Smart Grid Advanced Metering Annual Implementation Progress Report

APPENDIX A – REPORTS

I. INTRODUCTION

Pursuant to the June 2012 Order, ComEd was directed to submit information with its AIPR concerning any updates since submission of the AMI Plan to standards identified by the National Institute of Standards and Technology ("NIST"), including standards adopted by NIST's Smart Grid Interoperability Panel ("SGIP"), and how ComEd is addressing them.[33] In addition, in that same June 2012 Order, the Commission also directed ComEd to address in its 2013 AIPR: (1) if a Time-of-Use ("TOU") tariff will be proposed and the results of the dialogue with stakeholders regarding same; and (2) the development of a methodology to define and identify vulnerable customers and issues related to tracking information for vulnerable customers. ComEd did so, and in the order entered approving ComEd's 2013 AIPR, the Commission decided that any further discussion of these two issues was outside the scope of an AIPR proceeding.[34] Thus, while TOU and vulnerable customers are not issues in any proceeding that may be opened by the Commission to review ComEd's 2015 AIPR, ComEd does herein present, for informational purposes only, a discussion of its further efforts in 2014 to address these two issues.

Similarly, in the June 2012 Order, the Commission also directed ComEd to work with interested parties on the request for a map showing where distributed generation ("DG") would be good or bad. While the Commission did not specifically direct ComEd to report on the progress of the DG mapping request with its AIPR and specifically indicated that any issues regarding DG mapping should be brought before the Commission in a separate filing or rulemaking, ComEd is reporting on the status of this effort for the convenience of the Commission and all interested parties.

Lastly, in the Order the Commission entered in ComEd's recent energy efficiency three-year plan, the Commission ordered ComEd to propose a Voltage Optimization ("VO") study and to include it in ComEd's AMI Plan.[35] In compliance with that Order, a discussion of the proposed study is included in this Appendix.

A discussion of the status of each item described above is provided below.

II. UPDATED NIST INTEROPERABILITY STANDARDS

As noted above, in the June 2012 Order the Commission directed ComEd to report on any updates to applicable NIST standards and explain how it is addressing any such updates. The applicable NIST standards noted in the Revised AMI Plan are regularly reviewed by the IT team at ComEd for completeness and accuracy. Each standard is studied to identify any updates or changes, and to determine whether it has been superseded by newer or more appropriate standards.

[33] June 2012 Order at 25.

[34] 2013 AIPR Order at 10 and 15.

[35] Order of January 28, 2014 in Docket No. 13-0495 at 95.

In Q4 of 2014, prior draft revisions from 2013 concerning NISTIR 7628 Guidelines for Smart Grid Cybersecurity and NIST 7761 Priority Action Plan 2: Guidelines for Assessing Wireless Standards for Smart Grid Applications were officially published.

Updates within NISTIR 7628 Guidelines for Smart Grid Cybersecurity include:

- Finalized combined cyber-physical attacks descriptions
- Supplementary cybersecurity testing and certification approach and guide
- Best practices for 3rd parties to manage smart grid data and privacy concerns
- Cybersecurity issues associated with communications between electric plug-in vehicles and the smart grid
- New security awareness and training guides and templates (for both external consumers and internal personnel)
- Emerging privacy risks regarding the advent of new technologies and activities that could leverage the smart grid

Updates within NIST 7761 Priority Action Plan 2: Guidelines for Assessing Wireless Standards for Smart Grid Applications include:

- Extended approach and framework for modeling and evaluating wireless technologies
- Additional toolsets and templates for modeling and evaluating wireless technologies
- Sensitivity analysis and impacts for input parameters
- Further guidance, information, and considerations pertaining to wireless standards and implementing associated technologies for smart grid network designers/planners

The IT team reviewed these revisions accordingly and determined that the Revised AMI Plan remains aligned with the applicable NIST requirements detailed within the updated standards. This includes NIST recommendations related to customer data and privacy. Furthermore, the IT team continues to assess and evaluate any supplementary considerations that are mentioned by NIST for informational purposes.

Additionally, standard IT security management activities are completed by the IT team as a component of the required support of AMI systems. Security management activities are completed to align with ComEd policies and industry standards, and include activities such as deploying security system packages to allow for appropriate security and vulnerability monitoring, ensuring that deployed servers adhere to password and system control procedures, performing periodic server fixes and security updates, and performing vulnerability assessments as well as subsequent remediation steps to rectify any defects or findings.

III. TIME OF USE RATE

A. Consideration of Utility TOU Rates

As reported in Appendix A to ComEd's 2013 AIPR investigated in ICC Docket No. 13-0285, ComEd met with SGAC and other stakeholders at that time to discuss the development of time-of-use ("TOU") rates within Illinois' competitive market and reported the results of its meetings with stakeholders.[36] As a result of those meetings, ComEd concluded that a utility-offered TOU rate would be a potential disruption to the competitive market, and committed to continue to work with stakeholders on these issues. The Commission agreed with ComEd's conclusion and in its 2013 AIPR Order declined to require ComEd to offer a TOU rate. 2013 AIPR Order at 15. On February 13, 2015, the Citizens Utility Board and Environmental Defense Fund filed a Petition to Initiate a Proceeding to Investigate the Adoption of a Utility Time of Use Rate that was assigned ICC Docket No. 15-0100.

B. Facilitation of RES TOU Offerings

1. Background

In ICC Docket No. 12-0484, the Commission investigated ComEd's Petition to seek approval of tariffs implementing ComEd's Peak Time Savings ("PTS") program, pursuant to Section 16-108.6(g) of the PUA. In its interim PTS Order dated February 21, 2013, the Commission directed Staff to hold workshops with interested parties in order to address certain issues that arose during the investigation. Beginning in April 2013 and continuing on throughout 2014, Staff hosted a series of "Enabling the Market" workshops that were attended by utilities, consumer groups, RESs, and other interested stakeholders. In addition to the items the Commission directed the parties to address, the workshops covered several AMI-related topics, including the release of customer-specific information by electric utilities and enabling RESs to offer TOU and other dynamic pricing products, which eventually led to the development of ComEd's Rider RMUD – Residential Meter Usage Data ("Rider RMUD"), which is discussed in greater detail later in this section.

2. Release of Customer-Specific Information by Electric Utilities

Several of the initial issues discussed at the Staff-led workshops revolved around the electric utilities releasing customer-specific information to third parties. While one of those issues, i.e., identifying customers participating in ComEd's PTS program, had been raised in Docket No. 12-0484, other issues were identified in the workshop discussions that focused on how Sections 16-122 and 16-108.6 of the PUA impacted a utility's ability to release customer-specific information to third parties.

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[36] 2013 AIPR, App. A at 2-4.

Recognizing that these issues would not be resolved in the workshops, the Commission's Office of Retail Market Development ("ORMD") issued a report dated August 30, 2013 (the "Staff Report") requesting that the Commission investigate certain issues: (1) the release of aggregated, anonymous customer usage information; (2) the release of information identifying PTS and net metering customers; and (3) RES access to its customers' interval usage data that is not used for the purposes of billing a customer. The Commission initiated an investigation in these matters on September 4, 2013 in Docket No. 13-0506 ("Data Privacy Docket").

On January 28, 2014, the Commission entered an Order ("Data Privacy Order") in the Data Privacy Docket. On February 18, 2014, CUB filed a Motion for Clarification. The Commission granted CUB's Motion for Clarification in part and issued an Amendatory Order reflecting the clarification on March 19, 2014. On February 28, 2014, ComEd timely filed an Application for Rehearing. On March 19, 2014, the Commission granted ComEd's Application for Rehearing in part on the sole issue of whether Sections 16-122 and 16-108.6 of the PUA allow a utility to release anonymous customer usage data to third parties that are not enumerated in Section 16-122 (such as researchers, energy efficiency program providers, and others that are not Retail Electric Suppliers ("RESs") or municipalities).

On June 11, 2014, the ALJ issued a Proposed Order on Rehearing in this matter and the Commission entered an Order on Rehearing dated July 30, 2014 ("Data Privacy Order on Rehearing").

a. Aggregated, Anonymous Data

In the Data Privacy Order on Rehearing the Commission held as follows:

> Section 16-122 does not address the release of anonymous customer usage information and that the only limitation set forth by the plain language of Section 16-122 and Section 16-108.6 is the release of customer specific information. As noted in the Final Order, anonymous information is not customer specific information. Further, anonymous information will only be released by the utility pursuant to the data protocol adopted in the Final Order. This data protocol strips data of customer specific information and ensures only non-customer specific information will be released. Therefore, the release of such information to third parties, including parties that are not listed in Section 16-122, without customer authorization is not prohibited by Section 16-122 or Section 16-108.6 of the PUA. The Commission also believes the release of anonymous customer usage information to any party pursuant to the data protocol adopted in the Final Order is consistent with the legislature's intention to protect customer privacy since the information will be released in a manner that prevents it from being reasonably linked back to an identifiable customer. Additionally, the Commission concurs with the parties that making this information available is in the public interest and consistent with the goals and objectives of the PUA.

Data Privacy Order on Rehearing at 10-11. The Commission further found that, pursuant to Section 16-122, no fee is specifically required for this data; however, there is nothing in Section 16-122 to prevent the utilities from charging a reasonable fee when providing this information.

b. Identification of PTS and Net Metering Customers

From discussions during the workshops, there was an understanding that competitive suppliers have legitimate reasons to obtain certain information about individual customer accounts, and that freer access to various types of individual customer information could assist in realizing certain benefits available from the smart meter infrastructure. At the same time, ComEd and other parties expressed concerns related to customers' privacy interests – both in the obvious interest of adhering to state law and also because data privacy had been cited as a reason for customer refusals of smart meter deployment.

The Commission ruled that a customer's participation in PTS or net metering programs is billing data and that verifiable authorization from individual customers is required under the PUA before disclosure may occur. The Commission also determined that possession of an account number should be considered customer authorization to receive certain information about such customer's account, including whether the customer is a PTS or net metering customer, or a participant in any supply related or demand response program offered by the utility. In the Data Privacy Order dated January 28, 2014, the Commission also found that the electric utilities should not be required to provide lists of customers that possess one or more of the above mentioned characteristics, as this would contravene Section 16-122.

c. RES Access to Customer's Interval Data Not Used for Billing Purposes

Discussions in the workshops brought up the issue of RES access to interval data that ComEd collected from customers involved in the AMI Pilot, but was not used to develop the monthly bill for the customer. This request raised issues concerning what type of customer authorization the RES would need to obtain in order for the electric utility to provide non-billing interval data to the RES, and how the RES would verify to the electric utility that it had obtained proper customer authorization. Staff asserted that RESs should obtain customer authorization for access to this information either through initial signup or separate verifiable authorization consistent with Section 2EE of the Consumer Fraud and Deceptive Business Practices Act. In the municipal aggregation context, Staff recommended that RESs be required to disclose in the opt-out documentation that was sent to all customers in the municipality that this interval data was available and that the failure to opt-out of the program would constitute consent for the RES to have access to the information. Staff then proposed that RESs would certify to the utilities that they had obtained such authorization through the development of a new step in the direct access service request ("DASR") process. The Commission supported Staff's proposal regarding the level of authorization necessary to access customers' interval data, but directed that the parties come together in an effort to reach consensus regarding the method for achieving this result in workshops.[37] Through workshop discussions throughout 2014, the warrant forms and processes were developed and approved and are provided on the ComEd.com customer choice website.

Another development coming out of the Enabling the Market workshops were enhancements made to the Supplier Portal on the ComEd Choice website which provides historical customer data. These enhancements include the provision of non-billing daily interval data to suppliers that qualify for Rider RMUD and prefer to receive interval data daily instead of at the end of each billing period. The suppliers will be able to utilize a Supplier Portal to view this non-bill quality interval data on a daily basis (i.e. the day after). The Portal will retain a rolling 35 day historical interval usage for each customer on RMUD if the supplier would like to view the data. Since this data is not bill quality it may differ from what is sent at the end of the monthly billing period via EDI. The opportunity to add enhanced historical data to EDI communications for RESs is still being investigated.

3. RES TOU Offerings and Other Dynamic Pricing Products

During the Enabling the Market workshops held in 2013, parties explored the enhancements required to enable RESs to offer services and products enabled by AMI meters, including supply offerings incorporating TOU pricing, demand response and energy efficiency. These workshops addressed RESs' need for access to interval data from AMI meters and the electronic data interchange issues related to providing such data.

a. Residential Meter Usage Data ("Rider RMUD")

ComEd used the information and feedback from workshop participants to design Rider RMUD – Residential Meter Usage Data ("Rider RMUD"). The features of this pilot program and of the tariff were discussed in that workshop process and resulted in ComEd filing a petition and proposed tariff with the Commission on November 15, 2013 in Docket No. 13-0635. That petition was approved on December 4, 2013 by the Commission. Beginning January 16, 2014, Rider RMUD authorized ComEd to provide granular residential meter usage data to authorized RESs taking service under Rate RESS – Retail Electric Supplier Service ("Rate RESS") serving those residential customers that provide not only electric power and energy supply services, but also TOU pricing and/or demand response products, all as described in the tariff. Rider RMUD was filed and approved as a pilot tariff (a) because of technical limitations on the number of participating customers inherent in the legacy meter data management system ("MDMS") and (b) to limit the cost of the pilot to a reasonable and prudent sum.

Through the Enabling the Market workshops, ComEd was able to communicate to, and solicit feedback from, stakeholders around upgrading and replacing certain facilities, equipment and systems that were completed in order to establish Rider RMUD and subsequently eliminate the original customer cap. These include future technical improvements to the current production retail market systems, changes to the electronic data interchange ("EDI") system and other

[37] Data Privacy Order at 27.

downstream technologies to allow for electronic enrollment and un-enrollment and hourly intervals, replacement of the legacy Meter Data Management System ("MDMS") and related modifications to related systems and interfaces, internal systems and process testing, and developing plans for testing these modifications with suppliers. In August of 2014 ComEd completed the upgrade of the new MDMS. On October 31, 2014, ComEd filed revisions to Rider RMUD that the Commission allowed to become effective on December 15, 2014, increased the customer cap to 100,000 through the end of 2015, and eliminate the customer cap as of January 1, 2016 – at which point Rider RMUD will be offered generally rather than on its original pilot basis. As of the end of 2014, RESs were utilizing this service for 230 customers; well below any cap within the rider.

Additionally, some RESs are experimenting with new customer options to utilize the data offered through Rider RMUD through programs such as "Free Weekends" among others. The PlugInIllinois.com/smartmeter website provides a comprehensive table with details of RES offerings.

b. Peak Time Savings

In October 2014, ComEd opened enrollment in the PTS program, which provides all customers with an AMI meter, regardless of suppler, the opportunity to begin receiving credits for curtailments during the summer of 2015.

4. Additional commitments related to customized education related to TOU products:

ComEd's education and outreach efforts under the AMI Plan have included information on dynamic pricing products offered by ComEd and alternative suppliers and how customers can use them to achieve certain benefits. Customized education has focused on key customer segments based on available demographic data to achieve the following:

- Deliver low-income education and support programs to help seniors and economically disadvantaged understand how to manage energy effectively using smart meters and pricing programs (such as RRTP and PTS).
- Make sure that education regarding cost savings under AMI is reaching all customers including low-income customers participating in PIPP, LIHEAP or a DPA. Include education around PTS, RRTP and web tools. If a TOU rate becomes available in the future, ComEd will also include that tariff in its education efforts. How ComEd will educate customers is detailed in the marketing campaign for low income and senior customers.

IV. VULNERABLE CUSTOMERS

In 2013, ComEd held discussions with various stakeholders on vulnerable customers. These included discussions with the following: the Attorney General, the City of Chicago's Department of Family Services and Support and the Illinois Department of Commerce and Economic Opportunity ("DCEO"). In addition, ComEd held a stakeholder outreach meeting.

As ComEd reported in its 2013 AIPR, the stakeholders have agreed to define and identify vulnerable customers as customers belonging to the following customer groups:

1. Low income
2. Very young (from birth to age 5)
3. Older individuals (age 65 and older)
4. Those who have limited English proficiency or literacy
5. Individuals with a functional disability, such as impaired mobility
6. Persons who are socially isolated

There remain significant barriers to tracking vulnerable populations. ComEd's customer files do not contain information as to age, English fluency or other customer conditions so as to enable ComEd to place customers into the category of vulnerable customers. In addition, obtaining data on customers meeting any of the six criteria used to define vulnerable customers by zip code or census tract is not useful for purposes of the reporting requirements.

However, ComEd will continue to report on vulnerable customers using the limited information in its possession regarding low income customers (Group 1, above) and customers with qualifying life support equipment at the premises or having a certified medical condition in the household (Group 5, above) and will supplement such reports if additional verifiable data becomes available from other entities, such as DCEO. In addition, ComEd will continue to administer assistance programs and will engage in education and outreach for low income customers. Low income customers are defined as those customers who participate in the Low Income Heating Assistance Program ("LIHEAP"), the Residential Special Hardship Program, the CHA All Clear program, or the Percentage of Income Payment Plan ("PIPP").

In 2014 there were no further developments in acquiring data for Groups 2, 3, 4 or 6. As in 2014, in 2015 ComEd will continue to evaluate outreach to customers in need, where there is data to identify such customers, through alerts, enhanced messaging and payment arrangements.

V. DG MAPPING

In the June 2012 Order, the Commission determined that concerns raised by CUB and the ELPC about perceived barriers to the installation of DG needed to be addressed in a separate rulemaking. The Commission, however, directed ComEd to work with interested parties to implement their "request for a map showing where distributed generation would be good or bad."[38] Following meetings with interested parties, ComEd posted the map tool on its website

[38] June 2012 Order at 50.

and notified interested parties on August 15, 2013 of the posting of the map tool.[39] ComEd updated the map on October 1, 2014, plans to update the map once per year, and will continue to consider more frequent updates if there is a large increase in DG interconnection activities in the future. An update will also be necessary if and when there is a change to the rules that govern the review and approval of DG interconnection requests for DG facilities with a nameplate capacity of up to 10 MVA.[40]

VI. VOLTAGE OPTIMIZATION

A. Background

Voltage Optimization ("VO") is a combination of Conservation Voltage Reduction ("CVR") and Volt-VAR Optimization ("VVO"). These programs are intended to reduce end-use customer energy consumption and peak demand while also reducing utility distribution system energy losses. The ICC, in Docket No. 13-0495, stated that "A review of the record leads the Commission to believe that a VO feasibility study should be pursued and could in fact result in many direct and indirect benefits." The order also stated that "The record is also not clear whether there is already a budget earmarked for voltage optimization in ComEd's Smart Grid plan. If there is already, it should go forward; if not the Company is directed to include it with the next AMI plan filing." In accordance with ComEd's 2014 AIPR, a Voltage Optimization Feasibility study was completed by Applied Energy Group ("AEG") in December 2014.

B. Feasibility Study Approach

AEG was selected through a competitive bid process, based on the thoroughness of their proposed plan of work and the previous relevant experience to conduct a feasibility study of implementing Voltage Optimization on the ComEd distribution system. The study relied on industry standard modeling and engineering methods that have been used for electric utilities including:

- Use of power flow simulation feeder models derived from ComEd's Geographic Information System (CEGIS)
- Robust statistical techniques yielding representative system-level VO benefits and costs

The study methodology followed two major steps: 1) "total feeder prioritization" of potential candidates; and 2) "sample feeder detailed analysis" using load-flow simulations. Estimated VO

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[39] https://www.comed.com/customer-service/rates-pricing/interconnection/Pages/distribution-under-10000kva.aspx.

[40] 83 Ill. Admin. Code Part 466 – Electric Interconnection of Distributed Generation Facilities.

factors were applied to both steps. Two VO scenarios labeled Plans A and B were evaluated to compare the benefits of alternative levels of energy efficiency.

The initial step of "total feeder prioritization" classified 3,757 feeders out of ComEd's total population of approximately 5,650 feeders using a simplified load flow analysis of feeder characteristics involving load type, load density, feeder lengths, existing voltage control settings, real and reactive loads, line voltage drops and losses, line regulators installed, and conductor loading. Feeders were categorized as viable or non-viable for VO implementation, and viable feeders were prioritized based on a potential voltage-reduction magnitude-sensitivity impact analysis, and subsequent energy savings potential.

For the "sample feeder detailed analysis", a sample of 70 feeders from 16 substations was selected using a stratified random sampling approach to fairly represent the total feeder population. Detailed analyses of planning and loadflow simulations were performed to determine expected annual energy savings (kWh) and peak power reductions (kW) for each of two VO scenarios. This sample feeder analysis included an assessment of system upgrades between the existing system and VO-modified plans, including benefits/costs for each VO scenario, which were then extrapolated back to the total ComEd system level using statistical ratio estimation techniques linking the sample group, study group, and system population. In addition, a recommended VO pilot project was outlined to demonstrate the proposed VO implementation strategies, verify estimated VO factors, and develop simplified VO M&V procedures for ComEd's distribution system.

It is important to note that the study is not an implementation plan for VO. In fact, the results are statistically valid, but represent an instant change from current operations to one where VO is implemented fully and effectively on each viable feeder.

C. Feasibility Study Results

The Commonwealth Edison Voltage Optimization (VO) Feasibility Study Final Report ("VO Feasibility Study Report"), dated January 6, 2015 and prepared by AEG, is attached hereto in Subsection F.

<u>Key AEG Feasibility Study Findings</u>

- ✓ VO is likely to be cost-effective for viable feeders
  - The high level estimated potential Total Resource Cost (TRC) benefit cost ratio for viable feeders ranges from 2.2 to 2.3
- ✓ Deployment costs are primarily to increase feeder efficiency, minimize voltage drop and monitor last customer and system voltages
- ✓ ComEd has a relatively efficient feeder design
- ✓ Existing voltage regulation practices provide an opportunity for voltage reduction
- ✓ Approximately 50% of all ComEd feeders are believed to be viable for VO (2,890 of 5,655 feeders)

- Viable feeder criteria - 12kV feeders that supply residential and small C&I customers
- Non-viable feeders continue using traditional voltage regulation

Summary of Feasibility Study Analysis

	Plan A (Reduced Cost)	**Plan B (Greater Savings)**
Potential VO Savings • **Energy (GWh/year)** • **Peak Load (MW)**	1350 260	1900 360
Total VO Estimated Costs	$425 M	$575 M
VO Program TRC	2.20	2.30
Levelized Cost of Energy Saved ($/kWh)	$0.0193	$0.0185
Number of Viable Feeders	2890	2890
Average Energy Savings per Viable Feeder (MWh/yr)	470	660
Average VO cost per feeder	$150 K	$200 K
Average Voltage Reduction	3.0%	3.8%

<u>Key AEG Feasibility Study Recommendations</u>

✓ Design/Implement VO verification project(s) to validate:
- Method used to estimate energy savings
- Residential and commercial VO factor assumptions
- Test voltage optimization strategies
- Validate Line Drop Compensation (LDC) voltage control schemes
- Test End of Line (EOL) voltage feedback for overriding LDC controls
- Switched capacitor VAR control schemes
- Measurement and Verification protocol
- Effectiveness of Integrated Volt VAR Control (IVVC) applications

✓ Develop and implement VO analysis training, operations, and maintenance materials

✓ Improve VAR management with small capacitor banks using controls with VAR sensing

✓ Install EOL voltmeters on every VO feeder and voltage control device at the lowest voltage location

- ✓ Examine AMI voltage/loading data to determine actual feeder voltage drop and load profiles to determine the need to upgrade distribution transformers.

D. Planned ComEd Validation Project

Based on the VO Feasibility Study Report and the AEG Recommendations, ComEd plans to conduct a VO Validation Project as follows:

- ✓ Conduct a validation project to confirm annual estimated energy savings, deployment costs and implementation technologies for at least 2 substations with 4-to-6 feeders each
    - Selected feeders will represent urban, suburban and rural areas and will contain those evaluated by AEG with both higher and lower benefit-cost ratios
- ✓ Evaluate and select appropriate VO technologies at the validation substations
    - Validate both LDC and IVVC control technologies
- ✓ Begin VO operations of the validation project in 2016. It is anticipated that data collected over a 12-month operating period will be sufficient to validate the assumptions and conclusions reached in the feasibility study. Additional data collection and evaluation for a period of up to 12 months may be necessary if unanticipated operational issues arise during the validation project.
- ✓ Assess and report learnings from the results of the validation project

E. Budget and Cost Recovery

A preliminary estimate of the cost of the validation project is $2,000,000. As indicated above, the estimated cost to fully implement VO is expected to be in the range of $425-575 million. This amount may exceed what is available in the AMI budget. Therefore, at some point prior to full implementation, an appropriate cost recovery mechanism will need to be considered and addressed. ComEd notes that proposed legislation was introduced on March 19, 2015 (currently, Amendment 1 to Senate Bill 1879; Amendment 1 to House Bill 3328) that revises the Public Utilities Act to expressly address voltage optimization as an energy efficiency measure. The proposed Bills would find that "Voltage optimization is an energy efficiency measure that can deliver cost-effective energy savings for all retail customers, including low-income customers." (220 ILCS 5/16-108.11(a) new) They would also authorize utilities to file plans with the Commission for the implementation of "cost-effective voltage optimization on identified elements of its electric delivery system," subject to Commission review, and make clear that the costs of implementing voltage optimization, as well as validation of VO, shall be recovered through Article IX rates or under Section 16-108.5 of the Public Utilities Act. (220 ILCS 5/16-108.11(b) new). Going forward, the continued implementation of voltage optimization would be addressed in ComEd's energy efficiency assessments. (220 ILCS 5/8-103 (b-5); 220 ILCS 5/16-108.11(d) new). ComEd supports these Bills, as proposed.

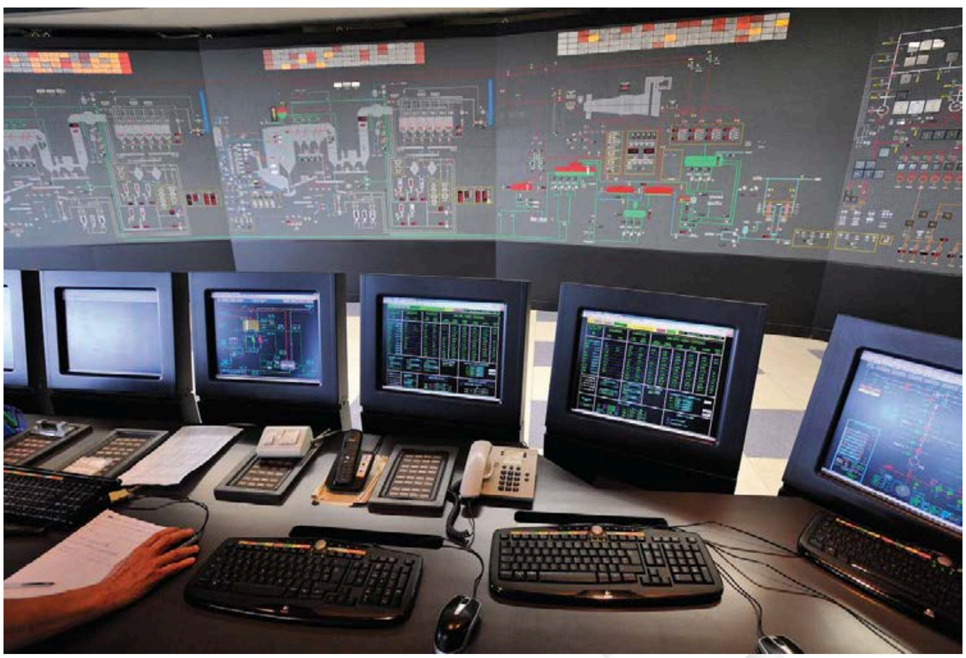
F. VO Feasibility Study Final Report

The VO Feasibility Study Final Report is attached below.

Report specifically developed for:

Commonwealth Edison Company

March 9, 2015



Voltage Optimization (VO) Feasibility Study

Final Report

Contract No. 01146430

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Distribution Feeder VO Screening
Potential VO Energy Savings and Cost Impacts

TASK 10: **Final Report**

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Contract No. 01146430

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1. Executive Summary

The Applied Energy Group (AEG) was contracted by Commonwealth Edison Company (ComEd) under Contract No. 01146430 to conduct an investigation of the feasibility and potential of energy savings and peak power reductions on ComEd's power system through systematic deployment of voltage optimization techniques and technologies. Voltage Optimization (VO) is defined to be a combination of Conservation Voltage Reduction (CVR) and Volt-VAR Optimization (VVO). VVO coordinates capacitor bank operation to reduce distribution losses and improve power factors. CVR initiates a systematic reduction of end-user voltages using load tap changers, line drop compensation, voltage regulators, and capacitors to reduce energy consumption.

The Illinois Commerce Commission (ICC) directed ComEd to conduct a feasibility study of adopting VO in the final order of Docket No. 13-0495 (2013 Energy Efficiency Plan). These programs are intended to reduce end-use customer energy consumption and peak demand while reducing utility distribution system energy losses. AEG conducted a feasibility study on ComEd's electric distribution system to quantify potential VO savings.

A primary objective of the study was to assess the magnitude of customer end-user and utility benefits available from two VO scenarios: A minimum cost VO scenario (Plan A) based on feeder upgrades required to bring the system up to ComEd defined performance standards; and a maximum savings scenario (Plan B) designed to optimize VO savings within the constraints of ComEd's Total Resource Cost (TRC) benefit-cost thresholds. In all cases, existing ComEd distribution system planning/design and operation guidelines were strictly followed. Not addressed was the impact of end-use energy savings on ComEd's distribution revenues and associated cost recovery.

1.1 Key Findings

- The potential to achieve cost-effective energy savings and demand reductions from VO on the ComEd distribution network is substantial. The study found cost-effective energy savings of as much as 1900 GWh-yr, equal to approximately 2% of ComEd's retail sales, at a cost of approximately $0.0185/kWh. This is roughly equivalent to ComEd's entire energy efficiency (EE) program goals for the next three years at a cost below most other EE program options.

- It is estimated 515 substations (64%) and 2,890 feeders (51%) are viable candidates for VO implementation with an average savings per viable feeder of 3.5%. This high savings estimate relative to other utility VO programs can be attributed to a number of factors, including low voltage drops across feeders due to short runs, relatively good system efficiencies (good phase and load balancing), favorable end-use load composition (low saturation of electric resistance heat), and current voltage settings (conservatively high).

- The primary determinants of feeder VO non-viability were voltage level (>25kV and <11kV urban networks were excluded), and customer class (large commercial and industrial loads are not good VO candidates).

- A majority of the distribution system requires efficiency upgrades (best industry practices) for VO to be effective. For example, Plan A (minimum cost plan) requires a $425 million investment to allow average voltages at the customer meter to be reduced by 2.96%, accounting for the majority of energy savings.

- ComEd design guidelines specify maximum secondary voltage drops of 6.0 volts. However, for the VO study, a utility best practice of 3.6 volts was used (or 3% on a 120-volt base) to allow potential energy savings to be maximized.

- The maximum energy savings (Plan B) can be achieved by investing an additional $150 million – a total of $575 million – over Plan A, resulting in an average voltage reduction of 3.81%. The incremental Plan B investments increase the total program TRC B-C ratio from 2.20 to 2.30.

- Isolating non-viable feeders from viable feeders at the same substation (and voltage control zone) is one of the key challenges to VO implementation. The use of IVVC rather than physical space-prohibited substation voltage regulator banks is the recommended feeder isolation solution.

- Capital cost recovery, lost revenue adjustments, and energy efficiency program inclusion are key regulatory hurdles for ComEd's VO strategy.

1.2 Approach

AEG's approach was designed to provide ComEd with the following benefits:

- Reliance on proven, industry standard modeling and engineering methods that have been used at other utilities similar to ComEd.

- Efficient use of ComEd's existing CYME distribution data sets to ensure timely and cost-effective results.

- Robust statistical techniques yielding representative and defensible system-level VO benefits and costs, appropriate for regulatory submittal.

- National perspectives on VO activities based on the collective experience of the AEG team.

AEG's methodology followed two major steps: 1) "Total feeder prioritization" of potential candidates; and 2) "Sample feeder detailed analysis" using load-flow simulations. Estimated VO factors were applied to both steps.

Fourteen (14) of ComEd's 19 operating regions were included in the study group. The initial step of "total feeder prioritization" classified 3757 feeders out of ComEd's total population of approximately 5650 feeders[1] using a simplified load flow analysis of feeder characteristics involving load type, load density, feeder lengths, existing voltage control settings, real and reactive loads, line voltage drops and losses, line regulators installed, and conductor loading. Feeders were categorized as viable or non-viable for VO implementation, and viable feeders were prioritized based on a potential voltage-reduction magnitude-sensitivity impact analysis, and subsequent energy savings potential.

Next, a sample of 70 feeders from 16 substations was selected using a stratified random sampling approach to fairly represent the total feeder population. Detailed analyses of planning and load-flow simulations were performed to determine expected annual energy savings (kWh) and peak power reductions (kW) for each of the two VO scenarios. This sample feeder analyses included an assessment of system upgrades between the existing system and VO-modified plans, including benefits/costs for each VO scenario, which were then extrapolated back to the total ComEd system level using statistical ratio estimation techniques linking the sample group, study group, and system population. In addition, a recommended VO staged deployment was outlined to demonstrate the proposed VO implementation strategies, verify estimated VO factors, and develop simplified VO M&V procedures for ComEd's distribution system.

The overall project design and process flow chart is shown in Figure 1. The numbers in the task boxes (T1, T2, etc.) refer to the 10 project tasks referenced throughout this report and listed below.

Task 1: Project Start Up (kick-off meeting)
Task 2: Develop Global Data Templates to facilitate data collection
Task 3: Sample Frame and Feeder Selection/Screening
Task 4: Develop Scenario Case List for "what-if" analysis
Task 5: Data Collection for representative feeders to be studied
Task 6: Conduct "What-if" Analysis on representative feeders
Task 7: Perform Benefit-Cost Analysis
Task 8: Extrapolate representative feeder results to system level
Task 9: Suggest Potential VO staged deployment to test study results
Task 10: Final Report/Presentation

[1] Except for secondary networks like the one serving downtown Chicago, which will need further discussion with the ComEd distribution planning group.

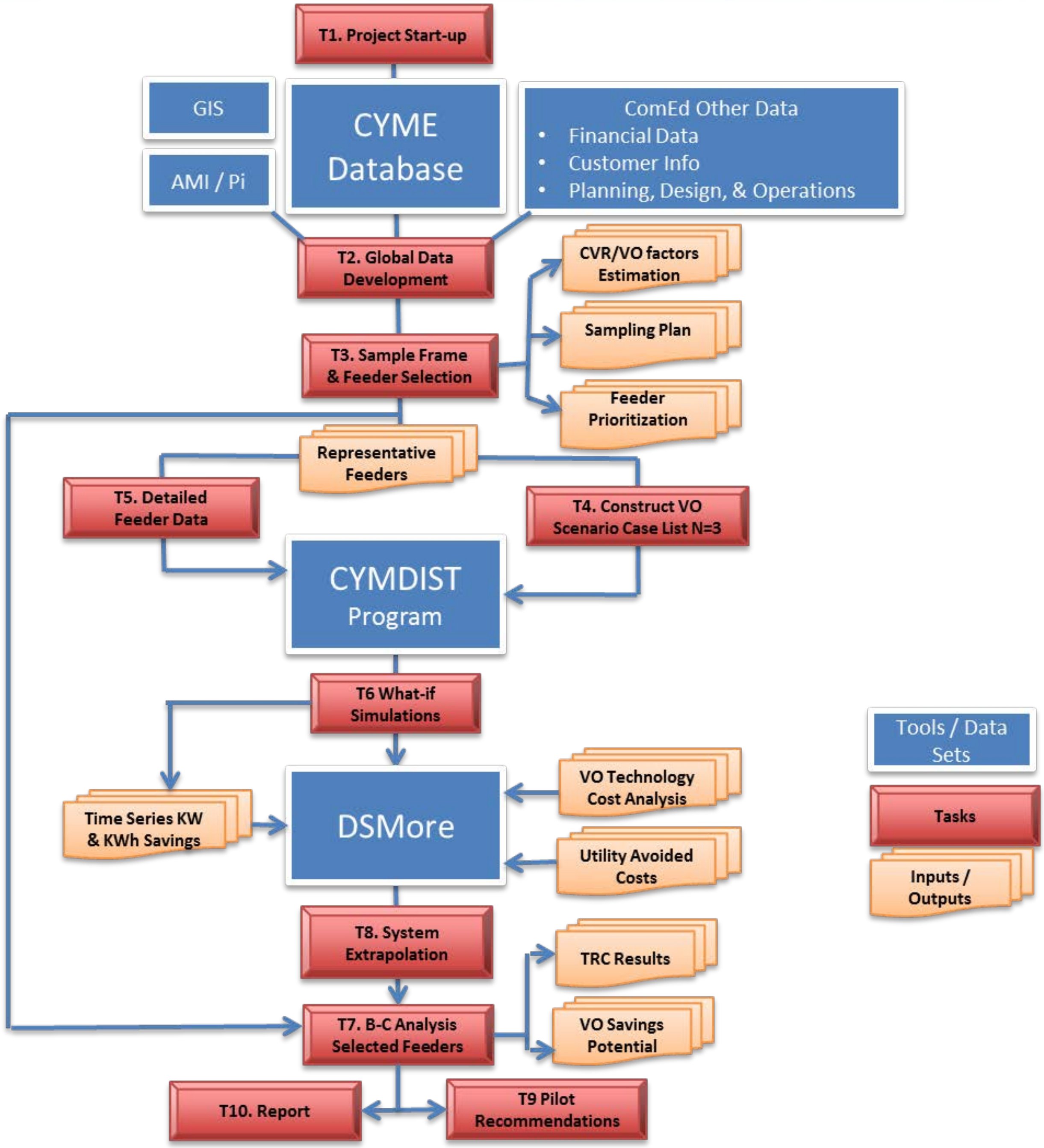


Figure 1 - Overall Project Design and Flow Chart

1.3 Project Results

The VO feasibility study results estimate the potential to reduce energy consumption by as much as 1900 GWh-y while reducing peak loads by approximately 360 MW. These results are based on the Plan B (maximum energy savings) analysis. The total upfront cost to implement Plan B is approximately $575 million, which represents an average savings per viable feeder of 3.5% at a levelized cost of energy (LCOE) of $0.0185/kWh-saved. It is estimated VO is viable on 515 of ComEd's 806 substations, representing 2890 feeders. The minimum cost Plan A generates 1350 GWh-yr of savings at a cost of $425 million. A summary of Plan A and Plan B results are presented in Table 1.

Table 1 - Summary of Project Results

	Plan A	Plan B
Total VO Savings Potential		
- Energy (MWh-yr)	1,350,371	1,912,952
- Peak Load (MW)	257	364
Total VO Installed Costs	$425,466,877	$574,232,508
VO Program TRC	2.20	2.30
Levelized Cost of Energy ($/kWh)	$0.0193	$0.0185
Number of Viable Feeders	2,890	2,890
Number of Viable Substations	515	515
Average Energy Savings (MWh-yr)		
- per viable feeder	467	662
- per viable substation	2,624	3,718
Average VO Cost		
- per viable feeder	$147,222	$198,699
- per viable substation	$826,902	$1,116,030

Energy savings from VO occur in two forms: Distribution line loss reductions and end-use load reductions. As seen in Figure 2, a majority of the energy savings comes from end-use load reductions. For Plan A, only 6% of total savings comes from distribution loss reduction. For Plan B, which includes more system improvements, distribution savings increase to 11%.

VO benefits are achieved through a number of capital improvements and operation changes on the distribution system. Total capital expenditures to achieve these benefits are $425 million for Plan A (minimum cost) and $574 million for Plan B (maximum savings). Capital costs include equipment, labor, and overhead. This equates to average costs per substation of $826,902 and $1,116,030 for Plans A and B respectively (Figure 3).

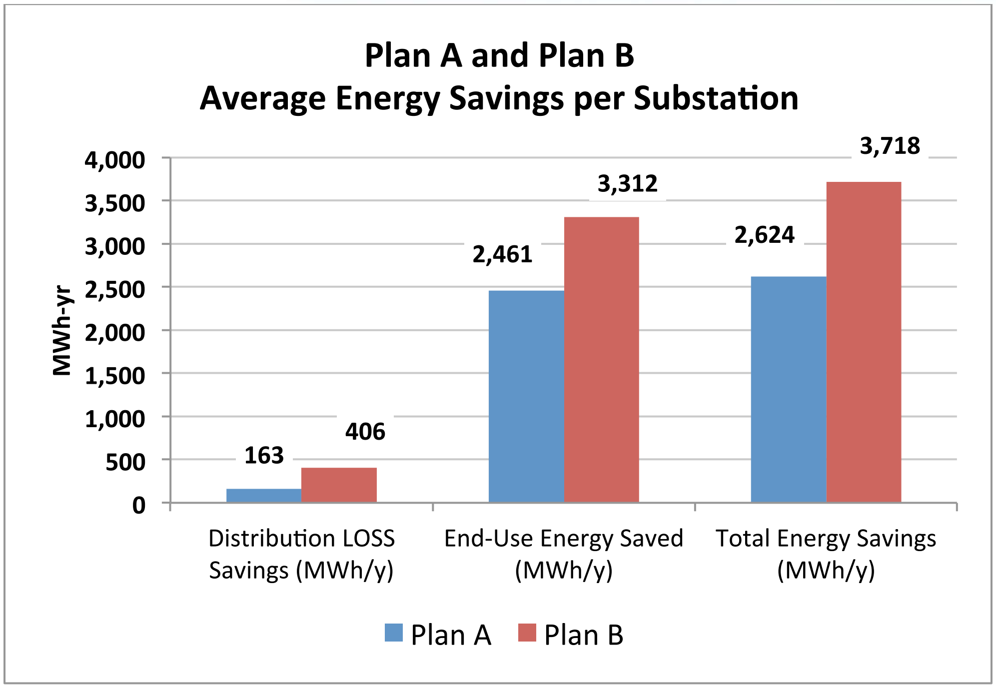


Figure 2 - Average Savings per Substation

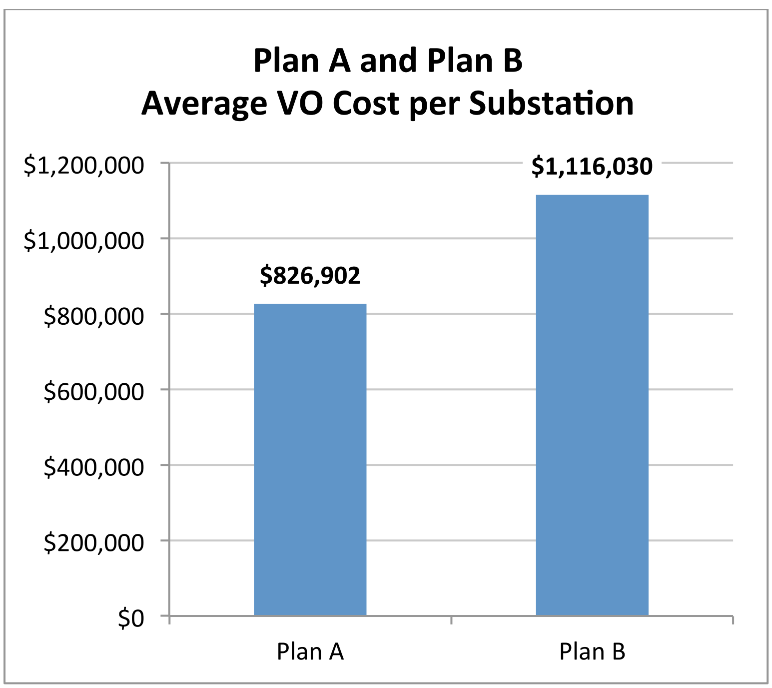
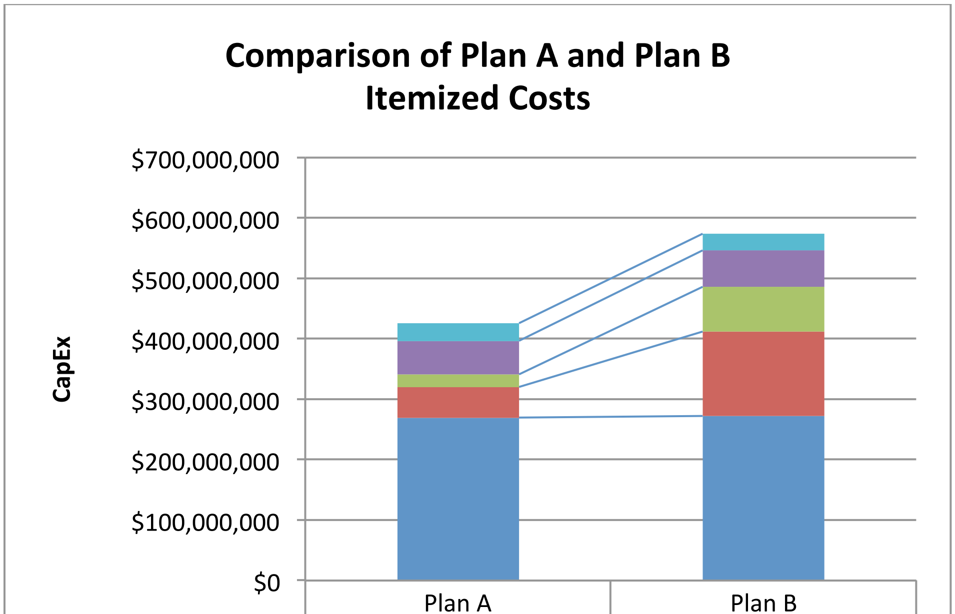


Figure 3 - Average VO Cost per Substation

Capacitor banks, both switched and fixed, represent the largest single capital expense (CapEx) item, accounting for over half of the total costs for both Plan A and Plan B. Voltage regulators and sensors are the next two largest expense categories. Additional voltage regulators and system upgrades (such as line reconductoring and phase upgrades) account for most of the additional Plan B costs. Integrated Volt/VAR Control (IVVC) is used primarily for isolating non-viable feeders with comparable costs in both plans. Figure 4 compares itemized VO costs for Plans A and B.



	Plan A	Plan B
IVVC	$28,708,191	$28,136,885
Sensors	$56,038,389	$60,404,979
System Upgrades	$20,336,883	$73,909,567
Voltage Regulators	$50,641,249	$138,897,955
Capacitor Banks	$269,742,165	$272,883,121

Figure 4 - VO Cost Itemization

A key study result is the screening and ranking of substations by VO cost and savings potential. This data can then be used to develop VO energy efficiency (EE) supply curves that present how much savings is available at a given cost. Figure 5 presents substation-based VO EE supply curves. While rankings were only developed for substations in the 14-region study group, the supply curves depicted in Figure 5 have been extrapolated to the system level.

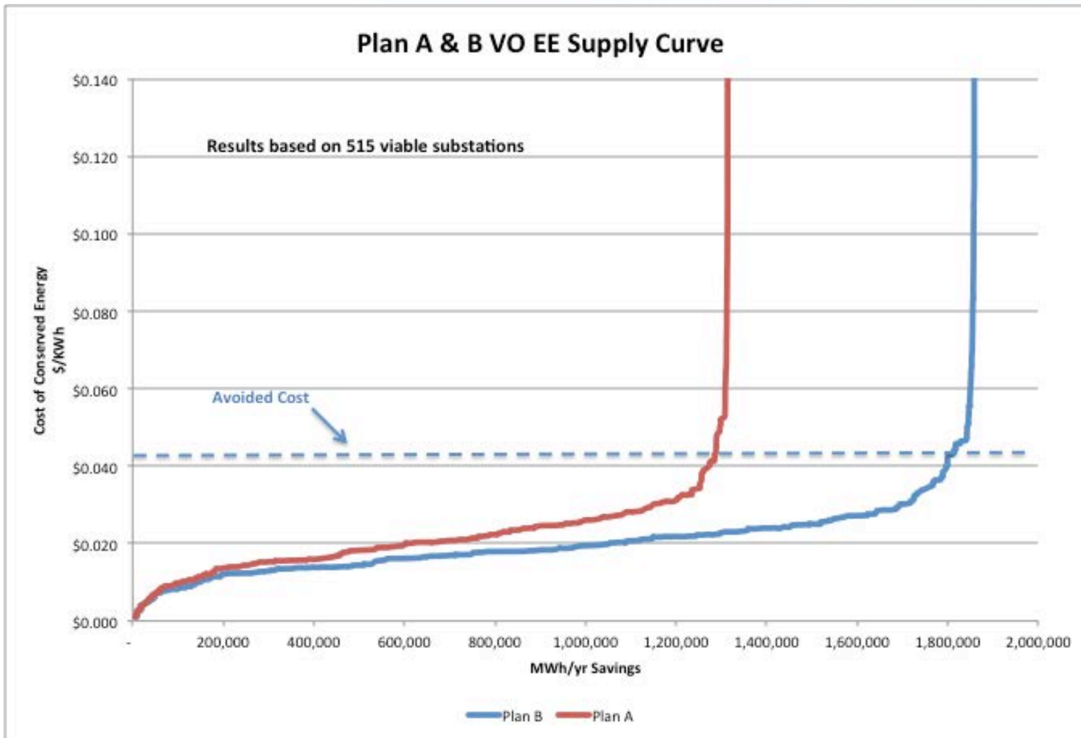


Figure 5 - VO EE Supply Curves

A key driver of the VO Feasibility Study was to assess the cost effectiveness of using VO to meet ICC EE program goals. Figure 6 provides an analysis of cost and savings potential in relationship to ComEd's 2014-2016 program goals. EE program data comes from ComEd's ICC filings for program years 2014, 2015, and 2016 and is based on total 3-year program costs and savings potential. VO cost and savings estimates are based on Plan B results and assume the entire VO program is implemented over the same 3-year period. This assumption may or may not be ComEd's actual implementation roadmap, but provides a basis of comparison between the two program types.

The key take-away from the chart is that VO has the potential to double ComEd's EE potential at a comparable cost to other EE program options.

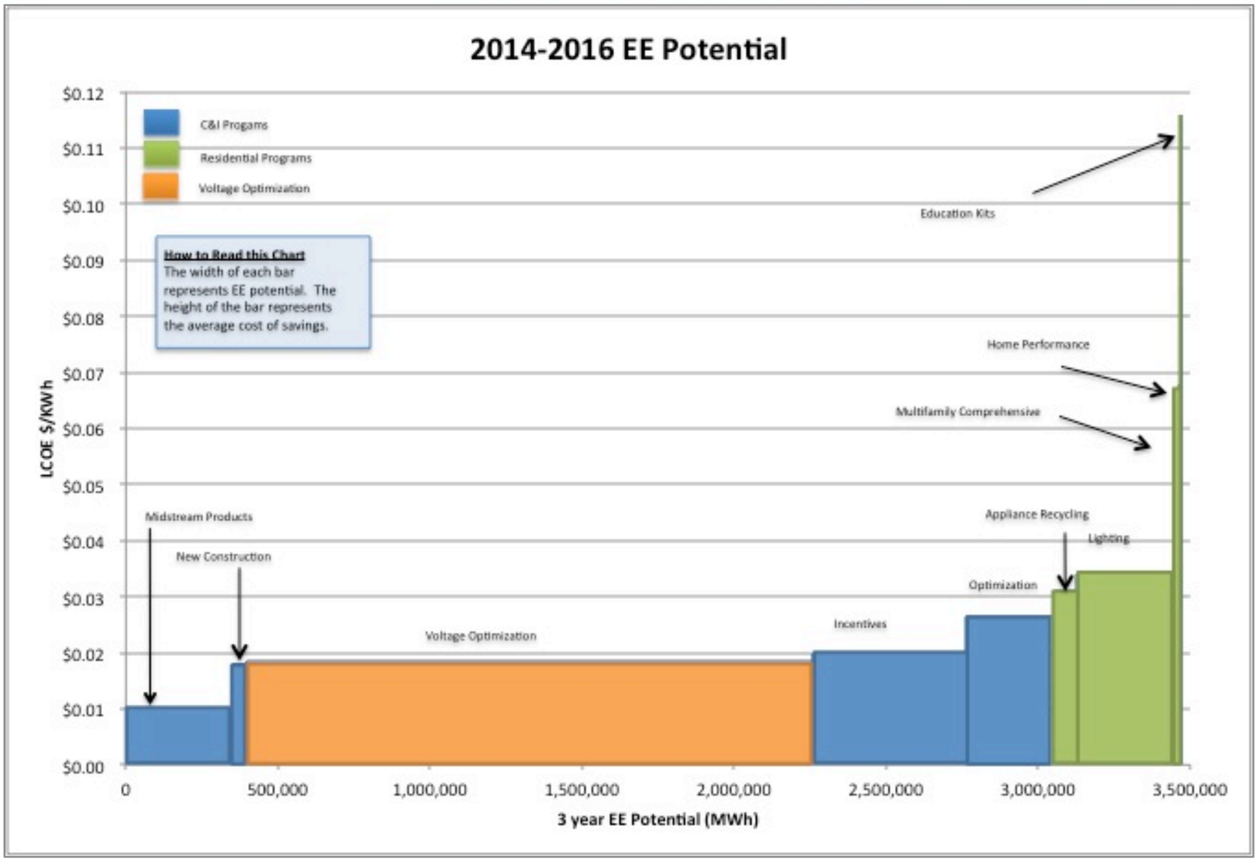


Figure 6 - EE and VO Benchmark Supply Curve

1.4 Key Recommendations

- Design/implement a VO staged deployment per the outline provided in Section 9.
- Develop and implement VO analysis training materials for distribution planning engineers, distribution operations personnel, and energy efficiency engineers. Recommended contents include engineering modeling assessments, economic analysis methods, capacitor placement methods, LTC/regulator/capacitor control settings, and annual volt/VAR maintenance and reporting procedures.
- Improve feeder VAR management with smaller capacitor banks (600 kVAR). Include VAR sensing and local control on all switched banks. Follow the Task 6 VAR application guidelines.
- Install EOL volt meters on every VO feeder and voltage control zone at the lowest voltage location to collect/transmit data and provide annual reporting of voltage performance.

- Examine AMI voltage/loading data to determine actual feeder voltage drop and load profiles. Results can be used to establish standards for addressing maximum allowable voltage drops (distribution transformer and secondary voltage drops) and minimum allowable primary voltages (i.e., 118.6 volts for an allowed 3.6 volt drop). Evaluate potential impacts (probability of customer transformers needing replacement) of primary voltages violating minimum standards. Revise transformer sizing guidelines based on this customer loading information.

- Maintain, correct, and/or upgrade GIS-CYMDist interface, software, and distribution system models at least annually or as needed.

2. Introduction

This report provides an overview of the approach used to perform a Voltage Optimization (VO) assessment of ComEd's distribution system to quantify energy savings potential (ESP) and associated cost impacts for each feeder. Prioritization methods, process steps, assumptions, and related formulations are described. A representative sample set of viable substation and feeder candidates (consisting of 16 substations and 47 viable feeders, down from 50, as explained in Section 7) are provided along with a method for extrapolating results to total system values. The process to develop "what-if" plans (Base Case, Plan A, and Plan B) for each viable feeder is described. VO thresholds used as the basis for feeder efficiency improvements are summarized along with application priorities and improvements rationale. VO staged deployment recommendations are described to verify M&V techniques, projected savings, and associated costs. Section 10 summarizes system-wide results, key findings, and recommendations for ESP, associated system improvements, ComEd standards, and operating practices.

The ComEd distribution system infrastructure and equipment database forms the basis for VO evaluation, which is obtained from ComEd's latest Geographical Information System (GIS), Transformer Load Management (TLM) System, Customer Information System (CIS), and Global Data sources. All initial screening evaluations are performed using Eaton's CYMDist load flow distribution analysis software assuming base case summer peak load conditions. Below is a summary of system and performance characteristics derived from the screening. All voltages are on a 120V base unless otherwise indicated.

2.1 General Distribution System Characteristics Investigated

- Distribution system includes a total of 5655 feeders (3757 feeders investigated)
- Total number of substations 806 (542 substations investigated)
- Number of viable VO feeders 1920
- Number of viable VO substations 346
- Investigated feeders serve 3.301 million customers
- Total number of residential customers is 2.897 million
- Total number of commercial customers is 406,658
- Total number of commercial customers <1MW is 406,658 and >=1MW is 271
- Average number of customers per feeder is 879
- Average feeder length to furthest point from source is 4.1 miles
- Average feeder has 4.9 miles of OH line and 4.3 miles of UG line
- There are 493 in-line voltage regulators connected or 0.13 regulators per feeder
- There are 4,650 shunt capacitors connected or 1.24 capacitors per feeders
- Average size of shunt capacitor banks connected is 1313 kVAR
- Total feeder summer peak load investigated is 16,699 MW and 4145 MVAR (lag)

- Total distribution transformer capacity is 52.683 million kVA
- Average distribution transformer loading is 35.0% of nameplate capacity
- Total distribution xfmr screened load is 18.428 million kVA.
- Total distribution xfmr screened load for residential is 9.023 million kVA.
- Total distribution xfmr screened load for commercial <1MW is 9.003 million kVA.
- Total distribution xfmr screened load for commercial >=1MW is 0.402 million kVA.

Note: *The number of commercial customers and amount of loads served for primary-fed services has not been identified for this initial screening evaluation.*

2.2 Feeder Performance Characteristics

- Length of overloaded conductor is 187.99 miles (approximately 0.3% of system total)
- Average feeder source load imbalance is 21.9%
- Average source feeder voltage setting average is 124.81V for substation bus.
- Average end-of-line lowest voltage is 120.5V three-phase and 120.1V single-phase
- All voltage regulation devices have no Line-Drop-Compensation (LDC) applied
- Substation voltage regulation bandwidths are 3.0V
- In-line voltage regulator average voltage setting is 125.0V
- In-line voltage regulators have volt bandwidths of 2.0V
- "Native" accumulated average volt-drop per feeder is 5.7V with no capacitors connected, all in-line volt-regulators on neutral tap, and 98% source power factor
- Average feeder average primary voltage is 123.68V

Note: *The amount of overloaded conductors of the 3757 feeders screened is based on power flows using conductor information from GIS and should be verified.*

Figure 7 summarizes the number of feeders served by each ComEd substation. Observations:

- 70% of ComEd substations serve 5 or less feeders.
- 15% serve between 5 and 15 feeders.
- 10% serve between 15 and 25 feeders.
- 5% serve more than 25 feeders.

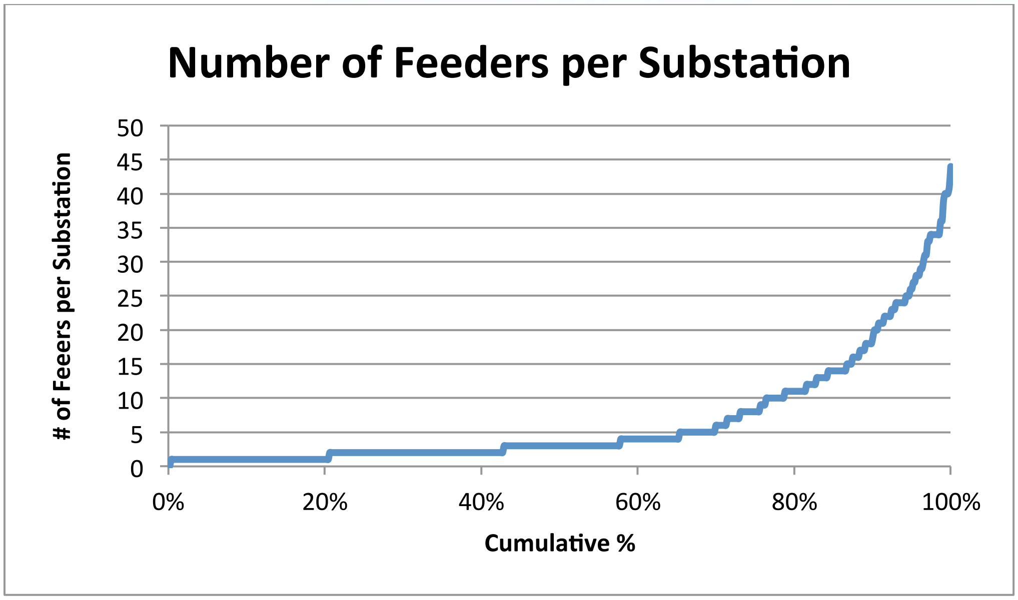


Figure 7 - Number of Feeders per Substation

The VO objective is to improve distribution system efficiency by cost-effectively managing voltages to maximize system loss reductions and end-use energy savings. Typical improvements include upgrades such as metering, load balancing (line reconfiguration, tap changes, minor phase upgrades and/or reconductoring), improved VAR (capacitor) management, and the addition of in-line voltage regulators. System efficiency also includes optimal loading and sizing of equipment for loss reduction, requiring long-range infrastructure improvements and replacements, expensive capital outlays, which are not included in this investigation. However, minimum upgrades to correct marginally overloaded lines or equipment are included.

An ideal (optimal) feeder can be described as one where an incremental change in power/energy NPV costs equals the incremental change in VO improvement NPV costs. Ideal feeder characteristics can vary between feeders and among utilities based on customer load type, cost of purchased power, and feeder electrical configuration. The following list describes ideal feeder characteristics based on Northwest Planning Conservation Council (NWPCC) Regional Technical Forum (RTF) VO M&V Protocol guidelines [5]:

- Source and in-line voltage regulator voltages near 119.0V for light load conditions
- Source and in-line voltage regulator voltages less than 124.0V for peak load conditions
- Primary minimum voltages near 119.0V for every hour of operation
- In-line voltage regulator bandwidths of 2.0V
- Source feeder load imbalance less than 20.0%
- Accumulated voltage drops for Voltage Control Zones (VCZ) less than 4.0V
- Primary line and distribution transformer no-load energy loss less than 2.0%

- Source reactive load near 100% compensated for every hour of operation
- Minimum allowed primary voltage 118.6V (assume 2.0V BW)
- Maximum allowed secondary voltage drop 3.6V (3%VD)

The analysis included development of ComEd-specific VO factors for summer and winter peak conditions. Factors were determined in Task 4 using empirical relations based on regional climate data and typical appliance mix by customer class.

All feeders served by a common substation or power transformer were evaluated as an integrated Voltage Control Zone (VCZ), since each feeder was impacted by the same source voltage regulator or LTC. Not all feeders can cost-effectively achieve performance thresholds. However, significant cost-effective savings are possible with some system upgrades.

Initial screening quantified performance indicators (Keywords) for each feeder (derived from load flow simulations) to identify viable feeder and substation candidates. Screening was based on summer peak load.

Before assessments could be performed, the following actions were required:

- Obtained feeder source MW and MVAR hourly data
- Determined residential and commercial VO factors
- Modeled and simulated (with CYMDist) distribution system feeder performance

The analysis tabulated the following major feeder characteristics to identify needed upgrades, approximate potential energy savings, and estimate implementation costs for each plan:

1) Identify and/or establish minimum allowed primary voltage.
2) Identify existing overloaded equipment and make appropriate corrections.
3) Improve source feeder load imbalance and reduce neutral currents.
4) Improve VAR compensation effectiveness to maintain near unity power factor 8760 hr/yr.
5) Reduce accumulated volt-drop for each Voltage Control Zone (VCZ) from source to lowest voltage point with additional VCZs (by adding voltage regulators).
6) Revise voltage control settings for source transformer LTCs and in-line voltage regulator to reflect the lowest maximum voltage necessary for peak loads and minimum voltage for light loads.

3. Data Collection Process

To facilitate the data collection process, a Global Data Request (GDR) template was populated with available system information needed for feeder VO prioritization and detailed sample feeder analyses. Included were the following data categories:

- General system information
- CYME and GIS database interface information
- Utility annual report and five-year capital information
- Distribution system equipment identifications and performance
- Planning and design voltage guidelines; planning and design loading guidelines
- Reactive load management VAR guidelines
- Distribution system metering
- Customer load data research information
- Distribution planning investment cost estimates
- Financial data assumptions

In addition to the GDR, the availability of specific distribution system data for the representative substations and feeders selected for more detailed VO analysis was captured using a set tables. Data included the following:

- General substation information
- Substation service area CYME and GIS database modeling data
- Substation equipment information
- Specific substation feeder information

The detailed data collection process followed a 3-step process as follows:

- Step 1: Check-boxes were marked by ComEd based on data availability using a set of interactive tables to simplify the collection process.

- Step 2: Data for a complete substation set (substation and feeders) was collected in the following formats: Draw File (.dwg), AutoCAD (.dxf), MS Word (.docx), MS Access (.mdb), PDF (.pdf), and/or Excel (.xlsx).

- Step 3: Additional data was requested as the needed during the analysis process.

All information was kept strictly confidential, with access limited to AEG project team members only.

4. VO Screening and Representative Feeder Selection

The steps below describe the screening process for VO energy savings, implementation costs (VO Costs), sorting of results, and selecting representative sample feeders/substations for detailed VO sample assessments.

Even though not part of the screening process, VO results extrapolation to total-system values is an important next step. As such, it is helpful to understand the context in which this occurs. Therefore, the extrapolation method is also provided below as Step 12.

Step 1 Perform an initial screening of all ComEd feeders to identify "viable" and "non-viable" feeder candidates. NOTE: Due to time and feasibility constraints, only 14 of the total 19 regions were included in the feeder screening process. The five regions that were not included will be statistically accounted for in the final results.

Step 2 Estimate potential VO energy savings (ESP) for each "viable" feeder.

Step 3 Convert energy savings per feeder to present value (PV) energy savings per feeder (ESP$).

Step 4 Estimate PV implementation costs per feeder (VO Costs). Allocate Class 1 non-viable feeder isolation costs to all other viable sister feeders on the same substation. Class 1 refers to feeders that have high amounts of commercial load or overloaded line miles. Class 2 refers to feeders where the voltage class is too high >25kV or too low <11kV or is network loop fed.

Step 5 Calculate the Benefit-Cost Ratio (BCR) and the Levelized Cost of Energy (LCOE) for each "viable" feeder candidate.

Step 6 Sort feeders by ESP. Rank each "viable" feeder consecutively from highest savings to lowest. The highest feeder rank (e.g., 4178) represents the highest energy savings potential. "Non-viable" feeders are listed but are ranked "zero" to signify they offer no cost-effective energy savings potential. Generate VO Energy Efficiency Supply Curves showing cumulative energy savings potential by LCOE.

Step 7 Group "viable" and "non-viable" feeders from **Step 6** by substation name. Each substation may include many feeders. Since feeders originating from a common substation bus have the same source voltage regulation, VO is best evaluated on a substation basis. Each substation is labeled with the total number of feeders, total potential energy savings, total costs, average energy savings per feeder, and average costs per feeder.

Step 8 Calculate total substation costs, average costs per feeder, and BCRs.

Step 9 Sort "viable" substation candidates by potential energy savings per feeder. Rank each "viable" substation consecutively from highest savings to lowest. The highest substation rank represents the highest energy savings potential per feeder. "Non-viable" substations are listed but ranked at "zero" to signify they offer no cost-effective energy savings potential.

Step 10 Group "viable" substations into four substation reference categories (or strata) by energy savings and cost per substation. Substations are divided by energy savings into categories of high-ESP$ and low-ESP$. They are further divided by substation costs of high-VO Costs and low-VO Costs. "Non-viable" substations are not included in the reference categories. The high-low VO Cost strata boundary is defined by the median VO Cost for all viable substations. The strata boundary for ESP$ is subsequently defined by the median ESP$ for low cost and high cost groups. This results in an equal distribution of substations in each of the four reference categories. The substation reference categories of high-low ESP$ and high-low VO Cost (HL, HH, LL, LH, listed in order of importance) are as follows:

HL Substations with high ESP$ >$1,474,535 and low VO Cost <=$362,267

HH Substations with high ESP$ > $1,474,535 and high VO Cost > $362,267

LL Substations with low ESP$ < $161,347 and low VO Cost <= $362,267

LH Substations with low ESP$ <$161,347 and high VO Cost > $362,267

Step 11 Select representative random substations from each reference category to include a total of 50 "viable" feeders (viable feeder final count was reduced from 50 to 47 as explained in Section 7, which did not significantly affect the sample design or precision). Due to the high variance of the number of feeders per substation in the reference categories (e.g., high ESP substations tend to be larger and have more feeders), the number randomly chosen substations for each category (strata) will vary. However, the number of feeders per strata will be somewhat consistent. This sampling method has two benefits: 1) It increases the VO estimation precision for the entire population, and 2) allows for statistical precision to be determined for each of the four strata.

Step 12 Extrapolate results from the sample substation VO detailed analysis to the entire system of reference categories. Extrapolation is not part of the screening process but is included here to better understand the overall process of how detailed sample assessment results are applied to the substation reference category sample frame. For each substation reference category, ratio adjustment factors for VO Cost and ESP are developed by comparing average feeder results from the sample to average feeder results from the population. Strata-specific ratio adjustment factors are then applied to the feeder results of the population, adjusting each individual feeder's VO Cost and ESP estimate up or down proportionally by substation, region, and total system. VO energy savings and costs are then recalculated based on ratio-adjusted feeder results. This extrapolation step is repeated for each sample VO option evaluated.

Feeder screening requires each feeder be assigned a relative VO potential savings and cost. These potential values are based on a set of formulations derived to fairly represent typical savings and implementation costs; and are applied independently to feeders, providing a robust method for comparing relative feeder potentials.

The formulations determine potential energy savings, costs, and BCR for each feeder. "Non-viable" feeder candidates have zero energy savings potential. The approach assumes cost-effective minimal upgrades as a VO pre-requisite. Formulations are described in the Task 3 final report.

4.1 Screening Results

A total of 14 regions, 3757 feeders (67%), and 542 substations (70%) were screened, providing a comprehensive representation of overall system conditions and performance. Table 2 lists ComEd regions screened with feeder and substation counts for each region. The exclusion of Chicago North does not materially affect the study results. A significant portion of the feeders are non-viable due to the following: 1) Rated 4kV and supply the low voltage grid (129 feeders); 2) Feed primary networks (200 feeders); and 3) Supply 1000kW or larger commercial loads (due to no sub-transmission being in the area) (many feeders).

Feeder prioritization summary results are shown in Table 3. Of the 3757 feeders evaluated, 1920 were classified as viable (51%) candidates and 1837 as non-viable. For the non-viable, 770 were Class 1 non-viable, and 1067 Class 2 non-viable. Class 1 refers to feeders with high amounts of commercial load or overloaded line miles. Class 2 refers to feeders where the voltage class is too high >25kV or too low <11kV or is network loop fed.

Highlighted key metrics include the following:

Total Feeders Classified	3757 Feeders . . . 100%
Viable VO Feeder Candidates	1920 Feeders . . . 51%
Non-Viable Feeder Candidates	1837 Feeders . . . 49%
Average Feeder BCR	1.05

Table 2 - ComEd Regions Screened

	Region	Screened	# Feeders	# Substations
			Adjusted to Match Study Group	
	Screened			
1	**Aurora DMC**	Yes	181	27
2	**Bolingbrook**	Yes	261	28
3	**Crestwood**	Yes	254	35
4	**Crystal Lake**	Yes	129	23
5	**DeKalb**	Yes	88	33
6	**Dixon**	Yes	110	45
7	**Elgin**	Yes	137	23
8	**Glenbard**	Yes	365	39
9	**Joliet**	Yes	282	59
10	**Maywood**	Yes	369	57
11	**Mount Prospect**	Yes	459	33
12	**Skokie**	Yes	458	63
13	**University Park**	Yes	53	27
14	**Chicago South**	Yes	611	50
			-----	-----
			3,757	542
			66%	67%
	NOT Screened			
1	**Freeport**	No	44	15
2	**Libertyville**	No	312	50
3	**Rockford**	No	197	36
4	**Streator**	No	59	35
5	**Chicago North**	No	1,286	128
			-----	-----
			1,898	264
			34%	33%
		SYSTEM TOTAL:	**5,655**	**806**

Table 4 provides a summary of average VO upgrade types per feeder. Figure 8 illustrates upgrades applied to feeders in Plans A and B. Average upgrade costs of $171,368 also include distributed Class 1 non-viable feeder isolation costs. Feeder isolation involves applying regulators, capacitors, Volt-VAR optimization, end-of-line voltage feedback control, and other feeder improvements to a Class 1 non-viable feeder (i.e., one serving large commercial loads). The isolation objective is to maximize the potential of viable feeder energy savings without impacting existing non-viable feeder voltage operation. Isolation upgrades prevent the non-viable feeder from becoming a limiting factor to sister viable feeders in a substation. Isolation costs are assumed to average $110,000 per feeder which are included in overall VO costs when evaluating substation energy savings potential.

Table 3 - Total System Feeder Prioritization Results

OVERALL SUMMARY OF FEEDER PRIORITIZATION RESULTS	TOTAL	AVG/FDR
Total Number of Feeders Investigated (#)	3757	
Number customers (#)	3,300,847	
Number residential customers (#)	2,897,055	771
Number commercial customers (#)	406,929	108
Number of Non_Viable Fdr Candidates for Volt Class Violation (#)	1067	28.4%
Number of Non_Viable Fdr Candidates for Lg Com Load & OL Line (#)	770	20.5%
Number of Viable Feeder Candidates (#)	1920	51.1%
Number of Cost-Effective VO Feeders >1,0 BCR (#)	1047	27.9%
Feeder VO Energy Savings (MWH)	728,642.4	380.0
Feeder VO Energy Savings PV COST ($)	$345,394,421	$179,893
Feeder VO Upgrades PV COST (w/ potential isolation costs) ($)	$329,051,314	$171,381
Feeder BCR (w/ potential isolation costs)	1.05	

SUMMARY OF NON VIABLE FEEDERS	TOTAL	
Number Non-Viable Fdr Candidates for Volt Class & Model Violation (#)--NV2	1067	28.4%
Number Non-Viable Fdr Candidates for Lg Com Load & OL Line (#)--NV1	770	20.5%
Total Number of Non-Viable Feeders (#)	1837	48.9%
Total Number of Viable Feeders (#)	1920	51.1%
Total Number of Feeders Investigated (#)	3757	
OBSERVED NON VIABLE FEEDER VIOLATIONS		
Substation Feeder Name=0, kW load<0, Acc VD<0, Sub=Unknown	145	NV2
Substation or Feeder Name "= NULL"	0	NV2
Number of Voltage Class ">NV_1"	292	NV2
Number of Voltage Class" <NV_2"	739	NV2
Number of Loop Feed "= NV_3"	0	NV2
Number of Sm Com Load too high ">NV_4"	136	NV1
Number of Lg Com Load too high "> NV_5"	198	NV1
Number of Res Customers too small "<NV_6"	926	NV1
Number of Sm Com Customers too high "> NV_7"	83	NV1
Number of Lg Com Customers too high ">NV_8"	198	NV1
Number of Overloaded LineMiles too high ">NV_9"	112	NV1

By treating the substation bus like a generation source, connected feeder voltages originating from this source can either be controlled by the source, line-specific equipment, reconductoring, or reconfiguration. If a dedicated line voltage regulator is added to a Class 1 non-viable feeder at or near the substation, the feeder "source" voltage can be raised or lowered with the regulator without impacting other viable sister feeders connected to the same source bus. Line-specific equipment can be added to non-viable feeder to correct power factor and other performance issues to maintain existing voltage operations. The resulting Class 1 non-viable feeder can then be operated essentially independent of sister feeders.

Table 4 - System Average Feeder VO Upgrades

AVERAGE VO ADDED UPGRADES for Viable Feeder Candidates	TOTAL	AVG/FDR
Volt-Regulator Additions (#)	1491	0.78
Reconfiguration Upgrades (#)	3115	1.62
Phase Upgrades (#)	162	0.08
Reconductor Upgrades (#)	52	0.03
Metering Additions (#)	1920	1.00
Fixed Capacitor Additions (#)	804	0.42
Switched Capacitor Additions (VAR Controlled) (#)	1611	0.84

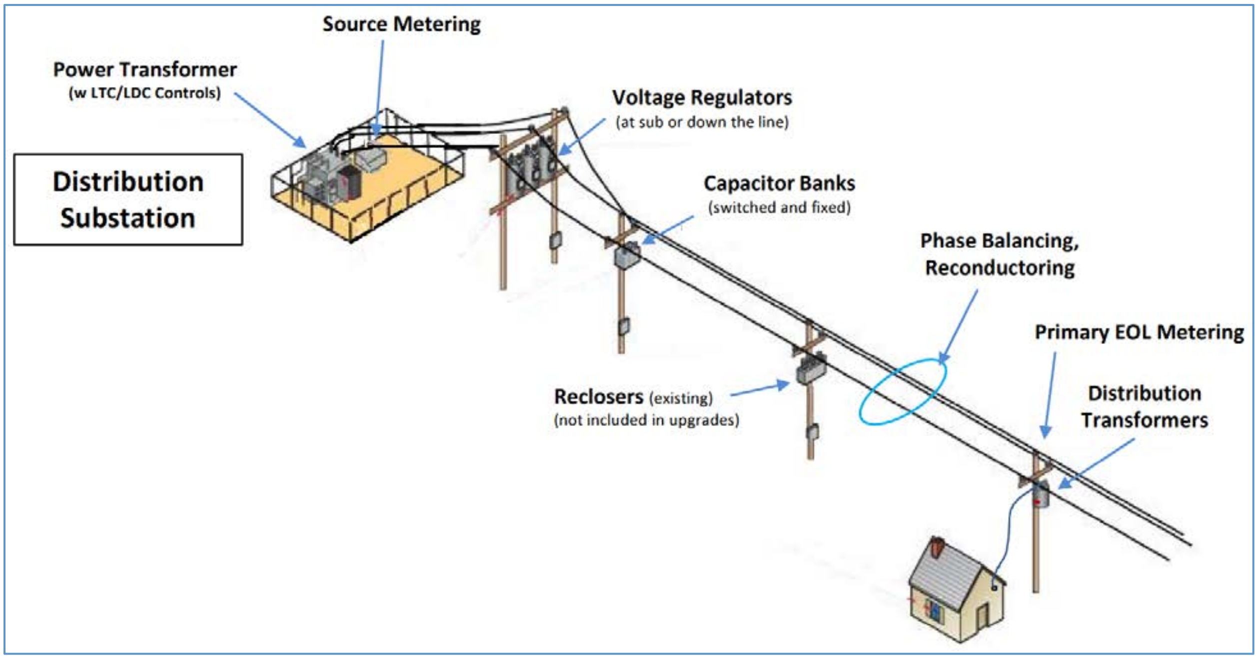


Figure 8 - Illustration of Efficiency Upgrades for Plans A and B

Initial screening energy savings potentials are shown in Table 5, suggesting there may be opportunities to lower the average voltage on viable feeders by 3.3% resulting in a savings of 380 MWh per feeder.

Table 6 summarizes total system statistics resulting from the CYMDist load flow simulations for the 14 screened regions. System totals and feeder averages are listed in the last two columns. The following are included: Total kW and kVAR loads, feeder power factor (after VO upgrades), feeder lengths, reactive loadings and connected capacitor banks, distribution transformer loadings, customer counts/types, phase balancing, voltages, and voltage drops. The average total voltage drop from substation to end-of-line is 5.7 volts. The detailed analysis investigates adding more upgrades to reduce this average drop. Table 7 provides a summary of all VO screening assumptions.

Table 5 - Summary of Initial Screening Feeder Energy Savings Potential

SUMMARY OF FEEDER ENERGY SAVINGS POTENTIAL	TOTAL	AVG/FDR
Average Voltage for Existing System (on 120 Base)	---	123.68
Average Voltage for VO Improved System (on 120 Base)	---	119.69
Average Change in Voltage (pu)	---	0.03326
VO Factor Weighted Average	---	0.66158
Distribution Transformer No-Load Loss Savings (MWH)	44,007.3	23.0
VO Energy Savings (MWH)	684,635.1	358.3
Total Feeder Energy Savings (MWH)	728,642.4	380.0
Total Energy Savings PV Benefit ($)	$345,394,421	$179,893

Table 6 - Total System Load Flow Simulation Summary Results

SUMMARY OF FEEDER SIMULATION RESULTS	Variables:	TOTAL	AVG/FDR
Feeder id (#)	KW_1	3757	
Total source peak real load (kW)	KW_7	16,698,863	4,446
Total source peak reactive load (kVAr)	KW_8	4,145,540	1,103
Source power factor ±%	KW_9		97.1%
Length of feeder (to furthest point from source) (mi)	KW_10	15,572	4.1
Total length of feeder OH (3ph is one unit) (mi)	KW_11	18,345	4.9
Total Length of feeder UG (3ph is one unit) (Mi)	KW_12	16,019	4.3
Number of inline 3ph (or 3-1ph) regulators connected (#)	KW_13	493	0.1
Number capacitors connected (#)	KW_14	4,650	1.2
Total reactive load for all customers (kVAr)	KW_15	5,580,424	1,485
Total capacitors connected (kvar)	KW_16	4,933,450	1,313
Total distribution transformer connected (kVA)	KW_17	52,683,444	14,023
Residential distribution transformer connected (kVA)	KW_18	14,350,384	3,820
Commercial distribution transformer connected (kVA)	KW_19	25,080,064	6,676
Total distribution transformer actual load (kVA)	KW_20	18,422,078	4,903
Residential customer actual load (kVA)	KW_21	9,018,477	2,400
Commercial customers actual load <1MW (kVA)	KW_22	9,001,703	2,396
Commercial customers actual load >=1MW (kVA)	KW_23	401,898	107
Number customers (#)	KW_24	3,300,847	879
Number residential customers (#)	KW_25	2,897,055	771
Number commercial customers (#)	KW_26	406,929	108
Number commercial customers with actual load <1MW (#)	KW_27	406,658	108
Number commercial customers with actual load >=1MW (#)	KW_28	271	0.07
Largest % conductor loading of max normal rating (%)	KW_29	594.6	106.0
Total length overloaded conductor > max normal rating (mi)	KW_30	187.99	0.05
Max normal MVA rating of source line section conductors (MVA)	KW_31		15.4
Source Ampere % imbalance phase current(%)	KW_32	333.3	21.90
Source operating voltage (120V base)	KW_33		124.81
Accum. total volt-drop "native" (120V base)	KW_34		5.7
Lowest 3ph avg voltage normal operation (120V base)	KW_35	88.3	120.5
Lowest 1ph avg voltage normal operation (120V base)	KW_36	85.7	120.1

Table 7 - VO Constants Used in the Screening Analysis

General Analysis

Distribution feeder annual load factor (pu)	0.350
Estimated residential VO Factor (weighted average for system wide) (pu)	0.610
Estimated commercial VO Factor (weighted average for system wide) <1MW (pu)	0.730
Distribution transformer no-load loss W per kVA (W)	3.0
Source & in-line volt-regulators with 32 step-volt tap changers with LDC capability	YES
Operation voltage bandwidth (V)	2.00
VO annual energy savings calculation based on NWPPC Simplified VO M&V Protocol	YES

Operations

Minimum allowed primary voltage (V)	118.5
Improved system source Volt setting (V)	119.00
Maximum accumulated volt-drop where no line regulation required (V)	5.00
Maximum accumulated volt-drop where one line regulation required (V)	7.50
Improved system accumulated volt-drop (V)	4.50
Improved system LDC volt-rise (V)	4.50
Maximum allowed source phase imbalance (%)	20.0%
Switched capacitor reactive compensation % of total var needs	66.7%

Implementation Costs - Fully Loaded *(See note below.)*

OH line reconductoring (3ph 336 MCM) ($/mi)	$225,000
New 3ph source regulator installation to isolate non-viable feeders ($/ea)	$110,000
New 3ph line 328A regulator installation (3 x 1ph units) ($/ea)	$63,000
OH & UG line reconfiguration modifications (line tap changes) ($/ea)	$2,000
OH line phase upgrade additions (1ph to 3ph) ($/mi)	$110,000
Fixed 600 kVAr capacitor additions or modifications ($/ea)	$5,500
Switching 600 kVAr capacitor additions or modifications with var control ($/ea)	$15,000
Source metering MW&MVAr additions per feeder ($/fdr)	$10,000
EOL Volt Metering (at lowest voltage location) 1 ph unit ($/fdr)	$3,000
Total length of added phase per feeder allowed (mi)	0.300
Total number of line reconfigurations allowed (tap changes)	10

Economic Analysis

Marginal purchase cost of avoided energy ($/MWh)	$42.00
Present value rate for energy & losses (pu)	6.9%
Annual inflation rate for energy purchase (pu)	3.0%
Planned efficiency VO program life (yr)	15
PV implementation cost adjustment to include O&M and Remaining Salvage value	1.25

Non-Viable Candidate

Nominal primary voltage > (kV)	26
Nominal primary voltage < (kV)	11
Source closed interconnection loop feed (Y or N)	YES
Commercial customers (actual load(<1MW) > (kVA)	7000
Commercial customers (actual load>=1MW) > (kVA)	0
Number of residential customers < (#)	50
Number of commercial customers (with actual load <1MW) > (#)	500
Number of commercial customers (with actual load >=1MW) > (#)	0
Total length of overloaded conductor sections (> max normal rating) > (mi)	0.40

<u>Note</u>: Screening and detailed assessments estimated the number of capacitors needed based on the assumption all feeders would be VAR compensated. Recommended capacitors per feeder are 600/kVAR units with switched capacitors being 66% (two-thirds) of the total. Capacitor placement was assumed to be optimal as described in Section 5 of this report. Capacitor costs were assumed to be overhead installations in all cases.

4.2 Sample Selection

The VO Feasibility Study research plan employs two types of VO estimation procedures: a) A simplified engineering analysis to estimate costs and energy savings potential for all non-screened "viable" feeders in participating regions of the ComEd service territory (n=1920); and b) detailed load flow simulations of feeder-specific VO implementation schemes on a representative sample of feeders. A key goal is the use of statistical sampling methods to extrapolate enhanced precision gained from the detailed analysis preformed on the sample of feeders to the more generalized cost and savings estimates derived for the general population of viable feeders.

4.2.1 Feeder Population Study Group

The feeder population study group represents the population of feeders in the ComEd service territory for which VO is feasible. The study group (sample frame) is a subset of all ComEd feeders and is defined as follows:

Total <u>System</u> Population:		5655
Less Non-Included Regions	(1898)	
Less Non-Viable Feeders	(1837)	
Total <u>Viable</u> Feeder Population Study Group:		1920

4.2.2 Substations and Feeders

It is typical for multiple feeders to be connected to and fed by the same substation transformer. As such, individual feeders are affected by "sister" feeders on the same transformer. From a modeling perspective, this means that feeders on the same substation transformers must be modeled as a group. As a result, substations, not feeders, are the primary sampling unit for the study. Individual feeder data are aggregated at the substation level to develop substation VO cost and ESP metrics as explained in Section 4. Statistically, this is referred to as cluster sampling – the substations each are a collection or "cluster" of feeders from the population, and it is not feasible to select individual feeders for the detailed analysis without including all feeders on the same substation bus.

4.2.3 Sample Stratification

Sample stratification has two purposes: 1) To reduce variability and thus increase precision of the population-level estimates of VO costs and savings potential; and 2) to better describe the characteristics of each stratum group.

The sample design consists of four strata: High and low VO costs; and high and low energy savings potential (ESP). Because the distribution of ESP values is very different for the low VO Cost and high VO cost groups, the ESP split within each VO Cost group is based on the substations in that group, resulting in different break points between low and high ESP. These strata (or reference categories) are defined as follows (based on total ESP$ and VO cost for each substation):

HH Substations with high ESP$ > $1,474,535 and high VO Cost > $362,267
HL Substations with high ESP$ > $1,474,535 and low VO Cost <= $362,267
LH Substations with low ESP$ < $161,347 and high VO Cost > $362,267
LL Substations with low ESP$ < $161,347 and low VO Cost <= $362,267

4.2.4 Sampling Method

A random sample of substations was drawn from each of the four strata. The number of substations selected in each stratum was a function of the number of feeders per substation. Substations were randomly chosen from each stratum, one at a time, until a threshold level of feeders was reached. In total, the project specified 50 viable feeders be included in the sample.

4.2.5 Sample List and Metrics

Table 8 summarizes the number of substations and feeders included in the sample. Table 9 lists all viable and non-viable feeders associated with each selected substation. Load flow simulations of feeder-specific VO implementation schemes will be run for each viable feeder. The results will be used to estimate feeder and total system VO potential.

Table 8 - Number of Substations and Feeders Included in the Sample

STRATA	# SUB-STATIONS	# FEEDERS	# VIABLE FEEDERS	AVERAGE FEEDER ESP	AVERAGE FEEDER VO COST	AVERAGE FEEDER BCR
HH	2	23	21	$142,370	$104,841	1.36
HL	6	15	11	$110,671	$97,207	1.14
LH	3	26	13	$90,201	$87,580	1.03
LL	5	6	5	$97,335	$105,156	0.93
Total	16	70	50			

Note: Viable feeder count was reduced from 50 to 47 as explained in Section 7, which did not significantly affect the sample design or precision.

Table 9 - List of Representative Feeders Included in the Sample

	SUB ID	FEEDER ID	Non_Viable Volt_Class=2 Large_Com=1 Networked=3	ESP MWH/YR	ESP PV$	VO Upgrade COST	STRATA (ESP-Cost)
1	TDC375	B7506	-	428	$202,679	$53,040	HH
2	TDC375	B7584	-	422	$200,194	$38,438	HH
3	TDC375	B7505	-	409	$193,892	$256,806	HH
4	TDC375	B7502	-	334	$158,205	$257,813	HH
5	TDC375	B7583	-	328	$155,712	$168,840	HH
6	TDC375	B7501	-	318	$150,706	$237,836	HH
7	TDC375	B7507	-	293	$139,009	$38,438	HH
8	TDC375	B7582	-	247	$116,991	$152,189	HH
9	TDC375	B7504	-	222	$105,055	$82,500	HH
10	TDC375	B7570	-	110	$52,205	$32,125	HH
11	TDC375	B7503	1	-	$0	$0	HH
12	TDC559	W599	-	471	$223,123	$59,580	HH
13	TDC559	W598	-	466	$220,700	$37,411	HH
14	TDC559	W595	-	429	$203,592	$134,606	HH
15	TDC559	W590	-	393	$186,228	$53,518	HH
16	TDC559	W592	-	366	$173,387	$132,484	HH
17	TDC559	W591	-	351	$166,236	$185,231	HH
18	TDC559	W593	-	342	$162,000	$114,188	HH
19	TDC559	W5911	-	302	$143,061	$46,364	HH
20	TDC559	W594	-	250	$118,643	$47,688	HH
21	TDC559	W5910	-	246	$116,548	$174,753	HH
22	TDC559	W596	-	182	$86,341	$107,500	HH
23	TDC559	W597	1	-	$0	$0	HH
24	DCB28	B285	-	172	$81,464	$95,000	HL
25	DCB28	B286	-	170	$80,753	$112,399	HL
26	DCD69	D690	-	403	$190,905	$100,634	HL
27	DCD69	D472	2	-	$0	$0	HL
28	DCD69	D470	2	-	$0	$0	HL
29	DCE71	E717	-	308	$145,863	$112,136	HL
30	DCE71	E718	-	305	$144,538	$249,840	HL
31	DCE71	E715	2	-	$0	$0	HL
32	DCE71	E716	2	-	$0	$0	HL
33	DCW148	W140	-	363	$172,003	$104,688	HL
34	DCW148	W142	-	340	$161,113	$201,250	HL

Table 9 - List of Representative Feeders Included in the Sample (Continued)

	SUB ID	FEEDER ID	Non_Viable Volt_Class=2 Large_Com=1 Networked=3	ESP MWH/YR	ESP PV$	VO Upgrade COST	STRATA (ESP-Cost)
35	DCW48	W4802	-	252	$119,639	$327,466	HL
36	DCW48	W4801	-	164	$77,843	$18,658	HL
37	DCW71	W712	-	531	$251,599	$16,250	HL
38	DCW71	W711	-	494	$234,348	$119,779	HL
39	DCW38	W386	-	360	$170,779	$256,991	LH
40	DCW38	W387	-	320	$151,809	$243,006	LH
41	SS513	W1313	-	467	$221,440	$170,782	LH
42	SS513	W1310	-	426	$201,991	$173,177	LH
43	SS513	W1312	-	311	$147,577	$111,253	LH
44	SS513	W1311	1	-	$0	$0	LH
45	SS513	W102	2	-	$0	$0	LH
46	SS513	W105	2	-	$0	$0	LH
47	SS513	W107	2	-	$0	$0	LH
48	SS513	W108	2	-	$0	$0	LH
49	SS513	W109	2	-	$0	$0	LH
50	SS513	W110	2	-	$0	$0	LH
51	TSS104	Z10440	-	483	$228,890	$143,990	LH
52	TSS104	Z10430	-	481	$228,073	$176,268	LH
53	TSS104	Z10441	-	447	$211,673	$200,500	LH
54	TSS104	Z10432	-	432	$204,825	$144,963	LH
55	TSS104	Z10437	-	421	$199,504	$228,911	LH
56	TSS104	Z10439	-	391	$185,216	$158,763	LH
57	TSS104	Z10438	-	313	$148,408	$141,598	LH
58	TSS104	Z10443	-	95	$45,050	$126,888	LH
59	TSS104	Z10434	1	-	$0	$0	LH
60	TSS104	Z10442	1	-	$0	$0	LH
61	TSS104	Z10433	1	-	$0	$0	LH
62	TSS104	Z10431	1	-	$0	$0	LH
63	TSS104	Z10435	1	-	$0	$0	LH
64	TSS104	Z10436	1	-	$0	$0	LH
65	DCE79	E791	-	255	$120,891	$68,594	LL
66	DCE79	E792	2	-	$0	$0	LL
67	DCH38	H385	-	108	$51,145	$91,813	LL
68	DCW17	W178	-	254	$120,624	$130,170	LL
69	DCW233	W332	-	290	$137,373	$223,473	LL
70	DCW73	W731	-	325	$153,976	$116,890	LL

5. Scenario Plan Case Development

5.1 Scenario Plan Development Objectives

Case scenarios, or plans, are needed for the "what-if" analysis of Task 6, where each case will be used to quantify potential energy savings and costs. A systematic approach will then be used to add/modify feeder equipment, and/or change system configurations/operations to define cost-effective plans that meet performance and economic constraints. The following plans will be developed:

- Base Case: **Meets** prerequisite performance thresholds by applying minimal system improvements to the Existing Case (as-is system conditions). Adjustments may have to be made to improve low voltage operations.
- Plan A: **Minimal** VO implementation costs; meets or exceeds VO performance efficiency threshold constraints; BCR[2] > 1. Plan A is the lowest cost plan that meets VO thresholds and is cost effective.
- Plan B: **Maximum** VO potential energy saved; meets or exceeds VO performance efficiency threshold constraints; BCR >1. Plan B is the highest energy saving scenario that meets VO thresholds and is cost effective.

Development begins by ensuring all performance thresholds are met. "What-if" scenarios are then designed to:

- Minimize primary voltage drops
- Reduce line and no-load losses
- Lower regulator/LTC voltage set points
- Consider alternative VO technologies

With reduced regulator/LTC set points, annual feeder average voltages will be lower, resulting in potential energy savings. Upgrades are added incrementally (in order of priority), with energy saving and cost impacts documented for each iteration.

[2] BCR = Benefit Cost Ratio

5.2 Performance Efficiency Thresholds

Performance efficiency thresholds establish conditions around which all cases can be developed. Thresholds were developed for ComEd-specific feeders based on NWPCC's Simplified VO M&V Protocol[3], establishing a foundation against which energy savings can be measured and verified.

Distribution feeder systems are considered inefficient if they have high hourly VAR flows; high voltage drops during peak load conditions; high amp-phase imbalances; high neutral currents; and voltages that violate ANSI C84.1 voltage standard ranges. Thresholds cannot always be met because of specific feeder characteristics. However, reasonable efforts can be made to closely satisfy the constraints.

Thresholds for this study include the following:

- Maximum hourly VAR flow of ±300 kVAR or hourly power factor > 97%
- VCZ[4] maximum primary voltage drop < 4.8 Volts (on 120 Volt base)
- Maximum phase imbalance < 25%
- Maximum neutral current < 50 Amperes
- Minimum EOL[5] voltage > 118.6 Volts (on 120 Volt base)
- Primary line conductor loading < 80% of maximum normal rating
- Primary line and distribution transformer no-load energy loss < 2%

5.3 Upgrade Priority

Successful VO implementations consistently report the order of upgrades is important when trying to optimize energy savings at the lowest cost. For example, low-cost improvements (such as load balancing) can greatly impact voltage drops, and should be done before considering higher-cost improvements (such as reconductoring). In a similar manner, adding or modifying capacitors to achieve near-zero VAR flow, reduces voltage drops all year and should be considered prior to higher-cost alternatives (such as voltage regulators).

Voltage-control threshold settings should be applied last, typically reducing source voltages from 125 volts to lower set points such as 119 volts using compensated R-settings. For properly VAR-controlled feeders, X-compensation may not be required.

Source metering (hourly MW and MVAR) and primary EOL metering (voltage) are needed on all feeders to assess ongoing performance against thresholds. Metering can be accomplished with

[3] Simplified Voltage Optimization (*VO*) M&V Protocol, NWPPC-RTF, Portland, OR May 4, 2010.
[4] VCZ = Voltage Control Zone
[5] EOL = End of Line

relays, regulator controls, or standalone meter sets.

Typical feeder improvements include the following 12 measures, listed in order of priority, from lowest cost (higher BCR[6]) to highest cost (lower BCR):

1. *Improve substation and feeder metering* – Identify substation metering improvements for power transformers and feeders (EOL voltages, and the load-side of line voltage regulators). Substation data collected includes hourly 3ph kWs and kVARs, and single-phase amps at substation voltage regulators. EOL (lowest voltage location) metering data includes hourly voltage data.

2. *Reconfigure (by switching)* – Reconfigure feeder by switching line sections from one feeder to another (to offload feeder) by opening and closing tie locations, and to offload adjacent line sections on the same feeder. This reduces line losses and primary voltage drops.

3. *Reconfigure (by tap changes)* – Reconfigure feeder sections (or transformer connections) from one phase to another to balance phase amps by relocating phase tap connections. This reduces line losses and primary voltage drops.

4. *Add or modify capacitors* – Add or modify fixed/switched capacitor banks to achieve optimal hourly VAR compensation (throughout the year). Switched capacitors minimize line VAR flow, reduce line losses, and reduce primary voltage drops. To determine the total amount of capacitors (fixed and switched), evaluate feeder annual VAR profiles.

5. *Add phase upgrades* – Add overhead and underground phase upgrades (1ph-to-2ph, 1ph-to-3ph, 2ph-to-3ph) to rebalance load and reduce voltage drops. This reduces line losses and primary voltage drops.

6. *Add line voltage regulators* – Add in-line voltage regulators to reduce primary voltage drops. Each regulator becomes a new VCZ for all feeder loads served downstream by the regulator.

7. *Reconductor line sections* - Replace heavily loaded conductors (above > 80% of normal maximum ratings) with larger capacity conductors. This reduces line losses and primary voltage drops.

8. *Replace distribution transformer/secondary systems* – Identify secondary systems where voltage drops exceed design targets and service voltages are less than 114V at peak. If low voltages occur before any improvements are made, the cost of the modifications should not be included in the total VO cost. However, if low voltages are due to reduced voltages from the VO alternative case, the cost should be included in the total VO cost. This enables lower

[6] BCR = Benefit Cost Ratio

voltage set points and reduces overall average system voltages. Typically, few transformer replacements will be necessary.

9. *Add new parallel feeders* – This reduces conductor loadings, system losses, and primary voltage drops.

10. *Install EOL feedback voltage sensing and control* – Substation load tap changers (LTCs), substation voltage regulators, and in-line voltage-regulator controls can be integrated with EOL voltage sensing to control feeder voltages. *For VO efficiency measures, these voltage feedback systems should only be applied after feeders are compliant with VO performance thresholds*. These real-time systems can provide operational intelligence for system dispatch and can be used where there is a large variation and/or fluctuation in load distribution and/or distributed generation. *EOL* voltage feedback sensing is used with line-drop-compensation (LDC) controls to provide added operational security. They can be best applied as feeder backup or "emergency" voltage control to avoid voltage violations. SCADA can be interfaced and integrated with these systems to provide capability for demand response and substation automation strategies. EOL feedback voltage control systems can help reduce overall average feeder voltages similar to non-feedback LDC systems.

11. *Install Integrated Volt-Var Control* (IVVC) – Volt-VAR applications attempt to control line voltages with capacitors and voltage-regulators. EOL voltage sensing is installed. *For VO efficiency measures, these voltage feedback systems should only be applied after feeders are compliant with VO performance thresholds*. IVVC systems integrate distribution model and load flow estimating algorithms to predict feeder voltages, amps, VARs, and loss performance. With some systems, the voltage can be controlled to the lowest level without violating power factor or EOL voltage constraints. Real-time systems work best when providing operational intelligence for system dispatch, and can be used where there are large fluctuations in load and distributed generation. They can be applied as feeder backup or "emergency" voltage control.

    IVVC control systems can reduce overall average voltages similar to what is possible with non-feedback LDC systems. However, for the typical application of residential and light commercial loads, in-line voltage-regulator LDC controls are more cost-effective for lowering average annual voltages. IVVC has distribution automation operational benefits other than VO that can necessitate/justify their use.

12. *Upgrade feeder to higher primary voltage class* – Feeders with a voltage class of less than 12kV are more likely to have higher system losses, higher conductor loadings, and higher voltage drops. Upgrading to a higher voltage class reduces line losses, conductor loadings, and primary voltage drops.

5.4 Plan Development Process

The as-is distribution system Existing Case is analyzed to determine load (annual MWh and peak kW) and no-load losses, and for compliance against performance thresholds. Minimal improvements are identified; i.e., minimum hourly VAR flow, maximum voltage drop, maximum phase imbalance, minimum EOL voltage, and no overloaded conductors. The upgraded system uses the same or similar voltage-control settings as the existing system. Adjustments may be needed to avoid low voltage operations. The upgraded system then becomes the VO Base Case from which all other alternative plans are measured. The Existing Case development process is shown in Figure 9.

Once the Base Case is established, Plan A and Plan B can be developed and measured against the following measures:

- VO performance threshold compliance.
- Change in system losses from Existing Case.
- Change in weighted annual average voltage from Base Case.
- Potential energy savings from Base Case.
- Present value cost of energy saved.
- Present value cost of upgrades, including threshold compliance upgrades.
- Resulting BCR.

Analyses of representative feeders are performed on a substation basis. All feeders served from the same voltage control bus (i.e., LTC or station voltage regulator) are considered to be in the same VCZ. Scenarios involving changes to VCZ regulator voltage set points impact all feeders served by that VCZ.

Plan A includes minimal investments to meet performance and BCR thresholds.

Plan B includes more investments to maximize energy savings while still meeting performance and BCR thresholds.

For each plan, energy savings and costs will be grouped by substation power transformer with all other feeders connected to the same VCZ. Once all substation assessments are complete, Plan A and Plan B results will be extrapolated to system totals.

This development process typically requires more engineering than traditional studies (which focus on maintaining reliability, avoiding equipment overloads, and preventing customer low voltages). As a guide, ten (10) assessment steps are performed sequentially (with some iterations required) until all thresholds and economic constraints are met, and optimal solutions found. The analysis process is shown in Figure 10.

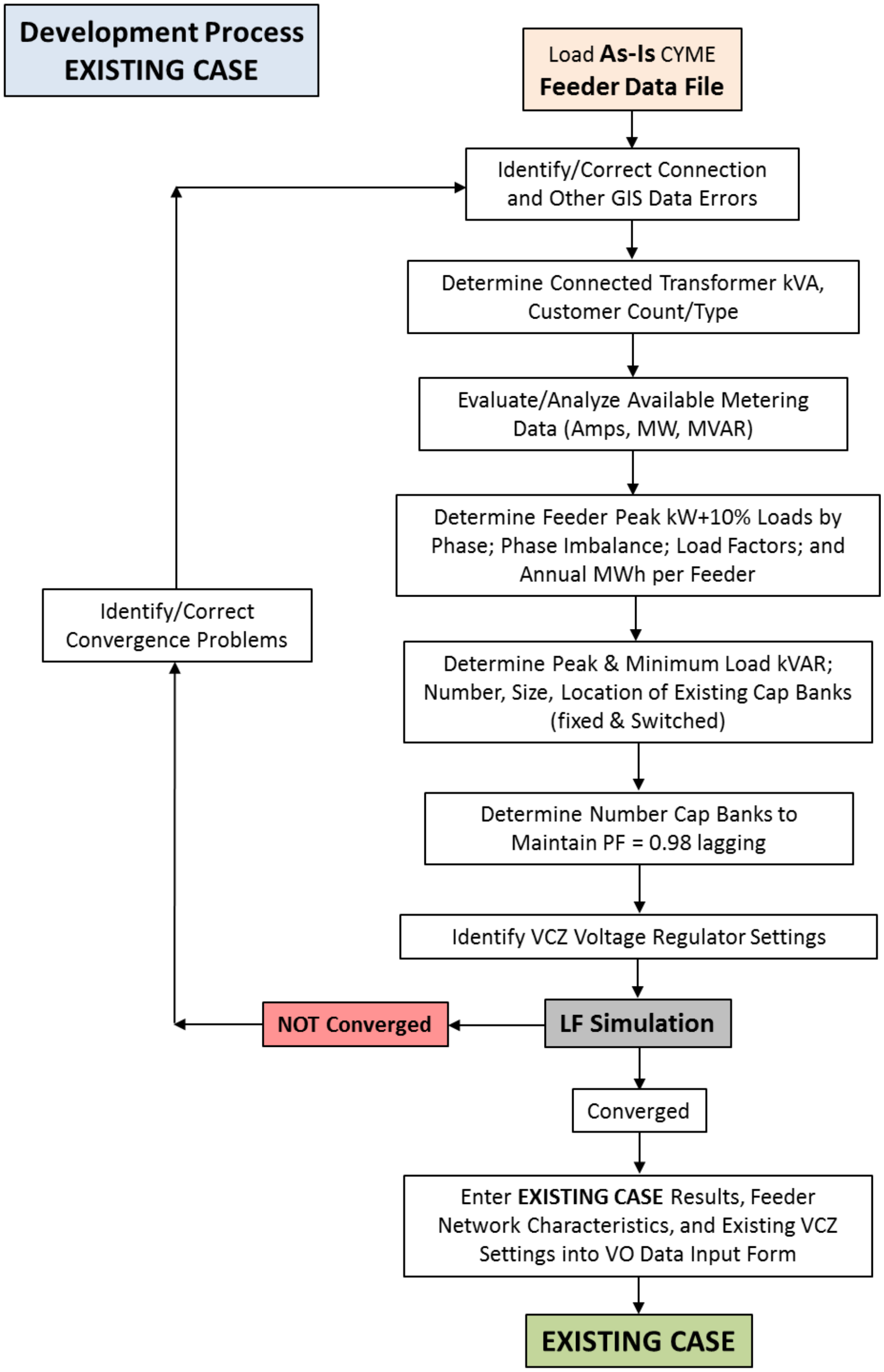


Figure 9 - VO Study Process for Existing Case

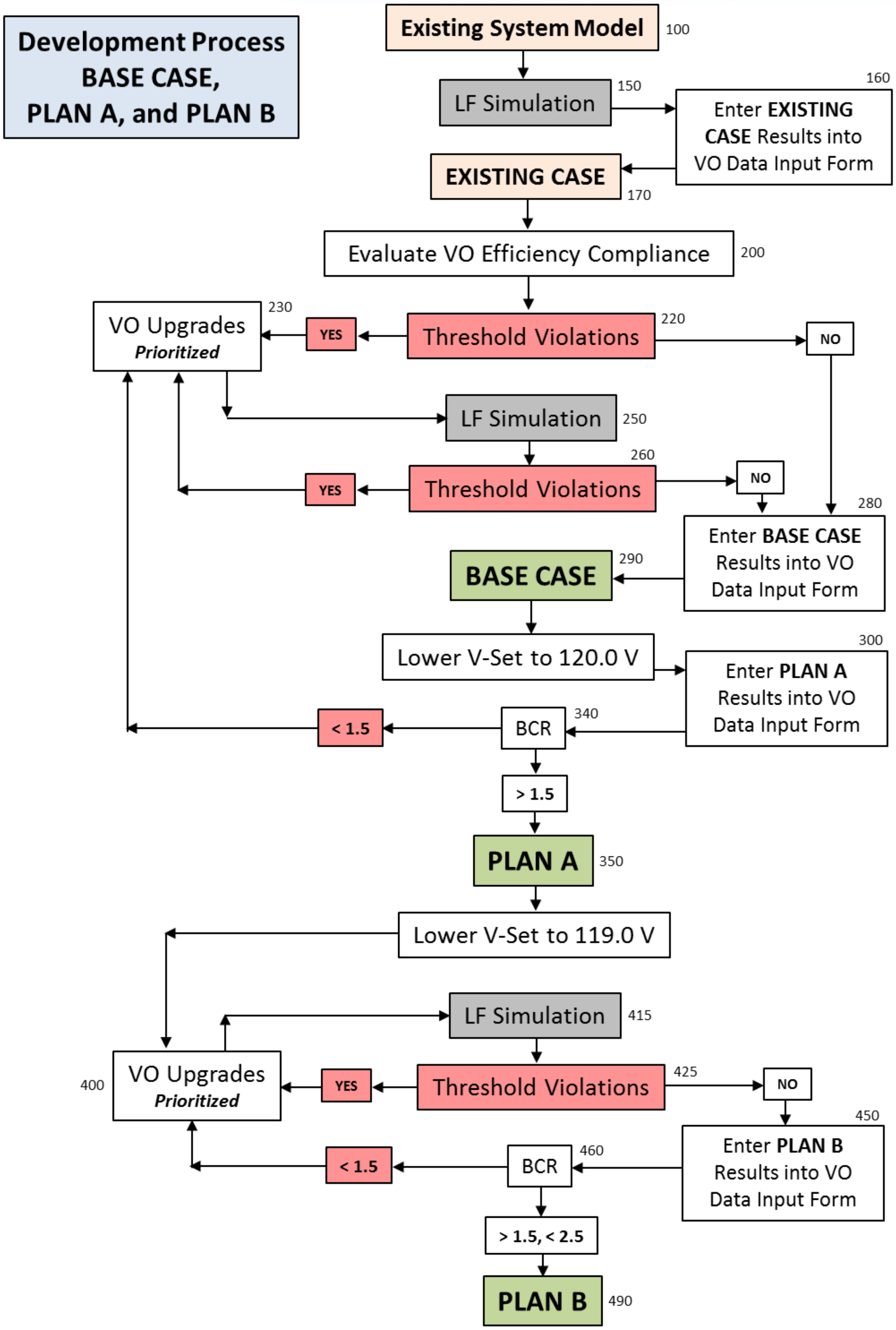


Figure 10 - VO Study Process for VO Simulation Cases

The <u>ten steps</u> follow:

1. Gather the following system information for each substation to be addressed:
   a. Substation transformer and feeder MW/MVAR hourly meter data.
   b. Substation transformer and feeder total annual load MWh.
   c. Feeder phase amp peak or hourly meter data.
   d. Substation one-line with transformer, regulators, breakers, and switches.
   e. Substation transformer nameplate MVA ratings.
   f. LDC control vendor, model, PT ratio, CT rating, V-Set, R&X, BW, & TD.
   g. Feeder capacitor bank control settings (volt, VAR, amp, time) and TD.
   h. Location of large customers (>1000 kW demand).
   i. Annual load factors for Winter and Summer peak conditions.
   j. MW and MVAR for Winter and Summer peak conditions.
   k. VAR management control strategies for existing system.
   l. Customer load characteristics for residential and commercial.
   m. VO factor (annual energy) estimates for typical residential and commercial customers.
   n. Utility construction and voltage drop standards.
   o. Economic analysis and DSMore assumptions.
   p. Energy and demand efficiency targets.
   q. Marginal cost of energy and demand.
   r. Existing voltage operational constraints.
   s. VO improvement unit costs.
   t. System topology mapping.
   u. Solved feeder CYMDist load models.

2. Prepare an **Existing Case** feeder model using CYMDist three-phase unbalanced load flow. All feeders common to the same VCZ should be analyzed together. Determine peak kW line losses for all feeders within the same VCZ for annual peak load conditions. Identify the amount of actual kVA for residential and commercial loads used to determine feeder VO factors.

3. Assess the **Existing Case** for compliance against performance thresholds for all feeders. Include voltage drop, phase amp balance, neutral current, minimum primary voltage, and minimum and average power factors (or VAR flows).

4. Create a VO **Base Case** by adding minimal system improvements to the Existing Case to meet performance thresholds. Feeders common to the same VCZ should be analyzed together. The Base Case uses the same or similar voltage control settings as the Existing Case. Adjustments may have to be made to improve low voltage operations.

The minimum allowed EOL voltage is 118.6V. Improvements typically include the following:

a. Reconfigure the feeder by switching load to adjacent feeders.
b. Reconfigure phases and connected transformers to balance load.
c. Add or modify capacitors (fixed and switched) to improve VAR management.
   - Determine the amount of fixed and switched capacitors needed and approximate locations based on annual VAR profiles.
   - The goal is to achieve near unity power factor for every hour of the year. Capacitor modeling is not necessary in CYMDist. Instead, 98% power factor is assumed for the load flow simulations.
d. Add minimal phase upgrades to improve EOL voltages.
e. Add line reconductoring to resolve line overloads.
f. Add necessary feeder metering upgrades.
g. Add necessary source and in-line voltage regulator LDC controls.

5. Determine and document the following using the "VO Data Input Form" application (Excel-based) for the **Base Case**:

   a. Threshold compatibility.
   b. Calculate net change in peak line kW losses and annual MWh losses between the Existing Case and Base Case (by running a Base Case load flow simulation).
   c. Determine VO upgrade investment costs for the Base Case.
   d. Determine VCZ max voltage settings (same as Existing Case).
   e. Determine VCZ max Volt-Drop and Volt-Rise (from Base Case load flow simulation).
   f. Calculate weighted annual average feeder voltages using VO M&V Protocol procedures.

6. Create a **Plan A** assuming the same performance thresholds as for the Base Case. Plan A represents the lowest-cost plan meeting efficiency performance and cost thresholds with BCRs greater than or equal to 1.0. Plan A has the same upgrades as the Base Case.

   VCZ voltage settings will be based on the feeder having the highest voltage drops during annual peak load conditions. VCZ Volt-Set points are at 120.0V with Volt-Drops the same as in the Base Case (VCZ Volt-Rise equals the Volt-Drop).

   Since the creation of Plan A is the same as for the Base Case, VO improvements are added to limit the maximum voltage drop for each VCZ to less than 4.0V, with the VCZ source-voltage control being the same as the Existing Case. For Plan A, LDC controls are applied to the source voltage using a setting of 120V.

   Determine and document the following using the "VO Data Input Form" application (Excel-based) for **Plan A**:

a. Document the maximum voltage drop for each VCZ.
b. Determine LDC control settings assuming 120.0V with R settings that result in the maximum Volt-Rise being equal to the maximum Volt-Drop.
c. Verify threshold compatibilities (should be no change from Base Case).
d. Identify and calculate net changes in line losses (same as Base Case).
e. Identify VO upgrade investment costs (same as Base Case).
f. Determine the weighted average substation area VO factor (pu).
g. Calculate weighted annual average voltage assessments for Plan A feeders using VO M&V Protocol procedures.
h. Calculate the change in average annual volts.
i. Calculate the change in feeder transformer no-load losses based on 3W per kVA and square-of-voltage change.
j. Calculate total energy saved between the Base Case and Plan A.
k. Calculated the PV cost of energy saved.
l. Calculate the PV cost of upgrades, including VO threshold compliance upgrades.
m. Calculate Plan A's overall BCR.

7. Proceed to Step 8 below if **Plan A** economic analysis results in a BCR that is greater than 1.5. Otherwise, revise/reduce Base Case upgrades and repeat Steps 4, 5, and 6 until the BCR is greater than or equal to 1.5.

8. Create a **Plan B** by adding more system improvements to increase energy savings. Plan B represents the highest energy savings potential plan. Additional higher-cost VO improvements will be made such as in-line voltage regulators, more phase upgrades, more reconductoring, and improved voltage control options (lower voltage settings, EOL line voltage feedback, IVVC controls, etc.).

   VCZ voltage settings will be based on the feeder having the highest voltage drop during annual peak loading conditions. VCZ Volt-Set points are reduced to 119.0V with the Volt-Drop same as the Base Case (VCZ Volt-Rise equals the Volt-Drop).

   Determine and document the following using the "VO Data Input Form" application (Excel-based) for **Plan B**:

a. Document the maximum voltage drop for each VCZ.
b. Determine LDC control settings assuming 119.0V with R settings that result in the maximum Volt-Rise being equal to the maximum Volt-Drop.
c. Verify threshold compatibilities (should be no change from Base Case).
d. Calculate net change in line losses (same as Base Case).
e. Identify VO upgrades investment costs (same as Base Case).
f. Determine the weighted average substation area VO factor (per unit).

g. Calculate weighted annual average voltage assessments for Plan B feeders using VO M&V Protocol procedures.
h. Calculate the change in average annual volts.
i. Calculate the change in feeder transformer no-load losses based on 3W per kVA and square-of-voltage change.
j. Calculate the total VO energy saved between the Base Case and Plan B.
k. Calculate the PV cost of energy saved.
l. Calculate the PV cost of VO upgrades, including VO threshold compliance upgrades.
m. Calculate Plan B overall BCR.

9. If **Plan B** results in a BCR less than 1.5, revise/reduce costs and/or reduce average voltage and repeat Step 8 until the BCR is greater than or equal to 1.0. If Plan B BCR is greater than 2.5, revise/increase upgrades and lower average voltages even more. Repeat Step 8 until the BCR is greater than or equal to 1.5 and less than 2.5.

10. Document results for each substation and feeder after **Plan A** (minimal investment) and **Plan B** (optimal investment) are determined. Include the following: Energy savings potential; total present value costs of investment and energy savings; average voltage change; change in system losses; and change in demand. Map savings to system load profiles for winter and summer periods to determine hourly demand impacts.

6. Detailed VO Analysis of Representative Feeders

6.1 Objectives

Satisfying minimum distribution feeder performance criteria is an important pre-requisite to applying voltage reduction measures.

The process begins by assessing the existing system for VO efficiency threshold compliance. Improvements are implemented sequentially (with some iteration) until all thresholds and economic criterion are met. The analysis methods were based on the concept of average system voltages as defined and developed by the NWPCC Regional Technical Form Committee May 2010 [14]. Total energy savings consist of two components: 1) End-use efficiencies on customer side of the service meter (energy savings); and 2) System loss reductions on ComEd's side of the meter (system loss savings).

Two alternative VO plans were developed (Plan A and Plan B) with potential energy savings, upgrade costs, and demand reductions identified for each.

Plan A represents the minimum cost to comply with VO efficiency performance thresholds and achieve BCRs >1.5. Results indicate energy savings can be as much as 60% of the total potential. Plan A voltage margins are higher than Plan B.

Plan B represents the maximum potential energy saved while meeting VO thresholds and achieving BCRs between 1.5 and 2.5 (1.5 < BCR < 2.5). The optimum solution is not always possible or practical due to the system configuration constraints, marginal changes to energy saved, and high costs. Plan B voltage margins are lower than Plan A.

6.2 Load Flow Simulations

The CYME electric distribution load flow program[7] was used to analyze the distribution feeders. Existing as-is feeder models were corrected with the aid of ComEd personnel to satisfy minimum performance thresholds.

CYMDist models single-phase or three-phase radial or looped systems for the following conditions:

- Load balancing
- Load allocation and load estimation
- Optimal capacitor sizing and placement
- Optimal voltage regulator placement

[7] The program used was CYME Power Engineering Software., part of Cooper Power Systems, Division of Eaton, cymeinfo@eaton.com.

- Cable ampacity
- Real time analysis
- Integrated Volt-VAR modeling and control

It was assumed ComEd models were reasonably up to date and accurately reflects real world conditions. Simulations where performed for the as-is system (Existing Case), an improved Existing Case to meet VO thresholds (Base Case), and an expanded VO upgrade case (Plan B). Plan A has same system configuration as the Base Case except for lower voltage set points and LDC applications.

Most feeder source voltages are fixed at 124.8 Volt (104% of nominal 120 Volts). Some are 124.5 Volts. Load simulations were performed using peak kW load data obtained from forecast information or the CYMDist database model plus 10% at 98% power factor lagging. All feeder-connected capacitors were disconnected. In-line volt-regulators were set at 124.8 Volt with bandwidths at 0.8 Volts. Substation modeling was not performed. It was assumed all necessary feeder capacitor banks were modified and/or relocated to achieve a near zero VAR flow of ± 300 kVAR for all hours. Capacitor improvement costs are included in Base Case upgrade costs.

As data is available with feeder phase amps, MW and MVAr phase demands, and/or MW and MVAr hourly load profiles. The peak load and phase contributions were assigned to each feeder.

6.3 Conductor Types and Loading Guidelines

Feeders with voltage classes of 12.47 kV and 13.2 kV were investigated. ComEd loading guidelines for primary overhead conductors and underground cables were used to evaluate conductor and cable performance. Feeder conductor and cable capacity ratings were incorporated in the CYMDist models.

Conductors commonly used for new overhead primary line construction are shown in Table 10. Conductor capacity ratings for normal (N) and emergency (E) conditions are given. Other conductors used are listed in ComEd Standard ESP_5.3.7.1.

Applications are provided to assist in the selection of underground cables in ComEd Standards ESP_5.3.8.2 and ESP_5.3.8.4.

Table 10 - OH Conductors Commonly Used for Primary Lines

CatID	Description (Note 1)						Application (Note 2)			Thermal Capability in Amperes (Note 3)			
	Size	Covering	Metal	Temper	Stranding	Lbs/ 1000 ft.	4 & 12.5kV	34kV	Neutral	Summer		Winter	
										N	E	N	E
0000357054	477	B	AAC	HD	19	448	●	●		765	925	965	1090
0000357220	4/0	B	AAC	HD	7	198	●	●		475	605	580	680
0000357906	1/0	B	AAAC	T81	7	116	●	●	●	335	420	405	475

Table 11 provides representative 15 kV class underground cable capacity ratings for normal and emergency conditions. Additional cables used are listed in Standard ESP_5.3.8.2.

ComEd Standard AM-ED-3007 describes the methodology used to adjust historical distribution system loads to a level that would be expected during design weather conditions. The design weather level is specified so that adequate capacity will be available during infrequent, but realistic extreme hot weather conditions.

Distribution Capacity Planning Guidelines (Standard AM-ED-Y013_R0001) to provide guidelines for load forecasting, area planning considerations, voltage regulation, and reactive planning. For this study, the maximum conductor loading allowed is assumed for normal summer conditions.

Table 11 - UG Cables Commonly Used for Primary Lines

Size and Material	Rated kV	Insulation and Covering	Catalog ID Number	Outside Diameter Inches	Min. Bend Radius Inches	Weight Lbs./Ft.	R~ 60Hz Ω /1000'	X_L~60Hz Ω /1000 '	Norm In Duct (2)	Emrg In Duct (2)	Norm Buried	Emrg Buried
350 CU	5	EXL	0000360831	2.77	17	10.35	0.037	0.036	360	450	400	470
#4 CU	15	EXL	0000360804	0.88	9	1.33	0.290	0.034 (5)	125	-	135	155
#4 CU	15	EXL	0000360814	1.90	12	3.99	0.290	0.051	125	-	135	155
1/0 CU	15	EXL	0000360313	1.01	11	1.71	0.116	0.027 (5)	150	180	225	250
1/0 CU	15	EXL	0000360314	2.18	14	5.13	0.116	0.044	150	175	225	250
4/0 CU	15	EXL	0000360315	1.16	12	2.40	0.059	-	255	300	315	365
4/0 CU	15	EXL	0000360316	2.50	15	7.20	0.059	0.039	255	300	315	365
500 CU	15	EXL	0000360317	1.52	16	3.68	0.027	-	425 (6)	490 (6)	490	580
500 CU	15	EXL	0000360318	3.28	20	11.04	0.027	0.035	425 (6)	490 (6)	490	580
#4 CU	15	EXLJ	0000360857	2.13	13	4.01	0.290	0.051	125	-	135	155
1/0 CU	15	EXLJ	0000360326	2.42	15	5.15	0.116	0.044	150	175	225	250
4/0 CU	15	EXLJ	0000360344	2.74	17	6.93	0.059	0.039	225	300	315	365
500 CU	15	EXLJ	0000360320	3.47	21	12.12	0.027	0.035	425 (6)	490 (6)	490	580
#2 SOL AL	15	EXCCJ	0000361045	.96	8	0.38	0.282	0.030 (5)	125	-	135	155
#2 SOL AL	15	EXCCJ	0000361046	2.07	11	1.14	0.282	0.052	110	-	135	155
#2 STRD AL	15	EXCCJ	0000361051	1.05	8	0.54	0.287	0.028 (5)	125	150	125	150
#2 STRD AL	15	EXCCJ	0000361052	2.27	11	1.7	0.287	0.052	110	150	125	150
3/0 AL	15	EXCCJ	0000361043	1.21	10	0.87	0.115	0.024 (5)	-	-	225	240
3/0 AL	15	EXCCJ	0000361032	2.60	13	2.6	0.115	0.041	188	240	165	265
750 AL (10)	15	EXCCJ	0000361033	3.91	20	5.4	0.029	0.034	365	515	390	625
750 CU	15	EXCCJ	0000361026	3.91	20	10.2	0.019	0.038	425	600	415	665
750 CU LSZH (8)	15	EXCCJ	0000361029	3.91	20	10.2	0.019	0.038	425	600	415	665

6.4 VO Improvement Costs

Distribution system capital equipment and installation costs depend on ComEd accounting practices, material requisition arrangements, labor costs, and general overheads. For this study, equipment VO installation costs are consistent with ComEd experience and previously used for VO screening assessments. System improvement costs are similar to those used for the scoping study. Depending on the plan chosen, the actual installation costs will be needed for final VO valuation. Assumed VO upgrade costs are shown in Table 12, which are based on market-based equipment costs times a 1.5 fully-loaded cost adder.

In addition to routine distribution equipment installations, this study considered EOL voltage feedback sensing and control as well as Integrated Volt-VAR Controls (IVVC). It was assumed that one IVVC controller is added at the substation for each non-viable feeder with EOL voltage sensing. In some cases, IVVC, EOL voltage feedback, and Volt-VAR control capacitors were applied to non-viable feeders to isolate them from the substation power transformer voltage control zone and maintain higher voltages for commercial customers. The amount of switched VARs added to non-viable feeders depends on the amount needed to raise feeder average voltages by 2 volts. Figure 11 shows a typical IVVC application to isolate non-viable feeders from sister feeders in the same voltage control zone.

Table 12 - VO Upgrade Unit Costs

Upgrade	Unit Costs
OH line reconductoring (3ph 336 MCM) ($/mi)	$225,000
New 3ph source voltage regulator installation to isolate non-viable feeder ($/ea)	$110,000
New in-line 328A voltage regulator (3 x 1ph units) ($/ea)	$63,000
OH & UG reconfiguration modifications (line or transformer tap changes) ($/ea)	$2,000
OH line phase upgrade additions (1ph-to-3ph) ($/mi)	$110,000
Fixed 600 kVAR capacitor bank addition or modification ($/ea)	$5,500
Switching 600 kVAR capacitor bank addition or modification with VAR control ($/ea)	$15,000
Feeder source and in-line voltage regulator metering MW & MVAR ($/VCZ)	$5,000
EOL voltmeter (at lowest voltage primary location) 1ph unit ($/VCZ)	$3,000
Source and voltage regulator control and EOL voltage feedback sensing ($/ea VCZ)	$4,500
IVVC substation controller ($/ea)	$50,000

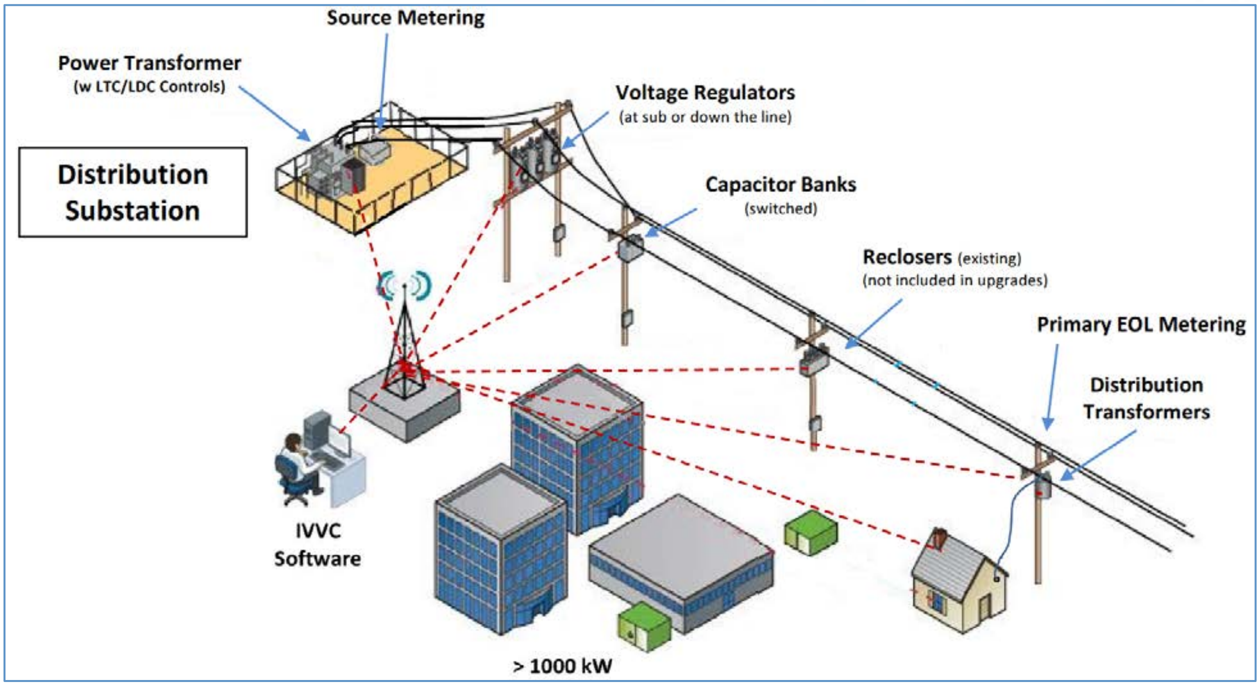


Figure 11 - Typical IVVC Application to Isolate Non-Viable Feeders

6.5 Economic Evaluation Approach and Financial Factors

Financial and economic factors used are given in Table 13. The avoided marginal cost of purchased power is $0.042/kWh for the base year 2014 with an energy cost inflation rate of 3.0% per year thereafter. The assumed minimum allowable BCR for ComEd is 1.00. Energy efficiency incentives are not included in the analysis. The energy savings program life is 15 years. Equipment life is assumed to be 33 years. A net salvage value was present worthed back to 15 years to compensate for the difference in years. The economic evaluation[8] of regional generation, transmission grid, and CO2 impact benefits and cost impacts as a result of ComEd VO implementation was not performed.

The objective of the economic analysis was to find an implementation plan that maximizes net energy savings while meeting permissible BCR targets. For this study, low cost solutions are those that meet minimum VO thresholds with BCRs greater than 1.5. High energy saving solutions are those with BCRs between 1.5 and 2.5. These targets are ideal and not always practical to achieve.

[8] The detailed economic analysis was performed using principles described in D. G. Newnan, T. G. Eschenbach, J.P. Lavelle, *Engineering Economic Analysis, Ninth Edition, 2004*.

The economic analysis estimates first-year VO investment costs, net present value of annual fixed charges and O&M expenses, net present value of remaining equipment life value beyond program life, and total improvement investment net present value. The benefits and costs are estimated for the net present value of system upgrades, and energy and demand savings for the life of the VO measures. The VO measure program lives are 15 years for energy savings (end-use savings) and 33 years for the system loss savings (ComEd system savings). A lump sum payment of 10% of initial VO investment is assumed in the tenth year. The program life can be extended indefinitely with: ComEd engineering, design, operations, and equipment application standards; additional 10% lump sum payments every ten years; continued annual O&M expenses, and annual capital VO investment sinking fund costs to replace VO capital improvements.

Table 13 - Financial Factors

Minimum Permissible Benefit-Cost-Ratio BCR (p.u.)	1.0
Capital Equipment Life Expectancy (yr)	33.0
Planned life of Energy Savings (yr)	15
Capitalized Annual Fixed Charged Rate (pu)	11.0%
Annual Inflation Rate for kW Demand (%/yr)	3.00%
Annual Inflation Rate for kWh Energy (%/yr)	3.00%
Annual Inflation Rate for Investment (%/yr)	3.00%
Annual Inflation Rate for O&M (%/yr)	3.00%
Marginal Purchase Demand Rate ($/kW/yr)	$0.00
Marginal Purchase Energy Rate ($/kWh)	$0.042
Annual Operation and Maintenance Expense (%/yr)	2.00%
Present Worth Rate for Cost of Energy & Losses (%/yr)	6.90%
Present Worth Rate for Cost of Investment (%/yr)	6.90%
Maintenance Lump Sum Amount in Future Year (%)	10.00%
Maintenance Lump Sum in Future Year (yr)	10
PV Credit for Remaining Salvage Value (Y or N)	Y

6.6 VO Factor Application

The Voltage Optimization factor (VO factor) is a key parameter in estimating the energy savings potential of VO deployments. The VO factor is a ratio of the change in annual energy use to the change in annual average voltage measured at the distribution transformer and calculated according to the following equation:

$$VO_{Factor} = \frac{\%\Delta E}{\%\Delta V}$$

Where:

$\%\Delta E$ = Change in customer energy consumption
$\%\Delta V$ = Change in annual average voltage at the distribution transformer

Annual energy VO factors are developed for residential, commercial, and industrial loads within ComEd's service territory. VO factors were developed in Task 4 by incorporating feeder characteristics such as load composition, voltage performance thresholds, and customer class. Table 14 provides examples of common end-use load types.

Table 14 - Common End-Use Load Types

Load Type	End Uses
Constant Impedance	Incandescent lighting, resistive water heaters, electric space heat, electric stoves, clothes dryers
Constant Current	Welding units, electroplating processes
Constant Power	Motors (at rated load), Power supplies, Fluorescent Lighting, washing machines

Although the end-use load mix for each customer class changes over time, the largest loads typically remain constant (i.e., HVAC, water heating, lighting and electronics). The annual profile has a summer peaking characteristic. Less than 10% of residential and commercial customers apply electric space heating. For the 56 sample feeders investigated, no commercial loads greater than 1000 kW demand and no industrial customers were included.

Energy VO factors by customer class assumed for this study are shown in Table 15. VO factors represent a per unit change in energy to per unit change in average annual voltage. Weighted VO factors were calculated for each feeder based on the residential and commercial kW actual load and associated customer class. Weighted VO factors for substations are the weighted VO factors of the feeders served by the substation. Table 16 summarizes calculated weighted average VO factors for each substation investigated.

Table 15 - Global Energy VO Factors by Customer Class for ComEd Study

Customer Class	Energy VO Factor
Residential	0.69
Commercial	0.90
Industrial	0.47

Table 16 - Substation Annual Energy Weighted VO Factors

Sub Id	Global VO Factor Res	Res Actual kVA Load	Global VO Factor Sm Com	Sm Com Actual kVA Load	VO Factor (weighted)
DCB28	0.69	3,369	0.90	1,424	0.752
DCD69	0.69	1,428	0.90	4,129	0.846
DCE71	0.69	7,196	0.90	3,472	0.758
DCE79	0.69	6,440	0.90	404	0.702
DCH38	0.69	2,036	0.90	1,020	0.760
DCW38	0.69	7,852	0.90	6,218	0.783
DCW48	0.69	7,334	0.90	2,653	0.746
DCW71	0.69	12,969	0.90	8,140	0.771
DCW73	0.69	4,150	0.90	1,017	0.731
DCW148	0.69	7,527	0.90	3,721	0.759
TDC375	0.69	37,461	0.90	18,676	0.760
DCW17	0.69	3,064	0.90	844	0.735
DCW233	0.69	2,757	0.90	2,234	0.784
TDC559	0.69	44,634	0.90	14,740	0.742
SS513	0.69	8,909	0.90	8,949	0.795
TSS104	0.69	14,144	0.90	5,555	0.749
		171,270		83,196	0.753

6.7 VO Efficiency Performance Thresholds

The following VO efficiency performance thresholds (or VO Threshold) were used to establish conditions around which all cases were developed:

- Minimum hourly VAR flow of ± 300 kVAR or hourly power factor > 97%
- VCZ maximum primary voltage drop < 4.8 Volts or 4% (on 120 volt base)
- Maximum phase imbalance < 25%
- Maximum neutral current < 50 Amperes
- Minimum EOL voltage > 118.6 Volts (on 120 volt base)
- Primary line conductor loading < 80% of maximum normal rating
- Primary line & distribution transformer no-load energy loss < 2%

For this study, 98% power factor was assumed for all feeders given improved VAR management for the Base Case. Maximum phase imbalances are 25%, with allowable primary line volt drops of 4.8V (or 4%) or less.

The associated protocol established a foundation against which energy savings could be measured and verified. Feeders not meeting this protocol were considered non-viable for voltage reduction, with energy savings potential not being measurable and verifiable.

Feeders were considered inefficient if they had high hourly VAR flows; high voltage drops during peak load conditions; high amp-phase imbalances; high neutral currents; and minimum voltages that violate ANSI C84.1 Standard voltage ranges. It was not always possible or practical to achieve all of the VO thresholds due to specific loading and feeder characteristics and geographical arrangements. Every reasonable and feasible attempt to meet objectives was made to closely satisfy the VO threshold constraints.

Once minimum thresholds were met, feeder efficiency losses could be reduced by lowering customer average voltages.

System parameters examined included maximum primary voltage drops, minimum end-of-line primary voltages, feeder phase imbalances, feeder neutral currents, conductor ampacities, and feeder minimum power factors and/or VAR flows.

Distribution transformers have both load and no-load losses. Secondary load losses are not appreciably altered with lower system voltages. However, transformer no-load losses are reduced by the square of the voltage change. Transformers have different efficiencies due to the wide variety of installed units. Since it is a formidable task to identify all distribution transformer nameplate no-load losses, average no-load loss was assumed to be 3.0 watts per connected kVA for all transformers.

6.7.1 Minimum Allowed Primary Volt & Secondary Voltage Drops

Minimum EOL primary voltages were determined based on best industry practices for secondary voltage drop design guidelines when maximizing energy savings from VO deployments. Secondary voltage drops can vary for every distribution transformer and conductor connection. ComEd design guidelines specify allowable maximum secondary volt-drop of 6.0 Volts. For this VO study, a utility best practice assumption of 3.6 volts or 3% on a 120-volt base is used. In some cases, these best practice guidelines may be violated due to added customer load, undersized transformer capacity, and/or customer non-coincidental demand.

With an assumed 2-volt bandwidth for all voltage regulator controls, the lowest simulated primary voltage was 118.6V ± 1V. Given a 114.0 volt minimum (ANSI C84.1 Standard Voltage Minimum) at the service entrance, or 114V + ½BW plus the assumed secondary voltage drop of 3.6V, yields a minimum allowable primary voltage of 118.6V ± 1V.

If end-use services have voltages less than the ANSI C 84.1 Voltage Normal Range "A" (114-126V), utilities typically correct secondary conditions; e.g., replace distribution transformers with larger units. This study does not include the costs to mitigate secondary voltage problems.

6.8 Overview of VO Analysis Process and Application Guidelines

This section provides an overview of the VO analysis process and application guidelines for each of the following areas:

- VO design process
- VO M&V protocol
- VO upgrade priorities
- Average voltage calculations
- Energy savings calculations
- Voltage regulator LDC applications
- Capacitor VAR management applications
- Benefits of AMI applications
- Integrated Volt-VAR Control (IVVC) application
- System data provided by ComEd

6.8.1 VO Design Process

The most important distribution system attribute when performing VO studies is comprehensive load flow modeling. ComEd uses CYMDist® routinely updated with its GIS database. About 30% of ComEd feeders required significant model revisions to perform the simulations. Most of revision work was performed in Task 3. Feeder modeling includes electric equipment characteristics (lines, regulators, capacitors, switches, etc.), regulator and capacitor control parameters, number and type of connected customers, circuit configurations, amount and type of connected load, and spatial location of equipment.

The second most important VO attribute is having complete substation and feeder metering information, including annual peak loads, annual MWh delivered, phase Amperes, and MW and MVAr hourly profile data. Because VO studies determine impacts of relatively small system alterations (voltage control changes, phase upgrades, load balancing, reconductoring, added regulators, reconfigurations, capacitor control changes, etc.) with high installation costs, accurate models are necessary to ensure results can be measured and verified.

ComEd substation and feeder metering varies from available amperes by phase only; to MW and MVAr demand and phase Amperes; to MW and MVAR and ampere phase hourly profile data. MW & MVAr load data was available on only 7 of the 16 substations. Substation voltage regulation is provided by power transformer LTCs and substation voltage regulators with control settings fixed at 124.8 V (on 120 V base) with 2 or 3 V bandwidths. (Note: Metering load profile data will be needed for any required field VO M&V testing to validate energy savings for VO implementations.)

The as-is distribution system Existing Case was analyzed to determine load (annual MWh and peak kW) and no-load losses, and for compliance against performance thresholds. Minimal improvements were identified; e.g., minimum hourly VAR flows, maximum voltage drops, maximum phase imbalances, minimum EOL voltages, and no overloaded conductors. The upgraded system uses the same or similar voltage-control settings as the existing system. Adjustments may be needed to avoid low voltage operations. The upgraded system becomes the VO Base Case from which all other alternative plans are measured.

Once the Base Case was established, Plan A and Plan B were developed and results reported for the following measures:

- Substation and Feeder weighted VO Factors
- VO performance threshold compliance
- Change in system losses from Existing Case
- Change in weighted annual average voltage from Base Case
- Potential energy savings from Base Case
- Potential demand reductions from Base Case
- Present value cost of energy saved
- Present value cost of upgrades, including threshold compliance upgrades
- Resulting BCR >1.5

An optimal VO Plan is one that maximizes energy savings potential, meets VO thresholds, and has BCRs >1.0. For this study, BCRs >1.5 were assumed to allow for unforeseen errors and/or modifications to the data modeling, operational constraints, and/or financial costs.

The VO study process includes the following steps:

1. Gather system information including metering data, customer load characteristics, *VO* Factor, financial parameters, efficiency targets, marginal cost of energy and demand, existing voltage operational parameters and constraints, unit costs, system topology mapping, and utility construction and voltage drop standards.
2. Prepare a distribution electrical ***Existing Case*** model.
3. Identify ***Existing Case*** efficiency threshold compliance.
4. Develop ***Base Case*** with VO upgrades to comply with VO efficiency thresholds and same volt setting as ***Existing Case.***
5. Identify system net change in kW peak line losses between the ***Existing Case*** and the final ***Base Case***. Identify the investment cost of system improvements.
6. Create ***Plan A Case*** by modifying ***Base Case*** with lower volt settings and VO upgrades.
7. Perform Pre-*VO* average voltage calculations and no-load loss assessments using ***Base Case*** VCZ voltage settings.
8. Perform Post-*VO* average voltage calculations and no-load loss assessment using ***Plan A*** VCZ voltage settings.
9. Determine changes average voltage, end-use energy consumption, line loss, and transformer no-load loss.
10. Perform economic analysis of costs and benefits for ***Plan A Case*** system.
11. Repeat steps 6 through 10 to create additional plans each by adding additional system improvements in order of priority. For each plan, if the Benefit Cost Ratio is less than the *BCR* target, repeat steps.
12. Prepare findings, results, and recommendations.

A detailed study includes two main development processes: Existing Case development; and VO Base Case, Plan A, and Plan B development. Existing Case development process steps are shown in Figure 9. Base Case, Plan A, and Plan B development process steps are shown in Figure 10.

6.8.2 VO Improvement Priority

Successful VO implementations consistently upgrade priorities are important when trying to optimize energy savings at the lowest costs. For example, low-cost improvements (such as load balancing) can greatly impact voltage drops and load balance, and should be done before considering higher-cost improvements (such as reconductoring). In a similar manner, adding or modifying capacitors to achieve near-zero VAR flows reduces voltage drops all year and should be considered prior to higher-cost alternatives (such as adding voltage regulators). Voltage-control threshold settings should be applied last, typically reducing source voltages from 124.8 volts to lower set points such as 119.0 volts using compensated R settings. For properly VAR-controlled feeders, X-compensation is typically not required.

The Existing Case performed as expected. By adding VO upgrades (in order of priority) to meet performance thresholds, the Base Case was successfully developed. Additional improvements for Plans A and B are to reduce primary voltage drops, reduce line losses, and enable lower voltage set points. Improvements are added incrementally as needed. Typical improvements include the following 12 measures (listed in order of priority, from highest savings lowest cost impacts to lowest savings highest cost impacts):

1. Improve substation and feeder metering
2. Reconfigure (by switching)
3. Reconfigure (by tap changes)
4. Add or modify capacitors
5. Add phase upgrades
6. Add in-line volt-regulators
7. Reconductor line sections
8. Replace selected distribution transformer/secondary systems
9. Add new parallel feeders
10. Install EOL feedback voltage sensing and control
11. Install Integrated Volt-Var Control (IVVC)
12. Upgrade feeder to higher primary voltage class

6.9 VO Improvements Common to all VO Plans

Substation and feeder source MW and MVAr profiles metering was added to all feeders. All viable candidates had capacitor VAR performance modified to yield near zero VAR flows of ±300 kVAR for all hours. All substation power transformer LTCs and in-line voltage regulators controls were assumed to have LDCs. Each viable feeder VCZ had EOL voltage metering installed. In cases where adjacent non-viable feeders were served from a common voltage regulation source, IVVC equipment was added to isolate the feeder from the viable feeders. IVVC additions included volt-VAR station controllers, EOL voltage feedback sensing, and switched capacitors. These IVVC additions were common to all plans.

6.9.1 Substation and Feeder Metering Applications

Substation and feeder metering data is needed to plan, design, operate, and monitor VO systems. The accuracy and completeness of engineering modeling and system performance (metering) is increased. VO operational impacts are small (i.e., losses, voltage service levels, voltage drops) as are performance tolerances (i.e., minimum voltage margins, feeder coincidence peak load factors, operation requirements).

For VO design, it is best to have 12 months of substation power transformer and feeder source metered data (kWh and kW demand and annual kWh). In addition, phase amps and volts sensing is collected for in-line volt-regulators equipped with source metering. VAR sensing is typically installed along the feeders along with EOL voltage sensing. Meter data does not need to be real time, but can be manually downloaded every six months or monthly using SCADA.

kW and kWh annual data are needed to determine accurate VCZ annual load factors and energy delivered. Annual peak kW is used with load flow simulations to determine maximum primary voltage drops for average voltage calculations. VCZ source meters and EOL voltmeters are used during the Pre-*VO* and Post-*VO* verification test period. EOL metering also is used to verify on-going compliance. Annual source measurements along with verification measurements provide the necessary elements to determine average annual voltages for Pre-VO and Post-VO conditions. Load profile metering is required if M&V testing and validation of VO savings are required. Power transformer and distribution line metering is used to estimate load and loss factors to estimate system losses and evaluate loss impacts.

For this study, it was assumed all power transformers, feeders, and line regulators had metering installed common to all plans, with EOL metering on feeder lowest voltage locations.

6.9.2 Feeder VAR Management Applications

All viable VO feeder candidates were assumed to have capacitor VAR performance modified to yield near zero VAR flows of nearly 100% reactive load compensation ±300 kVAR for all hours to meet performance thresholds. For ComEd, most capacitors are 1200 kVAR fixed for viable feeders. Base Case VAR management was modified to upgrade existing fixed banks with 600 kVAR and/or additional fixed and switched VAR controlled banks. Capacitor sizing, placement, type (fixed or switched), and control settings were based on feeder annual historical VAR profiles. Historical VAR profiles are used to determine minimum and maximum feeder VARs. Capacitor modifications and/or additions for the Base Case were included in all plans.

6.9.3 Feeder Volt-Regulator Line-Drop-Compensation Applications

All substation LTC power transformer and regulator voltage controls were assumed to have LDC. LDC provides a reliable method to maintain and lower voltages effectively for feeders with residential customers and small to medium commercial customers. LDCs were applied to all substation LTC and in-line voltage regulators.

If additional voltage regulators were required for the Base Case to meet VO thresholds, they were included in all VO plans. If additional LDC controllers were necessary, they were also included in all plans.

6.9.4 Capacitor VAR Management

All viable feeder candidates were assumed to have capacitor VAR management modified to yield near zero VAR flows of ±300 kVAR for all hours. The Base Case and Improved Case capacitor sizing, placement, and capacitor type (fixed or switched), and capacitor control settings were based on feeder annual historical VAR profiles. Historical VAR profiles were used to determine minimum and maximum VARs for adequate hourly VAR compensation.

Reactive power does not spin kWh meters and performs no useful work, but must be supplied. Using line shunt capacitors to supply reactive power reduces the amount of line current. Since line losses are a function of the current squared, reducing reactive power flows significantly reduces losses. By reducing the annual hourly VAR loading to near zero throughout the length of feeder, accumulated voltage drops are minimized, reducing line losses and eliminating the need for regulator reactive voltage %X compensation.

All feeders were assumed to have been modified for near 100% VAR flow. For Base Case and proposed case simulations, all feeder-connected capacitors were disconnected. All feeder voltages sources were assumed fixed at 124.8 volts with bandwidths set at 0.8 volts. *All feeder source loads were 110% annual peak kW loads at 98% power factor lagging*. In-line voltage regulators were set at 124.8 volts. Substation capacitors were not considered in the kVAR analysis.

As data was available either with feeder phase amps, MW and MVAr phase demands, and/or MW and MVAr hourly load profiles, peak load and phase contributions were assigned to each feeder. If no MVAr load profile data was available, existing capacitor kVARs were assumed to equal total kVAR feeder loading. Estimated fixed kVARs were assumed to be 50% of the total kVAR, and switched kVARs at 50% of the total. All capacitor banks were assumed to be 600 kVAR for both fixed and switched.

Capacitor switch controllers normally have counters to record the number of operations. Counters help to identify maintenance and control setting problems. It was assumed all capacitors are serviced at least once per year.

Other control methods, including automated VAR feedback controls, can be applied if the net result is a maximum leading or lagging kVAR that is less than compensation targets at the feeder source for every hour of the year. Feedback and/or IVVC can also be used to override VAR controls under emergency or abnormal conditions. If feeders can be operated from either direction, it is important the controller mode be capable of handling operations bi-directional flows.

For non-viable feeders connected within VCZs with viable sister feeders, VCZ voltage regulation requires augmentation to account for non-viable and viable voltage needs.

Non-viable feeders were assumed to have voltages representative of existing voltages. Substation or VCZ voltage regulation was assumed to be controlled via LDCs based on viable feeder loads. Non-viable feeders were equipped with EOL primary voltage feedback sensing as input to an IVVC master control station. IVVC controls non-viable feeder capacitors to maintain feeder primary voltages within existing or improved voltage limits. Primary voltage limits were 121 volts to 124 volts.

The number of switched capacitors needed for IVVC feeder systems to raise primary average voltage by 2 volts was determined from load flow simulations at 2/3 of the distance from the source. The VCZ source LDC loading was modified using IVVC to subtract non-viable feeder loadings from the LDC controller. The VCZ source LDC then became the non-viable feeder backup control in the event of an IVVC malfunction.

All selected representative sample viable feeder candidates VAR flows were modified to yield near zero var flows of ±300 kVAR for all hours.

6.9.5 AMI Applications

AMI can provide additional information to help improve energy efficiencies and minimize implementation costs. The data can be used to accurately assess customer load impacts and evaluate secondary voltage drops to establish reliable minimum primary voltage standards for feeder and substation voltage regulators. Secondary systems include distribution transformers and secondary service drops. For this study, ComEd AMI meter data was not evaluated or used.

6.9.6 IVVC Applications

IVVC applications monitor real-time voltages, watts and VARs from LTCs, regulators, capacitors, EOL voltage sensors, and additional monitoring points such as customer meters. Using this real-time data, the IVVC application triggers a control period during which real-time power factors and voltage measurements assign operational costs. Operational costs are determined by comparing analog measurements to substation power factor and voltage targets. The IVVC application objective is to minimize operational costs by managing real-time power factors and voltages and primary voltage targets.

IVVC control schemes ensure optimum performance. For most VO applications with residential and light-to-medium commercial customers, traditional LDC controls and VAR management schemes with switched VAR capacitor controls provide more cost-effective operation performance. However, when adjacent (sister) feeders are connected to the same voltage regulator or power transformer with significantly different load profiles and peak kW coincidence (i.e., < 80%) and high amounts of large commercial and/or industrial customer loading, traditional voltage regulation and VAR management approaches become less effective.

Large commercial and industrial customers require higher service entrance voltages compared to residential customers. Higher voltages are needed to coordinate with inefficient end-use electrical systems typically requiring end-use voltage drops greater than ANSI standards.

For this study, IVVC was used to maintain and isolate voltages for large commercial and industrial feeders (classified as non-viable candidates) by integrating with switched shunt capacitor banks, voltage measurement and VAR sensing along the feeder, source voltage regulation LDC controllers, and monitoring secondary service voltages for customers with AMI (Figure 11).

6.10 VO Improvements Common to all VO Plans

Substation and feeder source MW and MVAr profiles metering was added to all feeders. All viable candidates had capacitor VAR performance modified to yield near-zero VAR flows of ± 300 kVAR for all hours. All substation power transformer LTCs and in-line voltage regulators controls were assumed to have LDCs. Each viable feeder VCZ had EOL voltage metering installed. In cases where adjacent non-viable feeders were served from a common voltage regulation source, IVVC equipment was added to isolate the feeder from the viable feeders. IVVC additions included volt-VAR station controllers, EOL voltage feedback sensing, and switched capacitors. These IVVC additions were common to all plans.

6.10.1 Substation and Feeder Metering Applications

Substation and feeder metering data is needed to plan, design, operate, and monitor VO systems. The accuracy and completeness of engineering modeling and system performance (metering) is increased. Since VO operational impacts are small (i.e., losses, voltage service levels, voltage drops) as are performance tolerances (i.e., minimum voltage margins, feeder coincidence peak load factors, operation requirements), accurate data is important to success.

For VO design, it is best to have 12 months of substation power transformer and feeder source metered data (kWh and kW demand and annual kWh). In addition, phase amps and volts sensing are collected for in-line volt-regulators equipped with source metering. VAR sensing is typically installed along the feeders along with EOL voltage sensing. Meter data does not have to be real time, but can be manually downloaded every six months using SCADA.

kW and kWh annual data is needed to determine accurate VCZ annual load factors and energy delivered. Annual peak kW is used with load flow simulations to determine maximum primary voltage drops for average voltage calculations. VCZ source meters and EOL voltmeters are used during the Pre-VO and Post-VO verification test period. EOL metering also is used to verify on-going compliance. Annual source measurements along with verification measurements provide the necessary elements to determine average annual voltages for Pre-VO and Post-VO conditions. Load profile metering is required if M&V testing and validation of VO savings are required. Power transformer and distribution line metering is used to estimate load and loss factors to estimate system losses and evaluate loss impacts.

For this study, it was assumed all power transformers, feeders, and line regulators had metering installed common to all plans, with EOL metering on feeder lowest voltage locations.

6.10.2 Feeder VAR Management Applications

All viable VO feeder candidates were assumed to have capacitor VAR performance modified to yield near zero VAR flows of nearly 100% reactive load compensation ±300 kVAR for all hours to meet performance thresholds. For ComEd, most capacitors are 1200 kVAR fixed for viable feeders. Base Case VAR management was modified to upgrade existing fixed banks with 600 kVAR and/or additional fixed and switched VAR controlled banks. Capacitor sizing, placement, type (fixed or switched), and control settings were based on feeder annual historical VAR profiles. Historical VAR profiles are used to determine minimum and maximum feeder VARs. Capacitor modifications and/or additions for the Base Case were included in all plans.

6.10.3 IVVC and EOL Voltage Feedback and Control Application

If IVVC was required in the Base Case, IVVC applications were included in all VO plans. IVVC was used to isolate non-viable feeders by integrating with switched shunt capacitor banks, voltage measurement and var sensing along the feeder, EOL voltage sensing, source voltage regulation LDC controllers, and AMI for secondary service voltages. In some cases, only EOL voltage feedback, sensing, and control were required for feeders exhibiting lower feeder coincidence factors when compared to their adjacent (sister) feeders.

All IVVC and EOL voltage feedback control applications required for the Base Case were included in all VO plans.

6.11 Existing Case VO Performance Threshold Assessment

Minimum efficiency performance VO threshold objectives were identified (e.g., max voltage drops, min power factors, max phase unbalance, etc.).

System loss reductions and lower the customer average voltages were generally achieved. However, it was not always possible or practical to achieve all of VO thresholds due to specific loading and geographical constraints.

Maximum primary volt drops for substation service areas ranged from 0.30 volts to 13.4 volts. The average maximum voltage drop was 3.95 volts (lower than the 4.8 volt threshold).

Lowest primary voltages for substation service areas ranged from 124.5 volts to 111.1 volts. The average lowest voltage was 116.26 volts (higher than the 118.6 volt threshold).

Feeder phase amp imbalances for substation service areas ranged from 1.2% to 31.1% (<25% phase amp imbalance threshold). The average imbalance was 10.5%.

Maximum feeder conductor and cable length for correcting the substation service area overloads was 0.62 miles.

Capacitor additions to maintain annual var flow of 300 kVAR for all hours for substation service areas were 18 fixed 600 kVAR banks and 150 switched 600 kVAR banks. All switched capacitor banks needed for the Base Case were assumed to have VAR sensing with voltage override capability.

Existing case compliance with VO thresholds is summarized in Table 17. Highlighted values indicate non-compliance with VO thresholds.

Table 17 - Summary of Existing Case Compliance with VO Thresholds

Feeder Id	Sub Id	Source Volts	Source VCZ Max VoltDrop (V)	Source VCZ Lowest Primary Voltage (V)	Amp Phase Imbalance (pu)	Overloaded Line > 100% of Normal (mi)
B285	DCB28	124.8	4.70	120.1	0.077	
B286	DCB28	124.8	5.10	119.7	0.103	
D690	DCD69	124.8	3.90	120.9	0.050	
D470	DCD69	124.8	2.00	120.0	0.100	
D472	DCD69	124.8	2.00	120.0	0.100	
E717	DCE71	124.8	4.70	120.1	0.162	
E718	DCE71	124.8	3.90	120.9	0.134	
E715	DCE71	124.8	2.00	120.0	0.100	
E716	DCE71	124.8	2.00	120.0	0.100	
E791	DCE79	124.8	5.00	119.8	0.165	0.019
E792	DCE79	124.8	4.70	120.1	0.074	
H385	DCH38	124.8	9.70	115.1	0.097	
H385-North	DCH38	124.8	5.60	119.2	0.097	
W386	DCW38	124.8	3.90	120.9	0.108	
W387	DCW38	124.8	6.30	118.5	0.136	
W4801	DCW48	124.8	1.80	123.0	0.063	
W4802	DCW48	124.8	5.50	119.3	0.131	0.441
W711	DCW71	124.8	3.50	121.3	0.080	
W712	DCW71	124.8	1.80	123.0	0.012	
W731	DCW73	125.0	7.30	117.7	0.130	
W140	DCW148	124.8	2.60	122.2	0.086	
W142	DCW148	124.8	1.60	123.2	0.094	
B7501	TDC375	124.5	10.70	113.8	0.040	

Note: Highlighted values indicate non-compliance with VO thresholds.

Table 17 - Summary of Existing Case Compliance with VO Thresholds (Continued)

Feeder Id	Sub Id	Source Volts	Source VCZ Max VoltDrop (V)	Source VCZ Lowest Primary Voltage (V)	Amp Phase Imbalance (pu)	Overloaded Line > 100% of Normal (mi)
B7502	TDC375	124.5	5.20	119.3	0.060	
B7503	TDC375	124.5	2.20	122.3	0.029	
B7506	TDC375	124.5	3.60	120.9	0.222	
B7583	TDC375	124.5	6.80	117.7	0.252	
B7584	TDC375	124.5	2.20	122.3	0.089	
B7504	TDC375	124.5	13.40	111.1	0.077	
B7505	TDC375	124.5	5.90	118.6	0.023	
B7507	TDC375	124.5	3.00	121.5	0.070	
B7570	TDC375	124.5	0.50	124.0	0.030	
B7582	TDC375	124.5	5.80	118.7	0.276	
W178	DCW17	124.8	3.70	121.1	0.132	
W332	DCW233	124.8	2.40	122.4	0.083	0.063
W593	TDC559	124.8	3.60	121.2	0.172	
W594	TDC559	124.8	5.40	119.4	0.194	
W595	TDC559	124.8	2.20	122.6	0.154	
W596	TDC559	124.8	3.10	121.7	0.100	
W597	TDC559	124.8	3.80	121.0	0.127	
W5910	TDC559	124.8	2.90	121.9	0.093	
W590	TDC559	124.8	4.70	120.1	0.187	
W591	TDC559	124.8	2.60	122.2	0.114	
W592	TDC559	124.8	5.20	119.6	0.311	
W598	TDC559	124.8	4.10	120.7	0.083	
W599	TDC559	124.8	4.00	120.8	0.110	0.025
W5911	TDC559	124.8	3.60	121.2	0.301	
W1310	SS513	124.8	4.40	120.4	0.052	0.074
W1311	SS513	124.8	2.00	120.0	0.100	
W1312	SS513	124.8	1.00	123.8	0.032	
W1313	SS513	124.8	3.50	121.3	0.021	
Z10439	TSS104	124.8	3.90	120.9	0.073	
Z10440	TSS104	124.8	1.40	123.4	0.091	
Z10441	TSS104	124.8	4.20	120.6	0.132	
Z10442	TSS104	124.8	0.30	124.5	0.021	
Z10443	TSS104	124.8	0.40	124.4	0.031	

Note: Highlighted values indicate non-compliance with VO thresholds.

6.12 Plan A – Low Cost Solution

6.12.1 Summary

Plan A improvements include those identified for the Base Case and are common to all VO plans. Plan A meets threshold requirements for a minimum cost of $3,705,440. Overall energy saved is 19,639 MWh/yr. The average savings per substation is 1227.4 MWh/yr and the average per viable feeder is 417.9 MWh/yr. The average primary voltage Pre-VO is 124.13 V and Post-VO is 120.57 V (2.97% reduction). All LDC settings have a voltage set point of 120.0 volts. The total end-use energy savings are 18,422.5 MWh/yr. Average customer savings are 314.5 kWh/yr.

6.12.2 Plan A VO Improvements and Installed Costs

Plan A improvements and associated costs are summarized in Table 18 and Table 19.

Table 18 - Plan A VO Improvements

Sub Id	OH Line Reconductor (mi)	Station Regulator Addition (#)	In-line volt-regulator Addition (#)	OH & UG line or transf tap changes (#)	OH phase upgrades (mi)	Fixed 600 kVAr capacitor add (#)	Switched 600 kVAr capacitor add (#)
DCB28	0.00	0	0	0	0.00	0	2
DCD69	0.00	0	1	2	0.10	0	3
DCE71	0.00	0	0	0	0.00	3	4
DCE79	0.02	0	0	0	0.00	0	6
DCH38	0.00	0	1	3	0.00	0	2
DCW38	0.00	0	1	0	0.06	3	4
DCW48	0.44	0	0	0	0.00	1	4
DCW71	0.00	0	0	0	0.00	3	8
DCW73	0.00	0	1	0	0.00	1	2
DCW148	0.00	0	0	0	0.00	3	4
TDC375	0.00	0	3	5	0.00	0	53
DCW17	0.00	0	0	0	0.00	1	1
DCW233	0.06	0	0	0	0.00	1	3
TDC559	0.03	0	0	0	0.00	2	25
SS513	0.07	0	0	0	0.00	0	9
TSS104	0.00	0	0	0	0.00	0	20
	0.62	0	7	10	0.16	18	150

Table 19 - Plan A VO Improvements and Costs

Sub Id	Feeder Source & Regulator metering (#)	EOL Voltmeter (#)	EOL volt feedback sensing (#)	IVVC Application ($)	VO Upgrade Cost ($)
DCB28	2	2	0	$0	$46,000
DCD69	1	1	0	$0	$131,440
DCE71	2	2	0	$0	$92,500
DCE79	2	2	0	$0	$110,275
DCH38	5	5	0	$0	$139,000
DCW38	3	3	0	$0	$169,550
DCW48	2	2	0	$0	$180,725
DCW71	2	2	0	$0	$152,500
DCW73	1	2	0	$0	$109,500
DCW148	2	2	0	$0	$92,500
TDC375	14	15	1	$50,000	$1,163,500
DCW17	1	1	0	$0	$28,500
DCW233	1	1	0	$0	$72,675
TDC559	12	12	2	$150,000	$646,625
SS513	3	3	0	$0	$175,650
TSS104	5	5	1	$50,000	$394,500
	58	60	4	$250,000	$3,705,440

6.12.3 Average Voltage and End-Use Savings

Plan A average voltage reductions and end-use energy savings for each of the 16 substations are given in Table 20. The average primary Post-VO voltage is 120.57 volts compared to a baseline Pre-VO of 124.13 volts. The weighted annual average reduction in customer voltage for the sample substation areas is 3.55 volts or 2.96%.

6.12.4 System Line and No-Load Loss Savings

Plan A system line and no-load losses for each of the 16 substations are given in Table 21. The feeder service area total system loss reduction is 24,525.1 MWh for a savings of 1216.4 MWh. There is a no-load reduction of 820.8 MWh and line loss savings of 395.6 MWh. Total peak loss reduction is 387.5 kW (293.8 kW for line and 93.7 kW for no-load). Average feeder energy losses are 2.51% for Plan A compared to 2.68% for the Existing Case.

Table 20 - Plan A Average Voltage Reduction and End-Use Energy Savings

Sub Id	Existing kW Demand	Annual MWh Load	VO Factor (weighted)	Base Case Pre-VO Avg Volts	Post-VO Avg Volts	Voltage Change (pu)	End-Use Load Savings (MWh)
DCB28	4,793	15,577	0.752	123.89	120.91	0.0249	291.2
DCD69	7,020	19,868	0.846	124.02	120.30	0.0310	521.3
DCE71	12,138	33,852	0.758	124.13	120.67	0.0288	736.8
DCE79	11,533	33,375	0.702	124.15	119.81	0.0361	854.2
DCH38	3,377	10,375	0.760	124.04	120.77	0.0272	213.9
DCW38	15,575	47,753	0.783	124.21	120.61	0.0300	1,123.3
DCW48	11,274	31,421	0.746	124.30	120.50	0.0317	743.3
DCW71	14,025	62,809	0.771	124.11	120.68	0.0286	1,391.5
DCW73	5,620	16,819	0.731	124.30	120.65	0.0305	374.7
DCW148	10,980	33,315	0.759	124.43	120.36	0.0339	859.7
TDC375	63,190	259,799	0.760	123.32	121.69	0.0135	2,471.6
DCW17	4,387	12,200	0.735	124.21	120.59	0.0302	271.0
DCW233	5,532	15,450	0.784	124.47	120.33	0.0344	416.9
TDC559	63,731	218,503	0.742	124.05	119.44	0.0384	5,177.5
SS513	17,696	49,439	0.795	124.30	120.50	0.0316	1,248.3
TSS104	27,427	116,949	0.749	124.12	121.37	0.0230	1,727.4
	278,298	977,504.0					18,422.5

Table 21 - Plan A System Line and No-Load Losses

Sub Id	Annual MWh Load	Existing Line and No-Load Losses (MWh)	Revised Peak Line Loss (kW)	Reduction in Peak Line Loss (kW)	Savings in Line Loss (MWh)	Reduction in Peak No-Load Loss (kW)	Savings in No-Load Loss (MWh)	Revised Total Loss (MWh)	% Loss	Total Loss Energy Savings (MWh)
DCB28	15,577	595.0	81.3	0.0	0.0	2.6	22.6	572.4	3.67%	22.6
DCD69	19,868	498.8	102.0	1.6	1.9	2.5	22.2	474.7	2.39%	24.1
DCE71	33,852	897.7	187.5	0.0	0.0	4.2	36.9	860.8	2.54%	36.9
DCE79	33,375	1,043.6	350.4	3.5	4.6	4.5	39.8	999.2	2.99%	44.4
DCH38	10,375	686.1	94.2	6.4	8.8	3.3	28.6	648.7	6.25%	37.4
DCW38	47,753	883.9	209.4	4.6	6.3	3.9	34.0	843.5	1.77%	40.3
DCW48	31,421	681.9	11.3	217.6	255.0	2.9	25.5	401.4	1.28%	280.5
DCW71	62,809	1,240.8	129.9	0.0	0.0	5.8	50.7	1,190.1	1.89%	50.7
DCW73	16,819	425.7	139.1	2.2	2.9	1.6	13.9	408.8	2.43%	16.8
DCW148	33,315	829.2	92.8	0.0	0.0	5.2	45.4	783.9	2.35%	45.4
TDC375	259,799	7,264.8	1,603.3	34.3	83.0	10.5	92.1	7,089.6	2.73%	175.1
DCW17	12,200	293.1	47.3	0.0	0.0	1.6	13.7	279.3	2.29%	13.7
DCW233	15,450	387.8	34.0	5.2	6.1	2.6	22.4	359.4	2.33%	28.5
TDC559	218,503	5,725.8	1,001.7	7.9	14.6	27.7	242.9	5,468.3	2.50%	257.5
SS513	49,439	1,921.8	229.7	10.5	12.4	8.7	76.0	1,833.4	3.71%	88.3
TSS104	116,949	2,365.6	249.3	0.0	0.0	6.2	54.1	2,311.5	1.98%	54.1
	977,504	25,741.6	4,563.2	293.8	395.6	93.7	820.8	24,525.1	2.51%	1,216

6.12.5 VO Economic Analysis

Plan A demonstrates an annual energy savings of 19,639.0 MWh/yr (2.01% reduction) and 3892.6 kW coincidental feeder demand reduction. The feeder system loss is 2.51% of the total energy delivered compared to existing system losses of 2.63%.

Plan A substations have a relatively moderate overall BCR of 1.928 with total installed costs of $3,705,440 ($78,839/fdr). The net overall present value reduction in revenue requirements is $4,054,077 ($86,257/fdr). Total annual energy savings is 19,639.0 MWh/yr (417.9/fdr) for a program measure life of 15 years.

Plan A substation first year costs, O&M costs, energy saved, demand reduction, and BCR are shown in Table 22. Overall VO economic results are given in Table 23.

Table 22 - Plan A Economic Analysis Summary by Substation

Substation id	Number of Customers	VO Upgrade Costs (w/o Isolation Adders) (First Year $)	VO Upgrade Costs (w/ Isolation Adders) (First Year $)	Annual O&M Costs ($/y)	NPV of VO Upgrade Costs (w/ Isolation Adders) ($)	NPV of VO Energy Savings ($)	NPV of Revenue Requirement Savings ($)	Total VO Energy Saved MWh/y	Total Peak Demand Reduction kW/y	Benefit Cost Ratio
DCB28	1,031	$46,000	$46,000	$920	$59,934	$148,748	$88,814	313.8	58.0	2.48
DCD69	589	$131,440	$131,440	$2,629	$171,255	$258,526	$87,271	545.4	103.3	1.51
DCE71	2,182	$92,500	$92,500	$1,850	$120,520	$366,770	$246,250	773.7	144.4	3.04
DCE79	3,114	$110,275	$110,275	$2,206	$143,679	$425,940	$282,261	898.6	170.6	2.96
DCH38	660	$139,000	$139,000	$2,780	$181,105	$119,093	-$62,013	251.2	50.3	0.66
DCW38	1,687	$169,550	$169,550	$3,391	$220,909	$551,590	$330,681	1,163.6	222.2	2.50
DCW48	1,862	$180,725	$180,725	$3,615	$235,469	$485,314	$249,845	1,023.8	361.9	2.06
DCW71	2,581	$152,500	$152,500	$3,050	$198,695	$683,636	$484,942	1,442.2	270.5	3.44
DCW73	950	$109,500	$109,500	$2,190	$142,669	$185,609	$42,940	391.6	75.1	1.30
DCW148	3,417	$92,500	$92,500	$1,850	$120,520	$429,034	$308,515	905.1	168.7	3.56
TDC375	13,801	$1,163,500	$1,163,500	$23,270	$1,515,942	$1,254,628	-$261,313	2,646.8	515.1	0.83
DCW17	1,030	$28,500	$28,500	$570	$37,133	$134,995	$97,862	284.8	53.1	3.64
DCW233	1,397	$72,675	$72,675	$1,454	$94,689	$211,135	$116,445	445.4	87.1	2.23
TDC559	18,039	$646,625	$646,625	$12,933	$842,497	$2,576,315	$1,733,817	5,435.0	1,020.7	3.06
SS513	5,197	$175,650	$175,650	$3,513	$228,857	$633,579	$404,722	1,336.6	256.7	2.77
TSS104	4,908	$394,500	$394,500	$7,890	$514,000	$844,463	$330,464	1,781.5	334.8	1.64
	62,445	$3,705,440	$3,705,440	$74,109	$4,827,873	$9,309,375	$4,481,502	19,639	3,893	1.928

Table 23 - Plan A Economic Analysis Summary - Overall

	Plan A
General Substation Information	
Number of Substations Investigated	
Total Customers Served (#)	62,445
Number of Feeders (Viable and Non-viable) Investigated (#)	56
Number of Feeders (Viable) Investigated (#)	47
Substation Annual Peak Demand (kW)	278,298
Total Annual Energy Consumed (MWh/yr)	977,504
VO Energy Savings Potential	
Average Primary Voltage Pre-VO (V)	124.13
Average Primary Voltage Post-VO (V)	120.57
Average Customer VO Voltage Change (%)	2.96%
Substation Weighted Average VO factor	0.761
VO Energy Savings (MWh/y)	18,422.5
Line Loss Energy Savings (MWh/y)	395.6
No-Load Loss Energy Savings (MWh/y)	820.8
Distribution Line and Transf no-load loss (%)	2.51%
Total Energy Savings (MWh/y)	19,639.0
Total Coincidental Demand Reduction (kW)	3,892.6
Customer Average Energy Savings (kWh/yr)	314.5
Benefit Cost Projections	
Total VO Upgrade Cost - First Year ($)	$3,705,440
Annual O&M First Year Costs ($)	$74,109
Total VO Upgrade Cost (NPV)	$4,827,873
Total VO Energy Savings (NPV)	$9,309,375
NPV Revenue Requirement Savings ($)	$4,481,502
VO Benefit Cost Ratio (BCR)	1.928

6.13 Plan B – High Savings Solution

6.13.1 Summary

Plan B improvements include those identified for the Base Case plus additional upgrades. Plan B meets threshold requirements for a cost of $5,142,735. The maximum overall energy saved is 27,138.9 MWh/yr. The average savings per substation is 1696.2 MWh/yr and the average per viable feeder is 577.4 MWh/yr. The average primary voltage Pre-VO is 124.13 V and Post-VO is 119.56 V (3.81% reduction). Average voltage calculation methods are provided in Sections 2.8.4 and 7. All LDC settings have a voltage set point of 119.0 volts. Average Customer saves 434.6 kWh/yr.

6.13.2 Plan B VO Improvements and Installed Costs

Plan B improvements and associated costs are summarized in Table 24 and Table 25.

Table 24 - Plan B VO Improvements

Sub Id	OH Line Reconductor (mi)	Station Regulator Addition (#)	In-line volt-regulator Addition (#)	OH & UG line or transf tap changes (#)	OH phase upgrades (mi)	Fixed 600 kVAr capacitor add (#)	Switched 600 kVAr capacitor add (#)
DCB28	0.00	0	1	1	0.01	0	2
DCD69	0.00	0	1	2	0.10	0	3
DCE71	0.84	0	0	2	0.00	3	4
DCE79	0.02	0	0	0	0.00	0	6
DCH38	0.00	0	2	9	0.00	0	2
DCW38	0.21	0	1	5	1.09	3	4
DCW48	0.58	0	0	2	0.02	1	4
DCW71	0.00	0	0	3	0.00	3	8
DCW73	0.00	0	2	0	0.00	1	2
DCW148	0.00	0	0	0	0.00	3	4
TDC375	0.00	1	4	8	0.00	0	58
DCW17	0.00	0	0	6	0.00	1	1
DCW233	0.20	0	0	0	0.00	1	3
TDC559	0.00	0	3	9	0.00	22	19
SS513	0.07	0	2	1	0.00	0	9
TSS104	0.00	0	2	1	0.00	0	20
	1.91	1	18	49	1.22	38	149

Table 25 - Plan B VO Improvements and Costs

Sub Id	Feeder Source & Regulator metering (#)	EOL Voltmeter (#)	EOL volt feedback sensing (#)	IVVC Application ($)	VO Upgrade Cost ($)
DCB28	2	2	0	$0	$111,880
DCD69	1	1	0	$0	$131,440
DCE71	2	2	0	$0	$285,500
DCE79	2	2	0	$0	$110,275
DCH38	6	6	0	$0	$222,000
DCW38	3	3	0	$0	$339,200
DCW48	2	2	0	$0	$217,415
DCW71	2	2	0	$0	$158,500
DCW73	1	2	0	$0	$172,500
DCW148	2	2	0	$0	$92,500
TDC375	16	16	1	$50,000	$1,430,500
DCW17	1	1	0	$0	$40,500
DCW233	1	1	0	$0	$102,375
TDC559	15	7	2	$152,000	$870,000
SS513	5	5	0	$0	$319,650
TSS104	7	7	1	$50,000	$538,500
	68	61	4	$252,000	$5,142,735

6.13.3 Average Voltage and End-Use Savings

Plan B average voltage reductions and end-use energy savings are given in Table 26. The average Post-VO voltage is 119.56 volts compared to a baseline Pre-VO of 124.13 volts. The weighted annual average reduction in customer voltage for the sample substation areas is 4.57 volts or 3.81%. The total end-use energy savings are 24,173.7 MWh/yr.

6.13.4 System Line and No-Load Loss Savings

Plan B system line and no-load losses for each of the 16 substations are given in Table 27. The feeder service area total system loss is 22,776.4 MWh for a savings of 2965.2 MWh. There is a no-load reduction of 1042.0 MWh and line loss savings of 1923.2 MWh. The total peak loss reduction is 1280.0 kW (1161.1 kW for line and 118.9 kW for no-load). Average feeder energy losses are 2.33% for Plan B compared to 2.68% for the Existing Case.

Table 26 - Plan B Average Voltage Reduction and End-Use Energy Savings

Sub Id	Existing kW Demand	Annual MWh Load	VO Factor (weighted)	Base Case Pre-VO Avg Volts	Post-VO Avg Volts	Voltage Change (pu)	End-Use Load Savings (MWh)
DCB28	4,793	15,577	0.752	123.89	119.61	0.0357	419.1
DCD69	7,020	19,868	0.846	124.02	119.30	0.0393	661.4
DCE71	12,138	33,852	0.758	124.13	119.58	0.0379	972.4
DCE79	11,533	33,375	0.702	124.15	119.72	0.0369	867.2
DCH38	3,377	10,375	0.760	124.04	119.65	0.0365	288.0
DCW38	15,575	47,753	0.783	124.21	119.54	0.0389	1,457.5
DCW48	11,274	31,421	0.746	124.30	119.45	0.0405	948.3
DCW71	14,025	62,809	0.771	124.11	119.62	0.0375	1,820.0
DCW73	5,620	16,819	0.731	124.30	119.54	0.0397	488.8
DCW148	10,980	33,315	0.759	124.43	119.36	0.0422	1,070.6
TDC375	63,190	259,799	0.760	123.32	120.00	0.0277	5,003.6
DCW17	4,387	12,200	0.735	124.21	119.48	0.0395	354.1
DCW233	5,532	15,450	0.784	124.47	119.29	0.0432	522.7
TDC559	63,731	218,503	0.742	124.05	119.69	0.0364	4,958.3
SS513	17,696	49,439	0.795	124.30	119.26	0.0420	1,654.1
TSS104	27,427	116,949	0.749	124.12	119.84	0.0357	2,687.7
	278,298	977,504					24,173.7

6.13.5 VO Economic Analysis

Plan B demonstrates an annual energy savings of 27,138.9 MWh/yr (2.78% reduction) and 5879.3 kW coincidental feeder demand reduction. The feeder system loss is 2.33% of the total energy delivered compared to existing system losses of 2.63%.

Plan B substations have a relatively moderate overall BCR of 1.920, which is less than the 2.5 target demonstrating maximum optimal savings potential. Total installed upgrade costs are $5,142,735 ($109,420/fdr). The overall net present value reduction in revenue requirements is $5,597,064 ($119,086/fdr). Total annual energy savings is 27,138.9 MWh/yr (577.4/fdr) for a program measure life of 15 years.

Plan B first year costs, O&M costs, energy saved, demand reductions, and BCR are shown in Table 28. Overall VO economic results are given in Table 29.

Table 27 - Plan B System Line and No-Load Losses

Sub Id	Annual MWh Load	Existing Line and No-Load Losses (MWh)	Revised Peak Line Loss (kW)	Reduction in Peak Line Loss (kW)	Savings in Line Loss (MWh)	Reduction in Peak No-Load Loss (kW)	Savings in No-Load Loss (MWh)	Revised Total Loss (MWh)	% Loss	Total Loss Energy Savings (MWh)
DCB28	15,577	595.0	11.6	69.7	105.4	3.7	32.0	457.6	2.94%	137.4
DCD69	19,868	498.8	102.0	1.6	1.9	3.2	27.8	469.1	2.36%	29.7
DCE71	33,852	897.7	168.3	19.2	22.5	5.5	48.4	826.7	2.44%	71.0
DCE79	33,375	1,043.6	98.2	255.7	321.3	4.7	41.4	680.9	2.04%	362.7
DCH38	10,375	686.1	94.3	6.3	8.7	4.3	37.9	639.5	6.16%	46.6
DCW38	47,753	883.9	199.2	14.8	20.3	5.0	43.6	820.0	1.72%	63.9
DCW48	31,421	681.9	105.6	123.3	144.5	3.6	31.9	505.5	1.61%	176.4
DCW71	62,809	1,240.8	129.4	0.5	1.2	7.4	65.1	1,174.5	1.87%	66.3
DCW73	16,819	425.7	137.8	3.5	4.6	2.0	18.0	403.1	2.40%	22.6
DCW148	33,315	829.2	92.8	0.0	0.0	6.4	55.8	773.4	2.32%	55.8
TDC375	259,799	7,264.8	1,049.8	508.8	1,052.9	20.7	181.7	6,030.1	2.32%	1,234.6
DCW17	12,200	293.1	46.2	1.1	1.3	2.0	17.7	274.1	2.25%	19.0
DCW233	15,450	387.8	25.5	13.7	16.1	3.2	27.7	344.0	2.23%	43.8
TDC559	218,503	5,725.8	881.1	128.5	201.1	26.4	231.4	5,293.3	2.42%	432.5
SS513	49,439	1,921.8	229.4	10.8	12.7	11.3	98.7	1,810.3	3.66%	111.4
TSS104	116,949	2,365.6	245.7	3.6	8.6	9.4	82.8	2,274.2	1.94%	91.4
	977,504	25,741.6	3,616.9	1,161.1	1,923.2	118.9	1,042.0	22,776.4	2.33%	2,965

Table 28 - Plan B Economic Analysis Summary by Substation

Substation id	Number of Customers	VO Upgrade Costs (w/o Isolation Adders) (First Year $)	VO Upgrade Costs (w/ Isolation Adders) (First Year $)	Annual O&M Costs (First year $)	NPV of VO Upgrade Costs (w/ Isolation Adders) ($)	NPV of VO Energy Savings ($)	NPV of Revenue Requirement Savings ($)	Total VO Energy Saved MWh/y	Total Peak Demand Reduction kW/y	Benefit Cost Ratio
DCB28	1,031	$111,880	$111,880	$2,238	$145,770	$263,795	$118,025	556.5	153.1	1.81
DCD69	589	$131,440	$131,440	$2,629	$171,255	$327,591	$156,336	691.1	130.6	1.91
DCE71	2,182	$285,500	$285,500	$5,710	$371,982	$494,571	$122,589	1,043.3	209.7	1.33
DCE79	3,114	$110,275	$110,275	$2,206	$143,679	$583,021	$439,342	1,229.9	425.4	4.06
DCH38	660	$222,000	$222,000	$4,440	$289,247	$158,600	-$130,647	334.6	65.4	0.55
DCW38	1,687	$339,200	$339,200	$6,784	$441,949	$721,194	$279,246	1,521.4	297.1	1.63
DCW48	1,862	$217,415	$217,415	$4,348	$283,273	$533,134	$249,861	1,124.7	307.4	1.88
DCW71	2,581	$158,500	$158,500	$3,170	$206,512	$894,144	$687,632	1,886.3	354.2	4.33
DCW73	950	$172,500	$172,500	$3,450	$224,753	$242,390	$17,638	511.3	98.5	1.08
DCW148	3,417	$92,500	$92,500	$1,850	$120,520	$533,925	$413,406	1,126.4	210.1	4.43
TDC375	13,801	$1,430,500	$1,430,500	$28,610	$1,863,820	$2,957,074	$1,093,254	6,238.2	1,481.5	1.59
DCW17	1,030	$40,500	$40,500	$810	$52,768	$176,864	$124,096	373.1	70.5	3.35
DCW233	1,397	$102,375	$102,375	$2,048	$133,386	$268,532	$135,146	566.5	116.3	2.01
TDC559	18,039	$870,000	$870,000	$17,400	$1,133,536	$2,555,383	$1,421,847	5,390.8	1,098.3	2.25
SS513	5,197	$319,650	$319,650	$6,393	$416,477	$836,911	$420,434	1,765.5	336.8	2.01
TSS104	4,908	$538,500	$538,500	$10,770	$701,620	$1,317,360	$615,740	2,779.1	524.4	1.88
	62,445	$5,142,735	$5,142,735	$102,855	$6,700,547	$12,864,490	$6,163,943	27,139	5,879	1.920

Table 29 - Plan B Economic Analysis for Substations

	Plan B
General Substation Information	
Number of Substations Investigated	
Total Customers Served (#)	62,445
Number of Feeders (Viable and Non-viable) Investigated (#)	56
Number of Feeders (Viable) Investigated (#)	47
Substation Annual Peak Demand (kW)	278,298
Total Annual Energy Consumed (MWh/yr)	977,504
VO Energy Savings Potential	
Average Primary Voltage Pre-VO (V)	124.13
Average Primary Voltage Post-VO (V)	119.56
Average Customer VO Voltage Change (%)	3.81%
Substation Weighted Average VO factor	0.761
VO Energy Savings (MWh/y)	24,173.7
Line Loss Energy Savings (MWh/y)	1,923.2
No-Load Loss Energy Savings (MWh/y)	1,042.0
Distribution Line and Transf no-load loss (%)	2.33%
Total Energy Savings (MWh/y)	27,138.9
Total Coincidental Demand Reduction (kW)	5,879.3
Customer Average Energy Savings (kWh/yr)	434.6
Benefit Cost Projections	
Total VO Upgrade Cost - First Year ($)	$5,142,735
Annual O&M First Year Costs ($)	$102,855
Total VO Upgrade Cost (NPV)	$6,700,547
Total VO Energy Savings (NPV)	$12,864,490
NPV Revenue Requirement Savings ($)	$6,163,943
VO Benefit Cost Ratio (BCR)	1.920

6.14 Comparison of Alternative VO Plans

6.14.1 Economic Evaluation Analysis Methodology

The objective of the VO economic evaluations[9] was to identify solutions that maximize energy savings while meeting acceptable VO thresholds and ComEd BCR targets. As more system improvements were added, incremental energy saved diminished, resulting in lower BCRs. The economic analysis assumes no incentives are applied to ComEd first-year costs. The equipment life of 33 years is considered short, which also lowers the BCR.

The net present value of savings (reduced revenue requirements) is another consideration when comparing alternative plans. If net PV savings are zero, the BCR is 1.0, resulting in no change in net revenue requirements. The alternative plan development goal is to have BCRs greater than 1.5 to provide a cushion for possible inflation and financial risk (i.e., higher improvement costs, lower marginal costs, and higher inflation rates).

Net PV system improvement estimates include first year investment costs; net present value of annual fixed charges and O&M expenses; expected future equipment salvage; present worth value investment factors; and inflation rates. The energy efficiency measure (EEM) program life is assumed to be 15 years based on the NWPCC Simplified VO M&V Protocol. The VO savings life is 15 years, and the system improvement loss saving measure equipment life is set at 33 years. However, the VO energy savings measure program life can be extended (e.g., 20 years) if costs are added in a future year (e.g., at year 10 and 20) as a percentage of first year investment costs. In this study, the VO life is set at 15 years. A lump sum cost adder is included in year 10 costs, assuming 10% of the initial installed cost is needed to maintain the installation and sustain the annual savings. All system loss savings benefits and investment costs beyond the program life of 15 years are discounted and credited in the 15th year.

The avoided marginal cost of purchased power is assumed to be $0.042/kWh for the base year (2014) with an energy cost inflation rate of 3.0% per year thereafter.

[9] The detailed economic analysis was performed using economic principles described in D. G. Newnan, T. G. Eschenbach, J. P. Lavelle, *Engineering Economic Analysis, Ninth Edition*, Oxford University Press, Inc., New York, 2004.

6.14.2 Summary of Economic Comparison

A comparison of Plan A and Plan B results for the 16 substations and 56 feeders (consisting of 47 viable and 9 non-viable feeder candidates) is shown in Figure 12 and Figure 13. Included are expected energy savings and upgrade NPV costs; an overview applied upgrades; minimum primary voltages allowed; BCRs; and end-use MWh/yr savings.

VO energy savings are divided into two categories: 1) VO Energy Savings (end-use savings) and 2) VO System Loss Savings (ComEd system savings). The costs for impact of peak demand reductions were not evaluated in the study.

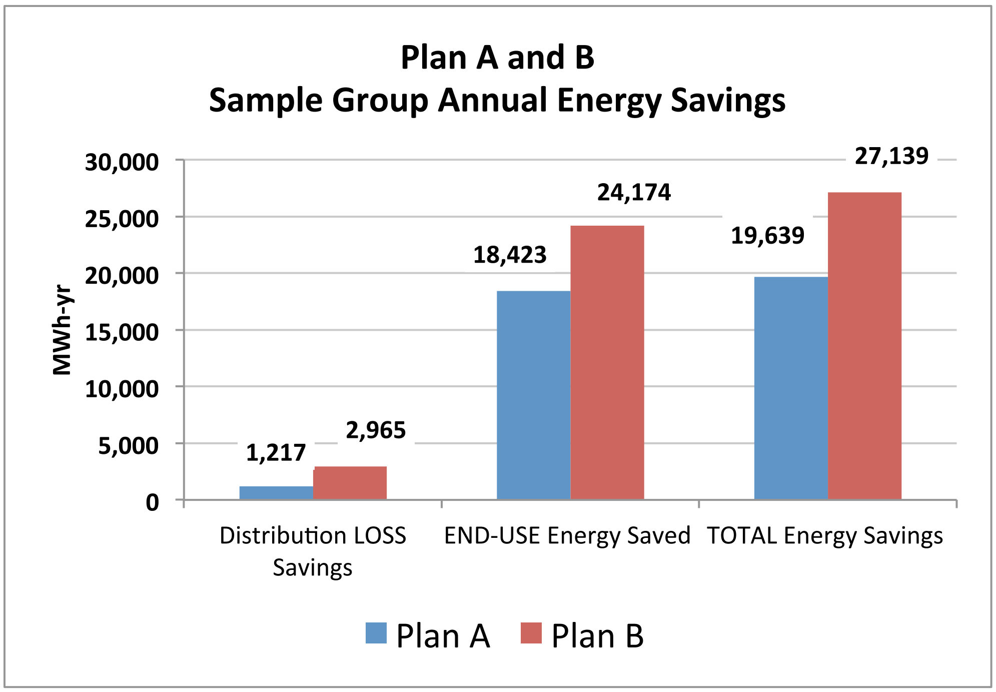


Figure 12 - Sample Group Total Energy Savings Potential

The ***lowest cost*** alternative VO plan is Plan A, with an installed first-year cost of $3,705,440 (or $78,839 per feeder) and total energy savings 19,639.0 MWh/yr (or 417.9 MWh/yr per feeder). Plan A includes improvements and upgrades necessary to meet VO thresholds. Plan A upgrades are summarized in Table 30.

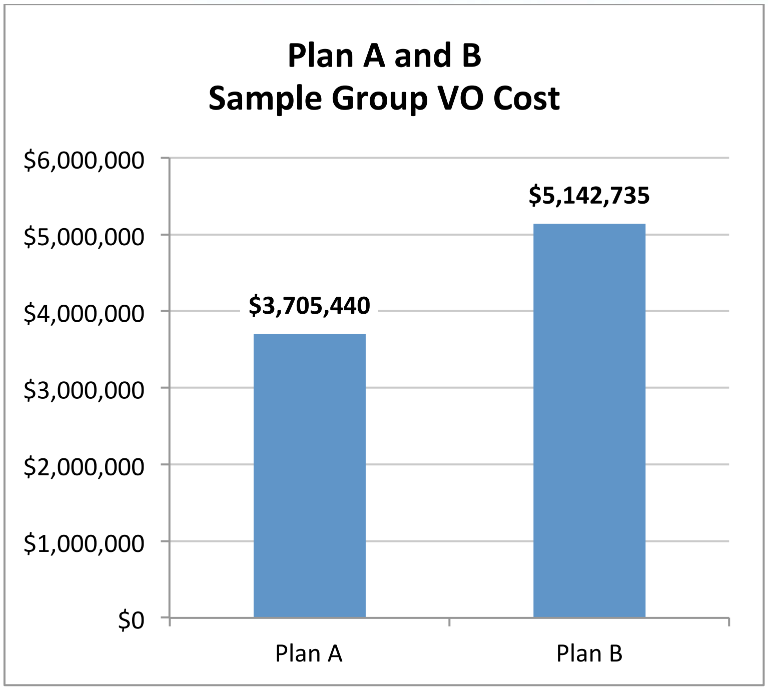


Figure 13 - Sample Group Total VO Cost

Table 30 - Plan A VO Upgrades

OH Line Reconductor (mi)	0.62
Station Regulator Addition (#)	0
In-Line Voltage Regulator Addition	7
OH & UG Line or Transformer Tap Changes (#)	10
OH Phase Upgrades (mi)	0.16
Fixed 600 kVAR Capacitor Additions (#)	38
Switched 600 kVAR Capacitor Additions (#)	150
Feeder Source & Regulator Metering (#)	58
EOL Voltmeters (#)	60
EOL Voltage Feedback Sensing (#)	4
IVVC Application ($)	$250,000
Total VO Upgrade Cost ($)	$3,705,440
VO Upgrade Cost (w/ Isolation Adders)	$3,705,440

Plan A system was designed for minimum primary EOL voltages of 120.0 volts. The overall evaluated BCR is 1.928, with average customer energy savings of 314.5 kWh per year.

The ***highest energy saving*** alternative VO plan studied is Plan B, with an installed cost of $5,142,735 (or $109,420 per feeder) and total energy savings 27,138.9 MWh/yr (or 577.4 MWh/yr per feeder). Plan B has the same system improvements as Plan A plus additional upgrades as needed. Plan B upgrades are summarized in Table 31.

Plan B is designed for minimum primary EOL voltages of 119.0 volts. The overall evaluated BCR is 1.920, with customer average savings of 434.6 kWh per year.

6.14.3 Plan A and Plan B Summary Comparison

Table 32 compares Plan A and Plan B general substation/feeder information, VO energy savings potential, and benefit cost projections.

Plan A benefits and costs for use with energy efficiency measure initiatives are given for VO Energy Savings (end-use savings) and VO System Loss Savings (ComEd system savings) as follows:

VO Energy Saving:	18,422.5 kWh/yr,	$370,544 cost,	$11,117 OM cost,	and 15-year life.
VO Loss Saving:	1,216.4kWh/yr,	$3,334,896 cost,	$100,046 OM cost,	and 33-year life.
Totals:	19,639.0	$3,705,440	$111,163	

Plan B benefits and costs for use with energy efficiency measure initiatives are given for VO Energy Savings (end-use savings) and VO System Loss Savings (ComEd system savings) as follows:

VO Energy Saving:	24,173.7 kWh/yr,	$514,220 cost,	$15,427 OM cost,	and 15-year life.
VO Loss Saving:	2,965.2 kWh/yr,	$4,628,515 cost,	$138,855 OM cost,	and 33-year life.
Totals:	27,138.9	$5,142,735	$154,282	

Table 31 - Plan B VO Upgrades

OH Line Reconductor (mi)	1.91
Station Regulator Addition (#)	1
In-Line Voltage Regulator Addition	18
OH & UG Line or Transformer Tap Changes (#)	49
OH Phase Upgrades (mi)	1.22
Fixed 600 kVAR Capacitor Additions (#)	38
Switched 600 kVAR Capacitor Additions (#)	149
Feeder Source & Regulator Metering (#)	68
EOL Voltmeters (#)	61
EOL Voltage Feedback Sensing (#)	4
IVVC Application ($)	$252,000
Total VO Upgrade Cost ($)	$5,142,735

Table 32 - Plan Comparison Summary

	Plan A	Plan B
General Substation Information		
Number of Substations Investigated		
Total Customers Served (#)	62,445	62,445
Number of Feeders (Viable and Non-viable) Investigated (#)	56	56
Number of Feeders (Viable) Investigated (#)	47	47
Substation Annual Peak Demand (kW)	278,298	278,298
Total Annual Energy Consumed (MWh/yr)	977,504	977,504
VO Energy Savings Potential		
Average Primary Voltage Pre-VO (V)	124.13	124.13
Average Primary Voltage Post-VO (V)	120.57	119.56
Average Customer VO Voltage Change (%)	2.96%	3.81%
Substation Weighted Average VO factor	0.761	0.761
VO Energy Savings (MWh/y)	18,422.5	24,173.7
Line Loss Energy Savings (MWh/y)	395.6	1,923.2
No-Load Loss Energy Savings (MWh/y)	820.8	1,042.0
Distribution Line and Transf no-load loss (%)	2.51%	2.33%
Total Energy Savings (MWh/y)	19,639.0	27,138.9
Total Coincidental Demand Reduction (kW)	3,892.6	5,879.3
Customer Average Energy Savings (kWh/yr)	314.5	434.6
Benefit Cost Projections		
Total VO Upgrade Cost - First Year ($)	$3,705,440	$5,142,735
Annual O&M First Year Costs ($)	$74,109	$102,855
Total VO Upgrade Cost (NPV)	$4,827,873	$6,700,547
Total VO Energy Savings (NPV)	$9,309,375	$12,864,490
NPV Revenue Requirement Savings ($)	$4,481,502	$6,163,943
VO Benefit Cost Ratio (BCR)	1.928	1.920

7. Extrapolation to System Level

A primary objective of the feasibility study was to develop accurate and defendable estimates of VO cost and energy savings potential. The research plan accomplished this through a multi-stage analysis that applied formula-based engineering to a study group based on feeder-specific load flow simulations on a representative sample of feeders. Sampling statistics were then used to extrapolate the results to the system level.

7.1 Project Study Groups

The feasibility study conducted an engineering analysis of individual feeders and substation groups. From a sample design perspective, VO costs and savings were evaluated at the feeder level using the four key project groups described below.

Group 1 - ComEd System Population. The ComEd system population is defined as the total number of primary network feeders and associated substations within ComEd's service territory, and is composed of 5655 feeders fed from 806 substations. Specifically excluded are 129 secondary networks in the downtown Chicago area deemed not appropriate for voltage optimization. The system population was developed based on data provided by ComEd's Distribution Planning Group. Individual feeder and substation data was derived primarily from ComEd's CYME and GIS databases.

Group 2 - Project Study Group. The project study group is a subset of feeders and substations included in the analysis. The study group consists of 3757 feeders and 543 substations, which is approximately two-thirds of the total system population. Not all feeders/substations were included; i.e., 1898 feeders and 264 substations were excluded. Five (5) of 19 initially selected ComEd regions were excluded due to unexpected data issues and project time constraints. In addition, feeders from the included 14 regions were excluded due to data issues. It was assumed these excluded feeders are adequately represented by feeders included in the study group.

Group 3 - Viable Feeder Study Group. The Task 3 screening analysis was conducted on all 3757 feeders of the project study group. Of these, 1837 were deemed non-viable for VO application due to their voltage class (less than 11 kV or higher than 29 kV), or customer make-up (large commercial and industrial >1000 kW). The remaining 1920 feeders and 543 substations make up the viable feeder study group. Preliminary VO costs and savings based on formula-based engineering analysis were developed for each of these feeders as documented in the project Task 3 report.

Group 4 - Sample Group. The sample group identified in Task 3 (screening) consisted of 16 substations and 70 feeders (50 viable and 20 non-viable). A later assessment reduced the total number of feeders from 70 to 61 as explained below.

The Chicago South substation (TSS104) consisted of 3 power transformers, 1 dedicated and 2 paralleled. The dedicated transformer (TR71) served 4 viable and 1 non-viable feeders. The paralleled transformers (TR72 and TR73) served 4 viable and 5 non-viable feeders. One of the viable feeders, Z10432, was reclassified to non-viable because it served Midway Airport, reducing the viable feeder count for the paralleled transformers (from 4 to 3), and increasing the non-viable feeder count (from 10 to 6). Since Midway is a sensitive load, re-configuration was not attempted. With only 3 viable feeders sharing a common bus with 11 non-viable feeders, isolation costs would have been too high to consider. Therefore, the 9 paralleled transformer feeders were excluded from the study, reducing the total feeder count from 70 to 61, and the viable feeder count from 50 to 46.

A feeder was then added to substation DCH38 (located in the Dixon region) by splitting H385 into two feeders, one serving the North and the other serving the South (H385 North and H385 South), increasing the viable feeder count from 46 to 47.

Because feeders need to be modeled as substation groups to capture interactive voltage effects across feeders in the same voltage control zone, the sample was drawn at the substation level. Substations were grouped into strata based on energy savings potential (ESP) and VO Costs:

HH Substations with high ESP$ > $1,474,535 and high VO Cost > $362,267
HL Substations with high ESP$ > $1,474,535 and low VO Cost <= $362,267
LH Substations with low ESP$ < $161,347 and high VO Cost > $362,267
LL Substations with low ESP$ < $161,347 and low VO Cost <= $362,267

The sample extrapolation process is shown in Figure 14.

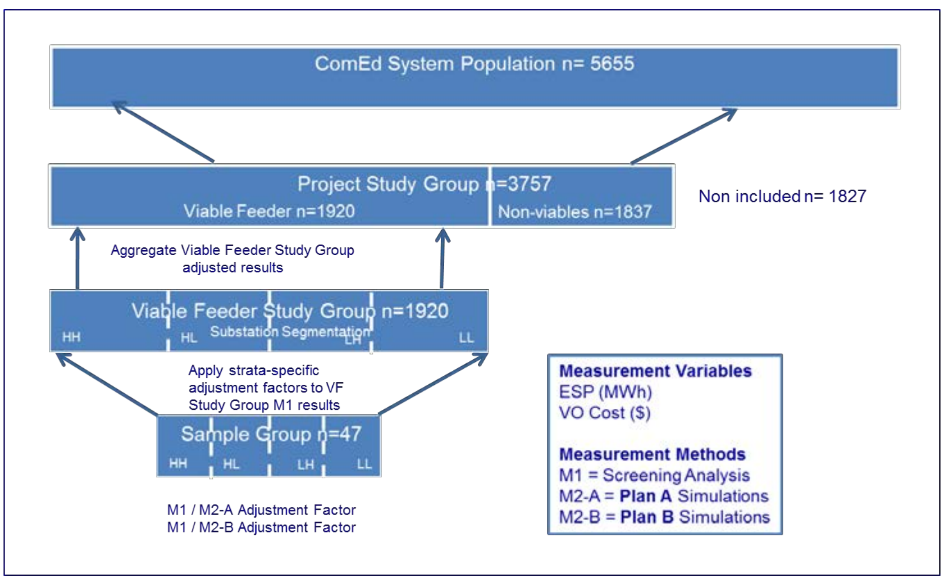


Figure 14 - Sample Extrapolation Process

7.2 VO Estimation Methods

The research plan used a sample-based two-stage estimation procedure. First, simplified cost and savings estimates were developed using a formulaic engineering analysis on all viable feeders in the study group (referred to as Method 1 or M1). Next, detailed load flow simulations and customized cost build-ups were performed on a representative sample of substation feeder groups (Method 2, or M2).

Three scenarios were modeled: a) Base Case; b) Low Cost (M2-A) (Plan A); and c) Maximum Energy Savings (M2-B) (Plan B). The two study groups are directly linked through a stratified random sampling approach of substation feeder groups and expanded to the population of viable feeders using a statistical ratio estimate. This sample design allows for extrapolation of M1 and M2 results to the ComEd system level with quantifiable levels of precision.

7.3 System Level Results

Summarized in Table 33 are system-level results for VO costs and ESP (MWh-yr). The lower cost scenario (Plan A) VO approach has a potential total cost of $425 million and results in energy savings of 1350 GWh per year. This is equivalent to a levelized cost of energy of $0.035/kWh. The maximum savings scenario approach (Plan B) has a total cost of $574 million and a savings potential of 1,912 GWh per year, or approximately 2.1% of ComEd's 2013 retail kWh sales.

Table 34 summarizes the relative precision of the sample-based M2-A and M2-B results extrapolated to the system population. The relative precision is calculated at a 90% confidence level. The precision estimates refer to the sampling error of performing the detailed M2 methodology on only a sample of 47 feeders as compared to results that would have been achieved had we performed the detailed M2 methodology on all 2,890 viable feeders in the ComEd population. It does not factor in the measurement error of the M2 simulation methodology compared to actual field observations.

Table 35 provides feeder-based extrapolation values resulting from sample group, study group and system population extrapolations. Table 36 provides similar extrapolations results based on substation values. (See Appendix 12.1 for a prioritized ranking of all 346 viable substations based on benefit-cost ratios.)

Table 33 - System-Level Results

	Total	Average per Feeder	Average per Substation
Plan A Results			
VO Cost	$425,466,877	$147,220	$826,902
VO ESP (MWh-yr)	1,350,371	467	2,624
Plan B Results			
VO Cost	$574,232,508	$198,696	$1,116,030
VO ESP (MWh-yr)	1,912,952	662	3,718

Table 34 - Relative Precision

	Total		Relative Precision at 90% Confidence	
Plan A Results				
VO Cost	$425,466,877	+/-	*66,946,483*	*15.7%*
VO ESP (MWh-yr)	1,350,371	+/-	*136,589*	*10.1%*
Plan B Results				
VO Cost	$574,232,508	+/-	*91,843,098*	*16.0%*
VO ESP (MWh-yr)	1,912,952	+/-	139,278	7.3%

Table 35 - Extrapolation Results - Feeder-Based

ComEd VO Feasibility Study
Feeder Sample Extrapolation

	Total ComEd System n=5655		Relative Precision at 90% Confidence		
# of Feeders	5655				
# Viable / Non-viable	**2,890**	**2765**			
Total VO ESP (MWh) - A	**1,350,371**		*+/-*	*136,589*	*10.1%*
Total VO Costs ($) - A	**$425,466,877**		*+/-*	*66,946,483*	*15.7%*
BCR Scenario A (Preliminary)	**1.50**				
Total VO ESP (MWh) - B	**1,912,952**		*+/-*	*139,278*	*7.3%*
Total VO Costs ($) - B	**$574,232,508**		*+/-*	*91,843,098*	*16.0%*
BCR Scenario B (Preliminary)	**1.58**				

	Project Study Group n= 3757					
	Viable Feeders	Non-Viable	-included Feeders	Relative Precision at 90% Confidence		
# of Feeders	1920	1837	1898			
Total VO ESP (MWh) - A	**897,143**			*+/-*	*90,745*	*10.1%*
Total VO Costs ($) - A	**$282,666,500**			*+/-*	*44,477,089*	*15.7%*
Total VO ESP (MWh) - B	**1,270,904**			*+/-*	*92,532*	*7.3%*
Total VO Costs ($) - B	**$381,501,597**			*+/-*	*61,017,598*	*16.0%*

	Viable Feeder Study Group n=1920			
Substation Strata	HH	HL	LH	LL
# of Feeders	1285	152	386	97
Avg. Feeder ESP - M1	412	377	322	191
Avg. Feeder VO Cost M1	$163,531	$108,826	$230,985	$137,353
Adjusted ESP- A	**483**	**539**	**417**	**351**
Adjusted VO Cost - A	**$159,943**	**$67,649**	**$140,420**	**$130,460**
Adjusted ESP - B	**694**	**693**	**591**	**466**
Adjusted VO Cost - B	**$203,273**	**$96,975**	**$227,298**	**$183,699**

Strata Definitions
HH - High ESP / High Cost
HL - High ESP / Low Cost
LH - Low ESP / High Cost
LL - Low ESP / Low Cost

M1= Screening analysis results
M2-A= Simulation results - **Plan A**
M2-B= Simulation results - **Plan B**

h	Sample Group n=47				
Substation Strata	HH	HL	LH	LL	*Total*
# of Feeders	21	11	9	6	*47*
Avg. Feeder ESP-M1	329	318	367	205	
Avg. Feeder VO Cost-M1	$114,826	$132,555	$176,150	$105,156	
Avg. Feeder ESP M2-A	385	455	476	379	
Avg. Feeder VO Cost M2-A	$112,307	$82,399	$107,085	$99,879	*Avg Adj Factor*
Adjustment Factor ESP A	**1.17**	**1.43**	**1.30**	**1.84**	***1.31***
Adjustment Factor VO Cost A	**0.98**	**0.62**	**0.61**	**0.95**	***0.79***
Avg. Feeder ESP M2-B	554	584	674	503	
Avg. Feeder VO Cost M2-B	$142,731	$118,119	$173,338	$140,639	
Adjustment Factor ESP B	**1.68**	**1.84**	**1.84**	**2.45**	***1.82***
Adjustment Factor VO Cost B	**1.24**	**0.89**	**0.98**	**1.34**	***1.10***

Table 36 - Extrapolation Results - Substation-Based

ComEd VO Feasibility Study
Substation Sample Extrapolation

	Total ComEd System n=806			Relative Precision at 90% Confidence	
# of Substations	806				
# Viable / Non-viable	**515**	**291**			
Total VO ESP (MWh) - A	**1,315,746**		+/-	210,902	16.0%
Total VO Costs ($) - A	**$421,705,974**		+/-	50,583,681	12.0%
BCR Scenario A (Preliminary)	**1.48**				
Total VO ESP (MWh) - B	**1,861,114**		+/-	215,012	11.6%
Total VO Costs ($) - B	**$568,093,150**		+/-	49,938,781	8.8%
BCR Scenario B (Preliminary)	**1.55**				

	Project Study Group n= 542				Relative Precision at 90% Confidence	
	Viable Substations	Non-Viable	Non-included Substations			
# of Substations	346	196	264			
Total VO ESP (MWh) - A	**884,782**			+/-	141,823	16.0%
Total VO Costs ($) - A	**$283,578,955**			+/-	34,015,329	12.0%
Total VO ESP (MWh) - B	**1,251,519**			+/-	144,586	11.6%
Total VO Costs ($) - B	**$382,017,974**			+/-	33,581,662	8.8%

Viable Substation Study Group n=346				
Substation Strata	HH	HL	LH	LL
# of Substations	86	86	87	87
Avg. Feeder ESP - M1	6153	667	1427	212
Avg. Feeder VO Cost M1	$2,443,459	$192,343	$1,024,830	$153,140
Adjusted ESP- A	**7199**	**919**	**1851**	**294**
Adjusted VO Cost - A	**$2,389,849**	**$130,175**	**$623,014**	**$145,455**
Adjusted ESP - B	**10359**	**1148**	**2622**	**389**
Adjusted VO Cost - B	**$3,037,275**	**$177,401**	**$1,008,471**	**$204,813**

Strata Definitions
HH - High ESP / High Cost
HL - High ESP / Low Cost
LH - Low ESP / High Cost
LL - Low ESP / Low Cost

M1= Screening analysis results
M2-A= Simulation results - **Plan A**
M2-B= Simulation results - **Plan B**

Sample Group n=16					
Substation Strata	HH	HL	LH	LL	*Total*
# of Substations	2	6	3	5	*16*
Avg. Feeder ESP-M1	3454	632	1100	246	
Avg. Feeder VO Cost-M1	$1,205,672	$250,140	$528,450	$126,188	
Avg. Feeder ESP M2-A	4041	871	1427	341	
Avg. Feeder VO Cost M2-A	$1,179,220	$169,292	$321,255	$119,855	*Avg Adj Factor*
Adjustment Factor ESP A	**1.17**	**1.38**	**1.30**	**1.38**	***1.25***
Adjustment Factor VO Cost A	**0.98**	**0.68**	**0.61**	**0.95**	***0.79***
Avg. Feeder ESP M2-B	5815	1087	2022	451	
Avg. Feeder VO Cost M2-B	$1,498,678	$230,708	$520,015	$168,767	
Adjustment Factor ESP B	**1.68**	**1.72**	**1.84**	**1.83**	***1.74***
Adjustment Factor VO Cost B	**1.24**	**0.92**	**0.98**	**1.34**	***1.10***

7.4 Factors Affecting Potential Results

The results presented in this study were generated using ComEd supplied data sources combined with a variety of industry accepted engineering calculations, statistical methods, commercial load flow modeling tools (CYME), and professional judgment. At every juncture, care was taken to ensure that the results from the study are both representative of the ComEd system, and unbiased. Table 37 provides a qualitative sensitivity analysis of the key parameters or methods used in the study.

Table 37 - Factors Affecting Potential Results

Parameter / Method	Source	Key Assumptions	Sensitivity
Feeder Peak Load (kW_7)	ComEd distribution planning data in CYME	Values are assumed to be measured values that accurately reflect historical feeder loadings	Feeder Peak kW is a key determinant of energy loads and savings. Distribution planners tend to overestimate kW loadings, which would negatively impact VO ESP.
Load Factor	Estimated for screening (M1); recorded (when available) or estimated for simulations (M2)	M1 = .35 M2 = .401 (avg.) Both load factors are considered conservative.	Load factor directly affects kWh savings. Conservative assumptions would underestimate savings potential
Engineering models and impedance calculations of voltage drops	Engineering calculations (M1) and CYME-DIST Load flow model (M2)	All calculations are based on industry accepted engineering methods	Load flow simulation results tend to be stable.
VO Factor	Estimated based on analysis of ComEd end-use characteristics and feeder-specific customer composition	The average VO factor of .753 is assumed to be conservative.	Energy savings is directly related to VO Factor. A bias up or down can significantly impact results.
Sampling and extrapolation methods	Random sampling and ratio estimation used for the sample and study groups. Feeder counts used to extrapolate from the study group to the system population level	Sample selection was unbiased. Excluded 4 regions were statistically similar to the other 14 regions.	Sampling precision is calculated as +/- 7% - 16% at 90% confidence levels
Existing System Power Factor	Estimated at 98%	Assumption based on industry standards.	Overestimating power factor increases voltage drop and energy savings potential

8. Benefit-Cost Analysis on Representative Feeders

8.1 DSMore Input Development

AEG and ComEd conducted a benefit-cost analysis of two voltage optimization (VO) plans at select feeders within ComEd's service territory. The analysis was based on system-level energy savings potential of high and low cost scenarios, which were inputted into the Demand Side Management Option Risk Evaluator (DSMore) cost-effectiveness analysis tool. Key parameters and economic assumptions used to develop the DSMore inputs are shown in Table 38. DSMore inputs were developed using the same methodology for each plan.

Table 38 - DSMore Input Parameters

Parameter	Plan A	Plan B
Energy Savings Potential (MWh)	1,350,371	1,912,952
First Year Capital Cost	$425,466,877	$574,232,508
Annual O&M Costs	$8,509,338	$11,484,650
Annual O&M Costs (% of First Year)	2%	2%
Replacement Cost (% of First Year)	10%	10%
Measure Life (years)	15	15
Equipment Life (years)	33	33
Replacement Year	10	10
Salvage Year	15	15

Energy savings potential and first year capital costs were taken directly from the system-level simulation results described in Task 8. Other economic assumptions based on generic industry specifications were used to develop the DSMore inputs.

8.2 Participation, Program Costs, and Credits

The VO program is counted as a single participant in the first year of the program. Energy savings potential represents annual energy savings attributable to the VO program. Free ridership is assumed to be zero since only customers serviced by feeders where VO is deployed will be impacted by the program. The DSMore cost-effectiveness tool allows for the four main utility cost categories described in Table 39.

Table 39 - DSMore Utility Cost Categories

DSMore Input	Description
Annual Administration Costs	Annual O&M costs
Implementation / Participation Costs	First year capital costs
Incentives	The VO program does not include incentives.
Other / Miscellaneous Costs	Replacement costs minus salvage value

The measured life is defined as the total number of years the VO program may be deployed to achieve savings. By contrast, equipment life reflects the total useful life of VO equipment. The first year capital cost represents the total utility outlay for equipment and system upgrades needed for the VO program. The annual O&M costs are estimated as a percentage of first year capital costs for each subsequent year of the program.

Asset depreciation and replacement costs used generic program economic assumptions. Replacement costs were determined as a percentage of the first year capital cost. At the end of the program, the utility is entitled to a credit equal to the depreciated asset value of VO equipment.

8.3 DSMore Load Shapes

Load shapes reflect the average weekday and weekend hourly savings by month and season for 2013. Hourly savings for each scenario were developed based on the total hourly load of customers serviced by feeders where VO is deployed. The total energy savings for each scenario were extrapolated to each hour based on the hourly load factor, which was normalized to achieve an average VO load factor of approximately 0.60. Table 40 summarizes calculations performed to develop DSMore load shapes.

Table 40 - DSMore Load Shape Parameters

Variable	Definition
Source Hourly Load	Total hourly customer load serviced by feeders where VO is deployed.
Normalized Source Load Factor	Proportion of source hourly load to max hourly load normalized to achieve 0.60 VO factor.
Hourly Savings	Annual savings for each scenario multiplied by normalized source load factor

Load shapes are presented in Figure 15.

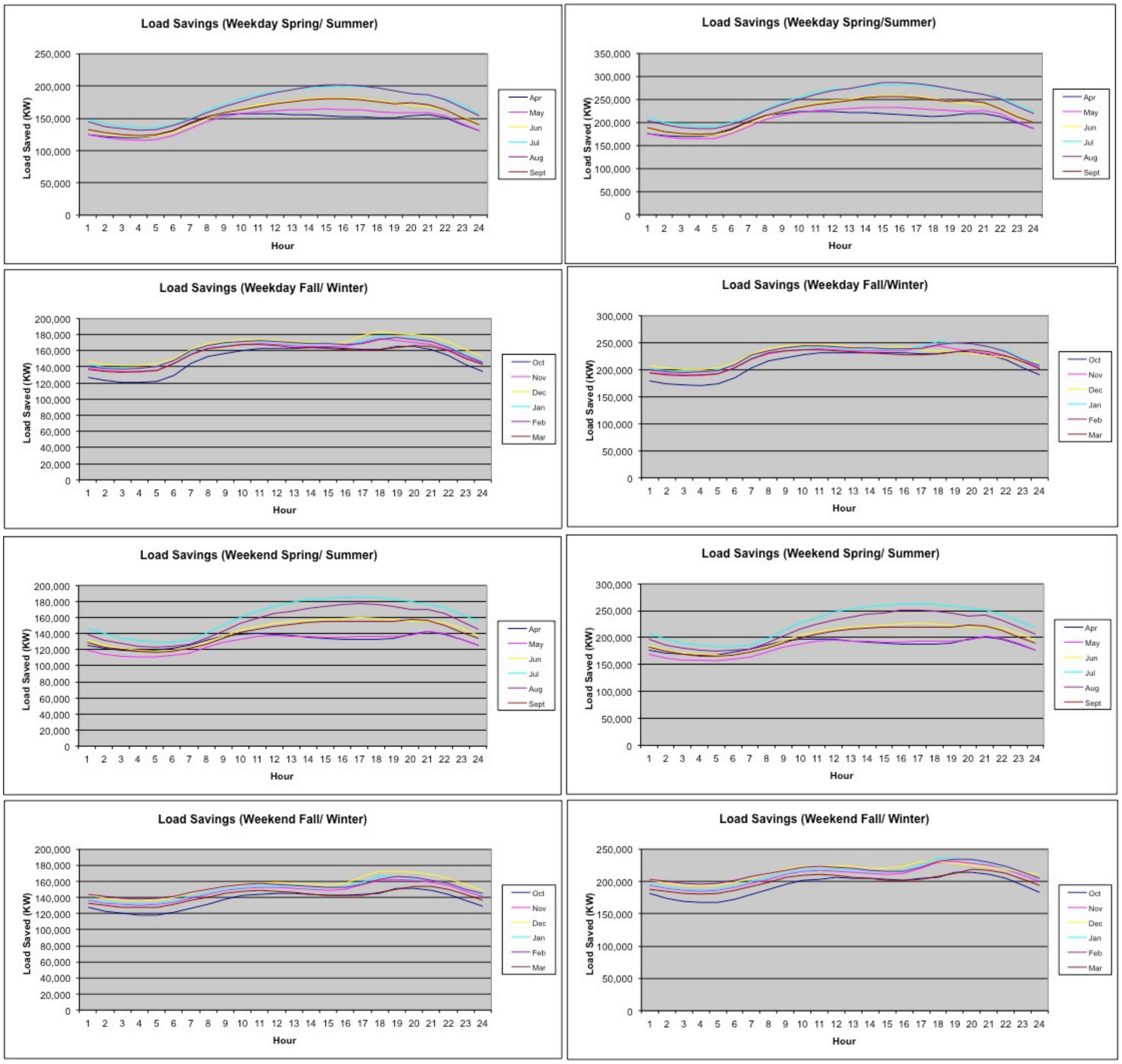


Figure 15 - DSMore Load Shapes

DSMore benefit-cost results are presented in Table 41 for Plan A and Table 42 for Plan B.

Table 41 - Plan A DSMore B-C Results

Present Values (PVs) of Costs and Benefits Per Test	Cost Based	Market-Based Minimum	Market-Based Today	Market-Based Alternate	Market-Based Option	Market-Based Maximum
Utility (PAC) Test						
Avoided Electric Production	$608,926,671.80	$408,387,082.11	$608,926,671.80	$1,302,393,048.05	$1,006,035,825.48	$8,964,342,220.65
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33
Avoided T&D Electric	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44
Avoided Ancillary	$82,568,793.61	$80,814,484.49	$82,568,793.61	$82,568,793.61	$82,568,793.61	$84,107,629.00
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$952,746,427.19	$750,452,528.37	$952,746,427.19	$1,646,212,803.43	$1,349,855,580.87	$9,309,700,811.42
Administration Costs	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13
Implementation / Participation Costs	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29
Other / Miscellaneous Costs	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79
Incentives	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.20	1.73	2.20	3.80	3.12	21.52
TRC Test						
Avoided Electric Production	$608,926,671.80	$408,387,082.11	$608,926,671.80	$1,302,393,048.05	$1,006,035,825.48	$8,964,342,220.65
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33
Avoided T&D Electric	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44
Avoided Ancillary	$82,568,793.61	$80,814,484.49	$82,568,793.61	$82,568,793.61	$82,568,793.61	$84,107,629.00
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$952,746,427.19	$750,452,528.37	$952,746,427.19	$1,646,212,803.43	$1,349,855,580.87	$9,309,700,811.42
Administration Costs	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13
Implementation / Participation Costs	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29
Other / Miscellaneous Costs	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79
Total	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Costs (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Tax Credits (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.20	1.73	2.20	3.80	3.12	21.52
RIM Test						
Avoided Electric Production	$608,926,671.80	$408,387,082.11	$608,926,671.80	$1,302,393,048.05	$1,006,035,825.48	$8,964,342,220.65
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33
Avoided T&D Electric	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44
Avoided Ancillary	$82,568,793.61	$80,814,484.49	$82,568,793.61	$82,568,793.61	$82,568,793.61	$84,107,629.00
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$952,746,427.19	$750,452,528.37	$952,746,427.19	$1,646,212,803.43	$1,349,855,580.87	$9,309,700,811.42
Administration Costs	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13
Implementation / Participation Costs	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29
Other / Miscellaneous Costs	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79
Incentives	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue (Electric)	$789,626,886.81	$786,492,622.60	$789,626,886.81	$789,626,886.81	$789,626,886.81	$792,673,721.10
Lost Revenue (Gas)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$789,626,886.81	$786,492,622.60	$789,626,886.81	$789,626,886.81	$789,626,886.81	$792,673,721.10
Net Fuel Lost Revenue (Electric)	$480,709,182.49	$478,562,658.26	$480,709,182.49	$480,709,182.49	$480,709,182.49	$482,739,294.39
Net Fuel Lost Revenue (Gas)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$480,709,182.49	$478,562,658.26	$480,709,182.49	$480,709,182.49	$480,709,182.49	$482,739,294.39
Test Results	0.78	0.62	0.78	1.35	1.10	7.60
Societal Test	1.04	0.82	1.04	1.80	1.48	10.17
Avoided Electric Production	$608,926,671.80	$408,387,082.11	$608,926,671.80	$1,302,393,048.05	$1,006,035,825.48	$8,964,342,220.65
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33
Avoided T&D Electric	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44
Avoided Ancillary	$82,568,793.61	$80,814,484.49	$82,568,793.61	$82,568,793.61	$82,568,793.61	$84,107,629.00
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$952,746,427.19	$750,452,528.37	$952,746,427.19	$1,646,212,803.43	$1,349,855,580.87	$9,309,700,811.42
Administration Costs	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13
Implementation / Participation Costs	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29
Other / Miscellaneous Costs	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79
Total	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Costs (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.20	1.73	2.20	3.80	3.12	21.52

Table 42 - Plan B DSMore B-C Results

Present Values (PVs) of Costs and Benefits Per Test	Cost Based	Market-Based Minimum	Market-Based Today	Market-Based Alternate	Market-Based Option	Market-Based Maximum
Utility (PAC) Test						
Avoided Electric Production	$858,912,292.07	$576,538,188.06	$858,912,292.07	$1,837,081,447.82	$1,419,009,203.74	$12,643,608,166.63
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14
Avoided T&D Electric	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75
Avoided Ancillary	$116,296,139.25	$113,941,873.32	$116,296,139.25	$116,296,139.25	$116,296,139.25	$118,188,633.06
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,345,299,617.22	$1,060,571,247.27	$1,345,299,617.22	$2,323,468,772.96	$1,905,396,528.89	$13,131,887,985.58
Administration Costs	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22
Implementation / Participation Costs	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87
Other / Miscellaneous Costs	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62
Incentives	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.30	1.82	2.30	3.98	3.26	22.49
TRC Test						
Avoided Electric Production	$858,912,292.07	$576,538,188.06	$858,912,292.07	$1,837,081,447.82	$1,419,009,203.74	$12,643,608,166.63
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14
Avoided T&D Electric	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75
Avoided Ancillary	$116,296,139.25	$113,941,873.32	$116,296,139.25	$116,296,139.25	$116,296,139.25	$118,188,633.06
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,345,299,617.22	$1,060,571,247.27	$1,345,299,617.22	$2,323,468,772.96	$1,905,396,528.89	$13,131,887,985.58
Administration Costs	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22
Implementation / Participation Costs	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87
Other / Miscellaneous Costs	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62
Total	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Costs (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Tax Credits (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.30	1.82	2.30	3.98	3.26	22.49
RIM Test						
Avoided Electric Production	$858,912,292.07	$576,538,188.06	$858,912,292.07	$1,837,081,447.82	$1,419,009,203.74	$12,643,608,166.63
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14
Avoided T&D Electric	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75
Avoided Ancillary	$116,296,139.25	$113,941,873.32	$116,296,139.25	$116,296,139.25	$116,296,139.25	$118,188,633.06
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,345,299,617.22	$1,060,571,247.27	$1,345,299,617.22	$2,323,468,772.96	$1,905,396,528.89	$13,131,887,985.58
Administration Costs	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22
Implementation / Participation Costs	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87
Other / Miscellaneous Costs	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62
Incentives	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue (Electric)	$1,114,173,804.88	$1,108,436,588.47	$1,114,173,804.88	$1,114,173,804.88	$1,114,173,804.88	$1,119,898,818.50
Lost Revenue (Gas)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,114,173,804.88	$1,108,436,588.47	$1,114,173,804.88	$1,114,173,804.88	$1,114,173,804.88	$1,119,898,818.50
Net Fuel Lost Revenue (Electric)	$678,192,441.40	$674,327,040.72	$678,192,441.40	$678,192,441.40	$678,192,441.40	$682,004,755.18
Net Fuel Lost Revenue (Gas)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$678,192,441.40	$674,327,040.72	$678,192,441.40	$678,192,441.40	$678,192,441.40	$682,004,755.18
Test Results	0.79	0.63	0.79	1.37	1.12	7.71
	1.07	0.84	1.07	1.84	1.51	10.37
Societal Test						
Avoided Electric Production	$858,912,292.07	$576,538,188.06	$858,912,292.07	$1,837,081,447.82	$1,419,009,203.74	$12,643,608,166.63
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14
Avoided T&D Electric	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75
Avoided Ancillary	$116,296,139.25	$113,941,873.32	$116,296,139.25	$116,296,139.25	$116,296,139.25	$118,188,633.06
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,345,299,617.22	$1,060,571,247.27	$1,345,299,617.22	$2,323,468,772.96	$1,905,396,528.89	$13,131,887,985.58
Administration Costs	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22
Implementation / Participation Costs	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87
Other / Miscellaneous Costs	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62
Total	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Costs (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.30	1.82	2.30	3.98	3.26	22.49

9. VO Staged Deployment Recommendation

A VO staged deployment is recommended to accomplish the following objectives:

a) Confirm methods used to estimate energy savings.
b) Validate residential and commercial VO factors.
c) Test voltage optimization strategies.
d) Validate LDC voltage control schemes.
e) Test EOL voltage feedback for overriding LDC controls.
f) Validate switched capacitor VAR control schemes.
g) Validate measurement and verification (M&V) protocol.
h) Test effectiveness of IVVC applications.

A pilot typically consists of at least two distribution substations with 4-to-6 feeders each, has a mix of at least 8000 residential and 800 commercial commercials (<1000 kW each). All substation, feeders, and EOL locations typically have primary metering for compliance and validation testing. If available, AMI customer metering can be used to provide detailed voltage and loading statistics.

Pre-demonstration engineering and operational characteristics include preparing single-line diagrams of substations, feeders, voltage control zones, regulator and capacitor locations, and large load customers. Expected feeder and VCZ maximum loadings, voltage ranges, and VAR flows must be provided. Service area GIS mapping data and distribution load flow analysis for each VCZ must be available. Location of meters and data available for each must be known. Control setting parameters for LDC controllers, capacitor VAR controllers, and IVVC controls must be available. Normal and emergency operating guidelines for VO controls, line switching, and outage reporting must be known.

It is recommended VO controls be operated at least once each day (i.e., turned “ON” and “OFF”) by changing the LDC settings from 119 volts (with R-settings) to 124.8 volts (with no R-settings). Voltages should be monitored to indicate non-compliance with minimum primary voltage requirements of 118.6 volts. Capacitor VAR control is continuously applied for both “ON” and “OFF” operational periods.

The ideal monitoring period is two years, with assessments every three months. However, a one-year period is acceptable, with assessments every two months. Shorter test periods make it difficult to adequately account for the large number of small changes that occur every day and differentiate between “real” and “noise” results. Measurements need to be made at each voltage control zone (VCZ) source and at end-users (if AMI data is available).

9.1 Implementation – Comprehensive List of Typical Components

9.1.1 Distribution System Planning and Design Engineering

- Pilot distribution substation and associated feeder selection
- Distribution system modeling
- Load flow simulations
- Energy savings estimates
- Distribution system upgrades
    - Shunt capacitors
    - Phase balancing
    - Source and line voltage regulators
    - Phase upgrades
    - Line reconductoring

9.1.2 Distribution Equipment Specification, Procurement, and Installation

- In-line voltage regulators
- Fixed shunt capacitors 600 kVAR
- Switched shunt capacitors 600 kVAR
- Capacitor switching VAR controls with voltage backup override
- Capacitor Volt-VAR sensing/metering
- EOL feedback communication interfaced to IVVC and/or LDC controllers
- LDC controllers for power transformers
- LDC controllers for in-line voltage regulators
- IVVC controllers at substations having one or more isolated feeders
- IVVC communication interfaced with station LDC controllers
- IVVC communication interfaced with line devices, and metering

9.1.3 Metering Specification, Procurement, and Insulation

- Power transformer LTC MW & MVAr, phase amps, and hourly voltage profile metering
- Feeder source MW & MVAr and hourly voltage profile metering
- Regulator MW & MVAr, phase amps, and hourly voltage profile metering
- EOL hourly voltage profile metering
- Metering data collection and storage infrastructure
- AMI customer profile metering (if available)
- Metering data evaluation, analysis, and reporting

9.1.4 Operation Control Engineering

- Line drop compensation
- Voltage feedback control
- VAR controls with voltage override
- IVVC controller parameters
- Metering integration and control
- SCADA interface communications, alarms, and supervisory controls

9.1.5 Engineering Assessment Standard Guidelines

- Application scenario selection strategies
- Planning, design, installation, and operation guidelines
- Engineering and operations training procedures
- System loss assessment methods and procedures
- Feeder energy savings and demand reduction M&V protocol development
- Engineering savings estimates, economic evaluations, and reporting templates

9.1.6 Implementation and trial testing

- Operational performance demonstration
- Metering data collection and storage
- Pilot trial operations “ON” and “OFF” testing
- Trial data statistical assessments (VO factor and average voltage formulations)
- Performance review and compliance validation

9.1.7 Operational Performance Assessment

- Voltage operational and performance control evaluation
- Power transformer LTC voltage bandwidth impact assessment
- VAR management performance validation
- VO factor assessment for M&V use
- M&V protocol guideline, average voltage formulation, and testing validation
- Customer impact and response assessments

9.2 Demonstration Scenarios

It is recommended the VO application scenarios described below be demonstrated (using different substations).

Scenario 1 - LDC (local control). LDC is applied only on viable feeders with local control for all source and line voltage regulators along with switched 600 kVAR capacitor banks having VAR sensing and control with voltage override backup. VCZ maximum voltage drops are less than 4 Volts. All LDC voltage settings are at 119 volts (with the R settings) voltage rises equal to the maximum voltage drop. All feeder VAR flows are at +/- 300 kVAR.

Scenario 2 - LDC (local control with remote voltage feedback override). LDC is applied only on viable feeders with local control and remote voltage feedback override for all source and line voltage regulators. The minimum primary voltage is 118.6 volts. Switched 600 kVAR capacitor banks are applied with VAR sensing and voltage override backup. VCZ maximum voltage drops are less than 4 Volts. All LDC voltage settings are at 119 volts (with R settings) voltage rises equal to the maximum voltage drop. All feeder VAR flows are at +/- 300 kVAR.

Scenario 3 - IVVC (remote voltage and VAR feedback) - IVVC applied on non-viable feeders maintains voltage levels of 122 volts to 124 volts. IVVC control interfaces with existing substation LTC LDC controller to adjust viable feeder voltage regulation. Non-viable VO feeders have EOL voltage feedback and volt-VAR sensing along the feeder. IVVC optimally controls feeder voltage profiles and minimizes VAR flows. Switched 600 kVAR capacitor banks with volt-VAR sensing are applied as needed to control customer voltages within specified limits.

Application scenarios are measured against the following criteria:

- VO performance threshold compliance
- Change in system losses from Existing Case
- Change in weighted annual average voltage from Base Case
- Potential energy savings from Base Case
- Present value cost of energy saved
- Present value cost of upgrades, including threshold compliance upgrades
- Resulting BCR

9.3 Verification

VO implementation requires ongoing compliance measurements to ensure performance thresholds are met. Feeder source and VCZ regulator metering (hourly profile MW and MVAr) and primary EOL feeder and VCZ metering (hourly voltage) are applied to all feeders. Metering can be accomplished using relays, regulator controls, or standalone meter sets.

Measurements also provide performance information regarding LDC voltage regulation, capacitor VAR management, and feeder voltage profiles. Demonstration includes adequate annunciation to allow for corrective SCADA actions in case of equipment or control malfunction. Demonstration includes assessment guidelines and operational control expectations; and documentation of customer complaints, equipment malfunctions, and/or control irregularities.

Feeder analysis is done on a substation basis. All feeders served from the same voltage control substation bus (i.e., LTC or voltage regulator) are considered to be in the same VCZ. Each in-line voltage regulator also forms a new VCZ. Changes to voltage regulator set points will impact all feeders and/or loads served by the same VCZ.

Meter data is used to verify average voltage calculation procedures. The protocol is to be revised to meet ComEd-specific needs. Procedures and application methods are to be developed. Performance thresholds are to be reviewed and revised as necessary. Application templates are to be developed to facilitate VO application by regional planning engineers, operations, and energy efficiency specialists. The protocol should include VO design process and control application guidelines.

The M&V protocol establishes a basis for measuring and verifying energy savings. Protocol methods are based on Equipment Condition Monitoring (ECM) guidelines that comply with requirements set forth in the Federal Energy Management Program (FEMP) M&V guidelines, Version 2.2, and International Performance Measurement & Verification Protocol (IPMVP), Volume I, March 2002.

The protocol defines an annual energy VO factor for estimating end-user energy savings from reduced average annual voltages. Typically, VO factors are based on load types and characteristics, consumption patterns, appliance use, and ambient weather conditions. Global residential and commercial annual energy VO factors based on ComEd customer loading and weather characteristics developed in Task 4.

VO factors are used with average feeder voltage-change formulations to determine total end-use energy savings. VO factors do not include distribution line or no-load (transformer core) loss savings, which are calculated separately.

Metering data collected for “ON” and “OFF” demonstration settings validate VO factors to be used with the protocol. Measurements are typically collected once each hour.

10. VO Feasibility Study Results, Findings, and Recommendations

10.1 Results

The VO feasibility study results estimate the potential to reduce energy consumption by as much as 1900 GWh-yr while reducing peak loads by approximately 360 MW. These results are based on the Plan B (Maximum Energy Savings) analysis. The total upfront cost to implement Plan B is approximately $575 million, which represents an average savings per viable feeder of 3.5% at a levelized cost of energy (LCOE) of $0.0185/kWh-saved. It is estimated that VO is viable on 515 of ComEd's 806 substations, representing 2890 feeders. The minimum cost Plan A generates 1350 GWh-yr of savings at a cost of $425 million. A summary of Plan A and Plan B results are presented in Table 43.

Table 43 - Summary of Project Results

	Plan A	Plan B
Total VO Savings Potential		
- Energy (MWh-yr)	1,350,371	1,912,952
- Peak Load (MW)	257	364
Total VO Installed Costs	$425,466,877	$574,232,508
VO Program TRC	2.20	2.30
Levelized Cost of Energy ($/kWh)	$0.0193	$0.0185
Number of Viable Feeders	2,890	2,890
Number of Viable Substations	515	515
Average Energy Savings (MWh-yr)		
- per viable feeder	467	662
- per viable substation	2,624	3,718
Average VO Cost		
- per viable feeder	$147,222	$198,699
- per viable substation	$826,902	$1,116,030

Energy savings from VO occur in two forms: Distribution line loss reductions and end-use load reductions. As seen in Figure 16, a majority of the energy savings comes from end-use load reductions. For Plan A, only 6% of total savings comes from distribution loss reduction. For Plan B, which includes more system improvements, distribution savings increase to 11%.

VO benefits are achieved through a number of capital improvements and operation changes on the distribution system. Total capital expenditures to achieve these benefits are $425 million for Plan A (minimum cost) and $574 million for Plan B (maximum savings). This equates to average costs per substation of $826,902 and $1,116,030 for Plans A and B respectively (Figure 17).

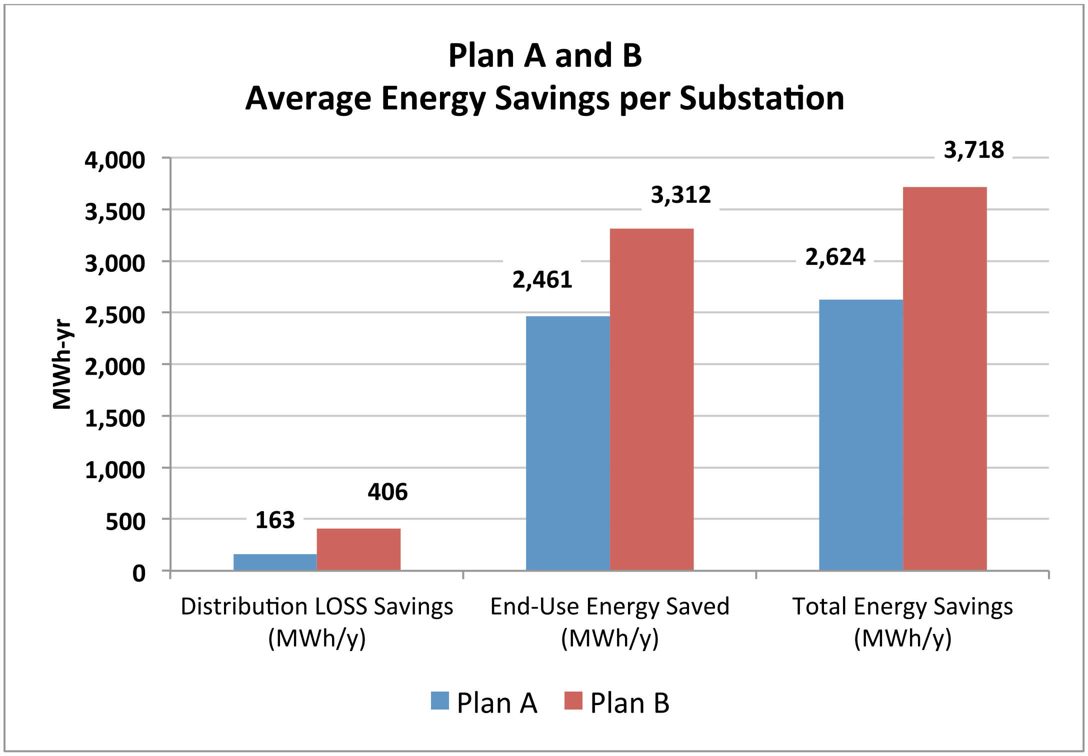


Figure 16 - Average Savings per Substation

Capacitor banks, both switched and fixed, represent the largest single capital expense (CapEx) item, accounting for over half of the total costs for both Plan A and Plan B. Voltage regulators and sensors are the next two largest expense categories. Additional voltage regulators and system upgrades (such as line reconductoring and phase upgrades) account for most of the additional Plan B costs. Integrated Volt/VAR Control (IVVC) is used primarily for isolating non-viable feeders with comparable costs in both plans.

Table 44 and Figure 18 compare itemized VO costs for Plan A and Plan B.

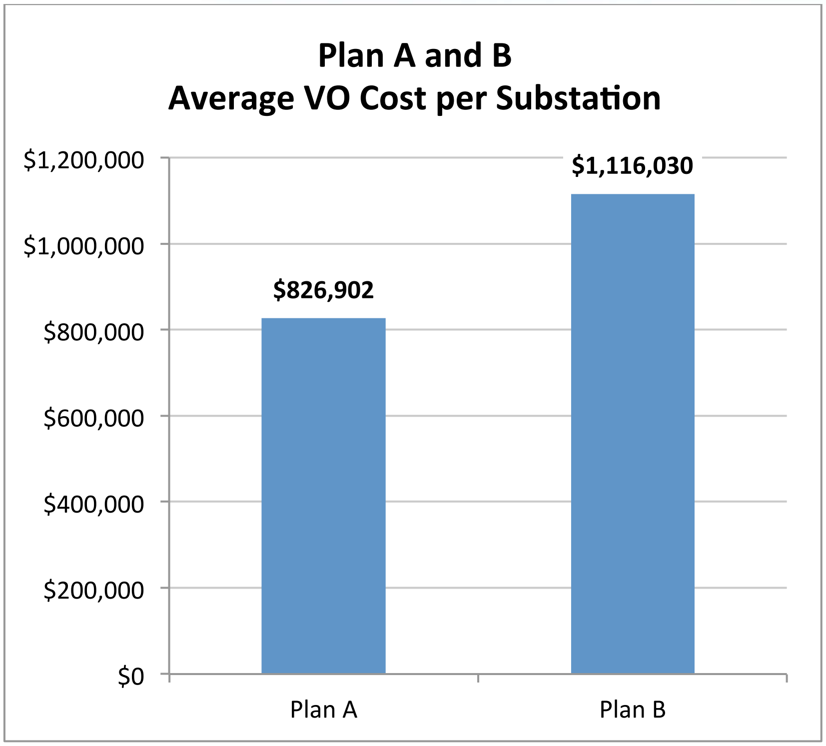
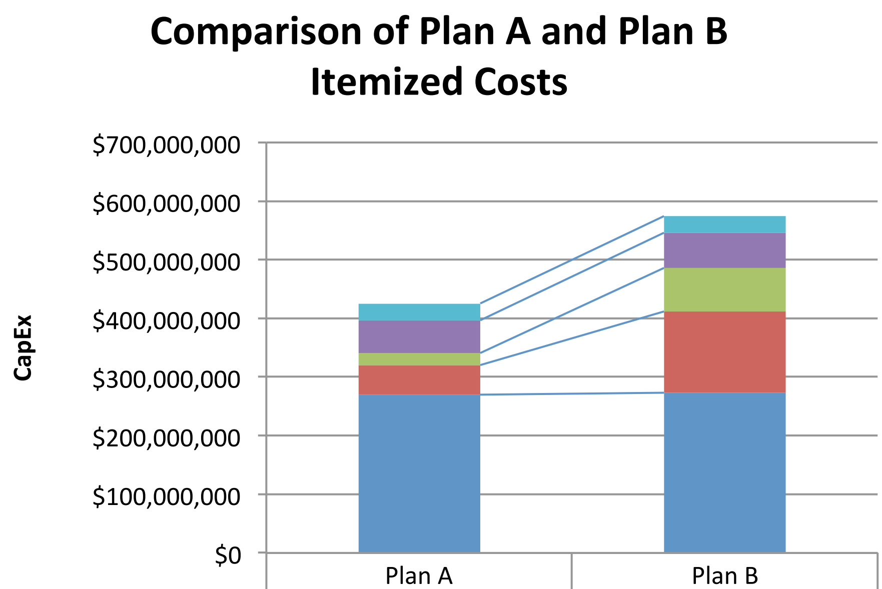


Figure 17 - Average VO Cost per Substation

Table 44 - System Level Itemization of VO Costs

		Plan A System-level		Plan B System-level	
	unit costs	Upgrades	Cost	Upgrades	Cost
OH line reconductoring (mi)	$225,000	71	$16,019,171	213	$47,983,438
Station regulator addition (#)	$110,000	0	$0	112	$12,281,974
In-line volt-regulator addition (#)	$63,000	804	$50,641,249	2010	$126,615,982
OH & UG line or transfer tap changes (#)	$2,000	1148	$2,296,655	5471	$10,942,122
OH phase upgrades (mi)	$110,000	18	$2,021,057	136	$14,984,008
Fixed 600 kVAR capacitor add (#)	$5,500	2067	$11,368,444	4243	$23,335,750
Switched 600 kVAR capacitors (#)	$15,000	17225	$258,373,721	16636	$249,547,372
Feeder source & regulator metering (#)	$5,000	6660	$33,301,502	7592	$37,962,464
EOL voltmeter (#)	$3,000	6890	$20,669,898	6811	$20,432,738
EOL volt feedback sensing (#)	$4,500	459	$2,066,990	447	$2,009,777
IVVC Application ($)	$50,000	574	$28,708,191	563	$28,136,885
			$425,466,877		$574,232,508



	Plan A	Plan B
IVVC	$28,708,191	$28,136,885
Sensors	$56,038,389	$60,404,979
System Upgrades	$20,336,883	$73,909,567
Voltage Regulators	$50,641,249	$138,897,955
Capacitor Banks	$269,742,165	$272,883,121

Figure 18 - VO Cost Itemization

A key study result is the screening and ranking of substations by VO cost and savings potential. This data can then be used to develop VO energy efficiency (EE) supply curves that present how much savings is available at a given cost. Figure 19 presents substation-based VO EE supply curves. While rankings were only developed for substations in the 14-region study group, the supply curves depicted in Figure 20 have been extrapolated to the system level.

A key driver of the VO Feasibility Study was to assess the cost effectiveness of using VO to meet ICC EE program goals. Figure 20 provides an analysis of cost and savings potential in relationship to ComEd's 2014-2016 program goals. EE program data comes from ComEd's ICC filings for program years 2014, 2015, and 2016 and is based on total 3-year program costs and savings potential. VO cost and savings estimates are based on Plan B results and assume the entire VO program is implemented over the same 3-year period. This assumption may or may not be ComEd's actual implementation roadmap, but provides a basis of comparison between the two program types.

The key take-away from the chart in Figure 20 *is that VO has the potential to double ComEd's EE potential at a comparable cost to other EE program options.*

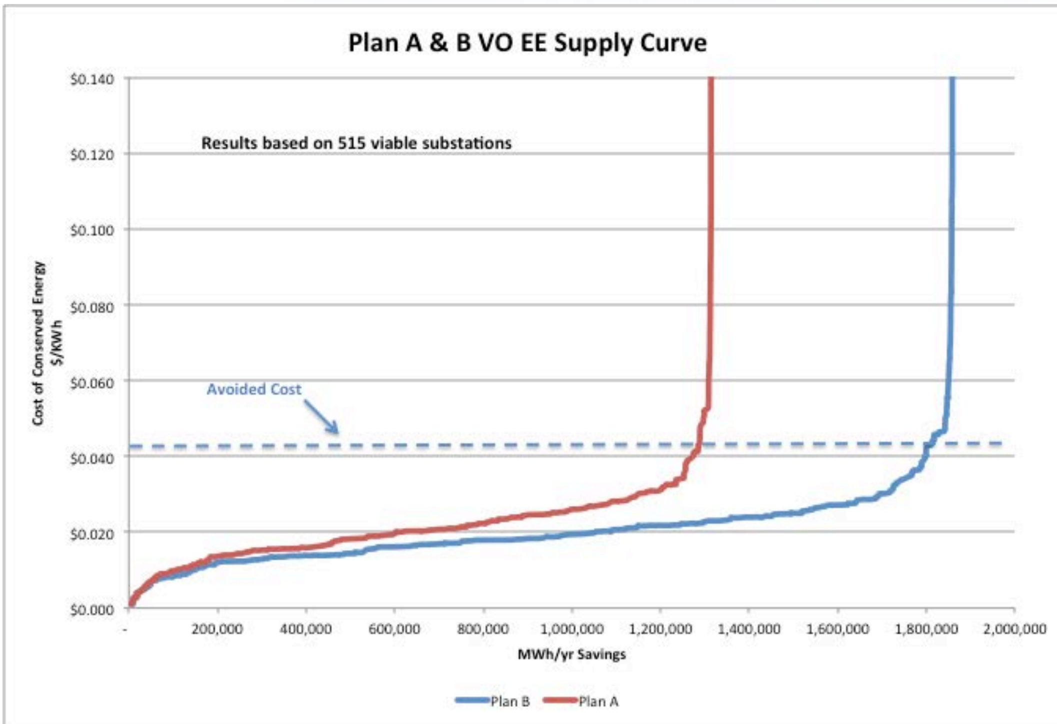


Figure 19 - VO EE Supply Curves

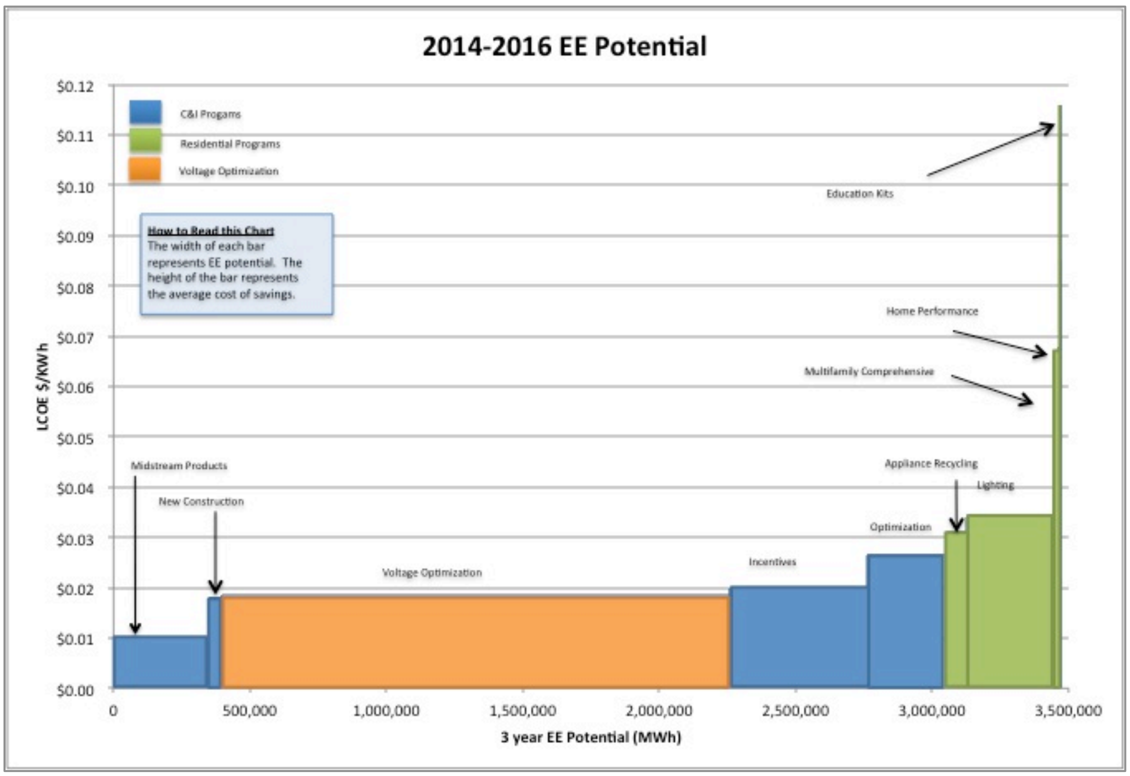


Figure 20 - EE and VO Benchmark Supply Curve

10.2 Key Findings

1. The potential to achieve cost-effective energy savings and demand reductions for VO on the ComEd distribution network is significant. The study found cost-effective energy savings of as much as 1,900 GWh-yr, equal to approximately 2% of ComEd's retail sales, at a cost of approximately $0.0185/kWh.

2. It is estimated that 515 substations (64%) and 2890 feeders (51%) are viable candidates for VO implementation. The average savings per viable feeder is 3.5%. This high savings estimate relative to other utility VO programs can attributable to a number of factors related to the ComEd system, including low voltage drops across feeders due to short runs and a relatively efficient distribution system, relatively good system efficiencies (good phase and load balancing), favorable end-use load composition (low saturation of electric resistance heat), and current voltage settings (conservatively high).

3. The primary determinants of feeder VO non-viability were voltage level (>25kV and <11kV urban networks were excluded), and customer class (large commercial and industrial loads are not good candidates for VO).

4. A majority of the distribution system requires efficiency upgrades (best industry practices) for VO to be effective. For example, Plan A (minimum cost scenario) requires a $425 million investment to allow average voltages at the customer meter to be reduced by 2.96%, accounting for the majority of energy savings.

5. ComEd design guidelines specify maximum secondary voltage drops of 6.0 volts. However, for the VO study, a utility best practice of 3.6 volts was used (or 3% on a 120-volt base) to allow potential energy savings to be maximized.

6. The maximum amount VO energy savings (Plan B) can be achieved by investing an additional $150 million – a total of $575 million – resulting in average voltage reduction of 3.81%. The incremental investments of Plan B increase the total program TRC B-C ratio from 2.20 to 2.30.

7. Isolating non-viable feeders from viable feeders on the same substation is one of the key challenges to VO implementation. The use of IVVC rather than substation-mounted voltage regulator banks is the recommended feeder isolation solution.

8. Capital cost recovery, lost revenues adjustments, and energy efficiency program inclusion are key regulatory hurdles for ComEd's VO strategy.

10.3 Additional Findings

9. Global annual energy VO factor development resulted in 0.69 for residential and 0.90 for commercial customers (<1000 kW). The overall average VO factor for the sample service area was 0.753.

10. Average customer energy savings are 314.5 kWh/yr for Plan A and 434.6 kWh/yr for Plan B.

11. Total feeder energy losses are 25,741.6 MWh/yr, representing 2.63% of total energy delivered (977,504 MWh/yr).

12. The average maximum voltage drop was 3.9 volts (lower than the 4.8 volt threshold). Maximum primary voltage drops ranged from 0.3 volts to 13.4 volts.

13. The lowest average voltage was 120.6 volts (higher than the 118.6 volt threshold). Lowest voltages ranged from 111.1 volts to 124.5 volts.

14. The average phase imbalance was 10.5%. Feeder phase amp imbalances ranged from 2.1% to 31.1% (compared to a threshold of 25% or less).

15. Feeder/substation load profile and M&V guidelines are needed for VO implementation to:

    a) Establish total annual energy per feeder.
    b) Determine the amount/size of fixed and switched capacitor banks per feeder.
    c) Determine annual feeder load factors (for average voltage calculations).
    d) Identify VCZ and non-coincidental load issues.
    e) Verify annual peak MW/MVAr loading.
    f) Determine maximum feeder imbalances at peak (assuming phase amps are available).

    If only peak MW load values are available, the following VO assumptions are typically made which may not fairly represent actual system performance:

    a) VCZ feeders peak at the same time.
    b) Annual load factor is set at 35% or as estimated from annual hourly PI amp data (assuming phase amps are available).
    c) Substation energy is distributed to sister feeders according to feeder peaks.
    d) Existing VAR compensation is adequate, with 100% VAR switching available.

    If load profile data is available for some feeders but not others, the data can be used to determine VO assumptions for similar feeders.

16. Detailed substation analyses required certain feeders to be isolated from sister feeders to allow for larger voltage reductions at the substations. Isolation techniques and associated costs were detailed in Task 6. It general, minimum isolated feeder EOL voltages were assumed to be 121

volts. However, if lower voltages are allowed, adjustments can be made accordingly. Adding in-line voltage regulators has the highest degree of controllability for maintaining voltages but may not be cost effective or feasible (e.g., physical space limitations).

17. Feeders requiring significant re-conductoring were considered non-viable since this cost is typically not a VO cost. However, once completed, the feeders should be considered potential VO candidates.

10.4 Recommendations

1. Design/implement a VO staged deployment per the outline in Section 9 and detailed in Task 9. Provide monthly/annual metering assessment reports to facilitate the VO verification process outlined in Task 6 and Task 9.

2. Develop and implement VO analysis training materials for distribution planning engineers, distribution operations personnel, and energy efficiency engineers. Contents to include engineering modeling assessments, economic analysis methods, capacitor placement methods, LTC/regulator/capacitor control settings, and annual volt/VAR maintenance and reporting procedures.

3. Improve feeder VAR management with smaller capacitor banks (600 kVAR). Include VAR sensing and local control on all switched banks. Follow the VAR application guidelines developed in Task 6 to determine the number/location of the banks. Apply voltage control override under emergency conditions. If possible, industry best practices suggest hourly VAR swings should be limited to less than 300 kVAR lagging and 300 kVAR leading for a total of 600 kVAR swing.

4. Install EOL volt meters on every VO feeder and VCZ at the lowest voltage location to collect/transmit data and provide annual reporting of voltage performance. Use voltage and VAR feedback on non-viable feeders for use with IVVC applications.

5. Examine AMI voltage/loading data to determine actual feeder voltage drop and load profiles. The results can be used to establish standards for addressing maximum allowable voltage drops (distribution transformer and secondary voltage drops) and minimum allowable primary voltages (i.e., 118.6 volts for an allowed 3.6 volt drop). Evaluate potential impacts (probability of customer transformers needing replacement) of primary voltages violating minimum standards. Revise transformer sizing guidelines based on this customer loading information.

6. Maintain, correct, and/or upgrade GIS-CYMDist interface, software, and distribution system models at least annually or as needed.

7. Develop in-house "normal design/operating standards" for maximum allowed phase load imbalances of < 25%, maximum allowed primary voltage drops < 4V, conductor loadings < 70% of normal max, station and in-line voltage regulator voltage bandwidths of 2 volts (plus/minus 1 volt), and maximum allowed secondary voltage drops < 3.6 volts.

8. Provide all in-line feeder voltage regulators with hourly profile metering (MW, MVAr, and volts). Implement monthly data collection processes.

9. Develop application guidelines for EOL voltage feedback sensing/control and backup override of LDC controls for VO feeders with less than a 80% coincidence factor compared to sister feeders in the same VCZ.

10. Apply LDC settings for viable VO feeders with voltage settings at 119 volts with Volt-Rise equal to the maximum voltage drop under peak conditions. Determine control R settings using R&X application guidelines developed in Task 6 for a 110% peak load probability. With hourly power factor near unity, X settings can be set to zero.

11. Apply IVVC to isolate feeders (large commercial/industrial loads, non-coincidental loads) in the same VCZ to maintain higher sustained voltages using EOL voltage feedback, source MW/MVAr metering, SCADA supervisory controls, substation IVVC feeder controllers, switched capacitors (VAR/voltage sensing), and existing LDC controllers. This will allow viable feeder voltages to be lowered and increase energy savings potential.

12. Provide substation power transformers with load-side 3-phase hourly profile metering (MW, MVAr, and volts). Implement monthly data collection processes.

13. Conduct annual inspections of capacitor banks and associated controls.

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12. Appendix

12.1 Viable Substations (346) Ranked by Benefit-Cost Ratio (BCR)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
1	DCW236	3,732	$61,713	41.81
2	DCW346	2,011	$38,795	35.84
3	DCW202	783	$19,138	28.30
4	DCW354	831	$22,362	25.69
5	DCW343	768	$26,142	20.31
6	DCB46	605	$25,495	16.42
7	DCD114	726	$31,311	16.03
8	DCG99	767	$33,433	15.85
9	DCW51	2,299	$105,518	15.07
10	DCD242	585	$27,375	14.76
11	TDC457	617	$32,569	13.10
12	DCE59	924	$57,654	11.08
13	DCW31	1,681	$108,766	10.69
14	DCH78	1,359	$88,485	10.62
15	DCW302	1,644	$116,669	9.74
16	DCW71	1,764	$125,462	9.72
17	DCE35	1,658	$118,205	9.70
18	DCC61	961	$70,829	9.38
19	DCE8	1,391	$109,815	8.76
20	DCD89	558	$44,168	8.73
21	DCW30	3,572	$299,266	8.25
22	DCW29	1,230	$112,992	7.52
23	DCW115	1,458	$134,658	7.49
24	TDC446	628	$58,221	7.46

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
25	SS311	606	$58,471	7.16
26	DCG121	732	$71,405	7.09
27	DCW50	2,255	$245,743	6.34
28	DCD80	847	$92,808	6.31
29	SS459	1,554	$171,119	6.28
30	DCD62	1,348	$149,177	6.25
31	DCD63	2,043	$226,507	6.24
32	DCH56	387	$43,633	6.13
33	DCG909	333	$37,814	6.09
34	TSS134	13,207	$1,594,750	5.73
35	DCD16	887	$109,273	5.61
36	TDC470	6,030	$746,611	5.58
37	TDC372	3,145	$392,244	5.54
38	TDC435	653	$81,748	5.53
39	DCJ87	927	$117,339	5.46
40	DCC21	325	$41,172	5.45
41	TDC505	8,499	$1,106,653	5.31
42	DCC85	679	$89,119	5.27
43	DCE17	683	$89,695	5.26
44	DCJ19	1,406	$187,939	5.17
45	DCD69	693	$92,817	5.16
46	TDC814	5,759	$773,694	5.15
47	DCE46	614	$82,918	5.12
48	TDC222	687	$92,981	5.11
49	DCD20	672	$92,808	5.01
50	TSS179	556	$76,902	5.00
51	DCW216	805	$112,234	4.96

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
52	SS834	234	$32,767	4.95
53	DCD40	1,779	$248,820	4.95
54	DCB96	602	$86,058	4.84
55	DCW119	1,045	$151,719	4.76
56	DCW348	677	$100,446	4.66
57	DCG42	914	$135,535	4.66
58	TDC414	7,451	$1,131,081	4.56
59	DCC66	459	$70,491	4.50
60	DCE72	668	$103,876	4.44
61	DCH76	720	$113,045	4.40
62	DCC25	324	$51,800	4.32
63	TSS118	9,186	$1,480,427	4.29
64	DCD115	366	$59,847	4.22
65	DCB54	499	$81,792	4.22
66	DCH27	714	$118,695	4.16
67	DCG88	725	$120,613	4.16
68	DCW25	1,532	$258,240	4.10
69	DCW28	679	$114,750	4.09
70	DCE16	1,420	$240,548	4.08
71	TDC444	3,473	$589,021	4.08
72	DCD351	1,560	$267,382	4.03
73	DCE29	2,171	$375,492	4.00
74	DCE28	1,861	$324,745	3.96
75	DCD46	1,568	$273,798	3.96
76	DCH65	1,850	$329,428	3.88
77	TDC549	5,044	$918,506	3.80
78	TDC317	3,630	$663,140	3.78

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
79	DCH70	591	$108,708	3.76
80	TSS89	15,176	$2,803,640	3.74
81	TSS63	13,684	$2,536,758	3.73
82	TDC205	5,298	$982,842	3.73
83	SS553	1,297	$242,822	3.69
84	TDC469	7,388	$1,394,064	3.66
85	TDC552	5,427	$1,038,273	3.61
86	TDC568	5,031	$963,820	3.61
87	DCC80	555	$106,968	3.59
88	SS884	159	$30,721	3.57
89	TDC550	9,564	$1,853,867	3.57
90	DCE79	467	$91,739	3.52
91	TDC216	7,474	$1,472,287	3.51
92	TDC510	1,566	$314,042	3.45
93	SS513	2,214	$447,947	3.42
94	TDC517	5,940	$1,202,291	3.42
95	TDC595	14,810	$3,007,256	3.41
96	DCF45	965	$196,993	3.39
97	TDC499	6,894	$1,420,202	3.36
98	TSS172	18,696	$3,863,928	3.35
99	TDC215	4,485	$928,158	3.34
100	TSS117	10,163	$2,110,588	3.33
101	DCW41	959	$199,663	3.32
102	TDC268	21,162	$4,411,396	3.32
103	DCJ92	1,108	$231,410	3.31
104	DCB53	1,397	$292,086	3.31
105	DCW304	1,328	$278,770	3.29

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
106	TSS60	14,647	$3,093,089	3.27
107	DCB51	1,239	$262,929	3.26
108	TDC559	6,392	$1,359,023	3.25
109	DCW46	1,260	$271,647	3.21
110	TDC436	14,699	$3,183,464	3.19
111	DCW35	1,299	$283,839	3.16
112	SS853	922	$203,228	3.14
113	TSS85	10,097	$2,225,929	3.14
114	TSS104	5,629	$1,300,780	2.99
115	TSS140	5,717	$1,334,032	2.96
116	DCW148	1,209	$282,171	2.96
117	TDC260	8,663	$2,053,506	2.92
118	TSS111	1,346	$325,962	2.86
119	TDC419	21,555	$5,221,075	2.85
120	TSS152	21,677	$5,286,509	2.84
121	TDC220	9,008	$2,212,292	2.82
122	TSS133	334	$82,920	2.78
123	TDC555	5,454	$1,357,595	2.78
124	DCH23	1,081	$269,520	2.77
125	TSS56	7,453	$1,875,255	2.75
126	TDC451	13,969	$3,515,579	2.75
127	DCW44	1,176	$296,057	2.75
128	TDC431	12,101	$3,074,588	2.72
129	TSS41	6,924	$1,772,204	2.70
130	DCB90	897	$229,772	2.70
131	SS741	695	$177,995	2.70
132	TDC648	11,036	$2,837,072	2.69

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
133	TSS51	5,579	$1,435,086	2.69
134	TDC557	5,321	$1,369,971	2.69
135	DCE82	1,003	$258,422	2.68
136	DCW336	1,949	$502,609	2.68
137	DCW73	594	$156,331	2.63
138	TDC240	4,819	$1,275,694	2.61
139	DCW334	727	$192,473	2.61
140	DCC33	549	$145,963	2.60
141	TSS129	9,313	$2,480,724	2.60
142	TDC487	4,841	$1,301,432	2.57
143	TSS88	6,656	$1,790,984	2.57
144	TDC566	19,305	$5,204,162	2.57
145	TDC213	19,287	$5,203,097	2.56
146	TDC581	13,454	$3,640,984	2.56
147	TDC411	5,360	$1,460,840	2.54
148	TDC221	5,306	$1,448,360	2.53
149	DCD187	1,168	$319,370	2.53
150	TSS120	9,967	$2,741,869	2.51
151	TSS57	8,322	$2,293,854	2.51
152	TDC454	10,370	$2,859,661	2.51
153	TDC440	4,769	$1,318,715	2.50
154	DCW211	852	$238,688	2.47
155	TSS59	4,724	$1,328,461	2.46
156	TDC259	8,744	$2,464,591	2.45
157	TDC416	10,355	$2,938,158	2.44
158	DCD47	585	$165,966	2.44
159	SS501	539	$154,504	2.41

(Continued)

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Rank	SUB ID	ESP MWH/YR	VO COST	BCR
160	TSS64	6,313	$1,824,508	2.39
161	DCH25	1,045	$302,403	2.39
162	TDC569	5,624	$1,638,994	2.37
163	TDC562	14,994	$4,386,073	2.36
164	TDC204	16,637	$4,925,515	2.34
165	DCJ13	636	$188,268	2.33
166	DCW10	1,066	$316,853	2.33
167	TDC439	5,067	$1,508,960	2.32
168	TSS149	1,296	$390,569	2.29
169	TDC572	6,031	$1,827,140	2.28
170	TDC574	13,491	$4,115,462	2.27
171	TSS79	3,585	$1,093,461	2.27
172	DCF17	947	$289,503	2.26
173	DCD255	739	$228,817	2.23
174	DCJ49	1,183	$367,607	2.23
175	TDC592	8,437	$2,621,954	2.23
176	TDC577	6,833	$2,127,235	2.22
177	TDC375	5,237	$1,638,333	2.21
178	DCE71	1,054	$333,857	2.18
179	TDC214	15,991	$5,089,788	2.17
180	DCD99	543	$174,408	2.15
181	DCE69	2,081	$672,593	2.14
182	DCB28	589	$191,288	2.13
183	TSS46	7,667	$2,494,497	2.13
184	TDC531	7,349	$2,397,480	2.12
185	DCJ18	627	$204,462	2.12
186	TDC461	13,024	$4,254,893	2.12

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
187	DCE12	1,099	$359,228	2.12
188	TDC840	15,393	$5,033,663	2.11
189	TDC443	6,675	$2,193,079	2.10
190	STA13-2	10,395	$3,419,460	2.10
191	DCW384	614	$204,688	2.07
192	TDC563	5,735	$1,912,912	2.07
193	TSS83	5,599	$1,868,220	2.07
194	DCB30	1,716	$575,311	2.06
195	TSS33	6,924	$2,322,893	2.06
196	DCJ68	1,073	$360,289	2.06
197	TDC225	3,214	$1,080,003	2.06
198	TDC580	9,869	$3,320,984	2.05
199	DCD133	544	$183,753	2.05
200	TDC539	6,207	$2,140,700	2.00
201	TDC570	11,571	$3,997,314	2.00
202	TDC561	11,856	$4,110,412	1.99
203	TSS101	8,944	$3,130,191	1.98
204	TDC458	4,016	$1,409,573	1.97
205	DCB35	155	$55,169	1.94
206	DCW340	334	$119,226	1.94
207	TDC465	7,214	$2,576,539	1.94
208	TDC406	6,119	$2,187,681	1.93
209	TSS76	4,932	$1,773,506	1.92
210	TSS136	16,183	$5,826,644	1.92
211	TSS78	5,021	$1,812,478	1.92
212	TDC593	2,970	$1,072,267	1.92
213	TSS43	4,601	$1,664,369	1.91

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
214	TSS106	4,399	$1,595,115	1.91
215	STAll	9,589	$3,489,315	1.90
216	DCE19	1,212	$444,432	1.89
217	DCJ29	494	$182,224	1.88
218	TSS48	3,387	$1,251,174	1.87
219	DCE77	1,305	$484,910	1.86
220	TDC258	6,580	$2,451,098	1.86
221	STA13	14,562	$5,440,015	1.85
222	DCW17	466	$174,093	1.85
223	DCJ69	1,405	$526,717	1.84
224	TSS145	16,161	$6,070,949	1.84
225	DCB26	202	$76,902	1.81
226	DCJ24	222	$84,801	1.81
227	DCH14	1,257	$483,171	1.80
228	TDC248	8,933	$3,456,151	1.79
229	DCJ32	487	$188,886	1.78
230	DCJ33	633	$245,456	1.78
231	DCW33	1,406	$547,073	1.78
232	TDC560	3,627	$1,425,655	1.76
233	DCW38	1,251	$492,016	1.76
234	TSS150	16,206	$6,534,163	1.72
235	DCD130	501	$202,377	1.71
236	TSS47	5,390	$2,196,205	1.70
237	TDC212	9,589	$3,910,589	1.70
238	TSS131	4,989	$2,034,469	1.70
239	TSS102	13,569	$5,552,856	1.69
240	DCC20	1,222	$500,097	1.69

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
241	DCB36	865	$356,770	1.68
242	TSS103	9,379	$3,892,047	1.67
243	TDC521	2,357	$980,777	1.66
244	DCH53	1,091	$467,380	1.61
245	TSS135	3,806	$1,633,513	1.61
246	TDC565	5,593	$2,405,491	1.61
247	TSS198	11,021	$4,741,621	1.61
248	TSS174	7,637	$3,305,104	1.60
249	DCH67	593	$258,773	1.58
250	DCH43	438	$191,084	1.58
251	TDC433	944	$414,005	1.58
252	DCF149	1,019	$447,737	1.57
253	DCW19	1,058	$466,429	1.57
254	DCW48	717	$319,236	1.55
255	DCC34	599	$270,327	1.53
256	TSS137	12,170	$5,528,829	1.52
257	TSS52	4,203	$1,918,266	1.52
258	DCE20	1,466	$677,457	1.50
259	SS316	2,650	$1,234,347	1.48
260	DCG128	451	$212,914	1.47
261	DCB57	366	$176,729	1.43
262	DCW152	616	$298,413	1.43
263	TSS55	3,132	$1,529,642	1.42
264	DCW118	1,003	$492,093	1.41
265	SS422	1,102	$540,477	1.41
266	DCF96	614	$302,706	1.40
267	TDC235	4,214	$2,122,402	1.37

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
268	DCW39	1,191	$602,628	1.37
269	TDC474	3,376	$1,725,216	1.35
270	TSS151	4,576	$2,361,906	1.34
271	TSS75	7,954	$4,166,054	1.32
272	DCH91	214	$112,260	1.32
273	DCW20	827	$436,359	1.31
274	DCW12	585	$315,403	1.28
275	DCH44	341	$184,063	1.28
276	DCB86	148	$80,078	1.28
277	TDC456	2,297	$1,249,771	1.27
278	TDC217	2,279	$1,241,554	1.27
279	TSS193	6,029	$3,302,053	1.26
280	DCW335	511	$283,868	1.24
281	DCJ23	517	$287,546	1.24
282	DCE18	791	$440,381	1.24
283	TDC250	915	$511,199	1.24
284	DCW233	530	$298,878	1.23
285	DCJ65	207	$117,740	1.22
286	DCW26	648	$374,188	1.20
287	SS460	1,435	$833,972	1.19
288	DCE21	510	$296,574	1.19
289	DCH39	828	$486,599	1.18
290	DCJ66	528	$315,143	1.16
291	DCB27	521	$311,996	1.15
292	DCE26	1,341	$803,933	1.15
293	DCH47	490	$298,120	1.14
294	DCH38	197	$122,792	1.11

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
295	DCJ17	727	$462,742	1.09
296	TDC233	5,825	$3,762,478	1.07
297	DCH54	170	$110,337	1.07
298	DCD229	451	$293,941	1.06
299	DCH26	602	$392,701	1.06
300	DCH40	514	$335,861	1.06
301	DCF122	460	$301,519	1.05
302	DCE24	579	$383,422	1.04
303	DCH41	153	$101,521	1.04
304	TDC556	1,719	$1,143,866	1.04
305	DCB64	597	$398,594	1.03
306	DCW102	483	$331,190	1.01
307	TDC206	5,701	$3,913,760	1.01
308	DCC3	503	$346,624	1.00
309	DCJ21	406	$282,949	0.99
310	TDC253	8,202	$5,734,188	0.99
311	DCB16	962	$679,167	0.98
312	SS558	1,272	$951,750	0.92
313	DCC19	360	$270,073	0.92
314	DCW16	619	$473,615	0.90
315	SS450	617	$472,360	0.90
316	DCK15	233	$182,224	0.89
317	DCC91	430	$344,386	0.86
318	DCH60	439	$363,555	0.84
319	DCD67	351	$292,337	0.83
320	DCB89	225	$187,021	0.83
321	DCB29	897	$783,212	0.79

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
322	SS249	1,212	$1,132,759	0.74
323	DCW14	263	$250,074	0.73
324	DCJ16	317	$310,320	0.71
325	DCJ76	347	$343,425	0.70
326	DCH36	417	$427,934	0.67
327	DCH49	455	$468,543	0.67
328	DCW64	348	$375,791	0.64
329	DCJ28	320	$359,310	0.62
330	DCH66	196	$230,993	0.59
331	DCH10	370	$460,608	0.56
332	DCH52	349	$434,733	0.55
333	SS312	161	$210,438	0.53
334	DCE38	236	$318,217	0.51
335	DCH28	142	$196,839	0.50
336	DCH57	232	$360,663	0.45
337	DCB52	282	$449,705	0.43
338	DCK19	285	$456,371	0.43
339	TSS132	231	$401,394	0.40
340	DCH62	25	$55,169	0.32
341	DCB17	183	$403,989	0.31
342	SS871	41	$90,339	0.31
343	TDC207	1,765	$4,485,676	0.27
344	SS894	53	$208,611	0.18
345	DCJ58	21	$119,006	0.12
346	DCJ62	18	$171,525	0.07

(Continued)