional" terms, such as reduction of kilowatt-hour losses and improvement in System Average Interruption Duration Index (SAIDI). The second step is to convert these functional benefits to monetary terms in dollars or dollars per year—monetizing the benefits.

The DVCalc model includes formulas for computing the functional benefits of each DMS application function and for monetizing the benefits, using technical and financial parameters that are commonly accepted in the industry. "Default" values, typical of those in the industry, are entered for parameters that may not be available to an individual utility company. Most benefits computed by DVCalc are expressed as annual benefits (e.g., dollars per year or kWh loss savings per year). Some benefits may occur only once in the lifetime of the project. Note that recurring benefits are calculated starting the year following commissioning of the system.

Benefits Analysis “trees” show the functional and the resultant monetized benefits for the FLISR function in Figure 2-3 and the Volt-VAR optimization (VVO) function in Figure 2-4.

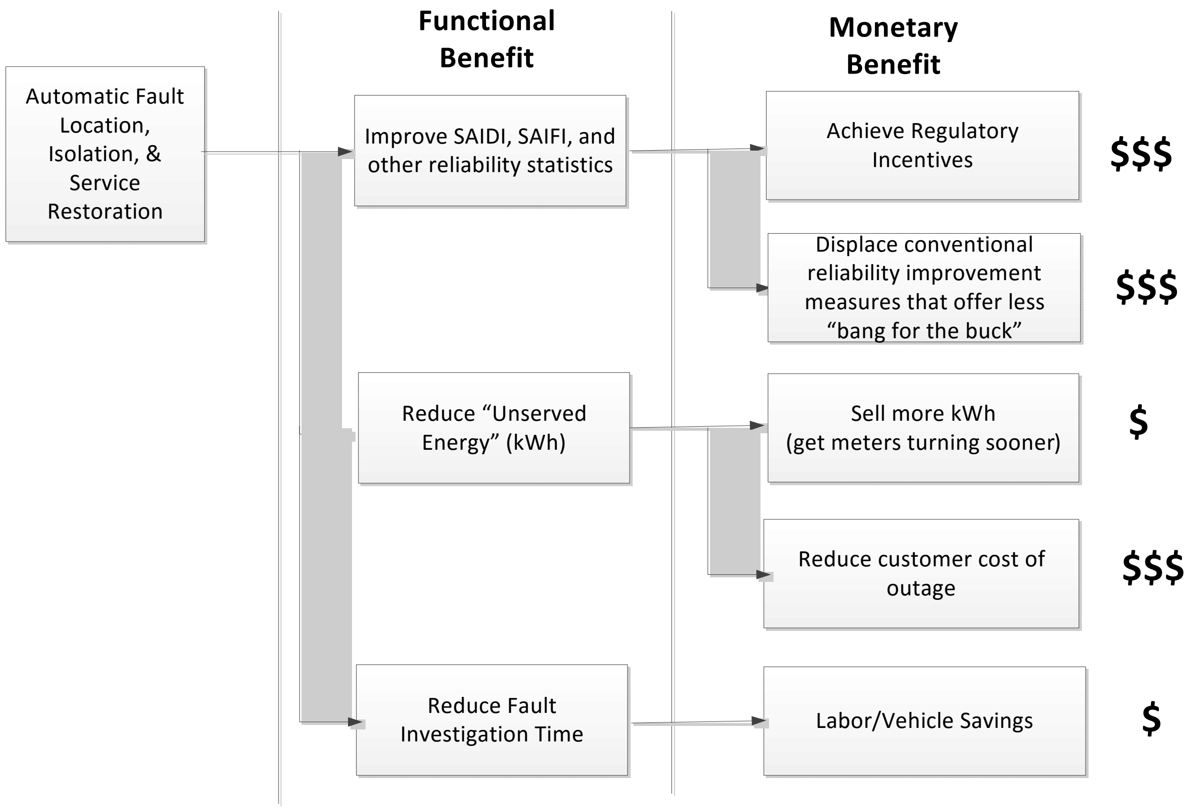

FIGURE 2-3 Benefits Tree for FLISR

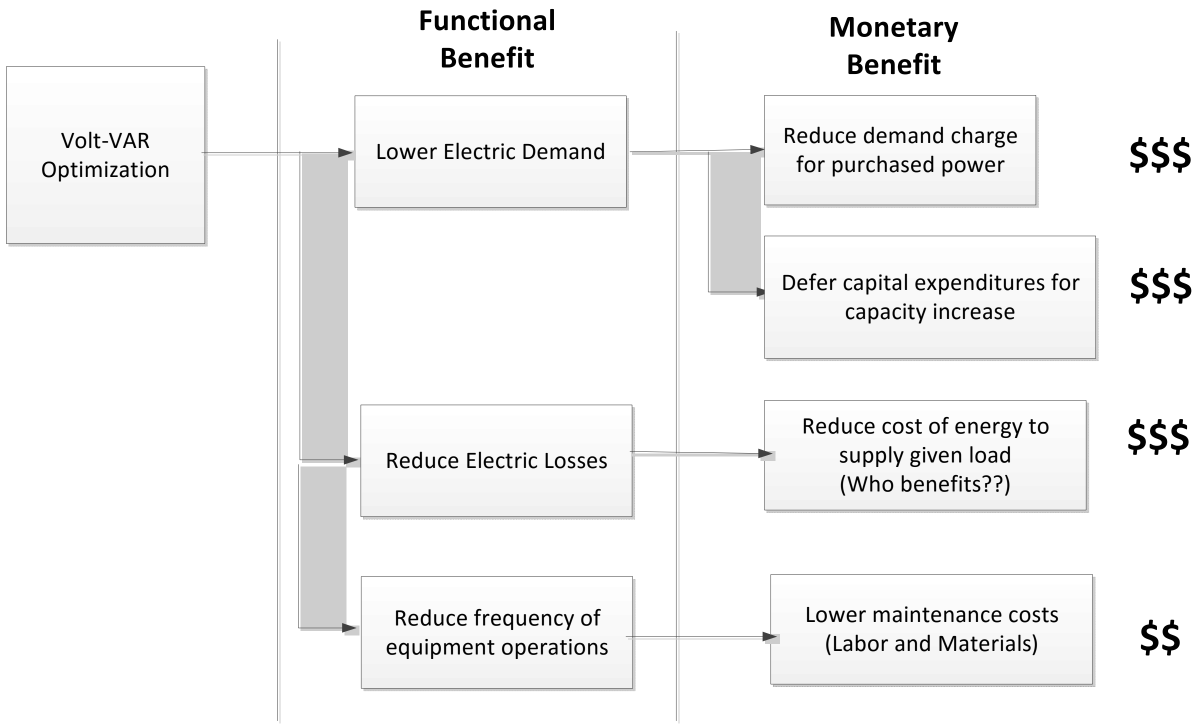

FIGURE 2-4 Benefits Tree for VVO

2.3.3.2 Cost Calculations

The total cost of ownership (TCO) for the DMS includes the "up front" costs (also known as "first costs") for planning, needs assessment, benefit cost analysis, procurement activities, and contract negotiation that are incurred prior to purchasing a DMS and associated field equipment and communication facilities. Also included as up-front costs are payments to system vendors and contractors for hardware, software, and services for design, implementation, testing, installation, and commissioning. These one-time costs are incurred during the first two to three years of the project prior to placing the system in service.

The TCO includes recurring costs to operate and maintain the system after it has been placed in service. It is common practice to compute such Operating and Maintenance (O&M) costs as a percentage of the first costs to procure and implement the system. This is the approach taken in the DVCalc model. These recurring costs are incurred on an annual basis over the life of the DMS, beginning the year that the system is commissioned.

2.3.3.3 Analysis of Revenue Requirements

Once the DMS benefits and TCO have been determined, the revenue requirements must be analyzed to determine if the benefits achieved by implementing the DMS outweigh the costs to implement, operate, and maintain the DMS over the life of this system. The DVCalc model uses present worth analysis to determine financial metrics, such as benefit to cost ratio, payback year, net present value, and other such factors that indicate whether the proposed DMS investment is economically justified. DVCalc computes the costs and benefits that are incurred each year over the life of the investment, which is assumed to be 15 years (this is an adjustable parameter in DVCalc).

The first costs begin during Year 1 of the project and are evenly spread over the number of years specified to implement and commission the system, (typically two to three). If the number of years to implement the system is three years, then DVCalc assumes that the amount spent in Year 1 is one-third of the total first cost, and that similar amounts are incurred in Years 2 and 3. Annual benefits and annual O&M costs begin the year following the completion of DMS commissioning. For example, if it takes three years to install and commission the system, annual benefits and O&M costs begin in Year 4.

The costs and benefits identified in the two previous sections of this report represent the cost or benefit savings that would result if incurred in Year 1 in the lifetime of the system. Since the costs and benefits are spread out over the entire life of the system (assumed to be 15 years, an adjustable parameter), the costs and benefits must be adjusted to account for inflation, load growth, rising fuel costs, and other such factors. Then, the net present value of the costs and benefits over the system life can be calculated using a utility specific “discount” rate (typically 6% to 7% at current interest rates). The steps for determining annual costs and benefits over the life of the system are stated below:

1. Determine the annual cost or benefit (usually computed in Year 1 dollars).
2. Multiply the Year 1 dollar cost and benefit by a suitable escalation factor for the type of cost or benefit:
    a. Costs and benefits associated with labor are escalated at the rate of inflation (e.g., 2% per year)
    b. Costs and benefits associated with electrical quantities (e.g., reduction of electrical losses) are escalated by a combination of inflation (or rising fuel costs) and electrical load growth
3. Multiply the adjusted cost or benefit value by a “present worth” factor based on the discount rate (DR). For example, the present worth factor for a cost or benefit that is incurred in Year 5 of the investment is:

$$Present\ Worth\ Factor\ = (1 + 1/DR)^5$$

DVCalc creates a table containing all of the escalated/discounted costs and benefits over the life of the investment and computes the financial parameters using standard Excel functions. Figure 2-5 contains an example of this table.

First Cost	1,000	dollars (one time cost)
O&M Cost	3	%/year
Annual Benefits	300	dollars/year
# Years to Complete Project	2	years
System Lifetime	10	years
Inflation Rate	2	%/year
Discount Rate	6	%/year

	Costs								Benefits					
Year	1st Cost	O&M	Tot Non Esc Cost	Esc Factor	Esc cost	Discount Factor	Esc/Disc Cost	Cumul Cost	Benefit	Esc Factor	Esc Benefi	Discount F	Esc/Dis Benefit	Cumul Benefit
1	$500	0	$500	1	$500	1	$500	$500	0	1.000	0.000	1.000	0.000	0.000
2	$500	0	$500	1.02	$510	0.943	$481	$981	0	1.020	0.000	0.943	0.000	0.000
3		$30	$30	1.040	$31	0.890	$28	$1,009	$300	1.040	312.120	0.890	277.786	277.786
4		$30	$30	1.061	$32	0.840	$27	$1,036	$300	1.061	318.362	0.840	267.303	545.089
5		$30	$30	1.082	$32	0.792	$26	$1,061	$300	1.082	324.730	0.792	257.216	802.305
6		$30	$30	1.104	$33	0.747	$25	$1,086	$300	1.104	331.224	0.747	247.510	1049.815
7		$30	$30	1.126	$34	0.705	$24	$1,110	$300	1.126	337.849	0.705	238.170	1287.985
8		$30	$30	1.149	$34	0.665	$23	$1,133	$300	1.149	344.606	0.665	229.182	1517.168
9		$30	$30	1.172	$35	0.627	$22	$1,155	$300	1.172	351.498	0.627	220.534	1737.702
10		$30	$30	1.195	$36	0.592	$21	$1,176	$300	1.195	358.528	0.592	212.212	1949.914

FIGURE 2-5 Sample Calculations Analysis of Revenue requirements

2.3.4 Documenting and Presenting the Results

One of the major business case challenges is obtaining approval from executives who make investment decisions. In addition, approval must be obtained from senior-level managers who oversee projects and, in some cases, must adjust departmental budgets and project budgets to fund recommended projects. For example, if a DMS project is funded in part by workforce productivity improvements, then some workforce cutbacks are needed, possibly in the form of contractor reductions, less overtime, and natural attrition (e.g., retirements). As another example, if DMS reliability improvement projects are justified based on displacing conventional reliability improvement measures (such as tree trimming, animal guards, and selective equipment replacement), then cutbacks in the budgets for conventional measures must occur.

The key to obtaining business case signoff and approval is to involve the affected managers and their staff in the preparation of the business requirements and objectives for the new DMS facilities from the very start. To be successful, the affected managers and their staff must validate all assumptions, confirm the practicality of the recommended new facilities, verify their effectiveness in replacing existing human and equipment resources, and, in general, agree with the recommendations.

2.4 BUSINESS CASE CHALLENGES

This section describes some of the key challenges that are often encountered when developing a business case.

2.4.1 Efficiency Improvements

Grid modernization applications, such as VVO, can help the utility reduce electrical losses, lower the peak electrical demand, promote energy conservation, and improve overall efficiency of the electric distribution system. The VVO benefit tree is shown in Figure 2-6.

2.4.2 Demand Reduction

The VVO application may reduce electrical demand (peak shaving) by lowering the voltage or improving power factor during peak load periods. The monetary benefit of peak demand reduction is different for vertically integrated electric utilities (generate, transmit, and deliver the electric power to end use customers) and distribution-only companies (purchase power from generation/transmission suppliers and deliver the power to end-use customers).

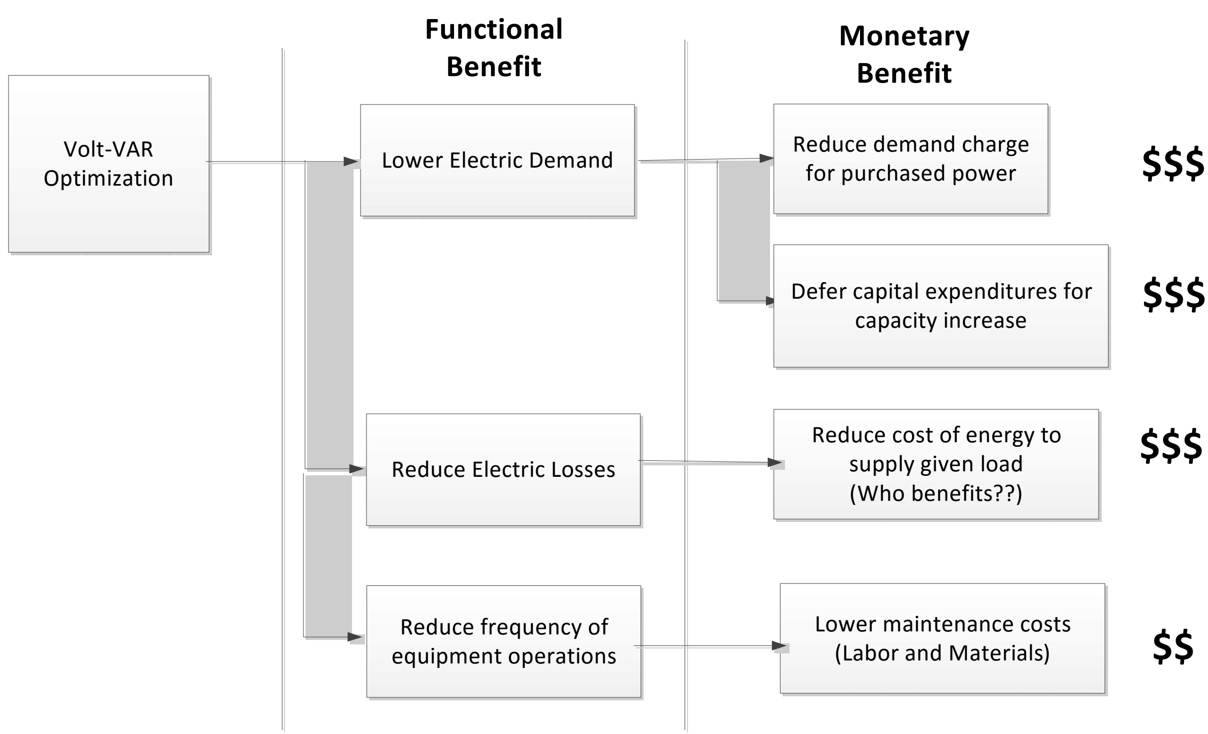

FIGURE 2-6 VVO Benefit Tree

The benefits of reducing the demand during peak load conditions are either (1) avoiding or deferring the cost of capacity additions for utilities that build and operate their own generating facilities; or (2) avoiding demand charges for utilities that purchase power. In both cases, the result is a demand price expressed in units of dollars per megawatt ($/MW) escalated at the rate of inflation to determine the cost savings at any year during the life of the VVO system.

Direct Build Option

For the direct-build option, the capacity cost includes direct capital costs of the generating unit (design costs, equipment costs, construction labor costs, etc.), indirect construction costs (construction management, startup, and commissioning costs), and other project costs (development and land costs, project contingency, interest during construction, etc.). Direct-build costs also include generating unit fixed O&M costs (labor and environmental expenses, general and administrative costs, etc.). The result is a projected demand price in dollars per kilowatt-year, which is multiplied by the demand reduction in megawatts to determine the annual benefit.

If electrical demand is reduced during the peak load period, it may be possible to defer capital projects that were planned to add capacity to the electric distribution system. The DVCalc model determines the number of years a capacity addition can be postponed by comparing the peak demand reduction obtained using VVO with the expected load growth rate. For example, if the expected demand reduction is 2% of peak load, and the load growth rate is estimated to be 1% per year, then the capacity addition may be postponed by two years (2% ÷ (1% per year)). Table 2-3 contains a simple example showing how the monetary benefits of a deferred capital expenditure may be determined. In this example, a $1 million capital investment is deferred two years. This example assumes a rate of inflation of 2.2% and a discount rate of 5.5%. As seen in Table 2-3, deferring the investment by two years results in a 6% savings over the life of the investment.

TABLE 2-3 Economic Analysis of Deferred Capital Expenditures

Inflation: 2.20%

Discount Rate: 5.50%

Investment Amount: 1000 k$ (2013)

O&M Cost: 3% (per year)

Year	Analysis of Non-Deferred Investment						Analysis of Deferred Investment					
	Initial Invest	O&M	O&M with Inflation	Total Annual Cost	PV Factor	PV Total Cost	Initial Invest. with Inflation	O&M	O&M with Inflation	Total Annual Cost	PV Facto r	PV Total Cost
2013	1000	0	0	1000	1.00	1000						0
2014		30	31	31	0.95	29.1						0
2015		30	31	31	0.90	28.2	1044	0	0	1044	0.90	938
2016		30	32	32	0.85	27.3		31	32	32	0.85	27
2017		30	33	33	0.81	26.4		31	33	33	0.81	26
2018		30	33	33	0.77	25.6		31	33	33	0.77	26
2019		30	34	34	0.73	24.8		31	34	34	0.73	25
2020		30	35	35	0.69	24		31	35	35	0.69	24
2021		30	36	36	0.65	23.3		31	36	36	0.65	23
2022		30	36	36	0.62	22.5		31	36	36	0.62	23
2023		30	37	37	0.59	21.8		31	37	37	0.59	22
2024		30	38	38	0.55	21.1		31	38	38	0.55	21
2025		30	39	39	0.53	20.5		31	39	39	0.53	20
2026		30	40	40	0.50	19.8		31	40	40	0.50	20
2027		30	41	41	0.47	19.2		31	41	41	0.47	19
2028								31	42	42	0.45	19
2029								31	42	42	0.42	18
						Cumulative total investment: 1334						**Cumulative total Deferred investment: 1252**
												Percentage Savings: 6%

Purchase Power Option

For the purchase power option, the demand price is generated from the specific tariff agreement that governs the purchased power agreement. A representative demand price is $80 per kilowatt year (Year 2013 dollars), which the program increases at the rate of inflation. For example, if VVO reduces the peak demand by one MW in the year 2015, then the savings for the year is $80,000 (in 2015 dollars).

2.4.3 Reduction of Electrical Losses

One of the possible functions of the VVO application is power factor correction. By correcting the power factor to near unity at all times, the amount of reactive power drawn from the substation to serve the inductive feeder load (motors, transformers, etc.) will be reduced. The magnitude of the current flowing on the distribution circuits will be reduced, which in turn will lower the electrical (I^2R) losses on the feeder. For example, improving the average power factor from 0.94 to 0.99 will reduce the electrical losses by approximately 10%. If the losses before power factor correction were 4% of total energy consumption, then the loss reduction with improved power factor would be approximately 0.4% of total energy consumed.

Electrical loss is electricity that must be generated or purchased by the electric utility for which no revenue is received. Electrical loss reduction in megawatt-hours can be monetized using the marginal generation energy price, which measures the additional cost of providing the next megawatt-hour of service.

BENEFITS OF DMS APPLICATIONS

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3 BENEFITS OF DMS APPLICATIONS

A fully developed DMS brings extensive functionality to distribution utility operations, starting with real-time data acquisition and control (DAC), a single distribution system model, and intelligent alarm processing for substation, feeder, and customer facilities. DMS applications can be used to (1) generate and validate safety protection guarantees (SPG) and switching orders; (2) provide integrated outage and distribution management systems to deliver improved outage management; and (3) perform optimal network reconfiguration. Other applications of advanced distribution management systems include (1) active management of distributed energy resources (DER) for improved distribution system performance; (2) expanded voltage and VAR control; (3) distribution asset management; (4) simulations for emergency preparedness drills under different scenarios for grid operations; and (5) interactive training.

3.1 TYPES OF DMS BENEFITS

This section summarizes significant benefits that can be achieved by implementing various applications in a DMS.

3.1.1 Safety of the Workforce and General Public

Maintaining safety of the electric utility workforce and the general public is a fundamental and essential business objective that applies to all electric distribution utilities. DMS applications that can assist in maintaining and improving distribution system safety are:

- **Supervisory control of distribution feeder devices.** Operating distribution system equipment energized at 12 kV and higher can pose a safety hazard for persons located in the vicinity of the device, especially when the operating condition of the device is unknown. Distribution Supervisory Control and Data Acquisition (SCADA) enables the distribution system operator to control the high- and medium-voltage devices via remote control with field personnel at safe distances. Note that remote control can be a double-edged sword when it comes to safety, because it is possible to remotely control the equipment without the knowledge and permission of field personnel in the vicinity of the switch. Such safety hazards can be effectively managed by applying well-established safety rules (tagging, clearances, permits, etc.) to the operation of DSCADA facilities.
- **Tagging, Permits, and Clearances.** The DMS can include application software that enables field workers to request all clearances, permits, and safety tags needed for their protection from inadvertent energization of high- and medium-voltage equipment being worked on. The DMS provides effective mechanisms to accurately create the necessary permits, tags, and clearances in accordance with established safety rules. The DMS will alert the system operators and field workers to other work in the vicinity of the proposed work, thus ensuring proper coordination.

- **Switch Order Management.** The DMS Switch Order Management (SOM) function enables the system operator to create and validate complex switching orders accurately and efficiently, thus ensuring that the switching orders are written in accordance with established safety procedures and minimizing the chance of human error. The DMS can also transmit the switching orders to field crews electronically using mobile data terminals, thus minimizing the chance of human error in conveying switching instructions to the field. The DMS SOM function always alerts the system operator to other work being performed on the same feeder or in the same vicinity so that all work activities are properly coordinated with maximum awareness of current tags, clearances, and permits on the same feeder or in the vicinity of the proposed work effort (Figure 3-1).

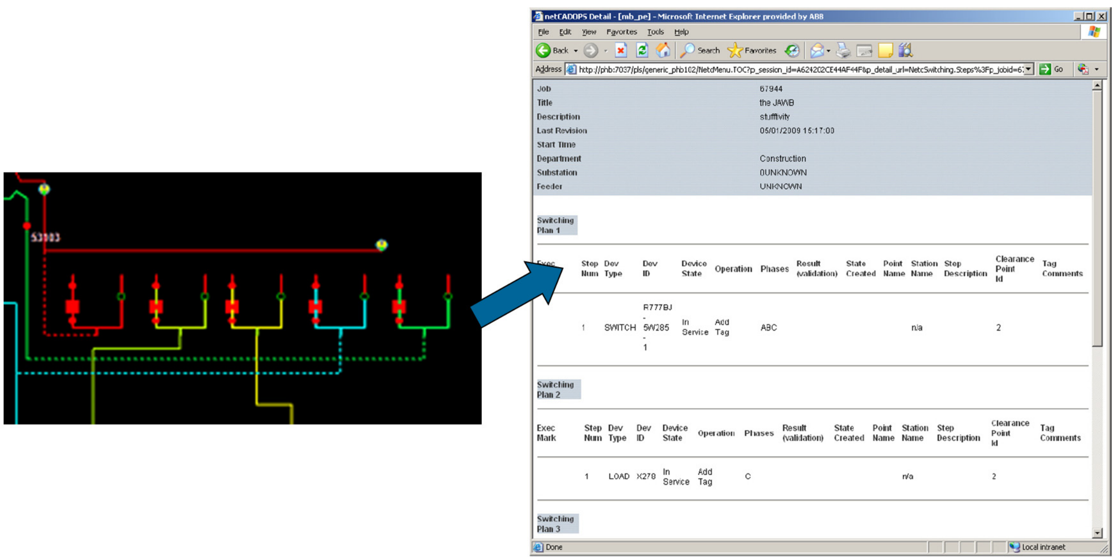

FIGURE 3-1 Using the DMS GUI to Create Switching Orders

- **Fault Location Isolation and Service Restoration.** The DMS Fault Location Isolation and Service Restoration (FLISR) function includes numerous features to ensure the safety of the field workers and the general public. When live line work is being performed on a given feeder, FLISR may be switched to "sectionalizer" mode, in which FLISR switches may be opened to isolate a fault. However, in a manner similar to the blocking of automatic reclosing ("hot line" tagging), switch closing and other automatic restoration activities are blocked to prevent re-energizing a section of feeder where field workers may be stationed. As another safety measure, switch closing is often automatically blocked after a specified time period (e.g., two minutes following initial fault detection) to prevent re-energization of downed wires that may have drawn the attention of public bystanders.
- **Distribution Training Simulators.** DMS distribution training simulators allow the utility to conduct realistic training exercises to ensure that the system operators are well

versed in the operating procedures for the new system. Benefits are summarized in Table 3-1.

TABLE 3-1 Training Simulator Benefits

Current State	Future State	Expected Benefits
• On-the-job training • Lessons learned during emergencies communicated in classroom or team meeting environment	• Interactive training simulator • Self-study for training new operators • Lessons learned replayed on training simulator with "what-if" capabilities • Formal certification of distribution system operators	• Reduced time and effort by senior operators to bring new operator candidates up to speed • Effective mechanism for conveying lessons learned • Realistic emergency preparedness drills

3.1.2 Cost of Service

The DMS may include several application functions that can assist the electric distribution utility to lower the cost of service, as described below:

- **Volt-VAR Control and Optimization.** The Volt-VAR Control and Optimization (VVO) application function performs numerous functions that can help the electric utility lower the cost of service. VVO determines optimal settings for voltage regulator and distribution cap bank controllers that can accomplish numerous objectives, such as electrical loss reduction, power factor improvement, and peak shaving. The monetary benefits of VVO are discussed in detail in Annex B.
- **Condition-Based Maintenance.** The DMS provides continuous monitoring and analysis of parameters that indicate the general health of distribution field equipment. Examples of monitored parameters include circuit breaker and recloser operation counters, contact wear indicators, circuit breaker timing, substation battery voltage performance, and transformer oil contaminant and moisture content. By basing maintenance and inspection requirements on equipment health measurements rather than fixed maintenance calendars, the electric distribution utility may be able to achieve significant cost savings without reducing the performance or reliability of the equipment.
- **Outage Planning.** The SOM function enables the utility to simulate planned outages using DMS short-term load forecasts for the planned outage time. The use of load forecasting enables the utility to anticipate potential overloads that may force the utility to halt the planned outage work in progress. Anticipating such problems in advance will enable the utility to avoid the cost of work startup and shutdown efforts due to unanticipated loading constraints.
- **Electronic Records Management.** The DMS may allow numerous manual tasks and paper-driven processes to be replaced with electronic and computer-assisted business processes that are more efficient and may produce significant cost savings for the utility.

- **Predictive Fault Location.** Predictive fault location enables the utility to identify possible fault locations much more accurately than distance-to-fault information supplied by protective relay intelligent electronic devices (IED) and outage management system (OMS)-predicted fault interrupting device techniques. The result is that a smaller portion of the feeder must be patrolled to identify the specific damage location, which in turn means a shorter fault investigation period. Such improvements may produce labor (contractor or overtime costs) and vehicle cost savings.

3.1.3 Customer Satisfaction

The DMS supports a number of applications that provide cost savings and improvements in the quality of service, which in turn can lead to increased customer satisfaction. As indicated in the previous section, the DMS can support a number of potential cost saving measures that may ultimately result in lower rates for electricity consumers.

The DMS application suite includes numerous functions that can improve the reliability and quality of service in a proactive manner—before customer calls or complaints occur. These functions can rapidly detect abnormal conditions (service outages, voltage sags and surges that may impact the customer, etc.), assess the damage, and, in some cases, can support a self-healing distribution network. The DMS advanced application suite includes a contingency analysis function that continuously reviews plausible overload conditions and outage events that could produce unacceptable conditions on the electric distribution system, such as widespread outages. Armed with such information about plausible emergencies, the distribution system operator may proactively prepare for such emergencies by deploying peak-shaving measures, load balancing, and, where applicable, dispatching of energy storage and distributed generating resources that may help mitigate the consequences should such a contingency occur.

The DMS, coupled with an OMS, includes numerous customer-facing applications that can help ensure customers receive accurate and up-to-date information about ongoing events, including actions the utility is taking in response to an event and when normal service will be restored. Recent storms that caused major outages in the northeastern United States and other regions of the country have brought electric utility performance during major storms to the forefront.

3.1.4 Reliability and Power Quality

Maintaining a high level of service reliability and power quality is another important business driver for most electric distribution utilities. Customer power outages should be infrequent, and should be as short as possible. The number of momentary interruptions lasting one minute or less should also be minimized. Service utilization voltage measured at the customer meter should be within the voltage ranges established by American National Standards Institute (ANSI) and other standards bodies for all customers under all loading conditions. The utility should rapidly detect and correct voltage sags, surges, and other voltage quality events caused by a variety of factors. An important business objective at many utilities is that the utility response should be proactive and such events should be detected and corrected before customers call to report the condition and complain.

- **DMS-Enhanced FLISR.** DMS application software provides useful enhancements to conventional FLISR that may enable downstream restoration activities to proceed in situations where power cannot be restored by conventional FLISR. For example, DMS FLISR enhancements may exploit energy storage or other distributed energy resources, fast demand response, and voltage reduction to reduce load and/or free up capacity so that a failed load transfer may be conducted. The benefits of this function are extensively discussed in Annex A.
- **Switch Order Management.** Restoring service to customers who have lost power due to a feeder fault may require operating engineers to develop a complex switching order that involves a detailed analysis of loading and voltage constraints. The DMS SOM application will facilitate the analysis of such complex situations, resulting in faster and more accurate development of switching plans needed to restore service. This, in turn, will result in an overall reliability improvement for the affected customers.
- **Predictive Fault Location.** Predictive Fault Location (PFL) provides a more accurate estimation of probable fault location than conventional methods, such as distance-to-fault information supplied by protective relay IEDs and fault-interrupting devices predicted by the OMS. The result is less patrol time and shorter overall fault investigation time, both of which translate into reliability improvement.
- **Dynamic Volt-VAR Control.** High penetrations of distributed generators, especially highly variable wind and solar powered generators, can produce rapid power swings and voltage fluctuations that may adversely impact the quality of power delivered to the electric distribution customers. Dynamic sources of capacitive and inductive VARs, managed by the DMS dynamic volt-VAR control (DVVC) application function, are able to mitigate this potential power quality problem. When voltage dips caused by sudden loss of DER power output occurs, the DVVC function will inject capacitive VARs at various locations to boost the voltage. Conversely, when voltage surges caused by sudden increases in DER power output occur, DVVC will inject inductive VARs at strategic locations. Figure 3-2 illustrates the impact of DVVC on feeders with a high DER penetration level.

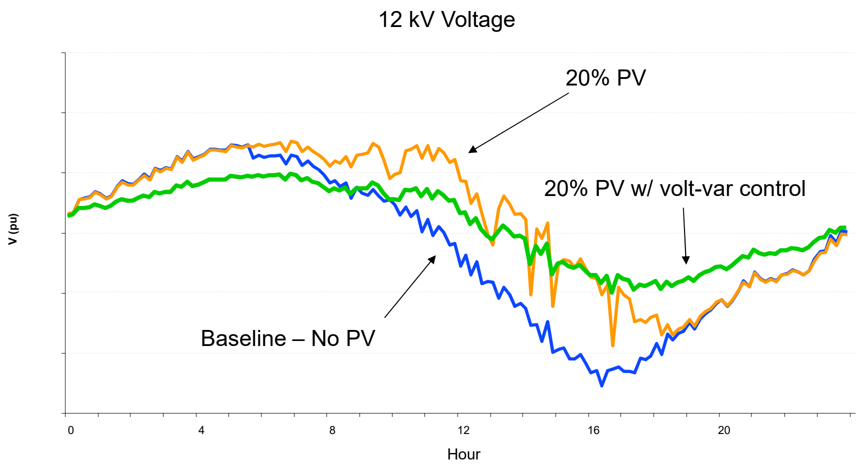

FIGURE 3-2 Power Quality Improvement with Dynamic VVO

3.1.5 Worker Productivity

Grid modernization, supported by the DMS and other external operation support systems, is transforming existing manual, paper-driven business processes to electronic, computer-assisted decision making with a high degree of automation. Productivity improvement measures offered by the DMS include (but are not limited to):

- **Electronic Record Keeping.** The ability to maintain as-designed, as-built, and as-operated models of the electric distribution system using DMS application software has greatly streamlined the current processes that use red-line (additions) and yellow-line (deletions) markup of paper maps. The benefit of improved productivity from a more streamlined process is potentially significant. Additional benefits are gained by reducing the latency associated with the manual update process. Table 3-2 shows expected benefits of electronic records management using DMS.

TABLE 3-2 Expected Benefits of Electronic Records Management

Current State	Future State	Expected Benefits
• As built model • Topology model (OMS) • Hand-drawn map updates • Record keeping latency	• As operated model • Full electrical model • Electronic map updates • Records match operated condition	• Labor-intensive processes eliminated • Single model available, serving all needs • Latest maps available to all users at time of need • Model-driven applications are enabled

- **Managing the Data Tsunami.** The DMS provides an effective mechanism for managing a wealth of new data coming from advanced metering infrastructure (AMI), a growing number of distributed sensors, and other more conventional information sources. Table 3-3 summarizes the benefits associated with big data management.

TABLE 3-3 Benefits of Big Data Management

Current State	Future State	Expected Benefits
• Substation alarms • Fixed high/low alarm limits • Operators alerted to problems as they occur • Many "nuisance" alarms	• Substation, feeder, customer alarms • Variable (conditional) alarm limits • Messages routing • Filtering • Problems anticipated while evolving	• Avoid potential for information overload • Operate equipment "closer to the edge" • Proactive response to "incipient" problems

- **Switch Order Management.** The DMS includes facilities that will greatly streamline the process of developing and validating the complex switching orders needed to plan work and restore service to customers whose electric service has been interrupted by a feeder short circuit. This functionality is especially valuable during major storm emergencies, when additional labor may be enlisted to develop switching procedures and overall restoration strategies. In such circumstances, worker productivity benefits due to reduced overtime and fewer outside contractors can be significant. Table 3-4 shows the benefits of DMS-based switch order management.

TABLE 3-4 Benefits of DMS-Based Switch Order Management

Current State	Future State	Expected Benefits
• Paper-driven processes • Manual preparation and checking	• Computer assisted processes • Strict enforcement of business and safety rules • Validation using power flow analysis	• Less manual effort (including overtime) • Improved coordination with nearby work • Lower risk of suspended work due to unanticipated constraints

- **Predictive Fault Location.** PFL will improve fault location accuracy and reduce the portion of the feeder that must be patrolled to determine the root cause of an outage. PFL can be especially valuable during widespread emergencies when outside contractors may be enlisted to perform this duty.

3.1.6 Energy Efficiency

As stated earlier, many electric utilities are seeking ways to improve the overall efficiency of their power delivery systems (transmission and distribution), with the objectives of decreasing carbon footprint, accommodating the need for capacity additions, and reducing overall cost of service. The DMS may include numerous application functions, such as VVO and load balancing, which can help reduce electrical losses and peak demand on the power delivery system. Table 3-5 shows the expected benefits of VVO enhancement using a DMS solution.

TABLE 3-5 Expected Benefits of Enhanced VVO Using DMS

Current State	Future State	Expected Benefits
• Autonomous controllers • Maintaining “acceptable” conditions • Capacitor switching to reduce losses	• Integrated Volt-VAR control system • Multi-objective strategy • Coordinated operation with self-healing • Better VVO through smart inverters • Dynamic Volt-VAR control	• Significant demand reduction and savings through energy conservation • Automatic detection of Volt-VAR device failures • Ability to override Volt-VAR control strategy during emergencies • Ability to stay in service following reconfiguration • Reduced implementation cost per substation

- **Power Factor Correction.** DMS Volt-VAR control and optimization are able to improve the power factor to near unity on targeted feeders through well-coordinated switching of distribution capacitor banks. Operating at a power factor close to unity will reduce the current flow on the transmission and distribution system, thereby lowering the total I^2R losses. The DMS provides several incremental benefits beyond conventional power factor correction techniques:
  - **Monitoring of Volt-VAR Control Devices.** The DMS uses its DSCADA capabilities to continuously monitor the operating status of voltage regulators and switched capacitor banks. Malfunctions of these devices (e.g., blown fuses) are quickly detected so a field crew can be dispatched to carry out repairs. In the past, device malfunctions were often detected during routine but infrequent inspections, so some malfunctions remained undetected for a considerable period of time. During that period, the operating benefits normally provided by the device were lost.
- **Operation Following Feeder Reconfiguration.** Earlier-generation power factor correction facilities were designed to work best when the feeder was in its normal configuration. When the feeder is reconfigured for any reason, the device settings may no longer provide the expected benefits. In some cases, electric distribution utilities have elected to disable their volt-VAR control system following feeder reconfiguration. The DMS eliminates this problem by basing its control decisions on the as-operated model of the distribution system. The DMS automatically updates the distribution system model when the feeder is reconfigured or other significant changes occur.
- **Voltage Reduction.** Many electric utilities are considering voltage reduction as a means to improve overall energy efficiency. The results of numerous demonstration projects and full-scale deployments, supported by the efforts of various industry research organizations, have shown that voltage reduction is an effective mechanism for reducing electricity demand and energy consumption without impacting the customer. To date, such efforts have reported efficiency improvements of between 1% and 3% of total energy consumption. The DMS model-driven voltage reduction application has numerous benefits compared with non-DMS approaches:
  - Better coordination of a wide variety of volt-VAR control devices.
  - Automatic adjustment of voltage reduction settings following feeder reconfiguration.
  - Ability to use distributed energy resources as part of the VVO strategy.
- **Optimal Network Reconfiguration.** Optimal Network Reconfiguration (ONR) is another DMS-based efficiency improvement function. The ONR function can identify ways that an electric utility can reconfigure a set of interconnected distribution feeders to meet a utility-specified objective function without violating any loading or voltage constraints on the feeder. As a minimum, the ONR objective functions may include:
  - Minimize total electrical losses on the selected group of feeders over a specified time period.
  - Minimize the largest peak demand among the selected group of feeders over a specified time period.

– Balance the load between the selected group of feeders (i.e., transfer load from heavily loaded feeders to lightly loaded feeders).

– Perform a combination of the objective functions listed above with a weighting factor for each.

3.1.7 Asset Utilization

Faced with limited and, in some cases, declining capital budgets, many utilities are seeking ways to avoid or at least postpone adding new facilities to their power delivery system. Achieving better utilization of existing power apparatus is one way to accomplish this business objective. DMS application functions, such as dynamic equipment rating and load balancing, enable electric utilities to utilize the available capacity of its power apparatus more effectively, allowing the utility to squeeze more capacity out of existing assets.

The DMS dynamic equipment rating function will calculate thermal ratings (real-time ampacities) of substation transformers and distribution feeders (underground cables and overhead lines) on a real-time basis. The objective of this function is to calculate variable ratings based on actual loading and ambient conditions, rather than worst-case weather and load assumptions. Weather data shall be used to support the dynamic equipment rating function. Table 3-6 summarizes other benefits of DMS-based asset management.

TABLE 3-6 Benefits of DMS-based Asset Management

Current State	Future State	Expected Benefits
• Calendar-based maintenance strategy • Fixed equipment ratings	• Condition-based maintenance • Fault anticipation • Dynamic equipment ratings	• Reduce maintenance costs and failure rates • Detect and correct problems that are still small • Squeeze more capacity out of existing assets

3.1.8 Distributed Energy Resources Accommodate

One of the most significant changes associated with the modern distribution system is high penetrations of DERs. In many jurisdictions, electric utilities face mandates to provide significant portions of their load through renewable generating resources, such as wind power and solar photovoltaic power generators. The electric utility must be able to accommodate these renewable distributed generating resources without adversely impacting the quality of service on the electric distribution system. Accommodating such resources is especially challenging due to the highly variable nature of wind- and solar-powered generating units, which can produce unacceptable voltage and power swings on the feeders.

The DMS can include application functions that enable the utility to model the impacts of DERs and develop and execute operating strategies, such as advanced reactive power control. These functions can help mitigate the adverse consequences of DERs, thereby accommodating additional DERs on the distribution feeders.

Table 3-7 shows the current state of DER management, the possible future state of DER management using DMS, and the expected benefits of this application.

TABLE 3-7 Expected Benefits of DER Management

Current State	Future State	Expected Benefits
• Monitoring and transfer tripping of large (utility scale) customer-owned generation • Anti-islanding protection for all customer-owned distributed generation units • Load management facilities for direct control of selected customer loads	• Active management of DERs (distributed generation, energy storage, controlled loads) for improved distribution system performance • Demand response for mitigating grid level and localized emergencies • Market operations for "virtual" power plants • Microgrid management	• Accommodates maximum amount of renewable generation • Enables microgrid islanding operation for serving critical loads during widespread system emergencies • Provides effective mechanism for demand reduction during peak loads and system emergencies • Enables new services for customer owned generation, i.e., participation in Independent System Operator (ISO) markets

DMS VALUE CALCULATOR

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4 DMS VALUE CALCULATOR

4.1 INTRODUCTION

Previous chapters of this report discuss the benefits that can be achieved by implementing key DMS applications. This chapter introduces a calculator that numerically computes the benefits of their implementation. A detailed description of this calculator is given in Annexes C and D.

The DMS Value Calculator (DVCalc) is a model that computes the costs and benefits of the most common advanced DMS applications—Volt-VAR Optimization (including VAR Dispatch and Conservation Voltage Reduction), Fault Location Isolation and Service Restoration (FLISR), Outage Management System (OMS), Switch Order Management (SOM), Distribution Training Simulator (DTS), Adaptive Protection, Dynamic Asset Rating, Equipment Condition-Based Maintenance, and Electronic Mapping.

DVCalc allows the user to evaluate the expected benefits and costs of the DMS over the life of the system using user-specific input data and other general industry information about the DMS that is applicable to the utility. The user can specify the DMS applications and external system interfaces that are required, select system architecture and integration technologies, and enter key operational and financial parameters.

DVCalc computes the expected benefits as well as the total cost of ownership of the selected DMS functions. The calculator includes an analysis of revenue requirements over the life of the system to determine key investment parameters. These parameters indicate the economic merits of the investment to determine if the selected DMS functions and technologies are justified. The DVCalc framework allows the addition of future DMS applications to the model.

DVCalc enables the user to compare the costs and benefits of various configuration and technology options. The following alternatives can be selected:

- Combined (shared model) OMS/DMS versus separate OMS and DMS
- Centralized versus decentralized distribution automation (DA) applications
- Model-driven versus "rules based" DA solutions
- FLISR operation using new DA switches versus using retrofits of existing line reclosers
- Industry standard enterprise service bus (ESB) integration technology versus specialized "homegrown" solutions

DVCalc considers the addition of substation automation solutions (substation data concentrators, intelligent electronic devices [IED], etc.), as well as a choice of IED integration standards and protocols (International Electrotechnical Commission [IEC] 61850, Distributed Network Protocol 3.0 [DNP3.0], etc.).

DVCalc performs an analysis of revenue requirements over a specified system life (e.g., ten years). It allows the user to specify the number of years to install the DMS and automatically spreads the planning, procurement, and implementation costs over this initial period. The resulting DMS benefits start to accrue after completion of the implementation period. Year 1 benefits computed by DVCalc are automatically escalated based on inflation, load growth, and other such factors, and then discounted using the prevailing interest rates.

DVCalc allows the user to select one or more methods of monetizing reliability improvement benefits. Methods include Value of Lost Load (VOLL) and Performance Based Rate (PBR) characteristics. It also allows the user to enter cost to customer of outages as generated by the U.S. Department of Energy (DOE) Interruption Cost Estimate (ICE) Calculator, available on-line.[i]

4.2 RESULTS FROM EXAMPLES

Section D.6 of Annex D illustrates six examples using DVCalc with representative industry data. The following results were obtained from running these examples:

- Examples 1 and 2 evaluate the costs and benefits of adding Volt VAR Optimization (VVO) to the DMS. Example 1 demonstrates that including the VAR Dispatch function of VVO provides a positive return on investment over the life of the system, with a benefit-to-cost ratio (BCR) of 1.38 and a payback interval of eight years.
- Example 2 evaluates adding the Conservation Voltage Reduction (CVR) function of VVO to the VAR dispatch function in Example 1. Adding this function improves the economic justification for the DMS considerably. The BCR improved to 2.19 and the payback interval was reduced from eight to six years.
- Example 3 demonstrates the addition of the FLISR application to the DMS. In this example, three new normally-closed DA switches were added to the 150 worst-performing feeders in an electric distribution system with 800 feeders. Adding FLISR on 150 of the 800 feeders produced a 20% improvement in overall system SAIDI and a 14% improvement in overall system SAIFI. These improvements were monetized using VOLL and PBR rewards. However, due to the very high cost to add three new DA switches per feeder, the BCR declined from 2.19 to 1.34 and the payback interval increased from six to nine years.
- Example 4 analyzes the option of retrofitting existing line reclosers with remote control capability to support FLISR rather than using completely new switches. This illustrates the ability of DVCalc to consider leveraging existing assets to the fullest extent. Because the cost of the retrofit option is much less than the cost of adding a completely new switch, the resulting economic justification is improved considerably.
- Examples 5 and 6 compare a shared model with OMS and DMS combined with models implementing OMS and DMS separately. The results show that the combined approach has a major economic advantage over the separate system approach.

CONCLUSIONS AND FUTURE WORK

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5 CONCLUSIONS AND FUTURE WORK

Recent industry surveys conducted by the DMS Task Force of the IEEE Smart Distribution Working Group (SDWG) show that one of the most significant challenges that electric utilities face when considering an investment in a DMS is lack of a business case. Electric utilities acknowledge that a DMS can play a key role in streamlining existing business processes and that advanced distribution applications running on a DMS can improve efficiency, reliability, asset utilization, and overall electric system performance. However, the industry lacks a widely accepted, effective means of demonstrating that the benefits gained by implementing a DMS outweigh the total cost of ownership.

Unlike protective relay systems and EMS systems that play a mission critical role in power grid operations, the DMS applications must be justified economically on a case-by-case basis because the DMS is not considered an essential (mission critical) facility.

5.1 CONCLUSIONS

The DVCalc model described in this report provides an effective mechanism for evaluating the costs and benefits of advanced DMS applications, which, can then be used by electric distribution utilities to determine if DMS implementation is economically justified.

The following conclusions were derived from the DVCalc examples:

5.1.1 Volt VAR Optimization with VAR Dispatch and Conservation Voltage Reduction

The Volt VAR Optimization application, including VAR Dispatch and Conservation Voltage Reduction (CVR), provides a positive return on investment and should be considered for any DMS implementation.

5.1.2 FLISR

The addition of FLISR to the suite of DMS application may adversely affect the economic justification of the project due to the very high cost of field equipment. However, if the feeders are already equipped with non-communicating line reclosers, it may be possible to retrofit the line reclosers with communication capabilities that would enable FLISR for substantially lower cost than installing totally new switches. The result is a significant improvement in the BCR and payback interval for almost the same reliability improvement benefits.

5.1.3 Combined OMS/DMS (Shared Model)

The combined OMS/DMS (shared model) approach is far more economical than the separate system approach.

5.2 FUTURE WORK

5.2.1 Conduct Specific Studies with Distribution Utilities using DVCalc

Conduct one or more studies in conjunction with electric distribution utilities to determine the actual cost justification for a DMS implementation by a utility using the DVCalc model. The main objectives of these specific utility studies would be to:

- Verify that the input data required to run DVCalc is readily available to each utility company.
- Confirm that the algorithms contained within DVCalc are correct and produce results that are consistent with detailed engineering studies.
- Determine if DMS implementation is economically justified for the specific utilities.

5.2.2 Enhance DVCalc with Algorithms for Distributed Energy Resource (DER) Management

The current version of DVCalc does not address the costs and benefits of managing distributed energy resources, such as distributed generation (including intermittent renewables), energy storage, and controllable loads (demand response). The high DER penetrations expected in the near future will create a need for advanced DMS to maintain distribution system efficiency, reliability, and overall performance, as well as support activities related to wholesale and retail markets in the future.

ANNEX A. FAULT LOCATION ISOLATION AND SERVICE RESTORATION

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CONTENTS

FIGURES

TABLES

ACRONYMS AND ABBREVIATIONS

AMI	Advanced Metering Infrastructure
DA	Distribution Automation
DG	Distributed Generation
DMS	Distribution Management System
DOE	Department of Energy
ICE	DOE Interruption Cost Estimate Calculator
FCI	Faulted Circuit Indicator
FLISR	Fault Location Isolation and Service Restoration
IED	Intelligent Electronic Devices
IEEE	Institute of Electrical and Electronics Engineers
kWh	kilowatt-hour(s)
LF	Load Factor
MW	megawatt(s)
OMS	Outage Management System
PBR	Performance-based Rates
PES	(IEEE) Power and Energy Society
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TCO	Total Cost of Ownership
VAR	Volt Amps Reactive (Reactive Power)
VVO	Volt VAR Optimization

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ANNEX A. FAULT LOCATION ISOLATION AND SERVICE RESTORATION

Fault Location, Isolation, and Service Restoration (FLISR) is one of the most common Distribution Management System applications implemented by electric distribution utilities because it provides significant reliability improvements that directly benefit customers. According to a recent survey of electric utilities conducted by the DMS task force of IEEE Power and Energy Society (PES) Smart Distribution Working Group, 85% of the respondents either have implemented or are planning to implement the FLISR application as part of their distribution grid modernization strategy.

FLISR may be implemented in a variety of architectures, including centralized (DMS, model-driven) and decentralized (substation-centered or fully distributed peer-to-peer) designs.

As proof of concept, many utilities elect to demonstrate FLISR functionality on selected, worst performing feeders. This decentralized approach on a small number of targeted feeders is simpler to deploy than a full-blown DMS solution.

As electric utilities transition from proof-of-concept demonstrations to full-scale system wide deployments, many elect centralized model-driven DMS-based FLISR applications. These applications offer advanced features not available on decentralized solutions such as the ability to handle high distributed generation (DG) penetration and to coordinate with other DMS applications like Volt-VAR optimization.

Despite the popularity and desirability of the FLISR application, building the business case for FLISR deployment is usually quite challenging owing to the high cost of automated line switches and communication facilities, and the difficulty of assigning monetary benefits to reliability improvements.

This annex focuses on the benefits and costs of deploying FLISR in both centralized and decentralized configurations. It includes a brief overview of FLISR operations, potential benefits, implementation costs, and algorithms for computing the benefits.

A.1 OVERVIEW OF FLISR OPERATION

When a permanent fault (a fault that does not burn off or clear by itself following the initial event) occurs on a distribution circuit, or the normal substation supply to the circuit is interrupted for any reason, many customers will experience a power outage. The outage will include customers served by transformers connected to both the faulted and the “healthy” (unfaulted) sections of the feeder.

A.1.1 Manual Service Restoration

With traditional distribution protection and control systems, customers on the faulted feeder may be out of service for an extended period (an hour or more) until field crews arrive on the scene to investigate, locate the fault, make the necessary repairs, and perform the manual switching needed to restore power. The timeline in Figure A-1 shows how long each of these operations may take during manual service restoration. The average customer is without power for more than an hour during such an event. Note that these outage times may be considerably longer if feeders are spread over a wide geographic area or are located in heavy traffic or rugged terrain that is difficult to patrol.

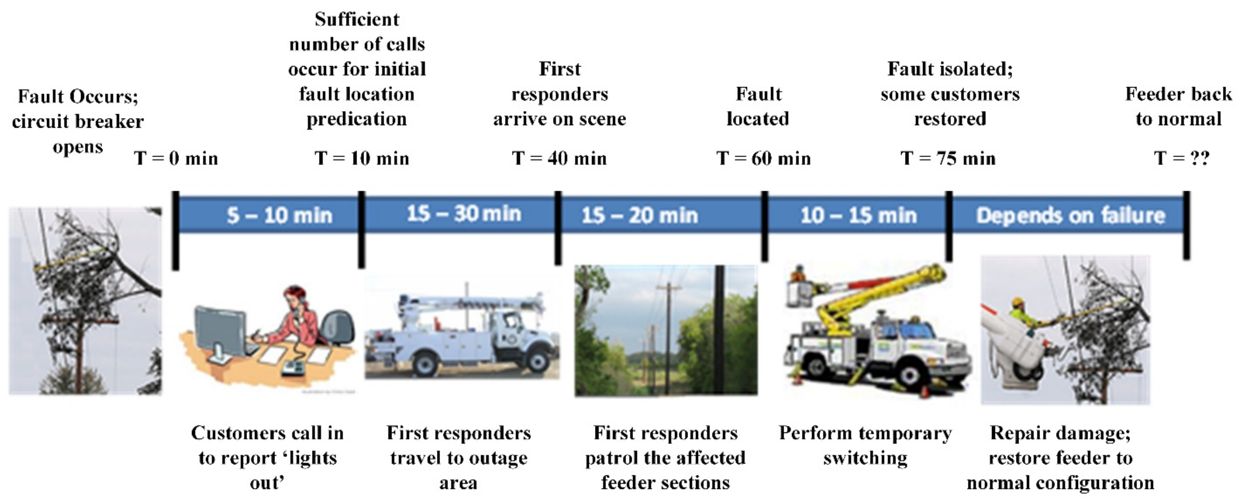


FIGURE A-1 Timeline for Manual Service Restoration

A.1.2 Service Restoration with FLISR

The objective of the FLISR function is to restore service automatically, to as many customers as possible, in less than one minute with no manual intervention, no voltage violations, and no equipment overload. The FLISR sequence of operations is described in subsections A.1.2.1-A.1.2.4.

Figure A-2 shows a typical feeder in its normal configuration feeding radially out of Substation 1. The feeder includes normally open ties to adjacent feeders, connected to Substations 2 and 3, that can be used when needed for backup purposes.

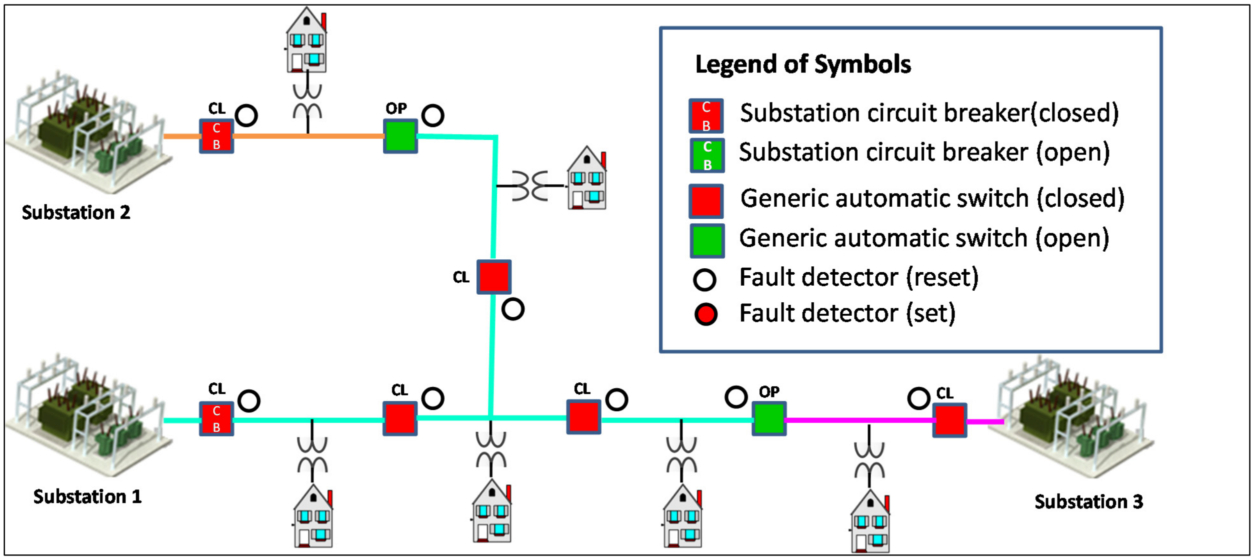


FIGURE A-2 Distribution Feeder in its Normal Configuration

A.1.2.1 Fault Detection

When a permanent fault occurs on the feeder, as shown in Figure A-3, the circuit breaker at Substation 1 will trip and interrupt service to all customers on the feeder. Figure A-2 illustrates how the flow of fault current causes the faulted circuit indicators (FCI) on two of the switches to "pick up" (become "set"). The status of all FCIs is then communicated automatically back to the processor containing the FLISR software.

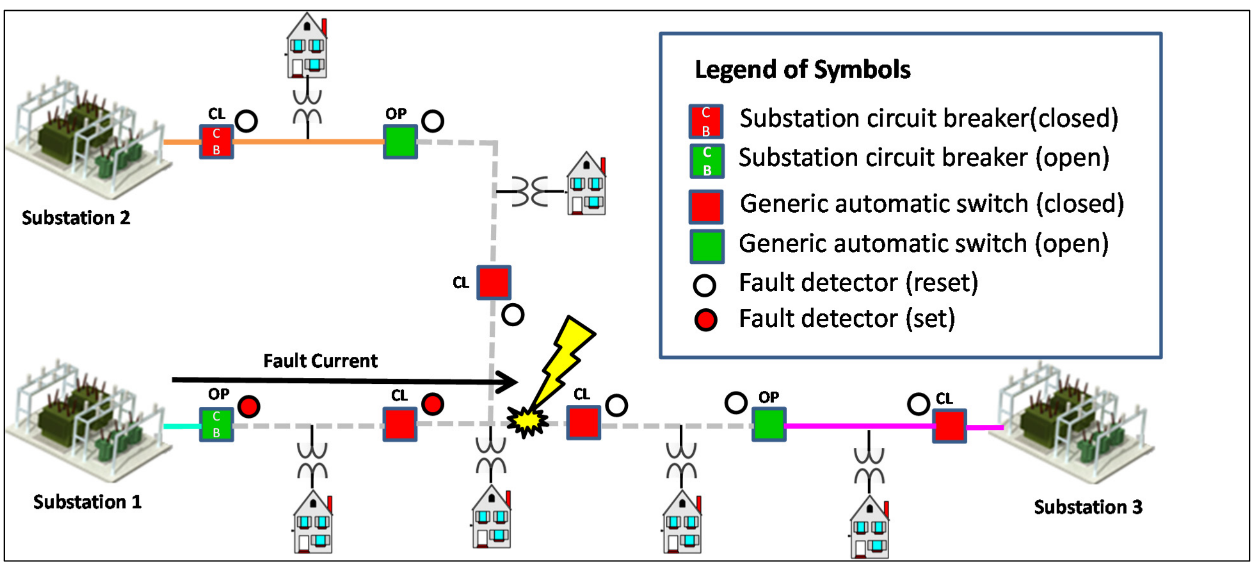


FIGURE A-3 Permanent Fault Occurs on the Feeder

A.1.2.2 Fault Location

The FLISR software uses a model of the distribution feeder and the status of the FCIs to locate the faulted section of the feeder (a portion of the feeder that is bounded by switches). In this case, the faulted feeder section is bounded by one FCI that is set and two FCIs that are not set, as shown in the highlighted section in Figure A-4.

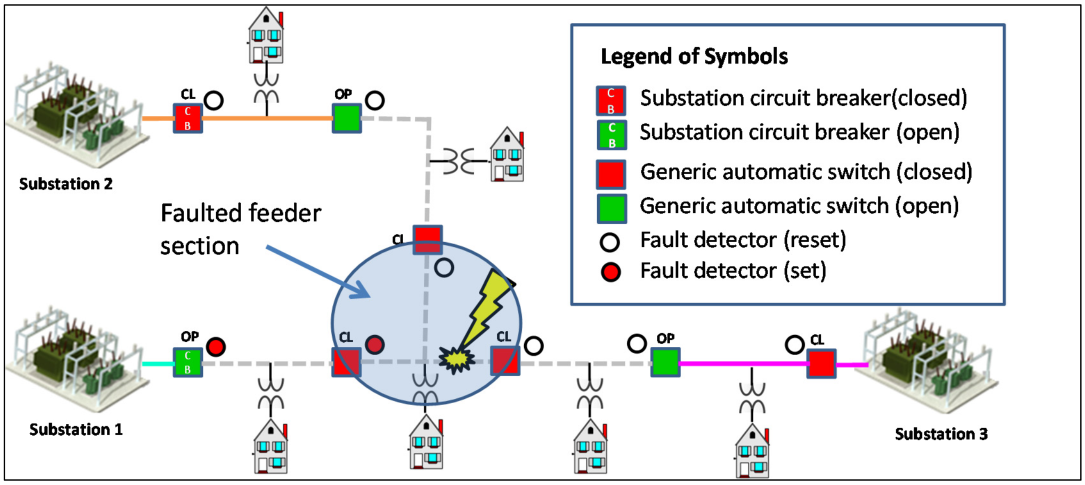


FIGURE A-4 Faulted Feeder Section Identified by FLISR

A.1.2.3 Fault Isolation

Once located, the FLISR system uses remote control to isolate the faulted feeder section by opening all switches that bound the section. The resulting configuration is shown in Figure A-5.

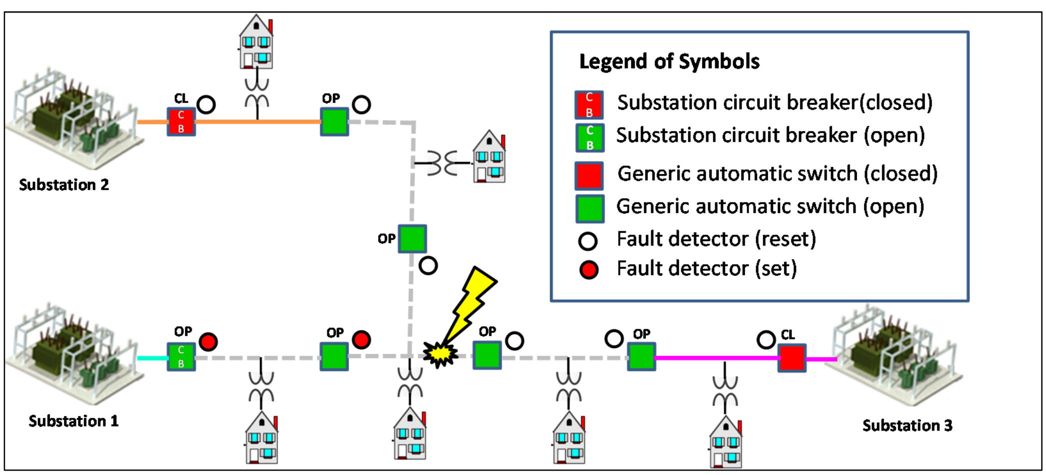


FIGURE A-5 Faulted Feeder Section Isolated by FLISR using Remote Controlled Switches

A.1.2.4 Restoring Service to Unfaulted Feeder Sections

After remote controlled switching has successfully isolated the faulted feeder section, FLISR will automatically close the Substation 1 circuit breaker to restore service to customers located upstream of the faulted section (closer to the substation). FLISR will close the normally open tie switches to restore service to customers located downstream of the faulted feeder section (farther from the substation), after first confirming that such switching actions do not produce equipment overloads and under-voltage conditions. Figure A-6 shows the final feeder configuration after all FLISR switching actions have been completed.

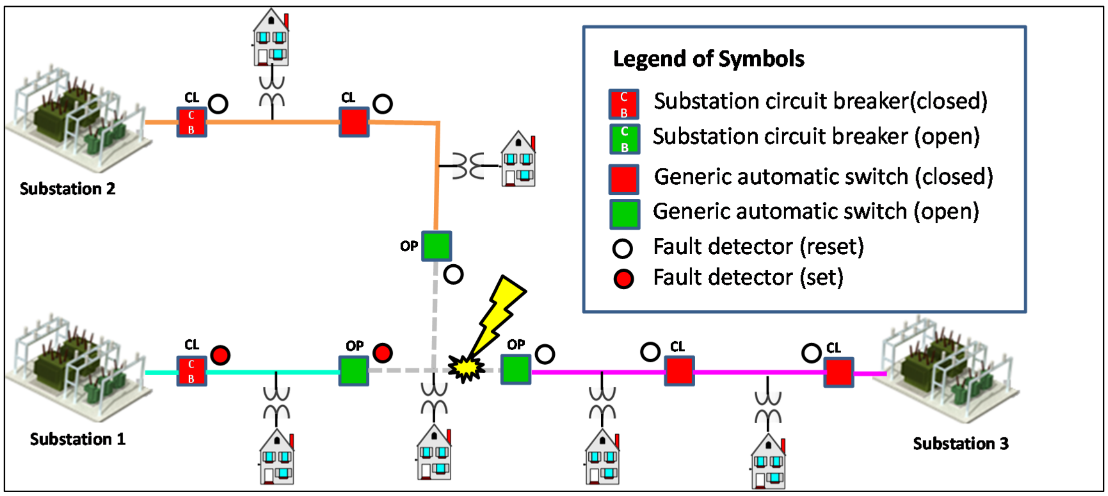


FIGURE A-6 Feeder Configuration after FLISR Actions are Completed

The FLISR actions described in sections A.1.2.2–A.1.2.4 restored service to most of the customers connected to the feeder, without manual intervention, in less than one minute. Therefore, the “momentary” interruptions experienced by customers connected to healthy (unfaulted) feeder sections do not count against the electric distribution utility’s SAIDI and SAIFI outage statistics.

A.2 FLISR FUNCTIONAL BENEFITS

This section covers the various functional (non-monetary) benefits that can be achieved using FLISR. These benefits include:

- Reduction in total outage duration (in minutes) that the typical customer experiences during a year.

- Reduction in the number of power outages experienced by the typical customer in a year.

- Reduction in amount of time spent doing fault investigation (i.e., patrol time), with related savings from decreased labor and vehicle roll-time.

- Slight increase in kilowatt-hour sales because of shorter power outage durations.

Annex A.3 of this document discusses approaches for converting functional benefits to monetary benefits (i.e., benefit “monetization”).

A.2.1 Reliability Improvement Benefits

The FLISR application will reduce the number of outage minutes for each customer as well as the number of extended power outages that exceed the established threshold (one minute or five minutes at most utilities). The following examples illustrate how customer outage minutes and customer outage events can be reduced with the FLISR automatic service restoration function.

The incremental benefits provided by FLISR are determined by comparing the total number of customer outage events and customer outage minutes experienced without FLISR to the number of outage events and minutes experienced with FLISR. The benefit calculations are included in the examples.

A.2.1.1 Base Case

This analysis compares a simple radial feeder with no midline switches to a second feeder with midline switches and FLISR. The following assumptions apply for this analysis:

1. The feeder serves a total of 200 customers with service connections evenly distributed. One hundred customers are serviced by connections in the first half of the circuit and the remaining customers are connected to the back half.

2. A total of two permanent faults occur on the feeder during the analysis. Since faults are equally likely to occur anywhere on the feeder, it is assumed that one fault occurs in the first half (Fault #1) and one fault occurs in the back half (Fault #2). The fault locations are illustrated in the figures for each case.

3. Each fault causes an outage that lasts 100 minutes.

Simple Radial Feeder with no mid-line switches. The base case, a simple radial feeder with no mid-line switches, is depicted in Figure A-7. This feeder has no automated switching capabilities so all 200 customers will experience an outage lasting 100 minutes for each fault. Therefore, the customer outage minute metric for the base case is 40,000 (2 events x 200 customers x 100 minutes). Similarly, the customer outage event metric is 400 (2 events x 200 customers). The customer outage minute and outage event metrics are used to calculate SAIDI and SAIFI.

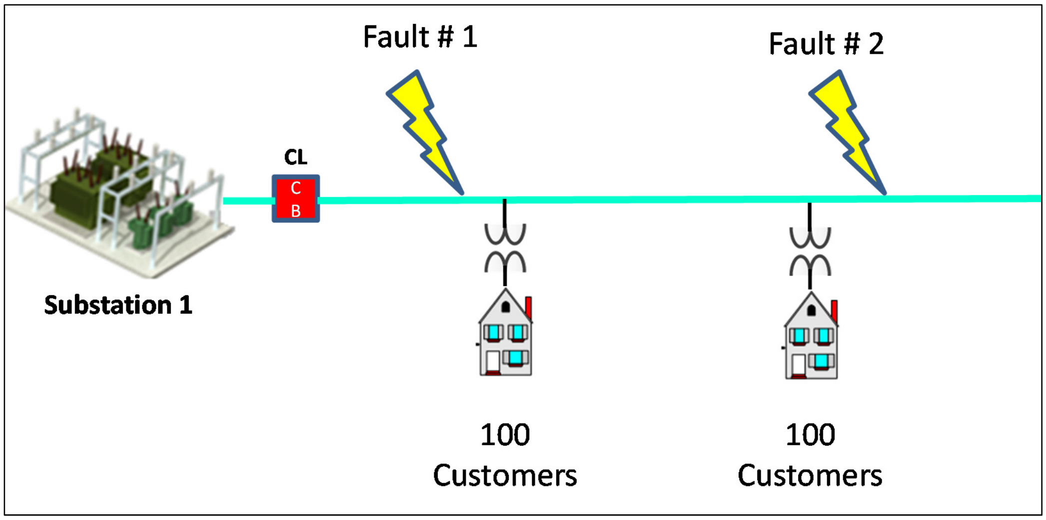


FIGURE A-7 Simple Radial Feeder with no Mid-Line Switches

Simple Radial feeder with Midline Switches plus FLISR. A remote-controlled midline switch plus a normally open tie switch connected to a backup source (Substation 2) is added to the simple feeder. Now, it is possible to apply FLISR capabilities. This configuration is shown in Figure A-8.

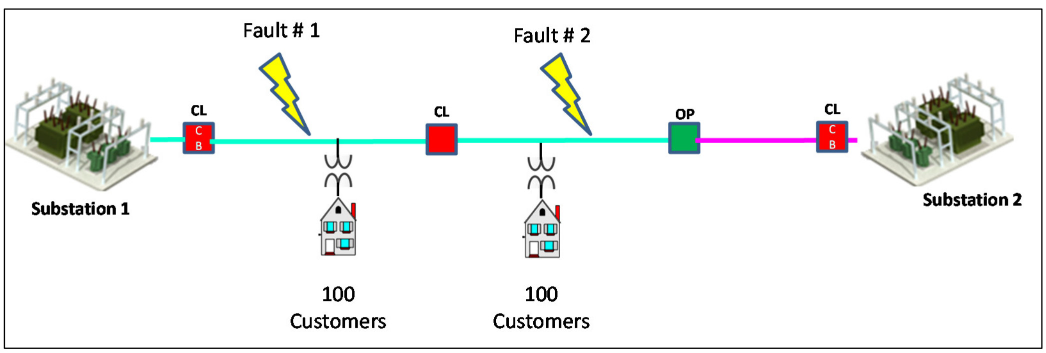


FIGURE A-8 Simple Radial Feeder with FLISR Capabilities

When Fault #1 occurs, FLISR will isolate the first half of the feeder and quickly transfer the back half to Substation 2. Now, only 100 customers will experience a 100-minute outage resulting in 10,000 customer outage minutes (100 customers x 100 minutes). When Fault #2 occurs, FLISR will isolate the back half of the feeder so only 100 customers will experience a 100-minute outage, resulting in 10,000 customer outage minutes (100 customers x 100 minutes). For the two faults, the customer outage minutes total 20,000 and the customer outage event totals 200 (2 events x 100 customers).

Table A-1 compares the base case and the addition of one midline switch and FLISR. Adding FLISR and one normally closed midline switch results in a 50% savings in both customer outage minutes and customer outage events (related to SAIDI and SAIFI, respectively).

TABLE A-1 Comparison of Base Case and Radial Feeder with FLISR and One Midline Switch

Example	Reliability Metrics	
	Customer Outage Minutes	Customer Outage Events
Base Case - Simple radial feeder with no midline switches	40,000	400
Simple radial feeder with FLISR and one midline switch	20,000	200
% Improvement	50%	50%

A similar assessment using two equally-spaced midline switches will show a 67% improvement in the two reliability metrics. Repeating the assessment with three midline switches will show a 75% improvement in the reliability metrics .

The percent improvement that can be achieved by implementing *N* midline switches on a feeder that had no automatic switching devices previously can be determined using the following formula:

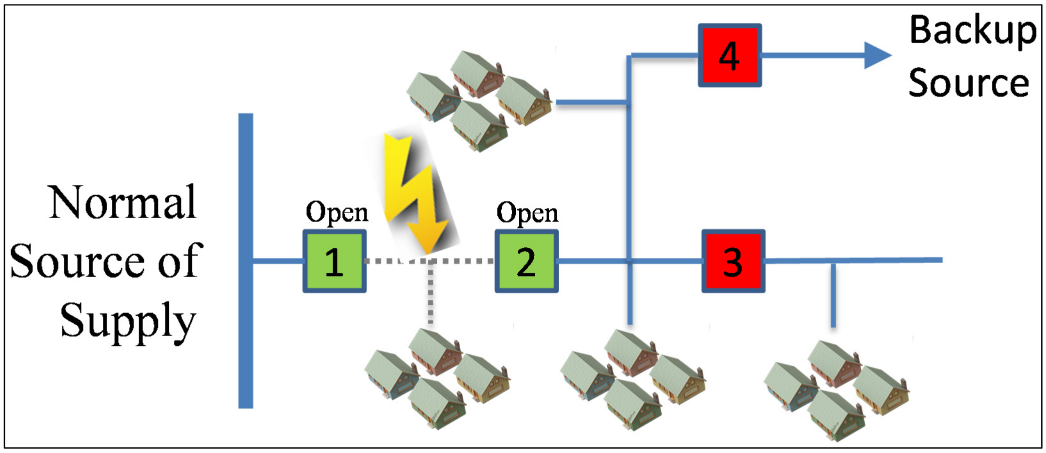
$$Percent\ Improvement\ = N/(N\ + 1)$$

where *N* = the number of normally closed automated midline switches that are installed in the feeder.

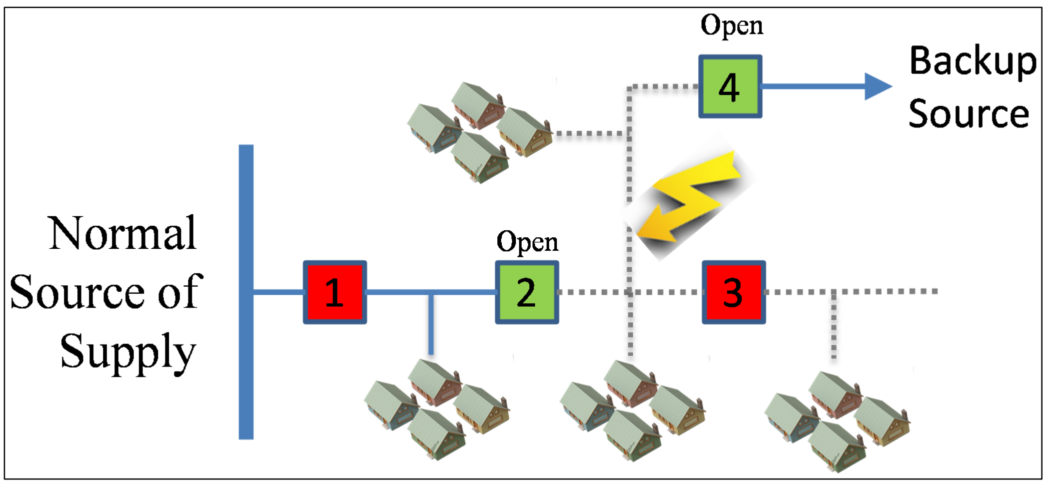
A.2.1.2 Convert Existing Standard Line Reclosers to "Smart" Switches

Many utilities have already implemented one or more line reclosers on their longer distribution circuits to prevent the entire feeder from tripping off line for a fault near the end of the feeder. In most cases, these line reclosers are fully autonomous devices that do not include any remote control capabilities. Also, if normally open tie switches are available, they may be manually operated, and rapid load transfers using remote control are not available. This section describes calculations of incremental benefits gained by adding remote control capabilities to non-communicating reclosers and tie switches.

Non-communicating Line Recloser. The base case, illustrated in Figure A-9, includes a single standard, non-communicating line recloser at the feeder midpoint with a manually-operable tie switch. The assumptions listed in case A.2.1.1 will be applied here with two faults occurring on the feeder during the year.



(a) Fault in Section 1–2: Downstream restoration possible



(b) Fault in Section 2–3: Downstream restoration not possible

FIGURE A-9 Fault Clearing with Non-Communicating Line Reclosers

If the first fault occurs upstream of the existing line recloser (closer to the substation), the substation circuit breaker will operate and all 200 customers will be without power for 100 minutes. See Figure A-9 (a). The customer outage duration metric for this upstream fault is 20,000 (1 event x 200 customers x 100 minutes) and the customer outage event metric is 200 (1 event x 200 customers). If the second fault occurs downstream of the recloser (farther away from the substation), the mid-line recloser will automatically isolate the downstream portion of the feeder and the upstream customers will not experience an outage. The customer outage duration metric for this downstream fault is 10,000 (1 event x 100 customers x 100 minutes) and the customer outage event metric is 100 (1 event x 100 customers). The total customer outage duration metric for the two events is 30,000 (20,000 + 10,000) and the total customer outage event metric is 300 (200 + 100).

Remote Control Line Recloser with FLISR. When remote control capabilities and FLISR functions are added to the recloser and tie switches, the reliability metrics change. If the first fault occurs upstream of the communicating line recloser, the substation circuit breaker will operate and all 200 customers will ***momentarily*** be without power. However, the downstream customers will be quickly transferred by FLISR using the remote-controlled tie switch to the backup source, so the downstream customers will not experience an outage that counts against the reliability statistics. The customer outage duration for this fault is 10,000 (1 event x 100 customers x 100 minutes) and the customer outage event is 100 (1 event x 100 customers). If the second fault occurs downstream of the recloser, the recloser will automatically isolate the downstream portion of the feeder and the upstream customers will not experience an outage. For this downstream fault, the customer outage duration metric is 10,000 (1 event x 100 customers x 100 minutes) and the customer outage event metric is 100 (1 event x 100 customers). The total customer outage duration metric for the two events is 20,000 (10,000 + 10,000) and the total customer outage event metric is 200 (100 + 100).

Table A-2 compares the base case (single non-communicating standard line recloser) and the FLISR scenario (one remote controlled midline switch). Adding remote control capabilities to a single existing non-communicating midline recloser and tie switch can reduce the customer outage minutes and customer outage events by 33%. Note that this reliability improvement benefit is less than the case described previously in which there were no switches to start with.

TABLE A-2 Comparison of Non-Communicating Recloser Scenario with Full Blown FLISR

Example	Reliability Metrics	
	Customer Outage Minutes	Customer Outage Events
Non-communicating recloser	30,000	300
With communications to existing recloser and tie switch	20,000	200
% Improvement	33%	33%

A similar assessment using two equally-spaced midline reclosers shows a 50% improvement in the two reliability metrics. Three midline reclosers provide a 60% improvement in the reliability metrics.

The percent improvement that can be achieved by implementing *N* remote controlled midline reclosers on a feeder that had N non-communicating reclosers can be determined using the following formula:

$$Percent\ Improvement\ = N/(N\ + 2)$$

where *N* = the number of normally closed remote-controlled reclosers that are installed on the feeder.

Note that the formula for calculating the reliability percent improvement by adding communication facilities to existing line reclosers is slightly different than the previous formula, used when no automatic switches are present at all. The percent improvement in reliability by adding FLISR to feeders that have no switches is somewhat higher than the percentage improvement that can be achieved when converting existing line reclosers to "smart" switches.

A.2.1.3 FLISR Benefits on Heavily Loaded Feeders

The calculations described in A.2.1.1 and A.2.1.2 assume that the available backup sources always have sufficient spare capacity to accommodate all possible load transfers from adjacent feeders that experience a line fault. This is equivalent to assuming that maximum loading never exceeds 50% of the rated capacity of the feeder.

In past years, electric utilities rarely loaded their distribution feeders more than 50% of rating except during emergencies involving feeder contingencies. However, in an effort to achieve better overall asset utilization, today's electric distribution utilities are loading distribution feeders considerably higher than 50% of the feeder rating. As a result, some attempts to transfer load from one feeder to an adjacent feeder following a fault may be blocked by FLISR because the adjacent backup feeder does not have sufficient capacity to accept a significant portion of the load from the feeder that contains the fault.

The DVCalc model includes a mechanism to estimate the reduction in predicted FLISR benefits due to blocked transfers for some faults due to high feeder loading. This mechanism, a FLISR "derating" factor, is applied to the normal estimated savings (i.e., without blocking) to determine the final estimated benefit. A derating factor of zero percent indicates that there is "zero" reduction in FLISR benefits because all required load transfers are permitted (no blocking). A derating of one indicates that the 100% of the load transfers recommended by FLISR are blocked due to heavy feeder loading. A derating factor between zero and one indicates that some transfers will be blocked and some will be permitted. For example, a derating factor of 0.6 indicates that 60% of the FLISR load transfers will be blocked and the FLISR benefit will be only 40% of the maximum possible that could be achieved if all load transfers were permitted.

Calculation of the FLISR derating factor is based on the following assumptions:

- If the peak load on the utility company's feeders is less than 50% of the feeder's rating, the load transfer is never blocked because the adjacent feeder is always able to accept load from an adjacent faulted feeder, even if the entire feeder needs to be transferred. Hence, the FLISR derating factor is zero (no derating required for blocked load transfers).

- If the average load, defined as peak load times the load factor (peak load x LF), on the feeder is greater than the feeder capacity, then the FLISR derating factor is 100% (no load transfers are possible). In other words, if the average load on the feeder exceeds the rating of the feeder, it is not possible to make any load transfers between feeders.

- If the peak load on the feeder is between 50% of rated capacity and (1/LF x capacity), then, on average, a portion of the load can be transferred from a faulted feeder to its backup. The benefit cost model assumes that there is a linear relationship between peak load and derating factor when feeders are loaded in this range.

Figure A-10 shows the relationship between the FLISR derating factor and peak load on the feeder. For this example, the LF is 0.65, and the peak load is 70% of the feeder rating. As seen in Figure A-10, the FLISR derating factor due to heavy feeder loading is 20%, meaning that only 80% of the required load transfers would be completed.

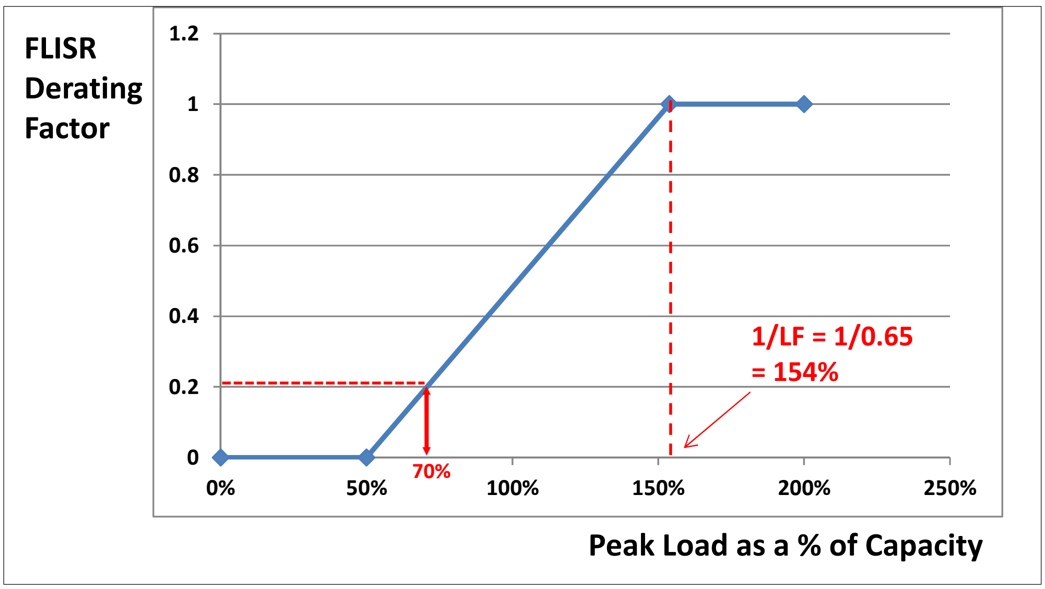


FIGURE A-10 FLISR Derating Factor versus Peak Load

A.2.2 Other FLISR Functional Benefits

Besides the reliability improvement benefits of reduction of customer outage minutes described in Section A.2.1, the FLISR application offers the following additional functional benefits.

A.2.2.1 Workforce Productivity Improvement

FLISR automatically locates the damaged portion of the feeder between two or more switches. As a result, field crews only need to patrol the portion of the circuit that was isolated by FLISR. Similar to the reliability improvement, the reduction in fault investigation time (patrol time) depends on the number of normally closed midline switches. If a single mid-line FLISR switch is installed, then patrol time is reduced by 50% (1/2); with two midline switches, patrol time is reduced by 67% (2/3); and in general with N switches, patrol time is reduced by $N/(N+1)$.

It should be noted that feeders equipped with properly coordinated standard line reclosers combined with customer outage telephone calls or advanced metering infrastructure (AMI), "last gasp" messages processed by an Outage Management System (OMS) would also predict a fault between switches 1, 2, and 3. Therefore, FLISR provides no fault location benefits that would reduce fault investigation and patrol time beyond what standard reclosers would provide.

A.2.2.2 Reduction of "Unserved" Energy

A power outage can be viewed as a lost opportunity for the electric utility to sell kilowatt-hours (kWh). Because FLISR restores service to a portion of the customers much faster than typical manual processes, the amount of unserved demand for electricity is reduced. The following example illustrates the calculation of the unserved energy benefit.

If one megawatt (MW) of load is interrupted for 60 minutes, then the potentially lost kWh sales are 1,000 kWh (60/60 hours × 1 MW). The lost sales can be monetized by multiplying the unserved energy (in kWh) by the electric utility profit for 1 kWh of sales, which is the cost to generate or purchase 1 kWh minus the revenue per kWh sold.

The actual savings may be less than the theoretical amount identified in this simple example. The savings differential is because some electrical appliances, particularly those controlled by thermostats, will consume more energy (for example, by running longer) when power is restored. Common practice is to apply an "unserved energy factor" to account for lost energy sales that will be made up in part by higher sales following service restoration—typically 0.50. Applying an unserved energy factor of 0.50 to the previous example brings the reduction of unserved energy attributed to FLISR to 500 kWh (0.50 × 1,000 kWh).

A.3 MONETIZING THE FLISR BENEFITS

Many of the functional benefits provided by FLISR do not translate easily into monetary terms. Consequently, plausible cost-benefit comparisons can be difficult to perform. For example, the FLISR application significantly reduces customer outage duration and the number of customer outage events. However, there is no well-established procedure for converting improved reliability to direct monetary benefits to determine if these benefits outweigh the high FLISR implementation cost.

The following sections describe mechanisms for monetizing the functional benefits that may be obtained through DMS implementation.

A.3.1 Reliability Improvement Benefits

Achieving a "self-healing" grid is frequently one of the major objectives of an electric distribution utility's grid modernization strategy. As seen in previous sections, the FLISR application function provides an effective mechanism for achieving the desired self-healing characteristic.

1. **Achieving Regulatory Incentives.** Some utilities may be subject to performance-based rates (PBR) that are keyed, in part, to performance against specified reliability metrics like System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Figure A-11 shows a representative PBR that provides a monetary incentive if the utility improves its SAIDI to 60 minutes or less. The PBR characteristic shown in Figure A-11 also includes monetary penalties if the average outage duration worsens, as well as a band of system SAIDI values that does not result in a penalty or reward.

   If a monetary reward/penalty structure exists, such as shown in Figure A-11, then it can be used to assign a monetary value to the reliability improvement measure. For example, using the PBR characteristics in Figure A-11, if a utility uses FLISR to improve system SAIDI from 90 minutes to 50 minutes, then the monetary value would be 200 units (reward of 100 units plus 100-unit penalty avoided).

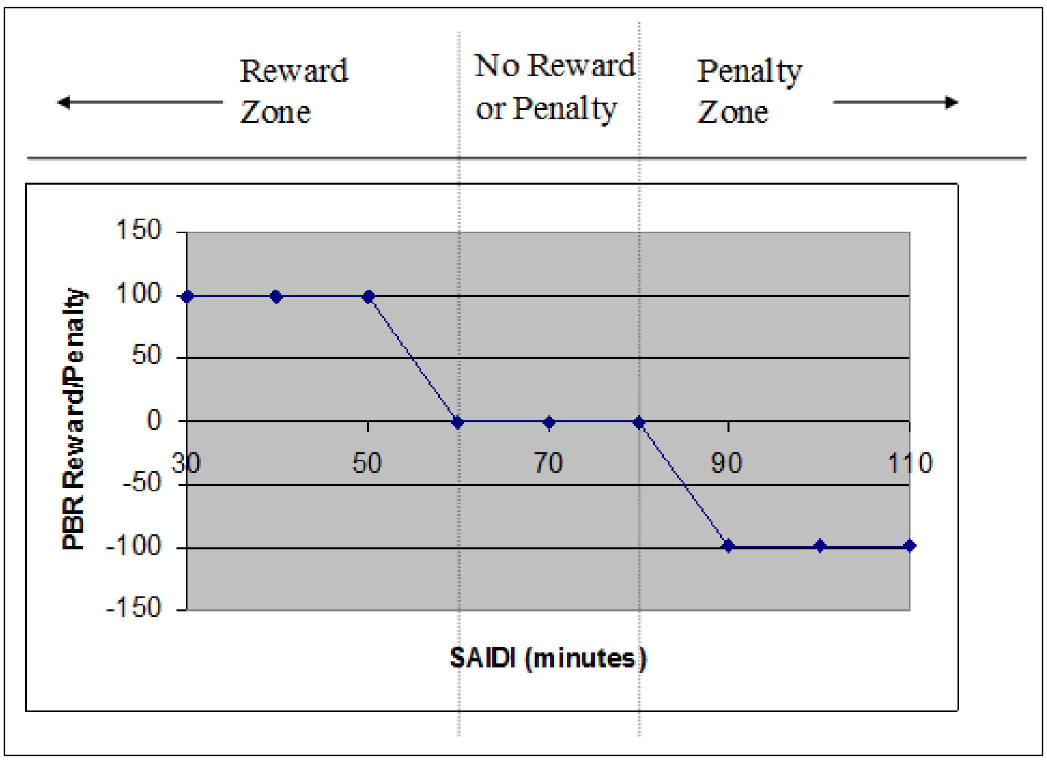


FIGURE A-11 Representative PBR Characteristic tied to Average Interruption Duration

Displace Conventional Reliability Improvement Measures. DMS reliability improvement measures may be used to displace expenditures on conventional reliability improvement measures, such as wildlife protection, selective equipment replacements, or “enhanced” tree trimming. The amount saved by eliminating the expenditure on conventional measures can be used to assign a monetary value to the DMS investment.

This metric is often referred to as the reliability improvement “bang for the buck.” If the FLISR bang for the buck exceeds the comparable metric for a conventional measure, then it may be beneficial for the utility to redirect funding for the conventional measure to FLISR. For example, if the system SAIDI improvement is one minute per $1 million spent on FLISR and only 30 seconds for every $1 million spent on wildlife protection, selective equipment replacement, or “enhanced” tree trimming, then the utility should consider redirecting some funding on conventional reliability improvement measures to a FLISR project.

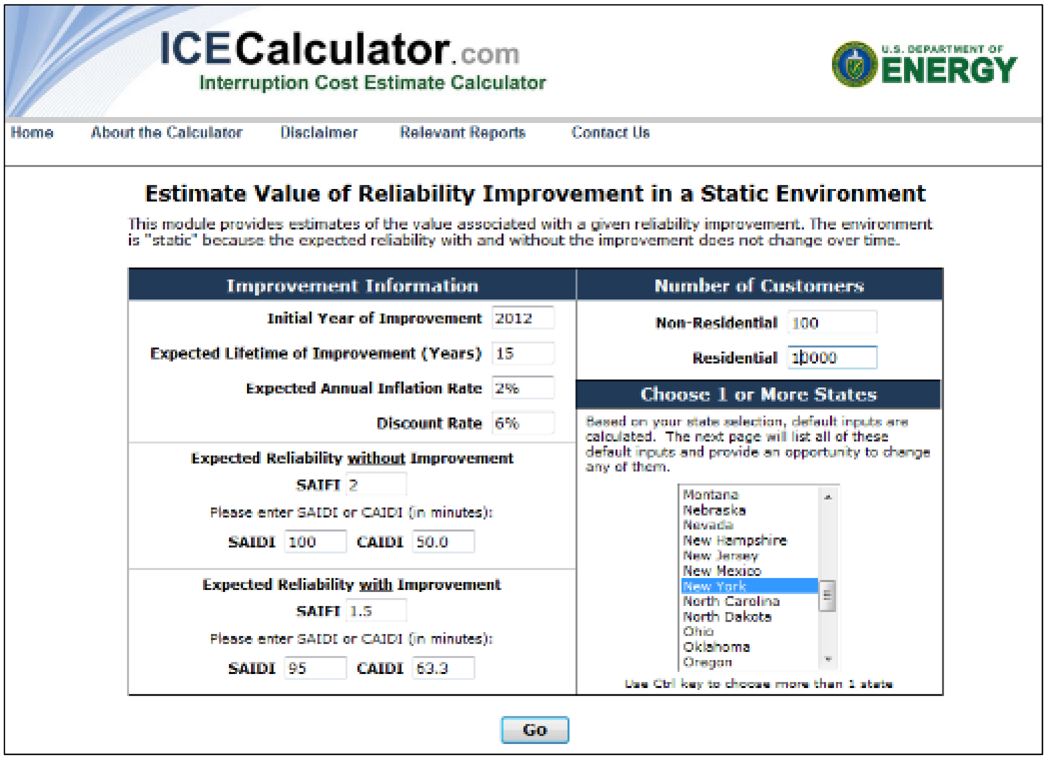
Note that if reliability improvement bang for the buck is used to justify a FLISR project, then the owner of the budget for conventional reliability measures must agree to assign a portion of this budget to FLISR. The money cannot be spent twice! Budget reassignment often results in one of the most significant challenges of business case development—gaining stakeholder acceptance and signoff on FLISR costs and benefits.

2. **Customer Outage Costs.** When power outages occur, electric distribution utility customers of all types (industrial, commercial residential, etc.) may experience considerable incremental operating expenses and losses until power is restored. Examples of these expenses and losses include (but are not limited to):
    - Loss of sales in retail stores
    - Loss of manufacturing productivity
    - Loss of raw materials for industrial processes
    - Spoiled food
    - Cost to run private generator

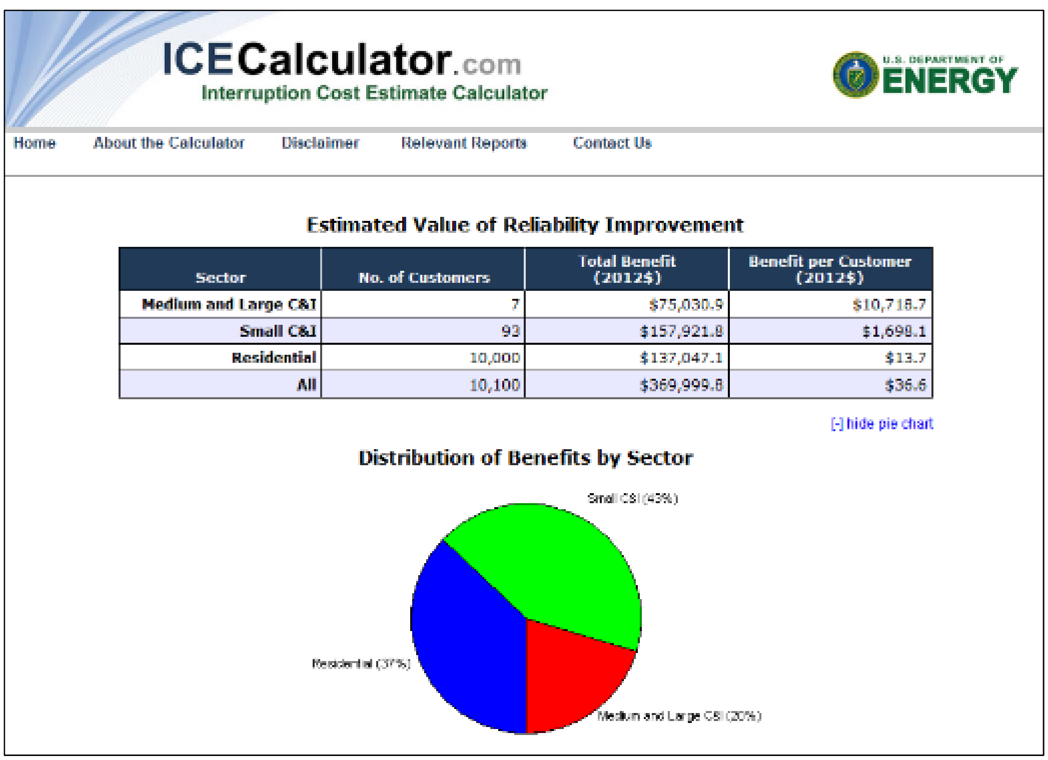
    Avoiding these types of customer losses usually does not benefit the electric utility **directly**. However, a business case that reduces customer costs is often viewed favorably by rate-making authorities, so the utility may be able to recover its investment (including the associated rate of return) on a reliability improvement investment such as FLISR.

    Methodologies for assigning a dollar value to customer outages have been documented by Lawrence Berkeley National Laboratory in a 2003 project sponsored by the U.S. Department of Energy (DOE) entitled, “A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys” (https://emp.lbl.gov/sites/all/files/lbnl-54365.pdf). This report documents ways to assign a dollar value to improvements in customer outages of various lengths in different regions of the United States.

    The concepts included in the above document have been encapsulated into the DOE “Interruption Cost Estimate (ICE) Calculator.” Sample input and output screens from this 2016 online model (http://www.icecalculator.com) are shown in Figure A-12.



(a) ICE Input Quantities



Sector	No. of Customers	Total Benefit (2012$)	Benefit per Customer (2012$)
Medium and Large C&I	7	$75,030.9	$10,718.7
Small C&I	93	$157,921.8	$1,698.1
Residential	10,000	$137,047.1	$13.7
All	10,100	$369,999.8	$36.6

(b) ICE Outputs

FIGURE A-12 DOE ICE Inputs and Outputs

The ICE calculator can be used to assign a dollar value to residential and nonresidential customer outage minutes (SAIDI) and outage events (SAIFI) for any state in the United States. The ICE online model can also be used to assign dollar values to SAIDI and SAIFI improvements, which in turn are used for the benefit cost analysis.

Unit costs for SAIDI and SAIFI improvements by state have been inserted in the benefit cost model and can be used in the DMS benefit cost analysis for reliability improvements.DVCalc allows the user to select which mechanism(s) to use to monetize the functional benefits provided by FLISR.

A.4 FLISR COSTS

This section describes the Total Cost of Ownership (TCO) factors that are included in the DVCalc model. TCO factors include the original cost to purchase, install, and commission the equipment and associated software, and the cost to maintain these facilities over the life of the FLISR system.

A.4.1 Distribution Automation Switches

Electrically-operable switches pose one of the most significant costs associated with FLISR implementation. Total FLISR implementation costs may be reduced significantly if electrically-operable switches are available on the existing distribution system. Sometimes an electric utility can add communication facilities to existing line reclosers and load break switches to achieve considerable cost savings. Another possible cost-saving measure is to install motor-driven or solenoid-driven electrical operating mechanisms to existing manual, gang-operated switches.

The following cost data is needed for the Distribution Automation (DA) switches:

- Purchase and installation cost per switch.
- Annual cost of maintenance of each switch. The program applies a user-specified fixed percentage of the purchase-and-installation cost on an annual basis in the analysis of revenue requirements.

A.4.2 Sensors

The FLISR system requires a variety of sensors for effective implementation. A means of detecting the time and approximate location of a fault must be provided to the substation that serves as the normal source of supply, as well as out on the feeders themselves. This requirement may be handled by protective relay Intelligent Electronic Devices (IED), current and voltage sensors that provide raw measurements to an intelligent processor, and FCIs that indicate if a fault has occurred downstream of the device (farther from the substation).

The user must enter unit costs for purchasing, installing, and commissioning the FLISR sensors into DVCalc. Maintenance costs are handled as a user-specified fixed percentage of the initial costs that are applied on an annual basis over the life of the equipment.

A.4.3 Communication Facilities

The FLISR system must include facilities that enable FLISR to acquire information (load data, fault detector status, open/closed position of each switch, etc.) from substation and feeder devices and to issue open and close commands to the DA switches. Each FLISR switch (including substation and feeder switches) must include two-way communication facilities for issuing control commands and retrieving data from the sensors and controllers associated with each device.

In addition, communication facilities must be added to allow data retrieval from standalone sensors that are included in the FLISR system, such as FCIs. In most cases, one-way communication facilities are sufficient for acquiring information from the field device.

A.4.4 FLISR Application Software and Processors

FLISR systems that use a “centralized” architecture (control center based or substation based) require data processing equipment and software at the specified centralized location or locations. DVCalc allows the user to specify a fixed cost to procure, design, build, install, and commission the necessary hardware and software.

FLISR may also use a distributed architecture in which the main FLISR logic resides in IEDs that are installed at each DA switch. The user is able to assign a fixed cost to each switch, and the program then calculates a total cost by multiplying the unit cost by the number of switches.

In both cases, annual maintenance costs are calculated using a user-specified fixed percentage of the initial costs.

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ANNEX B. VOLT VAR OPTIMIZATION

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CONTENTS

FIGURES

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ACRONYMS AND ABBREVIATIONS

ANSI	American National Standards Institute
CVR	Conservation Voltage Reduction
DER	Distributed Energy Resources
DG	Distributed Generation
DMS	Distribution Management System
FLISR	Fault Location Isolation and Service Restoration
GIS	Geographic Information System
IED	Intelligent Electronic Devices
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operators
kW	kilowatt(s)
kVAR	kiloVAR(s); 1000 units of reactive volt-amperes
LTC	Load Tap Changers
MW	megawatt(s)
OLPF	On-line Power Flow
PES	IEEE Power and Energy Society
PF	Power Factor
SCADA	Supervisory Control and Data Acquisition
TCO	Total Cost of Ownership
VAR	Volt Ampere Reactive (reactive power)
VVO	Volt VAR Optimization

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ANNEX B. VOLT VAR OPTIMIZATION

Volt-VAR Optimization (VVO) is an application function that plays a key role in helping electric distribution utilities achieve a variety of performance objectives, including increased efficiency, reduced electrical losses, peak shaving, and voltage quality improvement. These objectives are all key facets of distribution grid modernization strategies. VVO is expected to play a major role in helping electric distribution utilities accommodate very high penetrations of distributed energy resources (DER) by providing advanced voltage regulation capabilities.

VVO is one of the most common distribution grid modernization applications that has been implemented by electric distribution utilities. According to a recent survey of electric utilities conducted by the Distribution Management System (DMS) task force of IEEE Power and Energy Society (PES) Smart Distribution Working Group, approximately 68% of the survey participants have implemented or are planning to implement VVO as part of their distribution grid modernization strategy.

VVO may be implemented in a variety of architectures, including centralized (DMS, model-driven solution) and decentralized (substation-centered approach or fully distributed peer-to-peer) designs. As proof of concept, many utilities have elected to demonstrate VVO functionality on selected, worst-performing feeders using a decentralized approach. This approach is simpler to deploy than a full-blown DMS solution for a small number of targeted feeders.

As electric utilities transition from proof-of-concept demonstrations to full-scale system wide deployments, many have elected to deploy centralized model-driven DMS-based VVO applications. These applications offer advanced features not available on decentralized solutions such as the ability to handle high distributed generation (DG) penetration and coordinate with other DMS applications like Fault Location Isolation and Service Restoration (FLISR).

VVO offers many functional benefits that are relatively easy to monetize (compared to FLISR reliability improvement). However, VVO benefit cost analysis is often complicated by questions about who benefits. Therefore, when conducting a benefit cost analysis involving VVO, the analyst must carefully consider which of the many possible stakeholders (electric utility, customer, shareholder, energy supplier, or other stakeholder) receives the benefit. It is possible that VVO investments with a high positive return may not provide significant benefits to the entity making the VVO investment. For example, reducing the electrical losses may in fact benefit the supplier's bottom line and the distribution company's bottom line.

This annex focuses on the benefits and costs of deploying VVO in both the centralized and decentralized configurations. It includes a brief overview of VVO operations, potential benefits, implementation costs, and algorithms for computing the benefits.

B.1 OVERVIEW OF VOLT-VAR CONTROL[1]

Volt-VAR control is not a new concept. In fact, electric distribution utilities have been using various means of voltage control and reactive power flow for decades. In the past, the main reason for performing volt-VAR control was to maintain "acceptable" voltage on the distribution feeder under all loading conditions. Maintaining acceptable electrical conditions continues to be a key objective that must not be violated. However, today's electric distribution utilities also rely on voltage and VAR control to improve overall electrical efficiency, promote energy conservation, improve power/voltage quality, reduce peak electrical demand, support the reactive power needs of the bulk power grid, and accommodate high penetrations of DERs.
VVO is comprised of two main parts:

- **VAR Control**. VAR control is the management of reactive power flow in the electric distribution system. Controlling reactive power flow and maintaining the power factor (PF) close to unity will reduce electrical losses and minimize the flow of reactive power from the central generators over the transmission network to the distribution system. Achieving greater reactive power control will reduce overall electrical losses on the power system and free up capacity on the generating resources.
- **Voltage Control**. Voltage control ensures that the service delivery voltage is within the range specified in ANSI C.84.1 (1995) "Electrical Power Systems and Equipment–Voltage Ratings (60 Hz)" at all customer meters under all loading conditions. See Figure B-1 for a diagram showing the acceptable voltage range under various operating conditions. Many electric utility companies and independent system operators (ISO) use voltage control to reduce the voltage during system emergencies and peak load conditions. Controlling voltage in these cases reduces the real and reactive power needed to serve the existing load under peak load conditions, thereby freeing up capacity on generators and power delivery systems.

[1] The term "Volt-VAR control" is used in this report to refer to traditional schemes that focus on maintaining *acceptable conditions* at all times; the term "Volt-VAR Optimization" refers to multi-objective control schemes for *optimizing* distribution system efficiency and overall performance.

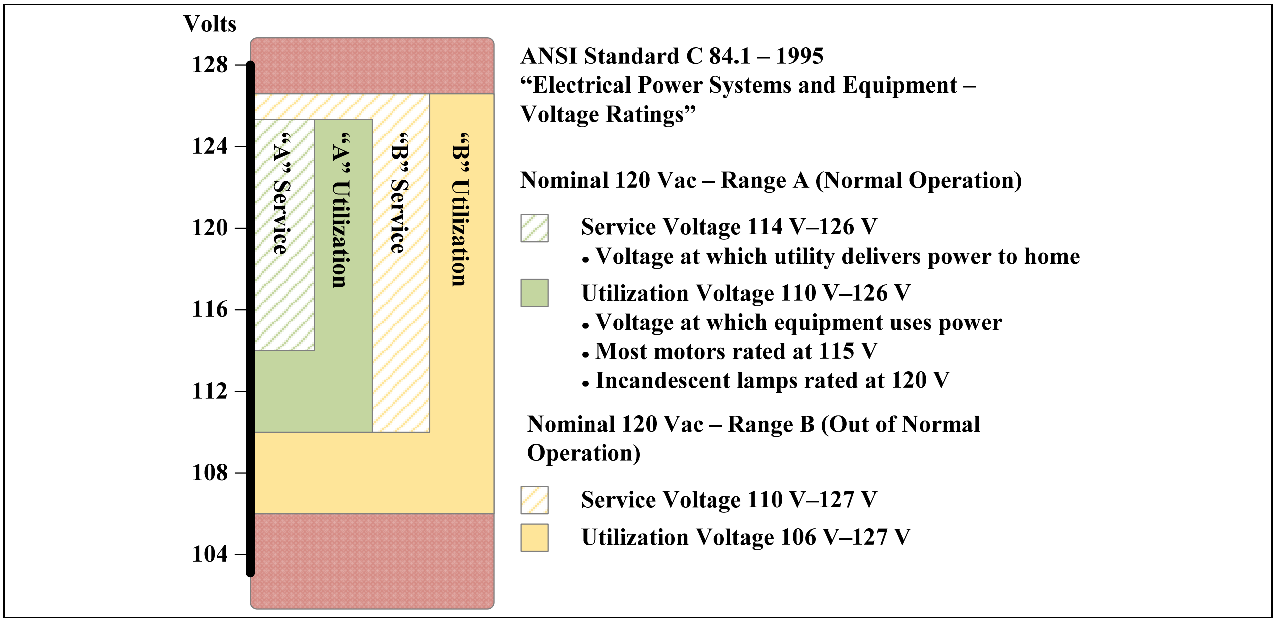

FIGURE B-1 Acceptable Voltage Range

Electric distribution utilities have traditionally controlled voltage and reactive power flow using substation transformers with load tap changers (LTC), voltage regulators in substations and out on the feeders, and fixed and switched capacitor banks located in the substations and out on the feeders close to the load centers. VVO uses these same devices equipped with more advanced controls to accomplish numerous business objectives while maintaining acceptable electrical conditions. The latest VVO systems also use "smart" inverters and power electronics-based "edge of network" devices to improve power system efficiency and overall performance.

The following sections describe the traditional approach to voltage and VAR control that electric distribution companies have used for years along with new approaches that utility companies are implementing as part of their grid modernization strategy. As will be seen, the modern grid approach to voltage and VAR control offers many significant advantages over the traditional approach. These advantages translate into functional and monetary benefits for the utility company and its customers that contribute to the economic justification of the system.

B.1.1 Traditional Approach to Volt VAR Control

Electric distribution utilities have traditionally performed Volt-VAR control using electromechanical controllers associated with switched capacitor banks and voltage regulators. Microprocessor-based controller intelligent electronic devices (IED) may also be used for this purpose.

The control objective is to switch a capacitor bank on/off or change the voltage regulator tap position when needed based on local measurements (measurements taken at the location of the equipment itself). The traditional approach is illustrated in Figure B-2 for pole mounted devices located out on the distribution feeders. The controller configuration is similar for voltage regulators (including substation transformer LTCs) and capacitor banks that are in substations.

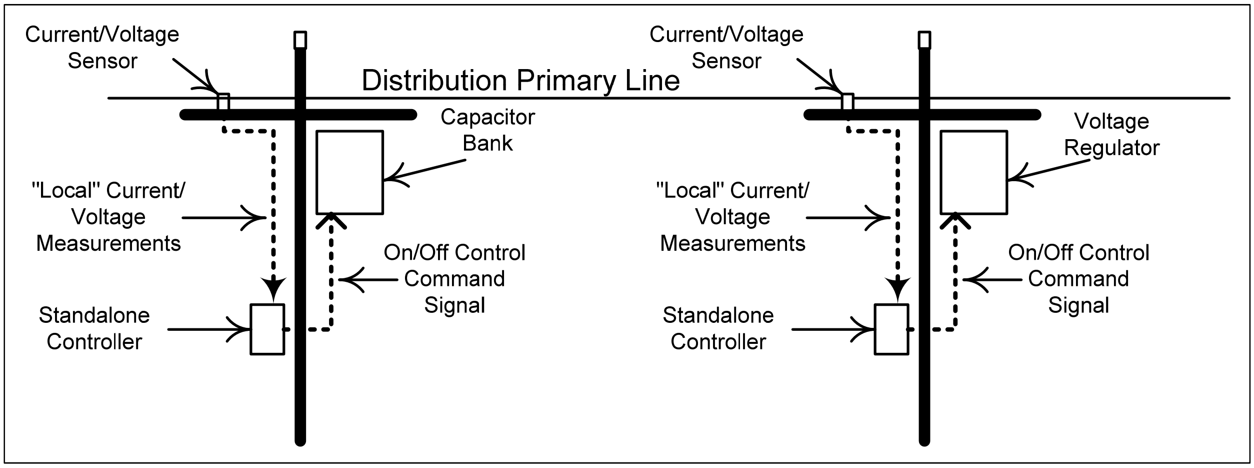

FIGURE B-2 Volt-VAR Control Using Electromechanical Controllers

In most cases, these controllers are strictly "standalone" devices. That is, the controllers do not include any communication facility that enables remote control or supports control decisions that are based on power system-level conditions.

The sequence of operations for the traditional approach is as follows:

1. Local pole mounted or substation mounted sensors measure specified electrical parameters (voltage, current, kilowatt [kW], kiloVAR [kVAR], etc.) and supply these measurements to the local controller via hardwired connections.
2. The controller compares the local measurements against predetermined settings stored in the controller.
3. If the local measurements exceed the internal settings, the controller sends a signal to operate the local capacitor bank or voltage regulator via hardwired connection.
4. The capacitor bank or voltage regulator receives the signal from the controller and operates the capacitor bank or voltage regulator as needed.

Simplicity, familiarity, and low cost are the main advantages of using the traditional standalone controllers. However, this approach lacks certain features necessary to obtain maximum benefits:

- **Lack of Self-Diagnostic Capabilities.** The standalone controller approach lacks self-diagnostic facilities to inform the system operator when the device is inoperative. If a capacitor bank fuse blows or a controller malfunction occurs, the system operator will not be aware of the condition because customers rarely call to report the abnormal voltage conditions that may occur when a volt-VAR control device is out of service. As a result, the capacitor bank or voltage regulator may be out of service until the device is routinely inspected months later. During this interval, the power factor will be lower than expected, electrical losses will be higher than expected, and the anticipated demand reduction may not occur.

- **Inability to Adapt to Changing System Conditions.** Standalone controllers lack the ability to adapt automatically to variable feeder electrical conditions and feeder reconfiguration triggered by FLISR operation or maintenance activities. For example, if the distribution feeder is reconfigured for load balancing purposes or if large (utility-scale) DG units come online or trip offline, the existing settings on standalone controllers may no longer be optimal for achieving the most efficient system conditions.
- **Lack of Coordination between VAR Control and Voltage Control Devices.** With standalone controllers, VAR control actions by capacitor banks may not be well coordinated with voltage control actions by voltage regulators and substation LTCs. Worst case, voltage reduction actions by voltage regulators may be countered by capacitor banks switching on to raise the voltage.

Modern VVO schemes, including the model-driven DMS-based solution, address the shortcomings of the traditional approach and provide valuable business benefits that go well beyond maintaining “acceptable” conditions.

B.1.2 Volt-VAR Optimization

The objective of modern VVO systems is to improve distribution system efficiency and overall performance while maintaining acceptable service delivery voltage for all customers under all loading conditions. VVO systems use many of the same components as traditional schemes, including substation LTCs, voltage regulators, and capacitor banks to control voltage and reactive power under normal and emergency conditions. If microprocessor-based controller IEDs are used for traditional volt-VAR control, they may also be re-used to implement VVO. Figure B-3 depicts a modern DMS, model-driven VVO solution.

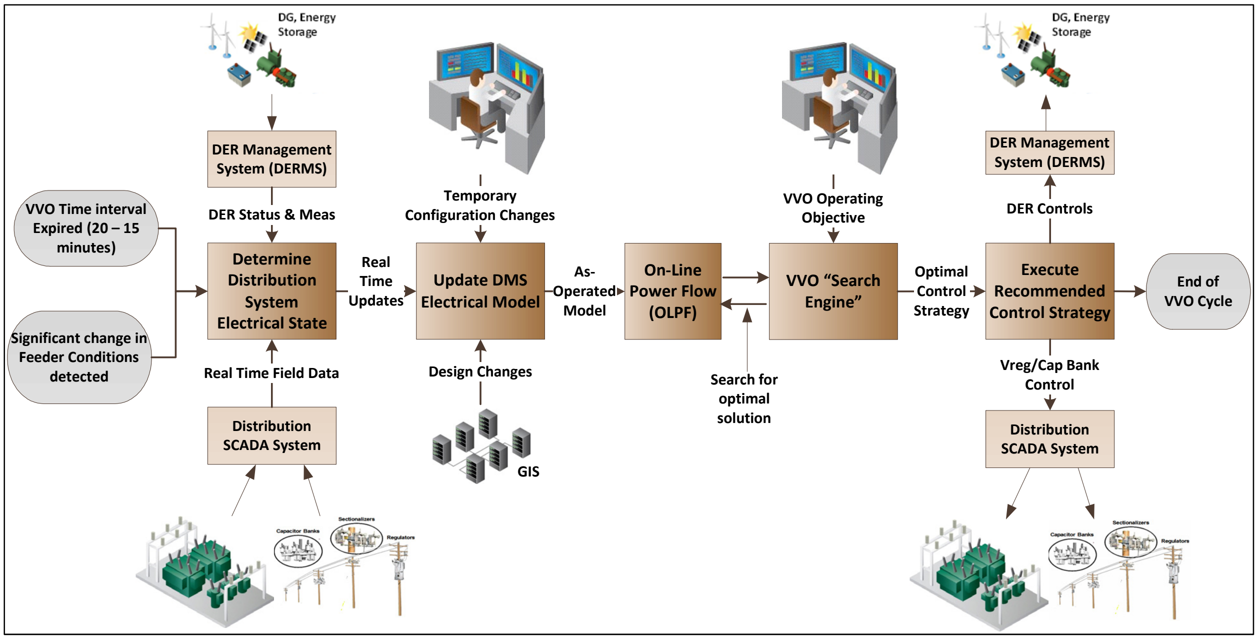

FIGURE B-3 DMS-Based Volt-VAR Optimization

Two principal differences exist between traditional volt-VAR control schemes and model-driven DMS-based VVO:

- **Central controller with advanced software (i.e., the DMS).** The DMS uses a power system model, rather than a fixed set of rules, to determine the optimal set of control actions for achieving user-specified business objectives (such as loss reduction, energy conservation, peak shaving, etc.) without violating voltage and loading constraints.
- **Two-way communication facilities between the DMS and the field devices.** Field devices may include substation LTCs, voltage regulators, switched capacitor banks, smart inverters, edge of network devices, etc. Two-way communication enables VVO to acquire real time measurements and status information representing the current state of the power system so that control actions are based on overall power system needs rather than local conditions. The communication facilities also allow continuous monitoring of the voltage and VAR control devices so that equipment failures are rapidly identified.

The general sequence of steps performed by VVO is listed below. These steps normally are repeated once every 10 to 15 minutes. However, a significant change detected in the field measurements may trigger an immediate execution of the VVO software.

1. **Data Acquisition**. The VVO solution uses the DMS Supervisory Control and Data Acquisition (SCADA) subsystem to acquire data from the volt-VAR field devices and relevant distributed sensors. This information is needed to determine the current state of the electric system. Typically, data is acquired from all devices at least once every five minutes. However, if the SCADA system detects a significant change in any voltage or load measurement or a status change of any volt-VAR control device, an

immediate demand scan of the field devices will be triggered to maintain the accuracy of the model representing the current state, or snapshot, of the power system.

2. **On-Line Model Update**. The DMS updates its model of the electric distribution model using information collected by SCADA so that the “as operated” state of the power system is correctly represented. In addition to updating the model based on real-time field measurements, the model may also be updated manually by the Power System Operator (dispatcher) to reflect any temporary changes, such as switching needed to isolate a portion of the feeder under maintenance. The model may also be updated based on changes to the power system design recorded in the utility company’s Geographic Information System (GIS).
3. **Control Action Identification**. The VVO software uses advanced analytical techniques and an On-line Power Flow (OLPF) program to identify the changes to the status and settings of the voltage and VAR control devices that would help meet the specified business objective or objectives. For example, if electrical loss reduction is the objective, then the VVO software will search for the combination of Volt-VAR control actions that would reduce losses the most without violating voltage and loading constraints.
4. **Remote Control of Volt-VAR Field Devices**. If VVO identifies a set of control actions that would help meet the VVO operating objective, then the VVO system will send these control actions to the Volt-VAR field devices via the SCADA system.

B.1.3 Advanced VVO Advantages

The DMS model-driven VVO solution has several advantages compared to the traditional standalone controller solution. The advantages translate into functional and monetary benefits that can provide economic justification for the advanced VVO system. Advantages of advanced VVO are discussed in this section and translation of the advantages into functional and monetary benefits is presented later in this Annex.

- **Volt-VAR control actions are based on system-level considerations rather than local conditions**. A “system level” view ensures that the voltage and VAR control devices are coordinated and are working together to provide the best overall solution. When voltage and VAR controlled devices are individually and independently controlled based on “local” measurements (as is the case with traditional volt-VAR control solutions), collective benefits from the effects of all devices are not realized. In fact, it is possible that independently controlled devices may have counterproductive results. For example, reducing the tap position on a voltage regulator to achieve Conservation Voltage Reduction (CVR) benefits could result in a downstream capacitor being switched on to boost the voltage. With a system level approach, all devices operate in a well-coordinated fashion to achieve maximum total benefits, resulting in greater improvements in system operations without violating voltage and loading constraints.
- All volt-VAR control devices are continuously monitored to determine the operating status and health of each device and its associated controller. Component failures can be

detected and addressed rapidly without relying on periodic routine inspections, which require a significant resource allocation. Elimination of periodic routine inspections is a direct labor savings. In addition, earliest possible detection of inoperative voltage and VAR control devices ensures that problems can be corrected quickly, thus avoiding customer complaints and loss of operating efficiency and control for a field device out of service.

- **Advanced VVO provides full coordination of control devices.** Fully coordinated control of voltage regulators and capacitor banks reduces the likelihood of contradicting control actions (e.g., voltage regulator lowers the voltage for peak shaving and capacitor bank switches on to elevate the voltage).
- **Advanced VVO adapts well to changing system conditions.** Advanced VVO can respond to variable conditions such as reconfiguration of feeders and changes in contributions from distributed energy resources. Volt-VAR control solutions based on standalone controllers and simple "rule-based" solutions may not operate correctly under abnormal feeder conditions caused by temporary feeder reconfiguration or other temporary changes. Often, rule-based Volt-VAR control systems are disabled when the feeder is reconfigured for any reason.

  A related DMS-based model driven solution benefit is that the objective function can be changed easily as power system level needs dictate. For example, VVO may normally operate in "reduced electrical losses" mode, but may be switched over to "peak shaving" mode if a major generator or critical transmission line is lost.

B.2 VVO BENEFITS

VVO provides numerous benefits that can provide economic justification for the VVO system investment. The benefit "tree" in Figure B-4 shows both functional and monetary benefits that can be achieved with VVO.

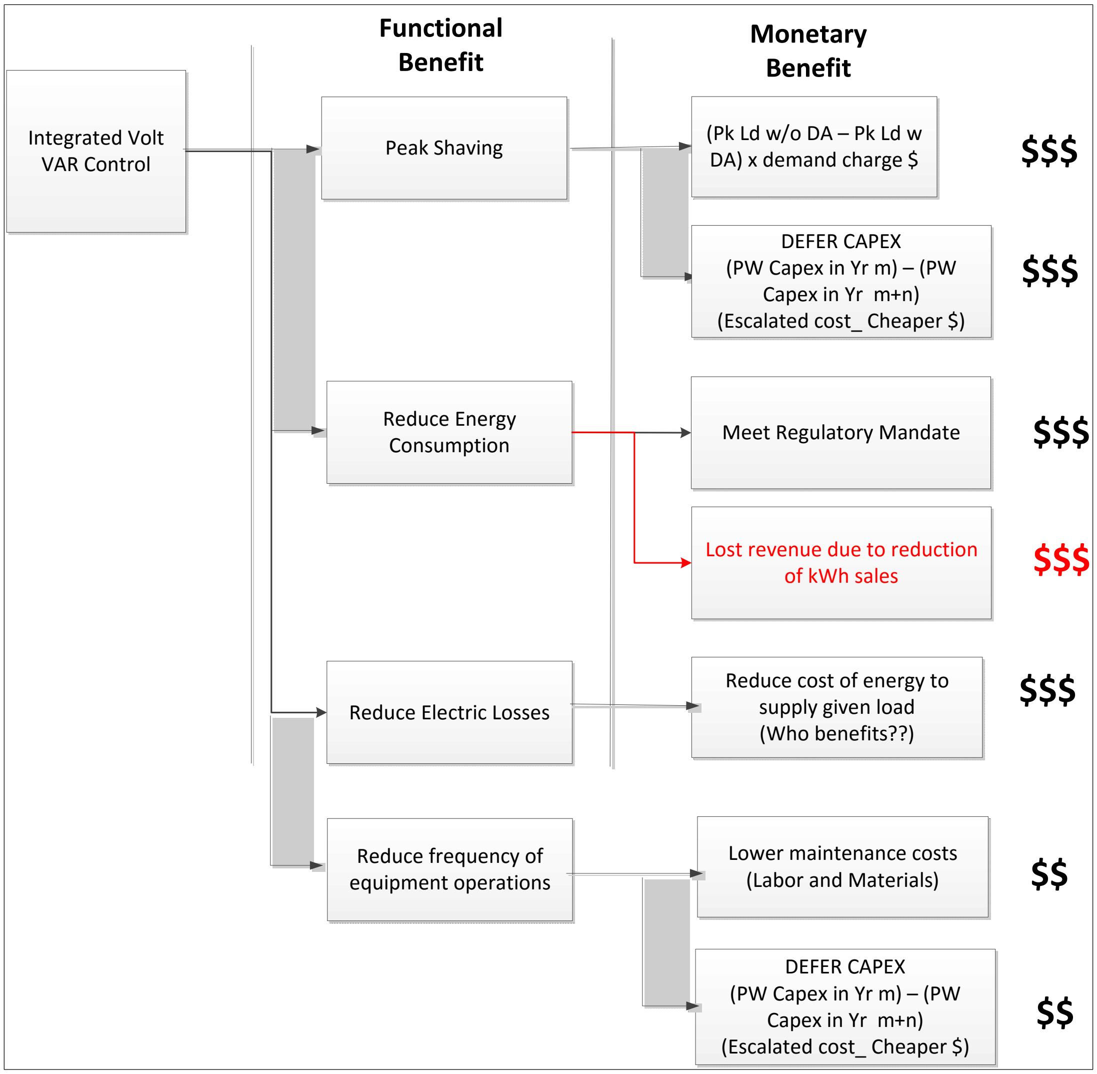

FIGURE B-4 VVO Benefit Tree

This section discusses the functional (non-monetary) benefits associated with VVO. Section B.2 and B.3 of this report presents approaches to convert functional benefits to monetary benefits ("benefit monetization").

- Reduction in electrical (I^2R) losses
- Reduction in peak electrical demand on either the total power system or at specific feeder locations
- Reduction in energy consumption as part of a regulatory body mandated energy efficiency program to reduce greenhouse gas emissions
- Elimination of routine inspections to detect inoperative voltage and VAR control power apparatus

B.2.1 Reduction of Electrical Losses

Most existing power factor correction schemes using standalone controllers are designed to switch capacitor banks on during peak load conditions. These peak load conditions are determined by timers set to match the usual peak load hours and by local measurements such as voltage and reactive power. As a result, conventional VAR control systems are most effective during peak load conditions and do little to improve power factor during off-peak conditions. It is common to see a power factor near unity during peak load conditions and considerably lower during off-peak periods.

A key objective of DMS-based VVO is to improve the power factor to near unity under all operating conditions, including peak load and off-peak.

The following formula is used to compute the percent reduction in losses for a given improvement in power factor. The derivation of this formula is provided in Appendix A of this report.

$$Percent\ reduction\ in\ electrical\ losses\ = 100\ \times\ \left(1 - Pf_i^2/Pf_f^2\right)$$

where

Pf_i = *initial average power factor prior to VVO deployment*

Pf_f = *final average power factor following VVO deployment*

B.2.2 Demand Reduction

Advanced VVO provides two mechanisms for reducing the peak demand on the electric system: voltage reduction at peak load conditions and power factor correction at peak load conditions.

B.2.2.1 Voltage Reduction During Peak Load Conditions

A growing number of electric utilities are reducing voltage during peak load conditions to reduce the peak demand on the electric system. Research has shown that reducing the voltage will lower the electricity consumed by many electrical devices. Many electric utilities have confirmed this method of reducing voltage through numerous field trials and actual reduction deployments.

The following formula is used to compute the approximate reduction in peak demand:

$$Reduction\ in\ peak\ demand\ due\ to\ voltage\ reduction = Pk\ \times\ CVR_f \times\ V_{red}$$

where:

Pk = *Peak load in MW prior to voltage reduction.*

CVR_f = *Voltage reduction factor, which is the percent reduction in power divided by the percent reduction in voltage; typically, this factor has a value between 0.7 and 0.8.*

V_{red} = *Allowable voltage reduction without going below minimum voltage at any point on the feeder. This value is feeder dependent; allowable voltage reduction is often between 2% and 3% of nominal voltage.*

For example, if peak load is 1,000 MW, CVR_f is 0.7, and the allowable voltage reduction is 2% during peak load conditions, then the demand reduction is calculated as follows:

$$Reduction\ in\ peak\ demand\ due\ to\ voltage\ reduction\ = 1{,}000\ \times 0.7\ \times\ 2\% = 14\ MW$$

B.2.2.2 Power Factor Improvement at Peak Load

If the power factor can be improved during peak load conditions, the peak electric demand in megawatts will also be reduced. The following formula can be used to determine the reduction in demand for a given improvement in power factor during peak load conditions. The derivation of this formula is provided in Appendix A of this report.

$$Percent\ reduction\ in\ peak\ electrical\ demand\ due\ to\ PF\ improvement\ = 100\ \times\ \left(1 - Pf_i/Pf_f\right)$$

where:

Pf_i = *initial power factor at peak load prior to VVO deployment.*

Pf_f = *final power factor at peak load following VVO deployment.*

To determine the reduction of peak demand due to power factor correction, the peak electrical demand prior to power factor correction is multiplied by the percent reduction factor listed above. The peak demand on the system is determined by measurement. If total energy consumption for this utility is 1,000 MW, the peak power factor before correction is 0.98, and the peak power factor following correction is 0.99, then the approximate peak load reduction in MW is computed as follows:

$$Reduction\ in\ peak\ demand\ due\ to\ PF\ improvement\ = 1{,}000\ \times (1 - 0.98/0.99\ )\ = 10\ MW$$

The above value will be escalated each year by the projected load growth. For example, if the projected load growth is 1% per year, then the peak demand reduction in Year 2 of the investment will be:

$$Year\ 2\ peak\ demand\ reduction = 10.1\ MW\ \left((1 + 1\%) \times 10\right)$$

B.2.2.3 Impact of Voltage Reduction on Reactive Power

Reducing the voltage has a significant impact on reactive power. The formula for reduction in reactive power demand is given below:

$$Percent\ reduction\ in\ Reactive\ Power\ Demand\ due\ to\ voltage\ reduction\ = Qk\ \times CVR_q\ \times\ V_{red}$$

where:

Qk = *Peak reactive power in MVAR prior to voltage reduction.*

CVR_q = *Voltage reduction factor for reactive power, which is the percent reduction in reactive power divided by the percent reduction in voltage; typically, this factor has a value between 3.0 and 3.5.*

V_{red} = *Allowable voltage reduction without going below minimum voltage at any point on the feeder. This value is feeder dependent; allowable voltage reduction is often between 2% and 3% of nominal voltage.*

For example, if peak reactive power is load is 200 MVAR, CVR_q for reactive power is 3.0, and the allowable voltage reduction is 2% during peak load conditions, then the reactive power reduction is calculated as follows:

$$Reduction\ in\ Peak\ Reactive\ Power\ due\ to\ voltage\ reduction\ = 200 \times 3.0 \times 2\% = 12\ MVAR$$

The reduction in peak reactive power (MVAR) coupled with a similar reduction in megawatt demand has the effect of increasing the power factor, which will reduce the potential savings that can be achieved with a power factor correction. For the example listed above, voltage reduction would improve the power factor at peak load from 0.98 to 0.982. The potential for peak shaving that can be achieved through power factor correction will be reduced by almost 2 MW.

B.2.2.4 Monetizing the Demand Reduction

DVCalc converts the megawatt savings to a monetary value by multiplying the peak demand reduction in megawatts by the demand price. If the energy price is $80/kW-year, the monetary value of demand reduction for this case is $800,000 in Year 1 of the investment. With an inflation rate of 2.2% per year, Year 2 savings will be $825,776:

$$Year\ 2\ savings =\ 10{,}100\ kW \times 80 \times\ (1 + 0.022)$$

B.2.3 Labor Savings

If the electric utility performs routine inspections to verify the status of all switched capacitor banks, then, following the deployment of VVO, these routine inspections can be performed less frequently or eliminated altogether, because VVO continuously monitors these capacitor banks. If applicable, the cost savings in reduced inspections can be considered a benefit of VVO deployment.

Note that at most electric utilities, manpower savings are not considered a "hard" monetary benefit unless a cost savings is actually realized in the form of a reduction in workforce, overtime costs, and/or fewer contractors.

B.2.4 Equipment Maintenance Savings

Deployment of advanced VVO on the electric distribution system may decrease the number of operations of the switched capacitors and voltage regulators. Some utilities have reported a significant decrease in the number of tap changer operations, which could, in turn, translate to maintenance costs savings. However, other utilities report having experienced an increase in voltage regulator and load tap changer operations following the VVO deployment, which would increase maintenance costs. The increase in tap changer operations may be caused by transitions between day-on and day-off modes.

B.3 VVO COSTS

This section describes the total cost of ownership (TCO) calculations used by DVCalc for the VVO application. TCO factors include the original cost to purchase, install, and commission the equipment and associated software, and the cost to maintain these facilities over the life of the VVO system.

B.3.1 Switched Capacitor Banks

VVO may require adding switched capacitor banks to the distribution feeder. The number of switched capacitor banks depends on the average power factor on the existing feeder, the target power factor following the implementation of VVO, and the feeder loading. DVCalc uses to compute the additional VAR support needed to elevate the power factor from the existing average level to the target level. The derivation of this formula is contained in Appendix A of this report.

$$Kvar = P * \left\{ \left[\sqrt{\frac{1}{PFi^2} - 1} - \sqrt{\frac{1}{PFf^2} - 1} \right] \right\}$$

where:

P = *peak load on the feeder (kW).*

PF_i = *average power factor before VVO.*

PF_f = *target power factor following VVO.*

For example, if the peak load is 5 MW, and the initial power factor is 0.94, then the kVAR needed to raise the power factor to a target of 0.99 is 1,102 kVAR. After calculating the number of kVAR needed, the value is converted to an integer number of 600 kVAR capacitor banks, rounding up to obtain the next highest integer number. Using this method, it is determined that two 600-kVAR banks would be needed to elevate the power factor from 0.94 to 0.99 for a feeder with 5 MW of load. The program then multiplies the number of additional capacitor banks by the cost per capacitor bank to determine the total cost of the addition.

B.3.2 Sensors

The VVO system requires a variety of sensors for effective implementation. The VVO system requires real and reactive power measurements from the head end of the feeder, plus data such as device status, current and voltage measurements, and real and reactive power measurements for each device controller. In addition, VVO requires near-real-time voltage measurements from strategic locations on the distribution feeder, such as feeder extremities, heavily loaded branch circuits, and voltage regulators (source and load side). If the electric utility has an AMI system that is able to deliver near-real-time voltage measurements from customer meters, then that is another excellent source of voltage feedback for VVO.

DVCalc allows the user to enter unit costs for purchasing, installing, and commissioning the VVO sensors. Maintenance costs are handled as a user-specified fixed percentage of the initial costs and are applied on an annual basis over the life of the equipment.

B.3.3 Communication Facilities

The VVO system must include communication facilities that enable VVO to acquire information from capacitor bank controllers, voltage regulators, and sensors installed at strategic locations out on the feeder. Each switched capacitor bank and voltage regulator must include two-way communication facilities for issuing control commands and retrieving data from the sensors and controllers associated with each device.

In addition, communication facilities must be added to allow data retrieval from standalone sensors that are included in the VVO system, such as over-current measurements and faulted circuit indicators. In most cases, one-way communication facilities are sufficient for acquiring information from the field device.

DVCalc handles communication costs as a user-specified fixed cost per field device. Annual maintenance costs and periodic fees for using public communication infrastructure are computed as a user-specified percentage of the initial costs.

B.3.4 Application Software and Processors

Model-driven DMS-based VVO systems use a centralized architecture that requires data processing equipment and software at the specified centralized location or locations. DVCalc allows the user to specify a fixed cost to procure, design, build, install, and commission the necessary hardware and software. Annual maintenance costs are handled by a user-specified fixed percentage of the initial costs.

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ANNEX C. DVCALC - DMS BENEFIT COST ANALYSIS TOOL

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CONTENTS

FIGURES

FIGURES (CONT.

ANNEX C. DVCALC - DMS BENEFIT COST ANALYSIS TOOL

DMS Benefit Cost Analysis Tool
Rev 0_9/12/2016
1. The worksheet "Dashboard" provides a convenient mechanism for entering "controlled" parameters which enable the user to define different DA/DMS scenarios that are based on different assumptions. For example, the Dashboard worksheet enables the user to select the DMS applications that are included in the analysis, identify different numbers of feeders to automate, and set a different target power factor for volt-VAR application for the analysis. Following the entry

FIGURE C-1 Analysis Control & Summary

Engineering Capacity Planning Software Tool ("Scrubbing")				
ID	**Description**	**Amount**	**Units**	**Remarks**
A	Number of engineering FTE's to do "scrubbing" of feeder loading data for capacity planning purposes	1	FTEs/year	Input from Utilco
B	% reduction of data scrubbing with DMS software tool	50%	%	Assumption
C	FTE savings using DMS data scrubbing tool	0.5	FTE's year	C = A x B
D	$ value of 1 FTE engineering time	$ 312,000	$/FTE	Input from Utilico
E	**$ Savings using DMS scrubbing tool**	**$ 156,000**	**$/Year**	**E = C x D**

FIGURE C-2 Engineering Capacity Planning

C-6

CONTROL PARAMETERS

Project Information	Amount
Initial Year of Project	2016
Number of years to implement system	3
DMS-OMS Requirement	**Yes or No**
Distirbution Management System Required	Yes
Outage Management System Required	Yes
Combined or Separated OMS/DMS	Combined
DA Applications Being Implemented	**Yes or No**
Fault Location Isolation & Service Restoration	Yes
Volt-VAR Optimization	Yes
DA Applications model driven or rule based?	Model driven
DA Applications centralized or decentralized?	Decentralized
"Control" Parameters for DA Applications	**Amount**
Number of feeders to automate	50
Number of DA Switches per feeder	2
Target power factor for VVO	0.99
Other Applications	**Yes or No**
Equipment Condition Based Maintenance	Yes
- Distribution feeder CBM	Yes
- SS HV Circuit Breaker CBM	Yes
- SS Transformer CBM	Yes
% of substations requiring ECM	50%
Switch Order Management	Yes
Training simulator	Yes
Data scrubbing for capacity planning	Yes
Dynamic Equipment Rating	Yes
Adaptive relaying (fuse saving)	Yes
Electronic Mapping	Yes
DMS/OMS interfaces that are required	**Yes or No**
Supervisory Control and Data Acquisition	Yes
Geospatial Information System	Yes
Advanced Metering Infrastructure	Yes
Work management system	Yes
System integration technology used	Standard ESB
Substation Automation	**Yes or No**
Add new digital relays for protection and SCADA	Yes
% of Substations that need digital relays	25%
Add new SA Data Concentrator at % of subs	Yes
% of Substations to automate	25%
Convert % of existing feeders to IEC61850?	Yes
% of feeders to convert to IEC61850	20%
Labor savings	**Yes or No**
Include labor savings in benefit-cost calculations	Yes
Outage post event review cost savings	Yes
Predictive fault location	Yes
Mechanism for Evaluating Reliability benefits	**Yes or No**
Use DOE ICE Software Tool	No
- If "Yes", enter $/year from ICE toolfor SAIDI & SAIFI Results	
Performance Based Rates	Yes
Value of Lost Load (VOLL) analysis	Yes
Reduction of lost kWh sales	Yes
Labor savings	Yes
Financial & Investment Data	**Amount**
Inflation rate	2.00%
Discount Rate	6.00%

SUMMARY OF RESULTS

Benefit Summary	$/Year
FLISR Benefits	$576,129
VVO Benefits	$239,660
Dynamic Asset Rating (DAR) Benefits	$3,219,200
Adaptive Relay (Fuse saving) Benefits	$2,092,480
Condition Based Maintenance Benefits	$569,267
Labor Savings	$948,791
Total Annual Benefits	**$7,645,526**

Cost Summary	Initial Investment	O&M Cost $/Year
Planning and Procurement	$1,659,375	
OMS/DMS Hardware & Software	$5,650,000	$169,500
Appplication software and studies	$1,250,000	$30,200
System Integration Costs	$1,150,000	$34,500
Substation Equipment	$3,802,500	$76,050
Feeder Equipment	$2,916,592	$58,332
Totals	**$16,428,467**	**$368,582**

Financial Results	
Net Present Value	$ 14,278,128
Payback year	2023 (7 years)
Benefit to cost ratio	2.75

Reliability Results	Amounts
SAIDI before	100
SAIDI After	90.92
% Improvement in SAIDI	**9%**
SAIFI Before	2
SAIFI After	1.90
% Improvement in SAIFI	**5%**

FIGURE C-3 Analysis Control & Summary

Benefit Summary	
Labor Savings due to Productivity Improvements	**$/Year**
Electronic mapping (reduce hand drawn updates)	$566,800
Generation of switching orders	$83,333
Reduction of operator training costs	$137,280
Engineering capacity planning savings	$156,000
Reduction in patrol time	$5,378
Total Labor Benefit	**$948,791**
FLISR Benefits	**$/Year**
Customer outage cost (from ICE tool)	$0.00
UTILCO Value of lost load	$491,648
UTILCO PBR SAIFI	$0
UTILCO PBR SAIDI	$81,531
Reduction of lost kWh sales	$2,950
Total FLISR Benefit	**$576,129**
VVO Benefits	**$/Year**
Electric Loss Reduction	$66,470
Peak Shaving Due to PF Correction	$61,190
Peak Shaving Due to Voltage Reduction	$112,000
Total VVO Benefit	**$239,660**
Dynamic Asset Rating (DAR) Benefits	**$/Year**
Reduction in lost kWh sales ($/Yr) for system	$19,200
Reduction in VOLL ($/Yr) for system (Customer outage savings)	$3,200,000
Total DAR Benefits	**$3,219,200**
Adaptive Relay (Fuse saving) Benefits	**$/Year**
Reduction in lost kWh sales ($/Yr) for system	$12,480
Reduction in VOLL ($/Yr) for system (Customer outage savings)	$2,080,000
Total Adaptive Relaying Benefits	**$2,092,480**
Condition Based Maintenance Benefits	**$/Year**
Fewer feeder inspections (labor)	$53,333
Fewer HV CB inspections/repairs (labor)	$28,125
Fewer HV CB inspections/repairs (material)	$25,000
Fewer HV CB Failures (rebuild/replace cost)	$83,333
Fewer HV CB Failures (reduce lost kWh sales)	$325
Fewer HV CB Failures (Value of Lost Load)	$54,167
Fewer Sub trf inspections/repairs (labor)	$6,000
Fewer Sub trf inspections/repairs (material)	$1,667
Fewer Sub trf Failures (rebuild/replace cost)	$208,333
Fewer Sub trf Failures (reduce lost kWh sales)	$650
Fewer Sub trf Failures (Value of lost load)	$108,333
Total ECM Benefits	**$569,267**
Total Benefits for System ($ per year)	**$7,645,526**

Cost Summary	Initial Investment	Annual O&M
System Procurement Cost		**$/Year**
System planning and Procurement	$481,250	---
Integ arch, environment, chg mgmt	$1,178,125	---
DMS/OMS Hardware	$750,000	$22,500
DMS/OMS System Software	$1,700,000	$51,000
Distribution system models	$3,200,000	$96,000
Application software & Appl studies		**$/Year**
Fault Location isolation and Serv Restore	$95,000	$1,900
Volt-VAR Optimization	$170,000	$5,100
Condition based maint for dist CBs (feeder ecm)	$30,000	$600
Condition based maint for HV CBs	$50,000	$1,000
Condition based maint for SS Trfs	$75,000	$ 1,500
Electronic mapping facilities	$200,000	$6,000
Switch Order Management	$200,000	$4,000
Training Simulator	$200,000	$6,000
Data scrubbing for capacity planning	$100,000	$2,000
Dynamic Asset Rating	$80,000	$1,600
Adaptive Relaying	$50,000	$500
System Integration Costs		**$/Year**
DMS-OMS Interface	$0	$0
DMS/OMS-GIS interface	$400,000	$12,000
DMS/OMS-AMI interface	$250,000	$7,500
DMS/OMS-SCADA	$250,000	$7,500
DMS/OMS-Work Management	$250,000	$7,500
Substation Equipment		**$/Year**
New Vreg Controller for LTC to support VVO	$ 7,500	$ 150
Add new SA data conc to % of existing substations	$ 1,325,000	$ 26,500
Add new digital relays for protection and SCADA	$ 1,100,000	$ 22,000
Implement IEC61850 at legacy substations	$ 160,000	$ 3,200
New sensors for transformer CBM	$ 700,000	$ 14,000
New sensors for HV CB CBM	$ 350,000	$ 7,000
Convert % of existing digital subs to IEC61850	$ 160,000	$ 3,200
Feeder Equipment		**$/Year**
DA switches for FLISR	$1,382,500	$27,650
Switched capacitor banks	$64,092	$1,282
Midline voltage regulators	$1,470,000	$29,400
	First Cost	**O&M ($/Yr)**
Total Costs for System	**$16,428,467**	**$368,582**

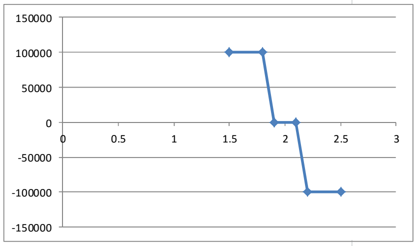
FIGURE C-4 Benefit & Cost Summary

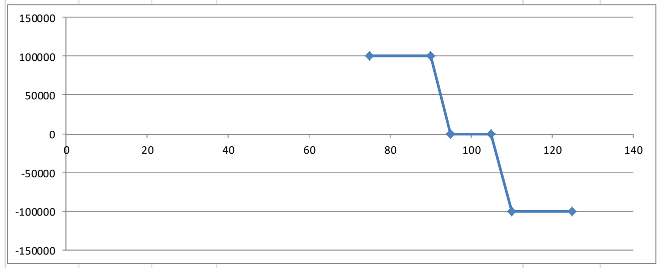
DMS-OMS Requirement			
Distirbution Management System Required	Yes	*Yes or No*	
Outage Management System Required	Yes	*Yes or No*	
Combined or Separated OMS/DMS	Combined	*Combined or Separate*	
DA Applications Being Implemented			
Fault Location Isolation & Service Restoration	Yes	*Yes or No*	
Volt-VAR Optimization	Yes	*Yes or No*	
DA Applications model driven?	Model driven	*Yes or No*	
Centralized or decentralized?	Decentralized	*Centralized or Decentralized*	
Number of feeders to automate	50		
Other Applications			
Equipment Condition Based Maintenance	Yes	*Yes or No*	
Electronic mapping	Yes	*Yes or No*	
Switch Order Management	Yes	*Yes or No*	
Training simulator	Yes	*Yes or No*	
Dynamic Equipment Rating	Yes	*Yes or No*	
Adaptive relaying (fuse saving)	Yes	*Yes or No*	
DMS/OMS interfaces that are required			
Supervisory Control and Data Acquisition	Yes	*Yes or No*	
Geospatial Information System	Yes	*Yes or No*	
Advanced Metering Infrastructure	Yes	*Yes or No*	
Work management system	Yes	*Yes or No*	
System integration technology	Standard ESB	*Homegrown or Standard ESB*	
Substation Automation			
Convert all subs to IEC61850?	Yes	*Yes or No*	
Electrical Data			
Load growth (% per year)	2.00%	*Input value from UTILCO*	
Total number of feeders	800	*Calculated from # substations*#trfs*#fdr/trf*	
Number of substations	100	*Input value from UTILCO*	
Number of HV breakers per substation	2	*Input value from UTILCO*	
Number of transformers per substation	2	*Input value from UTILCO*	
Number of feeders per substation transformer	4	*Input value from UTILCO*	
Peak load on distribution feeder (% of rating)	60.0%	*Input value from UTILCO*	
Load Factor	65%	*Input value from UTILCO*	
Peak Load on feeder (kW)	10000	*Input value from UTILCO*	
Distribution Power Factor (average)	0.970	*Input value from UTILCO*	
Reliability Data			
System SAIFI	2	*Input from UTILCO*	
% difference of worst performing feeders (SAIDI)	10%	*Assumption or input from UTILCO*	
System SAIDI	100	*Input from UTILCO*	
% difference of worst performing feeders (SAIFI)	10%	*Assumption or input from UTILCO*	
Average fault location (patrol) time (minutes)	30	*Input value from UTILCO*	
Average time to isolate fault (minutes) via manual switching	15	*Input value from UTILCO*	
Average travel time service (minutes) to reach fault vicinity	30	*Input value from UTILCO*	
Patrol time as % of total outage	40.00%	*Calculated from the above inputs*	
Financial Data			
Inflation rate	2.00%	*%/Yr*	
Discount Rate	6.00%	*%*	
UTILCO's Value of Lost Load (Economic Estimates)	$ 10,000	*$/MWh*	
Energy production cost per kWh	$ 0.16	*$/kWh*	
Value of 1 megawatt peak load	$ 80,000	$/MW/Yr	*Based on marginal power source*
Profit per kWh sold ($)	$ 0.06	*$/kWh*	*Production cost minus selling price*

FIGURE C-5 UTILCO Inputs

Inputs for defining PBR Characteristic for SAIFI		
System SAIFI (last year)	2.00	(Only Required if Performance Based Rates Apply)
Neutral zone	5%	
Maximum penalty/reward zone	10%	
Maximum Reward	100000	
Maximum penalty	-100000	

Inputs for defining PBR Characteristic for SAIDI			
System SAIDI (last year)	100	(Only Required if Performance Based Rates Apply)	75
Neutral zone	5%		90
Maximum penalty/reward zone	10%		95
Maximum Reward	100000		105
Maximum penalty	-100000		110
			125





Implementation Schedule		
Number of years to implement system	3	*Initial costs spread evenly over specified number of years starting at year 1*

Central processsors (hardware & system software)	Initial Cost	Annual O&M
DMS Hardware (separate DMS/OMS) (US$)	$ 500,000	
OMS Hardware (separate DMS/OMS) (US$)	$ 500,000	
Combined DMS/OMS hardware (US$)	$ 750,000	
DMS System software (no adv applications)	$ 1,000,000	
OMS System software (no adv applications)	$ 1,000,000	
Combined DMS/OMS software (no advance applications)	$ 1,700,000	
Annual O&M for all DMS & OMS hardware & software		3%

Labor Costs		Hourly		
Engineering labor ($/Manyear)	$ 312,000	$ 150.00		312000
External Labor ($/Manyear)	$ 260,000	$ 125.00		
Control room operator	$ 260,000	$ 125.00		
IT personnel	$ 260,000	$ 125.00		
GIS/OMS "Mappers"	$ 156,000	$ 75.00		
Substation test crew	$ 260,000	$ 125.00		
Line Crew labor rate ($/hour) (includes vehicle cost)		$ 200.00	*$/hour (includes vehicle cost)*	

Feeder Modelling	Initial Cost	Annual O&M	
Cost to build $ maintain model ($/feeder)	$ 4,000	3%	*Applies for centralized (model-driven) solution*

System integration costs	Initial Cost	Annual O&M	
DMS-OMS interface using Standard ESB	$ 300,000		*Only if separate OMS and DMS implemented*
DMS-OMS interface using home grown interface	$ 400,000		*Only if separate OMS and DMS implemented*
Combined DMS/OMS - GIS Integration using Standard	$ 300,000		
Combined DMS/OMS - GIS Integration using home grown interfac	$ 400,000		
Separate DMS or OMS interface to GIS using Standard ESB	$ 200,000		
Separate DMS or OMS interface to GIS using home grown interfac	$ 250,000		
Combined DMS/OMS - AMI Integration using Standard	$ 150,000		
Combined DMS/OMS - AMI Integration using home grown interfa	$ 250,000		
Separate DMS or OMS interface to AMI using Standard ESB	$ 100,000		
Separate DMS or OMS interface to AMI using home grown interfa	$ 150,000		
Combined DMS/OMS - Work Mgmt Integration using Standard	$ 150,000		
Combined DMS/OMS - Work Mgmt Integration using home grown	$ 250,000		
Separate DMS or OMS interface to Work Mgmt using Standard ESB	$ 100,000		
Separate DMS or OMS interface to Work Mgmt using home grown	$ 150,000		
Combined DMS/OMS - SCADA Integration using Standard	$ 150,000		
Combined DMS/OMS - SCADA Integration using home grown inte	$ 250,000		
Separate DMS or OMS interface to SCADA using Standard ESB	$ 100,000		
Separate DMS or OMS interface to SCADA using home grown inte	$ 150,000		
Annual O&M % for interface with Standard ESB		3%	
Annual O&M % for interface with homegrown solution		5%	

FIGURE C-6 UTILCO Inputs (cont.)

Combined DMS/OMS	# FTEs	"Blended"hourly rate	Amount	% of internal labor	% of internal labor
Planning	0.75	$ 138	$ 206,250	50%	50%
Procurement	1	$ 138	$ 275,000	50%	50%
Architecture and Integrations					
Establish integration architecture	0.75	$ 131	$ 196,875	25%	75%
Establish environment	0.25	$ 131	$ 65,625	25%	75%
Detailed integration specs - advanced applications	0.75	$ 131	$ 196,875	25%	75%
Change Management					
Develop Use Cases	2.5	$ 144	$ 718,750	75%	25%
			$ 1,659,375		

Separate DMS	# FTEs	"Blended"hourly rate	Amount	% of internal labor	% of internal labor
Planning	0.5	$ 138	$ 137,500	50%	50%
Procurement	0.5	$ 138	$ 137,500	50%	50%
Architecture and Integrations					
Establish integration architecture	0.5	$ 131	$ 131,250	25%	75%
Establish environment	0.25	$ 131	$ 65,625	25%	75%
Detailed integration specs - DMS apps	1.5	$ 131	$ 393,750	25%	75%
Change Management					
Develop Use Cases	1.25	$ 144	$ 359,375	75%	25%
			$ 1,225,000		

Separate OMS	# FTEs	"Blended"hourly rate	Amount	% of internal labor	% of internal labor
Planning	0.5	$ 138	$ 137,500	50%	50%
Procurement	0.5	$ 138	$ 137,500	50%	50%
Architecture and Integrations					
Establish integration architecture	0.5	$ 131	$ 131,250	25%	75%
Establish environment	0.25	$ 131	$ 65,625	25%	75%
Detailed integration specs - OMS apps	1.5	$ 131	$ 393,750	25%	75%
Change Management					
Develop Use Cases	1.25	$ 144	$ 359,375	75%	25%
			$ 1,225,000		

Electronic Mapping		
# of OMS/GIS "mappers" updating records (FTEs)	3.0	*Input from UTILCO*
% reduction in # of OMS/GIS "mappers" updating records (%)	50%	*Input from UTILCO*
% of control room operator time doing hand drawn map updates	20%	*Input from UTILCO*
# of control room operators	8	*Input from UTILCO*
% reduction in hand drawn updates with electronic mapping	80%	*Assumption*
Control Room Operator Training		
% of senior operator time for training new operators	20%	*Input from UTILCO*
% reduction in training time using training simulator	33%	*Assumption*
Data Scrubbing for Capacity Planning		
Number of engineering FTE's to do "scrubbing" of feeder loading data for capacity planning purposes	1	FTE/Year
% reduction of data scrubbing with DMS software tool	50%	%
Customer Data		
Total number of customers for the entire system	800000	*Input from UTILCO*
Number of customers on the one DA feeder	1000	*Calc - Total number of custs/#feeders*

FLISR Implementation		
FLISR Derating with decentralized Rule-based solution	10%	With rule-based solution, may not find solution in all cases - Pick derating factor between 5% and 10%
Number of FLISR Feeders	10	
Number of FLISR substations (Decentralized only)	3	
Number of normally closed DA switches per feeder	2	Control variable
Engineering studies needed for FLISR ($/Feeder)	$ 2,000	One time cost
Centralized FLISR software license	$ 200,000	
Decentralized FLISR software licenses	$ 25,000	per substation cost
Cost per DA switch	$ 50,000	
Controller for DA sw control (centralized applications)	$ 1,000	
Controller for DA switch controller (decentralized applications)	$ 2,000	
Application processor for decentral FLISR	$ 15,000	One per substation
Communication interface per switch	$ 1,500	
Annual O&M cost for flisr equipment & software		2%

FIGURE C-7 UTILCO Inputs (cont.)

VVO Implementation			
VVO Derating with Rule-based solution	10%	*Assumption*	*Should be between 5% to 15%*
Number of VVO Feeders	10	*Assumption*	
Number of VVO substations (Decentralized only)	3	*Input value from UTILCO*	
Distribution Primary Losses at Peak Load	6.250%	*Input value from UTILCO*	
Distribution Power Factor (average)	0.982	*Assumption*	
Target PF (for VAR Dispatch)	0.990	*Control variable for volt-VAR*	
Distribution PF (Peak load)	0.982		
Available voltage reduction	1.000%		
Additional voltage eduction if AMI is present	1.000%		
CVR Factor	0.700		
Engineering studies needed for VVO ($/Feeder)	$ 2,000		One time cost
Centralized VVO software license	$ 200,000	2%	One for entire system
Decentralized VVO software licenses	$ 50,000	3%	per substation cost
Switched capacitor bank	$ 4,000	2%	
Controller for switched cap bank (centralized applications)	$ 1,000	2%	
Controller for switched cap bank (decentralized applications)	$ 2,000	2%	
Midline voltage regulator	$ 25,000	2%	
Controller for vreg (centralized applications)	$ 1,000	2%	
Controller for vreg (decentralized applications)	$ 2,000	2%	
Communication interface for switched cap bank or vreg	$ 1,500	2%	
Other DMS Applications			
Switch Order Management Being Implemented (Yes/No)	Yes		
% of faults that require SOM analysis	50%	*SOM analysis required for faults in the first half of the feeder*	
Expected time savings with SOM (minutes)	5	*Control variable - insert value between 5% and 15%*	
Switch order management Cost	$ 200,000	2%	
Electronic Mapping	$ 200,000	3%	
Training Simulator Being Implemented (Yes/No)	Yes		
Training simulator	$ 200,000	3%	
Data scrubbing for capacity analysis	$ 100,000	2%	
Dynamic Asset Rating			
Dynamic Asset Rating Being Implemented (Yes/No)	Yes		
Number of hours per year load shedding due to equipment overlo	24		
Percentage amount of load shedding during these hours	2%		
Amount of Load shedding without DER	3%	Input assumption	
Amount of Load shedding with DER	2%	Input assumption	
% of feeders on which load shedding applies	10%		
Number of substations to be equipped with DAR	3	O&M	
Dynamic asset rating software	$ 50,000	2%	*Assumption*
Substaion sensors for dynamic asset rating ($/substation)	$ 10,000	*$/Substation*	
Adaptive Relaying			
Adaptive Relaying being implemented (Yes/No)	Yes		
Number of temporary faults per feeder	6		
% portion of feeder on fused laterals	40%		
Number of fused branchlines per feeder	20	O&M	
Adaptive relaying application software cost	$ 50,000	1%	Requires substation IEDs

FIGURE C-8 UTILCO Inputs (cont.)

C-12

Substation Automation	First cost	O&M (%/Yr)	
Convert all SA systems to IEC 61850? (Yes/No)	Yes		
Add new data concentrator to exsiting substation?	Yes		
Cost to procure and configure one digital relay ($/feeder)	$ 5,000	2%	
Cost to install 1 digital relay	$ 500		
Cost to add data concentrator to substation	$ 50,000	2%	*1 per substation*
Cost to install data concentrator in one substation	$ 3,000		
Cost to add IEC61850 comm module to existing relay	$ 500		$/relay
IEC 61850 configuration cost	$ 500		$/relay
% of feeders to convert to IEC 61850	20%		
Cost to add IEC61850 comm module to existing relay	$ 500	2%	
IEC 61850 configuration cost	$ 500		$/relay
Cost to add new data points with IEC 61850 ($/Feeder)	$ 1,000	2%	
Cost to add new data points with legacy serial protocol ($/Feeder)	$ 1,500	2%	
Labor to convert to IEC 61850 (Hours/device)	8		
Cost of new voltage regulator IED	$ 2,500	2%	*1 per trf required for implementing VVO*
Condition Based Maintenance			
Distribution feeder circuit breakers			
CBM for distibution feeders being implemented (Yes/No)	Yes		
Period of major inspections without ECM	5	Years	
Period of major inspections with ECM	9	Years	
# hours to do major inspection without ECM	12		
# hours to do major inspection with ECM	12	**O&M**	
Cost of distribution feeder CBM	$ 30,000	2%	
High Voltage Circuit Breakers			
CBM for high voltage CBs being implemented (Yes/No)	Yes		
Period of major inspections without ECM	4	Years	
Period of major inspections with ECM	8	Years	
# hours to do major inspection without ECM	18	Hours	
# hours to do major inspection with ECM	18	Hours	
Material cost per major inspection without ECM	$2,000		
Material cost per major inspection with ECM	$2,000		
Years between catastrophic HV CB failures without ECM	15	Years	
% failures detected early with ECM	25%	%	
Cost to Rebuild/Replace HVCB following catastrophic failure	$ 100,000		
Reduction in repair costs if HV CB problem detected early	50%		
Time to restore customers impacted by HV CB outage (hours)	1.00	*Assumption*	
Cost of CBM software for High voltage Circuit breakers	$ 50,000	2%	
	Serial/Legacy	**IEC 61850**	
Cost of new CB monitor for HV CB CBM (serial)	$ 3,000	3500	
O&M	3%	2%	
Substation Transformers			
CBM for substation transformers being implemented (Yes/No)	Yes		
Period of major inspections without ECM	10	Years	Input
Period of major inspections with ECM	15	Years	Assumption
# hours to do major inspection without ECM	24	Hours	Input
# hours to do major inspection with ECM	24	Hours	Input
Period of major inspections without ECM	10	Years	
Period of major inspections with ECM	15	Years	
Material cost for major inspections without ECM	$100	$/Yr	
Material cost for major inspections with ECM	$66.67	$/Yr	
Years between catastrophic SS trf failures without ECM	15.00	Years between failures	
% failures detected early with ECM	25%	%	
Cost to Rebuild/Replace following failure	$500,000	$	
Reduction in repair costs if problem detected early	25%	%	
Time to restore service to customers impacted by outage	2	hours	
	Serial/Legacy	**IEC 61850**	
Cost of new transformer monitor IED	$ 5,000	$ 5,500	
Cost of new on-line gas monitor IED for transformer	$ 8,000	$ 8,500	
CBM software for substation transformers	$ 10,000	$ 10,000	
Annual Maintenance %	3%	2%	
Cost of CBM on DMS for substation transformers	$ 75,000	2%	

FIGURE C-9 UTILCO Inputs (cont.)

Training Simulator Labor Savings				
ID	**Description**	**Amount**	**Units**	**Remarks**
A	% of senior operator time for training new operators	20%	%	Input from UTILCO
B	Number of operators doing this training	8	FTE's	Input from UTILCO
C	# of operator FTE's for training	1.6	FTE's	C = A x B
D	% reduction in training time using training simulator	33%	Assumption	Assumption
E	Operator training savings due to training simulator	0.528	FTE's	E = C x D
F	$ value of Operator time	$260,000	$/FTE	Input from UTILCO
G	**Annual savings**	**$137,280**	**$/year**	**G = E x F**

FIGURE C-10 Training Simulator

C-14

Financial Data		DMS (Yes/No)	Yes	FLISR ? (Yes/No)	Yes	**FLISR Architecture**	Decentralize	**# Fdrs**	10	**# Subs**	3	# Sw per feeder	0		
Inflation Rate	2.0%	OMS (Yes/No)	Yes	VVO (Yes/no)	Yes	**VVO Architecture**	Decentralize	**# Fdrs**	10	**# Subs**	3	Sw cap banks		Midline vreg	
Discount rate	6.0%	Model driven (Yes/No?)	Model driven	CBM (Yes/No)	Yes										
Load growth	2.00%	Centralized or decentralized?	Decentralized	SOM (Yes/No)	Yes										
Years to complete Invest	3	Combined or Separated OMs/DMS	Combined	Training simulator	Yes										
		Convert all subs to IEC61850?	Yes	***Interfaces***											
		Number of feeders to automate	50	SCADA	Yes										
				GIS	Yes										
				AMI	Yes										
				Work management	Yes										
				Sys Integ Tech	Standard ESB										

Financial Results			
Net Present Value	$ 14,278,128		
Payback year	2023	(7 Years)	2023 (7 years)
Benefit to cost ratio	2.75		

Year	**2016 NPV**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
TOTAL COSTS	$ 17,559,012	$ 1,659,375	$ 4,977,971	$ 5,496,465	$ 5,270,345	$ 396,194	$ 404,118	$ 412,200	$ 420,444	$ 428,853	$ 437,430	$ 446,179	$ 455,102	$ 464,204	$ 473,488	$ 482,958
Initial Investment	$ 15,135,225	$ 1,659,375	$ 4,977,971	$ 5,496,465	$ 5,270,345	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System planning and Procurement	$ 481,250	$ 481,250														
Integ arch, environment, chg mgmt	$ 1,178,125	$ 1,178,125														
DMS/OMS Hardware	$ 668,253		$ 255,000	$ 260,100	$ 265,302	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DMS/OMS System Software	$ 1,248,827		$ 578,000	$ 589,560	$ 265,302	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distirbution system models	$ 2,851,213		$ 1,088,000	$ 1,109,760	$ 1,131,955	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Application software & Appl studies																
Fault Location isolation and Serv Restore	$ 84,645		$ 32,300	$ 32,946	$ 33,605	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Volt-VAR Optimization	$ 151,471		$ 57,800	$ 58,956	$ 60,135	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Condition based maint for dist CBs	$ 26,730		$ 10,200	$ 10,404	$ 10,612	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Condition based maint for HV CBs	$ 44,550		$ 17,000	$ 17,340	$ 17,687	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Condition based maint for SS Trfs	$ 66,825		$ 25,500	$ 26,010	$ 26,530	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Electronic Mapping	$ 178,201		$ 68,000	$ 69,360	$ 70,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Switch Order Management	$ 178,201		$ 68,000	$ 69,360	$ 70,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Training Simulator	$ 178,201		$ 68,000	$ 69,360	$ 70,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capacity Planning Data scrubbing	$ 89,100		$ 34,000	$ 34,680	$ 35,374	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dynamic Asset Rating	$ 71,280		$ 27,200	$ 27,744	$ 28,299	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adaptive Relaying	$ 44,550		$ 17,000	$ 17,340	$ 17,687	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Integration Costs																
DMS-OMS Interface	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DMS/OMS-GIS interface	$ 356,402		$ 136,000	$ 138,720	$ 141,494	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DMS/OMS-AMI interface	$ 222,751		$ 85,000	$ 86,700	$ 88,434	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DMS/OMS-SCADA	$ 222,751		$ 85,000	$ 86,700	$ 88,434	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DMS/OMS-Work Management	$ 222,751		$ 85,000	$ 86,700	$ 88,434	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Substation Equipment																
New Vreg for LTC to support VVO	$ 6,683		$ 2,550	$ 2,601	$ 2,653	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New substation data concentrators	$ 1,180,580		$ 450,500	$ 459,510	$ 468,700	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New digital relays	$ 980,104		$ 374,000	$ 381,480	$ 389,110	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Implement IEC61850 at legacy substations	$ 142,561		$ 54,400	$ 55,488	$ 56,598	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Convert substations to IEC61850	$ 724,971		$ 10,880	$ 430,032	$ 438,633	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New sensors for transformer CBM	$ 623,703		$ 238,000	$ 242,760	$ 247,615	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New sensors for HV CB CBM	$ 311,851		$ 119,000	$ 121,380	$ 123,808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Feeder Equipment																
DA switches for FLISR	$ 1,231,813		$ 470,050	$ 479,451	$ 489,040	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Switched capacitor banks	$ 57,106		$ 21,791	$ 22,227	$ 22,672	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Midline voltage regulators	$ 1,309,776		$ 499,800	$ 509,796	$ 519,992	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

FIGURE C-11 Analysis of Revenue Requirements

C-15

$ -	$ -	$ 396,194	$ 404,118	$ 412,200	$ 420,444	$ 428,853	$ 437,430	$ 446,179	$ 455,102	$ 464,204	$ 473,488	$ 482,958			
$ -	$ -	$ 24,355	$ 24,842	$ 25,339	$ 25,845	$ 26,362	$ 26,890	$ 27,427	$ 27,976	$ 28,535	$ 29,106	$ 29,688	750000	$ 22,500	
$ -	$ -	$ 55,204	$ 56,308	$ 57,434	$ 58,583	$ 59,755	$ 60,950	$ 62,169	$ 63,412	$ 64,680	$ 65,974	$ 67,293	1700000	$ 51,000	
$ -	$ -	$ 103,913	$ 105,992	$ 108,112	$ 110,274	$ 112,479	$ 114,729	$ 117,023	$ 119,364	$ 121,751	$ 124,186	$ 126,670	3200000	$ 96,000	
$ -	$ -	$ 2,057	$ 2,098	$ 2,140	$ 2,183	$ 2,226	$ 2,271	$ 2,316	$ 2,362	$ 2,410	$ 2,458	$ 2,507	95000	2%	1900
$ -	$ -	$ 5,520	$ 5,631	$ 5,743	$ 5,858	$ 5,975	$ 6,095	$ 6,217	$ 6,341	$ 6,468	$ 6,597	$ 6,729	170000	3%	5100
$ -	$ -	$ 649	$ 662	$ 676	$ 689	$ 703	$ 717	$ 731	$ 746	$ 761	$ 776	$ 792	30000	2%	600
$ -	$ -	$ 1,082	$ 1,104	$ 1,126	$ 1,149	$ 1,172	$ 1,195	$ 1,219	$ 1,243	$ 1,268	$ 1,294	$ 1,319	50000	2%	1000
$ -	$ -	$ 1,624	$ 1,656	$ 1,689	$ 1,723	$ 1,757	$ 1,793	$ 1,828	$ 1,865	$ 1,902	$ 1,940	$ 1,979	75000	2%	1500
$ -	$ -	$ 6,495	$ 6,624	$ 6,757	$ 6,892	$ 7,030	$ 7,171	$ 7,314	$ 7,460	$ 7,609	$ 7,762	$ 7,917	200000	3%	6000
$ -	$ -	$ 4,330	$ 4,416	$ 4,505	$ 4,595	$ 4,687	$ 4,780	$ 4,876	$ 4,973	$ 5,073	$ 5,174	$ 5,278	200000	2%	4000
$ -	$ -	$ 6,495	$ 6,624	$ 6,757	$ 6,892	$ 7,030	$ 7,171	$ 7,314	$ 7,460	$ 7,609	$ 7,762	$ 7,917	200000	3%	6000
$ -	$ -	$ 2,165	$ 2,208	$ 2,252	$ 2,297	$ 2,343	$ 2,390	$ 2,438	$ 2,487	$ 2,536	$ 2,587	$ 2,639	100000	2%	2000
$ -	$ -	$ 1,732	$ 1,767	$ 1,802	$ 1,838	$ 1,875	$ 1,912	$ 1,950	$ 1,989	$ 2,029	$ 2,070	$ 2,111	80000	2%	1600
$ -	$ -	$ 541	$ 552	$ 563	$ 574	$ 586	$ 598	$ 609	$ 622	$ 634	$ 647	$ 660	50000	1%	500
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0	3%	0
$ -	$ -	$ 12,989	$ 13,249	$ 13,514	$ 13,784	$ 14,060	$ 14,341	$ 14,628	$ 14,920	$ 15,219	$ 15,523	$ 15,834	400000	3%	12000
$ -	$ -	$ 8,118	$ 8,281	$ 8,446	$ 8,615	$ 8,787	$ 8,963	$ 9,142	$ 9,325	$ 9,512	$ 9,702	$ 9,896	250000	3%	7500
$ -	$ -	$ 8,118	$ 8,281	$ 8,446	$ 8,615	$ 8,787	$ 8,963	$ 9,142	$ 9,325	$ 9,512	$ 9,702	$ 9,896	250000	3%	7500
$ -	$ -	$ 8,118	$ 8,281	$ 8,446	$ 8,615	$ 8,787	$ 8,963	$ 9,142	$ 9,325	$ 9,512	$ 9,702	$ 9,896	250000	3%	7500
$ -	$ -	$ 162	$ 166	$ 169	$ 172	$ 176	$ 179	$ 183	$ 187	$ 190	$ 194	$ 198	7500	2%	150
$ -	$ -	$ 28,684	$ 29,258	$ 29,843	$ 30,440	$ 31,049	$ 31,670	$ 32,303	$ 32,949	$ 33,608	$ 34,281	$ 34,966	1325000	2%	26500
$ -	$ -	$ 23,814	$ 24,290	$ 24,776	$ 25,271	$ 25,777	$ 26,292	$ 26,818	$ 27,354	$ 27,901	$ 28,459	$ 29,029	1100000	2%	22000
$ -	$ -	$ 3,464	$ 3,533	$ 3,604	$ 3,676	$ 3,749	$ 3,824	$ 3,901	$ 3,979	$ 4,058	$ 4,140	$ 4,222	160000	2%	3200
$ -	$ -	$ 693	$ 707	$ 721	$ 735	$ 750	$ 765	$ 780	$ 796	$ 812	$ 828	$ 844	32000	2%	640
$ -	$ -	$ 15,154	$ 15,457	$ 15,766	$ 16,082	$ 16,403	$ 16,731	$ 17,066	$ 17,407	$ 17,755	$ 18,110	$ 18,473	700000	2%	14000
$ -	$ -	$ 7,577	$ 7,729	$ 7,883	$ 8,041	$ 8,202	$ 8,366	$ 8,533	$ 8,704	$ 8,878	$ 9,055	$ 9,236	350000	2%	7000
$ -	$ -	$ 29,929	$ 30,528	$ 31,138	$ 31,761	$ 32,396	$ 33,044	$ 33,705	$ 34,379	$ 35,067	$ 35,768	$ 36,484	1382500	2%	27650
$ -	$ -	$ 1,388	$ 1,415	$ 1,444	$ 1,472	$ 1,502	$ 1,532	$ 1,563	$ 1,594	$ 1,626	$ 1,658	$ 1,691	64092	2%	1281.839187
$ -	$ -	$ 31,824	$ 32,460	$ 33,109	$ 33,771	$ 34,447	$ 35,136	$ 35,838	$ 36,555	$ 37,286	$ 38,032	$ 38,793	1470000	2%	29400

FIGURE C-12 Analysis of Revenue Requirements (cont.)

C-16

$ -	$ -	$ 7,537,515	$ 7,764,056	$ 7,998,190	$ 8,240,193	$ 8,490,349	$ 8,748,957	$ 9,016,325	$ 9,292,773	$ 9,578,633	$ 9,874,250	$ 10,179,983
$ -	$ -	$ 673,573	$ 698,867	$ 725,143	$ 752,442	$ 780,805	$ 810,272	$ 840,888	$ 872,699	$ 905,751	$ 940,095	$ 975,781
$ -	$ -	$ 576,044	$ 599,316	$ 623,528	$ 648,719	$ 674,927	$ 702,194	$ 730,563	$ 760,077	$ 790,784	$ 822,732	$ 855,971
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ 88,252	$ 90,017	$ 91,818	$ 93,654	$ 95,527	$ 97,438	$ 99,386	$ 101,374	$ 103,402	$ 105,470	$ 107,579
$ -	$ -	$ 3,456	$ 3,596	$ 3,741	$ 3,892	$ 4,050	$ 4,213	$ 4,383	$ 4,560	$ 4,745	$ 4,936	$ 5,136
$ -	$ -	$ 5,821	$ 5,938	$ 6,056	$ 6,177	$ 6,301	$ 6,427	$ 6,555	$ 6,687	$ 6,820	$ 6,957	$ 7,096
$ -	$ -	$ 280,799	$ 292,144	$ 303,946	$ 316,226	$ 329,001	$ 342,293	$ 356,122	$ 370,509	$ 385,478	$ 401,051	$ 417,253
$ -	$ -	$ 77,880	$ 81,026	$ 84,300	$ 87,705	$ 91,249	$ 94,935	$ 98,770	$ 102,761	$ 106,912	$ 111,231	$ 115,725
$ -	$ -	$ 71,694	$ 74,590	$ 77,604	$ 80,739	$ 84,001	$ 87,394	$ 90,925	$ 94,599	$ 98,420	$ 102,397	$ 106,533
$ -	$ -	$ 131,226	$ 136,527	$ 142,043	$ 147,782	$ 153,752	$ 159,964	$ 166,426	$ 173,150	$ 180,145	$ 187,423	$ 194,995
$ -	$ -	$ 3,486,279	$ 3,556,463	$ 3,628,070	$ 3,701,128	$ 3,775,668	$ 3,851,719	$ 3,929,312	$ 4,008,481	$ 4,089,256	$ 4,171,671	$ 4,255,760
$ -	$ -	$ 22,496	$ 23,405	$ 24,350	$ 25,334	$ 26,357	$ 27,422	$ 28,530	$ 29,683	$ 30,882	$ 32,130	$ 33,428
$ -	$ -	$ 3,463,783	$ 3,533,059	$ 3,603,720	$ 3,675,794	$ 3,749,310	$ 3,824,296	$ 3,900,782	$ 3,978,798	$ 4,058,374	$ 4,139,541	$ 4,222,332
$ -	$ -	$ 2,451,674	$ 2,550,721	$ 2,653,771	$ 2,760,983	$ 2,872,527	$ 2,988,577	$ 3,109,315	$ 3,234,932	$ 3,365,623	$ 3,501,594	$ 3,643,058
$ -	$ -	$ 14,622	$ 15,213	$ 15,828	$ 16,467	$ 17,132	$ 17,825	$ 18,545	$ 19,294	$ 20,073	$ 20,884	$ 21,728
$ -	$ -	$ 2,437,052	$ 2,535,508	$ 2,637,943	$ 2,744,516	$ 2,855,394	$ 2,970,752	$ 3,090,771	$ 3,215,638	$ 3,345,549	$ 3,480,710	$ 3,621,330

FIGURE C-13 Analysis of Revenue Requirements (cont.)

C-17

$ -	$ -	$ 645,190	$ 665,861	$ 687,260	$ 709,413	$ 732,349	$ 756,097	$ 780,688	$ 806,153	$ 832,526	$ 859,840	$ 888,131
$ -	$ -	$ 57,730	$ 58,884	$ 60,062	$ 61,263	$ 62,489	$ 63,738	$ 65,013	$ 66,313	$ 67,640	$ 68,992	$ 70,372
$ -	$ -	$ 30,443	$ 31,052	$ 31,673	$ 32,307	$ 32,953	$ 33,612	$ 34,284	$ 34,970	$ 35,669	$ 36,383	$ 37,110
$ -	$ -	$ 27,061	$ 27,602	$ 28,154	$ 28,717	$ 29,291	$ 29,877	$ 30,475	$ 31,084	$ 31,706	$ 32,340	$ 32,987
$ -	$ -	$ 90,203	$ 92,007	$ 93,847	$ 95,724	$ 97,638	$ 99,591	$ 101,583	$ 103,615	$ 105,687	$ 107,801	$ 109,957
$ -	$ -	$ 352	$ 359	$ 366	$ 373	$ 381	$ 388	$ 396	$ 404	$ 412	$ 420	$ 429
$ -	$ -	$ 58,632	$ 59,804	$ 61,000	$ 62,220	$ 63,465	$ 64,734	$ 66,029	$ 67,349	$ 68,696	$ 70,070	$ 71,472
$ -	$ -	$ 7,030	$ 7,314	$ 7,609	$ 7,917	$ 8,237	$ 8,569	$ 8,916	$ 9,276	$ 9,651	$ 10,041	$ 10,446
$ -	$ -	$ 1,953	$ 2,032	$ 2,114	$ 2,199	$ 2,288	$ 2,380	$ 2,477	$ 2,577	$ 2,681	$ 2,789	$ 2,902
$ -	$ -	$ 244,096	$ 253,957	$ 264,217	$ 274,891	$ 285,997	$ 297,551	$ 309,572	$ 322,079	$ 335,091	$ 348,629	$ 362,713
$ -	$ -	$ 762	$ 792	$ 824	$ 858	$ 892	$ 928	$ 966	$ 1,005	$ 1,045	$ 1,088	$ 1,132
$ -	$ -	$ 126,930	$ 132,058	$ 137,393	$ 142,944	$ 148,718	$ 154,727	$ 160,978	$ 167,481	$ 174,247	$ 181,287	$ 188,611
$ -	$ -	$ 1,021,181	$ 1,041,605	$ 1,062,437	$ 1,083,685	$ 1,105,359	$ 1,127,466	$ 1,150,016	$ 1,173,016	$ 1,196,476	$ 1,220,406	$ 1,244,814
$ -	$ -	$ 613,523	$ 625,793	$ 638,309	$ 651,075	$ 664,097	$ 677,378	$ 690,926	$ 704,745	$ 718,839	$ 733,216	$ 747,881
$ -	$ -	$ 90,203	$ 92,007	$ 93,847	$ 95,724	$ 97,638	$ 99,591	$ 101,583	$ 103,615	$ 105,687	$ 107,801	$ 109,957
$ -	$ -	$ 148,596	$ 151,568	$ 154,600	$ 157,692	$ 160,845	$ 164,062	$ 167,344	$ 170,690	$ 174,104	$ 177,586	$ 181,138
$ -	$ -	$ 168,859	$ 172,237	$ 175,681	$ 179,195	$ 182,779	$ 186,434	$ 190,163	$ 193,966	$ 197,846	$ 201,803	$ 205,839
(5,496,465)	(5,270,345)	4,689,648	4,809,217	4,932,220	5,058,766	5,188,970	5,322,951	5,460,831	5,602,739	5,748,806	5,899,168	6,053,967
(12,133,811)	(17,404,157)	(12,714,509)	(7,905,292)	(2,973,072)	2,085,694	7,274,664	12,597,614	18,058,446	23,661,185	29,409,991	35,309,159	41,363,125

FIGURE C-14 Analysis of Revenue Requirements (cont.)

C-18

Electronic Mapping				
ID	**Description**	**Amount**	**Units**	**Remarks**
A	# of OMS/GIS "mappers" updating records (FTEs)	3	FTE's/year	Input
B	% reduction in # of OMS/GIS "mappers" updating records (%)	50%	%	Assumption
C	FTE savings in OMS/GIS mappers with electronic mappring	1.5	FTE's/year	C = A x B
D	$ value of mapper FTE	$ 156,000	$/FTE	Input
E	**$ Savings due to "mapper" labor reduction**	**$ 234,000**	**$/Year**	**E = C x D**
F	# of control room operators	8	FTE's/year	Input
G	% of control room operator time doing hand drawn map updates	20%		Input
H	Total operator FTEs for hand drawn updates	1.6	FTE's/year	H = F x G
I	% reduction in hand drawn updates with electronic mapping	80%		Assumption
J	FTE savings for operators with electronic mapping	1.28	FTE's/year	J = H x I
K	$ Value of operator FTE	$ 260,000	$/FTE	Input
L	**$ Savings due to reduction in hand drawn updates by control room operators**	**$ 332,800**	**$/Year**	**L = J x K**
M	Total Savings	$566,800	$/year	M = E + L

FIGURE C-15 Electronic Mapping

EQUIPMENT CONDITION MONITORING

Distribution Feeders Fewer Feeder Inspections

Item	Description	Units	Amount	Source/Formula
A	Period of major inspections without ECM	Years	5	Input
B	Period of major inspections with ECM	Years	9	Input
C	# hours to do major inspection without ECM	Hours	12	Input
D	# hours to do major inspection with ECM	Hours	12	Input
E	Labor rate ($/hr) of crew members	$/Hr	$125.00	Input
F	Labor cost for inspections without ECM	$/Yr	$300.00	1/A x C x E
G	Labor cost for inspections with ECM	$/Yr	$166.67	1/B x D x E
H	# Distribution Feeders per substation	Feeders	8	Input
I	Labor savings due to fewer inspections	$/Yr/Sub	$1,067	(F - G) x H
J	Total number of substations		100	Input
K	% of substations requiring ecm	%	50%	assumption
L	# of substations requiring ecm		50	J x K
M	**Total Labor savings**	**$/Year**	**$53,333.33**	**I x L**

High Voltage Circuit Breakers

1. Fewer - Internal Inspections and Repairs -

Labor

Item	Description	Units	Amount	Source/Formula
A	Period of major inspections without ECM	Years	4.00	Input
B	Period of major inspections with ECM	Years	8.00	Input
C	# hours to do major inspection without ECM	Hours	18.00	Input
D	# hours to do major inspection with ECM	Hours	18.00	Input
E	Labor rate ($/hr) of crew members	$/Hr	$125.00	Input
F	Labor cost for inspections without ECM	$/Yr	$562.50	1/A x C x E
G	Labor cost for inspections with ECM	$/Yr	$281.25	1/B x D x E
H	Number of HV breakers per substation		2	Input
I	Labor savings due to fewer inspections	$/Yr/Substa	$563	(F - G) x H
J	Number of substations		100	Input
K	% of substations requiring ecm		50%	Assumption
L	Number of substations requiring ECM		50	L = J x K
M	**HV CB: Labor savings due to fewer inspections**	**$/Year**	**$28,125**	**M = I x L**

Material

Item	Description	Units	Amount	Source/Formula
A	Period of major inspections without ECM	Years	4	*Input*
B	Period of major inspections with ECM	Years	8	*Input*
C	Material cost per major inspection without ECM	$	$2,000	*Input*
D	Material cost per major inspection with ECM	$	$2,000	*Input*
E	Material cost for major inspections without ECM	$/Yr	$500	*1/A x C*
F	Material cost for major inspections with ECM	$/Yr	$250	*1/B x D*
G	Number of HV breakers per sub		2	*Input*
H	**Material savings due to fewer inspections**	**$/Yr/substa**	**$500**	***(E - F) x G***
J	Number of substations		100	*Input*
K	% of substations requiring ecm		50%	Assumption
L	Number of substations requiring ECM		50	L = J x K
M	**HV CB: Material savings due to fewer inspections**	**$/Year**	**$25,000**	***M = H x L***

FIGURE C-16 Equipment Condition Monitoring (ECM)

2. Fewer Catastrophic Failures Due to Better Monitoring

Item	Description	Units	Type 1 Sub	Source/Formula
A	Years between catastrophic HV CB failures without ECM	Years	15.00	Input
B	% failures detected early with ECM	%	25%	Assumption
C	Expected # of catastrophic failures per year with ECM	Failure/Yr	0.05	1 / A x (1 - B)
D	Cost to Rebuild/Replace following catastrophic failure	$	$100,000	Input
E	Reduction in repair costs if problem detected early	%	50%	Input assumption
F	Cost to Repair Fault detected while incipient	$	50000	D x (1 - E)
G	Expected Rebuild/Repair cost per breaker without ECM	$	$6,667	1/A x D
H	Expected Rebuild/Repair cost per breaker with ECM	$	$5,833	C x D + (1/A - C) x F
I	Number of HV breakers per sub		2	Input
J	Expected annual savings per substation	$/Yr/sub	$1,667	(G - H) x I
K	Total Number of substations		100	*Input*
L	% of substations requiring ecm		50%	*Input assumption*
M	Number of substations requiring ECM		50	*M = K x L*
N	**Savings in repair/rebuild costs for HV CBs**	**$/Year**	**$83,333.33**	***N = J x M***

HV Breaker ECM - Reduction in Lost Revenue

Item	Description	Units	Type 1 Sub	Source/Formula
A	Years between catastrophic HV CB failures without ECM	Failure/Yr	15.00	*Input*
B	% failures detected early with ECM	%	25%	*Input*
C	Expected # of catastrophic failures per year with ECM	Failure/Yr	0.05	*1/A x (1 - B)*
D	Time to restore customers impacted by HV CB outage	hours	1.00	*Input*
E	Peak load carried by transformers served through the HV CB	MW	10.00	*Computed fom inputs*
F	Load Factor		0.650	*Input*
G	Average load interrupted during failure	kW	6500	*E x F x 1000*
H	Average revenue per kWh sold	$/kWh	0.0600	*Input*
I	Lost revenue due to KWH sales during failure	$/HV CB	7	*G x H*
J	Number of HV breakers per sub		2	*Input*
K	**Lost revenue per year per substation**	**$/Yr/sub**	**$13**	***H x I x J***
L	Number of substations		100	*Input*
M	% of substations requiring ecm		25%	*Input assumption*
N	Number of substations requiring ECM		25	*N = L x M*
O	**Reduction in lost revenue due t HV CB Failures at all substations**	**$/Year**	**$325**	***O = K x N***

HV Breaker ECM - Reduction in Value of Lost Load

Item	Description	Units	Type 1 Sub	Source/Formula
A	Years between catastrophic HV CB failures without ECM	Failure/Yr	15.00	*Input*
B	% failures detected early with ECM	%	25%	*Input*
C	Expected # of catastrophic failures per year with ECM	Failure/Yr	0.05	*1/A x (1 - B)*
D	Time to restore customers impacted by HV CB outage	hours	1.00	*Input*
E	Peak load carried by transformers served through the HV CB	MW	10.00	*Computed fom inputs*
F	Load Factor		0.650	*Input*
G	Average load interrupted during failure	kW	6500	*E x F x 1000*
H	Value of lost load	$/kWh	10.0000	*Input*
I	VOLL due to KWH sales during failure	$/HV CB	1083	*D x (1/A - C) x G*
J	Number of HV breakers per sub		2	*Input*
K	**VOLL per year per substation**	**$/Yr/sub**	**$2,167**	***H x I x J***
L	Number of substations		100	*Input*
	% of substations requiring ecm		25%	
	Number of substations requiring ECM		25	
M	**Reduction in lost revenue due t HV CB Failures at all substations**	**$/Year**	**$54,166.67**	***J x K***

FIGURE C-17 Equipment Condition Monitoring (cont.)

SAIDI Improvement

Item	Description	Units	Type 1 Sub	Source/Formula
A	Years between catastrophic HV CB failures without ECM	Failure/Yr	15.00	*Input*
B	% failures detected early with ECM	%	25%	*Input*
C	Expected # of catastrophic failures per year with ECM	Failure/Yr	0.05	*1/A x (1 - B)*
D	Time to restore customers impacted by HV CB outage	hours	1.00	*Input*
E	Average number of customers affacted by the HV CB failure	# custs/fdr	1000	Input
G	Expected number of outages per year without CBM		0.067	*1/A*
H	Customer outage minutes without HV CB CBM		4000	
I	Customer outage minutes with CBM		3000	
J	Customer outage minutes savings per CB		1000	*H - I*
K	Number of HV CB per sub		2	
L	Number of substations		100	*Input*
M	% of substations requiring ecm		25%	
N	Number of substations requiring ECM		25	
O	Total customer outage minutes saved for entire system		50000	*J x K x L*
P	**Percent reduction of system SAIDI**		**0.06%**	M / (tot # custs x SAIDI)
Q	**Percent reduction of system SAIFI**		**0.06%**	

Transformers

1. Fewer - Internal Inspections and Repairs

Item	Description	Units	Amount	Source/Formula
A	Period of major inspections without ECM	Years	10	Input
B	Period of major inspections with ECM	Years	15	Assumption
C	# hours to do major inspection without ECM	Hours	24	Input
D	# hours to do major inspection with ECM	Hours	24	Input
E	Labor rate ($/hr) of crew members	$/Hr	$150.00	Input
F	Labor cost for inspections without ECM	$/Yr	$360.00	1/A x C x E
G	Labor cost for inspections with ECM	$/Yr	$240.00	1/B x D x E
H	Number of transformers per substation		2	Input
I	**Labor savings due to fewer inspections**	**$/Yr/sub**	**$240.00**	**H x (F - G)**
J	Total Number of substations		100	
	% of substations requiring ecm		25%	
	Number of substations requiring ECM		25	
K	**Sub Transformers: Labor savings due to fewer inspections**	**$/Year**	**$6,000.00**	**I x J**

Materials

Item	Description	Units	Amount	Source/Formula
A	Period of major inspections without ECM	Years	10	Input
B	Period of major inspections with ECM	Years	15	Input
C	Material cost per major inspection without ECM	$	$100	Input
D	Material cost per major inspection with ECM	$	$67	Input
E	Material cost for major inspections without ECM	$/Yr	$100	1/A x C
F	Material cost for major inspections with ECM	$/Yr	$67	1/B x D
G	Number of transformers per substation		2	Input
H	**Material savings due to fewer inspections**	**$/Yr/Trf**	**$66.67**	**G x (E - F)**
I	Number of substations		100	
	% of substations requiring ecm		25%	
	Number of substations requiring ECM		25	
J	**Sub Transformers: Labor savings due to fewer inspections**	**$/Year**	**$1,666.67**	**I x J**

FIGURE C-18 Equipment Condition Monitoring (cont.)

2. Fewer Catastrophic Failures Due to Better Monitoring

Item	Description	Units	Type 1 Sub	Source/Formula
A	Years between catastrophic SS trf failures without ECM	Failure/Yr	15.00	Input
B	% failures detected early with ECM	%	25%	Assumption
C	Expected # of failures per year with ECM	Failure/Yr	0.05	1/A x (1 - B)
D	Cost to Rebuild/Replace following failure	$	$ 500,000	Input
E	Reduction in repair costs if problem detected early	%	50%	Assumption
F	Cost to Repair Fault detected while incipient	$	$ 250,000	D x (1 - E)
G	Expected Rebuild/Repair cost per trf without ECM	$	$ 33,333	A x D
H	Expected Rebuild/Repair cost per trf with ECM	$	$ 29,167	C x D + (A - C) x F
I	Number of transformers per substation		2	Input
J	**Expected annual savings per substation**	**$/Yr**	**$8,333**	**(G - H) x I**
K	Number of substations		100	*Input*
	% of substations requiring ecm		25%	
	Number of substations requiring ECM		25	
L	**Savings in repair/rebuild costs for substation transformers**	**$/Year**	**$208,333**	***J x K***

Reduction of Lost Revenue Due to Fewer Catastrophic Failures

Item	Description	Units	Amount	Source/Formula
A	Years between transformer failures without ECM	Failure/Yr	15.00	Input
B	% failures detected early with ECM	%	25%	Assumption
C	Expected # of catastrophic failures per year with ECM	Failure/Yr	0.05	1/A x (1 - B)
D	Time to restore customers impacted by transformer outage	hours	2.00	Input
E	Peak load carried by substation transformer	MW	10.00	Input
F	Load Factor		0.650	Input
G	Average load interrupted during failure	kW	6500.0	E x F x 1000
H	Average revenue per kWh sold	$/kWh	0.06	Revenue - cost
I	Lost revenue due to KWH sales during failure	kWh	216.67	D x (1/A - C) x G
J	Number of transformers per substation		2	Input
K	Lost revenue per year per substation	$/Yr	$26	H x I x J
L	Number of substations		100	*Input*
	% of substations requiring ecm		25%	
	Number of substations requiring ECM		25	
M	**Reduction in lost revenue due to trf failures at all substations**	**$/Year**	**$650**	***K x L***

FIGURE C-19 Equipment Condition Monitoring (cont.)

Reduction in Unserved Energy (customer outage cost)

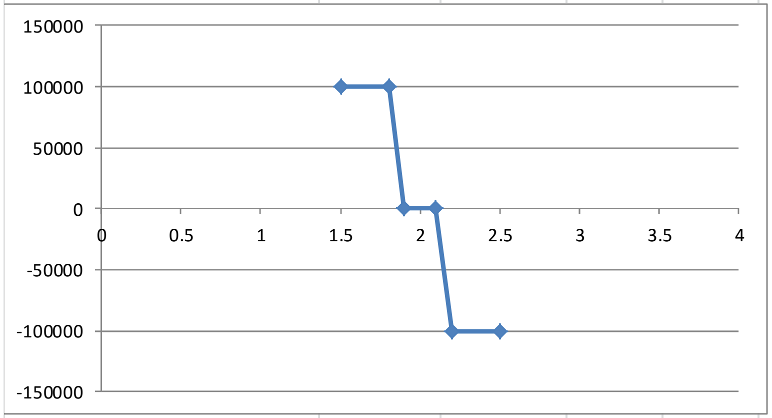
Item	Description	Units	Amount	Source/Formula
A	Years between transformer failures without ECM	Failure/Yr	15.00	Input
B	% failures detected early with ECM	%	25%	Assumption
C	Expected # of catastrophic failures per year with ECM	Failure/Yr	0.05	1/A x (1 - B)
D	Time to restore customers impacted by transformer outage	hours	2.00	Input
E	Peak load carried by substation transformer	MW	10.00	Input
F	Load Factor		0.650	Input
G	Average load interrupted during failure	kW	6500.0	E x F x 1000
H	Value of lost load	$/kWh	10.0000	*Input*
I	VOLL due to KWH sales during failure	kWh	216.67	D x (1/A - C) x G
J	Number of transformers per substation		2	Input
K	VOLL per year per substation	$/Yr	$4,333	H x I x J
L	Number of substations		100	*Input*
	% of substations requiring ecm		25%	
	Number of substations requiring ECM		25	
M	**VOLL due to trf failures at all substations**	**$/Year**	**$108,333**	***K x L***

SAIDI/SAIFI Improvement

Item	Description	Units	Amount	Source/Formula
A	Years between catastrophic transformer failures without ECM	Failure/Yr	15.00	*Input*
B	% failures detected early with ECM	%	25%	*Input*
C	Expected # of catastrophic failures per year with ECM	Failure/Yr	0.05	*1/A x (1 - B)*
D	Time to restore customers impacted by transformer outage	hours	2.00	*Input*
E	Average number of customers affacted by the transformer failu	# custs/fdr	1000	Input
F	Expected number of outages per year without CBM		0.067	*1/A*
G	Customer outage minutes without transformer CBM		8000	*D x E x F x 60*
H	Customer outage minutes with CBM		6000	*C x D x E x 60*
I	Customer outage minutes savings per transformer		2000	*H - I*
J	Number of transformer per sub		2	
	% of substations requiring ecm		25%	
K	Number of substations		25	*Input*
L	Total customer outage minutes saved for entire system		100000	*J x K x L*
M	**Percent reduction of system SAIDI**		**0.13%**	M / (tot # custs x SAIDI)
N	**Percent reduction of system SAIFI**		**0.13%**	

FIGURE C-20 Equipment Condition Monitoring (cont.)

Inputs for defining PBR Characteristic for SAIFI			
System SAIFI (last year)	2	1.5	100000
Neutral zone	5%	1.8	100000
Maximum penalty/reward zone	10%	1.9	0
Maximum Reward	100000	2.1	0
Maximum penalty	-100000	2.2	-100000
		2.5	-100000
Actual value	1.90		
Penalty/Reward (calculated)	$ -		



Inputs for defining PBR Characteristic for SAIDI			
System SAIDI (last year)	100	75	100000
Neutral zone	5%	90	100000
Maximum penalty/reward zone	10%	95	0
Maximum Reward	10000000%	105	0
Maximum penalty	-10000000%	110	-100000
		125	-100000
Actual value	90.92		
Penalty/Reward (calculated)	$ 81,531		

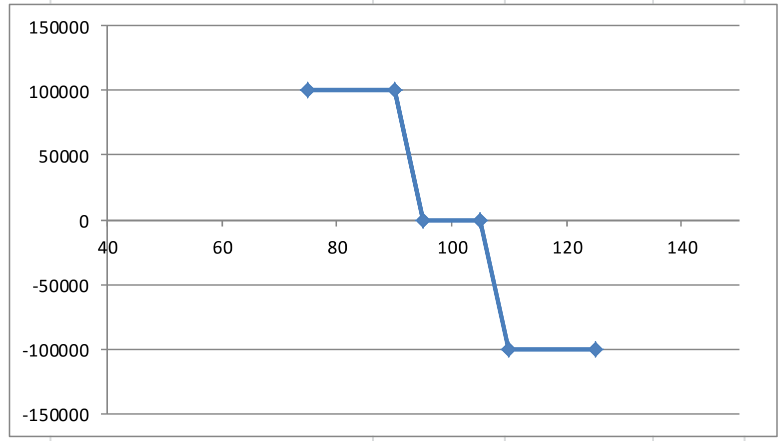


FIGURE C-21 PBR Calculations

C-25

Inputs for defining PBR Characteristic		**Slope**		
Maximum reward	100000	20000	80	100000
Level at which reward kicks in	95		80.88	100000
Level at which max reward achiev	90		81.76968	100000
Maximum penalty	-100000	20000	82.66915	100000
Level at which penaly kicks in	105		83.57851	100000
Level at which max penalty is rece	110		84.49787	100000
			85.42735	100000
			86.36705	100000
			87.31709	100000
			88.27757	100000
			89.24863	100000
			90.23036	95392.77
			91.2229	75542.09
			92.22635	55473.05
			93.24084	35183.25
			94.26649	14670.27
			95.30342	0
			96.35176	0
			97.41162	0
			98.48315	0
			99.56647	0
			100.6617	0
			101.769	0
			102.8884	0
			104.0202	0
			105.1644	-3288.62
			106.3212	-26424.8
			107.4908	-49815.5
			108.6732	-73463.4
			109.8686	-97371.5
			111.0771	-100000
			112.299	-100000
			113.5343	-100000
			114.7831	-100000
			116.0458	-100000
			117.3223	-100000
			118.6128	-100000
			119.9175	-100000
			121.2366	-100000
			122.5702	-100000
			123.9185	-100000
			125.2816	-100000
			126.6597	-100000
			128.053	-100000
			129.4616	-100000

FIGURE C-22 PBR Calculations (cont.)

FLISR App Software & Studies					
Central		Decentral			
One license	200000	Licenses	75000	25K per substation	
Engg studies	20000	Studies	20000	2K per feeder	
	220000		95000		
FLISR Field equipment					
Central		**Decentral**			
DA switch	50000		50000		
DA switch controller	1000		2000		
Communication interface	1500		1500		
Number of switches	25		25		
		Application proc	45000	One per substation	
Total	**1312500**	**Total**	**1382500**		

VVO App Software & Studies					
Central		Decentral			
One license	200000	Licenses	150000	50K per substation	
Engg studies	20000	Studies	20000	2K per feeder	
	220000		170000		
VVO Field equipment					
Central		**Decentral**			
Switched cap bank	4000	Switched cap ban	4000		
Cap bank controller	1000	Cap bank controll	2000		
Communication interface	1500	Communication i	1500		
# Cap banks	9	# Cap banks	9		
Vreg	25000	Vreg	25000		
#vregs	50	# Vregs	50		
Controller for vreg	1000	Controller for vre	2000		
LTC Vreg	2500		2500		
		Application proc	45000	One per substation	
Total	**$ 1,430,546**	**Total**	**$ 1,534,092**		
Cap banks	$ 55,546		$ 64,092		
Vregs	$ 1,375,000		$ 1,470,000		
	$ 1,430,546		$ 1,534,092		

FIGURE C-23 Cost Worksheet

GIS Interfaces	
Combined-Homegrown	400000
Combined-standard ESB	300000
Separate-Homegrown	500000
Separate-Standard ESB	400000

AMI Interfaces	
Combined-Homegrown	250000
Combined-Fiorano	150000
Separate-Homegrown	300000
Separate-Fiorano	200000

Work Mgmt Interfaces	
Combined-Homegrown	250000
Combined-Fiorano	150000
Separate-Homegrown	300000
Separate-Fiorano	200000

SCADA Interfaces	
Combined-Homegrown	250000
Combined-Fiorano	150000
Separate-Homegrown	300000
Separate-Fiorano	200000

Cost estimate for Dynamic Asset Rating	
DAR software and software configuration	$ 50,000
# of substations at which DAR is implemented	3
Sensor cost per substation	$ 10,000
Total cost of sensors	$ 30,000
Total initial Cost	$ 80,000
Maintenance cost for DAR function	
O&M for DAR software	$ 1,000
O&M for DAR sensors	#REF!

FIGURE C-24 Cost Worksheet (cont.)

Convert Substations to IEC61850		
Data concentrator ($/sub)		$/Sub
Replace/upgrade legacy IEDs	$ 5,000	$/device
Number of feeders per sub trf	4	
Number of transformers per sub	2	
Total number of devices per sub	10	
Labor cost	$ 12,000	
Total to convert sub to IEC 61850	**$ 62,000**	
Labor to convert to IEC 61850 (Hours/device)	8	Hours
Add all new data concentrators and networks	**Purch and install**	O&M
Material per sub	$ 50,000	
Labor per sub	$ 3,000	
Total cost per sub for DC	$ 53,000	
Total number of subs	$ 100	
% of subs being automated	25%	
Number of subs to automate	25	
Total for Data Concentrators	**$ 1,325,000**	**2%**
Add new IEDs for protection and SCADA		
Cost of one digital relay	$ 5,000	
Labor per sub	$ 500	
Total cost to add new relay ($/feeder)	$ 5,500	
Total number of feeders	$ 800	
% of feeders being automated	25%	
Number of feeders to automate	200	
Total for new digital relay IEDs	**$ 1,100,000**	**2%**

FIGURE C-25 Cost Worksheet (cont.)

Cost for digital relay	2000	2%
Install, Wiring, test	1500	
Total for digital relay	**3500**	**2%**
Add new sensor for trf CBM		
Sensor cost	3500	2%
Install wire test	1000	
Total for Trf CBM sensor	**4500**	**2%**
Add new sensor for HV CB CBM		
Sensor cost	2000	2%
Install wire test	1000	
Total for HV CB CBM	**3000**	**2%**
Convert digital substation to IEC61850		
Cost to add IEC61850 comm module to existing relay	$ 500	
IEC 61850 configuration cost	$ 500	
Total number of feeders	800	
% of feeders to convert to IEC 61850	20%	
Total number of feeders to convert	160	
Total cost for conversion	**$ 160,000**	**2%**

FIGURE C-26 Cost Worksheet (cont.)

Condition-based Maintenance Expenditures		
	Serial/Legacy	**IEC 61850**
Cost of new transformer monitor IED	5000	5500
Cost of new on-line gas monitor IED for transformer	8000	8500
Total number of substations	100	100
% of substations requiring ECM	50%	50%
# of Transformers	50	50
Total cost	**650000**	**700000**
Maintenance %	**3%**	**2.00%**
IEC 61850 used?		**Yes**
Selected cost	**Cost**	**700000**
	O&M	**2%**
	Serial/Legacy	**IEC 61850**
Cost of new CB monitor for HV CB CBM (serial)	$ 3,000	$ 3,500
# of HV CBs per substation	2	2
Total number of substations	100	100
% of substations requiring ECM	50%	50%
# of substations requiring ECM	50	50
Total # of HV CBs requiring ECM	100	100
Total cost for sensors for HV CB CBM	**$ 300,000**	**$ 350,000**
O&M Percentage	3%	2%
Annual O&M cost for HV CB sensors	**$ 9,000**	**$ 7,000**
# of HV CBs	50	50
Total cost for HV CBs	$ 150,000	$ 175,000
O&M	3%	2%
IEC 61850 used?		**Yes**
Selected cost	**Cost**	**175000**
	O&M	**2%**

FIGURE C-27 Cost Worksheet (cont.)

Switching Order Management (SOM) Application Function

The DMS SOM function generates an optimal switching plan to restore service to customers that are downstream of a faulted feeder section. The SOM function can be especially valuable to VECO due to the high peak load and load factor on VECO feeders that make it difficult to restore service to downstream customers while repairs are being made without overloading available backup sources. Without SOM, a manual analysis of possible switching strategies is needed before the actual switching is performed. This can be time consuming for VECOs heavily loaded feeders. With SOM, switching alternatives can be quickly evaluated using on-line power flow analysis. Note that SOM considers all possible switching actions, including manual switching. As a result the benefits apply to all feeders (Not just feeders with DA switches).

1. SOM function provides the most benefit faults that are close to the head-end of the feeder. For faults that are near the end of the feeder, only a small amount of load needs to be transferred, so its easier.
2. Assume that when switch plan is needed, SOM saves 10 minutes (control variable adjustable between 5 and 15 minutes) versus manual analysis
3. Assume switching plan is needed if fault is in the first x% of the feeder (x is a control variable). Therefore, savings apply to x% of the faults, and benefit (1-x%) of the customers
4. Total customer outage minutes = SAIDI x tot cust
5. Savings per event due to SOM: (10 minute savings) (applies to x% of faults) (for 1-x% of customers)
6. Savings (COM) = SAIFI * (x%)*[(1-x%)*cust per feeder]*(10 minutes)
7. Total COM = SAIDI * Tot Cust
8. % reduction of SAIDI = [SAIFI * x%(1-x%) * (cust per feeder)*10] / [SAIDI * Tot cust]

ID	Item	Value	Source	Comment
A	Average number of customers per feeder	1,000	*Input*	
B	Total number of customers	800,000	*input*	
C	Starting SAIFI	2	*Input*	
D	Starting SAIDI	100	*input*	
E	% of faults that require SOM analysis	50%	*SOM analysis required for faults in the first half of the feeder*	
F	Expected time savings with SOM (minutes)	5.00	*Control variable - insert value between 5% and 15%*	
G	Total customer outage minutes	80,000,000	*SAIDI x Tot # of customers*	
H	Customer outage minutes saved with SOM	2,500.00	*COM savings per feeder*	
ID	Number of feeders	800	*# of customers/# cust per feeder*	
J	Total COM savings (all feeders)	2,000,000	*# feeders x savings per feeder*	
K	**% improvement in system SAIDI**	**2.50%**		
L	**% improvement in system SAIFI**	**0**	***No SAIFI improvement***	

Realizeable Labor Savings from Switch order management

ID	Item	Value	Units	Remarks
A	Time to build switching order without SOM	60	*minutes*	Input from UTILCO
B	Time to build switching order with SOM	10	*minutes*	assumption
C	Time savings by using SOM (minutes per event)	50	*minute/event*	C = A - B
D	Number of events per year	800	*events per year*	D = SAIFI x # Feeders x # events that require SOM analysis
E	Total time savings for system operators	666.67	*hours/year*	E = C x D
F	Hourly rate for system operators	125.00	*$/hour*	Input from UTILCO
G	**Total annual savings for system operators**	**$ 83,333**	***$/Year***	**G = E x F**
H				
ID				
J				
K				
L				

FIGURE C-28 Switch Order Management

C-32

FLISR Reliability Improvement Using automatic load break switches (assuming feeders are loaded to 50% or less of capacity and there is always a backup source at the end of the feeder)									
If load break switches are used to implement FLISR, then all faults will initially be cleared by the substation circuit breaker. It is assumed that the CB will trip and reclose several times before locking out, at which point FLISR operation will be triggered. After the CB locks out, FLISR will locate and isolate the faulted feeder segment. Once the fault is isolated, FLISR will (in less than 1 minute) restore as many customers as possible without overloading backup feeders. Since the feeders in this case are loaded to less than 50% of capacity, upstream and downstream restoration are never blocked due to loading constraints. The reliability improvement will depend on the quantity of DA switches installed. Formulas for calculating the reliability benefits are shown below.									
A	Number of normally closed DA switches per feeder	2	*Control variable*	*"N" switches means that the feeder is divided into 1/N equal parts*					
B	Feeder SAIFI without DA	3.08	*Input*	*This is the system SAIFI value for an average feeder, which is the number of outages experienced by the "average" customer*					
C	% reduction in feeder SAIFI with DA switches	67%	*C = A / (A + 1)*	*Assumes you can always do downstream restoration*					
D	Feeder SAIFI with DA	1.03	*D = B * (1 - C)*	*This is SAIFI for this feeder after DA is implemented with the given number of switches*					
E	Reduction of feeder SAIFI with DA	2.05	*E=B - D*	*Simple calculation*					
F	Total number of customers for the entire system	300,000	*Input*	*Input from UTILCO - replace with actual number of customers*					
G	Number of customers on the one DA feeder	1,500	*Assumption*	*Replace with average number of customers per feeder*					
H	Impact on System SAIFI by automating 1 feeder	-0.010	*H = E * G / F*	*This is the amount system SAIFI is reduced by automating 1 feeder*					
I	System SAIFI if one feeder is automated	3.070	*I = B + H*	*This is system SAIFI after one feeder is automated with given number of switches*					
J	Number of similar feeders being automated	30	*Control variable*	*Assume this number of similar feeders will be automated*					
K	Change in System SAIFI if specified # feeders automated	-0.31	*K = J x H*						
L	System SAIFI if specified number of feeders is auto	2.77	*L = B + K*	*This is system SAIFI after automating specified number of feeders*					
O	Change in System SAIFI if # avg feeders automated	0.31							
P	Percentage improvement in SAIFI	10.00%			3.85				

FIGURE C-29 FLISR Worksheet

C-33

Repeat FLISR Reliability Improvement Calculations above, assuming FLISR done on worst performing feeders whose feeder SAIFI is 25% worse (more) than average				
Calculations are completely the same as above, but feeder SAIFI for the automated feeders is 25% worse than the average feeder (3.08 x (1+ 25%)) = 3.85				
A	Number of normally closed DA switches per feeder	2	*Control variable*	*"N" switches means that the feeder is divided into 1/N equal parts*
B	% difference of worst performing feeders	25%	*Assumption*	*Worst performing feeders have feeder SAIFI that is XX% higher than system SAIFI*
C	Feeder SAIFI for average feeder	3.08	*Input*	*Equal to system SAIFI*
D	Feeder SAIFI without DA	3.85	*D = C x (1 +B)*	*This is the system SAIFI value for the worst performing feeders*
E	% reduction in feeder SAIFI with DA switches	67%	*E = A / (A + 1)*	*Assumes you can always do downstream restoration*
F	SAIFI for worst performing feeders with DA	1.28	*F = D * (1 - E)*	*This is SAIFI for this feeder after DA is implemented with the given number of switches*
G	Reduction of SAIFI on worst performing feeders with DA	2.57	*G = D - F*	*Simple calculation*
H	Total number of customers for the entire system	300,000	*Input*	*Input from UTILCO - replace with actual number of customers*
I	Number of customers on the one DA feeder	1,500	*Assumption*	*Replace with average number of customers per feeder*
J	Impact on System SAIFI by automating 1 feeder	-0.013	*J = G * I /H*	*This is the amount system SAIFI is reduced by automating 1 feeder*
K	System SAIFI if one feeder is automated	3.067	*K = C + J*	*This is system SAIFI after one feeder is automated with given number of switches*
L	Number of similar feeders being automated	30	*Control variable*	*Assume this number of similar feeders will be automated*
M	Change in System SAIFI if specified # feeders automated	-0.39	*M = J x L*	
N	System SAIFI if specified number of feeders is auto	2.70	*N = C + M*	*This is system SAIFI after automating specified number of worst performing feeders*
O	Change in System SAIFI if # worst perf feeders automated	-0.39	*C + N*	
P	% change in system SAIFI	-13%	*O / C*	
	Costs	Qty	Unit cost	
	DA Switches	25	$ 50,000	
	Other FLISR Costs	10	$ 20,000	
			Total Cost	

FIGURE C-30 FLISR Worksheet (cont.)

C-34

SAIFI Improvement with DA

Scenario 3: Feeders are very heavily loaded, so some load transfers will be blocked, thus reducing the amount of SAIFI improvement

ID	Item	Value	Source	Comment
A	Peak load on feeders (% of rating)	60.00%	*Input*	*Peak feeder load as a percentage of rating - Input value from UTILCO*
B	Load Factor	0.650	*Input*	*Assumption*
C	Average load on feeder	39.00%	*A x B*	*Calculated value*
D	% of time **downstream** restoration will be permitted	61.00%	*1 - C*	*Calculated value - % of time downstream restoration is permitted*
	Apply a derating factor to account for downstream load transfers that are blocked due to heavy load			
E	Number of normally closed DA switches per feeder	2	*Control variable*	*"N" switches means that the feeder is divided into 1/N equal parts*
F	Feeder SAIFI for average feeder	2	*UTILCO Input*	*This is system SAIFI reported by UTILCO*
G	% SAIFI difference of worst performing feeders	10%	*Assumption*	*Worst performing feeders have feeder SAIFI that is 5% higher than system SAIFI*
I	Feeder SAIFI for "worst performing" feeder (no DA)	2.2	*F x (1 +G)*	*This is the system SAIFI value for the worst performing feeders*
J	% reduction in feeder SAIFI with DA switches	13.0%	*E / (2 x (E + 1)) x (1*	*% reduction includes the derating factor due to blocked downstream load transfers*
K	SAIFI for worst performing feeders with DA	1.91	*I x (1 - J)*	*This is SAIFI for this feeder after DA is implemented with the given number of switches*
L	Reduction of SAIFI on worst performing feeders with DA	0.29	*I - K*	*Simple calculation*
M	Total number of customers for the entire system	800000	*Input*	*Input from UTILCO*
N	Number of customers on the one DA feeder	1000	*Input*	*Replace with average number of customers per feeder*
O	Impact on System SAIFI by automating 1 worst performing	-0.0003575	*L x N / M*	*This is the amount system SAIFI is reduced by automating 1 worst-performing feeder*
P	System SAIFI if one feeder is automated	2.00	*F + O*	*This is system SAIFI after one feeder is automated with given number of switches*
Q	Number of similar feeders being automated	50	*Control variable*	*Assume this number of similar feeders will be automated*
R	Change in System SAIFI if specified # feeders automated	-0.02	*O x Q*	
S	System SAIFI if specified number of feeders is auto	1.98	*F + R*	*This is system SAIFI after automating specified number of worst performing feeders*
T	% change in system SAIFI	0.9%	*-R / F*	
U	Benefit derating factor (rules based approach only)	0.0%	*Assumption applies to rule based solutions (not model driven)*	
V	% reduction of SAIFI with derating factor	0.9%	*T x (1-U)*	
W	Reduction in Feeder SAIFI due to switch order manageme	0.0%		
X	Reduction in Feeder SAIFI due to dynamic equipment ratir	1.44%		
Y	Reduction in Feeder SAIFI due to adaptive protection (fus	2.4%		
Z	Reduction in Feeder SAIFI due to HV CB CBM	0.06%	From CBM Module	
AA	Reduction in Feeder SAIFI due to Substation transformer C	0.13%		
AB	**Adjusted SAIFI**	**1.90**	**F x (1-sum(W through Y)**	

FIGURE C-31 FLISR Worksheet (cont.)

C-35

SAIDI Improvement: SAIDI improvement is calculated in a similar manner - percent improvement (reduction) in System SAIDI will be slightly higher than SAIFI improvement because restoration time for damaged section will be shorter because only need to patrol portion of the feeder and for restoration activities

A	System SAIDI (minutes)	100		*Input - average outage time per year for typical customer*
B	% difference of worst performing feeders	10%	*Assumption*	
C	Feeder SAIDI for one of worst performing feeders	110	A x (1 + B)	*10% worse that average (system SAIDI)*
D	Number of DA switches	2	Control variable	
E	Feeder SAIDI improvement due to DA switching	13.0%		*Same as SAIFI improvement*
F	Percent of total restoration time for patrol	40.00%	*calculate from UTILCO Figures*	
G	Reduction in Feeder SAIDI due to reduce patrol time	26.7%	*F x D / (D + 1)*	*Additional SAIDI savings attributable to shorter patrol time for damaged section*
		2.50%		
H	Total reduction in feeder SAIDI due to DA & Patrol time	39.7%	*E + G*	
I	SAIDI for worst performing feeders with DA	66.37	*C x (1 - H)*	*% reduction of system SAIDI on one of worst performing feeders with given number of switches*
J	Reduction of SAIDI on worst performing feeders with DA	43.63	*I - C*	
K	Total number of customers for the entire system	800000	*Input from UTILCO*	
L	Number of customers on the one DA feeder	1000	*Input from UTILCO*	
M	Impact on System SAIDI by automating 1 worst performing	0.055	*J x L / J*	
N	System SAIDI if one feeder is automated	99.945	*A - M*	
O	Number of similar feeders being automated	50	*Control variable*	
P	Change in System SAIDI if specified # feeders automated	2.73	*M x O*	
Q	System SAIDI if specified number of feeders is auto	97.27	*A + P*	
R	Change in System SAIDI if # worst perf feeders automated	2.73	*P*	
S	% change in system SAIDI	2.7%	*R / A*	
T	SAIDI before adjustments	**97.27**		
U	Benefit derating factor (rules based approach only - not m	0.0%	*Assumption*	
V	**Adjusted SAIDI Reduction for rule based**	**97.27**	***S x (1-T)***	
W	Reduction in Feeder SAIDI due to switch order manageme	2.50%	**From SOM**	
X	Reduction in Feeder SAIDI due to dynamic equipment ratii	1.44%	**From DER module**	
Y	Reduction in Feeder SAIDI due to adaptive protection (fus	2.40%	**From adaptive relaying module**	
X	Reduction in Feeder SAIDI due to HV CB CBM	0.06%	**From CBM Module**	
Y	Reduction in Feeder SAIDI due to Substation transformer (	0.13%		
Z	**Final Adjusted SAIDI**	**90.92**	**V x (1-sum(W through Y)**	

FIGURE C-32 FLISR Worksheet (cont.)

C-36

Value of Lost Load (Customer outage cost savings)

Faster service restoration (getting the lights back on sooner) will result in the reduction of customer outage (lost load) costs

ID	Item	Value	Source	Comment		
A	Peak load on one feeder (MW)	10	*Input*			(outage min before - outage min after)x average load /60
B	Load Factor	65.00%	*Input*			Outage minutes before = SAIDI (before)
C	Average load on one feeder (MW)	6.5	*A x B*			Outage minutes after = SAIDI (after)
D	Number of feeders with FLISR	50.00	*Input*			average load = system peak load * load factor
E	Average system load (MW)	325.00	*C x D*			
F	System SAIDI before DA	100.00	*Input*			
G	System SAIDI with DA	90.92	*C x F / 60*			
H	Reduction of system SAIDI with DA (minutes)	9.08	*F - G*		0	
I	Reduction in lost MWh sold	49.16	*H / 60 x E*			
J	Value of lost load	$ 10,000	*$/MWH*			
K	**Reduction in lost revenue from kWh sales ($/year)**	**$ 491,648**	***I x J***			

Reduction of lost kWh sales

Faster service restoration (getting the lights back on sooner) will result in increased kWh sales, or conversely, the reduction of kWh sales that are lost during the outage

ID	Item	Value	Source	Comment
A	Peak load on one feeder (MW)	10	*Input*	
B	Load Factor	65.00%	*Input*	
C	Average load on one feeder (MW)	6.5	*A x B*	
D	Number of feeders with FLISR	50.00	*Input*	
E	Average system load (MW)	325.00	*C x D*	
F	System SAIDI before DA	100.00	*Input*	
G	Adjusted System SAIDI with DA	90.92	*C x F / 60*	
H	Reduction of system SAIDI with DA (minutes)	9.08	*F - G*	
I	Reduction in lost MWh sold	49.16	*H / 60 x E*	
J	Profit per kWh sold ($)	$ 0.06	*Assumption*	
K	**Reduction in lost revenue from kWh sales ($/Year)**	**$ 2,949.89**	***I x J***	

Labor Savings by Adding DA To worst Performing Feeders

Patrol time will be reduced by xx percent with automatic isolation (xx is the proportion factor based on # feeders)

Isolation time will be reduced because switch order management program reduces the time to develop switching strategy

ID	Item	Value	Source	Comment
A	Total outage time per year on worst performing feeders w	110.00	*Calculated above*	*Feeder SAIDI for worst performing feeders with no DA*
B	Portion of restoration time for patrol without DA	40.00%	*Calculated using UTILCO input*	
C	Patrol time on worst performing feeders without DA (min	44.00	*A x B*	
D	Number of DA switches per worst performing feeders	2	*Control variable*	
E	Reduction of patrol time with DA	14.67	*C x (1 - D/(D+1))*	
F	Annual number of events per worst performing feeder	2.20	*SAIFI (1 + worst performing factor (default is 10%))*	
G	Total crew time savings per worst performing feeder (min	32.27	*E x F*	
H	Total crew minute savings for all worst performing feeder	1613	*# DA Feeders x G*	
I	Hourly rate (crew + labor)	$ 200.00	*Assumption*	
J	**Total labor savings due to patrol time ($/Yr)**	**$ 5,377.78**	**H/60 x I**	

FIGURE C-33 FLISR Worksheet (cont.)

C-37

KVAR Required to Raise Distribution Primary Power Factor To Target PF				
ID	**Description**	**Amount**	**Units**	**Remarks**
A	Peak load per feeder	10000		Input
B	Number of feeders	10		Input
C	Peak Load on feeders being automated	100.00	MW	A x B / 1000
D	Average Distribution Power Factor	0.982		Input
E	Target Power Factor	0.990		Control variable
F	MVAR required to raise PF to target	5.127	MVAR	Dx{tan(acos(D)) - tan(acos(E))
G	**Number of 600kVAR banks required**	**9**		**F / 600**

MWH Loss Reduction				
ID	**Description**	**Amount**	**Units**	**Remarks**
A	Distribution Losses at Peak Load	6.250%	%	Input
B	Average Distribution Power Factor	98.2%		Input
C	Target Power Factor	99%		Controlled variable
D	Peak Load on Distribution System	100.0	MW	# Feeders x peak load
E	MW loss reduction by improving distribution power factor to target value	0.104	MW	D x A x (1 - B^2 / C^2)
F	Load Factor	65.000%		Input
G	Loss Factor	0.457		.15 x F + .85 * F^2
H	Average loss reduction	0.0474	MW	E x G
I	Total MWH Reduction	415	MWH	H x 8760
J	Energy cost per kilowatt-hour	0.160	$/kWh	Based on marginal energy source
K	Benefit due to electrical loss reduction	66,470	$/ Yr	I x J x 1000
L	Derating factor for rule-based solution	0%		Assumption (should be between 5% and 15%)
M	**Adjusted benefit**	**66,470**	**$/Yr**	**K x (1 - L)**

Distribution Primary Capacity Released By Improving Power Factor At Peak Load				
ID	**Description**	**Amount**	**Units**	**Remarks**
A	Peak load on automated distribution feeders	100.00	MW	# Feeders x peak load
B	Dist Primary Power Factor at Peak	0.982		Input
C	Target Dist Primary Power Factor	0.990		Control variable
D	Capacity Released in Distribution Primary Due to Improved Power Factor	0.8	MW	A x (1/B - 1/C)
E	Value of 1 megawatt peak load	$ 80,000	$/MW/Yr	Based on marginal power source
F	Savings	$ 67,989	#/Yr	D x E
G	Derating factor for rule-based (decentralized) solution	10%		Assumption (should be between 5% and 15%)
H	**Adjusted benefit**	**61,190**	**$/Yr**	**F x (1-G)**

Distribution Primary Capacity Released By Voltage reduction				
ID	**Description**	**Amount**	**Units**	**Remarks**
A	Peak load on feeders	100.00	MW	Input
B	CVR factor	0.70		Input
C	Allowable voltage reduction	1.00%		Input
D	Additional reduction if AMI present	1.00%		Input assumption
E	Reduction of peak demand	1.40	Mw	A x B x (C + D)
F	Value of 1 megawatt peak load	$ 80,000	$/MW/Yr	Based on marginal power source
G	Demand reduction benefit	$ 112,000	$/Yr	D x E
H	Derating factor for rule-based solution	0%		Assumption (should be between 5% and 15%)
I	**Adjusted benefit**	**112,000**	**$/Yr**	**F x (1 - G)**

FIGURE C-34 Volt VAR

Dynamic Equipment Rating

Need to add sensors on substation transformers to support this application - possibly some of the same sensors as ECM

Helps avoid load shedding when normal ratings are exceeded (reliability improvement)

Possibly defer capital expenditure, but unlikely for VECO due to high load growth

Basis of benefits

1. During extreme peak load periods in some months, may need to reduce load on designated transformers to prevent overload
2. Assume this normally happens between 5 and 10 hours per month
3. during these 5 to 10 hours per month, need to implement 5% load shedding
4. assume with dynamic equipment rating, can reduce the amount of load shedding by 10%
5. This represents an improvement in both SAIDI and SAIFI, which translates into various types of reliability improvement
6. Assume these load shedding events are excluded from SAIDI & SAIFI calculations; therefore no SAIDI SAIFI improvements

Dynamic Equipment Rating - Reduce amount of load shedding by dynamically calculating equipment ratings

ID	Item	Value	Source	Comment
A	Number of hours per year load shedding due to equipment overload occurs	24	*Assumption(control parameter)*	
B	% of feeders on which load shedding applies	10%	*Input assumption*	
C	Number of load shedding feeders	80	*B x Total number of feeders*	
D	Amount of Load shedding without DER	3%	*Input assumption*	
E	Amount of Load shedding with DER	2%	*Input assumption*	
F	Rated load on feeder (kWh)	16667	*kWh - peak load is 85.5% of rating (VECO Input*	
G	KWh sales lost without DER	960000	*kWh*	
H	KWh Sales lost with DER	640000	*kWh*	
I	Reduction of lost kWh sales	320000	*kWh*	
J	Profit per kWh	$ 0.06	*Input value*	
K	**Reduction in lost kWh sales per year**	**$ 19,200**	***I x J***	***$/Year***
L	Value of lost load ($/MWH)	10,000	*Calculated by ESTA*	
M	**Reduction in VOLL ($/Yr) for system (Customer outage savings)**	**$ 3,200,000**	*I / 1000 x L*	
N	Number of customers affected without DER	2400	*C x D x # Cust per feeder*	
O	Customer outage minutes without DER	3456000	A x N x 60	
P	Number of customers affected with DER	1600	*C x E x # Cust per feeder*	
Q	Customer outage minutes with DER	2304000	A x P x 60	
R	Customer outage minute savings with DER	1152000	O - Q	
S	**% reduction in system SAIDI**	**1.44%**	***R/ (Tot # customers x SAIDI)***	
T	**% reduction in system SAIFI**	**1.44%**	**Same as SAIDI**	

FIGURE C-35 Dynamic Equipment Rating

Adaptive Relaying

Cold-load pickup improvements - change settings to CLPU settings when CLPU conditions exist

Fuse saving - avoid permanent outages for temporary faults on fused branchlines - reliability improvement (avoid outage for temporary fault on fused branchline), avoid truckroll for fuse replacement when fuse blows for temporary fault

Benefit assessment for fuse saving

ID	Item	Value	Source	Comment
A	Number of temporary faults per feeder	6	*assumption*	
B	% portion of feeder on fused laterals	40%	*assumption*	
C	Number of fused branchlines per feeder	20	*Input value*	
D	# temporary faults per branch	0.120	*A x B / C*	Faults per year
E	Average load on each branch	130.000	*Fdr load x LF x B /C*	kW
F	Average duration of outage for temporary fault in which fuse blows (minutes)	50.0	*SAIDI/SAIFI*	minutes
G	lost kWh per year on each branch	13.000	*D x E x F / 60*	kWh
H	Lost load per year for all branches on feeder	260.000	*C x G*	kWh
I	Lost load for entire system	208000.000	*Tot # feeders x H*	kWh
J	Profit per kWh sold	$0.06	*Input value*	
K	**Reduction in lost kWh sales per year**	**$12,480**	***I x J***	$/Year
L	Value of lost load ($/MWH)	$10,000	*Calculated by ESTA*	
M	**Reduction in VOLL ($/Yr) for system (Customer outage savings)**	**$2,080,000**	*I / 1000 x L*	
N	# of customers per branch	20	*# cust per feeder /C*	
O	Customer outage minutes saved per branch	120		
P	Customer outage minutes saved per feeder	2400	*C x O*	
Q	Customer outage minutes saved for system	1920000	*P x # feeders*	
R	**% reduction is SAIDI due to fuse saving (adaptive relaying)**	**2.40%**	***M / (SAIDI x tot customers for system)***	
S	**% reduction is SAIFI due to fuse saving (adaptive relaying)**	**2.40%**	***Same as SAIDI improvement***	

FIGURE C-36 Adaptive Relaying

C-40

Inflation	2.00%			
Discount rate	6.00%			
Investment	$ 1,000,000			
# years	1	**Benefit**	**$ 37,735.85**	Benefit in Year 1 dollars if a $1M investment is defered by specified # years

FIGURE C-37 Deferred Capital Expenditure

C-41

Advanced Metering Infrastructure (AMI)
Enables innovative time of use tariffs (beyond scope of analysis).
Provides voltage feedback that will enable more effective Voltage Reduction.
Provides communication infrastructure for DA applications (cost savings versus requiring separate system).
AMI last gasp messages provide immediate fault prediction versus waiting for customer phone calls to trickle in.

FIGURE C-38 Advanced Metering Infrastructure

C-42

Outage Management System
Implementing a combined OMS/DMS offers significant cost savings. Combined system costs less than separate OMS & DMS, eliminates some expenisve interfaces (OMS-DMS not required, separate GIS-DMS & GIS-OMS not required. OMS benefits come mainly during major storm events with widespread outages (> 50% of customers out at one time) because OMS enables VECO to do better damage assessment, crew management, and restoration prioritization.
OMS will help locate faults on fused lateral taps. DA does not work if fault is cleared by a branchline fuse. OMS combined with either cust calls or AMI "last gasp" messages will identify fault location on branchlines and greatly reduce the patrol time. Without OMS, operator has to recognize that phone calls or last gasps are all coming from single fused brach - takes longer with manual analysis - predicton engine will identify faulted branch as soon as sufficient information comes in.
If VECO does not have DA, then OMS prediction engine can help locate mainline faults (shorter patrol time).

FIGURE C-39 Outage Management System

C-43

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ANNEX D. DVCALC OVERVIEW

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CONTENTS

FIGURES

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ACRONYMS AND ABBREVIATIONS

AMI	Advanced Metering Infrastructure
BCR	Benefit to Cost Ratio
CBM	Condition Based Maintenance
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DER	Dynamic Asset Rating
DMS	Distribution Management System
ECM	Equipment Condition Monitoring
ESB	Enterprise Service Bus
FLISR	Fault Location Isolation and Service Restoration
FTE	Full-time Equivalent(s)
GIS	Geographic Information System
HV CB	High Voltage Circuit Breaker
ICE	DOE Interruption Cost Estimate Calculator
IEC	International Electrotechnical Commission
kW	kilowatt(s)
kVAR	kiloVAR(s); 1000 units of reactive volt-amperes
NPV	Net Present Value
O&M	Operating and Maintenance
OMS	Outage Management System
PF	Power Factor
PBR	Performance-based Rates
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
VAR	Volt Ampere Reactive (reactive power)
VOLL	Value of Lost Load
VVO	Volt VAR Optimization

ANNEX D. DVCALC OVERVIEW

D.1 DVCALC OVERVIEW

The DVCalc model allows the user to evaluate the expected benefits and costs of the DMS over the life of the system using user-specific input data and other industry information about the DMS that is applicable to the utility. DVCalc enables the user to specify what DMS applications and external system interfaces are required, to select system architecture and integration technologies being used, and to enter many key operational and financial parameters. The spreadsheet computes the expected benefits of the selected DMS functions as well as the total cost of ownership for these functions. The spreadsheet includes an analysis of revenue requirements over the life of the system to determine key investment parameters indicating the economic merits of the investment that enable the user to determine if the selected DMS functions and technologies are economically justified.

This overview provides instructions on using the DVCalc spreadsheet, describes the structure of the model, and provides an overview of the methodologies used by the program. It contains high level instructions for running the program and describes the contents of each worksheet tab. Also, it includes several examples that illustrate the use of the DVCalc model.

D.1.1 General Information

The following general guidelines for using the model are provided:

- All input values that are needed to run DVCalc are entered on the "Analysis Control & Summary" worksheet and the "UTILCO Inputs" worksheet.
- DVCalc users should only enter values in spreadsheet cells that have yellow colored fill. Entering values into blue-colored cells and cells with no fill will overwrite spreadsheet linkages and formulas and may result in incorrect results, invalid references, and other anomalies.
- All DVCalc results update automatically when a control variable or input data value is updated. It is not necessary to run an Excel macro or request calculation updates to see updated results.
- The worksheet "Analysis Control & Summary" provides a convenient mechanism for entering "control" parameters that enable the user to define different DMS scenarios and view key parameters that indicate the results of economic analysis. Users can select the DMS applications that are included in the analysis, identify different numbers of feeders to automate, set a different target power factor for the Volt-VAR (Volt Ampere Reactive) application, and modify a wide variety of study parameters.
- The worksheet "UTILCO Inputs" contains the utility-specific data values that are used in the calculations. To change any value, simply type over the default value provided in yellow-colored cells.

- All DVCalc data entry fields and control parameters are populated with default values that represent typical industry values. It is recommended that the user save a copy of the original spreadsheet so that it is possible to return to the default values after making an analysis with some utility specific values entered.
- The worksheet "Benefit & Cost Summary" contains a listing of the calculated benefits and costs for individual DMS applications that are included in the specified scenario along with the totaled amounts.

D.2 ANALYSIS CONTROL & SUMMARY WORKSHEET

The Analysis Control & Summary worksheet (shown in Figures D-1 and D-2) enables the user to define the DMS "scenario" being evaluated. A scenario identifies the DMS application functions that are included in the analysis along with key parameters that define the specific system architecture and integration technology being considered. This worksheet also enables the user to enter key design parameters, such as the number of Distribution Automation (DA) switches per feeder, and financial data (e.g., inflation rate) that affect the costs and benefits of the DMS solution.

D.2.1 Control Parameters

The following scenarios or study parameters (Control Parameters) can be selected using the data entry fields provided in column B of the Analysis Control & Summary worksheet. Please refer to Figure D-1 to view the parameters described in this section.

	CONTROL PARAMETERS	
1	**CONTROL PARAMETERS**	
2	**Project Information**	**Amount**
3	Initial Year of Project	2016
4	Number of years to implement system	3
5		
6	**DMS-OMS Requirement**	**Yes or No**
7	Distirbution Management System Required	Yes
8	Outage Management System Required	Yes
9	Combined or Separated OMS/DMS	Combined
10		
11	**DA Applications Being Implemented**	**Yes or No**
12	Fault Location Isolation & Service Restoration	Yes
13	OMS will help locate faults on fused lateral taps. D	Yes
14	DA Applications model driven or rule based?	Model driven
15	DA Applications centralized or decentralized?	Decentralized
16		
17	**"Control" Parameters for DA Applications**	**Amount**
18	Number of feeders to automate	50
19	Number of DA Switches per feeder	2
20	Target power factor for VVO	0.99
21		
22	**Other Applications**	**Yes or No**
23	Equipment Condition Based Maintenance	Yes
24	- Distribution feeder CBM	Yes
25	- SS HV Circuit Breaker CBM	Yes
26	- SS Transformer CBM	Yes
27	% of substations requiring ECM	50%
28	Switch Order Management	Yes
29	Training simulator	Yes
30	Data scrubbing for capacity planning	Yes
31	Dynamic Equipment Rating	Yes
32	Adaptive relaying (fuse saving)	Yes
33	Electronic Mapping	Yes
34		

35	**DMS/OMS interfaces that are required**	**Yes or No**
36	Supervisory Control and Data Acquisition	Yes
37	Geospatial Information System	Yes
38	Advanced Metering Infrastructure	Yes
39	Work management system	Yes
40	System integration technology used	Standard ESB
41		
42	**Substation Automation**	**Yes or No**
43	Add new digital relays for protection and SCADA	Yes
44	% of Substations that need digital relays	25%
45	Add new SA Data Concentrator at % of subs	Yes
46	% of Substations to automate	25%
47	Convert % of existing feeders to IEC61850?	Yes
48	% of feeders to convert to IEC61850	20%
49		
50	**Labor savings**	**Yes or No**
51	Include labor savings in benefit-cost calculations	Yes
52	Outage post event review cost savings	Yes
53	Predictive fault location	Yes
54		
55		
56	**Mechanism for Evaluating Reliability benefits**	**Yes or No**
57	Use DOE ICE Software Tool	No
58	- If "Yes", enter $/year from ICE toolfor SAIDI & SAIFI Results	
59	Performance Based Rates	Yes
60	Value of Lost Load (VOLL) analysis	Yes
61	Reduction of lost kWh sales	Yes
62	Labor savings	Yes
63		
64	**Financial & Investment Data**	**Amount**
65	Inflation rate	2.00%
66	Discount Rate	6.00%
67		

FIGURE D-1 Control Parameters from Analysis Control & Summary Worksheet

D-11

SUMMARY OF RESULTS

Benefit Summary	$/Year
FLISR Benefits	$529,855
VVO Benefits	$1,198,298
Dynamic Asset Rating (DAR) Benefits	$3,219,200
Adaptive Relay (Fuse saving) Benefits	$2,092,480
Condition Based Maintenance Benefits	$569,267
Labor Savings	$811,511
Total Annual Benefits	**$8,420,611**

Cost Summary	Investment	$/Year
Planning and Procurement	$1,659,375	
OMS/DMS Hardware & Software	$5,650,000	$169,500
Appplication software and studies	$1,130,000	$26,600
System Integration Costs	$1,150,000	$34,500
Substation Equipment	$3,802,500	$76,050
Feeder Equipment	$3,172,960	$63,459
Totals	**$16,564,835**	**$370,109**

Financial Results	
Net Present Value	$ 21,095,537
Payback year	2023 (7 years)
Benefit to cost ratio	3.09

Reliability Results	**Amounts**
SAIDI before	100
SAIDI After	91.54
% Improvement in SAIDI	**8.46%**
SAIFI Before	2.00
SAIFI After	1.91
% Improvement in SAIFI	**4.26%**

FIGURE D-2 Concise Summary of DVCALC Results from Analysis Control and Summary Worksheet

D-12

1. **(Cells B2 to B4) Project information.** These cells include the initial year of the project and number of years to complete the installation. The first costs (procure, design, implement, commission) are spread out evenly over the number of years to complete the project.
2. **(Cells B6 to B9) DMS-OMS Requirement**. These cells are used to indicate if the DMS includes outage management (OMS) functionality and, if "Yes," enables the user to specify that a "combined" DMS/OMS architecture (DMS and OMS applications running on the same platform and sharing a common model) will be used versus a separate architecture where DMS and OMS are implemented on separate platforms. This field has a significant effect on software costs and system integration costs. The user can choose either "Combined" or "Separated" for this field.
3. **(Cells B11 to B20) Distribution Automation (DA) Applications Being Implemented.** These cells allow the user to indicate whether Fault Location Isolation and Service Restoration (FLISR) and Volt VAR Optimization (VVO) should be included in the analysis. If Yes, then the user can specify whether these applications are "rule-based" or "model-driven" and if these applications are centralized (main logic resides in the control center) or decentralized (main logic resides in the substation or out on the feeders). These cells also allow the user to identify the number of feeders to automate and to specify key DA parameters, such as number of normally closed DA switches (for FLISR) and VVO target power factor.
4. **(Cells B22 to B33) Other DMS Applications.** These data entry fields allow the user to identify DMS applications that are included in addition to OMS, FLISR, and VVO. For Equipment Condition Monitoring (ECM), this worksheet allows the user to enter the percentage of substations where ECM is being implemented (Cell B27).
5. **(Cells B35 to B40) DMS/OMS Interfaces that are required.** These fields allow the user to select the major systems to which DMS must interface and to identify the integration technology that is used (standard enterprise service bus [ESB] or other approach).
6. **(Cells B42 to B48) Substation Automation.** These fields allow the user to enter information on substation automation equipment needed to support the DMS applications.
7. **(Cells B50 to B53) Labor Savings.** These cells allow the user to indicate whether labor savings should be included in the analysis.
8. **(Cells B56 to B62) Mechanism for Evaluating Reliability Benefits.** These cells allow the user to select one or more mechanisms for monetizing reliability improvement benefits. If the user selects "Use DOE ICE softwaretool," then the user is required to enter in Cell B58 the annual savings computed by the ICE software tool.
9. **(Cells B64 to B66) Financial and Investment Data**. These cells are used to enter the current inflation rate (in %/year) and the discount rate (%/year).

D.2.2 Summary of Results

The Analysis Control & Summary spreadsheet also allows the user to view the key results of the program, such as benefits and costs, reliability improvement benefits of the proposed solution, and financial results of the analysis (net present value, etc.). Refer to Figure D-2 for a screen capture of this portion of the worksheet. All monetary values shown on the worksheet and elsewhere in the spreadsheet are in US dollars (US$).

A portion of the "Analysis Control & Summary" worksheet (Cells C1 through I22) is dedicated to displaying a concise summary of the analysis results. Following is a summary of the key information displayed in this summary.

1. **(Cells D1 to E9) Benefit Summary.** These cells display the annual savings associated with each DMS application in dollars saved per year.

2. **(Cells G2 to I9) Cost Summary.** These cells display the initial cost and the annual O&M cost for implementing, operating, and maintaining the DMS.

3. **(Cells D11 to E14) Financial Results.** These cells display the key financial parameters net present value, benefit to cost ratio (BCR), and payback year.

4. **(Cells D16 to E22) Reliability Results.** These cells identify the improvements in System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) that can be achieved by the DMS.

D.3 UTILCO INPUTS WORKSHEET

The UTILCO Inputs worksheet provides data fields for the user to enter detailed information about the Utility implementation. This worksheet contains over 300 input data items used in the analysis.

Many of the yellow data entry fields have a limited number of valid entries. A drop down box is provided for these fields to enable the user to select one of the valid entries. Whenever a data value is changed by the user, the spreadsheet automatically re-calculates the results and updates the results fields shown on the screen. It is not necessary to run macros or perform any other program execution actions to run the program. Note that the automatic formula calculation feature of Excel should be turned on to automatically updated program results (see "File", "Options", "Formulas" to view and change the calculation option that is currently set on the spreadsheet).

The UTILCO Inputs worksheet together with the Analysis Control & Summary worksheet include all of the data inputs required to run DVCalc. Inputs entered on the Analysis Control & Summary worksheet are copied onto rows 1 to 29 of the UTILCO Inputs worksheet for convenience. However, the user should not type over inputs from the Analysis Control & Summary onto the Utility inputs worksheet as this would overwrite links between the worksheets.

D.3.1 Electrical Data (Rows 31 to 41)

The Electrical Data, rows 31 to 41, shown for convenience in Figure D-3, contain utility-specific information on the electrical characteristics of the utility electric distribution system.

31	**Electrical Data**		
32	Load growth (% per year)	2.00%	*Input value from UTILCO*
33	Total number of feeders	800	*Calculated from # substations*#trfs*#fdr/trf*
34	Number of substations	100	*Input value from UTILCO*
35	Number of HV breakers per substation	2	*Input value from UTILCO*
36	Number of transformers per substation	2	*Input value from UTILCO*
37	Number of feeders per substation transformer	4	*Input value from UTILCO*
38	Peak load on distribution feeder (% of rating)	60.0%	*Input value from UTILCO*
39	Load Factor	65%	*Input value from UTILCO*
40	Peak Load on feeder (kW)	10000	*Input value from UTILCO*
41	Distribution Power Factor (average)	0.970	*Input value from UTILCO*

FIGURE D-3 Electrical Data

D.3.2 Reliability Data (Rows 43 to 51)

The Reliability Data, rows 43 to 51, contain information needed to compute the reliability–related benefits of the proposed DMS solution. These inputs are used by several applications that offer reliability improvement benefits, including FLISR, dynamic asset ratings (DER), adaptive relaying (fuse saving), and ECM. Any of these items can be changed by the user except for **Patrol time as % of total outage time** (Row 51), which is a calculated quantity.

Data items supplied by the Utility include:

- System SAIFI (Row 44) – the spreadsheet assumes this is the total outage duration per year for an average feeder at the utility
- System SAIDI (Row 46) - the spreadsheet assumes this is the total number of outage events per year for an average feeder at the utility
- Average fault location time (minutes) (Row 48)
- Average time to isolate fault (minutes) (Row 49)
- Average travel time service (minutes) to reach fault vicinity (Row 50)

Patrol time as a percentage of total outage (Row 51) is calculated using the last three items in the above list. This calculation is used to determine how much patrol time can be reduced by implementing fault location and isolation (part of FLISR).

43	**Reliability Data**		
44	System SAIFI	2	*Input from UTILCO*
45	% difference of worst performing feeders (SAIDI)	10%	*Assumption or input from UTILCO*
46	System SAIDI	100	*Input from UTILCO*
47	% difference of worst performing feeders (SAIFI)	10%	*Assumption or input from UTILCO*
48	Average fault location (patrol) time (minutes)	30	*Input value from UTILCO*
49	Average time to isolate fault (minutes) via manual switching	15	*Input value from UTILCO*
50	Average travel time service (minutes) to reach fault vicinity	30	*Input value from UTILCO*
51	Patrol time as % of total outage	40.00%	*Calculated from the above inputs*

FIGURE D-4 Reliability Data

It is assumed that reliability improvement measures will be applied only on the worst performing feeders (a common industry practice). For these feeders, the reliability improvement calculations assume that the SAIDI and SAIFI values are worse than average by the user specified amount contained in cell B46. As a default, it is assumed that the SAIDI and SAIFI values for worst performing feeders are approximately 10% higher than the average.

D.3.3 Financial Data (Rows 53 to 59)

Rows 53 to 59 of the "UTILCO inputs" worksheet contain financial information needed to monetize reliability and efficiency improvements for use in the analysis of revenue requirements.

53	**Financial Data**			
54	Inflation rate	2.00%	%/Yr	
55	Discount Rate	6.00%	%	
56	UTILCO's Value of Lost Load (Economic Estimates)	$ 10,000	$/MWh	
57	Energy production cost per kWh	$ 0.16	$/kWh	
58	Value of 1 megawatt peak load	$ 80,000	$/MW/Yr	*Based on marginal power source*
59	Profit per kWh sold ($)	$ 0.06	$/kWh	*Production cost minus selling price*

FIGURE D-5 Financial Data Used in the Analysis

Users can enter the following inputs into the Financial Data area of the UTILCO Inputs worksheet:

- **UTILCO's Value of Lost Load (Row 56):** This parameter provides an effective way to convert the recovery of customer load due to faster service restoration to US dollars. The default value is US$ 10,000.
- **Energy production cost per kWh (Row 57):** This parameter is the estimated cost of generating one kilowatt hour of energy.
- **Value of 1 megawatt peak load (Row 58):** This value is the estimated cost to add one MW of capacity to the Utility's generation supply. DVCalc uses this parameter to monetize the benefit of reducing peak electrical demand.
- **Profit per kWh sold ($) (Row 58):** This parameter is the profit received by Utility from the sale of one kWh of energy. The profit per kWh sold is used to compute the value of restoring service faster following an outage; speedy restorationenables the Utility to sell kWh that otherwise would have been lost if restoration is delayed.

D.3.4 Inputs for Defining Performance-based Rates Characteristic for SAIDI and SAIFI (Rows 62 to 67)

Rows 62 to 67 of the UTILCO Inputs worksheet enable the user to enter the parameters of characteristic curves that define the Performance-based Rate (PBR) rewards and penalties associated with SAIDI and SAIFI performance. A representative PBR characteristic is shown in Figure D-6.

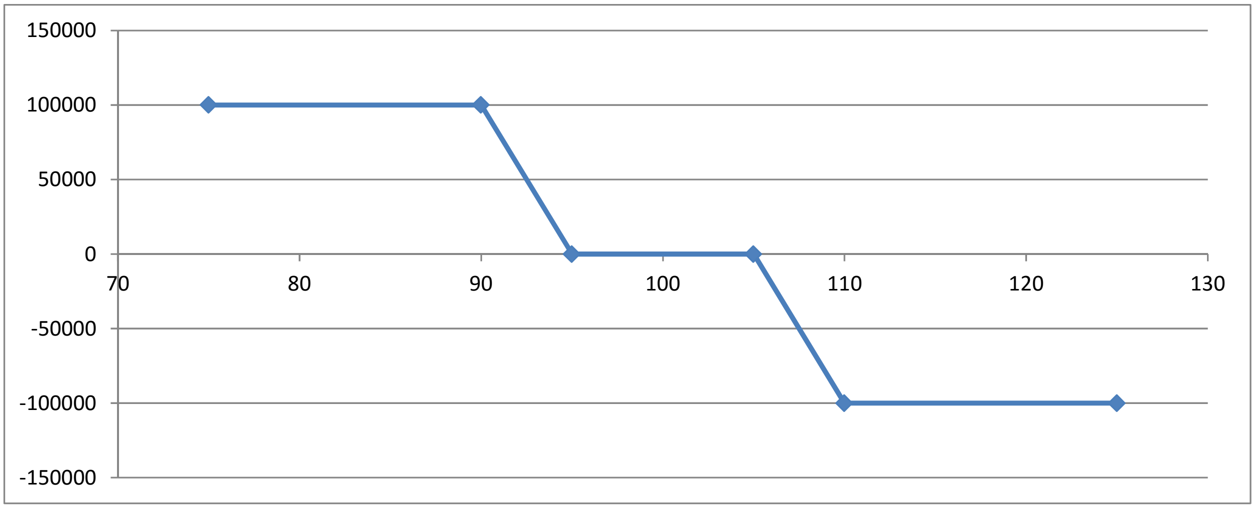


FIGURE D-6 Representative PBR Characteristic for SAIDI Generated by DVCalc

The PBR calculations are recorded in the worksheet "PBR Calcs." If PBRs do not apply (cell B55 of the Analysis Control & Summary worksheet = **No**), then this area of the UTILCO Inputs worksheet is not used. If PBRs apply, then the following inputs are needed to define the SAIDI PBR. Figure D-7 contains an image of the PBR Characteristic portion of the UTILCO Inputs worksheet.

62	**Inputs for defining PBR Characteristic for SAIFI**		
63	System SAIFI (last year)	2.00	(Only Required if Performance Based Rates Apply)
64	Neutral zone	5%	
65	Maximum penalty/reward zone	10%	
66	Maximum Reward	100000	
67	Maximum penalty	-100000	

62	**Inputs for defining PBR Characteristic for SAIDI**		
63	System SAIDI (last year)	100	(Only Required if Performance Based Rates Apply)
64	Neutral zone	5%	
65	Maximum penalty/reward zone	10%	
66	Maximum Reward	100000	
67	Maximum penalty	-100000	

FIGURE D-7 Representative PBR Characteristics for SAIDI and SAIFI

- **System SAIFI (SAIDI) (Row 63):** System SAIFI (SAIDI) is the center point of the characteristic on the x-axis. This data field automatically populates from other data entry field on the Utility inputs spreadsheet.
- **Neutral zone (Row 64):** The neutral zone is the range of SAIFI (SAIDI) for which no payment is made (i.e., no reward or penalty). The neutral zone is the system SAIFI (SAIDI) value plus and minus the percentage inserted in this field.
- **Maximum Penalty/Reward Zone (Row 65):** If the SAIFI (SAIDI) value falls outside the neutral zone, the penalty or reward increases linearly until a maximum penalty or reward is reached at the edge of the penalty/reward zone. This zone is defined as the system SAIFI (SAIDI) value plus and minus the percentage value inserted in the data entry field in row 64.
- **Maximum reward and penalty (Rows 66 and 67):** The values inserted in these field are the maximum penalty and reward (in US dollars) associated with the PBR.

D.3.5 Cost of Central Processors (Rows 75 to 82)

Rows 75 to 82 of the UTILCO Inputs worksheet defines the implementation costs and O&M costs for the main DMS hardware and software. These values are for the DMS/OMS system software and do not include the advanced applications selected by the user—application software costs are inserted elsewhere in this worksheet. All values are in US dollars.

Cost estimates are provided for the various combinations of combined DMS/OMS and separated DMS and OMS. The spreadsheet logic selects the appropriate values based on the user's configuration selections in the Analysis Control & Summary worksheet.

- **Rows 75 to 80** contain the initial one-time costs to purchase and install the DMS-OMS system hardware and software.
- **Row 82 (Cell C82)** contains a percentage factor that is applied to the one-time implementation cost to determine the annual O&M costs for the DMS-OMS system hardware and software.

75	Central processsors (hardware & system software)	Initial Cost	Annual O&M
76	DMS Hardware (separate DMS/OMS) (US$)	$ 500,000	
77	OMS Hardware (separate DMS/OMS) (US$)	$ 500,000	
78	Combined DMS/OMS hardware (US$)	$ 750,000	
79	DMS System software (no adv applications)	$ 1,000,000	
80	OMS System software (no adv applications)	$ 1,000,000	
81	Combined DMS/OMS software (no advance applications)	$ 1,700,000	
82	Annual O&M for all DMS & OMS hardware & software		3%

FIGURE D-8 Central Processor Hardware and Software Costs

D.3.6 Labor Costs (Rows 84 to 91)

Rows 84 to 91 identify the labor costs used by the spreadsheet to compute installation costs and labor-related benefits. See Figure D-9 for a depiction of this portion of the UTILCO Inputs worksheet.

84	**Labor Costs**		**Hourly**	
85	Engineering labor ($/Manyear)	$ 312,000	$ 150.00	
86	External Labor ($/Manyear)	$ 260,000	$ 125.00	
87	Control room operator	$ 260,000	$ 125.00	
88	IT personnel	$ 260,000	$ 125.00	
89	GIS/OMS "Mappers"	$ 156,000	$ 75.00	
90	Substation test crew	$ 260,000	$ 125.00	
91	Line Crew labor rate ($/hour) (includes vehicle cost)		$ 200.00	*$/hour (includes vehicle cost)*

FIGURE D-9 Labor Costs

D.3.7 Feeder Modelling (Rows 93 to 94)

The Feeder Modelling rows, 93 to 94, of the UTILCO Inputs worksheet contains the unit costs to develop and maintain electrical models used by advanced DMS applications. The values inserted in these fields are used only if the user indicates that the DA applications are model driven (see Cell B14 of the Analysis Control & Summary worksheet).

- **Initial Cost (Cell B94)** indicates the cost to build an electrical model for one distribution feeder.
- **Annual O&M (Cell C94)** indicates a percentage factor that is multiplied times the Initial Cost to determine the annual O&M cost for maintaining each model over the life of the system.

93	**Feeder Modelling**	**Initial Cost**	**Annual O&M**	
94	Cost to build $ maintain model ($/feeder)	$ 4,000	3%	*Applies for centralized (model-driven) solution*

FIGURE D-10 Feeder Modelling Cost

D.3.8 System Integration Costs (Rows 96 to 116)

Rows 96 to 116, of the UTILCO Inputs worksheet are used to enter the implementation and O&M costs for the required interfaces between the DMS, OMS, and external systems selected on the Analysis Control & Summary worksheet. Refer to Figure D-11 for a depiction of this portion of the UTILCO Inputs worksheet.

96	System integration costs	Initial Cost	Annual O&M	
97	DMS-OMS interface using Standard ESB	$ 300,000		*Only if separate OMS and DMS implemented*
98	DMS-OMS interface using home grown interface	$ 400,000		*Only if separate OMS and DMS implemented*
99	Combined DMS/OMS - GIS Integration using Standard	$ 300,000		
100	Combined DMS/OMS - GIS Integration using home grown interfac	$ 400,000		
101	Separate DMS or OMS interface to GIS using Standard ESB	$ 200,000		
102	Separate DMS or OMS interface to GIS using home grown interfac	$ 250,000		
103	Combined DMS/OMS - AMI Integration using Standard	$ 150,000		
104	Combined DMS/OMS - AMI Integration using home grown interfa	$ 250,000		
105	Separate DMS or OMS interface to AMI using Standard ESB	$ 100,000		
106	Separate DMS or OMS interface to AMI using home grown interfa	$ 150,000		
107	Combined DMS/OMS - Work Mgmt Integration using Standard	$ 150,000		
108	Combined DMS/OMS - Work Mgmt Integration using home grown	$ 250,000		
109	Separate DMS or OMS interface to Work Mgmt using Standard ESB	$ 100,000		
110	Separate DMS or OMS interface to Work Mgmt using home grown	$ 150,000		
111	Combined DMS/OMS - SCADA Integration using Standard	$ 150,000		
112	Combined DMS/OMS - SCADA Integration using home grown inte	$ 250,000		
113	Separate DMS or OMS interface to SCADA using Standard ESB	$ 100,000		
114	Separate DMS or OMS interface to SCADA using home grown inte	$ 150,000		
115	Annual O&M % for interface with Standard ESB		3%	
116	Annual O&M % for interface with homegrown solution		5%	

FIGURE D-11 System Integration Costs

This section allows the user to enter costs for each of the interfaces, allowing for cost variations associated with using a standard ESB versus another "homegrown" integration technology. This section also accounts for different interfacing requirements and costs associated with a combined OMS/DMS versus separated DMS and OMS systems.

- **Rows 97 and 98** allow the user to enter the implementation costs of the interface between DMS and OMS. Note that this interface is not required if a combined OMS-DMS architecture is selected.
- **Rows 99 to 102** allow the user to enter the costs to implement interfaces between DMS-OMS and the Geographic Information System (GIS). If a separate DMS and OMS architecture is selected, the two different interfaces are required (one for DMS and one for OMS). These rows also allow the user to enter different system interface costs using the standard ESB versus the homegrown system interface solution.
- **Rows 103 to 106** allow the user to enter the costs to implement interfaces between DMS-OMS and the Advanced Metering Infrastructure (AMI) system. If a separate DMS and OMS architecture is selected, the two different interfaces are required (one for DMS and one for OMS). These rows also allow the user to enter different system interface costs using the standard ESB versus the home-grown system interface solution.
- **Rows 107 to 110** allow the user to enter the costs to implement interfaces between DMS-OMS and the Work Management System. If a separate DMS and OMS architecture is selected, the two different interfaces are required (one for DMS and one for OMS). These rows also allow the user to enter different system interface costs using the standard ESB versus the homegrown system interface solution.

- **Rows 111 to 114** allow the user to enter the costs to implement interfaces between DMS-OMS and the Supervisory Control and Data Acquisition (SCADA) system. If a separate DMS and OMS architecture is selected, the two different interfaces are required (one for DMS and one for OMS). These rows also allow the user to enter different SI costs using the standard ESB versus the homegrown system interface solution.
- **Rows 115 and 116** allow the user to enter percentage factors for computing the annual O&M associated with each interface. Different factors are supplied to determine the O&M amount for a standard ESB versus a homegrown ESB solution.

D.3.9 Initial Planning and Procurement Costs (Rows 118 to 150)

The Planning and Procurement section of the UTILCO Inputs worksheet allows the user to enter the information needed to compute the costs of "up front" activities, such as needs analysis, use case development, integration environment and architecture development, system procurement and vendor selection activities, and other costs that precede the actual implementation efforts. Figure D-12 shows this portion of the UTILCO Inputs worksheet.

118	Combined DMS/OMS	# FTEs	"Blended"hourly rate	Amount	% of internal labor	% of internal labor
119	Planning	0.75	$ 138	$ 206,250	50%	50%
120	Procurement	1	$ 138	$ 275,000	50%	50%
121	Architecture and Integrations					
122	Establish integration architecture	0.75	$ 131	$ 196,875	25%	75%
123	Establish environment	0.25	$ 131	$ 65,625	25%	75%
124	Detailed integration specs - advanced applications	0.75	$ 131	$ 196,875	25%	75%
125	Change Management					
126	Develop Use Cases	2.5	$ 144	$ 718,750	75%	25%
127				$ 1,659,375		
128						
129						

130	Separate DMS	# FTEs	"Blended"hourly rate	Amount	% of internal labor	% of internal labor
131	Planning	0.5	$ 138	$ 137,500	50%	50%
132	Procurement	0.5	$ 138	$ 137,500	50%	50%
133	Architecture and Integrations					
134	Establish integration architecture	0.5	$ 131	$ 131,250	25%	75%
135	Establish environment	0.25	$ 131	$ 65,625	25%	75%
136	Detailed integration specs - DMS apps	1.5	$ 131	$ 393,750	25%	75%
137	Change Management					
138	Develop Use Cases	1.25	$ 144	$ 359,375	75%	25%
139				$ 1,225,000		
140						

141	Separate OMS	# FTEs	"Blended"hourly rate	Amount	% of internal labor	% of internal labor
142	Planning	0.5	$ 138	$ 137,500	50%	50%
143	Procurement	0.5	$ 138	$ 137,500	50%	50%
144	Architecture and Integrations					
145	Establish integration architecture	0.5	$ 131	$ 131,250	25%	75%
146	Establish environment	0.25	$ 131	$ 65,625	25%	75%
147	Detailed integration specs - OMS apps	1.5	$ 131	$ 393,750	25%	75%
148	Change Management					
149	Develop Use Cases	1.25	$ 144	$ 359,375	75%	25%
150				$ 1,225,000		

FIGURE D-12 Initial Planning and Procurement Costs

The costs computed from the data supplied in this section are applied in the first year of the project prior to the start of implementation. For example, if a three-year implementation schedule is specified, the initial planning and procurement activities occur in Year 1 followed by implementation activities in Years 2 to 4.

Separate amounts are required for a combined OMS/DMS, separate DMS, and separate OMS. The spreadsheet only uses the values that apply to the configuration specified by the user in the Analysis Control & Summary worksheet. Instructions are provided for Rows 117 to 125 (Combined DMS/OMS); however, the same instructions apply to the remaining two configuration categories.

- Column "B" of each row identifies the total number of Full-time Equivalents (FTE) required to complete each activity. This include internal FTEs (utility labor) and external FTEs (outside contractors).
- Column "E" of each row identifies the percentage split of the total FTEs between internal and external labor. The user should enter the percentage of the total FTEs supplied by the utility employees (internal labor). The balance of the FTEs is assumed to be external resources (outside contractors). In other words, if the user enters 40% for "% of Internal Labor," then the spreadsheet assigns 40% of the FTEs to utility employees (at the internal labor rate specified in section 6.3.6) and 60% of the total FTEs (1–40%) to external resources at the rate specified in Section 6.3.6).

D.3.10 Electronic Mapping (Rows 152 to 157)

A major activity in many of today's distribution control rooms is updating the maps used by dispatchers, field crews, construction personnel, line crews, and other electric utility personnel. Many of the business processes for updating these important graphical records are very labor intensive manual efforts, with a significant number of hand-drawn updates. The Electronic Mapping DMS function will streamline the record keeping process, resulting in a significant labor savings for control room personnel.

Figure D-13 lists the DVCalc input parameters needed to compute the benefits of this application.

152	**Electronic Mapping**		
153	# of OMS/GIS "mappers" updating records (FTEs)	3.0	*Input from UTILCO*
154	% reduction in # of OMS/GIS "mappers" updating records (%	50%	*Input from UTILCO*
155	% of control room operator time doing hand drawn map upd	20%	*Input from UTILCO*
156	# of control room operators	8	*Input from UTILCO*
157	% reduction in hand drawn updates with electronic mappin	80%	*Assumption*

FIGURE D-13 Input Data for Electronic Mapping Application

D.3.11 Control Room Operator Training (Rows 159 to 161)

One of the most significant challenges facing today's electric utilities is an aging workforce. Senior control room personnel spend a considerable amount of effort preparing junior personnel to take over for their more senior counterparts. Much of this training is typically conducted "on–the-job" by senior operators working closely with the new trainees. A significant portion of this activity is often conducted on overtime, which can be a costly undertaking. By using a dispatcher training simulator, new trainees can spend more time in self-study without supervision and instruction by senior operators. Figure D-14 shows the input data needed by DVCalc to compute the benefits of using a Dispatcher Training Simulator to conduct control room operator training.

159	**Control Room Operator Training**		
160	% of senior operator time for training new operators	20%	*Input from UTILCO*
161	% reduction in training time using training simulator	33%	*Assumption*

FIGURE D-14 Input Data for Control Room Operator Training Benefits

D.3.12 Data Scrubbing for Capacity Planning (Rows 163 to 165)

Planning engineers who are responsible for estimating load growth for capacity planning purposes currently must do a considerable amount of data "scrubbing" on feeder loading data to ensure that the calculated load growth is accurate. For example, it is necessary to combine loading measurements from SCADA with switching logs posted by the Dispatchers to ensure that load temporarily transferred to a backup source is not "double counted" in the load growth calculations.This manual scrubbing of load data is a labor-intensive effort. The DMS data scrubbing software, offers considerable labor savings to complete this activity. Figure D-15 shows the DVCalc input data requirements to compute the benefits of this application.

163	**Data Scrubbing for Capacity Planning**		
164	Number of engineering FTE's to do "scrubbing" of feeder loading data for capacity planning purposes	1	FTE/Year
165	% reduction of data scrubbing with DMS software tool	50%	%

FIGURE D-15 Input Data for Capacity Planning Data Scrubbing

D.3.13 Customer Data (Rows 167 to 169)

The Customer Data rows contain information regarding customer counts specified by the utility. These customer counts are used to compute the impact of DA and other DMS/OMS applications on reliability metrics SAIDI and SAIFI.

- Row 168 contains the total customer count for the entire system
- Row 169 contains the customer count for an average Utility feeder.

D.3.14 FLISR Implementation (Rows 173 to 187)

The FLISR Implementation section of the UTILCO Inputs spreadsheet contains values needed to compute the benefits and costs of implementing the Fault Location Isolation and Service restoration (FLISR) DA application.

173	**FLISR Implementation**		
174	FLISR Derating with decentralized Rule-based solution	10%	With rule-based solution, may not find solution in all cases - Pick derating factor between 5% and 10%
175	Number of FLISR Feeders	10	
176	Number of FLISR substations (Decentralized only)	3	
177	Number of normally closed DA switches per feeder	2	Control variable
178	Engineering studies needed for FLISR ($/Feeder)	$ 2,000	One time cost
179			
180	Centralized FLISR software license	$ 200,000	
181	Decentralized FLISR software licenses	$ 25,000	per substation cost
182	Cost per DA switch	$ 50,000	
183	Controller for DA sw control (centralized applications)	$ 1,000	
184	Controller for DA switch controller (decentralized applicatio	$ 2,000	
185	Application processor for decentral FLISR	$ 15,000	One per substation
186	Communication interface per switch	$ 1,500	
187	Annual O&M cost for flisr equipment & software		2%

FIGURE D-16 FLISR Input Data

Each input value is explained below:

- **FLISR Derating with Rule Based Solution (Row 174):** Model-driven FLISR solutions cost more in many cases, but are more effective at finding a service restoration strategy than rule-based solutions. This benefit is especially true for heavily loaded feeders, such as the Utility electric distribution feeders. The derating factor entered on this row is applied to the initial benefits computed by the FLISR algorithms to account for the less effective rule based solution technique. That is, if the derating factor is entered as 10% and the FLISR solution technique is not "Model driven" (see Analysis Control & Summary worksheet, Cell B14), the initial SAIDI and SAIFI improvement computed by the FLISR Benefit Cost Analysis (BCA) algorithm is multiplied by 90% (100% -10%).
- **Number of Feeders, Substations, and DA Switches (Rows 175 - 177):** These inputs are entered in the Analysis Control & Summary worksheet and are included here for convenience only. The user should not overwrite these data fields.
- **Engineering studies (Row 178):** Prior to implementing FLISR on any feeder, an engineering study should be performed on the targeted feeder and its backup sources to determine the optimal locations of DA switches and to verify that switching can be done under worst case conditions without producing unacceptable electrical conditions or protection difficulties on the affected feeders. The amount entered in this field represents the cost to perform each feeder study.

- **FLISR software licenses (Rows 180 and 181):** These rows contain the software license fees for the FLISR application. The value inserted for the centralized software license applies to centralized DA applications only. The FLISR license fee is a one-time cost. For decentralized DA applications a separate license is required for each substation. Therefore, the decentralized license cost must be multiplied times the number of substations.
- **Cost per DA switch (Row 182):** This data entry field contains the installed cost of one DA switch. This cost must be multiplied times the number of DA switches to determine the total cost of the system.
- **Controller for DA switches (Rows 183 to 184):** an intelligent device controller must be provided at each DA switch in order to implement the DA application. Row 183 contains the cost of the controller used for a centralized DA application. Row 184 contains the cost of the control used for a decentralized DA application. The controller cost for a decentralized application is higher than the controller used for a centralized application, because more of the DA logic is implemented in the controller when the application is decentralized.
- **Application processor for decentralized application (Row 185):** Decentralized DA applications require one or more application processors in the field for performing DA application algorithms. To determine the cost of the decentralized DA application, the value provided in this field is multiplied times the number of DA substations (cell B176 in the UTILCO Inputs worksheet).
- **Communication interface per switch (Row 186):** Each switch/controller installation requires a communication interface to its associated application processor. The value entered in Row 186 is the average cost of the communication facilities required to implement this interface. To determine the total cost, the cost per communication interface is multiplied by the number of DA switches to determine the total cost of communication facilities for the DA system.
- **Annual O&M costs for DA equipment and software (Cell C187):** The percentage amount entered in this worksheet cell is multiplied by the total implementation (initial) cost to determine the annual cost for operating and maintaining the associated equipment.

D.3.15 Volt VAR Optimization (VVO) Implementation (Rows 189 to 209)

This section of the UTILCO Inputs worksheet contains values needed to compute the benefits and costs of implementing the Volt VAR Optimization (VVO) DMS application. Figure D-17 shows the DVCalc input values required to compute VVO benefits and costs.

189	**VVO Implementation**			
190	VVO Derating with Rule-based solution	10%	*Assumption*	*Should be between 5% to 15%*
191	Number of VVO Feeders	10	*Assumption*	
192	Number of VVO substations (Decentralized only)	3	*Input value from UTILCO*	
193	Distribution Primary Losses at Peak Load	6.250%	*Input value from UTILCO*	
194	Distribution Power Factor (average)	0.982	*Assumption*	
195	Target PF (for VAR Dispatch)	0.990	*Control variable for volt-VAR*	
196	Distribution PF (Peak load)	0.982		
197	Available voltage reduction	1.000%		
198	Additional voltage reduction if AMI is present	1.000%		
199	CVR Factor	0.700		
200	Engineering studies needed for VVO ($/Feeder)	$ 2,000		One time cost
201	Centralized VVO software license	$ 200,000	2%	One for entire system
202	Decentralized VVO software licenses	$ 50,000	3%	per substation cost
203	Switched capacitor bank	$ 4,000	2%	
204	Controller for switched cap bank (centralized applications)	$ 1,000	2%	
205	Controller for switched cap bank (decentralized applicatior	$ 2,000	2%	
206	Midline voltage regulator	$ 25,000	2%	
207	Controller for vreg (centralized applications)	$ 1,000	2%	
208	Controller for vreg (decentralized applications)	$ 2,000	2%	
209	Communication interface for switched cap bank or vreg	$ 1,500	2%	

FIGURE D-17 DVCalc Input Data For VVO

Each input value is explained below:

- **VVO Derating Factor with Rule Based Solution (Row 190):** Model-driven VVO solutions cost more in many cases, but are more effective at finding a Volt VAR switching strategy than rule-based solutions. This benefit is especially true for heavily loaded feeders, such as the utility electric distribution feeders and for frequently reconfigured feeders. The derating factor entered into this row is applied to the initial benefits computed by the VVO algorithms to account for the less-effective rule based solution technique. That is, if 10% is entered for the derating factor and the VVO solution technique is not "Model driven" (see Analysis Control & Summary" worksheet, Cell B14), the initial improvements computed by the VVO BCA algorithm is multiplied by 90% (1 -10%).
- **Number of Feeders and Substations (Rows 191-192):** These inputs are entered in the Analysis Control & Summary worksheet and are included here for convenience only. This user should not overwrite these data fields.
- **Distribution Primary Losses at Peak Load (Row 193):** This data entry field contains the distribution system losses as a percentage of peak load. This value is typically determined by the utility company as part of a system loss study.
- **Distribution Power Factor inputs (Rows 194 to 196):** Rows 194 and 196 contain information about the actual power factor on the electric distribution system during average and peak load conditions respectively. The user should enter the values specified by Utility in the data fields contained in these rows. Row 195 contains the "target" power factor that was specified by the user in the Analysis Control & Summary worksheet. The target power factor is repeated for convenience only, and should not be overridden by the user.

- **Available voltage reduction (Rows 197 and 198):** The percentage entered in Row 197 is the amount that the voltage may be lowered on targeted feeders without violating established low-voltage limits. This value is used to determine the benefits associated with the conservation voltage reduction algorithms that are part of the VVO application. Row 198 contains an additional reduction in voltage that is possible when an effective mechanism is provided to supply voltage feedback to the conservation voltage reduction algorithm. In this case, the voltage feedback would be supplied by the AMI system. This additional voltage reduction is only provided if the user indicates that the DMS-OMS solution is integrated with AMI.
- **CVR factor (Row 199):** The value entered in this data field indicates the load-to-voltage sensitivity of the targeted feeder. For example, a CVR factor of 0.7 indicates that the load is reduced by 0.7% for every 1% voltage reduction. The default value of 0.7 is representative of CVR factors that have been reported by the industry.
- **Engineering studies (Row 200):** Prior to implementing VVO on any feeder, an engineering study should be performed on the targeted feeder to determine the optimal locations of switched capacitor banks and voltage regulators. The amount entered in this field represents the cost to perform each feeder study.
- **VVO software licenses (Rows 201 and 202):** These rows contain the software license fees for the VVO application. The value inserted for the centralized software license applies to centralized DMS applications only. The centralized software license is a one-time cost. For decentralized DA applications, a separate license is required for each substation. Therefore, the decentralized license cost must be multiplied by the number of substations.
- **Cost of switched capacitor bank (Row 203):** This data entry field contains the installed cost for one switched capacitor bank. The DVCalc algorithm calculates the number of switched capacitor banks needed to raise the power factor from the actual (as reported by the Utility) to the target. The quantity of switched capacitor banks is multiplied by the unit cost to determine the total cost for switched capacitor banks.
- **Controller for switched capacitor banks (Rows 204 to 205):** an intelligent device controller must be provided at each switched capacitor bank in order to implement the DA application. Row 204 contains the cost of the controller used for a centralized VVO application. Row 205 contains the cost of the control used for a decentralized DA application. The controller cost for a decentralized application is higher than the controller used for a centralized application, because more of the VVO logic is implemented in the controller when the application is decentralized.
- **Midline Voltage regulators (Rows 206 to 208):** It may be necessary to add a midline voltage regulator and associated controller to each distribution feeder on which the VVO voltage reduction application will be implemented. These rows contain unit costs for the voltage regulators and associated controllers.
- **Communication interface per switch (Row 209):** Each switched capacitor bank and midline voltage regulator requires a communication interface to its associated application processor. The value entered in row 209 is the average cost of the communication facility required to implement this interface. The cost per communication interface is multiplied

by the number of switched capacitor banks and midline voltage regulators to determine the total cost of communication facilities for the DA system.

D.3.16 Other DMS Applications (Rows 211 to 235)

This section of the Utility Input worksheet allows the user to enter information needed to evaluate the benefits of several key DMS applications.

D.3.16.1 Switch Order Management (Rows 212 to 219)

The DMS Switch Order Management (SOM) program assists the system operator in developing the optimal switching strategy needed to restore service following an outage. Computer-assisted generation of switching orders is especially valuable for utility companies (like Utility) that have heavily loaded feeders. The SOM program rapidly finds the switching strategy that can restore service to as many customers as possible following an outage without overloading backup facilities. SOM inputs required by DVCalc are listed in Figure D-18.

211	**Other DMS Applications**			
212	Switch Order Management Being Implemented (Yes/No)	Yes		
213	% of faults that require SOM analysis	50%	*SOM analysis required for faults in the first half of the feeder*	
214	Expected time savings with SOM (minutes)	5	*Control variable - insert value between 5% and 15%*	
215	Switch order management Cost	$ 200,000	2%	

FIGURE D-18 Switch Order Management Data Inputs

The Switch Order Management data entry fields are described below:

- **Percentage of faults that require SOM analysis (Row 213):** In some cases, such as faults that occur near the end of a feeder, it is not necessary to run SOM analysis because the switching strategy is often straightforward and does not require complex analysis. However, for faults that occur near the head end (substation end) of the feeder, detailed analysis may be needed to split the load among several backup sources. In this case, SOM analysis can be quite beneficial. The user should enter in Row 213 the percentage of faults (on average) that require SOM analysis to develop an effective switching strategy. The default value of 50% assumes that SOM analysis will be needed for all faults that occur in the first one half of the feeder.
- **Expected time savings with SOM (Row 214):** This data entry field enables the user to enter the average time savings achieved using the SOM application versus manual development of switching orders. The default value of 5 minutes is a very conservative estimate of the time saved using the SOM application to develop switch orders. For the purposes of calculating reliability improvement benefits, it is assumed that reducing the time to develop switching orders by 5 minutes also reduces overall system restoration time by 5 minutes.

D.3.16.2 Dynamic Asset Rating (Rows 220 to 229)

In many cases, the ratings of key power system assets such as underground cables and substation transformers are based on conservative seasonal assumptions about the ambient conditions in the vicinity of the asset in question. Dynamic asset rating enables the utility to compute ratings of these assets based on actual ambient conditions rather than conservative seasonal assumptions. In most cases this results in a higher rating for the equipment than would otherwise be used. It is assumed that using dynamic equipment ratings would help avoid the need to intentionally shed load to prevent overloading the power system assets. Reducing the amount of manual load shedding will improve overall system reliability.

Figure D-19 shows the data inputs DVCalc requires for the Dynamic Asset Rating benefit cost analysis.

220	***Dynamic Asset Rating***			
221	Dynamic Asset Rating Being Implemented (Yes/No)	Yes		
222	Number of hours per year load shedding due to equipment overl	24		
223	Percentage amount of load shedding during these hours	2%		
224	Amount of Load shedding without DER	3%	Input assumption	
225	Amount of Load shedding with DER	2%	Input assumption	
226	% of feeders on which load shedding applies	10%		
227	Number of substations to be equipped with DAR	3	O&M	
228	Dynamic asset rating software	$ 50,000	2%	*Assumption*
229	Substaion sensors for dynamic asset rating ($/substation)	$ 10,000	*$/Substation*	

FIGURE D-19 DVCalc Input data for Dynamic Asset Rating

The dynamic asset rating software data fields are described below:

- **Number of hours per year load shedding due to overload occurs (Row 222):** This value is the number of hours per year load shedding normally occurs on one or more of the Utility substation transformers. The default value entered in this row (24 hours) is representative of other utilities whose distribution assets are heavily loaded. If necessary, the user should enter a quantity that more accurately reflects the duration of load shedding due to equipment overload that normally occurs on the Utility system.
- **Percentage amount of load shedding during these hours (Row 223): T**his input is an assumed value of load shedding that normally occurs when Utility substation transformers become severely overloaded. The default value is 2%, which means that 2% of the load supplied via the substation transformer is tripped to mitigate the overload. If necessary, the user should enter a quantity that more accurately reflects the amount of load shedding due to equipment overload that normally occurs on the Utility system.
- **Percentage amount of load shedding during these hours when dynamic asset rating is applied (Row 225):** This input is an assumed value of load shedding that would still be required during emergency if dynamic asset rating is implemented. The user should enter

a quantity that reflects the actual amount of load shedding that would be needed if dynamic asset rating were applied.

- **Percentage of feeders and # of substations at which dynamic asset rating is needed (Rows 226 to 227):** DVCalc assumes that dynamic asset rating software will only be applied at the most heavily loaded substations and feeders. Rows 226 and 227 enable the user to specify the percentage and/or specific quantity of feeders in substations that should receive this application.
- **Dynamic asset rating implementation costs (Rows 228 and 229):** These two rows contain information about the initial, one-time costs of implementing the required software and intelligent sensors. The estimated operating and maintenance costs for this equipment are determined by the percentage amount that is entered in row 228.

D.3.16.3 Adaptive Relaying (Rows 230 to 235)

The adaptive relaying DMS function enables the automatic switch over to alternative relay settings as conditions dictate. One application of adaptive relaying that is particularly beneficial is referred to as "fuse saving". When a temporary (self-clearing) fault occurs on a fused branch line, the fuse may blow unnecessarily, causing an extended outage for customers that are served via this fused branch line. Adaptive relaying may be used to clear such temporary faults before the fuse blows and then automatically restore (reclose) service in less than one minute. Fuse saving can produce a significant reliability improvement, as measured by SAIDI and SAIFI.

The following inputs are used by the adaptive relaying benefit cost calculation software:

- **Adaptive relaying being implemented (Row 231):** This data fields is copied from the summary–dashboard worksheet and is provided here for convenience only. Users should not type over the information displayed in the status, as this would disable the link between the two worksheets
- **Number of temporary faults per feeder (Row 232):** The user should enter the average number of temporary faults that occur per year on a representative Utility distribution feeder.
- **Percentage portion of the feeder on fused laterals (Row 234):** The value contained in this field is the approximate percentage of the total feeder that is served via fused laterals. The default value shown (40%) is representative of industry practice. The user should update this value, if necessary, to more accurately reflect the specific electric distribution system under analysis.
- **Number of fused branch lines per feeder (Row 234): The** value is the approximate number of fused branch lines on the average electric distribution feeder. The default number reflects common industry practice. The user should replace the default with a value that more accurately depicts the electric distribution feeders in question.

- **Adaptive relaying application software costs (Row 235):** the values entered in these data-entry fields are the software license fee (one-time cost) and the ongoing annual operating and maintenance costs associated with this application.

D.3.16.4 Substation Automation (Rows 237 to 252)

The section covers the costs to upgrade existing substation automation facilities using a legacy protocol (Distributed Network Protocol [DNP] 3.0, Modbus, etc.) to International Electrotechnical Commission [IEC] 61850, which has become an industry-standard for intra-substation communications. The data entries in these rows are the cost to add the equipment needed to implement and maintain this new communication standard.

The data values needed by DVCalc for computing the cost of substation automation are shown in Figure D-20.

237	Substation Automation	First cost	O&M (%/Yr)	
238	Convert all SA systems to IEC 61850? (Yes/No)	Yes		
239	Add new data concentrator to exsiting substation?	Yes		
240	Cost to procure and configure one digital relay ($/feeder)	$ 5,000	2%	
241	Cost to install 1 digital relay	$ 500		
242	Cost to add data concentrator to substation	$ 50,000	2%	*1 per substation*
243	Cost to install data concentrator in one substation	$ 3,000		
244	Cost to add IEC61850 comm module to existing relay	$ 500		$/relay
245	IEC 61850 configuration cost	$ 500		$/relay
246	% of feeders to convert to IEC 61850	20%		
247	Cost to add IEC61850 comm module to existing relay	$ 500	2%	
248	IEC 61850 configuration cost	$ 500		$/relay
249	Cost to add new data points with IEC 61850 ($/Feeder)	$ 1,000	2%	
250	Cost to add new data points with legacy serial protocol ($/Feeder)	$ 1,500	2%	
251	Labor to convert to IEC 61850 (Hours/device)	8		
252	Cost of new voltage regulator IED	$ 2,500	2%	*1 per trf required for implementing VVO*

FIGURE D-20 Substation Automation Costs

D.3.16.5 Condition Based Maintenance (Rows 254 to 306)

The Condition Based Maintenance (CBM) hardware (sensors) and software will enable the Utility to streamline its business processes for monitoring and maintaining key distribution system assets, such as substation transformers, high-voltage circuit breakers in distribution substations, and distribution feeder circuit breakers. Implementing the CBM application will enable the Utility to reduce its maintenance costs for this equipment by lengthening the interval between routine (calendar-based) tear down inspections. This application will also enable the Utility to detect equipment problems early while still in an incipient stage, so they may be corrected before catastrophic failures occur. Early problem detection will reduce the time and expense needed to repair, rebuild, or replace the equipment in question.

The section of the UTILCO Inputs worksheet enables the user to enter the parameters needed to compute the projected savings that can be achieved by implementing CBM. The variables used to calculate the projected savings for distribution feeder circuit breakers, high-voltage circuit breakers, and substation transformers are different. However, the formulas for computing the projected savings are similar.

D.3.16.6 Distribution Feeder Circuit Breakers (Rows 256 to 262)

The potential savings for distribution feeder circuit breakers are limited to a reduction of the frequency of performing routine electrical and mechanical inspections of feeder circuit breakers. DVCalc inputs for this function are shown in Figure D-21.

256	***Distribution feeder circuit breakers***		
257	CBM for distibution feeders being implemented (Yes/No)	Yes	
258	Period of major inspections without ECM	5	Years
259	Period of major inspections with ECM	9	Years
260	# hours to do major inspection without ECM	12	
261	# hours to do major inspection with ECM	12	**O&M**
262	Cost of distribution feeder CBM	$ 30,000	2%

FIGURE D-21 DVCalc inputs for Distribution Feeder Circuit Breakers

The Distribution Feeder Circuit Breaker required inputs are described below:

- **Period of major inspections with and without CBM (Rows 258 and 259):** Row 258 should specify the interval in years between routine electromechanical inspections of the feeder circuit breakers that is currently being used by the Utility. Row 259 should identify the period between routine electromechanical inspections after CBM has been implemented. The default value for this parameter is based on industry experience.
- **Number of hours to do an electromechanical inspection of feeder circuit breakers with and without condition based maintenance (Rows 260 and 261):** The time required to perform electromechanical inspection of feeder circuit breaker is not expected to change with the new software. Eight hours is entered as a default value for these parameters. The savings are derived from performing these maintenance activities less frequently.
- **Cost of CBM software for electric distribution feeders (Row 262):** This row contains the estimated cost of software licenses for the feeder circuit breaker CBM software and the percentage factor for computing the expected ongoing annual maintenance for the software.

D.3.16.7 High-voltage circuit breakers (Rows 264 to 282)

The benefits of deploying CBM for high-voltage circuit breakers installed in the Utility Company's distribution substations include a reduction in routine electromechanical inspections and early detection of incipient failures. The latter benefit is expected to result in lower costs to repair/rebuild/replace the failed circuit breaker and avoid lengthy customer outages when catastrophic failures occur in this equipment. This High Voltage Circuit Breakers section of the UTILCO Input worksheet is pictured in Figure D-22.

264	***High Voltage Circuit Breakers***			
265	CBM for high voltage CBs being implemented (Yes/No)	Yes		
266	Period of major inspections without ECM	4	Years	
267	Period of major inspections with ECM	8	Years	
268	# hours to do major inspection without ECM	18	Hours	
269	# hours to do major inspection with ECM	18	Hours	
270	Material cost per major inspection without ECM	$2,000		
271	Material cost per major inspection with ECM	$2,000		
272	Years between catastrophic HV CB failures without ECM	15	Years	
273	% failures detected early with ECM	25%	%	
274	Cost to Rebuild/Replace HVCB following catastrophic failure	$ 100,000		
275	Reduction in repair costs if HV CB problem detected early	50%		
276	Time to restore customers impacted by HV CB outage (hours)	1.00	*Assumption*	
277	Cost of CBM software for High voltage Circuit breakers	$ 50,000	2%	
278				
279		**Serial/Legacy**	**IEC 61850**	
280				
281	Cost of new CB monitor for HV CB CBM (serial)	$ 3,000	3500	
282	O&M	3%	2%	

FIGURE D-22 DVCalc inputs for High Voltage Circuit Breakers

The following input parameters are required to make the necessary calculations of the benefits and costs of this DMS application:

- **Period of major inspections with and without CBM (Rows 266 and 267):** Row 266 should specify the interval in years between routine electromechanical inspections of the high-voltage circuit breakers that is currently being used by Utility. Row 267 should identify the period between routine electromechanical inspections after condition based maintenance has been implemented. The default value for this parameter is based on industry experience.
- **Number of hours to do an electromechanical inspection of high voltage circuit breakers with and without CBM (Rows 268 and 269):** The time required to perform electromechanical inspection of high-voltage circuit breakers (HV CB) is not expected to change with the new software. Sixteen hours is entered as a default value for these parameters. Savings achieved by deploying CBM for high-voltage circuit breakers is derived by performing routine maintenance activities less frequently.
- **Material costs for routine electromechanical inspections of high-voltage circuit breakers (Rows 270 and 271):** The user should enter the material cost for each routine

of the mechanical inspection. Default values shown in the worksheet are based on industry experience.

- **Years between catastrophic HV CB failures (Rows 272):** The value entered in this row should reflect the Utility's experience with high-voltage circuit breaker failures.
- **Percent failures of high-voltage circuit breakers detected early with CBM (Row 273):** The default value entered on this row is based on industry experience with the condition based maintenance application function.
- **Cost to Rebuild/Replace HV CB following catastrophic failure (Row 274):** The value entered in this row should reflect the Utility's experience with high-voltage circuit breaker failures.
- **Reduction in repair costs if HV CB problems detected early (Row 275):** The default value entered for this row is based on industry experience.
- **Time to restore customers impacted by a high-voltage circuit breaker failure (Row 276):** The default value entered for this row is based on industry experience.
- **Cost of CBM software for HV CBs (Row 277):** This field includes software license fees (one-time costs) and recurring annual operating and maintenance (O&M) costs expressed as a percentage of the license fee.
- **Cost of new circuit breaker monitors to support the HV CB ECM application (Rows 281 and 282):** These costs may be different depending on the communication standards adopted by the Utility (legacy versus IEC 61850).

D.3.16.8 Substation Transformers (Rows 286 to 306)

The benefits of deploying CBM for substation transformers installed in distribution substations include a reduction in routine electromechanical inspections and early detection of incipient failures. The latter benefit is expected to result in lower costs to repair/rebuild/replace the failed transformer and avoid lengthy customer outages when catastrophic failures occur in this equipment. The Substation Transformers section of the UTILCO Input worksheet is pictured in Figure D-23.

286	***Substation Transformers***			
287	CBM for substation transformers being implemented (Yes/No)	Yes		
288	Period of major inspections without ECM	10	Years	Input
289	Period of major inspections with ECM	15	Years	Assumption
290	# hours to do major inspection without ECM	24	Hours	Input
291	# hours to do major inspection with ECM	24	Hours	Input
292	Period of major inspections without ECM	10	Years	
293	Period of major inspections with ECM	15	Years	
294	Material cost for major inspections without ECM	$100	$/Yr	
295	Material cost for major inspections with ECM	$66.67	$/Yr	
296	Years between catastrophic SS trf failures without ECM	15.00	Years between failures	
297	% failures detected early with ECM	25%	%	
298	Cost to Rebuild/Replace following failure	$500,000	$	
299	Reduction in repair costs if problem detected early	25%	%	
300	Time to restore service to customers impacted by outage	2	hours	
301		**Serial/Legacy**	**IEC 61850**	
302	Cost of new transformer monitor IED	$ 5,000	$ 5,500	
303	Cost of new on-line gas monitor IED for transformer	$ 8,000	$ 8,500	
304	CBM software for substation transformers	$ 10,000	$ 10,000	
305	Annual Maintenance %	3%	2%	
306	Cost of CBM on DMS for substation transformers	$ 75,000	2%	

FIGURE D-23 DVCalc inputs for High Voltage Circuit Breakers

The following input parameters are required to calculate the benefits and costs of this DMS application:

- **Period of major inspections with and without condition based maintenance (Rows 288 and 289):** Row 288 should specify the interval in years between routine electromechanical inspections of the substation transformers that is currently being used by Utility. Row 289 should identify the period between routine electromechanical inspections after CBM has been implemented. The default value for this parameter is based on industry experience.
- **Number of hours to do an electromechanical inspection of substation transformers with and without CBM (Rows 290 and 291):** The time required to perform electromechanical inspection of substation transformers is not expected to change with the new software. Sixteen hours is entered as a default value for these parameters. Savings achieved by deploying CBM for substation transformers is derived by performing routine maintenance activities less frequently.
- **Material costs for routine electromechanical inspections of substation transformers (Rows 294 and 295):** The user should enter the material cost for each routine in the mechanical inspection. Default values shown in the worksheet are based on industry experience.
- **Years between catastrophic substation transformer failures (Rows 296):** The value entered in this row should reflect the Utility's experience with high-voltage transformer failures.

- **Percent failures and substation transformers detected early with CBM (Row 297):** The default value entered on this row is based on industry experience with the condition based maintenance application function.
- **Cost to Rebuild/Replace substation transformer following catastrophic failure (Row 298):** The value entered in this row should reflect the Utility's experience with high-voltage transformer failures. However, since this information was not supplied by the Utility, default values based on industry experience have been used.
- **Reduction in repair costs if high-voltage transformer problems detected early (Row 299):** The default value entered for this row is based on industry experience.
- **Time to restore customers impacted by a high-voltage transformer failure (Row 300):** The default value entered for this row is based on industry experience.
- **Cost of new transformer and gas monitors to support the high-voltage transformer CBM application (Rows 302 and 303):** these costs may be different depending on the communication standards adopted by Utility (legacy versus IEC 61850).
- **Cost of CBM software for substation transformers (Rows 304 to 306):** These fields include software license fees (one-time costs) and recurring annual operating and maintenance (O&M) costs expressed as a percentage of the license fee.

D.4 WORKSHEETS FOR INDIVIDUAL DMS CALCULATIONS

D.4.1 FLISR Worksheet

This section discusses the analysis performed to determine if the benefits achieved by deploying FLISR exceed the cost to implement, operate, and maintain these facilities. The following types of benefits can be achieved by deploying FLISR:

- **Improvement in Service Reliability**. Deploying FLISR on the distribution feeders will reduce outage duration and frequency as indicated by SAIDI and SAIFI, respectively . There is no widely accepted industry standard approach for assigning monetary value to such reliability improvements. The BCA spreadsheet includes several user-selectable mechanisms (see the Analysis Control & Summary worksheet) for monetizing the reliability improvements achieved by using FLISR. The same mechanisms are used to monetize the reliability improvement benefits of other DMS applications such as adaptive relaying (fuse saving).
- **Savings in Field Crew Labor**. FLISR will reduce the fault investigation time through improved fault locating mechanisms. FLISR will narrow down the portion of the feeder that needs to be patrolled. Also, remote control capabilities will eliminate some of the required switching actions, producing a small incremental savings.
- **Reduction in Unserved Energy**. FLISR will restore power faster enabling the utility to get the lights on sooner, and to sell more kilowatt hours that would otherwise be lost. The additional kilowatt-hours sold is a FLISR benefit.

The following sections describe calculation of FLISR "functional" benefits (including reduced customer outage minutes, fewer extended outage events, etc.).Conversion of the functional benefits to US dollars (i.e. monetization) is also described.

D.4.2 Functional Benefits of FLISR

The spreadsheet includes the following simplified formula for estimating the reliability improvement benefit achieved by applying FLISR to a distribution circuit. This formula (see Equation 1 below) can be used to estimate the percent reduction in customer outage minutes when FLISR is applied to a feeder that starts with no feeder automation or automatic line reclosers.

Reliability Improvement Formula:

$$Percent\ Reliability\ Improvement\ = 100 \times N/(N+1) \qquad (D\text{-}1)$$

where N = number of normally closed FLISR line switches.

To illustrate the use of this formula, if there are two normally closed DA switches on the distribution circuit, then the reliability of the feeder is improved by 2/3, that is (2 / (2+1)). This calculation is intuitive because, in this case, the two FLISR switches divide the feeder into three equal parts, so that only one-third of the customers on the feeder will be affected by a line feeder fault.

This equation is only applicable when the following assumptions are true:

1. Permanent faults are equally likely to occur anywhere on the feeder.
2. Customers are evenly distributed over the entire length of the feeder. That is, the number of customers per mile is constant over the entire length of the feeder.
3. The FLISR switches are spaced such that there are equal numbers of customers between each pair of switches and equal likelihood of a fault occurring between any pair of switches.
4. There is at least one reliable backup source of power supply that is downstream of every normally closed line switch.
5. Each backup source is connected to the main feeder by a normally-open tie switch that can be remotely controlled by FLISR. This BCA spreadsheet always adds the cost of a normally-open tie switch to the cost calculations.
6. The backup sources include sufficient spare capacity so that load transfers by FLISR are never blocked by lack of capacity.

It is reasonable to assume that assumptions 1 through 5 above are valid. However, the user must give attention to assumption 6 if feeders are very heavily loaded (over 80% of capacity or higher), which is extremely high compared to industry norms. If a fault occurs when the load is near peak on a feeder that is loaded to 80% of its capacity, only 20% of the faulted feeder's load can be transferred to a backup feeder, versus 67% under ideal conditions.

The BCA spreadsheet for FLISR includes a mechanism to account for blocked load transfers caused by high feeder loading, which, in turn, reduces the amount of reliability improvement. This mechanism takes into account the following factors:

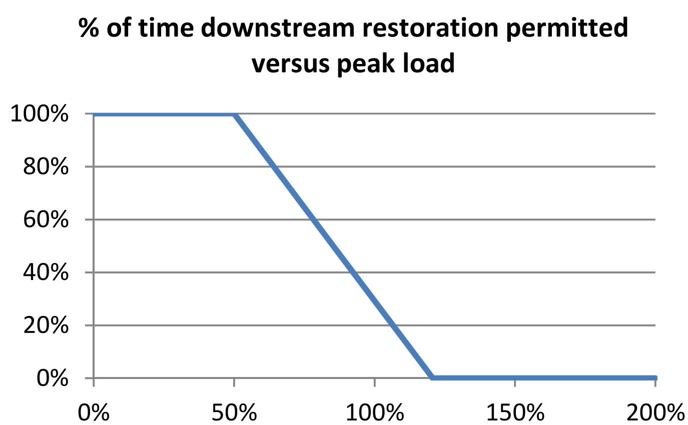
1. "Upstream" restoration (restoration of a load connected to a feeder section that is closer to the normal source than the faulted section) is always permitted regardless of the load at the time of the fault.
2. "Downstream" restoration (restoration of a load that is connected to a feeder section that is farther from the normal source than the faulted section) may or may not be blocked owing to lack of capacity on the faulted feeder. During peak load periods, the downstream restoration would most likely be blocked. However, during off peak periods the load may be small enough to allow the load transfer to go through. The percent of time a downstream load transfer would go through depends on the size of the load:

a. If the peak load is less than or equal to 50% of the feeder rating, then downstream restoration would always be permitted. Therefore, the percentage of time that downstream restoration would be permitted is 100%.

b. If the average load (peak load times load factor) is equal to or greater than 100% of the feeder rating, downstream load transfers would never be permitted. Therefore, the percentage of time that downstream restoration would be permitted is zero percent.

c. The program assumes that if the feeder load is somewhere between these two extremes, the percent of time downstream load transfers would be permitted varies linearly with the peak load.

The FLISR worksheet includes a characteristic curve that represents the above logic (see Figure D-24). Using the technique described above and the Utility-specified peak load of 85.5% of rated capacity, downstream load transfers would be permitted 49.8% of the time.



Peak Load (% of rating)	% of time downstream restoration permitted
0%	100%
50%	100%
85.50%	49.8%
121%	0%
200%	0%

FIGURE D-24 Downstream Restoration Permitted Calculations

Equation 1 must be modified to reflect the fact that downstream restoration may not be permitted 100% of the time. It can be shown that for the ideal feeder (one that satisfies the six assumptions listed above), exactly half of the FLISR reliability improvement is achieved through upstream restoration and exactly half of the FLISR benefit is achieved through downstream restoration. So, Equation 1 may be rewritten as follows:

Percent improvement = (upstream restoration improvement) + (downstream restoration improvement)

$$= \frac{1}{2} \times [N/(N+1)] + \frac{1}{2} \times [N/(N+1)]$$

where N is the number of normally closed DA switches per feeder)

For heavily loaded feeders, the downstream restoration limiting factor must be applied, as shown below:

Percent improvement for heavily loaded feeder:

$$= \frac{1}{2} \times [N/(N+1)] + \frac{1}{2} \times [N/(N+1)] \times (factor)$$

$$= N/\,[2 \times (N+1)] \times (1 + factor)$$

$$= N/\,[2 \times (N+1)] \times (1 + 49.8\%) \textit{ for Utility feeder loading.}$$

D.4.3 FLISR Worksheet Calculations

The FLISR benefit calculations are illustrated in table format in the worksheet itself. The worksheet tables include all inputs and assumptions (obtained from the UTILCO Inputs worksheet) as well as formulas for the benefit calculations. Formulas and sources of inputs are illustrated in Column D of each table.

D.4.3.1 SAIFI Improvement with FLISR

SAIFI improvement is achieved by restoring service to many of the customers on a faulted feeder in less than one minute through automatic sectionalizing. DVCalc uses the reliability improvement algorithms described in the previous section to calculate the SAIFI improvement attributable to FLISR.

Key points about the SAIFI improvement calculation table are listed below:

- The calculations are performed for "worst performing" feeders only. The SAIFI value for worst performing feeders is the starting SAIFI value for the entire Utility system plus an adder to account for the fact that the SAIFI value for worst performing feeders is greater than the system SAIFI value.
- The SAIFI improvement is calculated first for the worst performing feeders. Then, the effect on FLISR is scaled to a system level and is determined by multiplying the SAIFI improvement for worst performing feeders by a factor equal to the total number of customers on the automated worst performing feeders times the total number of customers on the entire Utility system.
- If a rules-based approach (not model driven) is selected by the user (on the "System-Dashboard" worksheet) the SAIFI improvement is reduced by a user-specified "derating" factor (default value is 10%) to account for the reduced effectiveness of rules-based solutions compared to model-driven solutions, especially for complex feeders.

- The FLISR SAIFI improvement worksheet includes the SAIFI improvements from other DMS applications (see rows 70 to 74). The results are combined to provide a final value for SAIDI improvement that can be used for PBR calculations and customer outage cost calculations based on the DOE Interruption Cost Estimate (ICE) model.

D.4.3.2 SAIDI Improvement with FLISR

The calculation of SAIDI improvement from FLISR is similar to the calculations for SAIFI described above. However, additional SAIDI improvement is achieved through a reduction in patrol time, which does not impact SAIFI. Without DA, the entire feeder may have to be patrolled to identify the fault location. With DA only the faulted segment of the feeder needs to be patrolled.

$$\textit{Fractional portion of the feeder that needs to be patrolled:}$$

$$= 1/(N + 1)$$

For example, if $N = 2$, the fractional portion of the feeder that must be patrolled is 1/3. This additional benefit applies only to customers on the faulted segment of the feeder (e.g., 1/3 for $N= 2$) and explains why the denominator in the formula that appears on Row 85 of the FLISR worksheet is squared.

D.4.3.3 Value of Lost Load

Customer outage costs will be reduced if power is restored more quickly using FLISR. Lost kilowatt hours are determined by multiplying the outage duration (SAIDI) times the average feeder load in kW. Lost load savings by deploying FLISR is determined by subtracting the lost load in kWh after DA installation from the lost kWh before DA installation. The resulting amount in kWh is multiplied by the Value of Lost Load (VOLL) factor to monetize the VOLL resulting from FLISR.

D.4.3.4 Reduction of Lost kWh Sales

The reduction of lost kWh sales is determined in the same manner as VOLL (see the Section D.4.3.3). However, instead of multiplying reduction of lost kWh by the VOLL factor, reduction of lost kWh is multiplied by the Utility profit per kWh (assumed to be $0.06/kWh in US dollars).

D.4.3.5 Labor Savings from Reduction of Patrol Time

Fault investigation time (patrol time) will be reduced by adding FLISR because only the faulted section of the feeder as identified by FLISR needs to be patrolled. The Utility has specified that the patrol time is approximately 40% of the total restoration time (SAIDI). The restoration time savings in minutes is determined by multiplying the patrol time factor (40%) by the difference in

SAIDI with and without FLISR. This value is multiplied by the crew hourly rate, including vehicle cost (assumed to be $50/hour in US dollars), to determine the annual labor savings.

D.4.4 Volt VAR Optimization Worksheet

The Volt VAR application will achieve significant efficiency improvements and peak load reduction benefits, as described in the following sections.

D.4.4.1 MWh Loss Reduction

The Volt VAR application can improve the feeder power factor from its current average value (default PF is 98.2%, a very high value compared to industry norms). Improving the power factor to the target value (specified in cell B20 in the Analysis Control & Summary worksheet with a default value of 0.99) will reduce the current flow on the feeder, which in turn reduces the I^2R losses. The formula for computing the reduction in electrical losses for a given improvement in PF is:

$$Percent\ Reduction\ in\ Electrical\ Losses\ = 100 \times \left(1 - Pf_i^2/Pf_f^2\right)$$

where:

Pf_i = *initial average power factor prior to VVO deployment.*

Pf_f = *final average power factor following VVO deployment.*

Pf_f, the final average power factor following VVO deployment, is a target or controlled variable used by DVCalc in its benefit calculations. The DVCalc software assumes a default value for Pf_f of 0.99. The DVCalc user can change the default value as needed.

To determine the reduction of losses in kilowatt-hours, the electrical losses prior to power factor correction by VVO are multiplied by the percent reduction factor given above. The initial losses on the electric distribution system often are determined by a system loss study. For example, the system loss study may indicate the distribution system losses are approximately 3% of total energy consumption. If total energy consumption for this utility is 10,000 gigawatt-hours (GWh), the average power factor before correction is 0.95, and the average power factor following correction is 0.99, then the reduction in losses in megawatt-hours is computed as follows:

$$Reduction\ in\ Electrical\ Losses = 10{,}000\ GWh\ \times 3\%\ \times\ (1 -\ 0.95^2/0.99^2)$$

$$= 23{,}753\ MWh$$

The derivation of this formula is given below:

The initial load on the circuit is given by the following formula:

$$Load\ (L_i) = (current\ (I_i) \times voltage\ (V) \times PF_i)$$

where:

I_i = current delivered to the circuit before power factor correction.

V = source voltage.

PF_i = power factor measured at the head end of the feeder before correction.

After power factor correction, the load on the circuit is given by:

$$Load\ (L_f) = (current\ (I_f) \times voltage\ (V) \times PF_f)$$

where:

I_f = current delivered to the circuit before power factor correction.

V =source voltage.

PF_f = power factor measured at the head end of the feeder after correction.

Assume that the source voltage V and the load L do not change when power factor is corrected. Therefore:

$$L_f \ = \ L_i$$

substituting:

$$I_i \times V \times PF_i = I_f \times V \times PF_f$$

and rewriting:

$$I_i = I_i \times PF_i / PF_f$$

This formula gives the change in current resulting from PF correction.

The losses before and after power factor correction are given by:

$$LOSSES_I = I_i^2 \ \times R$$

Initial losses are known from system loss study.

$$LOSSES_f = I_f^2 \ \times R = \ \left[I_i \times PF_i / PF_f\right]^2 \times R\ (through\ substitution)$$

$$= (I_i^2 \ \times R) \times (PF_i / PF_f)^2$$

$$= LOSSES_i \times (PF_i / PF_f)^2$$

Change in losses due to PF correction is the difference between initial and final losses:

$$= LOSSES_i \times (1 - (PF_i / PF_f)^2)$$

Annual energy losses, $LOSSES_i$, for the Utility is 6.250%.

The formula for $LOSSES_i$ yields the reduction in kWh that are consumed in electrical losses.

For the Analysis of Revenue Requirements, DVCalc escalates the above value each year by the projected load growth. For example, if the projected load growth is 1% per year, then the energy loss savings in Year 2 of the investment will be:

$$Year\ 2\ energy\ loss\ savings = 23{,}753\ MWh \times (1 + 1\%)$$
$$= 26{,}128\ MWh$$

DVCalc then converts the megawatt-hour savings to a monetary value by multiplying the loss reduction in kilowatt-hours by the **marginal generation energy price**. If the energy price is $80 per MWh, the monetary value of reduced losses for this case is $315,070 in Year 1 of the investment. With an inflation rate of 2.0% per year and a load growth rate of 1% per year, Year 2 savings will be:

$$Year\ 2\ energy\ loss\ savings$$
$$= \$1{,}957{,}601/year \times (23{,}753\ MWh \times 80 \times (1 + 2\%) \times (1 + 1\%))$$

As with the FLISR application, if the solution is rule-based, a derating factor is applied to the results to account for the reduced effectiveness of the rule-based solution compared to the model-driven solution.

D.4.4.2 Reduction in peak Electrical demand using voltage reduction

A growing number of electric utilities are reducing voltage during peak load conditions to reduce the peak demand on the electric system. Industry experience has shown that reducing the voltage will lower the electricity consumed by many electrical devices. Many electric utilities haveconfirmed this method of reducing voltage by numerous field trials and actual reduction deployments by many electric utilities.

The formula for computing the approximate reduction in peak demand is shown below:

$$Reduction\ in\ peak\ demand\ due\ to\ voltage\ reduction\ Pk \times CVR_f \times V_{red}$$

where:

Pk = *Peak load in MW prior to voltage reduction.*

CVR_f = Voltage reduction factor, which is the percent reduction in power divided by the percent reduction in voltage; typically this factor is between 0.7 and 0.8.

V_{red} = *Allowable voltage reduction without going below minimum voltage at any point on the feeder. This value is feeder dependent; allowable voltage reduction is often between 2% and 3% of nominal voltage.*

For example, if peak load is 1,000 MW, and CVR_f is 0.7, and the allowable voltage reduction is 2% during peak load conditions, then the demand reduction is calculated as follows:

$$Reduction\ in\ peak\ demand\ due\ to\ voltage\ reduction\ = 1{,}000\ \times 0.7\ \times\ 2\% = 14\ MW$$

The Utility CBA spreadsheet has a default value of 1% voltage reduction. This value is increased by 1% (to a total of 2%) if an accurate and reliable form of voltage feedback (such as near real-time voltage feedback form AMI) is available.

D.4.4.3 Distribution Primary Capacity Released by Improving Power Factor at Peak Load

Improving the power factor during peak load conditions will lower the electrical losses when the load is at peak, which in turn will reduce the peak load. The formula used to determine the percent reduction in peak load due to power factor improvement is slightly different than the formula used to compute the average loss savings, as described below.

If the power factor can be improved during peak load conditions, the peak electric demand in MW will also be reduced. The following formula can be used to determine the reduction in demand for a given improvement in power factor during peak load conditions.

$$Percent\ reduction\ in\ peak\ electrical\ demand\ due\ to\ PF\ improvement\ = 100\ \times\ \left(1 - Pf_i/Pf_f\right)$$

where:

Pf_i = *initial power factor at peak load prior to VVO deployment.*

Pf_f = *final power factor at peak load following VVO deployment.*

To determine the reduction of peak demand due to power factor correction, the peak electrical demand prior to power factor correction are multiplied by the percent reduction factor listed above. The peak demand on the system is determined by measurement. If total energy consumption for this utility is 1,000 msegawatts, the peak power factor before correction is 0.98, and the peak power factor following correction is 0.99, then the approximate peak load reduction in MW is computed as follows:

$$Reduction\ in\ peak\ demand\ due\ to\ PF\ improvement = 1{,}000 \times (1 - 0.98/0.99) = 10\ MW$$

The function demand reduction benefit in MW is multiplied by the value of 1MW capacity, which is based on the marginal power cost (default value is $80,000 in US dollars).

D.4.4.4 KVAR Required to Raise Distribution Power Factor to Target Power Factor (Rows 2 to 10)

Additional reactive power sources may be needed to raise the power factor to a target level. The amount of VAR support that is required depends upon the initial power factor for the feeder in question, the desired target value of power factor, and the load on the feeder. This section describes the derivation of a simple formula that can be used to estimate the amount of VARs that are needed to raise the power factor from an initial value (PF_i) to a target value (PF_t) for a given feeder load.

Figure D-25 shows the relationship between load (kW) and reactive power (kVAR) prior to performing any power factor correction actions.

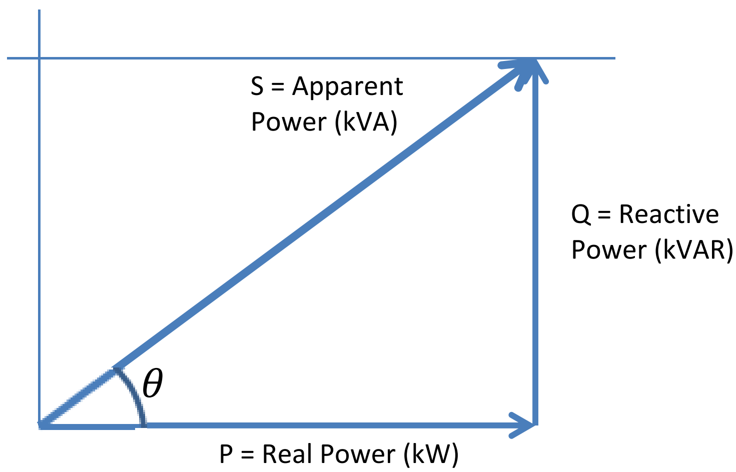


FIGURE D-25 C-23 KW – KVAR – kVA Vector Diagram

From the Figure D-25, it is observed that: $\tan(\theta) = \frac{Q}{P}$

so that:

$$\boldsymbol{Q = P * \ tan(\theta)} \qquad \text{(D-1)}$$

The following definition of power factor $Power\ Factor\ (PF) = \cos(\theta)$ may be rewritten as:

$$\boldsymbol{\theta = acos(PF)} \qquad \text{(D-2)}$$

Substituting equation D-2 into equation D-1, the following equation may be written:

$$\boldsymbol{Q = P * tan(acos(PF))} \qquad \text{(D-3)}$$

Equation D-3 provides a formula for computing the reactive power Q needed to obtain power factor PF for a given load P.

The reactive power needed to raise the power factor from PF_i to PF_t for a load P is the difference between the reactive power Q_t needed for power factor PF_t and the reactive power Q_i needed for power factor PF_i. Q_t and Q_i are computed using equation D-3, and the amount of reactive power needed to raise power factor from PF_i to PF_t is the difference between Q_i and Q_t. See equation D-4 below.

$$Reactive\ power\ to\ add == \boldsymbol{P} * (\boldsymbol{tan}(\boldsymbol{aco\,s}(\boldsymbol{PF_t})) - \boldsymbol{tan}(\boldsymbol{aco\,s}(\boldsymbol{PF_i}))) \qquad \text{(D-4)}$$

D.4.5 Switch Order Management Worksheet

It is often necessary to determine a switching strategy for restoring service to "downstream" customers while repairs are being made to a faulted feeder section. Developing the switching strategy manually can be time consuming especially for heavily load feeders that may have to split between several backup sources to prevent overloads and other adverse consequences. The SOM software automatically assists the system operators in performing the analysis so that a switching strategy can be prepared in less time. Faster preparation of switching orders results in faster service restoration which, in turn, translates to reliability improvement.

The benefit calculations used in this spreadsheet depend on two key issues:

1. Switching order analysis is not required for all faults. In fact, if he fault is near the end of the feeder (furthest from the supply substation), a switching strategy is unnecessary. Hence, a factor of 50% has been used to determine the percentage of faults that require a switching order.
2. Time savings with computer-assisted switching orders is the difference between the time to complete manual analysis and the time to complete computer-assisted analysis. The default value in the spreadsheet is 5-minute savings, which is a very conservative value.

D.4.6 Dynamic Asset Rating Worksheet

During extreme peak load periods in some months, may need to reduce load on designated transformers to prevent overload. It has been assumed that such severe overloads happen between 5 and 10 hours per month on approximately 10% of the Utility feeders (these assumptions may be changed by the spreadsheet user by modifying the values on the UTILCO Inputs worksheet). During these severe overload periods, it has been assumed that Utility implements 5% load shedding actions to mitigate the problem.

The dynamic asset rating application helps to reduce the amount of load shedding needed by computing equipment ratings that are based on actual conditions rather than conservative seasonal assumptions. As a result, it is assumed that the amount of load shedding can be reduced by 10% of the current value (user configurable parameter), resulting in reduction of outage time for customers that would otherwise be impacted by load shedding.

The spreadsheet computes the improvement is SAIDI and SAIFI that can be achieved through dynamic asset rating, and then monetizes the result using the user selected techniques (VOLL, ICE model, PBR, etc.)

D.4.7 Adaptive Relaying Worksheet

Temporary (self-clearing) faults are very common on overhead electric distribution systems. When a temporary fault occurs on a fused branch line, the fuse will blow resulting in a permanent outage for customers that are served on that branch. The DMS adaptive relaying function enables a process known as "fuse saving" that will assist in eliminating the problem of blown fuses for temporary faults. Protective relays in the distribution substations are equipped with two setting groups; one setting group includes an instantaneous setting that will operate the feeder circuit breaker to trip for all faults on the feeder, including temporary faults that are located on fused branch lines. This prevents the fuse from blowing for a temporary fault. After the initial tripping by the substation circuit breaker, this breaker will reclose using the second setting group which is properly coordinated with all branch line fuses. If the fault still exists upon reclosing, this indicates that the fault is permanent, so the fuse will blow. If the fault is a temporary, self-clearing fault, then reclosing will be successful and all customers will have service with only a short (less than one minute) interruption of service during the reclose interval.

D.4.8 Equipment Condition Monitoring (ECM) Worksheet

The principal behind ECM is that improved monitoring of key electric power apparatus (distribution feeder circuit breakers, high voltage circuit breakers in distribution substations, and substation transformers) will enable the utility company to perform routine electromechanical inspections less frequently (labor and material savings), and to detect problems in the equipment early on so that corrective action can occur before catastrophic failure occurs.

D.5 BENEFIT AND COST SUMMARY WORKSHEET

This worksheet provides a more detailed summary of all costs and benefits associated with the selected DMS scenario. All values shown in his table are expressed in Year 1 dollars. The Benefit Summary identifies the annual monetary benefits associated with the selected scenario broken down by application and type of benefit. These benefits begin the year after the implementation is completed through the end of the project life. The Cost Summary includes the initial (one time) implementation costs and the ongoing O&M costs for each application and major architectural component. These costs are incurred each year following the completion of the implementation project.

The user should **not** type anything in these fields as this would overwrite the links to cells in other worksheets containing the benefit calculations.

D.6 EXAMPLES

This section contains examples illustrating the use of the DVCalc software.

GETTING STARTED

The user should open the spreadsheet and select the "Analysis Control & Summary" worksheet. The worksheet that appears on the screen should include a "Control Parameters" area (colored grey) and a "summary of results" section (colored pink).

To obtain the same results as shown in the following examples, the user should ensure that the input values containing in the "UTILCO Inputs" worksheet are the default values contained in the Version 1.0 of the DVCalc worksheet. If any of the values in the "UTILCO Inputs" worksheet have changed, the results obtained may not exactly match the examples provided below. In this case, the default values should be restored before proceeding.

In addition to ensuring that the UTILCO inputs are set at the original default values, the user should ensure that all of the DMS application functions are turned off by setting the control parameters on the "Analysis Control & Summary" worksheet to the original default values. Figure D-26 shows the default control parameters. The user should restore the default settings of each control parameter to ensure that the results received match the examples.

This starting point includes implementing and maintaining a DMS that does not include and applications and interfaces to external systems. Hence, for this starting point, DVCalc shows the Baseline DMS cost (with no applications) but does not include any DMS benefits. The results shown in the "Summary or Results" portion of the "Analysis Control & Summary" worksheet should match the screen capture shown in Figure D-27. If the results do not exactly match, one or more data items have been changed or control parameters have changed and should, therefore, be restored to the original default values to achieve matching results. As noted in the DVCalc

	A	B
1	**CONTROL PARAMETERS**	
2	**Project Information**	**Amount**
3	Initial Year of Project	2016
4	Number of years to implement system	3
5		
6		
7	**DMS-OMS Requirement**	**Yes or No**
8	Outage Management System Required	No
9	Combined or Separated OMS/DMS	
10		
11	**DA Applications Being Implemented**	**Yes or No**
12	Fault Location Isolation & Service Restoration	No
13	Volt-VAR Optimization	No
14	DA Applications model driven or rule based?	Model driven
15	DA Applications centralized or decentralized?	Centralized
16	Number of feeders to automate	100
17	Number of DA Switches per feeder	2
18	Convert non-comm reclosers to DA switches?	No
19	Target power factor for VVO	0.99
20	VVO Includes VAR dispatch?	No
21	VVO includes Voltage Reduction?	No
22		
23	**Other Applications**	**Yes or No**
24	Equipment Condition Based Maintenance	No
25	- Distribution feeder CBM	No
26	- SS HV Circuit Breaker CBM	No
27	- SS Transformer CBM	No
28	% of substations requiring ECM	0%
29	Switch Order Management	No
30	Training simulator	No
31	Data scrubbing for capacity planning	No
32	Dynamic Equipment Rating	No
33	Adaptive relaying (fuse saving)	No
34	Electronic Mapping	No

	A	B
34	**DMS/OMS interfaces that are required**	**Yes or No**
35	Supervisory Control and Data Acquisition	No
36	Geospatial Information System	No
37	Advanced Metering Infrastructure	No
38	Work management system	No
39	System integration technology used	Standard ESB
40		
41	**Substation Automation**	**Yes or No**
42	Add new digital relays for protection and SCADA	No
43	% of Substations that need digital relays	0%
44	Add new SA Data Concentrator at % of subs	No
45	% of Substations to automate	0%
46	Convert % of existing feeders to IEC61850?	No
47	% of feeders to convert to IEC61850	0%
48		
49	**Labor savings**	**Yes or No**
50	Include labor savings in benefit-cost calculations	Yes
51		
52		
53	**Mechanism for Evaluating Reliability Impr Ben**	**Yes or No**
54	Use DOE ICE Software Tool	No
55	- If "Yes", enter $/year from ICE toolfor SAIDI & SAIFI Results	
56	Performance Based Rates	Yes
57	Value of Lost Load (VOLL) analysis	Yes
58	Reduction of lost kWh sales	Yes
59	Labor savings	Yes
60		
61	**Financial & Investment Data**	**Amount**
62	Inflation rate	2.00%
63	Discount Rate	6.00%

FIGURE D-26 Starting DVCalc Control Parameters for Example Cases

instructions, users should only type into yellow-filled cells to prevent overwriting spreadsheet linkages.

The following should be observed in the "Summary of Results" portion of the "Analysis Control & Summary" worksheet:

- All benefits are zero dollars per year because no DMS applications are included
- The Cost summary includes the costs to deploy a DMS with no advanced applications. There are no initial costs associated with substation and feeder equipment. The Investment and O&M $/Year should match the values shown on Figure D-27
- The financial results indicate a negative net present value (NPV), no payback, and zero benefit-to-cost ratio which is expected if there are costs and no benefits
- There are no reliability improvement benefits (SAIDI and SAIFI before and after DMS are the same)

If one or more of the observations on the actual starting spreadsheet do not match Figures D-26 and D-27, then one or more of the default values included in the DVCalc spreadsheet has changed. All values should be restored to the default values before proceeding with the examples.

SUMMARY OF RESULTS

Benefit Summary	$/Year
Reliability Improvement Benefits	$0
VVO Benefits	$0
Dynamic Equipment Rating Benefits	$0
Adaptive Relay (Fuse saving) Benefits	$0
Condition Based Maintenance Benefits	$0
Labor Savings	$0
Total Annual Benefits	$0

Cost Summary	Investment	$/Year
Planning and Procurement	$1,225,000	
OMS/DMS Hardware & Software	$4,100,000	$298,000
Appplication software and studies	$0	$0
System Integration Costs	$0	$0
Substation Equipment	$0	$0
Feeder Equipment	$0	$0
Totals	$5,325,000	$298,000

Financial Results	
Net Present Value	$ (6,851,464)
Payback year	No Payback
Benefit to cost ratio	0.00

Reliability Results	Amounts
SAIDI before	100
SAIDI After	100.00
% Improvement in SAIDI	**0.00%**
SAIFI Before	2.00
SAIFI After	2.00
% Improvement in SAIFI	**0.00%**

FIGURE D-27 Starting Results Summary for DVCalc Examples

The set of test cases is intended to be run in the sequence shown below. The starting point for example 2 is the result of example 1. Similarly, example 3 should follow example 2, etc.

EXAMPLE 1: ADD VOLT-VAR OPTIMIZATION TO THE DMS

This example illustrates how to add Volt-VAR Optimization to the suite of DMS applications. The example also shows how to modify several parameters that DVCalc uses to compute the VVO benefits and costs. For this example:

- Centralized, model-driven VVO application software will be added to the baseline (starter) DMS.
- The DMS VVO application will apply VAR dispatching to 150 distribution feeders
- The Target Power Factor after VVO deployment is 0.98

The user should perform the following steps to execute this test case. Note that data fields in the "Summary of Results" portion of the "Analysis Control & Summary" will update as each data entry is made; the user should wait until all steps are completed before verifying that the correct results have been achieved.

1. Select Volt-VAR Optimization as one of the DA applications being implemented by changing "No" to "Yes" in Cell B13 on the "Analysis Control & Results" worksheet
2. Enter a target power factor of 0.98 in Cell B19 of worksheet "Analysis Control & Summary"
3. Enter the quantity 150 in Cell B16 ("Number of Feeders to Automate") of worksheet "Analysis Control & Summary"
4. Select "Yes" for the "VVO Includes VAR dispatch?" field (Cell B20 of the "Analysis Control & Summary" worksheet.

At the completion of steps 1 – 4 above, the Summary of Results portion of the "Analysis Control & Summary" worksheet should match Figure D-28.

	D	E	F	G	H	I
1	**SUMMARY OF RESULTS**					
2	**Benefit Summary**	**$/Year**		**Cost Summary**	**Investment**	**$/Year**
3	Reliability Improvement Benefits	$0		Planning and Procurement	$1,225,000	
4	VVO Benefits	$1,551,367		OMS/DMS Hardware & Software	$4,100,000	$298,000
5	Dynamic Equipment Rating Benefits	$0		Application software and studies	$500,000	$10,000
6	Adaptive Relay (Fuse saving) Benefits	$0		System Integration Costs	$0	$0
7	Condition Based Maintenance Benefits	$0		Substation Equipment	$0	$0
8	Labor Savings	$0		Feeder Equipment	$1,439,880	$28,798
9	**Total Annual Benefits**	**$1,551,367**		**Totals**	**$7,264,880**	**$336,798**
10						
11	**Financial Results**					
12	Net Present Value	$ 3,324,037				
13	Payback year	2024 (8 years)				
14	Benefit to cost ratio	1.38				
15						
16	**Reliability Results**	**Amounts**				
17	SAIDI before	100				
18	SAIDI After	100.00				
19	% Improvement in SAIDI	**0.00%**				
20	SAIFI Before	2.00				
21	SAIFI After	2.00				
22	% Improvement in SAIFI	**0.00%**				

FIGURE D-28 Summary of Results for Example 1

The user should make the following observations in Figure C-28:

- As seen in Cell E4 of the "Analysis Control & Summary" worksheet, the VVO benefits associated with the VVO VAR dispatch function are $1,551,367/year.
- As seen in Cells H9 and I9, the costs have risen because of the additional cost to add VVO application software and feeder equipment (switched capacitor banks). Note that DVCalc computes the number of capacitor banks needed to raise the power factor from the value prior to implementing DVO to the target value.
- The financial results section shows a positive net present value, a payback interval of 8 years, and a benefit to cost ratio of 1.38. These parameters indicate that an investment on DMS with only the VVO VAR dispatch application implemented is economically viable.
- The Reliability results section is unchanged because the VVO Var Dispatch function does not affect reliability.

Additional details about the results can be viewed by viewing the "Benefit & Cost Summary" worksheet and the "Analysis of Revenue Requirements" worksheet.

EXAMPLE 2: ADD VOLTAGE REDUCTION (CVR) TO THE DMS

This example illustrates how to determine the value of adding the Conservation Voltage reduction (CVR) function of VVO to the suite of DMS applications. The user should perform the following step to execute this test case (Note that it is assumed that the user has previously completed the VAR Dispatch example).

1. Select "Yes" for the "VVO Includes Voltage Reduction?" field (Cell B21 of the "Analysis Control & Summary" worksheet.

At the completion of this step, the Summary of Results portion of the "Analysis Control & Summary" worksheet should match Figure D-29.

	D	E	F	G	H	I
1	**SUMMARY OF RESULTS**					
2	**Benefit Summary**	**$/Year**		**Cost Summary**	**Investment**	**$/Year**
3	Reliability Improvement Benefits	$0		Planning and Procurement	$1,225,000	
4	VVO Benefits	$3,651,367		OMS/DMS Hardware & Software	$4,100,000	$298,000
5	Dynamic Equipment Rating Benefits	$0		Application software and studies	$500,000	$10,000
6	Adaptive Relay (Fuse saving) Benefits	$0		System Integration Costs	$0	$0
7	Condition Based Maintenance Benefits	$0		Substation Equipment	$7,500	$150
8	Labor Savings	$0		Feeder Equipment	$5,564,880	$111,298
9	**Total Annual Benefits**	**$3,651,367**		**Totals**	**$11,397,380**	**$419,448**
10						
11	**Financial Results**					
12	Net Present Value	$ 15,560,464				
13	Payback year	2022 (6 years)				
14	Benefit to cost ratio	2.19				
15						
16	**Reliability Results**	**Amounts**				
17	SAIDI before	100				
18	SAIDI After	100.00				
19	% Improvement in SAIDI	**0.00%**				
20	SAIFI Before	2.00				
21	SAIFI After	2.00				
22	% Improvement in SAIFI	**0.00%**				

FIGURE D-29 Summary of Results for Example 2

The user should make the following observations in Figure D-29:

- As seen in Cell E4 of the "Analysis Control & Summary" worksheet, adding Voltage Reduction function has increased the VVO benefits have increased the VVO benefits from $1,551,367/year to $3,651,367/Year.
- As seen in Cells H9 and I9, the costs have risen because of the additional cost to add substation equipment (controller for voltage regulator) and feeder equipment (midline voltage regulators).
- The financial results section shows that the NPV has improved from $3 million to $15 million, the payback interval has improved from 8 years to 6 years, and the benefit to cost ratio has improved from 1.38 to 2.19. These changes indicate that adding CVR to the DMS VVO application has a very positive impact on the DMS investment.
- The Reliability results section is still unchanged because voltage reduction does not affect reliability.

EXAMPLE 3: ADD FLISR TO THE DMS

This example illustrates how to add FLISR to the suite of DMS applications. The example also shows how to modify several parameters that DVCalc uses to compute the FLISR benefits and costs. For this example:

- Centralized, model-driven FLISR application software will be added to the baseline (starter) DMS.
- The DMS FLISR application will apply FLISR on 150 distribution feeders.

- Three new normally-closed DA switches will be added to each of the feeders being automated, along one normally-open remote controlled tie switch that connects to a backup feeder.
- It is assumed that there are no existing non-communicating line switches on the feeders prior to the FLISR deployment

The user should perform the following steps to execute this test case.

1. Select Fault Location Isolation and Service Restoration as one of the DA applications being implemented by changing "No" to "Yes" in Cell B12 on the "Analysis Control & Results" worksheet.
2. Enter the quantity 3 in Cell B18 of worksheet "Analysis Control & Summary" to designate that there are three normally-closed DA switches per DA feeder. Note that DVCalc automatically adds a normally-open remote controlled ties switch to each feeder.

At the completion of steps 1 – 2 above, the Summary of Results portion of the "Analysis Control & Summary" worksheet should match Figure D-30.

SUMMARY OF RESULTS

Benefit Summary	$/Year
Reliability Improvement Benefits	$3,487,380
VVO Benefits	$3,651,367
Dynamic Equipment Rating Benefits	$0
Adaptive Relay (Fuse saving) Benefits	$0
Condition Based Maintenance Benefits	$0
Labor Savings	$12,100
Total Annual Benefits	**$7,150,847**

Cost Summary	Investment	$/Year
Planning and Procurement	$1,225,000	
OMS/DMS Hardware & Software	$4,100,000	$298,000
Application software and studies	$1,000,000	$20,000
System Integration Costs	$0	$0
Substation Equipment	$7,500	$150
Feeder Equipment	$33,127,380	$662,548
Totals	**$39,459,880**	**$980,698**

Financial Results	
Net Present Value	$ 14,013,722
Payback year	2025 (9 years)
Benefit to cost ratio	1.34

Reliability Results	**Amounts**
SAIDI before	100
SAIDI After	79.89
% Improvement in SAIDI	**20.11%**
SAIFI Before	2.00
SAIFI After	1.72
% Improvement in SAIFI	**13.92%**

FIGURE D-30 Summary of Results for Example 3

The user should make the following observations in Figure D-30:

- As seen in Cell E9 of the “Analysis Control & Summary” worksheet, adding FLISR function has increased the DMS benefits from $3,651,367/Year to $7,150,847/year.
- As seen in Cells H9 and I9, the costs have risen significantly because of the additional cost to add normally-close DA switches to the 150 feeders being automated.
- The financial results section shows that the economic justification for the DMS with VVO and FLISR has diminished. The NPV has decreased from $15 million to $14 million (lower net value over the life of the system), the payback interval has changed (gotten worse) from 6 years to 9 years, and the benefit-to-cost ratio has decreased (gotten worse) from 2.19 to 1.34. These changes indicate that adding FLISR to the DMS has a negative impact on the DMS investment.
- The Reliability results section shows that adding FLISR will provide a significant improvement in both system SAIDI and SAIFI. Note that the “before” and “after” SAIDI/SAIFI numbers reflect the reliability statistics for the entire system (800 feeders) even though FLISR is being added only to 150 feeders, which, supposedly, are the worst performing feeders.
- The decline in economic parameters is due to the fact that reliability improvement benefits do not directly convert to monetary benefits. This example uses VOLL and Performance-based rate rewards/penalties (which may not apply to most utilities) to monetize reliability improvement. If customer outage cost savings, computed by the DOE Interruption Cost Estimator (ICE), had been used, the monetary value of the reliability improvement would have been much greater, producing a positive impact on the results. This difference is because the ICE software model typically assigns a much higher value to customer outage costs than other mechanisms for monetizing reliability improvement benefits.

EXAMPLE 4: ADD FLISR TO FEEDERS WITH NON-COMMUNICATING RECLOSERS IN PLACE

As stated in earlier sections of this document, it is possible to achieve a significant cost savings by retrofitting existing line reclosers with communication capabilities that support FLISR rather than adds all new DA switches. The reliability improvement gained is slightly smaller, but the cost savings by retrofitting existing switches versus installing all new switches is very significant. This example illustrates how to evaluate the costs and benefits of FLISR using retrofit line reclosers rather than all new DA switches.

The user should perform the following step to execute this test case.

1. Select “Convert non-comm reclosers to DA switches?” by changing “No” to “Yes” in Cell B17 on the “Analysis Control & Results” worksheet

At the completion of steps 1 above, the Summary of Results portion of the "Analysis Control & Summary" worksheet should match Figure D-31.

SUMMARY OF RESULTS

Benefit Summary	$/Year
Reliability Improvement Benefits	$3,032,204
VVO Benefits	$3,651,367
Dynamic Equipment Rating Benefits	$0
Adaptive Relay (Fuse saving) Benefits	$0
Condition Based Maintenance Benefits	$0
Labor Savings	$12,100
Total Annual Benefits	**$6,695,672**

Cost Summary	Investment	$/Year
Planning and Procurement	$1,225,000	
OMS/DMS Hardware & Software	$4,100,000	$298,000
Application software and studies	$1,000,000	$20,000
System Integration Costs	$0	$0
Substation Equipment	$7,500	$150
Feeder Equipment	$9,502,380	$190,048
Totals	**$15,834,880**	**$508,198**

Financial Results	
Net Present Value	$ 34,624,541
Payback year	2022 (6 years)
Benefit to cost ratio	2.97

Reliability Results	**Amounts**
SAIDI before	100
SAIDI After	82.68
% Improvement in SAIDI	**17.33%**
SAIFI Before	2.00
SAIFI After	1.78
% Improvement in SAIFI	**11.14%**

FIGURE D-31 Summary of Results for Example 4

The user should make the following observations in Figure D-31:

- As seen in Cell E9 of the "Analysis Control & Summary" worksheet, retrofitting existing line reclosers instead of installing new DA switches has decreased the DMS benefits from $7,150,847/year to $6,695,672/Year.
- As seen in Cells H9 and I9, the costs have declined by almost 60% (from $39,459,880 to $15,834.880) because of the lower cost to retrofit existing line reclosers rather than install all new switches.
- The financial results section shows a significant improvement in economic justification. The investment payback interval has decreased from 9 years to 6 years and the BCR has improved from 1.34 to 2.97.
- The Reliability results section shows that the reliability improvement benefit gained by retrofitting existing non-communicating line reclosers is slightly less than if FLISR was added to feeders with no automatic switch.

The dramatic improvement in DMS economic justification illustrated by this case illustrates the benefit of leveraging existing assets to the fullest extent when deploying DMS advanced applications.

EXAMPLE 5: ADD OMS FUNCTIONALITY TO THE DMS

In this example, OMS functionality is added to the DMS in a separate OMS-DMS configuration. This example also includes the addition of standard ESB interfaces between GIS, AMI, and SCADA with the separate DMS-OMS configuration.

The user should perform the following steps to execute this test case.

1. Select "Outage management System Required?" by entering "Yes" in Cell B8 in the "Analysis Control & Results" worksheet.
2. In the "Combined or Separated OMS/DMS" field (Cell B9 in the "Analysis Control & Results" worksheet) make the selection "Separate" to select the separate OMS-DMS configuration
3. Select the following three interfaces (choose the entry "Yes" for each interface):
   – GIS interface (Cell B36)
   – AMI interface (Cell B37)
   – SCADA interface (Cell B35)

At the completion of steps 1 to 3 above, the Summary of Results portion of the "Analysis Control & Summary" worksheet should match Figure D-32.

	D	E	F	G	H	I
1	**SUMMARY OF RESULTS**					
2	**Benefit Summary**	**$/Year**		**Cost Summary**	**Investment**	**$/Year**
3	Reliability Improvement Benefits	$3,849,579		Planning and Procurement	$2,450,000	
4	VVO Benefits	$4,071,367		OMS/DMS Hardware & Software	$8,200,000	$596,000
5	Dynamic Equipment Rating Benefits	$0		Application software and studies	$1,000,000	$20,000
6	Adaptive Relay (Fuse saving) Benefits	$0		System Integration Costs	$1,100,000	$33,000
7	Condition Based Maintenance Benefits	$0		Substation Equipment	$7,500	$150
8	Labor Savings	$12,100		Feeder Equipment	$9,502,380	$190,048
9	**Total Annual Benefits**	**$7,933,047**		**Totals**	**$22,259,880**	**$839,198**
10						
11	**Financial Results**					
12	Net Present Value	$ 36,273,985				
13	Payback year	2022 (6 years)				
14	Benefit to cost ratio	2.41				
15						
16	**Reliability Results**	**Amounts**				
17	SAIDI before	100				
18	SAIDI After	77.68				
19	% Improvement in SAIDI	**22.33%**				
20	SAIFI Before	2.00				
21	SAIFI After	1.78				
22	% Improvement in SAIFI	**11.14%**				

FIGURE D-32 Summary of Results for Example 5

The user should make the following observations in Figure D-32:

- As seen in Cell E3 of the "Analysis Control & Summary" worksheet, adding OMS to the DMS increases the reliability improvement benefit from $3,032,204/Year to $3,849,579/Year (approximately 27% improvement). The increase in reliability is because the OMS functionality will enable dispatchers to identify a predicted fault location and dispatch crews to the correct location faster than without OMS, thus shortening the overall service restoration time. This effect is especially true for faults that occur beyond lateral fuses, which have no backup sources that can be utilized by FLISR.
- In the Reliability Results section, it can be seen that SAIDI (outage duration) has improved from 82.68 minutes to 77.68 minutes (approximately 6% improvement). Note that SAIFI is not impacted by the addition of OMS because OMS does not shorten outage duration below one or five minutes (the threshold for permanent versus temporary interruptions).
- The cost has risen considerably because of the addition of OMS software and hardware and several new interfaces to external systems. (See cells H9 and I9).
- The impact on financial indicators is mixed. The NPV has risen by approximately 5% indicating slightly better financial value over the life of the system. However, the BCR has dropped from 2.97 to 2.41 (a 23.1% change) indicating that the system that includes OMS is less economical over the life of the system.

The next example includes an assessment of the combined OMS/DMS platform, which is a current industry trend.

EXAMPLE 6: IMPLEMENT A COMBINED OMS-DMS WITH SHARED MODEL

In this example, OMS functionality is added to the DMS in a combined OMS-DMS configuration. All other parameters from the previous example remain the same.

The user should perform the following step to execute this test case.

1. In the "Combined or Separated OMS/DMS" field (Cell B9 in the "Analysis Control & Results" worksheet) make the selection "Combined" to select the Combined OMS-DMS configuration

At the completion of this step, the Summary of Results portion of the "Analysis Control & Summary" worksheet should match Figure D-33.

	D	E	F	G	H	I
1	**SUMMARY OF RESULTS**					
2	**Benefit Summary**	**$/Year**		**Cost Summary**	**Investment**	**$/Year**
3	Reliability Improvement Benefits	$3,849,579		Planning and Procurement	$1,659,375	
4	VVO Benefits	$4,071,367		OMS/DMS Hardware & Software	$5,350,000	$423,000
5	Dynamic Equipment Rating Benefits	$0		Application software and studies	$1,000,000	$20,000
6	Adaptive Relay (Fuse saving) Benefits	$0		System Integration Costs	$600,000	$18,000
7	Condition Based Maintenance Benefits	$0		Substation Equipment	$7,500	$150
8	Labor Savings	$12,100		Feeder Equipment	$9,502,380	$190,048
9	**Total Annual Benefits**	**$7,933,047**		**Totals**	**$18,119,255**	**$651,198**
10						
11	**Financial Results**					
12	Net Present Value	$ 41,294,404				
13	Payback year	2022 (6 years)				
14	Benefit to cost ratio	3.00				
15						
16	**Reliability Results**	**Amounts**				
17	SAIDI before	100				
18	SAIDI After	77.68				
19	% Improvement in SAIDI	**22.33%**				
20	SAIFI Before	2.00				
21	SAIFI After	1.78				
22	% Improvement in SAIFI	**11.14%**				

FIGURE D-33 Summary of Results for Example 6

The user should make the following observations in Figure D-31:

- As seen in Cell E3 of the “Analysis Control & Summary” worksheet, when switching from Separate to Combined OMS/DMS architecture, the reliability improvement benefit is unchanged.
- In the Reliability Results section, it can be seen that SAIDI (outage duration) is unchanged.
- Considerable cost savings are achieved by switching to a combined architecture. As seen in cell H9, cost is reduced from $22,259,880 to $18,119,255 (approximate 19% savings). Combined architecture reduces cost because the complex interface between DMS and OMS is no longer needed and separate interfaces are not required between DMS and OMS to external systems.
- The impact on financial indicators is positive. The NPV has risen to $41,294,404 (approximately 14% better than separate OMS-DMS approach) indicating better financial value over the life of the system. The BCR has increased from 2.41 to 3.00 (a 24% improvement). The payback interval remains unchanged (6 years).

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