ELECTRIC POWER RESEARCH INSTITUTE

Design and Assessment of Volt-VAR Optimization Systems

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Technical Update, December 2011

EPRI Project Manager

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PRODUCT DESCRIPTION

Utilities are seeking to improve the overall efficiency and performance of the distribution system to squeeze more capacity out of existing facilities and to accommodate high penetrations of distributed energy resources, including renewable generating sources with highly variable output. Distribution voltage optimization (DVO) will play a major role in accomplishing these objectives without compromising safety, asset protection, and operating constraints (such as maximum loading and minimum/maximum voltage levels).

This report explains how electric utilities can successfully use DVO effectively to accomplish the desired objectives. It includes an overview of DVO requirements, an assessment of various approaches to implement DVO, an analysis of DVO design parameters, summaries of DVO projects that have been implemented by electric utilities, descriptions of current vendor offerings, and other valuable information about DVO.

Results and Findings

DVO has proven to be an effective mechanism for improving the overall efficiency of the distribution system by reducing electricity usage (demand and energy) and electrical losses without compromising basic operating constraints and objectives. DVO can also provide additional benefits such as the reduction in tap changer operations. The improved visibility of distribution voltage conditions DVO systems has also led to the early discovery of problems in switched capacitor banks, voltage regulators, and load tap changers.

The most common DVO objectives are energy conservation and peak shaving, which utilities are achieving through voltage reduction. Voltage reduction is proving to be one of the most cost-effective measures to achieve these objectives because this application can leverage existing voltage and volt-ampere-reactive (VAR) control equipment.

Many electric distribution utilities are currently evaluating DVO through small- to medium-scale demonstration projects on actual feeders, and the energy savings results and peak shaving results achieved have generally been positive. Several North American utilities that have implemented or are in the process of implementing a distribution management system (DMS) have included DVO as one of the key DMS advanced application functions. Several utilities that are currently investigating and demonstrating DVO have indicated that this application will be included in a future DMS to gain additional flexibility and performance that is provided by the model-driven solution.

Challenges and Objectives

One of the most significant challenges facing electric utilities that are seeking to deploy DVO systems is the lack of mature, field-proven vendor products. Many system vendors offer DVO solutions that are based on these more sophisticated design approaches, but few are mature, field-proven products. This report includes a section on current vendor offerings that summarizes the current offerings, level of experience, solution approach, unique features, and other information to assist the utility company in identifying and evaluating vendors.

Another major challenge facing utilities deploying energy efficiency improvement projects such as DVO is cost recovery. Suitable cost recovery mechanisms must be provided to enable the electric distribution utility to replace revenue lost because of lower kilowatt-hour sales on more efficient distribution systems. This report summarizes revenue recovery mechanisms (such as revenue decoupling) that are being used by some electric distribution utilities that have deployed DVO.

A closely related subject that is covered in this report is verifying the benefits of energy efficiency measures such as DVO. It is especially challenging to identify the actual energy efficiency improvements associated with DVO because energy efficiency cannot be measured directly. The stochastic (random) nature of customer loading makes it difficult to determine the actual benefit at any given time. This report describes measurement and verification (M&V) techniques that can be used to estimate the benefits over time with a reasonable level of confidence.

Applications, Value, and Use

This project developed guidelines for dealing with the challenges described previously and other challenges that are described in other sections of this report. The findings documented in this report will serve as a valuable reference manual for electric distribution utilities that are contemplating DVO implementation. Electric utilities should use the results presented in this document to assist in the planning, design, specification, installation, commissioning, and verification of DVO systems.

Approach

EPRI views this research as meshing with a number of programs involving advanced distribution system analysis. EPRI personnel have extensive knowledge of this area and personally know key vendor representatives, which has enabled EPRI to receive ready cooperation from most of the vendors of interest. EPRI's goal is to make the know-how for DVO more widely dispersed, ultimately leading to more choices for EPRI members for tools with this capability.

Keywords

Conservation voltage reduction
Critical measurements
Line drop compensation
Measurement and verification
Voltage reduction
Voltage regulation

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INTRODUCTION

Project Background

Voltage optimization on distribution systems has the potential to reduce losses on the distribution system itself and also facilitate energy conservation and/or demand management on the customer side. There are many different approaches for implementing voltage optimization systems, ranging from centralized model-based management of the distribution voltage to substation based controls to individual controls acting independently on capacitors and regulators throughout the system.

This project builds on substantial work in 2009 and 2010 to evaluate and characterize the different approaches for voltage optimization. The EPRI Green Circuits initiative has created a library of distribution models that can be used to evaluate different control approaches. In addition, a supplemental project in 2010-2011 is developing advanced load models that will provide better estimates of the effectiveness of voltage optimization in terms of energy conservation and demand reduction. The work conducted as part of this project provides analytical models of the basic approaches for voltage optimization. These analytical models of the control system implementation have been applied on a set of distribution systems that represent the variety of distribution system characteristics.

The result is an initial guide for implementing voltage optimization as a function of distribution characteristics. This effort is being coordinated with the IEEE Power and Energy (PES) Society's Volt/Var Task Force that was recently formed under the Smart Distribution Working Group.

Scope and Objectives

The objective of this project and report is to provide guidelines for successful implementation of Distribution Voltage Optimization (DVO) based on EPRI experiences, research, and analysis; lessons learned by electric distribution utilities that have already implemented DVO on their distribution system; DVO system vendor inputs; and research in the academic community. The guidelines and reference materials contained in this report will be extremely valuable to utilities that are contemplating implementing a new DVO system or upgrading an existing demonstration project.

This project provides:

- A foundation for implementing voltage optimization systems as a function of distribution system characteristics and existing infrastructure
- Tools for assessing voltage optimization performance at the design stage (support of business case development)
- Field experience from actual implementations
- New functionality that can improve the performance of voltage optimization systems

The scope of the project and report are limited to “steady state” distribution voltage optimization. This includes managing continuous voltage levels and reactive power (VAR) flow within acceptable limits while improving the overall efficiency of the distribution system. This project and report does **not** address the important issue of “dynamic” voltage control which involves mitigating the consequences of short duration (measured in seconds and minutes) voltage perturbations resulting caused major, non-linear customer loads and high penetrations of distributed generation facilities (especially wind power and solar photovoltaic distributed generators) that have highly variable output power.

Organization of this Report

This report is organized as follows:

- **Section 1 – Introduction** - provides the project background, summarizes the key research objectives for this project, and provides an overview of the specific work activities of the project.
- **Section 2 – Distribution System Optimization in the Smart Grid Era –** provides a summary of key issues pertaining to distribution system optimization. Lays foundation for other more detailed sections of the report.
- **Section 3 – Approaches to Distribution Voltage Optimization –** Identifies the four major approaches to distribution system optimization and summarizes the major strengths and weaknesses of each approach.
- **Section 4 – Modeling and Analysis of DVO Approaches –** This chapter provides an analytical comparison of the various approaches to DVO. The analysis uses OpenDSS models of feeders from our funding members to compare the approaches from technical and economic views.
- **Section 5 – Specific Design Issues Pertaining to DVO –** This chapter does a deep dive into key design issues pertaining to DVO. This section includes detailed information on critical input measurements for DVO, DVO control strategy and settings, impact of distributed energy resources, communication issues, modeling for DMS-based DVO, determining the costs and benefits (including discussion of Measurement and Verification approaches). The list of issues is aligned with the VVO workshop conducted in Charlotte.
- **Section 6 – Vendor Offerings –** This chapter summarizes the Distribution Voltage Optimization solutions offered by various system suppliers. The section includes system descriptions, functionality, general architecture used, unique features, and (where available) recent project descriptions.
- **Section 7 – Utility Case Studies –** This chapter summarizes distribution voltage optimization efforts by various electric utilities that have already implemented a DVO system or demonstration project.
- **Section 8 – Summary and Conclusions –** contains a summary of the major findings, conclusions, and recommendations of the study.

2

DISTRIBUTION VOLTAGE OPTIMIZATION IN THE SMART GRID ERA

Introduction

Volt-VAR control is not a new concept. In fact, electric distribution utilities have used volt-VAR control for many years to accomplish one of the basic design objectives for the distribution system, which is to maintain acceptable voltage for all customers under all loading conditions. In the United States, electric utilities use the ANSI C84.1 standards to identify the acceptable voltage range. Fig. 2-1 depicts this basic requirement for volt-VAR control. Another basic objective for conventional Volt-VAR control is to maintain power factor at an acceptable level (ideally, near unity) to minimize electrical losses and voltage drop along the feeder.

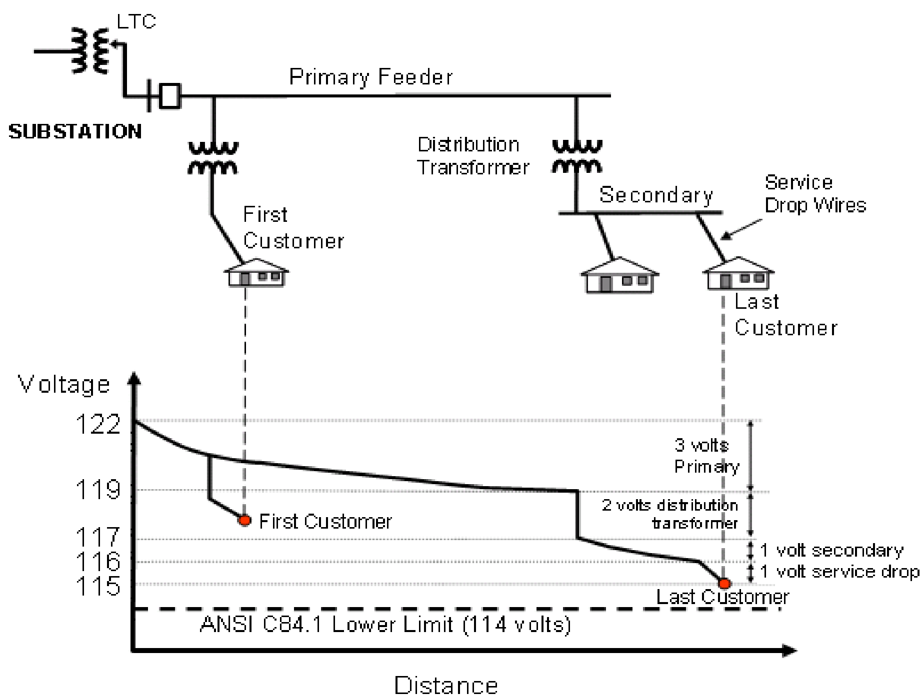

Figure 2-1
Maintaining Acceptable Voltage Levels For All Customers [1]

In recent years, the smart grid concept has revolutionized the way electric utilities design and operate their electric distribution systems. The smart grid concept has dramatically changed the design and operation of modern Volt-VAR control systems. As a result, the objectives for Volt-VAR Control have expanded considerably beyond simply maintaining acceptable voltage and power factor. “Volt-VAR Control” has become “Volt-VAR Optimization”, which has the expanded objectives to increase overall efficiency, reduce electrical demand, promote energy conservation, and improve power quality.

Impact of Smart Grid on VVO Requirements

The electric utility industry widely accepts the following design objectives for the modern power grid [2]:

1. Self healing
2. Motivates and includes the customer
3. Resists attack
4. Provides power quality for the 21st century needs
5. Accommodates all generation and storage options
6. Enables markets
7. Optimizes assets and operates efficiently

Volt-VAR control systems for the modern power grid will play a key role in achieving several of these objectives:

- Self healing – The Volt-VAR Optimization (VVO) system must continue to operate correctly following the "self healing" switching actions performed by automatic restoration systems. Such switching actions may change the position of existing voltage regulators and capacitor banks relative to the feeder's source of supply. The VVO system must adapt the settings of these devices to avoid misoperation while in the altered feeder configuration.
- Accommodates all generation and storage options – High penetrations of distributed energy resources (DERs) and other active components out on the distribution feeders provide both an opportunity and a challenge for electric distribution utilities. DERs can reduce the flow of real and reactive power from central generating resources, thereby reducing electrical demand and electrical losses on the transmission and subtransmission systems. However, DERs can dramatically alter the power flow along the feeder, causing voltage rise and other phenomena that that will challenge existing volt-VAR control facilities. In addition, DERs may impose voltage fluctuations that cannot be tolerated by the electric distribution customers. The VVO system must be flexible enough to exploit the opportunities while mitigating the adverse consequences of DERs. In this way, VVO will play a key role in achieving this smart grid objective.
- Optimizes assets and operates efficiently – Today's electric utilities are facing considerable pressure to operate as efficiently as possible under all operating conditions, the benefits being reduced losses and greenhouse gas emissions, improved asset utilization, and lower demand on existing facilities. VVO will play a major role in achieving these new and important operating objectives.

Volt-VAR Optimization systems must accommodate distributed energy resources (DERs), and must respond automatically when the status or output level of DERs changes. In addition, Volt-VAR Optimization systems must operate effectively following feeder reconfiguration, which will happen more frequently in a smart distribution grid due to optimal network reconfiguration, automatic service restoration, and other applications involving "smart" switching.

Major VVO Functions

As the name implies, Volt-VAR control and optimization is generally comprised of two main parts: VAR control and Voltage control. Early volt-VAR control schemes handled these two main functions separately via independent controllers with little or no coordination of control actions. The current industry trend is integrated volt-VAR control in which control of switched capacitor banks, voltage regulators, substation transformer load tap changers (LTCs), and other volt-VAR control devices is fully coordinated to produce optimal results.

VAR Control

VAR control is the management of reactive power flow in the electric distribution system. In the past, VAR control focused on maintaining power factor (PF) on the distribution system as close to unity as possible to reduce electrical losses and to minimize the flow of reactive power from the central generators over the transmission and transmission networks to the distribution system. VAR control was usually accomplished by installing fixed and switched capacitor banks in the distribution substations and out on the distribution feeders themselves. The control objective is to switch the capacitor bank on when needed most based on “local” measurements (measurements taken at the capacitor bank location itself) that directly or indirectly indicate the need for more reactive power compensation. Figure 2-2 lists the typical control parameters for switched capacitor banks with standalone controllers.

VAR control has grown considerably more complicated in the smart grid era due to the presence of Distributed Energy Resources (DERs) on the distribution feeders, which can operate with a leading power factor (VAR source) or lagging power factor (VAR consumer).

- Voltage
- Time
- Temperature
- Time-biased voltage
- Time-biased temperature
- VAR control
- Current control strategies
- Voltage/temperature override

Figure 2-2
Control Parameters For Switched Capacitor Banks

It is common practice to operate DERs whose point-of-connection is near the feeder source of supply as a reactive power source. This minimizes the reactive power demand on the central generators and transmission grid. DERs located near the end of a feeder are commonly operated with a lagging power factor. The voltage drop associated with the flow of reactive power over the length of the feeder compensates for the voltage rise associated with reverse power flow from distributed generators located at feeder extremities.

Voltage Control

Voltage control is the management of voltage at all points along the distribution feeder. The primary objective for voltage control has been to maintain acceptable voltage for all customers under all loading conditions. Figure 2-3 shows the range of acceptable voltage conditions. It is common practice for utilities to operate in the upper portion of the acceptable voltage range. This ensures that the voltage will not temporarily dip below the voltage range for “out of normal operation” shown in the figure when voltage sags caused by faults that can occur anywhere on the power grid.

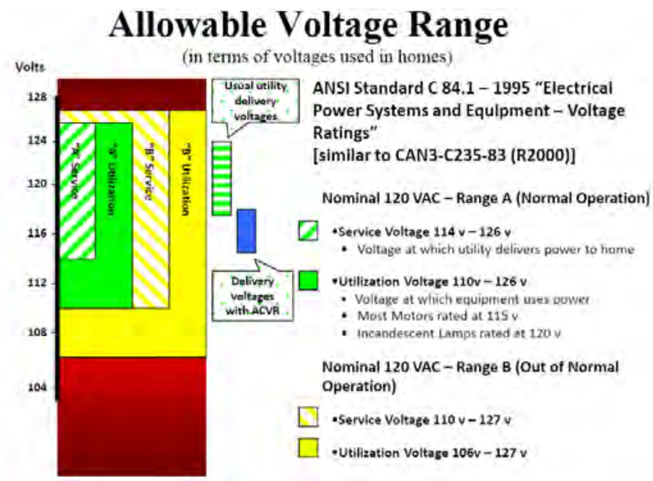

Figure 2-3
Acceptable voltage range (courtesy of PCS Utilidata)

Elements of the smart grid impose numerous challenges on the voltage control requirements for electric distribution feeders. Perhaps the most significant challenges are associated with the presence of large scale distributed energy resources (distributed generators, renewables, and energy storage) out on the distribution feeders. These resources can produce power flow in the reverse direction (back towards the primary electric utility substation), often producing a voltage rise as you move further from the substation instead of the normal voltage drop. If distribution feeders with a high penetration of DERs are fed from the same substation bus as a feeder that does not have a high penetration of DERs, the situation shown in Figure 2-4 may occur, in which one feeder experiences high voltage while a feeder fed from the same bus experiences low voltage.

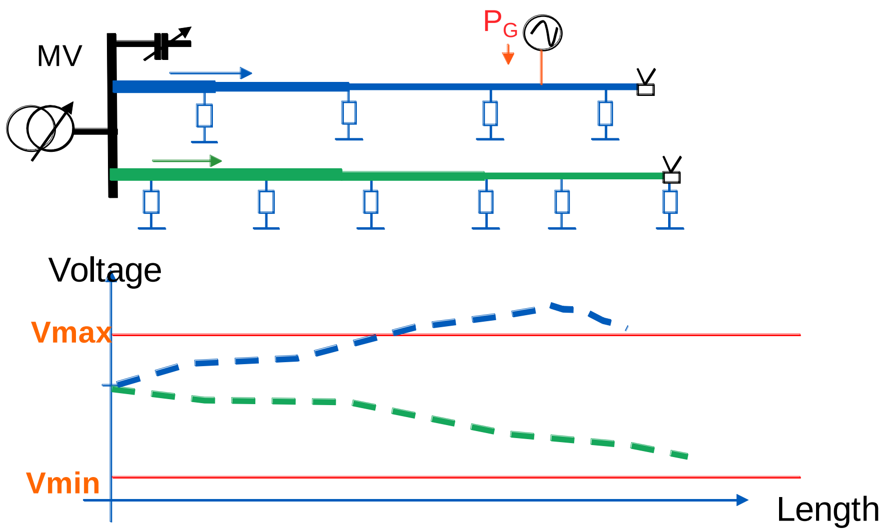

Figure 2-4
Conflicting Voltage Control Requirements [3]

Traditional voltage control schemes often use line drop compensation (LDC) to regulate feeder voltage. The LDC scheme uses the bus voltage measurement, measured power flow through the voltage regulator or LTC, and voltage regulator settings representing the line resistance and reactance to compute the voltage at a fictitious point on the feeder that is near the load center of the feeder. This method may not operate correctly when a significant portion of feeder load is carried by distributed generation and thus does not pass through the LTC or voltage regulator. In such cases, a traditional voltage regulator or LTC using line drop compensation may interpret the low through-current flow as a feeder minimum load condition when the load is actually near peak load. If so, the voltage regulator or LTC may actually lower the voltage when increased voltage is needed.

Reverse power flow caused by large scale distributed generation may cause bidirectional voltage regulators to misoperate. Bidirectional voltage regulators work well when the reverse power flow is caused by feeder reconfiguration. However, when reverse power flow is caused by DG units, the bidirectional voltage regulator will attempt to regulate the strong normal source of the feeder, and in most cases will be unsuccessful in doing so. In such cases, the bidirectional voltage regulator must be informed whether the reverse power flow is due to feeder reconfiguration or large scale DG contribution. (Section 5 contains a more detailed description of this potential problem)

Clearly, additional intelligence is needed to address the DER contributions that complicate traditional distribution voltage regulation.

Voltage Reduction

Recently, as electric utilities seek to address energy efficiency and conservation portfolios, many electric distribution utilities are turning to voltage reduction as a way to satisfy energy efficiency, demand reduction, and energy conservation objectives. Voltage reduction involves operating the distribution feeder at a voltage that is in the lower portion of the acceptable voltage range (See Figure 2-3). Electric utility experience, backed by extensive laboratory testing [4], has shown that many electrical loads, especially electric motors, consume less real and reactive power and perform just as well (or better) when voltage is lowered slightly. When voltage reduction is performed at all times (24 hours per day, seven days per week), this is called “Conservation Voltage Reduction”. This is because 24-hour-per-day operation is primarily intended to promote energy conservation. If voltage reduction is used only during peak load periods for purposes of peak shaving, the term voltage reduction (VR) or voltage optimization is commonly used.

Many electric utilities and their associated grid management authority have used voltage reduction as a means of reducing power quickly during a peak load emergency. In the past, such voltage reductions were referred to as “brown-outs” due to the dimming effect voltage reduction may have on incandescent light bulbs. For the most part the term no longer applies as the newer generation of compact fluorescent lamps remains bright as voltage is reduced by up to five percent. Numerous utilities are planning to operate with reduced voltage on a continuous basis (for energy conservation) or during peak load periods (for demand reduction).

To implement VR effectively with no adverse impact on consumer electrical loads, it is often necessary to implement distribution infrastructure improvements to “flatten” the voltage profile along the feeder. This allows more voltage reduction without violating minimum voltage constraints. Figure 2-5 illustrates the use of switched capacitor banks to “flatten” the voltage profile, followed by voltage reduction. The green line in this figure represents the starting voltage profile at one point in time along the feeder. The red line shows the impact of voltage “flattening”. In this cases the effect was achieved by switching on the three switched capacitor banks that are installed on the feeder. The brown line in Figure 2-5, shows the effect of voltage reduction on the “flattened” voltage profile. As seen n Figure 2-5, the voltage level at the end of the feeder that is furthest from the substation changes very little from the starting point. However, the voltage at all other points along the feeder are reduced considerably. This illustrates the benefit of voltage conditioning.

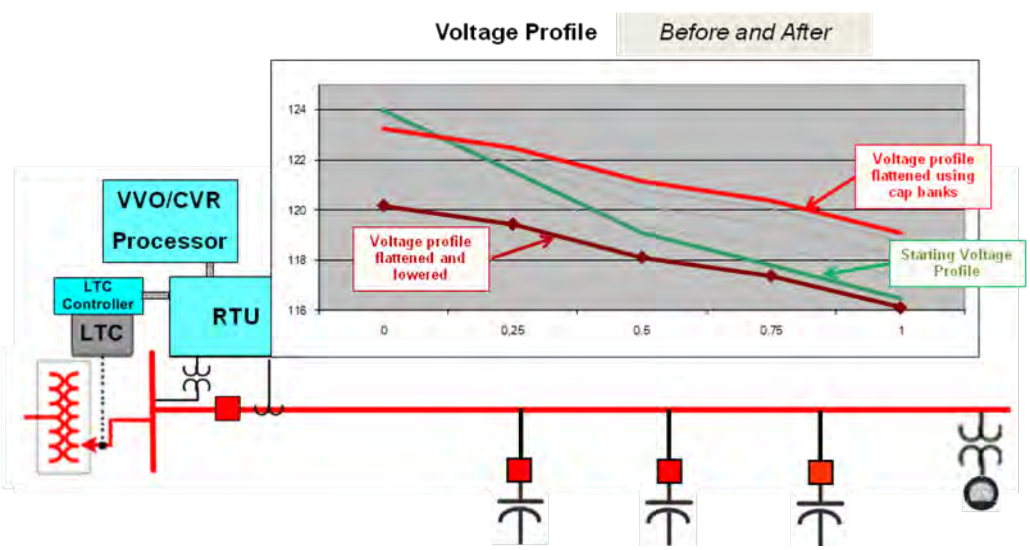

Figure 2-5
“Flattening” And “Lowering” The Voltage Profile

Many electric utilities view VR as a very attractive measure for efficiency improvement, because, in most cases, significant benefits can be achieved for a minimal investment and with no customer sacrifices. Because VR can usually be implemented without making major investments in equipment and infrastructure improvements, benefits can be achieved in the shortest possible time.

The specific benefits that can be achieved on any particular substation and group vary based on customer type (residential, commercial, industrial, etc), time of day, day of week and season, climate zone, and other such factors. The amount of benefit is also affected by the degree to which voltage can be reduced. Feeders whose minimum voltage is near the bottom of the acceptable range will provide little or no VR benefits, while feeders with higher distribution voltage often gain the most from VR.

VR benefits will be affected by new “up and coming” appliances that comprise a growing percentage of the load. Many new appliances will be equipped with electronic controls that improve the nominal efficiency of the device. Many of these controls exhibit “constant power” behavior which is not favorable for achieving CVR benefits. With constant power loads, the electricity consumed by the device stays constant as voltage is reduced. However, as the voltage is reduced, current increases which can produce higher electrical (I^2R) losses on the feeder. Due to the critical nature of the application (e.g., system emergency voltage reduction), it is important to be able to predict the outcome of voltage reduction.

To assist electric utilities in evaluating the short term and long term benefits of VR and CVR, EPRI has embarked on a new research effort: “Load Modeling for Voltage Optimization” [5]. This project includes laboratory testing to identify characteristics of new appliances under reduced voltage conditions, development of a library of customer load models for standard customer classes, and extensive field demonstrations to verify the accuracy of the new customer load models. This research effort is being coordinated with the Volt-VAR Task Force of the IEEE PES Smart Distribution Working Group and its task force for volt-var optimization.

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3
APPROACHES TO VOLT VAR CONTROL AND OPTIMIZATION

Approaches to VVO

Electric distribution utility requirements for Volt-VAR control and optimization have evolved considerably in recent years. To address the expanding requirements for volt-VAR control, several new approaches to volt-VAR control have been introduced.

- Traditional Standalone Controller Approach
- SCADA "Rule-Based" System
- DMS "Model-Based" Solution
- Heuristic (Self Learning, Auto-Adaptive) Approach

This section describes these approaches and identifies the major strengths and weaknesses of each approach.

Traditional Standalone Controller Approach

Traditionally, electric distribution utilities have used standalone controllers for operating switched capacitor banks, voltage regulators (including substation transformers with under load tap changers), and other volt-var control devices. These standalone controllers use internal device settings and "local" measurements (current, voltage, ambient conditions, etc) to determine the suitable control actions for the associated capacitor bank or voltage regulator. Figure 3-1 depicts the local controller approach.

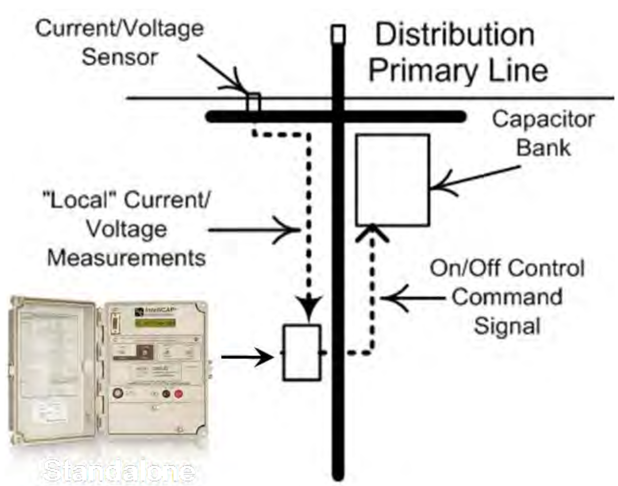


Figure 3-1
Standalone Volt-Var Controller Approach

This approach has served the industry well for many years, and continues to be a very effective approach in some circumstances. The major strengths and weaknesses of this approach are listed below:

- Strengths
  - This is the least expensive approach because, for the most part, it uses existing equipment. The approach does not require a communication facility which can be expensive to implement and maintain.
  - This is the most familiar approach, and thus requires little or no learning curve for operating and maintenance personnel. The value of this strength cannot be overstated. Other more sophisticated approaches to VVO require new operating procedures and a considerable amount of training that must continue throughout the life of the system.
- Weaknesses
  - The controllers lack the flexibility to respond to changing conditions out on the feeder (feeder reconfiguration, presence or absence of distributed energy resources, etc). When such changes occur, the controllers may not operate in optimal fashion.
  - This approach does not provide voltage feedback for critical measurement points on the feeder which is necessary for “closed loop” control. As a result, the system must operate with a greater margin above the minimum acceptable voltage to avoid violating minimum voltage constraints.
  - The approach does not include communications of any sort. While this has already been identified as a strength of the standalone approach (avoids cost to implement and maintain), lack of communications is also a significant weakness of the approach. The controllers rely completely on local measurements and do not contain information about changing system or feeder conditions at remote locations. Without communications, it is not possible to implement “closed loop” control, which requires voltage feedback from feeder extremities and other possible “lowest voltage” locations. As a result, a larger operating margin is needed to avoid violating voltage limits and constraints.
  - System operators are not able to monitor the operation of the switched capacitor banks due to lack of communication facilities. If the controller, switch, or capacitor banks itself fails, the electric utility may not know this until a manual inspection occurs.
  - There is minimal coordination between standalone controllers. Typically, the controllers include coordinating time intervals that ensure the controllers do not execute conflicting control actions (“hunting”) with other standalone voltage and VAR control devices.

As a result of the limitations listed above, the standalone controller method may not work well in circumstances where feeders are frequently reconfigured and on feeders that include large scale distributed generating units. However, the controllers themselves will play a significant role as end-point device controllers, and will also enable “failsafe” mode for the “system” approaches described next.

SCADA "Rules-Based" Approach

Arguably the most common approach to VVO in use today is the SCADA "rules based" approach, which is depicted in Figure 3-2. This approach determines what volt-VAR control actions to take by applying a predetermined set of logical "rules" to a set of real time measurements from the associated substation and feeder. An example rule is: "If the voltage measured at point "X" is less than 120 volts AND the reactive power flow measured at the substation end of the feeder is greater that 900kVAR (lagging), then switch capacitor bank "1" to the ON position". These rules are determined in advance by the distribution engineers and operators using power flow analysis.

The SCADA rules-based approach is similar to the standalone controller approach in that both approaches rely on intelligent controllers for interfacing with the switched capacitor banks, voltage regulators, LTCs, and other volt-VAR control devices. The most significant difference between the SCADA rules-based approach and the standalone controller approach is the addition of communication facilities that are typically part if a Distribution Supervisory Control and Data Acquisition (DSCADA) system. The communication facilities enable the system to base its control actions on overall system conditions rather than just on local conditions at the site of the capacitor bank or voltage regulator. The communication facilities also enable the electric distribution utility to monitor the operating status of the field voltage control and VAR control equipment so that appropriate actions can be taken immediately when a component failure occurs.

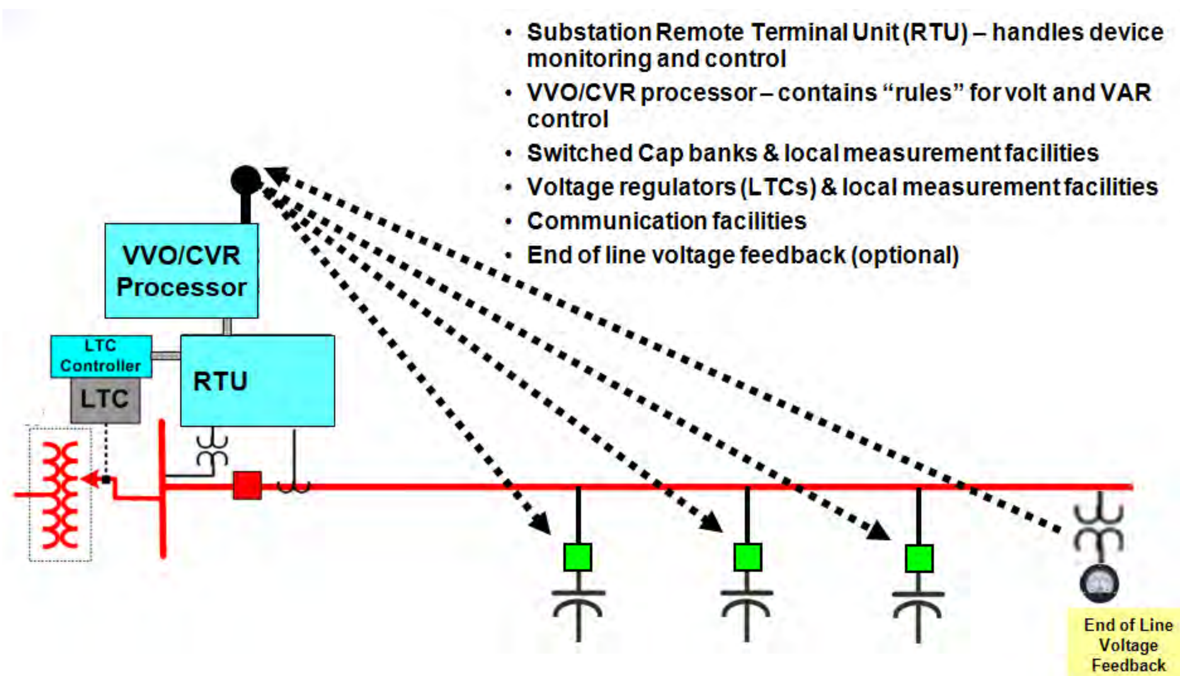


Figure 3-2
SCADA Rules Based Approach

The major strengths and weaknesses of this approach are listed below:

- Strengths
  - Control actions are based on overall distribution system conditions rather than local measurements. This ensures that the resulting control actions are the best from an overall system standpoint and are not driven solely by localized measurements.
  - The rules-based approach is able to receive critical measurement feedback for closed loop control that allows the utility to operate with smaller safety margin to achieve additional benefits versus “open loop” control (has no feedback from critical measurement locations).
  - The operation of independent Volt-VAR devices can be coordinated to some extent via the rules.
  - The distribution system operator is able to monitor the health and performance of the system. If a component failure occurs, this is automatically detected and reported to the operator so that the problem can be corrected in the shortest possible time.
  - The SCADA Rules based approach is less costly to build and maintain than the DMS Model-Driven solution.
- Weaknesses
  - The rules-based approach requires a SCADA facility that provides communication coverage to any point on the distribution feeder. This is not a problem for electric utilities that have DSCADA facilities. However, adding these facilities can be expensive for utilities that do not already have DSCADA.
  - The rules-based approach does not work well on distribution feeders that are heavily meshed, because the rules become too complex if a large number of switching possibilities exist.
  - It is often not possible to anticipate all the possible operating conditions of distributed energy resources in a fixed set of rules. Therefore, the rules based approach may not be effective on feeders that have a high penetration of distributed energy resources.

The SCADA rules-based approach is a considerable improvement versus the standalone controller approach due to its ability to base control actions on a holistic view of the distribution system rather than local measurements. This approach works well for the operating environment that exists on many electric utility distribution feeders today (minimal DG, infrequent changes in feeder configuration0. However, in the future as the penetration of large DG units grows and advanced distribution applications (such as optimal network reconfiguration) become prevalent, the rules-based approach may lack the flexibility to address all future operating possibilities. In such cases, a more sophisticated “model-driven solution may be needed.

As stated earlier, the SCADA rules based approach is the most widely used architecture by utilities that are currently demonstrating VVO concepts on their feeder. However, in the future, as electric distribution utilities are faced with an increasing penetration of DG and feeder reconfiguration becomes more frequent for load balancing and other reasons, utilities are expected to migrate their VVO system to one of the more sophisticated approaches, including the DMS model-driven system, which is described in the next section.

DMS "Model-Driven" Approach

This VVO approach uses a distribution system model that represents the "as-operated" state of the distribution system, an on-line power flow (OLPF), and an advanced "search engine" to determine the optimal set of control actions needed to accomplish one or more VVO objective functions. Objective functions for model-driven VVO can include:

- Minimize electrical losses
- Maximum energy conservation (minimize energy consumption)
- Minimize electrical demand
- Combination of the above

In addition to the primary objective functions listed above, it is also possible to bias the recommended control actions to minimize control actions on high maintenance power apparatus, such as substation transformer load tap changers.

The model driven approach is typically implemented as part of a Distribution Management System (DMS). Figure 3-3 depicts the basic operation of the DMS model-driven VVO approach. As seen in this figure, the system uses distribution SCADA facilities to acquire real time field inputs and execute VVO control actions, an on-line power flow (OLPF) program to compute electrical conditions at any point on the feeder, and an advanced "search engine" to identify the optimal switching action..

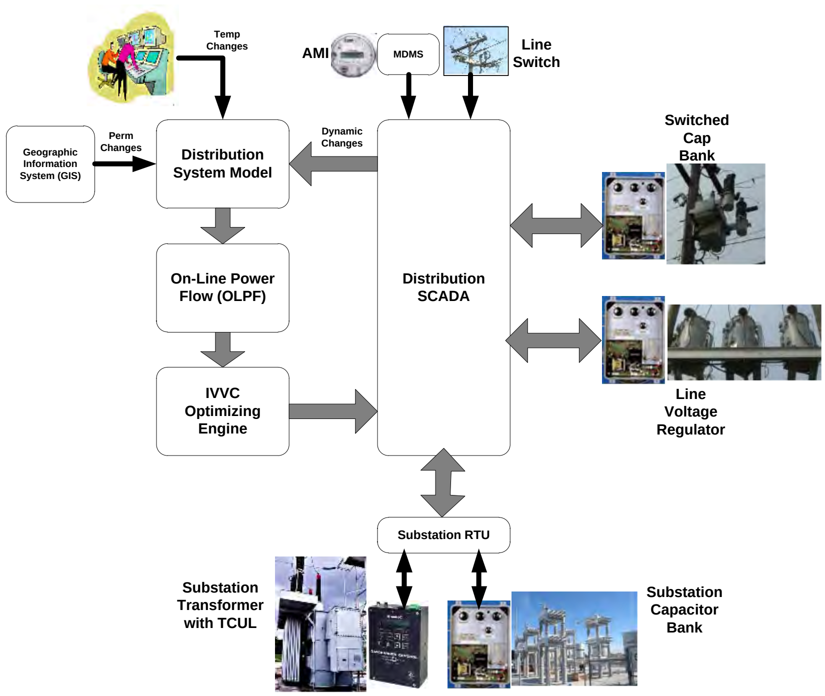


Figure 3-3
DMS Model Driven Approach

The distribution system model is divided into two parts: a physical model and a load model. The physical model represents the energized equipment (distributed energy resources, transformers, switchgear, voltage regulators, capacitor banks, etc.) as well as the connections between equipment (wires and cables). The DMS physical model is commonly created and maintained via an interface between the DMS and the utility company's Geographic Information System (GIS), which is often the official data repository for information about company distribution assets. However, portions of the physical model (such as the distribution substation information) may reside in separate systems such as an Energy Management System (EMS) that is used to monitor and control transmission and central generation assets.

The GIS may also not include information about the 120/240V secondary circuits that connect distribution service transformers to the customer meters. Some utilities that have used the model-driven DMS approach use a fixed value (e.g., 3 volts) to represent the voltage drop between the distribution transformer and the customer meter.

The load portion of the model includes information about the customer load at all distribution transformers along the distribution circuit. This information is needed by the DMS On-Line Power Flow (OLPF) program to calculate the voltage and load flow at all feeder locations on a continuous basis. The load model must also include accurate representation of the load-voltage sensitivity of the load at each transformer. Load models are often based on historical "load profiles that were created using statistical load surveys. In the future, as more utilities deploy advanced metering information systems, it is possible that measurements from customer meters will play a significant role in the load modeling process. For example, it is possible to use AMI data to periodically adjust the historical load surveys to account for changing loads at each meter. EPRI research has shown that this approach greatly improves the accuracy of the powerflow solution. With greater accuracy, it will be possible to reduce the VVO operating margin to achieve additional benefits.

Building and maintaining an accurate model of the distribution system is, without question, one of the most daunting tasks and one of the most significant barriers to successful DMS deployment. Two of the biggest challenges are GIS data quality and lack of standard interfaces between DMS and GIS. It is expected that development and use of industry standard interfaces such as the Common Interface model (CIM) and/or MultiSpeak will assist utilities in successfully completing this important modeling task.

The major strengths and weaknesses of the DMS model-driven approach to VVO are listed below:

- Strengths
  - The model-driven approach provides maximum flexibility to address the varying conditions that are expected on the smart distribution grid. Since the model reflects the current "as operated" state of the distribution feeder, the recommended Volt VAR control actions represent the best available actions for the current feeder conditions. This includes consideration of varying distribution feeder topology, active distributed energy resources, and other variable components.
  - Volt-VAR control actions for switched capacitor banks, voltage regulators (including LTCs), and distributed energy resources (including smart inverters) are fully coordinated.
  - It is easy to change the VVO operating objectives as special system-level needs arise.
- Weaknesses
  - This approach is typically the most expensive VVO approach in terms of total cost of ownership. One of the most significant expenses is the cost to build and maintain the distribution system model
  - There are few examples of model-driven VVO systems that are actually operating in the field. DMS vendor experience in implementing model driven VVO systems is limited at this time. Note, however, that there are several full scale examples of DMS model-driven VVO solutions that are currently being implemented in North America. As a result, the industry will gain considerable experience from these deployments during the next few years, and lack of mature, field-proven systems will diminish as an important issue.

Heuristic (Self learning) VVO Systems

Like the rules-based and model-driven approaches to VVC&O, the heuristic approach processes real-time distribution system information acquired from distributed sensors to determine appropriate volt-VAR control actions and provide closed-loop feedback to accomplish electric utility specified objectives. Heuristic solutions automatically adjust ("adapt") their control strategy based on the results of previous control actions. The heuristic approach uses advanced signal processing techniques rather than predetermined rules or dynamic models of the electric distribution system to determine what control actions are needed. This represents a significant advantage versus the rule-based and model-driven solutions due to the difficulties in building and maintaining the rules and models to match the "as operated" state of the distribution system. Figure 3-4 depicts the approach.

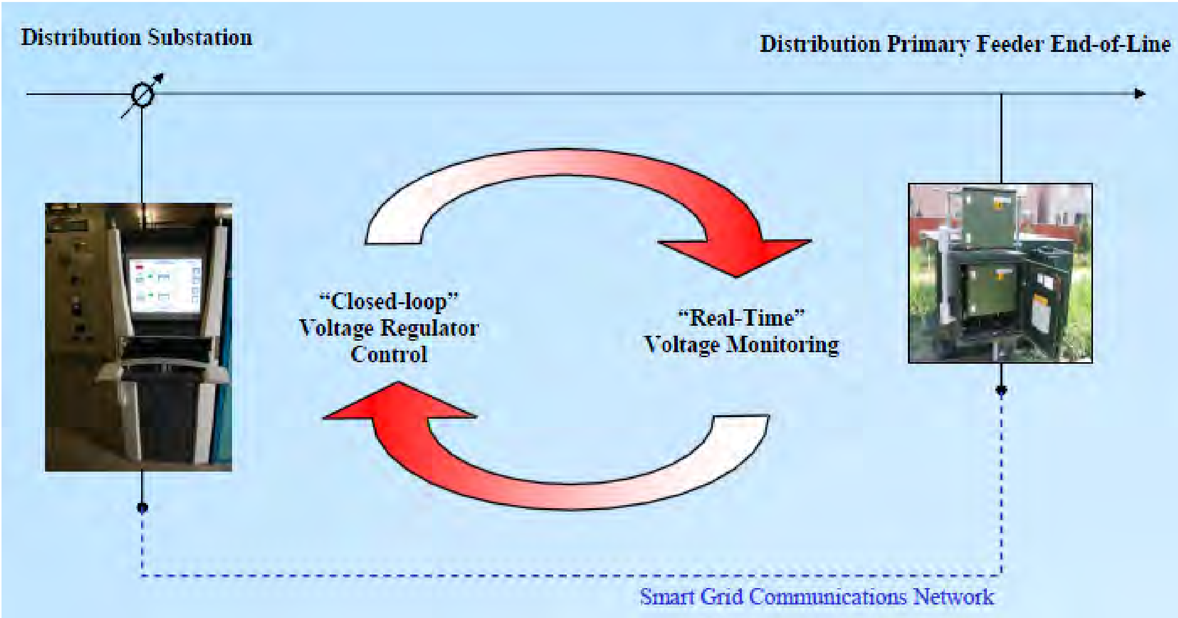


Figure 3-4
Auto-Adaptive Approach to VVO (Reprinted with permission from PCS Utilidata)

The real-time measurements required by the auto-adaptive approach are similar to the information required by the rules-based and model-driven approaches. The measurement set typically includes source voltages by phase, total feeder current by phase, kW by phase, kvar by phase, and primary voltages at or near the end of the distribution feeders by phase. Ambient weather conditions (temperature, humidity, precipitation, solar radiation, etc) are also used in some cases.

The heuristic approach is essentially a "self learning" approach that bases future control actions on the results of previous (historical) control actions performed under similar circumstances. The following descriptions of the "learning" process and the "control" process are greatly simplified but generally depict the way heuristic, self-learning systems operate.

- The Learning Process

  Learning occurs whenever a volt-VAR control action occurs. Prior to performing the control action, the system stores the initial "state" of the electric distribution system. The "state" includes key parameters that determine the electric distribution system response to the proposed control action. As a minimum, the distribution system "state" includes the following parameters:

  – Electrical Parameters (E): Present load and voltage at various locations (critical measurement locations) on the distribution system, reactive power flow, etc.

  – Ambient Conditions (A): Temperature, humidity, weather, etc

  – Time and date (T): Time of day, season, weekday/weekend/holiday

After recording the initial state, the system performs the proposed volt-VAR control action (raise or lower a tap position, open or close a switched capacitor bank switch, etc.). Once the proposed control action has been completed, the system once again records the system state. The initial state, control action, and final state is recorded for use in evaluating future control actions. In essence, the system "learns" that when the distribution system is in state "i", and you perform control action "j", the result will be state "k". Figure 3-5 depicts this simplified description of the learning process.

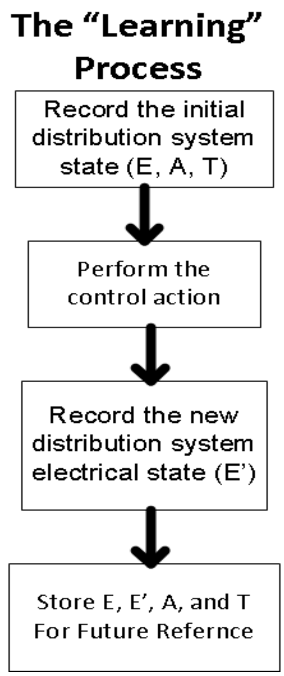


Figure 3-5
The Heuristic Learning Process

- The Control Process

To determine if a volt-VAR control action is needed to achieve the system's operating objective (reduce losses, promote energy conservation, peak shaving, etc.), the system reviews the records of past control actions to determine if any control action can improve the current state of the system. If the system locates such a control action, then the system executes the action and then stores the record of control action (initial state, control action, final state). Figure 3-6 contains a simplified depiction of the control process for the heuristic control process.

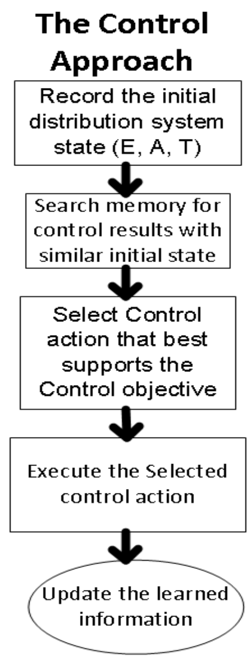


Figure 3-6
The Heuristic Control Process

The controllers that perform the signal processing algorithms are typically located in the distribution substation that is associated with the feeders being controlled. However, it is possible for a single system to control feeders in multiple substations. In this case, the controller can be installed at a distribution control center (centralized approach) or one of the controlled substations.

When a feeder is reconfigured either permanently or temporarily, the auto-adaptive approach is inherently able to reconfigure itself and continue operating as long as the switching changes are reported to the controller. Since many operating activities are not monitored by SCADA (installation of feeder cuts and jumpers, manual operation of disconnect switches, etc.) some mechanism is needed to manually incorporate such changes in the controller. This same procedure is needed for the rule based approach and the DMS model-driven approach. The auto-adaptive approach is also inherently able to incorporate the impacts of DERs in its volt-VAR control decisions. However, additional Research and Development (R&D) and field trials may be needed to demonstrate these capabilities.

The major strengths and weaknesses of this approach are listed below:

- Strengths
  - The heuristic approach does not require an as-operated software model of the distribution system. This is a very significant advantage, because it can be very difficult and expensive to build, validate, and maintain this model.
  - Heuristic VVO does not require a predetermined set of rules. Again, this is a very significant advantage because the rules may not be flexible enough to handle all the varying conditions encountered on the smart distribution grid.

- Weaknesses
  - Because the signal processing algorithms used by the heuristic auto-adaptive approach are often regarded as confidential intellectual property, few details are available on the internal workings of this approach. This is troublesome for some electric utilities that require full disclosure of the theory of operation for all essential control systems.
  - While heuristic systems are inherently able to adapt to changing feeder configurations and the varying presence of distributed energy resources, these capabilities have not been demonstrated by the system suppliers that offer a heuristic approach. This is a major barrier for distribution feeders on which these conditions exist.

The heuristic, auto adaptive approach to DVO is a promising approach that offers significant advantage over other DVO system approaches, as explained above. As a result, a growing number of DVO solution providers are developing and incorporating elements of the heuristic approach in their DVO offerings. Pending further development of the capability to respond feeder reconfiguration and high penetrations of Distributed Energy Resources, the heuristic approach holds promise for future deployment.

Choosing the Correct Solution Approach

Figure 3-7 lists a number of major factors to consider when selecting an approach for DVO. A red dot means that the evaluation factor favors the approach. A black dot indicates that the evaluation criteria does not favor the proposed approach. A white dot indicates that the evaluation criterion neither favors nor discourages the proposed solution.

Evauation Criteria	Standalone controller	SCADA Rules based	Heuristic Auto Adaptive	DMS Model Driven
Small number of feeders being automated	Red	White	White	Black
Large number of feeders being automated	White	Red	White	Red
Many volt and VAR control devices to coordinate	Black	White	Red	Red
Low budget	Red	White	White	Black
Lack of communications and DSCADA facilities	Red	Black	Black	Black
Voltage level (not a distinguishing factor)	White	White	White	White
Feeder meshing and potential for frequent reconfiguration	Black	White	White	Red
High penetration of distributed energy resources	Black	White	White	Red
DMS planned for implementation	White	White	White	Red
Need for flexible operating objective	Black	White	Red	Red
Lack of data for model	Red	Red	Red	Black

Figure 3-7
Choosing the Right DVO Approach

Conclusions

Electric distribution utilities, commercial establishments, and industrial facilities have been able to use Volt-VAR optimization and control to achieve valuable benefits, including reduced electrical losses, improved efficiency and energy conservation, and lower demand in support of their energy efficiency portfolios. Utilities have also achieved additional benefits such as reduced operations of load tap changers and capacitor switching operations, which can help to extend the useful life of these components.

DVO should continue to play a significant role in achieving key smart grid objectives. However, it is important that the industry gain a better understanding of the impact of voltage optimization on key loads so that short and long term benefits can be predicted and better understood. Current efforts by EPRI, PNNL, NEETRAC, and other entities are important to gain a better understanding of future benefits of voltage optimization. The impact of distributed energy resources and other active distribution system components on DVO systems must also be better understood.

Standalone controllers and fixed rule-based systems are currently the most popular approaches that are being used by today's utilities to "prove" the VVO concept. The simplicity of these approaches and transparency of the control algorithms makes these approaches well suited to enable utility companies to gain a clear understanding of the VVO issues, challenges, and benefits. However, many utilities recognize that a more sophisticated solution technique may be needed to accommodate frequent feeder reconfiguration and the uncertainties associated with a high penetration of customer-owned DERs. Hence, there is a long term trend towards DMS model-driven solutions that can address these concerns.

The heuristic auto-adaptive approach is growing in popularity and numerous applications of this approach are currently installed on electric utility distribution feeders, commercial campus environments, and industrial facilities. The lessons learned by these initial deployments will help determine whether the auto-adaptive approach can accommodate the challenges posed by the smart distribution grid. Results to date have been very positive, but further development is needed especially in cases where frequent feeder reconfiguration is possible and high penetrations of distributed energy resources may exist.

While the industry has years of experience in the area of Volt-VAR Control and Optimization, further effort is needed to prove that the current suite of DVO solutions is able to meet the challenges of increasingly dynamic and active electric distribution systems. Each of the four main DVO approaches identified in this paper has merit and will play a role in future smart distribution systems.

4
QUANTITATIVE ANALYSIS OF APPROACHES TO VVO

Besides the “qualitative” strengths and weaknesses described in the previous section for the four main approaches to DVO, the different approaches offer different “quantitative” benefits. Differences in quantitative benefits include more or less reduction in electrical demand, energy consumption, and electrical losses. There are several reasons for the differences in quantitative benefits for the four approaches:

- Approaches that include voltage feedback from critical measurement points (e.g. lowest voltage points) can operate at lower voltages due to having this feedback and can therefore achieve lower voltage setpoints and therefore greater benefits.
- Approaches that do not have voltage feedback from critical voltage measurement locations require greater operating margin to ensure that the voltage does not go below the minimum at lowest voltage points, especially when faults occur on nearby portions of the power grid..
- Approaches that are able to adapt to changing feeder conditions (e.g., feeder reconfiguration) can continue to provide benefits when the feeder is in an off-normal conditions.

The analysis also showed that some approaches required fewer changes in voltage regulator and LTC tap position and fewer capacitor bank switching operations. This is because some approaches are better at coordinating control actions by various independent controllers and thus avoid unnecessary control actions due to “hunting” and other such factors. In addition, the more sophisticated approaches are “forward looking”. That is, the control algorithms are better able to prioritize a limited number of control actions for each device.

As part of this project, EPRI used its OpenDSS software tool to model and analyze actual distribution feeders to determine the relative benefits of the different approaches to DVO. The analysis was performed on distribution feeders that have been modeled from the substation down to the customer meters, and thus considers the impact of medium voltage/low voltage distribution transformers as well as the secondary circuits that connect to the customer meters. The analysis used actual feeder data and load measurements that were collected over a one year period from one utility. Feeder data includes periodic real and reactive power measurements captured at the substation end of the feeder by the DSCADA system. Load interval data acquired from AMI was also used in the analysis.

EPRI first created a base case starting point using the feeder model along with the actual DSCADA measurements and AMI data for the targeted feeder. In this base case, no attempt was made to alter the existing control strategy for voltage regulating devices (load tap changer transformers, line voltage regulators, etc) and capacitor banks. To analyze the impact and benefits of the alternate DVO approaches, EPRI simulated the impacts of each control strategy.

The following metrics were used to compare the benefits of each alternative solution:

- Minimum/maximum voltage on the circuit
- Peak real and reactive power
- Real and reactive energy consumption
- Electrical losses
- Number of substation LTC and voltage regulator tap changes
- Number of capacitor bank switching actions

The OpenDSS model was set up to simulate the settings and control strategy of each of the different types of control systems. The baseline information was taken from an actual implementation of heuristic auto-adaptive DVO. Since the heuristic approach is the most difficult to simulate in OpenDSS, a case study involving feeders on which the auto-adaptive approach is actually running in day on-day off mode was used. The recorded results were used to evaluate the performance of the heuristic auto-adaptive system. Different control actions and strategies were applied to the "day off" measurements to determine the impact of the remaining DVO approaches on the same feeder with roughly the same data.

Introduction

A model of an actual distribution substation with four radial feeders was utilized to perform the DVO modeling for this report. The model was developed using geographic information system (GIS) data that was provided in the MultiSpeak format. The MultiSpeak data was imported into Milsoft's WindMil distribution system analysis package and an in-house converter was used to convert this representation to the OpenDSS analysis package for the DVO modeling and simulation. The data in the MultiSpeak/WindMil file did not include complete impedance information (only size, length, rating, etc), so additional data was obtained from the participating utility to develop the full electrical model.

A one-line diagram of the four feeders is shown in Figure 4-1. The substation is indicated by the red square and the capacitor locations are indicated by the green circles. The substation has two 22.5 MVA (base rating) power transformers in parallel which convert the incoming transmission service to 13.2 kV grounded-wye for distribution to the community. At the head of each of the feeders there are presently three single-phase regulators, for a total of twelve single-phase regulators (three per feeder, or one for each phase per circuit). The set-points for each of the regulators, as found, were 123V, on a 120V basis, and they are set to regulate their local bus (i.e., line drop compensation not used).

A total of fifteen (15) fixed and switched capacitor banks are located out on the feeders to provide reactive power compensation as well as voltage support. These fifteen banks total 12.750 kvar. Three of the capacitors are switched on timers, while the rest are fixed and/or switched on an as-needed basis (by utility personnel) depending on the utility's operational needs. This as-needed switching is performed by troubleshooters/line-personnel as there is no remote communications mechanism to remotely control any of the capacitors.

The circuits provide electric power to a small town that is in a fairly rural area. The loads on the circuits consist of a mixture of industrial, commercial, and residential customers. There are several large industrial customers in the MW load range near the substation. Some commercial customers are also found near the substation, which is located near the downtown area of the small city.

Peak loading on the substation for 2009/2010/2011 is in the neighborhood of about 28 MW, exceeding slightly the base rating of one of the substation transformers, but not near its upper ratings with cooling.

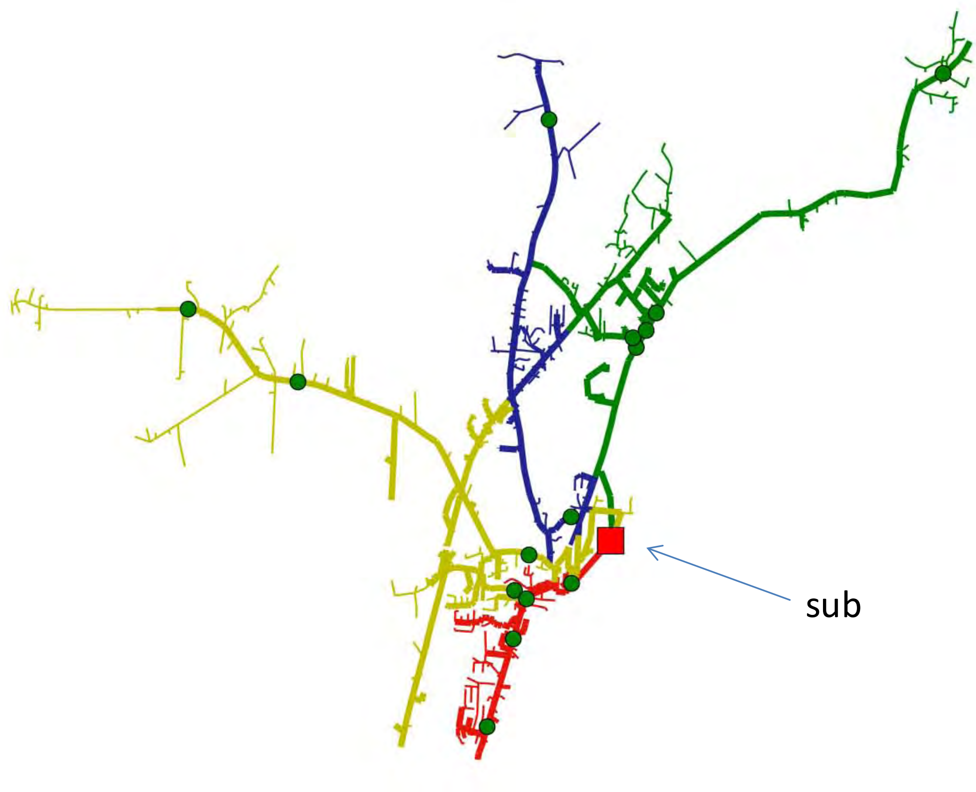


Figure 4-1
One-line diagram of the feeders with substation and capacitor locations indicated

Normal Operations

The normal operations modeling and simulation was performed to mimic the conditions that exist on the distribution substation before any voltage-only, or volt-var optimization steps are undertaken. For the normal operations case, the twelve single-phase regulators are each set to 123V and are set to regulate their local 'downstream' (regulated-side) buses to this voltage level. No line-drop compensation is utilized.

The capacitor switching scheme was set to mimic the conditions that existed in the field from mid-March 2010 to mid-March 2011. This is the time-frame for which all of the simulations were performed.

As mentioned previously, there are three time-controlled capacitors and the rest were switched on an as-needed basis for reactive compensation, voltage control, or both. Since the utility did not provide records as to the 'as-needed' capacitor switching dates/times, EPRI iteratively switched those capacitors to find a 'best' match given the DSCADA measurement data provided for each of the four feeders. EPRI assumed that the loads' power factors are constant (based on load class) throughout the year, in the absence of additional measurement data. Therefore, the matching of reactive power between measured and modeled was not as close as it was for the active power component.

The annual power profiles (kW and kvar) for the 'normal operations' case is shown in Figure 4-2 from the simulations.

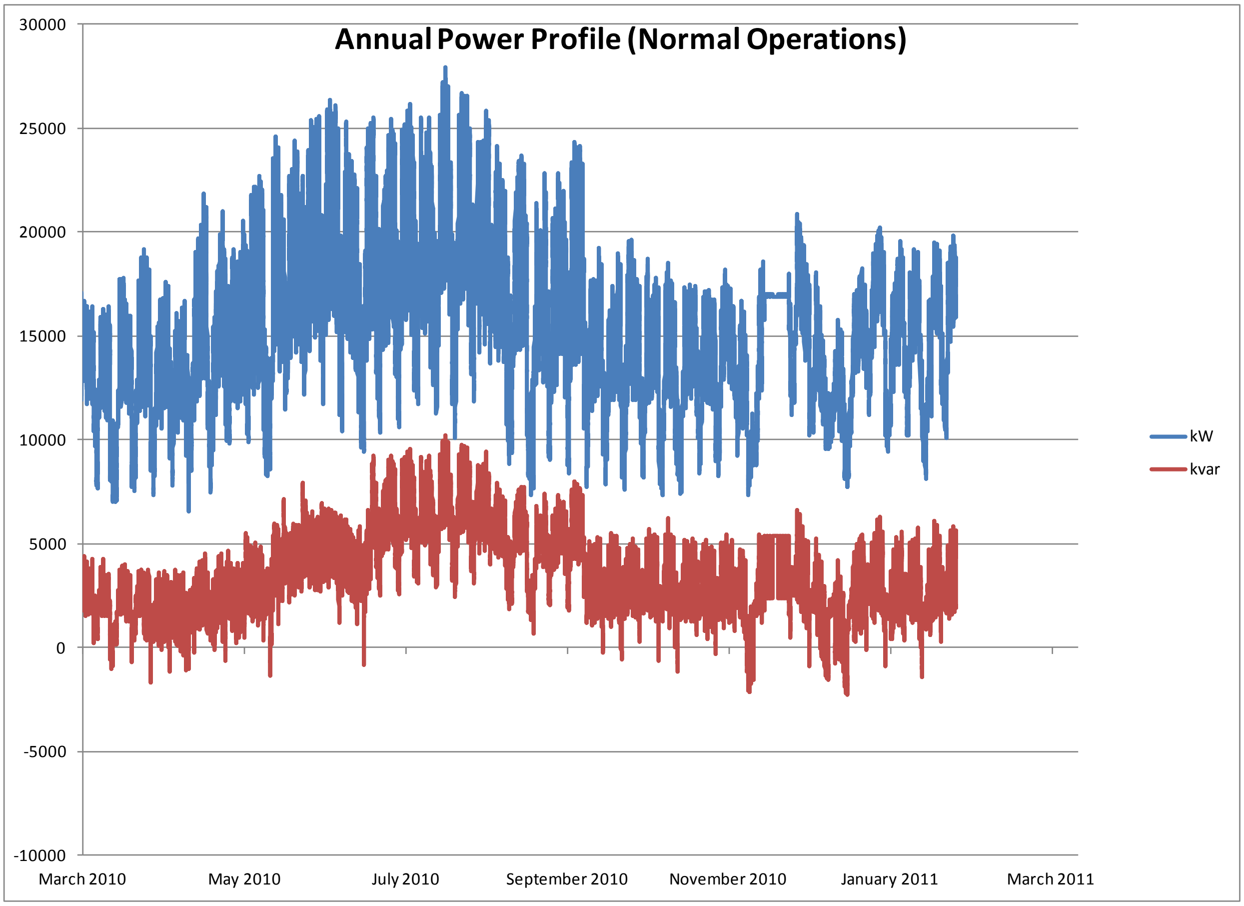


Figure 4-2
Annual power profile for the Normal Operations modeling case.

In running this simulation EPRI captured the following key metrics relating to the powers, voltages, and equipment switching/operation. These are summarized in Table 4-1.

Table 4-1
Summary results from the Normal Operations case simulation

Parameter	Value	
Annual Average power factor (|x|)	0.975	
Power factor at peak load interval	0.939	
Peak (active power) demand	27908	kW
Reactive Power Demand at peak demand hour	10249	kvar
Active Power Consumption at peak demand hour	27066	kW
Reactive Power Consumption at peak demand hour	9767	kvar
Losses at peak hour	842	kW
Losses at peak hour as a percentage of Base Case Peak Active Power	3.02%	
Parameter	**Value**	
Yearly Active Energy	134740	MWh
Yearly Reactive Energy	28861	Mvarh
Yearly Active Energy Consumption	131627	MWh
Yearly Reactive Energy Consumption	51690	Mvarh
Yearly Losses	3113	MWh
Yearly losses as a percentage of Base Case Active Energy	2.31%	
Parameter	**Value**	
Number of tap operations over the year	10968	
Number of regulators	12	
Number of capacitor operations over the year	1196	
Number of capacitors (switched/total)	3/15	
Annual Minimum voltage (primary only)	111.0	
Annual Average voltage (primary only)	121.4	
Annual Maximum voltage (primary only)	126.5	

Stand-alone Controls with Conservation Voltage Reduction set to 120V (local bus)

This case shows the results of upgrading the existing capacitor controls to a set of var-controlled and voltage-controlled capacitor banks. For this case there were seven (7) switched capacitor banks. The break-down by control type and var contribution is shown in Table 4-2.

Table 4-2
Capacitor controls for the stand-alone controls with conservation voltage reduction set to 120V case

Control Type	kvar under this type of control
Var	6200
Voltage	1050

The regulators were each set to regulate their local buses to an average of 120V, which is 3V lower than the normal operations case. A power profile showing active and reactive power is shown in Figure 4-3 for this case of stand-alone controls.

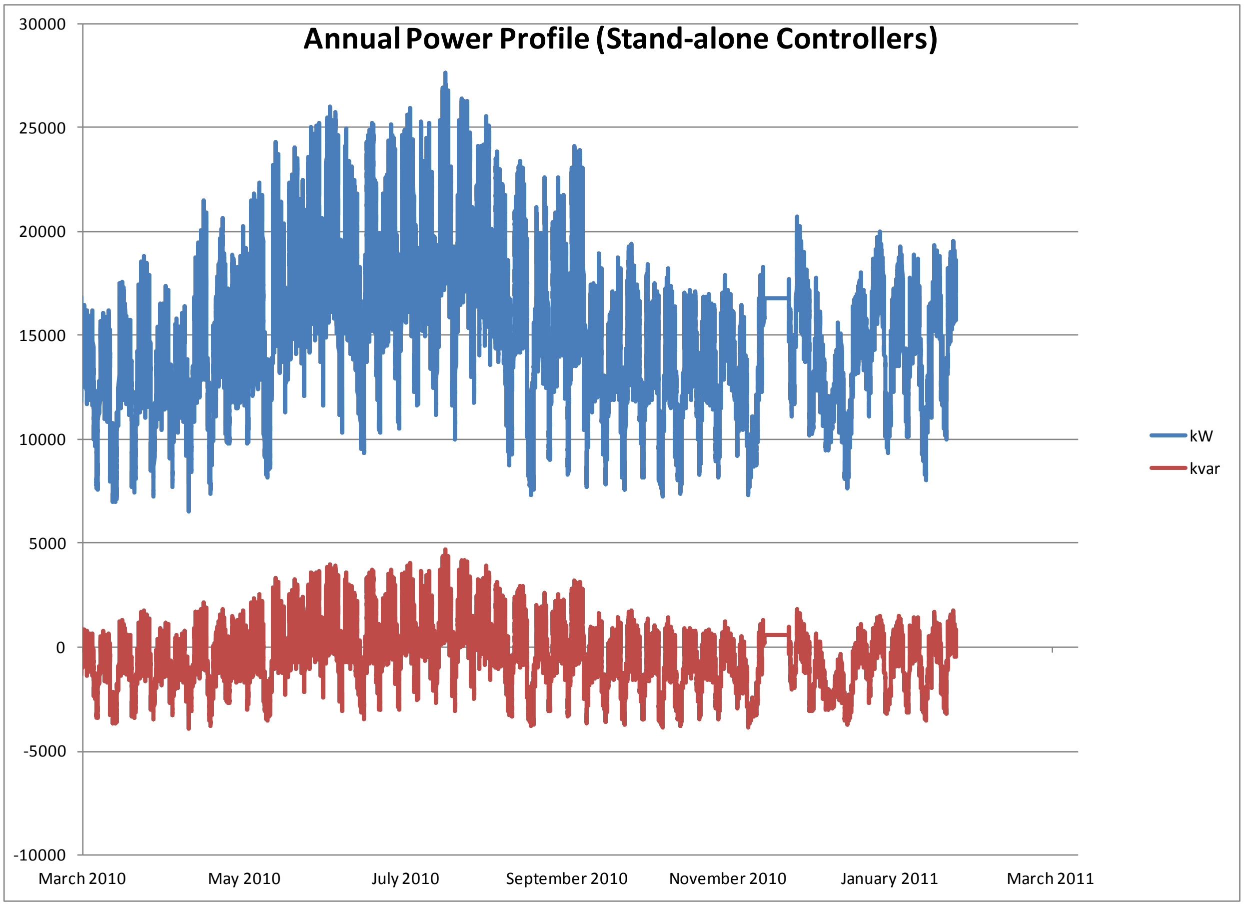


Figure 4-3
Power Profiles for the stand-alone controls case with 120V (local) CVR.

A summary of the results for this case is shown in Table 4-3.

Table 4-3
Summary of the stand-alone controllers simulation with an average of 120V local bus regulator set-points.

Parameter	Value	
Annual Average power factor (|x|)	0.991	
Power factor at peak load interval	0.986	
Peak (active power) demand	27625	kW
Reactive Power Demand at peak demand hour	4708	kvar
Active Power Consumption at peak demand hour	26831	kW
Reactive Power Consumption at peak demand hour	9408	kvar
Losses at peak hour	794	kW
Losses at peak hour as a percentage of Base Case Peak Active Power	2.85%	
Parameter	**Value**	
Yearly Active Energy	133281	MWh
Yearly Reactive Energy	-2923	Mvarh
Yearly Active Energy Consumption	130165	MWh
Yearly Reactive Energy Consumption	49102	Mvarh
Yearly Losses	3116	MWh
Yearly losses as a percentage of Base Case Active Energy	2.31%	
Parameter	**Value**	
Number of tap operations over the year	7025	
Number of regulators	12	
Number of capacitor operations over the year	154	
Number of capacitors (switched/total)	7/15	
Annual Minimum voltage (primary only)	111.3	V
Annual Average voltage (primary only)	119.3	V
Annual Maximum voltage (primary only)	127.0	V

Rules-based VVO with Conservation Voltage Reduction using End-of-Line Feedback

For this simulation case, a set of simple rules were utilized to control the capacitors on the circuit. The basic algorithm/set of rules is as follows:

1. Determine the feeder-head reactive powers (three-phase)
2. If the vars are lagging (inductive) then add capacitors that are not presently in-service until either the system achieves 0 kvar flow, or the smallest capacitor is larger than the inductive vars.
3. If the vars are leading (capacitive) then switch out capacitors that are presently in-service until either the system achieves 0 kvar flow, or the smallest capacitor is larger than the capacitive vars.
4. After completing steps 2 or 3, as appropriate based on feeder-head var flows, allow the regulators to regulate their respective end-of-line feedback buses to 118.4.

The power flows resulting from this simple rules-based approach are shown in figure xx. A summary of the key parameters of the case is shown in Figure 4-4. Note the very large number of tap operations for this simulation. One feeder has low voltages on it to begin with and the regulator tap operations from this feeder contribute the most to the total number of tap operations, as the regulators attempt to achieve the target voltage.

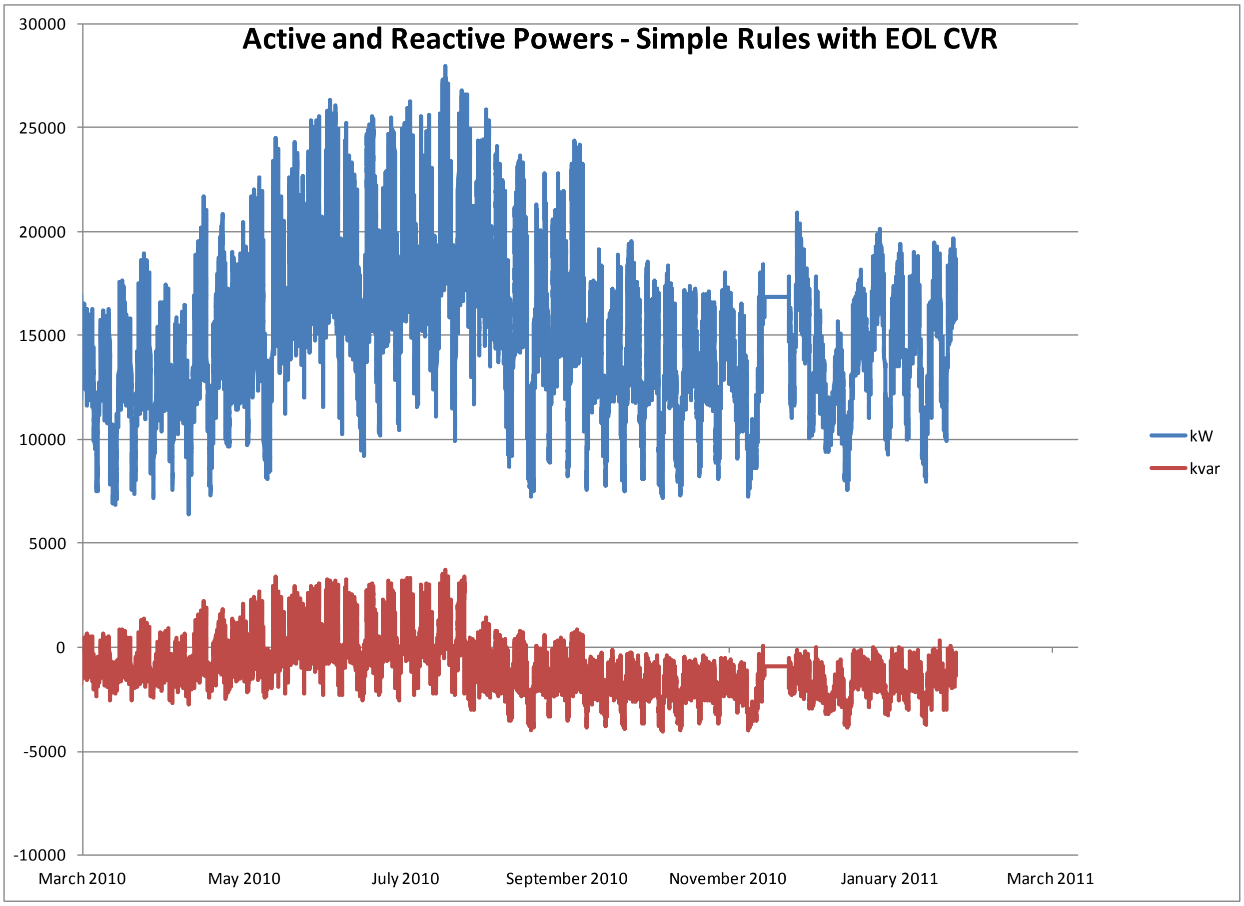


Figure 4-4
Active and reactive power flows from the simple rules-based approach.

Table 4-4
Summary of the key parameters from the simple rules-based approach.

Parameter	Value	
Annual Average power factor (|x|)	0.990	
Power factor at peak load interval	0.991	
Peak (active power) demand	27987	kW
Reactive Power Demand at peak demand hour	3733	kvar
Active Power Consumption at peak demand hour	27196	kW
Reactive Power Consumption at peak demand hour	10064	kvar
Losses at peak hour	791	kW
Losses at peak hour as a percentage of Base Case Peak Active Power	2.83%	
Parameter	**Value**	
Yearly Active Energy	133527	MWh
Yearly Reactive Energy	-8535	Mvarh
Yearly Active Energy Consumption	130464	MWh
Yearly Reactive Energy Consumption	49867	Mvarh
Yearly Losses	3063	MWh
Yearly losses as a percentage of Base Case Active Energy	2.27%	
Parameter	**Value**	
Number of tap operations over the year	42291	
Number of regulators	12	
Number of capacitor operations over the year	2107	
Number of capacitors (switched/total)	15/15	
Annual Minimum voltage (primary only)	114.0	V
Annual Average voltage (primary only)	118.8	V
Annual Maximum voltage (primary only)	128.2	V

DMS-Based VVO

This approach to volt-var optimization utilizes a software-based model of the electric distribution system and attempts to minimize an objective function (and other criteria, as desired) to achieve utility-specified goals related to VVO.

The OpenDSS program was utilized as the principal component to represent the model of the distribution system. It was ‘driven’ via a script developed in the python scripting language. OpenDSS was driven or controlled via the standard Windows COM interface that is provided by the OpenDSSengine.dll COM server.

The basic sequence of steps for this approach is:

1. Solve the distribution circuit(s) in its/their present configuration
2. Capture key pieces of information necessary to calculate the objective function.
3. Calculate the objective function.
4. Make changes to the circuit configuration such as switching on or off capacitors or changing tap positions on regulators

5. Re-calculate the objective function.
6. Repeat steps 4 and 5 for various combinations of circuit combinations
7. Find the circuit configuration which minimizes the objective function and record power, loss, voltages, and other pertinent data for this 'final' configuration and store for later retrieval and analysis.

The construction of the objective function will vary based upon the utility-specific operational objectives. For instance, one utility might choose to minimize losses, while another utility might like to minimize energy consumption. The objective function can include multiple components and weights can be assigned to each of these components to 'emphasize' different aspects of the objective function.

For the purposes of this case, we chose an objective function containing four components. Those five components are:

- Minimize total kW losses
- Minimize total consumption
- Minimize the number of buses which had voltages above a threshold
- Minimize the number of buses which had voltages below a threshold
- Minimize var flow at the substation bus

The weighting on the components were set to: 5%, 30%, 5%, 30%, and 30%. Each component was normalized prior to being weighted such that the possible output values for the complete objective function would range between 0 and 1.

The changes to the circuit configuration consisted of switching capacitors on each of the four circuits, beginning with the most geographically distant capacitors first, and then turning on additional capacitors as we 'move' closer to the substation bus. Once a capacitor was switched on, the regulators were allowed to settle to their given set-points under these new conditions.

As mentioned in the sequence of steps description above, we collected key data necessary to calculate the objective function and the objective function was calculated each time a capacitor was switched (after the regulators 'settled').

Since there were 15 capacitors, a total of 15 simulation runs were performed for each time interval of the simulation and the objective function was evaluated for each of these runs.

Given that part of the objective function involved voltage violations, the python script requested the voltages from ALL buses in the four feeders (including customer buses). The processing of this voltage data in the python script resulted in substantial computation time, so we chose to perform the analysis for this approach to VVO just for 100 hours on each side of the peak time interval. Future research will look at an entire annual (35,040 quarter-hour time intervals) simulation.

A chart showing the power profiles for 100 hours on each side of the peak loading interval is shown in Figure 4-5. The power factor at the peak hour was 1.0 at the substation distribution bus.

Note the step changes, at times, in var flow at the substation bus. This is due to the lack of tracking of the historical (prior) states of the circuit in the algorithm as implemented in python for this case.

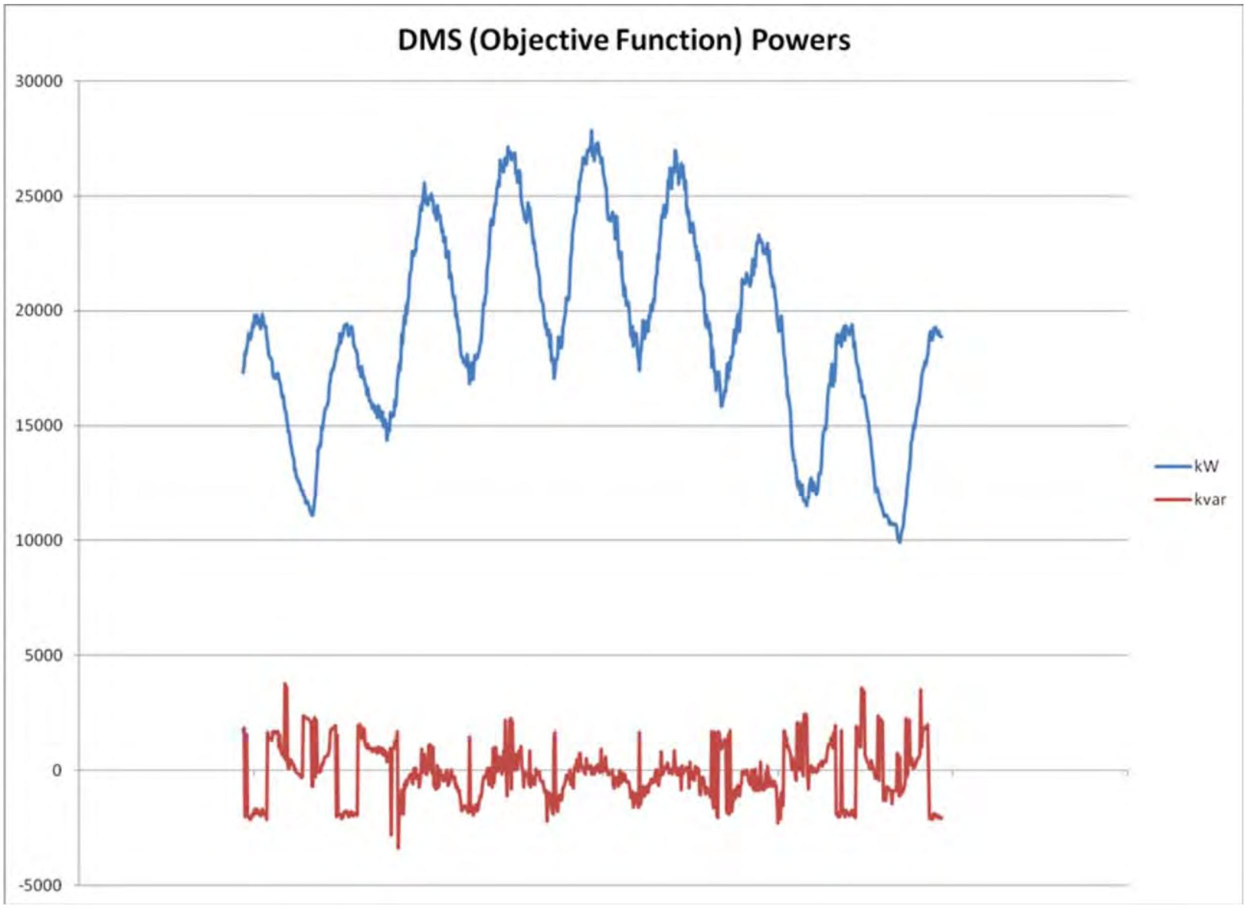


Figure 4-5
Power Profiles for the DMS (objective-function-based) approach

Conclusions

It is difficult to state with confidence that one DVO approach provides superior benefits versus another DVO approach based on the results of this one set of feeder modeling and analysis. However, the analysis does illustrate the benefit of being able to conduct a long sequence of power flow runs using hourly data over a one year period, This capability enables the planning engineer to explore the impact and benefits of different control strategies and settings using actual data from the feeders in question.

Several conclusions can be drawn from the analysis:

- DVO solutions that included closed loop feedback from critical measurement locations resulted in more power factor improvement, reduction of peak load and kVAR, and more energy savings. This can be attributed to the ability to operate with less operating margin when closed loop feedback from critical measurement locations exists.
- The more sophisticated approaches produce more electrical loss reduction than the simpler approaches. However, it should be noted that the magnitude of loss reduction is significantly less than reduction in energy consumption (ratio of reduction of energy consumption to reduction of electrical losses is roughly 10 to 1).
- The number of voltage regulator tap change operations is significantly lower with the more sophisticated, closed loop control approaches compared to the standalone controller approach.

5
SPECIFIC DESIGN ISSUES PERTAINING TO DVO

To successfully implement a DVO system, the electric utility must make the right choices for detailed design issues pertaining to the system. This section addresses many of the issues that need to be addressed in DVO system planning, design, implementation, and verification. The guidelines and recommendations contained in this section are based on the DVO implementation experiences of EPRI personnel and lessons learned by electric distribution utilities that have implemented DVO on their system. The section also includes recommendations and information supplied by DVO system vendors that have recently designed and implemented DVO systems for electric utilities.

Topics included in this section include:

- Basic Control Strategy (Energy Conservation Mode, Peak Shaving Mode)
- Device Control Method (DVO Settings, Tap Changer Operations, Avoiding Counter-Acting DVO Control Actions)
- DVO Operation Following Feeder Reconfiguration
- Impact of Distributed Energy Resources (DERs) on Volt-VAR Optimization (Steady State Impacts, Dynamic Impacts)
- Infrastructure Improvements
- DVO Communications (Handling of DVO System Contingencies)
- DMS Approach to DVO (The Physical Model, The Load Model, Load to Voltage Sensitivity)
- DVO Input Requirements (Measurement Accuracy, Using AMI Data for DVO, Critical Measurement Locations)
- DVO Economic Issues (DVO Benefits, Cost Recovery Strategy, Measurement and Verification (M&V) Strategy)

Basic Control Strategy

One of the key design decisions the utility must make concerns the fundamental business objectives for DVO. In particular, will the electric utility use the DVO system continuously to maximize energy savings or will the system be activated only during peak load conditions and power system emergencies for peak shaving and emergency demand reduction? In some cases, the utility requires the flexibility to switch between these two main control strategies based on power grid conditions and other business drivers. In such cases, the DVO system must support both the energy conservation mode and the peak shaving mode.

Energy Conservation Mode

In energy conservation mode, the objective of DVO is to achieve as much efficiency improvement as possible through energy conservation and electrical loss reduction. Therefore, DVO is activated at all times, 24 hours a day, seven days a week. While in energy conservation mode, the only time that control actions for voltage optimization would **<u>not</u>** be performed is during DVO system failure and when DVO control actions cannot be performed due to distribution system operating constraints.

The distribution system constraints that must be considered include the following items:

- <u>Voltage quality limits at the customer sites (normal, emergency):</u> DVO control actions must not cause the utilitization voltage at any customer meter to violate the high and low voltage limits specified in ANSI standard C84.1 (Electrical Power Systems and Equipment – Voltage Ratings) for normal and out-of-normal conditions.
- <u>Flow limits for distribution elements:</u> DVO control actions must not cause power flow through any distribution system energized component to exceed its normal and emergency ratings.
- <u>LTC and voltage regulator range limits:</u> DVO should not attempt to raise or lower LTC and voltage regulator tap positions beyond the physical limits of the device.
- <u>Limits on the number of tap changer operations per day:</u> Where applicable, DVO should enforce limits on the number of tap changer operations per day. Limiting the number of tap changer operations will reduce equipment maintenance requirements for the device and possibly extend the life of the equipment, which is an important Asset Management objective for many electric utilities.
- <u>Limits on the number of capacitor switching operations per day:</u> DVO should enforce limits on the number of switched capacitor bank operations per day.
- <u>Limits on the time interval between consecutive capacitor switching operations:</u> DVO should prevent shunt capacitor banks from being re-inserted prior to the dissipation of electrical charge stored within the capacitor units.

Energy conservation mode does not require any special “triggering” logic because DVO is in effect in service all the time.

Peak Shaving Mode

For some electric utilities, the main objective for DVO is peak demand reduction. Numerous electric distribution co-ops and municipal utilities that have demand charges in their energy supply tariffs. Therefore, reducing the peak demand during a billing interval results in direct savings in electricity supplier costs. Some utilities use voltage optimization to avoid or defer major investments in capacity additions.

When voltage reduction is used primarily for peak shaving, the objective is to switch voltage reduction on during as short an interval as possible surrounding the actual coincident peak load interval and then return the system to normal voltage regulation following the peak load period. The interval of voltage reduction should be as short as possible to minimize lost kilowatt-hour sales during off peak periods.

If the coincident peak load interval always occurs at the same time, same day of the week, and same day of the month, the task of triggering voltage reduction is easy. However, this is rarely the case. One electric distribution co-op that uses voltage reduction to reduce its coincident peak load reported that in the cooler months (November through March), peak load almost always occurs between 6 am and 8 am. However, the peak load interval occasionally ends at 9 am. Sometimes, the peak load occurs during colder evening hours. During warmer months, the potential peak load interval is even wider. Figures 5-1 and 5-2 illustrate the variability of peak load time and day for this utility. Under such loading conditions, it is often difficult to reliably capture the peak load interval while minimizing the amount of voltage reduction during peak load hours.

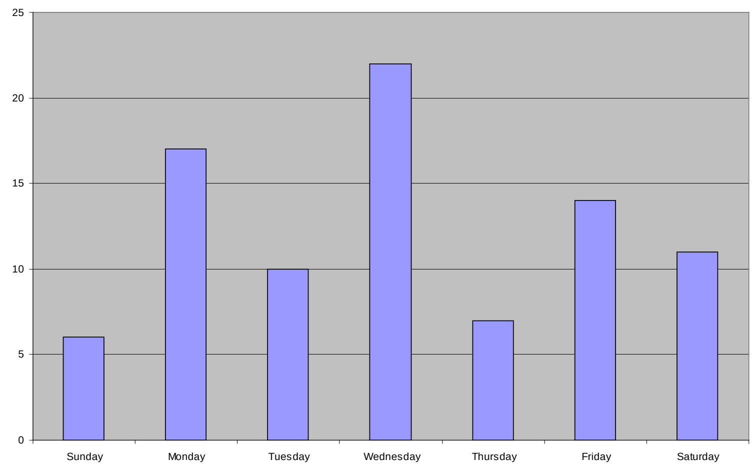


Figure 5-1
Day of Week Peak Load Occurs

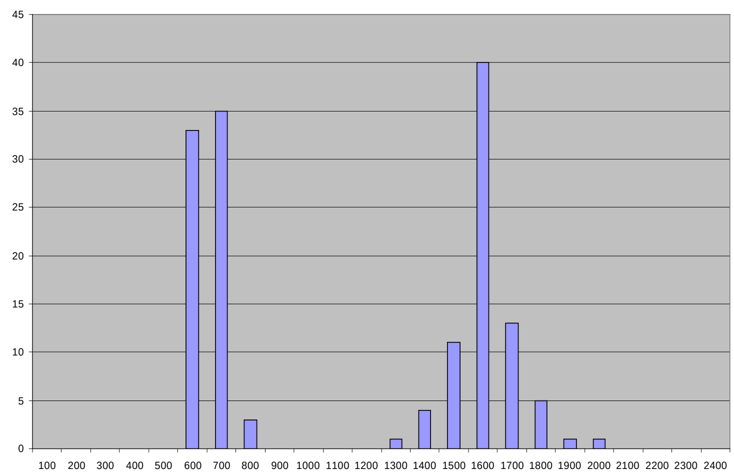


Figure 5-2
Peak Load Occurrence by hour of day

If the peak load time and day varies too much and cannot be predicted reliably based on historical loading records, the recommended practice is to use Short Term Load Forecasting (STLF) to determine, with reasonable accuracy, if a peak load interval will occur within the next 24 hours. STLF is an advanced distribution application that should be included in the suite of Distribution Management System (DMS) applications or implemented as a separate standalone function. STLF typically uses historical load and weather data to forecast the system load automatically every hour, for up to a 168-hour (7-day) rolling forecast. STLF may use both a weather-adaptive and a similar-day forecast methodology to obtain the most accurate prediction.

STLF provides the load forecast for a next few hours (i.e. 1-6 hours) or even up to 24 hours ahead for the entire distribution network as well as for each supply substation. This forecasted information helps the operator estimate the time period when the peak load can be expected and is used to trigger the voltage reduction function on just before the predicted peak load interval and return to normal voltage mode just after the forecasted peak load interval.

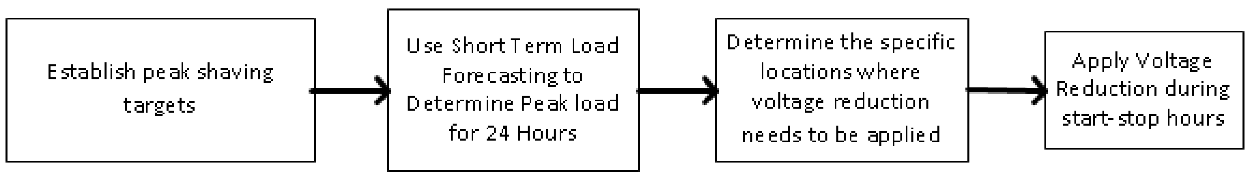


Figure 5-3
Using Short Term Load Forecasting to Determine Peak Load Interval

For example, an electric distribution utility may wish to limit the peak load on its system to 5000 MW to avoid having to add new combustion turbine peaking units to handle the rising peak load. In this case, the STLF function is used to forecast whether the peak system load will approach this limit during the next 24 hours. STLF will also determine the hours during which the peak load limit may be exceeded. Voltage reduction will be triggered during these hours and normal voltage regulation will be restored when the interval is over.

Besides providing the best hours for voltage reduction, the DMS can also determine the specific locations (substations or feeders) where voltage should be reduced to achieve the desired target.

Device Control Method

One of the DVO design issues concerns how the system actually controls the field device (LTC, voltage regulator, switched capacitor banks, etc.). Most systems that are being implemented today use Intelligent Electronic Devices (IEDs) to interface with the field device. The DVO system sends commands to the IED, which, in turn, handles the actual device control signals.

There are two main strategies for controlling the volt var control devices:

- Direct control of the device itself. For switched capacitor banks, this involves direct (open/close) control of the capacitor bank switch. For voltage regulators and LTCs, direct control involves raising and lowering the tap position via raise and lower commands.

- Modify settings in an intelligent controller. If the voltage regulators and switched capacitor banks include intelligent electronic device (IED) controllers, it is possible for the VVO system to alter the VVO settings themselves when a control action is needed. Actual control actions (raise/lower, open/close) are then handled by the IED controller using local measurements and the revised settings. For LTCs and voltage regulators, the VVO system may lower the controller band-center setting to band center change is needed.

The choice of control strategies varies from utility to utility:

- BC Hydro uses a mixed approach. The DVO system issues commands to change the position of switched capacitor banks (direct control) and alters settings on voltage regulator or Load Tap Changer IEDs to regulate voltage (indirect control).
- Xcel Energy's control strategy is similar to BC Hydro. However, the Xcel system is able to directly control (raise or lower) the voltage regulators (including LTCs)
- Dominion Resources adjusts the voltage regulator bandcenter settings (indirect control) to change the voltage.

Based on recent discussion at the IEEE PES volt-var task force meeting, the general consensus was that indirect control (change settings) was the preferred approach because it requires fewer interactions between the DVO master system and the controlled devices. The indirect approach usually performs better when the central processor or communication facilities go out of service. In this case, the controller continues to use the last good settings received from VVO or can revert to default settings if necessary. This results in a much smoother transition from remote control to local control. With the direct control approach, the transition from direct control to standalone control following a DVO system failure could be a more significant change.

Another advantage of the indirect approach is that this approach enables the utility company to take advantage of some of the basic control functionality that is inherent in the IED. With the direct approach, the logic needed to replicate the inherent IED functionality must be incorporated in the DVO "system". For example, switched capacitor bank controller IEDs will automatically add a time delay to ensure that the capacitor bank itself is fully discharged before allowing the switch to close again. With the direct open/close method, this switching constraint must be enforced by the DVO system. Similarly, a common LTC control function is voltage limit control (also referred to as "first house" protection) which is usually inherent in the IED. This feature guards against having excessive voltage at the substation bus (and the first houses along the feeder) when line current is high. Again, when direct control is used, this logic must be incorporated in the DVO system.

One of the DVO system suppliers, PCS Utilidata uses the direct control approach for all devices. They have found that the direct approach provides more flexible operation of the controlled device. Direct control enables PCS Utilidata's Adaptivolt system to make "forward looking" control decisions. That is, some control actions are intentionally delayed because the DVO system has determined that a better time for the control action will occur shortly or may be altogether unnecessary due to anticipated voltage and load changes. PCS Utilidata indicates that this approach has enabled its customers to achieve a significant reduction in the number of LTC and voltage regulator tap position changes and capacitor bank switching actions. This is a significant benefit because the life of tap changer contacts and mechanism depends almost exclusively upon the number of tap change operations.

Since most DVO systems base their switching actions on current system conditions and are do not look forward in time like PCS Utilidata, the indirect approach to control (setting changes) has several advantages versus the direct control approach. However, if a more flexible control strategy is needed in the future to conserve tap changer operations and other switching actions, direct control may indeed become the strategy of choice.

DVO Settings

Voltage set points in LDC systems are generally set more conservatively to insure ANSI and CAN standard voltage limits are not violated either on the high end or on the low end.

The amount of potential voltage reduction depends upon the bandwidths around the voltage set points. The smaller the necessary bandwidth, the lower the voltage set point can be. The lower the voltage set point the higher the energy conservation and demand reduction potentials. Bandwidth is the difference between the upper and lower acceptable voltage around the voltage set point. Empirical experience over many years by utilities and manufacturers has led to the recommended minimum bandwidth setting of no less than the equivalent of one tap position above and one tap position below the set point. Failure to observe this minimum bandwidth may lead to excessive tap change operations and to premature tap changer failure.

As a result, LTC and voltage regulator bandwidth is usually set to at least two times the step voltage and is symmetrical above and below the voltage set point. Bandwidth settings of 2, 2.5 or 3 volts on a 120 volt basis are commonly used. These recommendations are the same regardless of whether LDC is being implemented or not.

Tap Changer Operations

When tap changes are controlled conventionally, either with or without LDC, the number of tap changes that occur depends upon the Bandwidth and the Time Delay settings. The time delay settings determine how long the voltage must be “out of band” before the regulator control initiates a tap change.

Most utilities target the range of 117.5 V – 120 V (on an equivalent basis) as lowest primary voltage along the feeder during operation with reduced voltage. That is, VR will not intentionally reduce primary voltage at any point on the feeder below 117.5 V – 120 V. The typical bandwidth of voltage regulation devices is 2-4V. A tighter voltage bandwidth increases the number of tap changer operations, which imposes additional wear and tear on the tap changer. Each feeder or substation may need different voltage reduction targets based on local system conditions.

Some utilities have implemented measures within their DVO system to control the number of switching actions that may occur each day:

- Dominion noted that its VVO system limits LTC/voltage regulator bandcenter changes to one change every two hours.
- Xcel Energy is seeing a maximum of 5-7 capacitor bank switching events per day when trying to maintain a near unity power factor. Their OpenGrid software is configurable to minimize the device operations below the utility's tolerance level. One of their objectives for the settings is to minimize the number of operations while accomplishing the design objectives

Avoiding Counter-Acting DVO Control Actions

The operation of numerous independent volt VAR control devices (voltage regulators, LTCs, and switched capacitor banks) on the distribution feeders must be carefully coordinated to prevent counteracting control actions from occurring. For example, if voltage is intentionally reduced to reduce demand or energy consumption using voltage regulators and LTCs, switched capacitor banks should not attempt to counteract these control actions by raising the voltage. Furthermore, if a feeder includes multiple sets of voltage regulators, without proper coordination, the possibility exists for counteracting control actions between the different sets of voltage regulators.

Coordination of volt-VAR control actions should be handled by a combination of *coordinating time intervals* and *control action blocking*. Coordination of multiple sets of voltage regulators in series should be handled using different time delays on each device. Since voltage regulation activities will affect the voltage at all downstream devices, upstream regulation should be completed first before the downstream devices operate. It is common practice for LTCs and voltage regulators that are located closer to the substation to operate with less time delay than voltage regulators that are located downstream (further from the substation). With this approach, upstream voltage regulating devices will operate first to raise or lower the voltage followed (as needed) by downstream devices.

To coordinate more than one switched capacitor bank with switched VAR controls, the most distant unit is set to have the shortest time delay and the unit closest to the supply substation has the longest time delay. This is the opposite strategy to voltage regulators. With multiple switched capacitor banks, the most distant capacitor banks are set to switch first, followed by units that are located closer to the substation. (Source: "Electric Power Distribution Handbook", T. Short, P 287)

DVO systems most often handle the coordination between voltage regulators (including LTCs) and switched capacitor banks via a combination of coordinated time delays and control action blocking.

A common practice for DVO solutions is to block voltage regulators from changing their tap position during capacitor bank switching and to block capacitor bank switching during voltage regulator tap position changes. For example, the following sequence of steps is commonly performed by DSCADA rule-based DVO systems:

- Block all voltage regulators (including LTCs) from performing any tap changing to raise or lower the voltage.
- Determine what capacitor switching actions can be performed without causing a leading power factor at the head end of the feeder. These capacitor bank switching actions have the dual effect of “flattening” (narrowing) of the feeder voltage profile and improving the power factor at the head end of the feeder for reduced losses.
- Once all possible capacitor switching actions have been completed, the capacitor bank controls are then blocked to prevent further control actions by the switched capacitor banks.
- The DVO system then unblocks the LTCs and voltage regulators to allow voltage regulating activities in accordance with stored settings. Coordination of series voltage regulators is handled with increasing time delays for downstream devices, as described earlier in this section.

DVO Operation Following Feeder Reconfiguration

Distribution feeders are occasionally reconfigured during maintenance activities and to restore service from a backup source following a permanent feeder fault. When a feeder is reconfigured, the Volt-VAR control scheme (including DVO) must continue to operate correctly following feeder reconfiguration. This can be a challenging objective because volt-VAR control devices (capacitor banks, voltage regulators, etc.) may no longer be positioned in the ideal location. For example, a switched capacitor bank that is normally placed near the midpoint of a feeder may be located at the tail end of a reconfigured feeder. In addition, powerflow may be in the opposite direction to normal if a portion of the feeder is transferred to an alternate source. Feeder reconfiguration is expected to occur more frequently on smart distribution systems that include automatic sectionalizing, service restoration, and optimal network reconfiguration (for load balancing).

It is especially important that the volt-VAR controller IEDs associated with switched capacitor banks and voltage regulators have settings that produce acceptable voltage and VAR flow conditions under all loading conditions for all plausible feeder reconfiguration strategies. In many cases, feeder performance and efficiency may diminish with the normal controller settings following feeder reconfiguration. But in all cases, the voltage level and equipment loading must remain within acceptable limits at all times. If the initial controller settings do not satisfy these requirements, then new settings must be applied to the voltage and VAR controllers prior to energizing the reconfigured feeder.

If a switched capacitor or voltage regulator is located on a circuit that can be operated from either direction, the associated controller must be able to able to operate correctly with normal and reverse power flow. Newer controller IEDs are able to detect reverse power flow and switch to reverse power flow mode when power flow in the reverse direction is detected. Figures 5-4 and 5-5 illustrate the operation of a bidirectional voltage regulator with power flow in the normal and reverse direction. As seen in Figure 5-4, the moveable tap is **raised** to increase feeder voltage under heavy load conditions with power flow in the forward direction. However, with power flow in the reverse direction, the moveable tap must be lowered to raise voltage under heavy loading conditions.

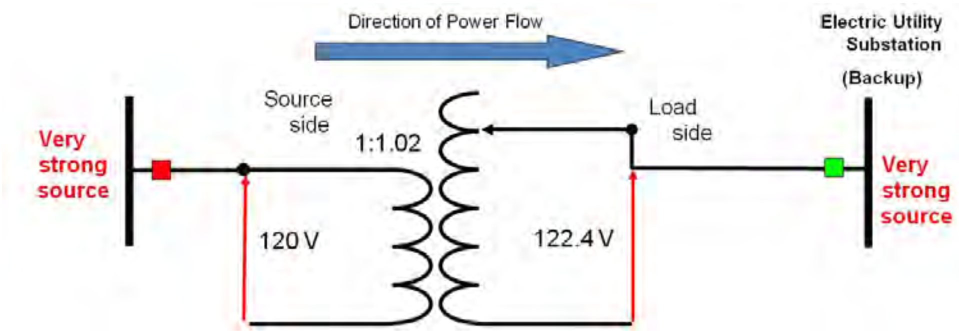


Figure 5-4
Bidirectional Voltage Regulator – Power Flow in Forward Direction

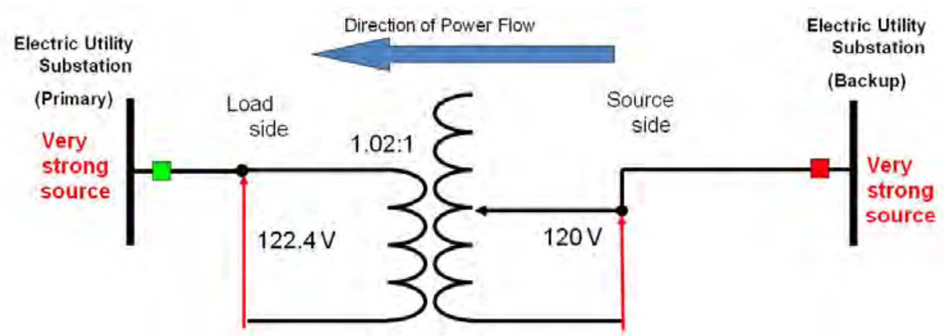


Figure 5-5
Bidirectional Voltage Regulator – Power Flow in Reverse Direction

More advanced DVO systems, such as the model-driven DMS approach are able to deal effectively with feeder reconfiguration because the approach uses an as-operated model of the distribution system. When feeder reconfiguration occurs, the control algorithms identifies the best volt VAR control actions to achieve the specified objective function (energy conservation, loss reduction, peak shaving, etc.) without violating any operational constraints.

However, in most cases, the DSCADA rules-based approach must be disabled and revert to local standalone controller mode when feeder reconfiguration occurs. This is because it is usually not possible to accommodate all of the possible feeder reconfiguration combinations in the relatively simple set of rules.

While the heuristic, auto-adaptive approach is inherently able to accommodate feeder reconfiguration, this feature has not yet been demonstrated by any vendor that offers this solution approach. As a result, heuristic, auto-adaptive systems often revert to local standalone controller mode when feeder reconfiguration occurs.

Impact of Distributed Energy Resources (DERs) on Volt-VAR Optimization

Distributed Energy Resources (DERs), including energy storage devices and distributed generating units, are having a significant impact on distribution voltage optimization. This includes *steady state* impacts and *dynamic* impacts, which are discussed in the following sections.

Steady State Impacts

Steady state refers to electrical conditions that vary at the rate of normal load variations, which can remain stable with no significant changes for many minutes or even hours. High penetrations can produce adverse steady state conditions which are mostly due to reverse power flow caused by generator output that exceeds the amount of customer load that is downstream from the generator. Reverse power flow due to distributed generators can cause voltage to rise at locations close to the generator and drop off at locations closer to the substation source.

While conventional bidirectional voltage regulators are able to properly handle reverse power flow due to feeder reconfiguration (see the previous section for discussion of bidirectional voltage regulators, they may not work correctly for handling reverse power flow caused by distributed generating units. This is because the electric grid source at the substation is always much stronger source that the DG units. So, during peak load conditions, when the bidirectional voltage regulator attempts to **raise** the voltage on the side of the voltage regulator that is connected to the electric utility grid by lowering its moveable tap, the effect is **lower** voltage on the DG side of the regulator. Figure 5-6 illustrates this situation.

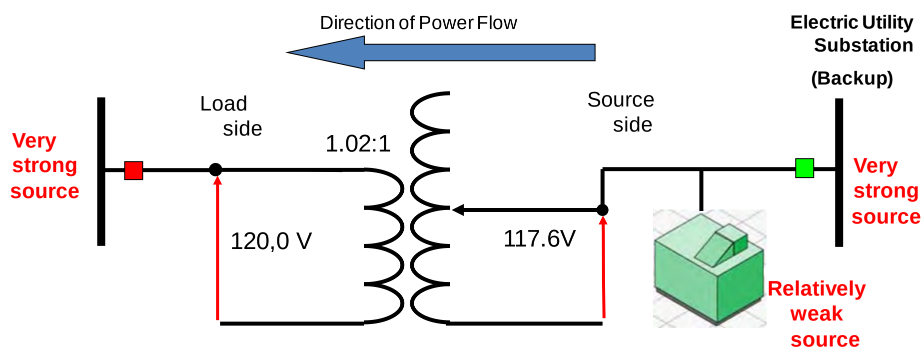


Figure 5-6:
Reverse Power Flow due to DG Unit

For proper voltage regulator operation with reverse power conditions caused by high DG output, the voltage regulator control must be able to distinguish between reverse power flow caused by DG units. One way to do this is to examine the position of tie switches that connect to alternate sources. If one or more of these switches is closed, the reverse power flow is most likely caused by feeder reconfiguration, which can be handled effectively with conventional bidirectional voltage regulators. If the tie switches are open, reverse power flow is most likely due to contributions from DG units, so the correct voltage regulator response is to treat the power flow as forward direction. This solution requires communication facilities, which, by definition of the DVO approaches, are not available with standalone controllers. The proposed solution works well for the DVO approaches that include communication facilities.

Another approach that may be used with standalone controllers is to examine the direction of reactive power flow in addition to real power flow. Power flow in one direction and reactive power flow in the opposite direction usually indicates that the reverse power flow is caused by DG units.

Dynamic Impacts

Much attention is being given to the adverse impacts of renewable generating resources (wind power, solar photovoltaic units, etc.) which can have highly variable power output. When the power output from a utility scale (1-10 MW) solar PV unit or wind turbine suddenly drops off due to cloud cover or significant change in wind speed, the power that was formerly supplied by the DG units must be delivered from the supply substation over the length of the feeder. The increased power flow along the feeder may cause a significant voltage drop along the feeder that is experienced by some or all customers that are served by the feeder. Within seconds or minutes, voltage regulators respond by raising the voltage to compensate for the increased voltage drop, and the customers experience a voltage rise. Within seconds, the clouds pass and the wind resumes resulting in increased power output from the renewable DG units and elevation of feeder voltage. Voltage regulators respond quickly to lower the voltage, and this cycle of short duration voltage fluctuations continues on the feeder.

The voltage control strategy described above results in a significant increase in tap changer operations, which increases the maintenance cost and may also reduce the life of the tap changer. Furthermore the dynamic voltages swings may be perceived by customers in the form of voltage flicker.

One way to address the dynamic voltage fluctuations associated with renewable generating sources is by using “smart” inverter controls. When power output from the DG unit suddenly drops off, the smart inverter detects this situation and rapidly ramps up its VAR output. By doing so, the voltage drop caused by drawing more power from the electric utility grid is compensated by drawing less reactive power from the grid.

Figure 5-7 shows a typical P-Q characteristic for a smart inverter, and Figure 5-8 shows the effect of smart inverter control actions on feeder voltage.

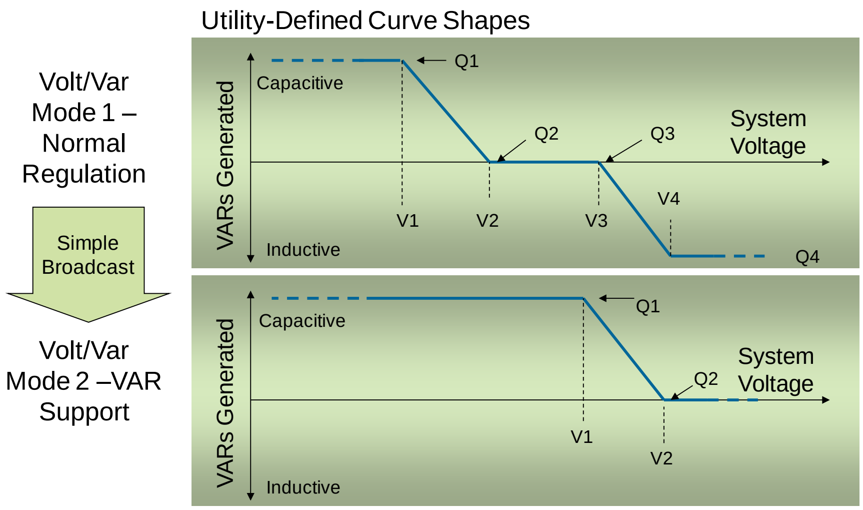


Figure 5-7
P-Q Characteristic for a Smart Inverter

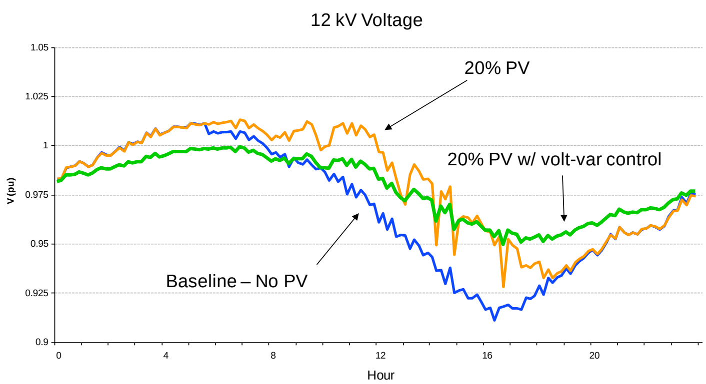


Figure 5-8
Voltage Response With and Without Smart Inverters

Infrastructure Improvements

To squeeze the maximum possible benefits out of DVO, some improvements may be needed to the distribution feeder assets and controls. Typical changes include modifications and additions to energized assets (conductors, capacitor banks, voltage regulators, etc.), upgrades to volt-VAR controller IEDs and communication facilities, and implementation of new sensors at critical measurement locations.

Many electric distribution feeders are currently limited in the amount of voltage optimization benefits that can be achieved because of existing operating constraints. In the case of CVR or voltage reduction for peak shaving, the lowest voltage on the feeder may already be near the minimum acceptable service delivery voltage under certain loading conditions. This prevents further voltage reduction to achieve the results described in this report. Figure 5-9 illustrates the initial voltage profile showing the lower limit and the voltage profile following feeder conditioning (infrastructure improvements).

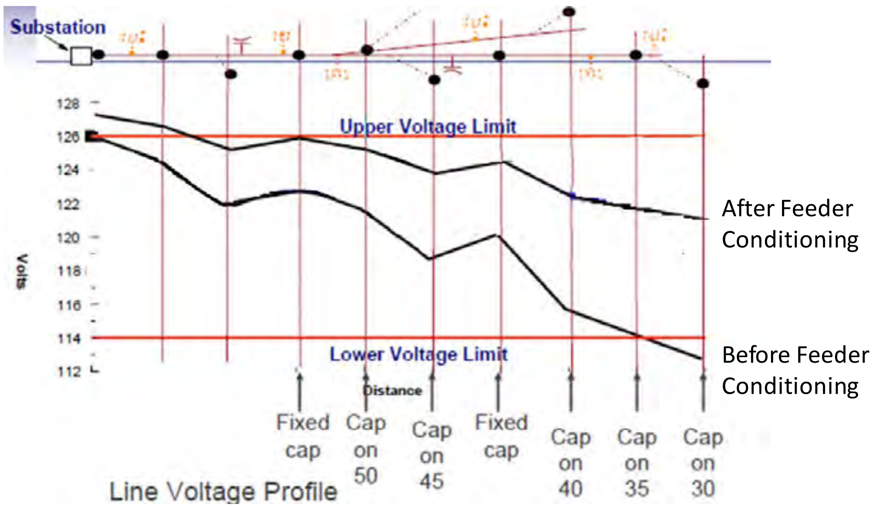


Figure 5-9
Voltage Reduction Constrained by Low Voltage Limit

Feeder conditioning (infrastructure improvements) may be needed to "flatten" or narrow the voltage profile as shown in the above figure to eliminate low voltage constraints that limit the benefits of voltage reduction:

- Addition of fixed and switched capacitor banks and mid-line voltage regulators. Additional volt VAR control devices are often needed to minimize the voltage drop and raise the voltage as needed to provide sufficient margin for voltage reduction. Figure 5-10 below illustrates the use of voltage regulators and switched capacitor banks to flatten the voltage profile.

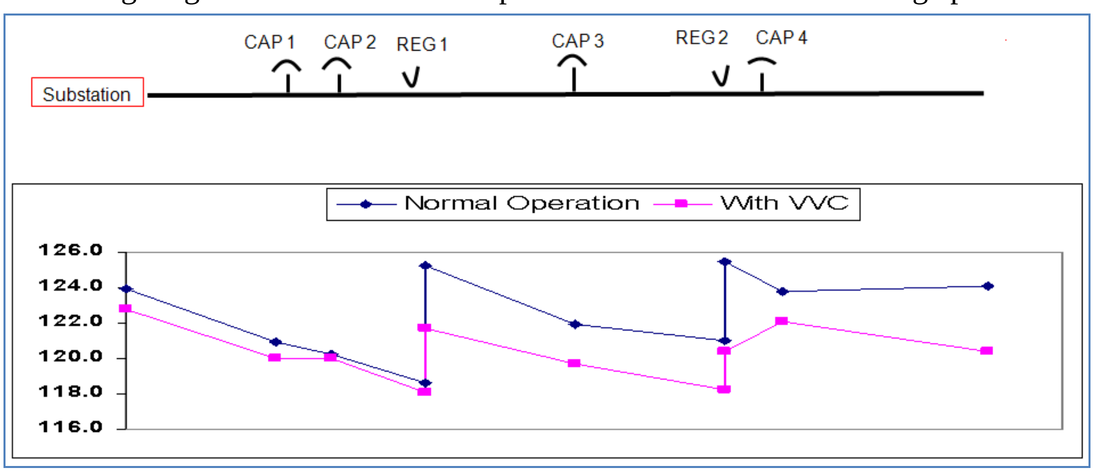


Figure 5-10
Flattening or Narrowing the Voltage Profile

- Feeder re-configuration: Some electric distribution utilities have reconfigured their distribution feeders to provide better load balance and less voltage drop along the length of the feeder. Besides raising the lowest voltage point on the feeder for increased voltage reduction capability, load balancing will also help in reducing losses for additional feeder efficiency improvement.

- Feeder phase balancing: If the loading on each phase of the distribution circuit is significantly out of balance, then the voltage on one phase may be significantly lower than the other phase. The lowest phase voltage therefore becomes the limiting facto or voltage reduction. Figure 5-11 illustrates this problem. From this figure, it can be seen that the voltage on phase A is lower than the voltage on phases B and C by at least 1 volt at locations that are greater than 4 miles from the substation. Balancing the loading between phases will elevate the voltage on the phase that was previously (before load balancing), therefore providing a greater margin for voltage reduction. In addition, phase balancing will by itself reduce losses thereby improving the overall efficiency of the feeder.

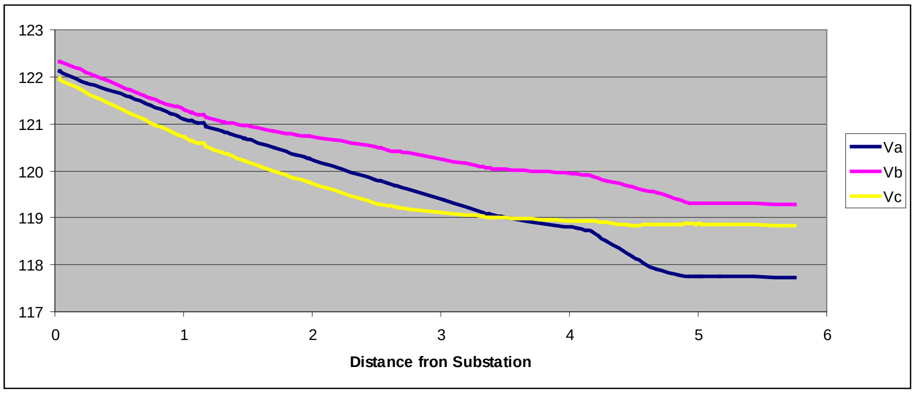


Figure 5-11
Voltage Imbalance Between Phases

- Reconductoring: Replacing existing circuit conductors with larger sized conductors reduces the voltage drop along the feeder which consequently raises the lowest voltage on the feeder to permit addition voltage reduction benefits. Secondary and service reconductoring as well as transformer replacements may be needed to correct low voltage conditions.

In addition to the improvements to energized assets, modifications and additions to the feeder monitoring and control equipment may be needed, as listed below.

- Replacement of electromechanical volt-VAR controllers with Intelligent Electronic Devices (IEDs): Some utilities have found it necessary to upgrade their voltage regulator controllers and switched capacitor bank controllers with IEDs that support remote control and monitoring and enable a more flexible DVO operating strategy. The newer IED controllers also serve as important measurement locations in support of the DVO strategy
- Addition of two way communication facilities: If facilities do not exists for handling two-way communications between the DVO master station and the field device, then these must be added.

- Addition of sensors at critical measurement locations: Achieving the maximum possible benefit for DVO requires having “closed-loop” feedback from sensors positioned at critical locations on the feeder. One of the most important measurements is the lowest voltage point on the feeder. As explained later in this report, the lowest voltage point is not always at a feeder extremity. The lowest voltage point may be on the source side of a line voltage regulator that could be located near the midpoint of the feeder, on a heavily loaded lateral, or at numerous other locations on the feeder. Electric utilities often add sensors at twenty or more locations on the feeder to provide closed loop feedback of voltage and other quantities, Without these measurements, additional operating margin must be included in the voltage reduction strategy, thereby reducing the DVO benefits.

One utility seeking to make a significant reduction in peak demand through system wide implementation of voltage reduction invested over $100 million to accomplish the following objectives:

- Modernize substation data transport communication infrastructure to IP
- Establish distribution system two-way communication to:
- Feeder remote sensors, regulators, capacitors, reclosers, and switches
- Upgraded DSCADA system to process additional data requirements
- Conduct feeder conditioning to limit feeder voltage drop to 2V

To achieve these objectives, specific feeder conditioning improvements made by this utility included:

- Balance Load by re-tapping ~5,000 transformers and line taps
- Adding 20% more line capacitors
- More than quadrupling the number of line regulators
- Added approximately 300 miles of new phase wire

Some utilities have elected to pursue DVO to the fullest extent possible without significant improvements to the distribution circuits. And in many cases have been able to achieve significant benefits with little or no infrastructure improvements. To achieve DVO benefits without significant infrastructure improvements, a utility may limit the period of DVO operation to off peak periods (e.g., 65% to 80% of peak load).

This section lists some of the findings and conclusions from the workshop pertaining to infrastructure improvements needed to effectively implement VVO.

- Most utilities are planning to add capacitor banks for power factor correction and voltage profile flattening to maximize DVO benefits. Careful system planning needs to occur between the Distribution, Transmission and Generation organizations at a utility when a large number of capacitor banks are to be installed for VVO. Harmonics caused by additional capacitor bank switching must also be considered.

- Some utilities have found that voltage imbalances between phases are the most constraining part to implementing DVO on their feeders. Improving the balance between phases may be a pre-requisite to VVO deployment.
- Secondary and service reconductoring as well as transformer replacements may be needed to correct low voltage conditions.

A key question is whether the cost of infrastructure improvements outweighs the incremental benefits gained when the infrastructure improvements are implemented. This must be explored on a case by case basis

DVO Communications

Effective and reliable two-way communication facilities are essential for implementing advanced DVO systems such as the DSCADA rules-based approach, the DMS “model-driven” approach, and the heuristic auto-adaptive approach. The more advanced VVO solutions include communication facilities that enable VVO to base its control decisions on a wide array of measurements at strategic feeder location rather than basing control actions only on local (at the device itself) conditions. Communication facilities enable remote monitoring for rapid failure detection and supervisory control that enables operators to override normal operations when necessary.

The current trend is to use IP based communications for field devices. Therefore the controller IEDs should support a 10 / 100 Mbps Ethernet connection. In addition, the end device controller IEDs should include RS-485, RS-232 and/or Fiber serial ports that support communications of 115.2 Kbps or greater.

Most of today’s DVO systems use DNP3 protocol, that includes the full suite of DNP3 features such as DNP File Transfer and unsolicited report by exception. However, there is growing interest in using the IEC 61850-standard for DVO and other DA communications. Further development and demonstration is needed to build confidence in this approach. Some systems are using Modbus for handling field communications, but this is usually not the preferred protocol for DVO communications.

Cyber Security is of course a significant concern for all DVO communications. The system should permit multiple master source address authentication, source address validation, multi-level access codes, logging of all transactions with date / time, and other such features.

The specific communication media varies from utility to utility. With the growing deployment of AMI and its associated “ubiquitous” communication infrastructure, there is considerable interest in using the AMI network for handling DA communications. Some utilities are successfully using 900MHz RF mesh network and other meter end point communication facilities for DVO monitoring purposes. Some utilities report that utility mesh radios worked reasonably well for circuit reconfiguration but not for DVO. In some cases, mesh radio polling results show less than 100% success on sending out or receiving information. One utility has reported that they had seen the communication success rate around 50% on certain devices. The success rate is on polls and control logic had to be adjusted to be more tolerant of missed polls for short periods of time.

Some utilities are now using wireless communications for limited SCADA reporting functions instead of or in addition to the traditional 900 MHz radio communications. For controlling the switched capacitor banks and voltage regulators, many electric utilities have elected to use cellular networks and other licensed and unlicensed facilities for communicating with DVO field devices. Often, these technologies are used as part of the AMI communication backhaul infrastructure. As WiMax deployment grows for AMI systems or other purposes, this is expected to provide a very effective mechanism for DVO.

The performance and response time for the DVO application is not as demanding as other DA applications such as Fault Location Isolation and Service Restoration (FLISR) which requires multiple communication round trips between field devices and the master station in less than one minute. DMS model driven DVO solutions typically run once every five to ten minutes, so more frequent polling is unnecessary.

The most common polling rate for SCADA-based DVO systems is 6 seconds. However, some utilities are decreasing the SCADA poll times from a minimum of 6 seconds to tens of seconds. Utilities are looking to maximize the communications frequency bandwidth. As a result, many are exploring and some have implemented report-by-exception on status points and alarms. Report-by-exception monitoring is almost always combined with a 10-15 minute “integrity poll” of the devices.

Handling of DVO System Contingencies

The more advanced DVO systems depend on nearly continuous interactions between sensors, controllers, and intelligent processors. If any component fails or communications between components is lost, suitable corrective action must be taken, because it is essential to maintain acceptable electrical conditions out on the feeders at all times. The DVO system must be able to detect components failures and revert to a failsafe position to avoid having unacceptable conditions out on the feeder. In most cases, DVO systems revert to local “standalone controller” mode using default controller settings when system failures occur.

The DVO function must have a “failsafe” design. That is, no control action that would produce unacceptable voltage or loading conditions shall be requested by the DVO system as a result of the failure of any DVO component. When a DVO component is out of service for any reason (controller failure, loss of communications, controller manually bypassed, blown capacitor fuse, etc.) the DVO should continue to operate in these abnormal situations, if this is possible without producing unacceptable voltage and loading conditions, using the remaining DVO components.

If a critical number of components are failed or not available for any reason, DVO switch to “local” operating mode. While the system is in “local” mode, the controller IEDs should operate in “standalone” fashion using internal (default) settings, with no central control.

Volt-VAR controller IEDs should possess a “heart beat” function in its communication capability to detect loss of communication with the master station within a specified time period (for example, 10 minutes). The DVO system should periodically check that the feeder IEDs are communicating using the “heat-beat” functionality of the controller. If the local controller fails to communicate with the DVO central processor for a specified time period, the controller should revert to local (standalone) control.

This topic was discussed extensively during the EPRI DVO Workshop that was conducted in June 2011. Following are the highlights of workshop discussions pertaining to this subject..

- Group consensus was that loss of communications to the field devices is best handled at the device level.
- The most common approach is to use the field device's "heartbeat" function to determine if system level control has failed. The heartbeat feature usually consists of a timer within the local controller that must be periodically reset by the master controller. If the timer is not reset in the allotted time, this indicates that either the master controller or the communication facilities are not operating correctly. In this case, the field device will automatically revert to local standalone control using default settings.
- Some field device controllers may wait for a predefined time, which is usually user-adjustable, for communications to be re-established before reverting to the default settings of the controller. However, some controllers have a non-adjustable factory setting (S&C "Intellicap Plus" capacitor bank controller resets in one minute). Several utilities reported using a 5-12 minute heartbeat failure time delay.
- One utility reported using a 4 hour return-to-local delay if the DMS system has not received updated readings from the feeder monitors.
- One utility's DVO system(s) suspends all DVO actions and reverts back to standalone local control for all devices when a predefined number of devices fail to communicate within a given period. The DVO controller(s) at this utility revert to local standalone operations when 20-30% of the devices of the system being controlled fail to communicate.

DMS Approach to DVO

Today's electric distribution systems depend on intelligent field devices and control systems to maintain efficiency, reliability and performance while improving safety and protection of distribution assets. At the center of attention is the Distribution Management System (DMS), which will almost certainly play a major role in the future as smart grid roadmaps become reality.

Many industry experts envision DMS-based DVO as the ultimate DVO solution because the DMS uses an "as operated" model of the distribution system. The DMS based approach is able to respond effectively to frequent changes in distribution feeder configuration, providing the most effective set of volt VAR control actions to achieve utility specified "objective functions" that is possible given the current set of operating conditions. In comparison, non-DMS approaches to DVO are often disabled, reverting to local standalone control, when the feeder is reconfigured, because these systems have difficultly adapting to out-of-normal conditions. The DMS DVO solution is inherently better equipped to determine the impacts of distributed energy resources (DERs) on feeder voltage and reactive power flow, because this solution can include detailed models that are needed to analyze the contributions of these resources.

Numerous electric utilities have already implemented a DMS or are planning to do so in the near future to help electric utility personnel monitor and control the distribution system in an "optimal" manner while improving safety and asset protection. Figure 5-12 contains a simplified depiction of a DMS system. Most of these utilities are planning to include DVO as one of the advanced distribution applications in the DMS. A common industry trend is to conduct a DVO "proof of concept" using a SCADA rules driven solution technique before eventually migrating to the DMS model-driven solution.

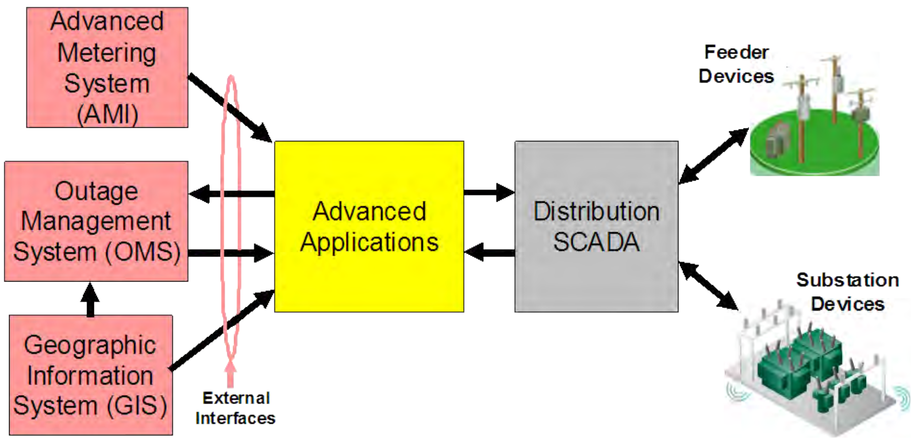


Figure 5-12
DMS Components

The biggest challenge when implementing a DMS model-driven DVO solution is building and maintaining a distribution system model that represents the as-operated state of the distribution system. The model includes two main parts: a physical model and a load model.

The Physical Model

The physical model contains information about the electrical characteristics of the distribution network. This includes electrical impedances, equipment ratings, voltage transformation ratios (where applicable), operating state (e.g., open or closed as in switchgear), physical dimensions (for example, length of a conductor section), and other such information. The physical model also includes information about the feeder topology, which defines how the individual equipment components are connected to one another. For the DVO application, the physical model must extend from the substation load tap changer to the customer meter. Is some cases, the feeder model extends beyond the substation transformer to include a portion of the transmission or subtransmission system.

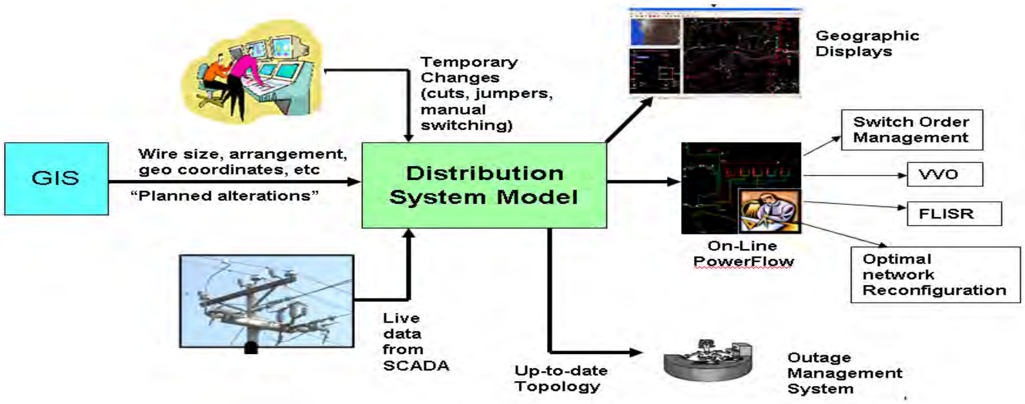


Figure 5-13
Building and Maintaining the Physical Model

As shown in Figure 5-13, the distribution system physical model is usually built and maintained via an interface between the DMS and the electric utility's Geographic Information System (GIS). However, information for some portions of the model, such as the distribution substation and the secondary 120V/240V network, typically do not reside in the GIS. In addition, some temporary model changes (cuts, jumpers, etc) may be updated manually by the distribution system operators.

- The accuracy and completeness of the GIS data is often a major concern. Some physical details that are needed to build the model, such as physical arrangement of conductors on the pole, are not available. The arrangement of conductors is needed to determine the line reactance per mile. If this information is not available, the utility may be forced to assign default values that may not reflect the actual conditions in the field and therefore would introduce some inaccuracy to the calculations
- One of the most common and widespread issues is phase identification. Phase identification errors apply to individual transformers and consumers as well as entire single phase and two phase laterals. Such errors produce unacceptable distortions to the power flow results which will adversely impact several major DMS advanced applications, including VVO. EPRI has a Phase ID supplemental project to study a way to identify the phase of the meter by analyzing induced or naturally occurring voltage variations between phases over time. Such measures will help reduce the problems associated with modeling errors

Most DMS vendors are able to perform simple checks to help identify modeling errors. For example, the vendor software can identify distribution feeder components that are not connected to any other component (physically isolated component), loops in feeders that are radial in nature, an A phase component permanently connected to a B phase component, and other such simple checks.

One of the keys to success is to always update the GIS data source when a problem is discovered. There is a tendency to only update the DMS model (or the Engineering model that uses the same GIS data) when an error is discovered. Correcting the GIS will ensure that all users of the data will be informed and that the error does not reoccur in the future if the model needs to be rebuilt from scratch.

The Load Model

Several key DMS application functions (including DVO) rely on the correct operation of an On-Line Power Flow (OLPF) program. OLPF is similar to the traditional power flow program that is used by distribution engineers to plan and design the distribution feeders. A key difference is that OLPF uses real-time or near real time load information to compute the electrical conditions (current, voltage, power, etc) and any point on the feeder in real-time or near real time.

In addition to the physical feeder model described in the previous section, OLPF requires measurements or estimates of power that is being injected into the feeder from the electric grid and (where applicable) by generators that are connected to the feeder. Power injection at the substation is usually measured with sufficient accuracy by distribution SCADA. Power injected by utility scale (1 to 10 MW) customer owned generation is also measured in near real time.

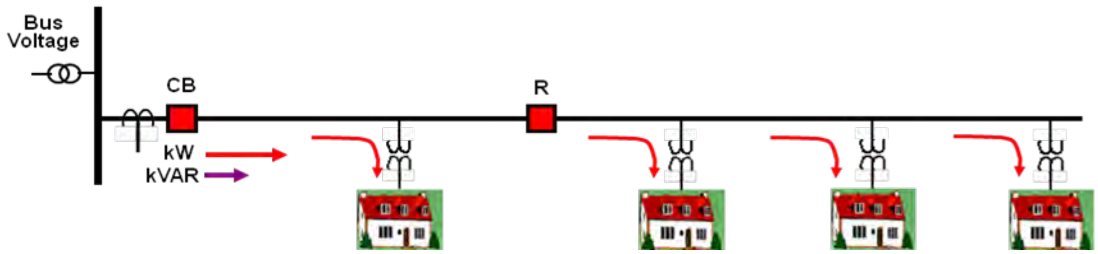


Figure 5-14
On-Line Power Flow Calculations

As seen in Figure 5-14, OLPF also requires accurate measurements or estimates of the load that is being withdrawn from the feeder by customer loads. This information has never been available for most loads in real-time or near real time. If an AMI system is available, then the loading information is available in the meter and meter data management system. However, it is not practical to acquired data in near real time form every meter on the feeder. As a result, OLPF must rely on estimates of the load at any given point of time.

The most common way to estimate the load is to use customer “load profiles” that indicate the peak daily load and the average percent of peak load at any hour of the day for various types of customers. Figure 5-15 shows a typical load profile diagram for a residential customer. In the past, load profiles were created by conducting statistical load surveys. With today’s AMI systems, the accuracy of the load profiles can be improved considerably using interval data for the AMI system.

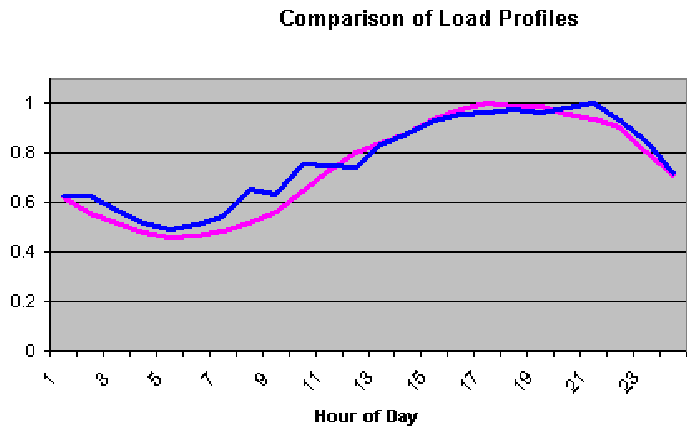


Figure 5-15
Load Profile Data for a Residential Customer

Load estimation generally works as follows:

- Power is measured in real time or near real time at the head end of the feeder by the DSCADA system. This is the total power delivered (injected) to the feeder
- The load at each customer location is estimated by applying appropriate hourly load factor load factor for the time of day to the estimated peak load from the load survey. This is the initial estimate of load.
- The initial estimates of all loads connected to the feeder are summed to determine and estimate of the total load on the feeder.
- The total load estimate is compared with the total injected power that was measured by DSCADA. The ratio between total estimated load and total measured load is computed and this factor is applied to each initial load estimate to determine the final load estimate that is used by the power flow.

The accuracy of this process can be improved by installing sensors to monitor load flow at a mid feeder location (such as a line recloser). Load allocation is performed in a similar manner, however the mid line measurement is used to allocate the loads that are downstream from the measurement point. This will improve the accuracy of the load estimates.

Load to Voltage Sensitivity

With the rapidly growing interest in using voltage reduction as a key element of DVO, it is absolutely essential to include load-to-voltage (LTV) sensitivity effects in the DVO load model. This ensures that the effect of operating with off-nominal voltage is properly represented. It is common practice to include an average LTV sensitivity factor, such as 0.7 or 0.8, in the load model. This is the average value reported by electric utilities who have conducted voltage reduction field trials.

It should be noted that LTV sensitivity factors vary from feeder to feeder depending on customer mix (residential, commercial, industrial, etc.), season, and even time of day.

EPRI's supplemental project ("Load Modeling for Voltage Optimization") is developing a library of customer load models that can be used to accurately represent the effects of load to voltage sensitivity.

DVO Input Requirements

DVO input requirements vary depending on the DVO approach that is used. The standalone controller approach relies solely on local real-time measurements, whereas the SCADA rules based approach, the DMS model driven approach, and the heuristic auto adaptive approaches require real time, near-real-time and historical measurements from a variety of locations in the substation an out on the feeders.

Measurement requirements for standalone controllers depend on the selected control strategy. The voltage control strategy for switched capacitor banks requires voltage measurements. The voltage with temperature override requires ambient temperature measurements along with the voltage measurements. Other measurements that may be needed to support the selected local control strategy include current (amperes) and reactive power.

The required inputs for the SCADA Rules based approach typically include voltage measurements at all switched capacitor bank locations and at the substation bus, and real and reactive power delivered to each feeder. It is also beneficial to acquire the actual open/closed position of each capacitor bank switch and the actual tap position of the substation transformer Load Tap Changer and voltage regulator. In addition, real-time voltage measurements are needed from feeder locations at which the lowest voltage is likely to occur. This information is needed to provide "closed loop" feedback to the voltage reduction rules to ensure that the low voltage constraints are not violated.

The DMS model driven approach requires all of the inputs that are identified above for SCADA rules based DVO. In addition, the DMS DVO solution may also utilize current, voltage, real power and reactive power measurements from line reclosers and other midline devices. Furthermore, load measurements and/or estimates are needed to support the On-Line Power Flow application used by the DMS DVO application.

The heuristic auto-adaptive approach requires roughly the same measurement data as the DMS model driven approach but does not require measurements of individual customer loads. Required input data typically includes substation bus voltages, end of line voltages, currents, real and reactive power, ambient temperature, and operating status of all volt and var control devices. Data is collected every 15 to 30 seconds.

Measurement Accuracy

Measurement accuracy is especially important for the DVO application.

Voltage and VAR control actions are based on operating margins of a few percentage points, so high measurement accuracy is critical, especially for providing closed loop feedback to the voltage reduction scheme.

Conventional voltage sensors typically have an accuracy of 1% - 2% for current and voltage measurement in the normal operating range. For example, Lindsey Manufacturing Company's , CVMI Clamp Top sensors (See figure 5-16) have 1% current and voltage accuracy, and Piedmont Bushings & Insulators, LLC offers current/voltage line post sensors that have accuracy ranging from ±1% to ±3%. Measurements provided by line reclosers and other "SCADA ready" switchgear have an accuracy of between 2% and 3%. Measurements obtained from protective relay IEDs may be even more inaccurate, because the instrument transformers (CTs and PTs) that feed these IEDs introduce additional error of 0.3% or 0.6%, depending on the class of the instrument transformer.

Figure 5-16
Lindsey CVMI Line Post Sensor

These error levels seem small, but 2% measurement accuracy for nominal voltage of 120 volts is 2.4 volts which is very significant when performing voltage reduction with closed loop feedback. Additional operating margin on voltage reduction target is needed to ensure that voltage limits are not violated during voltage reduction intervals

A newer class of optical current/voltage sensors is more accurate than the conventional sensors described above. For example, the Optisensor™ optical current/voltage sensor from Optisense (see figure 5-17) has accuracy within 0.5%. According to Alabama Power, these sensors cost considerably more than conventional sensors. However, the better accuracy allows smaller operating margins which may offset the higher cost of these units.

Figure 5-17
Optisensor™ Optical Current/Voltage Sensor

Revenue meters (AMI) offer a measurement accuracy that is typically in the range of 0.2%, making them well suited (from an accuracy standpoint) for voltage feedback than sensors for accuracy reasons and meter placement reasons

Using AMI Data for DVO

AMI will provide a wealth of new information regarding the electrical conditions out on the distribution feeders, some of which is useful for effective DVO deployment. AMI systems can provide voltage measurements for DVO voltage feedback from the locations that matter most for voltage reduction purposes: the customer point of service delivery. AMI meters are ideally located for serving the need for lowest voltage monitors because they are located everywhere on the feeder where customers are connected and because they indicate voltage at the exact point of delivery (i.e., the voltage "seen" by the customers. Primary meters have the disadvantage of not measuring the voltage drop between the primary circuit and the meter, which includes voltage drop across the distribution transformer (approximately 2 volts, the secondary circuit (approximately 1 volt), and the individual service drop (approximately 1 volt).

AMI meters also have better accuracy (0.2% accuracy) than other measurement systems, such as sensors, transducers, and controller IEDs. In addition, some AMI meters provide a "safety net" that can send a warning or alarm message to the DVO system whenever line voltage at any customer site drops below a pre-defined limit for a configurable qualification time.

Electric utilities have been able to use AMI meter information to identify low voltage issues that were previously undetected. AMI meter voltage and usage information can uncover voltage issues that were not realized in the past. This may lead to additional infrastructure improvements including reconductoring of secondary circuits or transformer upgrades. Although these improvements increase the cost, the improvement in the voltage profile could lead to more VVO benefits that outweigh the cost of infrastructure upgrades.

It is not practical for the DVO application to monitor voltage measurements from all AMI meters in real time (once a minute or less) or near real time (once every 10 to 15 minutes). This would overburden the AMI communication network and other AMI system components. Some utilities, such as Dominion Resources, have had success in using select meters as voltage monitoring points within segments of lines known to have the lowest voltages. These monitoring points are used as remote feedback points for the regulation devices and provide anywhere from 2-15 minute interval data required by DVO for voltage feedback. Selecting a small number of meters that may experience lowest voltage from thousands of possible meters is a challenging task; a section on determining critical measurement locations is provided later in this report.

Despite the advantage listed above, there are some areas of concern about using secondary voltage readings from AMI meters to provide VVO voltage feedback.:

- Most meters are unable to communicate using DNP3 and report back in real-time. Most meters are unable to communicate directly with the DVO system, DMS, or DSCADA system due to lack of support for the most widely used SCADA communication protocols and standards (DNP3, IEC 61850, Modbus, etc.). AMI data must flow from the meter to the meter data management system, and is then transferred from the MDMS to the DVO system using Enterprise Service Bus (ESB) or other IT networking technique. This introduces latency (delays) that may be unacceptable for voltage feedback.
- Should use average voltage measurements rather than instantaneous meter readings which tend to bounce around as individual large appliances switch on and off.

EPRI recommends that electric utilities that have implemented AMI use the AMI voltage measurements for DVO closed loop feedback. Between 10 and 20 selected AMI meters should be used for voltage feedback at any given time. Methods for selecting the best metering locations are provided later in this chapter. In addition, the exception reporting “safety net” should be used to identify lowest voltage meters that are not continuously monitored. Rather than use individual AMI meter voltage readings that can change frequently with individual customer appliances, a smoothing technique such as a rolling average or combination of readings from multiple meters at the same general location should be used.

To minimize the burden on AMI meter networks and backhaul communication facilities, the selected voltage readings from AMI meters should be acquired on a near-real-time basis (once every 5 to15 minutes) at the same frequency as the DVO calculation interval.

Critical Measurement Locations

To achieve the maximum possible benefit from voltage reduction, it is necessary to provide the DVO system with voltage information from the lowest voltage point on the feeder at any given time. In many cases, the lowest voltage point on the feeder occurs at the end-of-line extremities of the feeder. However, the lowest voltage point may occur anywhere on the feeder. For example, as shown in Figure 5-18, the lowest voltage on the feeder occurs on the source side of a voltage regulator which is located near the mid-point of the feeder.

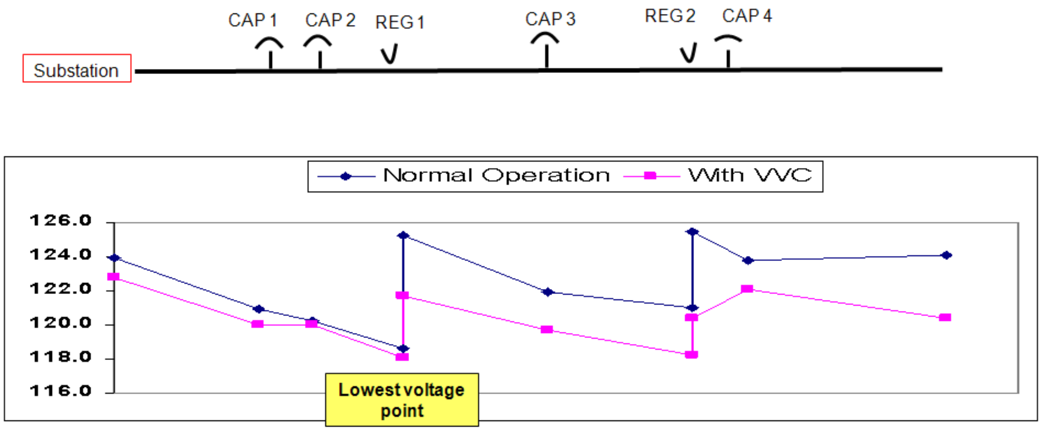


Figure 5-18
Lowest Voltage Point Near Voltage Regulator

The lowest voltage point on the feeder may occur anywhere on the feeder, and it may change with time as conditions vary. The lowest voltage point on a feeder may change if the feeder is reconfigured for any reason. If a major portion of a feeder is transferred to a second feeder, feeder midpoints may become feeder end-points following feeder reconfiguration. In fact, the substation end (head end) of the feeder may become the end-of-line of the new feeder following feeder reconfiguration. In addition, the location of the lowest voltage can vary with the time of the day or season of the year.

As part of this DVO project, EPRI determined that the lowest voltage point on a feeder can often be captured by measuring a reasonably-sized subset of (approximately 20) AMI meters or separate voltage sensors connected near the distribution service transformer that serves the lowest voltage meters. Figure 5-19 summarizes the results of this analysis for one feeder. As seen in this figure, the absolute lowest voltage point of the feeder may be captured 80% of the time by continuously monitoring only twenty meters out of several thousand AMI meters on the given feeder over an entire year. Further analysis shows that these twenty metering locations are within one percent of the lowest voltage measurement (1.2 volts on a 120 volt scale) over 99% of the time in the same year. EPRI concludes therefore that it is feasible to capture the lowest voltage measurement within one volt almost 99% of the time with a reasonable sized meter sample (20 meters or less).

# of Meters	% of Lowest Voltage Readings	% of Total # of Meters
1	17%	0.1%
3	40%	0.3%
10	68%	1.0%
20	80%	2.0%
147	100%	14.9%

To Within X% of lowest voltage reading	% of the Time
0.50%	93.82%
1.00%	98.01%
1.50%	99.01%
2.00%	99.24%

Figure 5-19
Analysis of Lowest Voltage Locations Using AMI Data Records

It is essential to obtain certain critical measurements, especially voltage measurements at possible low voltage points on the feeder. These low voltage measurements provide valuable feedback to determine if further voltage reduction is possible. The lowest voltage point can be found anywhere on the feeder and can vary depending on the time of day, day of the week, or season of the year.

Noted low voltage measurement locations include:

- Capacitor banks
- Regulation points (feeder regulators and LTC)
- Critical points along the line such as reclosers and switches with SCADA capabilities
- End of the line monitoring
- End of heavily loaded laterals
- Locations that are predicted to have low voltage based on a series of power flow runs.

AMI meter data is a great resource for identifying locations prone to having the lowest voltage on a circuit for a given interval of time. Time intervals of 15 minutes or hourly average voltage readings are sufficient to identify critical voltage measurements. The following steps can be used to determine these locations:

1. Obtain 12 months of AMI hourly average voltage readings for the circuit in question
2. Determine the lowest circuit voltage per interval
3. Identify the meter(s) with this corresponding lowest voltage reading per interval
4. Sum up the number of low voltage occurrences per meter
5. Select only one meter per transformer (the meter with largest number of low voltage occurrences)
6. Select the meters to monitor based on the most low voltage occurrences, location on the feeder, and other utility specific needs or requirements
7. Repeat analysis on a periodic basis or after a circuit reconfiguration

EPRI's investigation of critical measurement locations using past year measurement data also revealed certain distinct trends about where the lowest voltage points occurred. These trends are summarized below:

- Some meters were the lowest voltage points only during winter months. These meters are most likely associated with customers located in areas with high concentrations of electric heating. These meters are therefore good candidates for lowest voltage metering points during winter months.
- Some meters exhibited lowest voltage during summer months, implying that there is a significant amount of air conditioning load in the area, making them ideal characteristics for lowest voltage metering during summer months.

The electric utility should exploit the voltage exception reporting capabilities of the automatic meter (if available). This facility should alert the operator that voltage is near the minimum acceptable value, so that the operator can assess the situation and if necessary disable the voltage reduction scheme for the affected utility. At least two alert levels should be provided: a warning level if the voltage is lower than expected, and an alarm level if minimum voltage limit has been violated. If an alarm occurs, the utility may consider automatic disabling of voltage reduction.

DVO Economic Issues

This section covers DVO benefits and cost recovery strategies for energy efficiency projects such as DVO. Measurement and Verification (M&V) techniques for determining the energy efficiency improvement benefits through field trials are also discussed.

DVO Benefits

Electric utilities and their customers are able to achieve a wide variety of benefits from the DVO deployment. DVO benefits that have been achieved by electric utilities are summarized below:

- ***Reduction of electrical demand:*** Electric utilities that have used voltage reduction for peak shaving have reported savings between 1.5% to 2.1% of peak load. Utilities that purchase power from suppliers may reduce demand charges for direct savings. Other utilities may be able to eliminate or postpone capital expenditures for capacity additions by reducing their electrical demand. Progress Energy (Carolinas) credits voltage reduction for reducing demand by approximately 310 MW, thereby eliminating the need for two peak shaving CTs). The load reduction resulting from VR may also reduce overloading on targeted distribution facilities (substations and feeders). Voltage reduction also provides an effective and "non-invasive" form of Demand Response.
- ***Reduction of energy consumption:*** Electric utilities who have used CVR for energy conservation have reported savings in energy consumption of between 1.3% and 2%. The value and beneficiary of this benefit is often hard to determine, but CVR can be handled like any other energy conservation measure. It should be noted that between 90% and 95% of the energy conservation benefits is on the customer side of the meter. Utility side benefits are attributed to distribution transformers and unmetered loads such as street lighting.
- ***Reduction of Electrical Losses:*** The DVO system can help reduce electrical losses. Most loss reduction benefit comes from power factor correction. Voltage reduction may contribute additional loss reduction benefits, but this affect is small compared to energy conservation results. For constant power loads (power electronics, variable frequency drives, etc.), voltage reduction will increase current, and this increased current flow will actually increase losses. In any case, the reduction of electrical losses attributable to DVO is between 5% and 10% of the losses without DVO. If distribution losses are between 2% and 4% of total energy consumption, then the loss reduction is between 0.1% and 0.4% of the total energy consumption.
- ***Early Detection and correction of voltage quality problems:*** One of the side benefits of DVO is early detection of voltage problems through better monitoring of feeder voltage conditions. Benefits include reduction in the number of High and Low voltage complaints, early detection of customer voltage quality conditions, including flicker.

- ***Reduced number of tap changer and capacitor switching operations:*** PCS Utilidata has reported that, based on actual field experience, CVR VVO can reduce tap change operations up to 33%, reducing wear and maintenance costs on this equipment while at the same time not increasing capacitor switching operations .
- ***Increased Equipment Life:*** One of the potential benefits of operating at reduced voltage is extended life for some electrical devices. Snohomish Public Utility District, one of the early CVR implementers, has reported that some appliances (especially incandescent light bulbs) have experience a 15% increase in useful life. EPRI has not tested this hypothesis in its laboratories, and is unaware of any other institution that has verified equipment life extension with certainty. One of the major causes of electrical device failure is insulation deterioration resulting from excessive heat. More efficient electrical appliances, such as electric motors, consume less electrical energy in the form of heat. So, it is intuitive that equipment efficiency improvements will extend appliance life.

Cost Recovery Strategy

All investments have to make sense ("be prudent") from the fundamental economic perspective; that is, the benefits must exceed the costs! Electric utility investments must also make sense from a ratemaking, revenue recovery standpoint. It is not enough for the benefits to outweigh the costs if the utility company pays the costs and another entity (e.g., customers, suppliers) achieves the benefits. Many utilities perceive that there is lack of incentive for efficiency and reliability improvements in traditional ratemaking.

Figure 5-20 shows some of the cost recovery measures that are being considered for electric utility investments in efficiency and reliability improvements for which the primary beneficiary is often someone other than the utility itself.

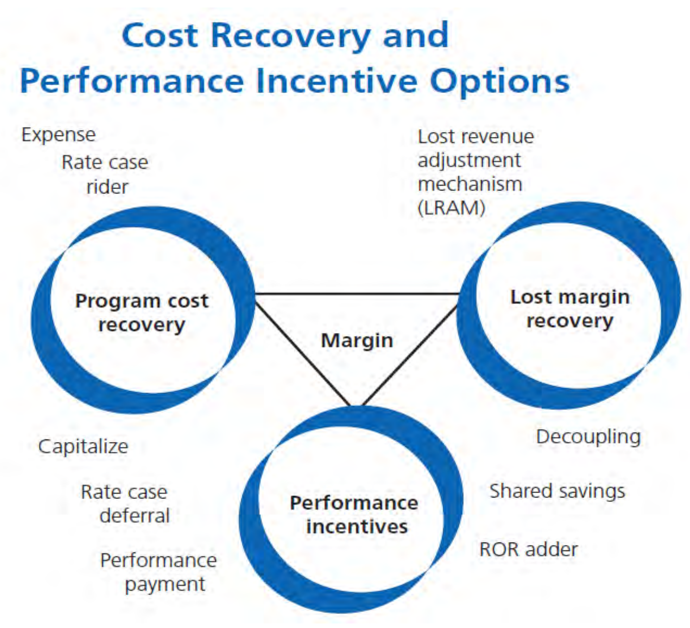


Figure 5-20
Cost Recovery and Performance Incentive Options
(source: Aligning Utility Incentives with Investment in Energy Efficiency - A Resource Of The National Action Plan For Energy Efficiency, November 2007)

The primary cost recovery mechanisms used today for electric utility efficiency improvement projects are:

- **Program Cost Recovery**: With this approach, the electric utility can recover prudently-incurred costs of efficiency investments on a dollar-for-dollar basis. This is designed to make a utility whole on its investment. However, cost recovery alone will not address the lost margin revenue the utility will face due to reduced energy sales. In addition, cost recovery does not factor in opportunity costs: demand response and energy efficiency investments displace supply-side investments for which the utility can earn a profit
- **Targets: Incentives and Penalties:** Some states have set specific targets for utilities around demand reduction, energy savings, and/or reliability improvement, and in many cases have attached a financial "carrot and stick" to the targets. In most cases, the financial incentive or penalty is considerably less than implementation cost
- **Lost Margin Recovery:** This cost recovery mechanism is usually comprised of one of the following two mechanisms: Shared Savings and Revenue Decoupling. With shared savings, utility receives a percentage share of the savings (avoided costs), Shared savings approach may include penalties for failing to achieve the desired objective. Currently, most revenues tied to sales, which, in most cases, provides a disincentive to promote energy efficiency. Revenue Decoupling increases the amount of revenues recovered through "fixed" distribution charges, and periodically adjusts electric rates, up or down, to account for differences between authorized and actual revenues. Revenue decoupling is currently one of the most popular cost recovery mechanisms.

Measurement and Verification (M&V) Strategy

One of the most significant challenges facing utilities that are conducting DVO projects and "proof of concept" demonstrations is determining the actual benefits that are being achieved through voltage optimization. Determining the benefits would be relatively simple if feeder loading and operating conditions were very consistent from day to day. If loading and operating conditions were identical each day, it would be a simple matter to apply DVO for a day and then compare the day's results with the previous day.

Unfortunately, determining the benefits is not that simple. The electrical conditions of every feeder can vary significantly from day to day due to:

- Environmental Conditions
  - Local ambient temperature
  - Humidity
  - Sun irradiation
  - Cloudiness
  - Wind direction and strength
- Societal Issues
  - Public events
  - TV shows

- Technological/commercial issues
  - Changes in manufacturing industry
  - Changes in sales

These factors may be significantly different even at “similar” days, e.g. weekdays of the same week. The CVR test methodologies used by some utilities include measurements of some of these factors, mostly the temperature. However, to factor- in the temperature into the changes of the load requires the knowledge of the load-to-temperature dependency, which by itself depends on a number of factors and is not the same at different times.

So, when DVO is applied it is difficult to determine whether the subsequent changes in electrical conditions (energy consumption, losses, demand, etc) can be attributed to natural variations or DVO.

This section discusses several approaches that have been used to separate the DVO effects from natural random fluctuations.

“Flip the Switch and Observe” Approach

One approach is to record the current electrical state of the distribution system (current, voltage, real/reactive power, etc), initiate DVO, and then quickly record the resulting electrical conditions before natural, random fluctuations occur. This “flip the switch and observe” approach is effective for observing the immediate response to voltage reduction. Often the initial response is quite significant. However, CVR effects almost always decay with time, as shown in Figure 5-21. This is because electrical devices that are switched on and off by a thermostat (electric heat, electric hot water heaters, electric stoves, etc.) simply run longer with reduced voltage to deliver a fixed amount of energy. When such devices run longer, the natural operating diversity is lost, and more devices are on at the same time thus reducing the perceived demand response. As seen in Figure 5-21, the CVR factor starts high and decays to a lower values after several hours due to the gradual loss of diversity. Figure 5-21 was created in a controlled environment, producing clean and smooth results. On an actual feeder, random loading effects would occur during that interval, making it impossible to distinguish DVO impact from natural variations.

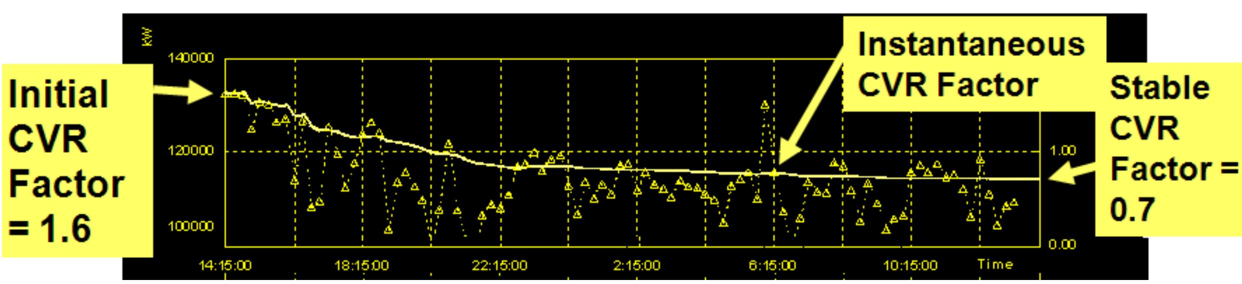


Figure 5-21
Time Delayed Effects of DVO

To determine the benefits have been achieved, the utility must answer the question: “What would have happened” if DVO had not been running? “Comparing what would have happened” with “what did happen” will enable the utility to determine the DVO benefit.

Several mechanisms are currently being used to perform this comparison, as described ni the following sections.

Powerflow Approach to Measurement and Verification

S&C Electric's IntelliTeam VV DVO system has an embedded Measurement and Verification (M&V) application that reports the real-time DVO system savings. This M&V application is based on a real-time power flow engine with state estimation.

S&C's M&V approach compares the actual feeder measurements when running DVO (the "optimized system) to a simulated dynamic baseline load to calculate and verify the demand reduction. The demand reduction achieved by the system is calculated by using the difference of measured demand (MW and MVAR) and energy consumption (MWh) to a simulated baseline system demand and energy consumption. The simulated baseline demand and energy consumption represents what would have occurred if the VVO system was not running.

For example, as shown in Figure 5-22, one of the capacitor banks has been switched on by DVO control (as shown in the top diagram which represents the actual "optimized" conditions. The lower diagram which was generated using an On-Line Power Flow simulation, shows that the same capacitor banks would have been off if under local control.

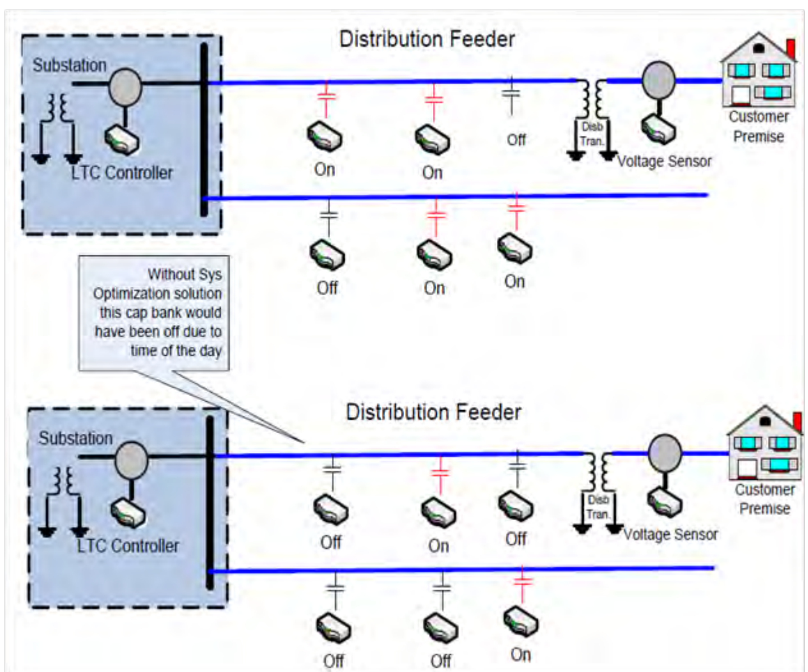


Figure 5-22
Comparison of DVO Result with Simulated results

The M&V software calculates the difference in measured demand and energy consumption wioth DVO running and the calculated values using OLPF. The M&V baseline is prepared at regular intervals, typically every 5 minutes, using network simulations while the IntelliTeam VV applications are running. M&V utilizes a three-phase real-time unbalanced power flow and state estimator to calculate the demand reduction achieved using the IntelliTeam VV applications. The power flow engine simulation prepares the baseline model topology and uses the systems “native” load (i.e. load without capacitor banks) to estimate the demand which would have occurred without the S&C IntelliTeam VV solution. It also takes customer load type into account and determines what load tap changer and capacitor bank operations would have occurred if the IntelliTeam VV control scheme was not engaged. The output of this analysis provides the baseline demand to calculate the energy savings by comparing it with the real-time measured demand. One of the key advantages of this approach is that the IntelliTeam VV applications continue to operate while the M&V process runs. Figure 5-23 shows a sample results screen.

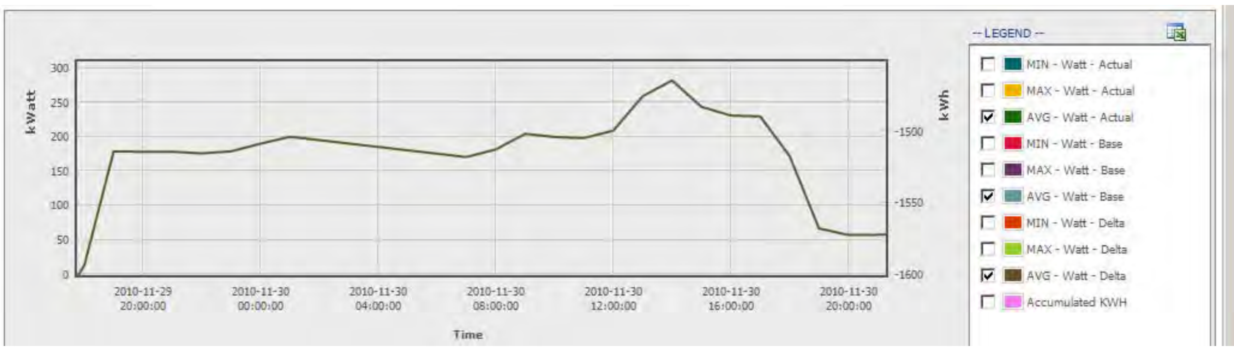


Figure 5-23
Sample M&V Results

An advantage of S&C’s approach is that CVR benefits are determined while DVO is continuously running. A disadvantage is that the power flow results require assumptions about load-voltage sensitivity (CVR factors), which are not known until the analysis is completed (a “Catch 22” situation).

M&V Using Day-On/Day-Off Testing

A common approach to M&V that has been adopted by numerous electric utilities and research organizations is commonly referred to a “Day On/Day Off” testing. This approach involves running DVO for a short period (one day, one week, etc.), followed by a similar period of operation without DVO running. The process of switching back and forth between DVO on and DVO off is continued for a period of time (up to one year) and then analyzing the results to determine the benefits.

Ideally the process would be as simple as comparing the actual measurements from the DVO-off period with the DVO-on period to compute the difference between the two days. If the difference were entirely due to voltage reduction, this simple comparison would work. Figure 5-24 shows a comparison of the loading on a single feeder for two consecutive days, one day with reduced voltage and one day with normal voltage. For these two days, the natural loading variations caused by factors other than voltage changes are very similar. So the effects of voltage reduction are easy to see: the pink line (reduced voltage) is clearly lower that the blue line (normal voltage) most of the time.

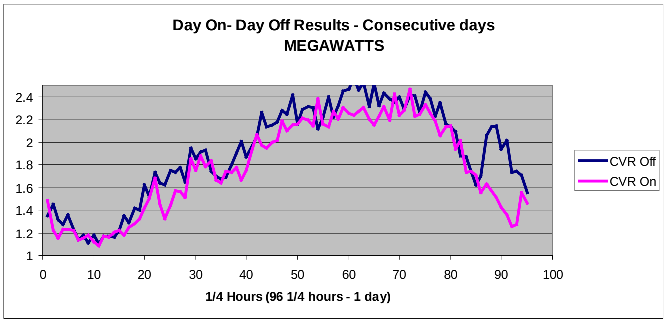


Figure 5-24
Feeder Loading On Similar Days With And Without Voltage Reduction

However, as explained earlier in this section, most of the day-day changes are caused by effects other than voltage reduction (special days, weather conditions, feeder reconfiguration, etc). Figure 5-25 shows a comparison of the loading on a single feeder for two consecutive days for which the "other" factors are present. As can be seen on this diagram, feeder loading is sometimes lower on the day when voltage is at normal levels. This indicates that the voltage effects are "masked" by "other" factors. For this reason, a method is needed to distinguish voltage effects from "other" effects.

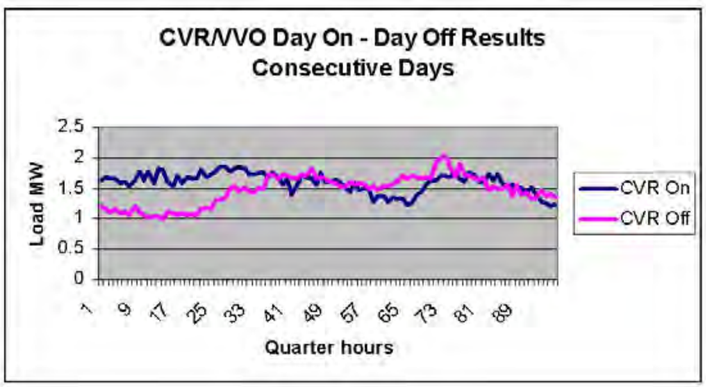


Figure 5-25
Feeder Loading On Consecutive Dissimilar Days With And Without Voltage Reduction

The most common method is to observe day-on/day-off data over a longer period (up to one year) and then analyze the information using statistics. The objective of the statistical analysis is to determine "what would have happened" on DVO-on days if voltage reduction had not been applied. Voltage reduction effects can then be determined by comparing "what would have happened" to "what actually happened" when voltage was reduced.

There are two main approaches for this analysis, both of which involve multiple regression analysis of day on/day off results:

Northwest Energy Efficiency Alliance (NEEA) Approach: This approach has been used by PCS Utilidata (CVR Protocol Number 1), Pacific Northwest National Laboratories (PNNL) and other entities to determine "what would have happened" on voltage reduction days. The regression analysis develops the relationship between temperature (heating days and cooling days) and load. Following is the general formula that is used to estimate the load given temperature measurements:

$$\mathbf{kW = \beta 0 + \beta 1 * hdh + \beta 2 * cdh}$$

Where: hdh = heating-degree hours
cdh = cooling-degree hours

The factors in these equations are determined by applying least-squared-error curve fitting and multiple regression techniques to a set of load and temperature measurements acquired prior to implementing voltage reduction. To compute what "would have happened" if DVO was not running, the power is estimated using the formula and the actual temperature measurement.

Figure 5-26 shows the relationship between temperature measurements and load for one circuit. As seen on the figure, the estimated load calculated using the formula (indicated as a blue V-shaped characteristic with a flat bottom portion) provides a reasonable approximation to the actual measured load (shown by green and blue circles).

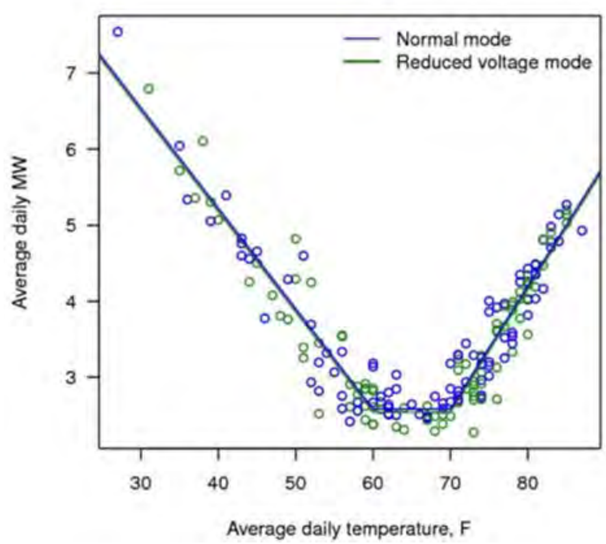


Figure 5-26
Predicting Load from Temperature Measurements

EPRI Green Circuits "Similar Circuit" Method: The M&V method used during Green Circuits CVR field trials uses measurements from one or more similar circuits instead of temperature to determined "what would have happened". In this methodology, the load changes unrelated to the voltage are separated by comparison of load changes in the test feeder(s) with the load changes in one or more reference feeder. The test bus is the one, where the voltage will be changed every other day by a percentage up and by the same percentage down. The reference bus is the one, where the voltage is practically not changed (constant voltage setting), and the unrelated load changes are well correlated with the unrelated load changes of the test feeder.

Following are the recommended steps for selecting a suitable “similar circuit”:

1. Select another control bus/feeder of the same category in the vicinity of the test bus/feeder
2. Obtain real and reactive load measurements for the test bus/feeder(s)) and candidate reference bus/feeders for 1-2 week time interval before the voltage test. Record the 15-min average load (energy) or instantaneous measurements with 15-min or less time intervals between measurements.
3. Derive for each bus a series of percent change in real and reactive loads which are separated from one another by a 24-hour interval, i.e., determine the change of load for the same times of different days (see Figure 5-27). These measurements will provide information on daily average load (daily energy consumption) dependency on voltage because the changed voltages are kept for 24 hours. At the same time, the measurements will provide information on load dependences at different times of day, including the times closely around the time of the voltage change from one level to another. The latter can be used as an indicator of load-to-voltage dependency (LTV) that can be used for load reduction objective, but not for energy conservation objective.

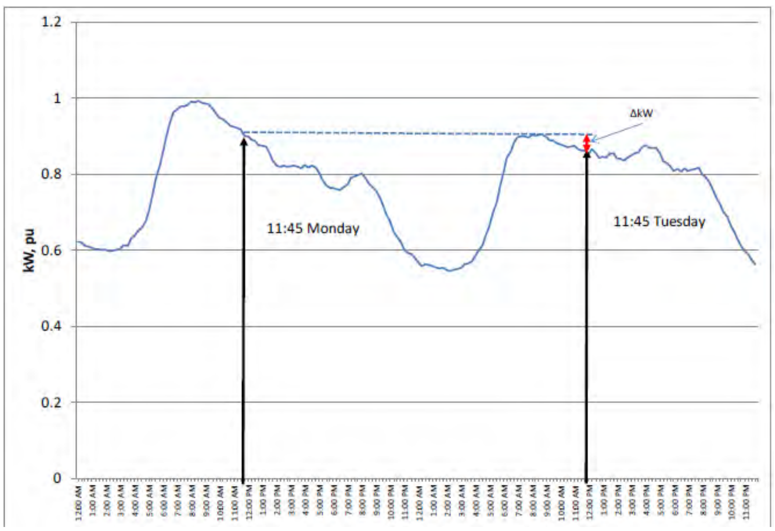


Figure 5-27
Defining Changes of KW at 24-Hour Intervals

4. Calculate the cross-correlation coefficients between the load changes of the test bus series and the same-time load changes at the reference bus (feeder). It is recommended that if the correlation coefficient between the changes of kW is greater than 0.8, the candidate reference bus can be accepted. The requirements for the reactive load can be less strict, because, typically, the var dependences on voltage are much stronger than the kW dependences, and the masking factors are not so influential.

The next step is to perform multiple regression analysis to define the relationship between the test feeder load and the reference feeder load. The result is a formula similar to that shown below that can be used to compute "what would have happened" on the test feeder.

kW = k0 + k1 * kWcomp + k2 * Vstate + (error term)

Where: kWcomp = avg power measured at a comparable circuit
Vstate = 1 for normal voltage, 0 for reduced voltage
(error term) – assumed to be normally distributed

Figure 5-28 shows the relationship between load measurements on the reference bus/feeders and loading on the test bus. As seen on the figure, the estimated load calculated using the formula (indicated as blue and green straight lines) provides a very good approximation to the actual measured load (shown by green and blue circles).

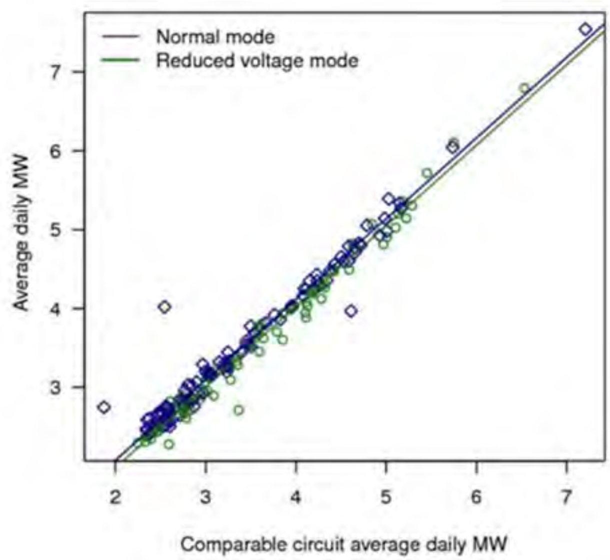


Figure 5-28
Predicting Load from Temperature Measurements

6
ELECTRIC UTILITY CASE STUDIES

This chapter contains a summary of the key findings, conclusions and recommendations of the research effort. This section summarizes the VVO plans and practices identified by the electric utilities that participated in the workshop. This section contains only highlights from the presentations and utility lead discussions, such as general approach to VVO, project status, major challenges and lessons learned, and benefits achieved or expected. Topics covered also include:

- Key results from demonstrations and widespread deployment – future plans
- Current status of volt-VAR control (VVC) and VVO at each utility (planned, demonstration or widespread implementation)
- Vendor(s) used (if any)
- Key challenges and success stories

XCEL Energy

Xcel is implementing the “Open Grid” software developed by Current Group (now part of S&C Electric Company) to implement its DVO solution. The new product name is Intelliteam VV. Project goals are to:

- Improve Power Factor
- Meet Interconnection Requirements
- Reduce Losses
- Reduce Carbon – Energy Savings

This is a “centralized” control scheme (i.e., the main DVO logic resides in servers located in the distribution control center). Figure 6-1 contains a high level depiction of this system.

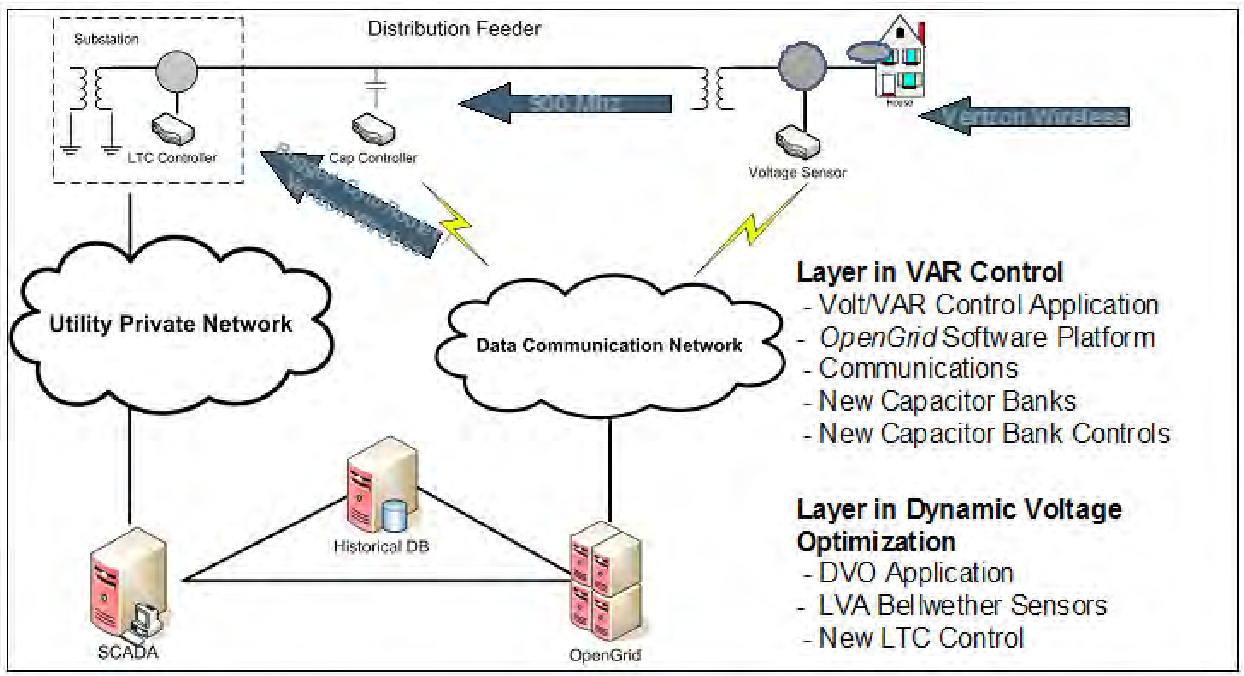


Figure 6-1
Xcel Energy DVO Scheme

The major functions performed by Open Grid include:

- Flatten Voltage Profile with Capacitors
- Load Tap Changer Control
- Reduce Voltage

Volt/VAR control has been operating in automated mode since February 2010. During this period, the following results were achieved:

- Substation power factor has been maintained above .985.
- Bus voltage was reduced from the historical 124.3 bandcenter, with the largest voltage reduction observed during light load periods.
- Instantaneous kW demand was reduced by 1.2% to 2.2% for a voltage reduction of 1.5% - 2.5% during initial testing. This represents a CVR factor of 0.72 to 0.86. These results were computed using the Measurement and Verification (M&V) approach developed by Current Group.

Duke Energy

Duke Energy has on-going VVO pilot projects to test different control schemes with three different vendors: Cooper Power Systems, General Electric (GE), and Alstom. Two of these projects use a “rule-based” VVO control system; the third system uses a Distribution Management System (DMS) model driven approach to VVO.

- The Cooper Yukon system is a central server based system that uses rule-based, real-time methods to control the voltage and VAR levels. This system can be set up so that the minimum voltage level depends on time of day.
- The GE product has intelligence built into the Remote Terminal Unit (RTU) at the substation. It also uses rule-based, real-time methods for voltage and VAR control.

Each of these rule-based systems measures the system conditions and determines the best control actions for voltage regulators and switched capacitor banks based on a pre-established set of rules to dynamically optimize the distribution system. The Cooper Yukon system automatically adapts its settings and control actions based on current power system conditions. In essence, this system “learns” the best actions to take based on historical system operations.

The third VVO demonstration project at Duke uses the Alstom DMS model-based VVO control system which controls switched capacitor banks and voltage regulators in an optimal manner to achieve one or more VVO objective functions (reduce energy consumption, lower demand, lower losses, etc). An advantage of this approach versus the “rules based” systems is that it automatically adapts to changing feeder conditions (such as feeder reconfiguration). Duke is currently using this product in "study mode" to evaluate the VVO performance. In this mode, the system recommends VVO control actions to the distribution system operator, but does not actually execute the control actions in the field.

American Electric Power

American Electric Power’s (AEP’s) “Grid Management” vision is centered on the IVVC management of distributed generation resources, automation, outage restoration and other controllable devices to optimize the delivery of energy to the customer. The goal of the IVVC is to have an immediate impact on demand and energy reduction that would lead to lower emissions and reduced infrastructure spending. To accomplish this, AEP is planning to utilize existing distribution line equipment along with additional voltage regulators and VAR-control devices on the distribution system to reach a near unity power factor and maintain a lower voltage level.

AEP is currently demonstrating volt-VAR control systems from two vendors: General Electric and PCS Utilidata. The GE IVVC technology has been applied to 5 substations with 11 circuits (4 - 34 KV and 7 – 13 KV circuits). The PCS Utilidata AdaptiVolt system was installed on a substation with 6 - 13 KV circuits.

Both technologies have proven effective in reducing the voltage level of the circuit and improving VAR flows thus reducing substation loading. Early results from the independent study conducted by Battelle showed approximately 3% reduction in energy and a 2-3% reduction in demand. The loss reduction associated with voltage reduction was very small (less than 0.3%) compared to energy reduction.

Throughout the demonstration project, AEP has gained valuable knowledge that will help them as they deploy IVVC on more substations and feeders. The key lessons learned are as follows:

- The utility must work close with the vendors as control algorithms are being developed, so that new and legacy equipment work well together.
- Line sensors and communications systems providing critical measurements back to the volt-VAR controller need to be very reliable and accurate in order to fully optimize the flow of power and to minimize operations of voltage and VAR regulation devices.
- Additional economic analysis is needed to determine the balance point between infrastructure investments versus the incremental benefit to demand and energy reduction due to these investments.

Southern Company (Alabama Power)

Alabama Power is working with Alstom to embed a DMS model-based VVO solution into their Integrated Distribution Management System (IDMS). Some of the IDMS components have already been deployed but the Alstom advanced program suite, which includes VVO, will not be deployed until 2012. At that time, Alabama Power will test and deploy a VVO-based demand response program that is expected to reduce peak demand by 185 MW.

Dominion Resources

Dominion Resource’s VVO system can be classified as a “hybrid” solution that includes uses a combination of DMS components, substation devices, feeder equipment, and AMI facilities to accomplish their VVO objectives. Dominion has embraced the use of AMI meter readings as the voltage input to the substation voltage regulation device to control the voltage profile of the feeder. Approximately ten metering locations are used for this purpose. The specific AMI measurement locations used by VVO are periodically reviewed to ensure that these metering locations actually do represent the lowest voltage on the feeder; daily metering reports are used for this purpose. The DMS uses these measurements to determine what voltage bandcenter setting to send to the voltage regulators to accomplish the VVO objectives.

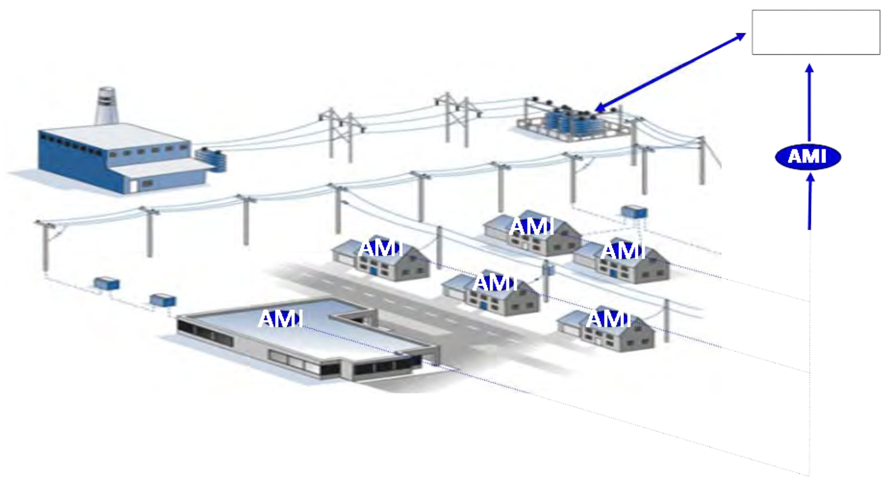


Figure 6-2
Diagram of the Dominion VVO system flow of AMI information.

Dominion's CVR approach has resulted in a valuable understanding of where and when low voltages occur on the system. One important lesson was that low voltages can occur anywhere on the circuit, as illustrated in Figure 6-4. In addition, the location of the lowest voltage can vary with the time of the day or season of the year. AMI meter voltage and usage information can uncover voltage issues that were not realized in the past. This may lead to additional infrastructure improvements including reconductoring of secondary circuits or transformer upgrades. Although these improvements results in more costs, the improvement in the voltage profile could lead to more VVO benefits that could outweigh the additional costs infrastructure upgrades.

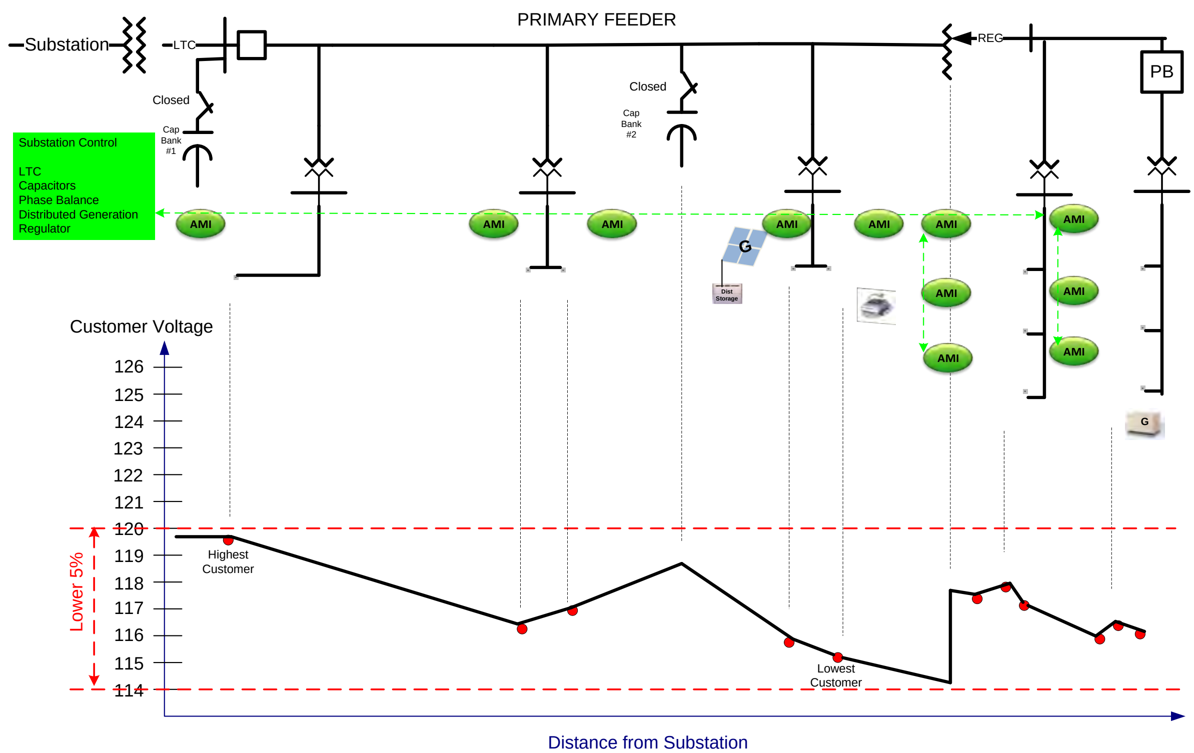


Figure 6-3
Dominion Feeder Schematic and Voltage Profile Showing Areas of Low Voltage.

Pee Dee Electric Cooperative

Pee Dee Electric Cooperative's CVR program has been in use for 25 years. The average annual load reduction they receive from CVR is 2.59%. At times, a load reduction of greater than 3% is achieved especially during months of milder weather. In addition to the demand reduction, the CVR program provides a strong MVAR benefit to the system. Pee Dee's uses standalone voltage regulators to implement their VVO solution. To perform CVR, voltage regulator settings are lowered manually. The amount of voltage reduction that takes place is conservative due to lack of feeder voltage monitoring/feedback devices.

The CVR program is used monthly as a demand response program to their reduce peak. Since they are billed monthly based on their peak demand, they spend a great deal of time forecasting when the peaks will occur and implementing the CVR program during this peak periods. CVR dispatches usually span a 3-4 hour period to ensure they shave the peak and to avoid a secondary peak when the CVR dispatch is over. The CVR program is part of the state-wide integrated resource and demand response plan.

In order to accurately predict the monthly peak periods, Pee Dee analyzes historical data. Over time they have determine that peaks are more likely to occur on Wednesdays than any other day of the week. Ironically, a number of Pee Dee peaks occur on holidays. Winter peaks normally happen around 7 AM whereas summer peaks take place around 4 PM. Based on experience of predicting peaks, Rob indicated that summer peaks are harder to predict than winter peaks.

Ameren

Ameren is currently in the planning and development stage of DVO implementation. Ameren's VVO goal is to improve ("flatten") the voltage profile and correct the power factor for reduced losses through capacitor switching. After improving the voltage profile and correcting the power factor, Ameren may elect to reduce voltage across the feeder for CVR.

Ameren plans to use a "rule based" approach to VVO. The proposed rules are outlined in use cases developed jointly by Ameren and EPRI. Figure 6-5 shows a configuration block diagram of the planned Ameren VVO solution.

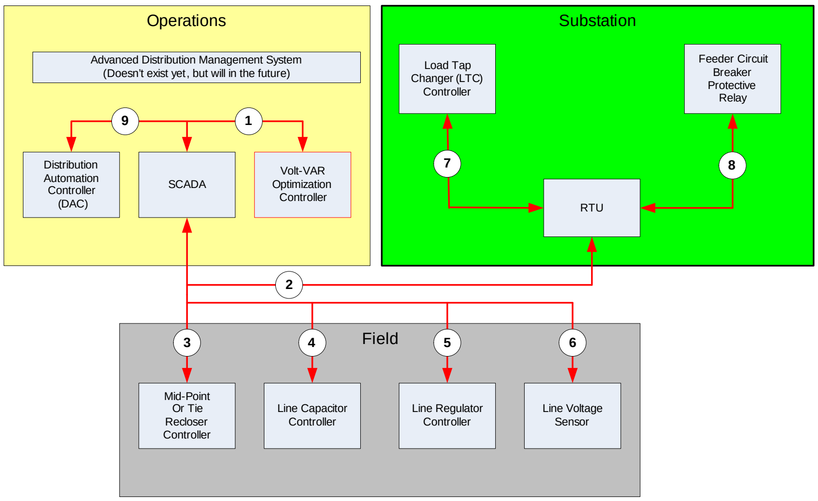


Figure 6-4
Ameren VVO Controller Diagram from Use Case

Installation of equipment and the continued development of the use case will occur throughout 2011. Ameren is presently reviewing VVO products from vendors. Based on what they find with these products, they may decide to write their own VVO controller software. The last half of 2011 thru 2012, Ameren will conduct CVR testing and other evaluations to determine the value of CVR on their system as well as the right mix of DA equipment to install to gain the most benefit out of a full CVR deployment.

In the future, Ameren may elect to perform VVO on a new DMS that is currently being deployed.

British Columbia Hydro

British Columbia Hydro (BCH) has many years of experience in Volt-VAR Optimization. The current VVO solution is a model-driven solution developed by Dr. Nokhum Markushevich (formerly of Utility Consulting International) that has been installed in ten substations to date. VVO models are built using information from the BCH GIS. However the models are maintained manually. The VVO PC-based processors receive real time inputs from the BCH Energy Management System (EMS), compute the necessary control actions to accomplish selected objective functions, and then pass the recommend control actions back to the EMS for execution. This system supports numerous objective functions – the objective function “reduce energy consumption” is used at this time.

The existing VVO application will eventually be replaced by a model-driven VVO solution that is currently being deployed on a new Telvent DMS.

Hydro Quebec

Hydro Quebec’s method of VVO uses strategically placed monitoring meters along the circuit to provide a voltage feedback loop for the volt-VAR control system.

Hydro Quebec’s VVO solution includes two operating modes: static mode and dynamic mode. The static mode uses a seasonal set of parameters for the voltage controllers that provides fewer system benefits and requires more operator intervention. The dynamic mode uses voltage feedback measurements to derive a voltage target for the controller based on a network simulator analysis of the controlled system. The controller voltage target or set-point is recalculated ea time feeder topology changes or load changes by a significant amount. The dynamic mode is more complex but it provides around 2% more demand reduction than the static mode.

The VVO program, called the CATVAR project, presently consists of 1 substation with 12 feeders, 3 remote-controlled capacitor banks and 6 remotely monitored voltage transformers. In 2011, Hydro Quebec plans to add 6 substations, 35 remotely monitored voltage transformers and 65 remote-controlled capacitor banks. By 2014, the project will consist of 130 substations, 1000 remotely monitored voltage transformers and 802 remote-controlled capacitor banks. At the end of the project, they plan to transition to a new IVVO tool that will be embedded in their DMS.

Based on the operation of their pilot/demonstration system, they have identified some technical issues and challenges to overcome prior to full deployment of the IVVO enabled DMS system. They foresee the need to properly train engineers as well as system operators and linemen in the areas of advance system planning and operations. Due to the critical nature of receiving timely information from remote devices, processing this data, and sending out control settings, they are planning for a robust communication system and a rigid maintenance program for the electronic devices. In addition, careful attention must be applied to simulation and load modeling of the system.

7
CURRENT VENDOR OFFERINGS

This section describes the current offerings from suppliers of commercial Volt-VAR Optimization systems. Some vendors provided detailed explanations of their current VVO offering or offerings. In such cases this has been include in the vendor write-ups. For vendors that did not provide detailed product descriptions, their section includes information from their publically accessible website.

In each case, the section includes background information about each vendor, product descriptions (including general architecture, functional specifications, and unique feature (if any)). The section also provides descriptions of DVO systems that have recently been implemented by the vendor (with the approval of the electric utility that implemented the system).

Descriptions of products from the following vendors are included in this section. EPRI greatly appreciates the support provided by these DVO system suppliers that assisted in preparing this section:

- Alstom T&D
- Cooper Power Systems
- Efacec ACS
- PCS Utilidata
- S&C Electric Company
- Telvent
- Utility Consulting International
- Ventyx

Names of other DVO vendors that offer DVO systems or components, but did not participate in this product survey are listed at the end of this section.

Efacec ACS

Efacec Advanced Control Systems (Efacec ACS) of Atlanta, Georgia (www.efacec-acs.com) offers a Volt-VAR control and optimization solution named Integrated Volt/VAR Control (IVVC). IVVC is part of the Efacec ACS PRISM™ product suite, which is a key part of Efacec ACS's broader smart grid solution. The primary objective of the IVVC function is to reduce electric feeder losses while minimizing distribution voltage within acceptable operating limits. Recent projects including IVVC that have been deployed or are in early stages of deployment are Avista Utilities (Spokane, WA), Long Island Power Authority (LIPA) and Peninsula Light Co. (Gig Harbor, WA).

The Efacec ACS IVVC solution is best characterized as a "model-driven" solution that uses a three-phase unbalanced power flow with state estimation. IVVC uses an "as-operated" distribution network model to compute the optimal settings for capacitor bank switches and voltage regulators (both mid-line regulators and substation Load Tap Changing transformers). The application software has the effect of first flattening and improving the feeder voltage profile and then raising or lower feeder voltages as required and as permitted by bus and feeder voltage limits.

IVVC improves energy conservation by reducing load demand in both peak and non-peak periods of operation of the distribution system. The load demand reduction is achieved by minimizing the power loss while maintaining voltage as low as possible without violating distribution voltage constraints. IVVC attains power loss reduction by setting transformer taps and by controlling capacitor banks while feeder voltages are kept above the low limit through a coordinated adjustment of voltage regulators.

Individually operable capacitors on the feeder are identified by topology tracing from a feeder breaker downstream. Feeder loads are estimated to calculate voltage, branch flows, and power factors. The branch flows at capacitor locations are analyzed so that the capacitor banks are sorted in descending order based on their branch reactive power flows. The capacitor with the largest branch reactive power is selected as a control candidate. Its impact on feeder voltages is calculated and checked against the limits using a series of load flow calculations. If any constraint is violated, this capacitor bank will be passed over and the next capacitor is processed. Otherwise, a control command is issued to operate this capacitor bank. Finally, to verify if a given capacitor operation violates any voltage constraints, the changes in voltage and power factor are calculated considering the effect of the capacitor operation.

IVVC applies defined rules to determine the control action for each capacitor bank, considering maximum number of control operations, minimum on, or minimum off times and an adjustable dead band to prevent unnecessary controls.

Once capacitor bank statuses are determined, a load flow calculation is performed to find the highest and lowest voltages in the system assuming all capacitor banks take the expected control actions (either on or off). The transformer tap position is then adjusted such that the lowest voltage is maintained above the low voltage limit. In addition, voltage regulators on each phase are adjusted based on the voltages on the other two phases to achieve balanced three phase voltages.

The load flow calculation is further performed to verify that both power factor and voltage constraints are satisfied. As the real time condition changes with time, the IVVC function can be run periodically at a user adjustable time interval

Because the IVVC application utilizes a real-time topology model and distribution load flow, it has the ability to adapt and determine appropriate optimization solutions even when the network is in an abnormal state (due to temporary switching, cuts, jumpers, etc.).

IVVC searches for the best combination of switching actions of remotely controlled feeder and station capacitors, substation transformer load tap changers, and mid-line voltage regulators based on the user-entered optimization objectives. The software ensures that basic operating constraints established for the feeder (high/low voltage limits, maximum loading of all feeder components, minimum power factor, and power losses) are satisfied. The IVVC switching actions can also be constrained when the maximum number of actions of control elements per day has been exceeded and/or the minimum acceptable time between two successive control actions of a control element has not been met.

The IVVC application is fully integrated with the Efacec ACS DMS/OMS platform (PRISM), including a GIS interface and associated data conversion module to provide as-engineered (static) information about the electric distribution system that is needed to build the distribution system model used by the program. The GIS interface / modeling tool, DASmap™, enables simultaneous creation of the network model and operational geo-spatial system displays. DASmap also supports incremental updates from the GIS.

The IVVC application can also be deployed on the Efacec ACS Centrix™ platform as a stand-alone or “bolt-on” architecture that interfaces to the utility’s existing Supervisory Control and Data Acquisition (SCADA) system. The SCADA interface for Centrix is implemented with a “software RTU” that exchanges data using DNP 3.0 protocol, so no interface engineering is required. The interface provides real-time inputs to the IVVC algorithms and also enables real-time control of field devices. . Network model creation is greatly simplified for the Centrix platform through the use of pre-engineered templates provided with the solution, in addition to a custom spreadsheet entry form for electrical parameter data. A proprietary import/conversion tool combines the chosen template and supplied data to build the load flow model and operational schematic displays. No GIS source is required when using the Centrix solution.

The IVVC application can be simulated in off-line “study” mode. This enables the utility company to analyze the IVVC operation and predict results using a real network model and historical feeder data without interfering with the on-line network model database. Following implementation, the same simulation model can be used to verify the savings and efficiency gains against the predictions. The study mode also provides a valuable IVVC training tool for engineers and operators.

The operator interface allows an operator to determine the status of the system, turn it on and off, and remotely operate switches, regulators, LTCs and capacitors. The primary interface is a feeder one-line representation of the network showing complete colorization with telemetered values.

The system provides a platform on which to build other Smart Grid functionality with Efacec ACS advanced Distribution Applications.

PCS Utilidata

PCS UtiliData of Spokane, Washington (www.pcsutilidata.com) offers a VVO solution named AdaptiVolt™. The system is best characterized as an “auto-adaptive” solution technique that does not require pre-determined rules or as-operated models of the distribution system. Among AdaptiVolt™ electric utility users are American Electric Power (Ohio), Ripley Power and Light Company (Tennessee) and Veridian Connections (Ontario, Canada). AdaptiVolt™ is also being used by industrial companies and large end users of electric energy for efficiency improvements and voltage management internal to the companies themselves. Figure 7-1 depicts the basic operation of AdaptiVolt.

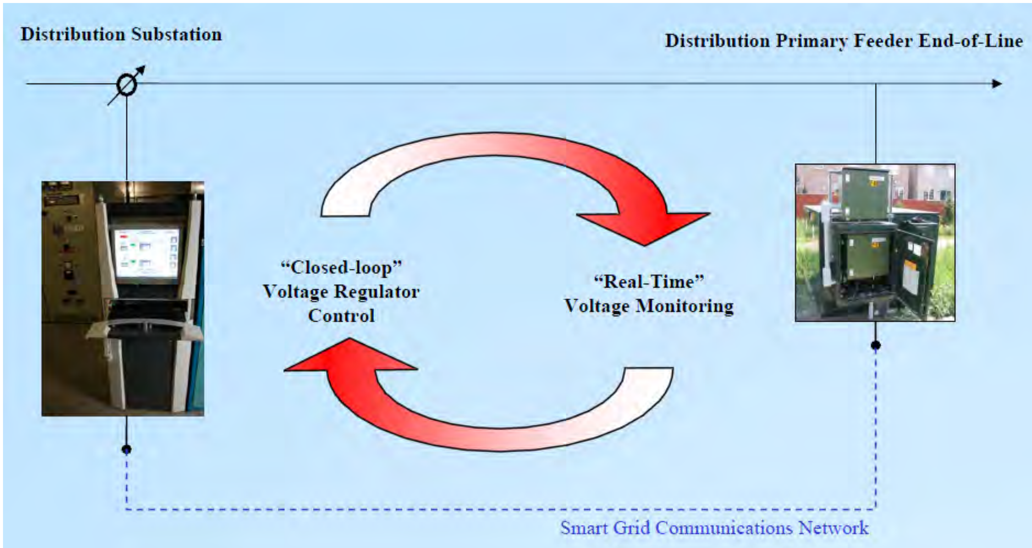


Figure 7-1
PCS UtiliData AdaptiVolt™ general approach

The AdaptiVolt™ system uses digital signal processing (DSP) to extract information about the behavior of the distribution system in "real-time" from signals acquired from sensors and controllers located in the substations and out on the distribution feeders. Using these DSP techniques, AdaptiVolt™ uses data from the impact of the transmission delivery, structural components and customer behavior to forecast near-future operations, thereby maximizing efficiency while making near-optimal volt/VAR control decisions.

The real-time measurement data required by AdaptiVolt™ includes (as a minimum) source voltages by phase, total feeder current by phase, kW by phase, kvar by phase, and primary voltages at or near the end of the distribution feeders by phase. Ambient weather conditions (e.g. temperature) are also collected for use in measurement and verification analysis.

Rather than issuing operating set points to voltage regulation devices, AdaptiVolt™ takes supervisory control of the voltage regulator controllers (and capacitor elements), allowing the AdaptiVolt™ forecasting capabilities to reduce the number of tap operations without increasing capacitor bank operations. This method of control commonly reduces voltage regulator operations by 20-30%.

The controllers that implement the signal processing algorithms are typically located in the distribution substation that is associated with the feeders being controlled. Figure 7-2 depicts a typical AdaptiVolt™ configuration. It is also possible for a single system to control feeders in multiple substations. In this case, the controller can be installed at a distribution control center (centralized approach) or one of the controlled substations.

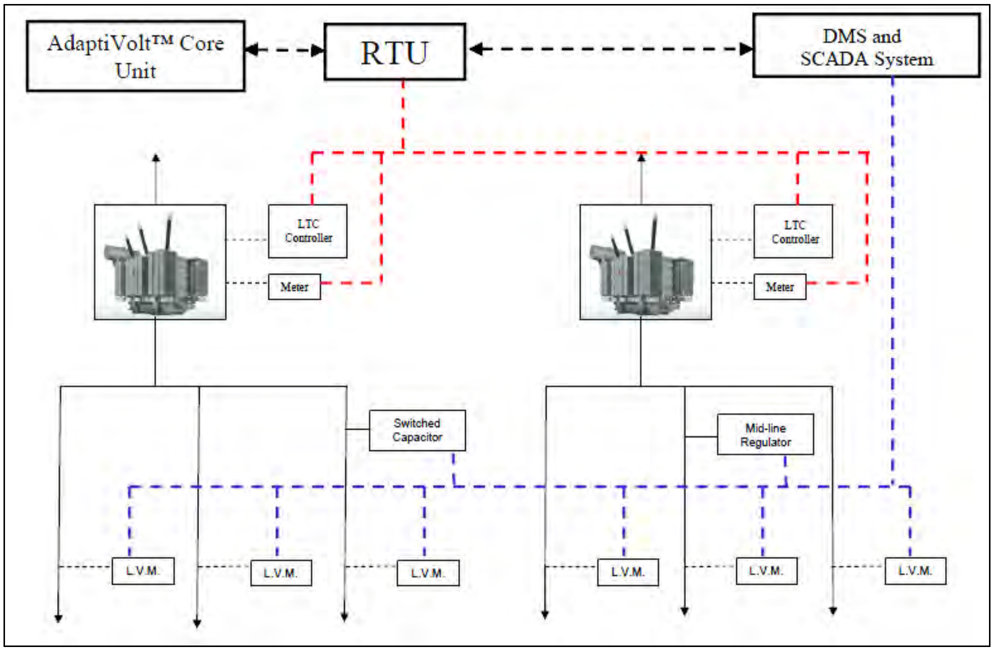


Figure 7-2
AdaptiVolt™ Architecture (Sample)

When a feeder or feeders are reconfigured either permanently or temporarily, AdaptiVolt™ will be able to reconfigure itself and continue operating as long as the switching changes are reported to the controller. The unique DSP algorithms in AdaptiVolt™ make it uniquely positioned to be able to incorporate the impacts of DERs in its volt-VAR control decisions. Operation following feeder reconfiguration and operation in the presence of high penetrations of DER have not yet been demonstrated.

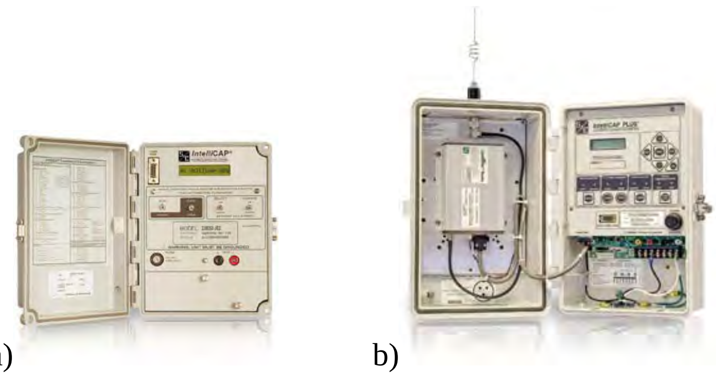
The operating parameters (e.g. voltage delivery thresholds, field communications settings, etc.) are user configurable, resulting in numerous benefits, including maximizing VVO benefits (i.e. system availability) and insuring that AdaptiVolt™ VVO operation does not violate required service voltage ranges.

A unique feature of AdaptiVolt™ is that a PCS UtiliData developed, 3rd party verified, measurement and verification (M&V) protocol for VVO is seamlessly integrated into the product. The AdaptiVolt™ system automatically collects the data required (including temperature data) for the analysis and conducts the protocol experiments without operator intervention, allowing the benefits accruing from VVO to be accurately reported.

S&C Electric Company

Founded in 1911, S&C Electric Company (www.sandc.com) is a Chicago-based company that designs and manufactures switching and protection products for electric power transmission and distribution. S&C's current offerings pertaining to Distribution Voltage Optimization (DVO) include intelligent electronic devices (IEDs) for switched capacitor bank control, sensors, and supporting communication facilities. In 2011, S&C acquired the Grid Optimization solutions from Current (formally known as CURRENT Group), which included a Volt-Var Optimization System. This VVO system is offered by S&C as “IntelliTeam® VV Volt-Var Optimization System”.

S&C offers a line of automatic capacitor controls and sensors that can serve as “standalone” controllers and can also serve as part of a Volt-VAR Optimization “system”. There are two products in the line of switched capacitor controllers: IntelliCAP® and IntelliCAP PLUS®. Figure NN shows the two S&C automatic capacitor bank controllers.



a) b)

Figure 7-3
a) IntelliCAP, b)IntelliCAP PLUS

Both products include features that are valuable for implementing distribution capacitor control schemes, including:

- A range of control strategies for local standalone control based on voltage, time, temperature, time-biased voltage, time-biased temperature, VAR, and current control strategies
- Ability to block shunt capacitor banks from being re-inserted prior to the dissipation of electrical charge trapped within the capacitor units,
- Daily limits on the number of switching operations control strategies

The most significant difference between the two products is provision of communication capability. IntelliCAP is intended for stand-alone operation. However, IntelliCAP PLUS supports one-way or two-way communication facilities that enable the unit to operate in response to switching commands from a centralized VVO system. With a two-way communication device installed, local status information and feeder data are additionally available remotely, and remote configuration is possible. The IntelliCAP PLUS controller includes a “SCADA heartbeat” function that allows the controller to revert to local, stand-alone control upon loss of control or communication from the central control system.

Further details about the two controllers and other automation and protection devices offered by S&C may be obtained at (www.sandc.com/products/automation-control/automatic-capacitor-controls.asp).

S&C has also partnered with Current to provide electric utilities with an option for a distribution voltage sensor that can be combined with the IntelliTeam VV system for real-time monitoring of distribution voltages. These sensors can be deployed in a stand-alone fashion, which include integrated communications such as Verizon Wireless 3G, or can be paired with a third party communications radio, like S&C's SpeedNet system, through an environmentally protected Ethernet connection. These sensors can be installed on the secondary side of a distribution transformer (rated up to 480 volts) or on the primary lines using potential transformers. This provides utility's with a flexible installation approach as they can determine where the sensors will provide the most benefits in terms of measuring the voltage and reporting it back to the central control system. The sensors provide accuracy measurements of +/- .5%. Figure 7-4 below shows the Current sensors.

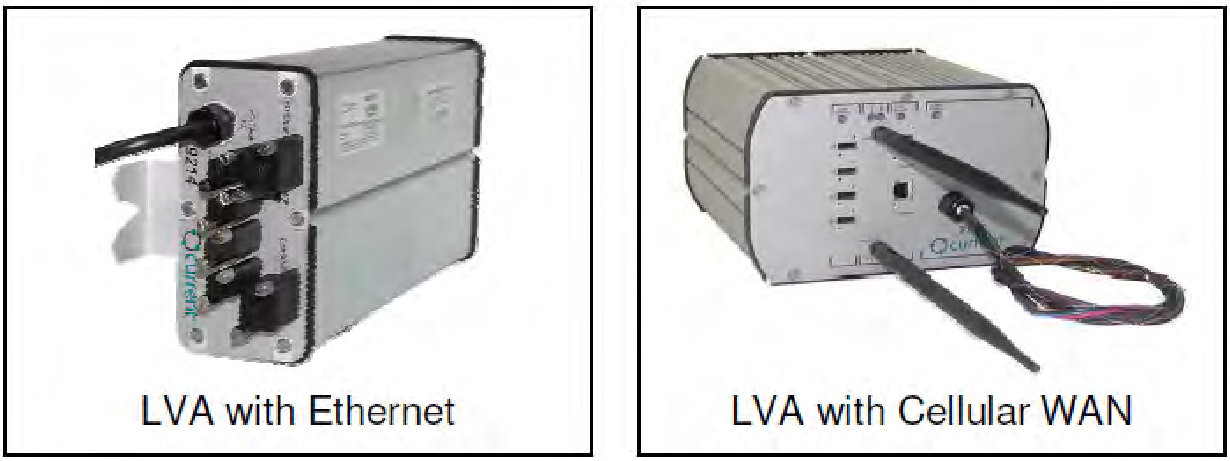


Figure 7-4
Current Voltage Sensors

S&C's Intelliteam VV Volt-Var Optimization System is a centralized/regional based system (e.g. can be located in the substation or distribution control center) that simultaneously controls capacitor banks, line voltage regulators, and load tap changers to accomplish utility specified objectives. The IntelliTeam VV system is currently in service at XCEL Energy (Colorado) and Blue Grass Electric Cooperative as well as other utilities. Figure 7-5 depicts the general IntelliTeam VV architecture.

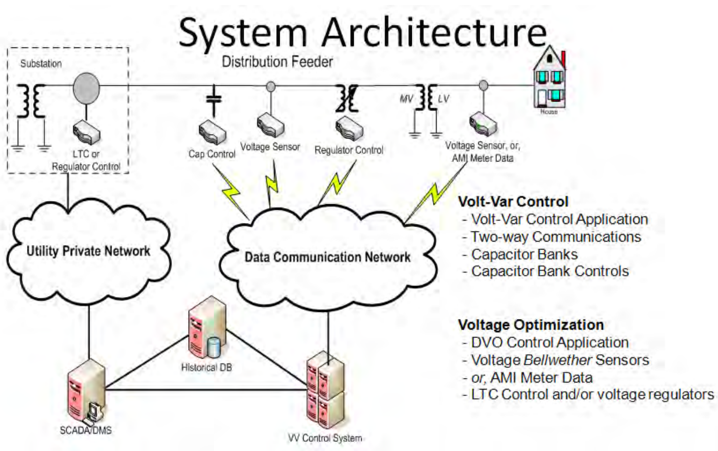


Figure 7-5
S&C IntelliTeam VV Architecture

IntelliTeam VV inputs include real-time voltage measurements from AMI meters or distribution sensors, along with health and status information from substation Remote Terminal Units (RTUs), capacitor bank controls, load tap changer controls, and line voltage regulator controls. These inputs are applied to a *heuristic, closed-loop, rules based* algorithm, which manages and maintains system power factor targets and overall system voltage profile through appropriate control of the field devices. The algorithm uses the real-time measurements to determine whether or not the voltage or VAR flow needs to be adjusted by looking at the system as a whole and not as individual points within the system. It does this by utilizing configurable parameters and thresholds that are based on an understanding of how the system will react to the capacitor bank changes and voltage adjustments. There are also several checks and balances within the algorithm to avoid hunting and cycling, which can cause excessive or unnecessary control actions to take place.

IntelliTeam VV can operate as a “stand-alone” system or in a “bolt-on” architecture that interfaces to the utility’s existing Supervisory Control and Data Acquisition (SCADA) system. In bolt-on design, the SCADA interface provides real-time data to the IntelliTeam VV algorithms and once IntelliTeam VV analyzes the real-time data it sends the control actions that need to take place to the SCADA system for execution.

Additional features of IntelliTeam VV include:

- <u>Integrated power-flow-based dynamic Measurement and Verification (M&V)</u> - IntelliTeam VV is able to measure and verify the system savings and overall benefits it has achieved, through use of an integrated online, unbalanced distribution power flow engine with state estimation. A model of the system baseline is compared with actual real-time measurements to determine the benefits achieved by the system. Real power, reactive power, and apparent power savings are reported, in real time, along with the loss reduction savings, without operating in “day on-day off” mode which is common for other M&V approaches. This M&V approach is described further in Section NN of this report.

- Optional Topology Model – Intelliteam VV optionally includes an “as operated” feeder topology model that incorporates all switching and protective devices real-time status. This feature enables the system to adapt its control algorithms as needed when feeder reconfiguration occurs. This feature is not required to perform volt-VAR optimization when the feeder is in its normal configuration. However, the feature is a useful add-on when frequent feeder reconfiguration is anticipated.
- Semi-Automatic Operator Familiarization Mode - IntelliTeam VV can be configured to recommend particular actions but not automatically take those actions. This capability allows the user to become familiar with the algorithm and the decisions it makes prior to fully implementing the system.
- Measurement and Verification: The IntelliTeam VV system has an embedded Measurement and Verification (M&V) application that reports the real-time system savings. The Measurement and Verification application is based on a real-time power flow engine with state estimation.

Telvent

Telvent of Fort Collins, Colorado (www.telvent.com) offers a Volt-VAR control and optimization solution as part of its Distribution Management System (DMS) product suite, which is a key part of Telvent’s broader smart grid solution (refer to www.telvent.com/en/business_areas/smart_grid/solutions_overview/smart_grid/index.cfm for an overview of Telvent’s overall smart grid solution. Recent Telvent DMS projects that include Distribution Voltage Optimization have been deployed or are being deployed at Progress Energy (Carolinas), British Columbia Hydro, and Hydro One (Ontario, Canada), as well as numerous implementations in Europe and Asia. Telvent was recently acquired by Schneider Electric. This acquisition has not altered the VVO technical solution that was included in Telvent’s VVO projects awarded prior to the acquisition.

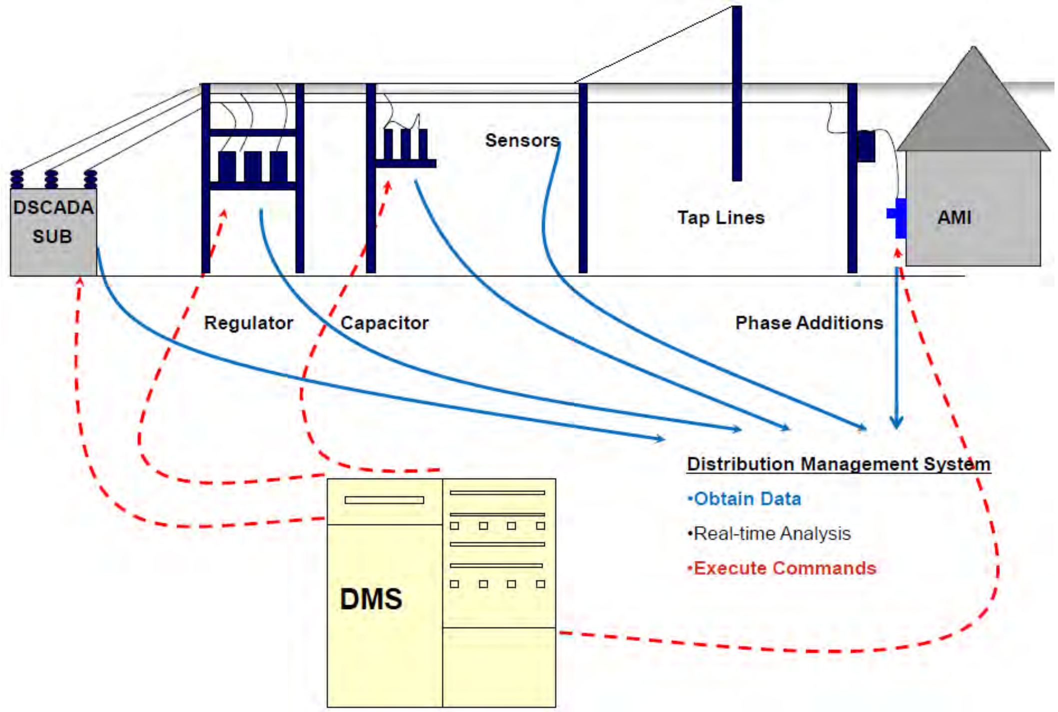


Figure 7-6
Simplified Telvent VVO Solution

Telvent's VVO solution is best characterized as a "model-driven" solution that uses an unbalanced optimal power flow with state estimation coupled with a combinatorial discrete programming algorithm. The Telvent VVO solution uses an "as-operated" distribution network model to compute the optimal settings for capacitor bank switches and voltage regulators (both mid-line regulators and substation Load Tap Changing transformers). The application software has the effect of first flattening and improving the feeder voltage profile and then raising or lower feeder voltages as required and as permitted by bus and feeder voltage limits.

The VVO application searches for the best combination of switching actions of remotely controlled feeder and station capacitors, substation transformer load tap changers, and mid-line voltage regulators based on the user-entered optimization objectives. The software ensures that basic operating constraints established for the feeder (high/low voltage limits, maximum loading of all feeder components, minimum power factor, and power losses) are satisfied. The VVO switching actions can also be constrained when the maximum number of actions of control elements per day has been exceeded and/or the minimum acceptable time between two successive control actions of a control element has not been met.

Once the basic constraints are satisfied, the optimization software seeks to addresses one or more of the following optimization objectives:

- Optimal voltage profile of the entire network.
- Minimum power losses;
- Minimum active and reactive power consumption from the transmission network

- Maximum power factor of the consumption from the transmission network;
- Maximum distribution utility revenue – with this objective, voltage control is used to lower the energy consumption when the relative price of the purchased electric energy is high

The Telvent VVO application is fully integrated with the Telvent DMS platform. However the application can be implemented with a “bolt-on” architecture that interfaces to the utility’s existing Supervisory Control and Data Acquisition (SCADA) system and Geographic Information System (GIS). The SCADA interface provides real-time inputs to the VVO algorithms and also enables real-time control of field devices. The GIS interface and associated data conversion module provide as-engineered (static) information about the electric distribution system that is needed to build the distribution system model used by the program. When feeder reconfiguration occurs, the VVO model is updated automatically to reflect the “as operated” state of the system.

The VVO application can be executed in off-line “study” mode. This enables the utility company to analyze the VVO operation and predict results without interfering with the on-line network model database. The study mode also provides a valuable VVO training tool for engineers and operators In simulation mode,

Utility Consulting International

Utility Consulting International (UCI) of Cupertino, California (www.uci-usa.com) offers a VVO solution as part of its suite of advanced distribution applications. UCI’s VVO is best characterized as a “model-driven” solution whose calculations are based on the optimization of an unbalanced three-phase power flow for distribution systems. VVO was implemented as a pilot project at British Columbia Hydro (BC Hydro) in 1995 and was later updated for commercial use and is currently in continuous operation for a number of BC Hydro substations. The application was also implemented in a number of pilot projects (Jacksonville Electric Association, Florida Power Corporation, and Oklahoma Gas and Electric).

The UCI VVO program searches for the best voltage at the voltage-controlled bus and for the states of remotely controlled feeder and station capacitors based on the user-entered optimization objectives. The optimization objective could be one of the following:

- Conservation voltage and var control (minimization of cost of production within normal voltage limits)
- Maximum kWh consumption with nominal voltage
- Load reduction (minimization of cost of production within user-defined voltage limits)
- Economic operating conditions based on real-time pricing (minimization of the difference between the cost of production and revenue)
- Weighted combination of the above

The optimization is constrained by normal and emergency voltage limits, load limits, load tap changer regulation range, number of capacitor switching operations per day, and numerous other factors.

Controlled feeder parameters include:

- Bus voltages controlled by LTC
- Capacitor statuses
- DER status and load

UCI's VVO program also includes a Distributed Generation (DG) commitment module that searches for the least-cost alternative of power production and delivery. It recommends starting a DG and loading it to a certain level, if the incremental cost of power production covering the load and the power losses is smaller with the DG than without the DG, and it recommends stopping the DG, if the incremental cost of power production and delivery is lower without the DG.

The UCI VVO system uses a "bolt-on" architecture that interfaces to the utility's existing Supervisory Control and Data Acquisition (SCADA) system and Geographic Information System (GIS). The SCADA interface provides real-time inputs to the VVO algorithms and also enables real-time control of field devices. The GIS interface and associated data conversion module provides "as-engineered" (static) information about the electric distribution system that is needed to build the distribution system model used by the program. When feeder reconfiguration occurs, the VVO model is updated by the program's Topology Modeling and Testing module to reflect the "as operated" state of the system.

In addition to performing on-line controls, UCI's VVO solution includes a "study mode" that can be used as an off-line simulation tool for performing VVO and DMS evaluation studies.

Ventyx

Ventyx of Atlanta, Georgia (North American Headquarters) (www.ventyx.com) was acquired by ABB, a power and automation company, in June 2010 and became part of ABB's Network Management business unit within the Power Systems Division. Ventyx offers a VVO solution (see Figure 7-9 below) as part of its suite of applications in the Network Manager DMS product line. The Ventyx VVO is best characterized as a "model-driven" solution that uses an unbalanced optimal power flow that is coupled with a mixed integer optimization engine. The Ventyx VVO application has been running at Oklahoma Gas and Electric Company since May of 2010**.** During the summer of 2011, OG&E added an additional 42 circuits equipped with capacitor controllers and 16 circuits with automatic reclosers to take advantage of the Fault Location, Isolation and System Restoration (FLISR) application that runs on the same network model. CPS Energy is currently implementing a pilot project with VVO. Dixie Electric Membership Corp has acquired the VVO software which will go into production in 2012. In 2012, the VVO application will be delivered to CenterPoint and Detroit Edison.

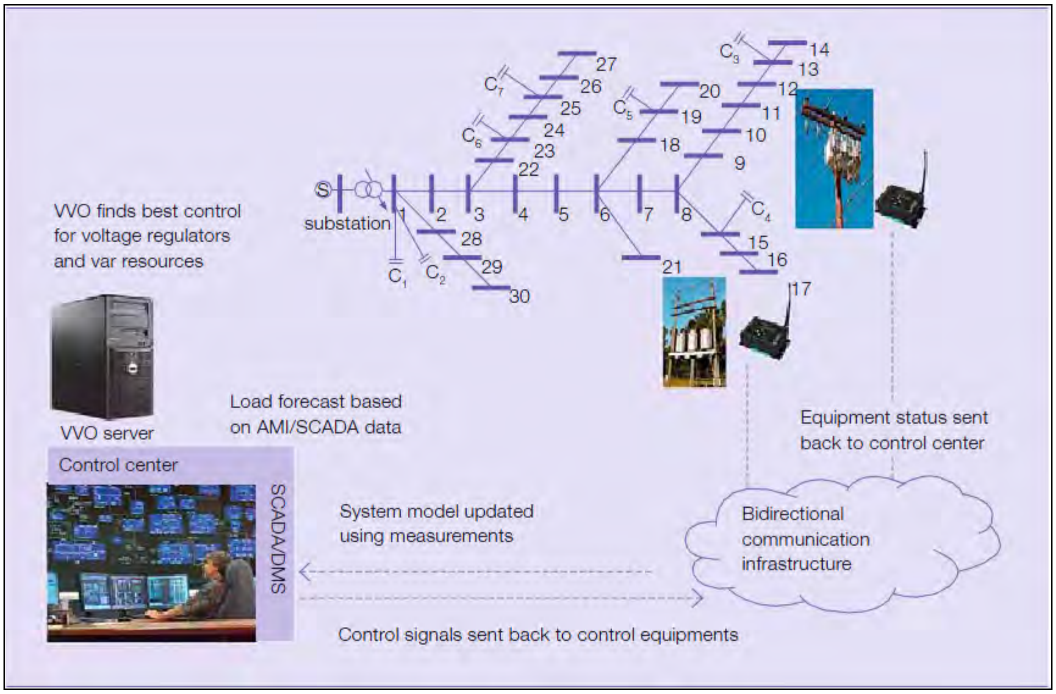


Figure 7-7
Ventyx VVO Solution

The Ventyx VVO solution uses an "as-operated" distribution network model to compute the optimal settings for capacitor bank switches and tap changers (both voltage regulators and Load Tap Changing transformers). The application software can be configured with the objective of lowering losses and/or demand.

The VVO application searches for the best voltage at the voltage-controlled bus and for the states of remotely controlled feeder and station capacitors and regulators based on the user-entered optimization objectives. The optimization objective could be one of the following:

- Loss minimization via capacitor control. VVO can minimize total losses on a per feeder basis or a per substation basis.
- Demand minimization via LTC/regulator control. VVO minimizes demand by determining and changing regulator and LTC positions to lower system voltage. The solution considers the voltage-dependent component of individual loads, modeling reduction in demand vs. reduction in voltage.
- A combination of the above. When both objectives are selected, it will first flatten and improve the feeder voltage profile and then raise or lower feeder voltages as required and as permitted by bus and feeder voltage limits.

VVO respects the line and equipment ratings so that the optimal solution does not result in voltage or current violations or violate required service voltage ranges. The VVO application uses the Unbalanced Load Flow and Load Allocation applications to verify that the proposed control actions do not violate any constraints.

Controlled feeder parameters include:

- Bus voltages controlled by LTC
- Capacitor bank statuses
- Feeder voltages controlled by regulators

The 2012 software release will include an advanced scheduler and a voltage set point control capability for distributed generation. A future VVO release will include VAR control for solar inverters.

The Ventyx VVO allows substation and/or distributed feeder capacitors as well as regulators to be gang-operated or operated as single phase units. This option is especially valuable on distribution systems that contain a considerable amount of single-phase load and may be experiencing significant voltage imbalance.

The Ventyx VVO application is fully integrated with the Ventyx Network Manager DMS platform which includes Supervisory Control and Data Acquisition (SCADA) functionality. However the application can be implemented with a "bolt-on" architecture that interfaces to the utility's existing SCADA system and Geographic Information System (GIS). The SCADA interface provides real-time inputs to the VVO algorithms and also enables real-time control of field devices. The GIS interface and associated data conversion module provide as-engineered (static) information about the electric distribution system that is needed to build the distribution system model used by the program. When feeder reconfiguration occurs, the VVO model is updated automatically to reflect the "as operated" state of the system, including line cuts, jumpers, disconnects, fuses and other non-SCADA monitored devices and circuit reconfiguration actions taken by field crews. The same "as operated" network model is used by other applications running on Network Manager DMS, including Fault Location, Restoration Switching Analysis (RSA), FLISR, and Line Unloading.

The VVO application can be executed in off-line "study" mode. This enables the utility company to analyze the VVO operation and predict results without interfering with the on-line network model database. The study mode also provides a valuable VVO training tool for engineers and operators.

Alstom

Alstom uses the Load and Volt/Var Management (LVM) function of its DMS suite combined with the SCADA to create an Integrated Volt/Var Control (IVVC) system that is capable of improving the efficiency of the distribution network. It does this by recommending optimal adjustments to network operating parameters to achieve various objectives such as minimizing demand while eliminating or avoiding overloads and maintaining supply voltage within regulatory limits.

Brief Description of The System

The automated IVVC function controls capacitors and voltage regulating devices, including regulators and Load Tap Changers (LTCs), to improve the operation of the network and meet specified operating targets. The critical aspect of achieving a truly effective result from automated Volt/Var management is that the control commands, or "plans", must be based on the analysis of a significant area of the distribution network and the changes must be coordinated across all of the active regulating devices. This is referred to as global, as opposed to local, optimization. The IDMS is able to use both SCADA data and the real-time dynamic model of the entire network and can control all devices simultaneously to achieve full IVVC capability. With these characteristics the IVVC function also complies with the industry definition of Integrated Volt/Var Optimization (IVVO).

IVVC issues recommendations to improve the voltage quality, provide reactive support to the surrounding distribution system, reduce system demand in a peak-shaving or continuous manner, and minimize losses.

IVVC executes in the following modes:

- **Closed-Loop—**IVVC directly issues commands for the control of substation capacitors, feeder capacitors, Load Tap Changer (LTC) controllers, and voltage regulators for a pre-defined problem formulation in real-time.
- **Advisory—**IVVC generates a recommended plan for the control of voltage devices which is presented to the operator. After review, the operator can manually select the plan for execution. This mode is run in real-time but no action taken.
- —IVVC uses the study DPF base case configuration as the starting point. The user can then modify network conditions to analyze "what-if" scenarios.

In real-time mode, circuit voltage inputs from SCADA as well as from customer meters can be incorporated into IVVC to identify differences between the calculated state of the distribution network and the measured network state. These measurements will provide an "operating envelope" for IVVC to work within. When differences are identified they can be used to guide analyst investigation into the cause. If identified differences between calculated voltage states and measurements are too large, Closed-Loop execution of IVVC recommendations, or plans, will be suspended for all the circuits of the associated substation. The primary network voltage measurements will be modeled as SCADA analog points.

IVVC executes in real-time mode (Advisory or Closed-Loop) with the following triggers:

- Periodic trigger – executes at pre-defined intervals
- Event triggers, including change in circuit connectivity or change of device status and changes in feeder head flow or voltage
- Manual execution

If unsuccessful operations occur during Closed-Loop execution of a plan, an operator can execute IVVC manually after tags have been applied to the malfunctioning devices. The tagged malfunctioning devices will be excluded from subsequent IVVC solutions until the tags are removed.

IVVC supports the following problem formulations:

Problem Formulation	**Description**
Reduction of overloads and violations	No overloads and voltage violations are allowed in the distribution lines and buses.
Minimize demand	All enabled controls are moved to reduce the station demand (kW) to the lowest feasible value, subject to the user-selected voltage and flow constraints.
Reactive area support	This will strive to achieve a target power factor at the distribution substation high-side bus. The area target power factors are pre-defined in lookup tables based upon area load. The user-selected limits will be respected.
Loss Minimization	All enabled control devices are used to reduce the total losses in the distribution system. These losses include line losses, reactor losses and transformer losses.

IVVC issues commands for the coordinated control of the following devices:

- Substation capacitors on the distribution side of the substations
- Feeder capacitors via changing the breaker status
- LTC controllers via changing control settings
- Feeder single-phase and three-phase voltage regulator controllers via changing control settings

The control devices considered by IVVC are user configurable. The IVVC application will always respect the latest known status/tap position of the station capacitors, feeder capacitors, LTCs and regulators in its solution, even if the devices are not eligible IVVC control devices.

The IVVC constraints include the following:

- Voltage quality limits at the customer sites (normal, emergency)
- Flow limits for distribution elements
- User or database defined voltage limits for given sites in the distribution primaries
- LTC and voltage regulator range limits
- Limits on the number of capacitor switching operations per day
- Limits on the time interval between consecutive capacitor switching operations

The operation and monitoring of IVVC is part of the IDMS and therefore is fully integrated with all other aspects of network operation. Additional controllers, display consoles or system management are not required.

The implementation of IVVC as part of the integrated SCADA/DMS system provides a single point of monitoring and control for all network devices. The operators are able to remotely control capacitor banks, voltage regulators and LTCs on distribution lines and in distribution substations as well as initiate IVVC operations – all from the same set of screens.

Tabular Results

The operation of IVVC is monitored through a series of tabular displays which shows both the present operation and the targets (target power factor, target reductions and recommended control actions) for each iteration of the program.   In a future development, additional displays showing cumulative loss reduction and demand reduction will be provided.

The performance of IVVC can also be monitored using the standard trending functions of the SCADA/DMS as shown in Figure 7-8

Figure 7-8
IVVC Demand Minimization trend display

Voltage conditions for any point in the network which violate the high or low voltage limits are displayed on the geographic network view using colored halos (see Figure 7-9). Voltages for individual devices are available on attribute pop-up displays.

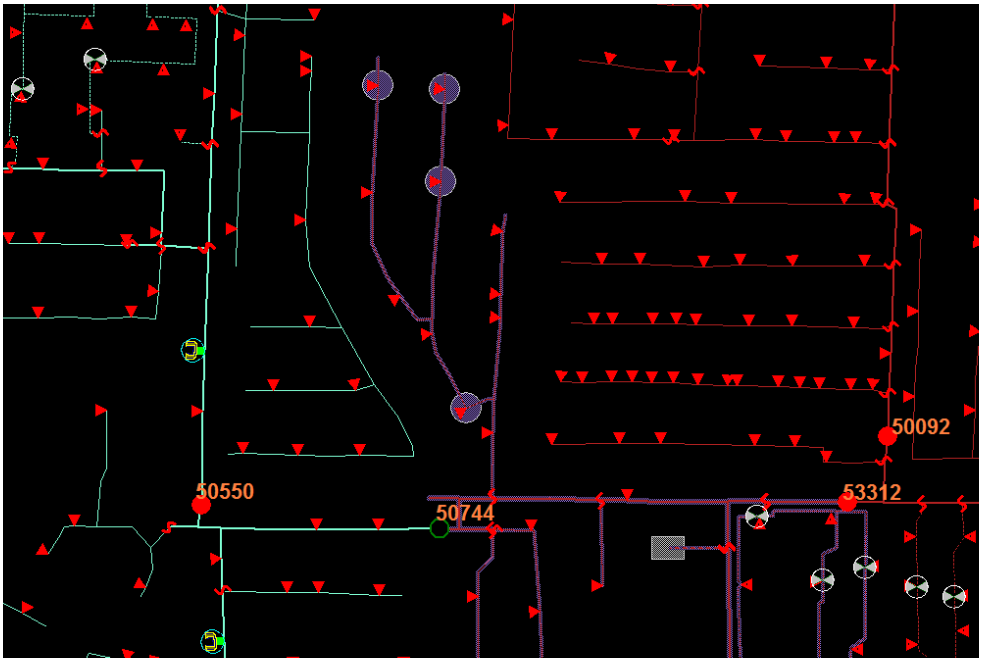


Figure 7-9
Geographic view of voltage violations

The primary goal of IVVC is to improve the operating performance of the distribution network by:

- Reducing network voltages to the lowest level possible within regulatory limits and thereby reducing demand
- Reducing voltages under emergency conditions to avoid blackouts
- Optimizing the operation of network control devices to minimize losses
- Providing reactive support for the transmission network at times of abnormally high or low voltage

IVVC is an integral part of the overall SCADA/DMS and therefore does not require separate maintenance and support. The IDMS network models support all functions including IVVC, removing the need for dedicated model building and maintenance.

The operation and monitoring of IVVC is performed within the IDMS operating environment, providing a single, consistent set of displays. There is no need for separate consoles or monitoring system. The operator is able to directly control network devices from the same displays. IVVC performance can be monitored and reported as part of the overall network operation.

The SCADA/DMS system will provide IVVC functionality to the entire network with the following capabilities:

- Conservation Voltage Reduction (CVR) – reduce voltage to the lowest level possible without violating requirement to supply voltage within ANSI C84.1 Range A (+ 5%)
- Emergency Voltage Reduction – reduce voltage below ANSI C84.1 to reduce load during system emergency as a last step before rolling blackouts (for times of power supply, Watts, stress)
- Loss optimization

The integration of IVVC with the SCADA/DMS means that network models are automatically updated as part of the regular model management process and any changes, expansions or reconfigurations of the network are automatically incorporated.

IVVC can be enabled or disabled for each substation and its connected feeders from the same displays that are used to remotely control and monitor the network control devices. Proposed enhancements include:

- Implementation of additional displays to show the cumulative benefits achieved by loss minimization and demand reduction
- Include power factor monitoring at the substation with the ability to use power factor targets or limits
- Add the ability to operate using different IVVC modes (in different load areas or different substations
- Enable and validate Maximum VAR support – turn on as many capacitors as possible without violating voltage limits. (for times of reactive power stress or low voltage on the transmission system)
- Add capability for minimum VAR support – turn off as many capacitors as possible without violating voltage limits (for times of high voltage on the transmission system)
- Provide reports/alarms of non-functioning or mis-operating capacitor banks, voltage regulators, and LTC’s
- Add capability to flag/report problems detected by neutral sensors and/or VAR monitoring at substation when capacitors are remotely commanded to operate
- Add capability to flag/report problems detected from scheduled operation of capacitor banks (i.e., scheduled operation to verify operational integrity of any capacitors that have gone more than (X) days without an operation)
- Enhance the control capability of the IVVC system to place the various device controllers in local control mode when the central VVC is unavailable or otherwise unable to provide control
- Allow for remote engineering access to capacitor, regulator, and LTC controls at the same time that IVVC is running and controlling equipment

As more telemetry becomes available within the distribution network, IVVC will be enhanced to take advantage of these near-real-time observations to improve the quality of network analysis and optimization solutions. Network measurements can be used to help guide model maintenance, improve solution quality and augment the Volt/Var control algorithms.

In particular the following enhancements are proposed.

- Use more measurements to achieve a better result by validation of the IVVC plans prior to issuing the controls
- Use more measurements, such as voltages at critical points in the network, to improve the IVVC solution
- Build an IVVC mode that works on an identity matrix of connectivity for parts of the network where there is little or no confidence in impedance or load information
- Use more measurements to perform post execution review of plans:
  - Automatically highlight the differences between measured values and calculated values
  - Report the differences, per solution and historical differences
  - Create a per feeder and per substation quality indices based on measurement comparison and Bus Load Allocation quality
  - Use the quality index to target analyst scrutiny of particular substation models
  - Use the quality index to disable closed-loop IVVC for particular substations
  - Use the quality index to disable other optimization functions for particular substations
- Use the estimated solution to identify suspect measurements or topology
- Use more measurements to solve state-estimation for pockets of redundancy (internal to network solution)
- Use more measurements to identify power diversion – leveraging the availability of MDM data

Cooper Power Systems

Cooper Power Systems (CPS) (www.cooperindustries.com) is a division of Cooper Industries, which is a diversified global manufacturer of electrical components. CPS, based in Waukesha, WI (near Milwaukee) designs and manufactures switching and protection products for electric power transmission and distribution. CPS current offerings pertaining to Volt-VAR management include its Integrated Volt-VAR Control (IVVC) system along with intelligent electronic devices (IEDs) for switched capacitor bank control and voltage regulator control, sensors, and supporting communication facilities. IVVC is part of the CPS Yukon product suite.

CPS offers a line of automatic capacitor controls and automatic voltage regulator controls that can serve as “standalone” controllers and can also serve as part of a Volt-VAR Optimization “system”. There are two main products in the line of switched capacitor bank controllers and voltage regulators, which are depicted in figure 7-10.

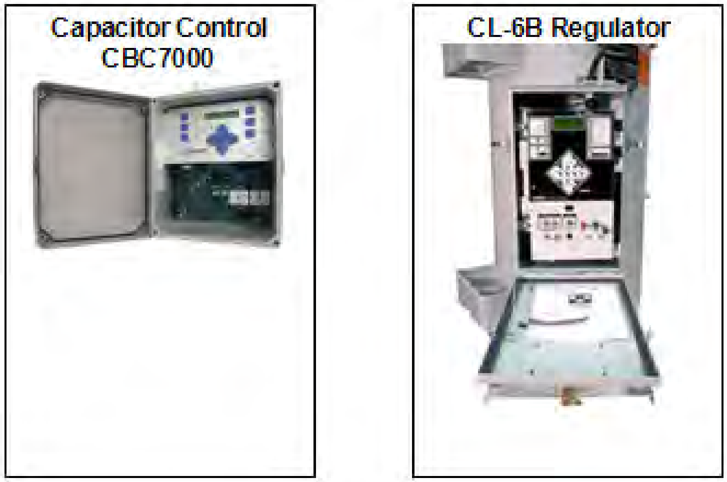


Figure 7-10
CPS Capacitor Bank Controllers and Voltage Regulators

The CPS CBC7000 capacitor bank controller includes features that are valuable for implementing distribution capacitor control schemes, including:

- A range of control strategies for local standalone control based on voltage, time, temperature, time-biased voltage, time-biased temperature, VAR, and current control strategies
- Ability to block shunt capacitor banks from being re-inserted prior to the dissipation of electrical charge trapped within the capacitor units,
- Daily limits on the number of switching operations control strategies

The CPS CL-6B regulator control is a SCADA ready control that can be integrated into the distribution system.

- Provides several modes of operation, including Sequential, Voltage Averaging and Time Integrating
- Configurable with settings like adjustable voltage range, bandwidth, and time delay.
- Tap-changer compatibility enabling it to correctly operate a range of tap-changers common in the industry including the three models of Cooper Power Systems Quik-DriveTM Tap-Changers
- Supports advanced control features like alternate configuration, leader/follower schemes, and tap changer diagnostics and maintenance.

Both products support one-way or two-way communication facilities that enable the unit to operate in response to switching commands from a centralized VVO system. With a two-way communication device installed, local status information and feeder data are additionally available remotely, and remote configuration is possible. Cooper Power Systems CL-6B Regulators and 7000 family of Capacitor Bank Controls both support loss of communications functionality. Both device types support the identification of communication network failures and the transition to local automated control when a communication network failure has occurred. This loss of communications functionality allows these control devices to intelligently toggle between operations mode insuring that power quality standards are not violated due to a failure in the automation technology.

Further details about the two controllers and other automation and protection devices offered by CPS may be obtained at
(http://www.cooperindustries.com/content/public/en/power_systems.html).

CPS's Yukon IVVC volt-var management system is a centralized software application that is typically installed on a server in an IT server room that simultaneously controls capacitor banks, line voltage regulators, and load tap changers to accomplish utility specified objectives. Figure 7-11 depicts the general Yukon IVVC approach.

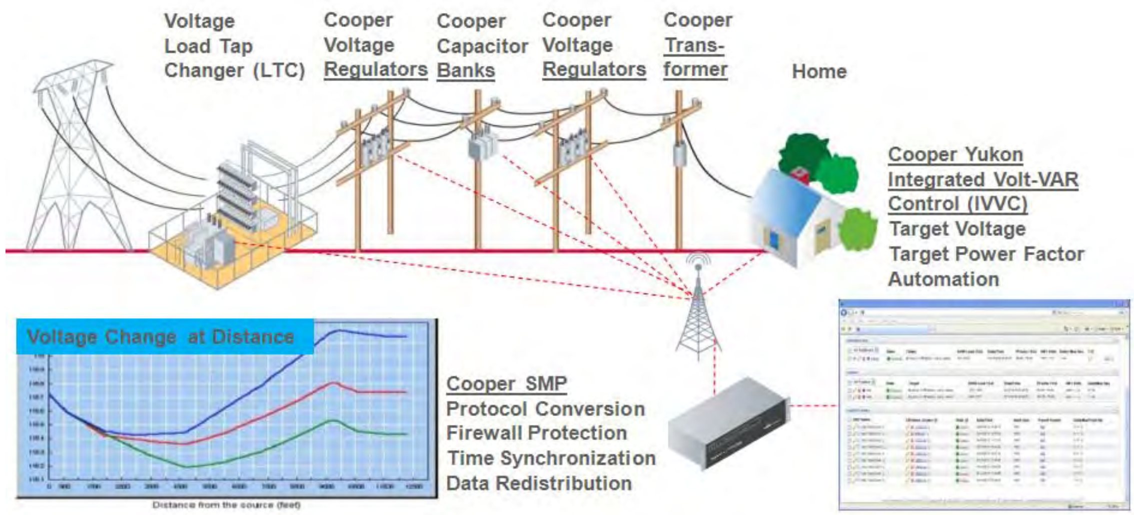


Figure 7-11
Yukon IVVC Architecture

The Yukon IVVC application monitors real-time voltages, watts and VARs from LTC's, regulators, capacitors, medium voltage sensors, and additional monitoring points, such as customer meters. Using this real time set of analog measurements, the Yukon IVVC application will trigger a control period during which the real time power factor and voltage measurement set is assigned an operational cost. The operational cost is determined from the analog measurement set compared against substation power factor and voltage targets. The Yukon IVVC application's objective is to minimize the operational cost by managing real time power factor and voltages as close as possible to the substation power factor and voltage targets.

The Yukon Volt-VAR Management system does not require an impedance and topology model or an unbalanced power flow solution. The IVVC application uses a heuristic algorithm to simulate changes in power factor and voltages as a function of changes in LTC, regulator, and capacitor bank control statuses and positions. The Yukon IVVC heuristic algorithm correlates real-time measurement data with historical data to simulate these changes.

At the beginning of each control period, the Yukon IVVC application iterates through a series of capacitor bank status changes to determine if the operational cost can be improved. Simulated changes in power factor and voltages are determined from historical data archived by the Yukon IVVC application. The historical data provides an understanding of how the system will react to the capacitor bank changes and voltage adjustments. If the operational cost is significantly improved by a particular capacitor bank status change, the Yukon IVVC application issue a capacitor bank control command. Successful operation of that capacitor bank is confirmed by the Yukon IVVC application via a new set of real time analog measurements. The application will analyze the set of voltages to determine if an LTC operation would improve the voltage measurement set towards its specified target. If yes, the Yukon IVVC application issues an LTC raise/lower command.

The Yukon IVVC application supports "wait periods" that follow execution of any control action: tap position raise/lower or capacitor bank status open/close. The Yukon IVVC application waits a configurable period of time after a control action has completed before the analysis period is executed. This functionality is enabled to prevent unnecessary tap change controls due to system voltage sensitivity.

Yukon IVVC can operate as a "stand-alone" system or in a "bolt-on" architecture that interfaces to the utility's existing Supervisory Control and Data Acquisition (SCADA) system. In bolt-on design, the SCADA interface provides real-time data to the Yukon IVVC algorithms and once Yukon IVVC analyzes the real-time data it sends the control actions that need to take place to the SCADA system for execution.

Additional features of Yukon IVVC include:

- **Semi-Automatic Operator Familiarization Mode** – Yukon IVVC can be configured to recommend particular actions but not automatically take those actions. This capability allows the user to become familiar with the algorithm and the decisions it makes prior to fully implementing the system.
- **IVVC Operation Following Feeder Reconfiguration:** Support for the automated re-coordination of capacitor banks and down-line regulators in the IVVC application due to feeder section switching is not currently supported in the Yukon IVVC application. However, support is planned for Q4 2011.

Other DVO Products and Solutions

Some of the other DVO products and solutions are mentioned below. Note that detailed product descriptions in previous sections were included for those utilities that responded to EPRI's request for information. The level of detail provided in this report does not reflect any special endorsement or positive/negative assessment of the vendor's offerings.

- Radio Control Central Stations Inc. (RCCS) (www.rccscontrols.com), which has a license agreement with ABB, offers a DVO system and communication solution named VVMS, that is best characterized as a SCADA, rules based solution. VVMS is also being used by numerous electric distribution utilities as the foundation for a DMS model-driven solutions (i.e.,, enables two-way communications with Volt-VAR field devices and basic control capabilities for these devices.

- Beckwith Electric Company (www.beckwithelectric.com) offers a line of standalone controllers for switched capacitor banks and voltage regulators (including substation transformer load tap changers)
- Schweitzer Engineering Labs (www.selinc.com) offers a line of standalone controllers for voltage control and VAR control. SEL also offers a Volt-VAR control system that is best characterized as a “rules-based” system.
- GE Energy offers a DMS model-driven solution as well as a decentralized solution that is best characterized as rules-based.
- Siemens also offers a DMS model-driven solution and a decentralized solution that is best characterized as rules-based.
- Survalent Technologies (www.survalent.com/solutions/smart-dms/smartdms-volt-var-control) offers a Volt-VAR control solution as part of its Smart DMS product.
- Open Systems International (OSI Inc) offers a volt-VAR optimization solution that is part of its Monarch product suite. Additional details are contained in www.osii.com/pdf/dms/OpenAVC_PS.pdf

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SUMMARY OF FINDINGS, CONCLUSIONS AND RECOMMENDATIONS

Utilities are seeking to improve the overall efficiency and performance of the distribution system to squeeze more capacity out of existing facilities and to accommodate high penetrations of distributed energy resources, including renewable generating sources with highly variable output. Distribution Voltage Optimization (DVO) will play a major role in accomplishing these objectives without compromising safety, asset protection, and operating constraints (maximum loading, minimum/maximum voltage levels, etc.).

This report explains how electric utilities can successfully use DVO effectively to accomplish the desired objectives. It includes an overview of DVO requirements, an assessment of various approaches to implement DVO, an analysis of DVO design parameters, summaries of DVO projects that have been implemented by electric utilities, descriptions of current vendor offerings, and other valuable information about DVO.

Results and Findings

DVO has proven to be a very effective mechanism for improving the overall efficiency of the distribution system by reducing electricity usage (demand and energy) and reducing electrical losses without compromising basic operating constraints and objectives. DVO can also provide additional benefits such as the reduction in tap changer operations. The improved visibility of distribution voltage conditions DVO systems has also led to the early discovery of problems in switched capacitor banks, voltage regulators, and load tap changers.

The most common DVO objectives are energy conservation and peak shaving, which utilities are achieving through voltage reduction. Voltage reduction is proving to be one of the most cost effective measures to achieve these objectives, because this application can leverage existing voltage and VAR control equipment. On average, energy consumption has been by 1.3% to 2% of total energy consumption by Conservation Voltage Reduction (CVR) and electric demand has been reduced by 1.5% to 2.1% by utilities that have used voltage reduction for peak shaving. Electrical losses can also be diminished through voltage reduction. However, the amount of loss reduction that can be achieved through voltage reduction 0.2% and 0.3% of total energy consumption, which is considerably less that the reduction of energy consumption and demand.

Many electric distribution utilities are currently evaluating DVO through small to medium scale demonstration projects on actual feeders and the energy savings results and peak shaving results achieved to date have generally been positive. Several North American utilities that have implemented or are in the process of implementing a Distribution Management System (DMS) have included DVO as one of the key DMS advanced application functions. A number of utilities that are currently investigating and demonstrating DVO have indicated that this application will be included in a future DMS to gain additional flexibility and performance that is provided by the model-driven solution.

Challenges and Objectives

One of the most significant challenges facing electric utilities that are seeking to deploy distribution voltage optimization systems is lack of mature, field-proven vendor products. While numerous demonstration projects are currently underway, most of these projects utilize standalone controllers or SCADA rule-based systems that are simplistic relative to the more sophisticated (and more flexible) DMS model-driven solutions and heuristic auto-adaptive approaches. Many system vendors offer DVO solutions that are based on these more sophisticated design approaches, but few are mature, field proven products. This report includes a chapter on current vendor offerings that summarizes the current offerings, level of experience, solution approach, unique features and other information to assist the utility company in identifying and evaluating various vendors.

Another major challenges facing utilities deploying energy efficiency improvement projects such as DVO is cost recovery. Suitable cost recovery mechanisms must be provided to enable the electric distribution utility to replace revenue lost due to lower kilowatt-hour sales on more efficient distribution systems. This report summarizes some of the revenue recovery mechanisms (such as revenue decoupling) that are being used by some electric distribution utilities that have deployed DVO.

A closely related subject that is covered in this report is verifying the benefits of energy efficiency measures such as DVO. It is especially challenging to identify the actual energy efficiency improvements associated with DVO because energy efficiency cannot be measured directly. The stochastic (random) nature of nature of customer loading makes it very difficult to determine the actual benefit at any given point in time. As a result, various statistical techniques must be used to estimate the benefits achieved by energy efficiency projects. This report describes Measurement and Verification (M&V) techniques that can be used to estimate the benefits over time with a reasonable level of confidence.

Applications, Values, and Use

This project developed guidelines for dealing with the challenges listed above and numerous other challenges that are detailed in other sections of this report. These guidelines are based on EPRI experience, research, and analysis, as well as lessons learned from various electric distribution utilities and research activities from the academic community. During this project, EPRI conducted DVO workshops and seminars, participated in IEEE working groups on DVO, and participated in various industry forums to discuss issues and challenges facing utilities that are deploying DVO.

These findings are documented in this report which will serve as a valuable reference manual for electric distribution utilities that are contemplating DVO implementation. Electric utilities should use the results presented in this document to assist in the planning, design, specification, installation, commissioning, and verification of DVO systems.

Following are key benefits that members will be able to achieve though this project

- Members will be able to better plan DVO investments through an understanding of application requirements and performance under different circumstances.
- Members will be able to use the Distribution System Simulation software (OpenDSS) as a platform for evaluating DVO for their own distribution systems. Example applications will provide templates for these evaluations.
- Members will be able to assess the economics and benefits of different applications as a function of their implementation costs.

EPRI Perspective

EPRI views this research as meshing with a number of programs involving advanced distribution system analysis. EPRI personnel have extensive knowledge of this area and personally know key vendor representatives. This has enabled EPRI to receive ready cooperation from most of the vendors of interest. EPRI also has some experience developing distribution-oriented tools with the capabilities of modeling urban networks through its publicly-available OpenDSS simulation software. By making this tool open source, EPRI's goal is to make the know-how for analyzing urban networks more widely dispersed, ultimately leading to more choices for EPRI members for tools with this capability.

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