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

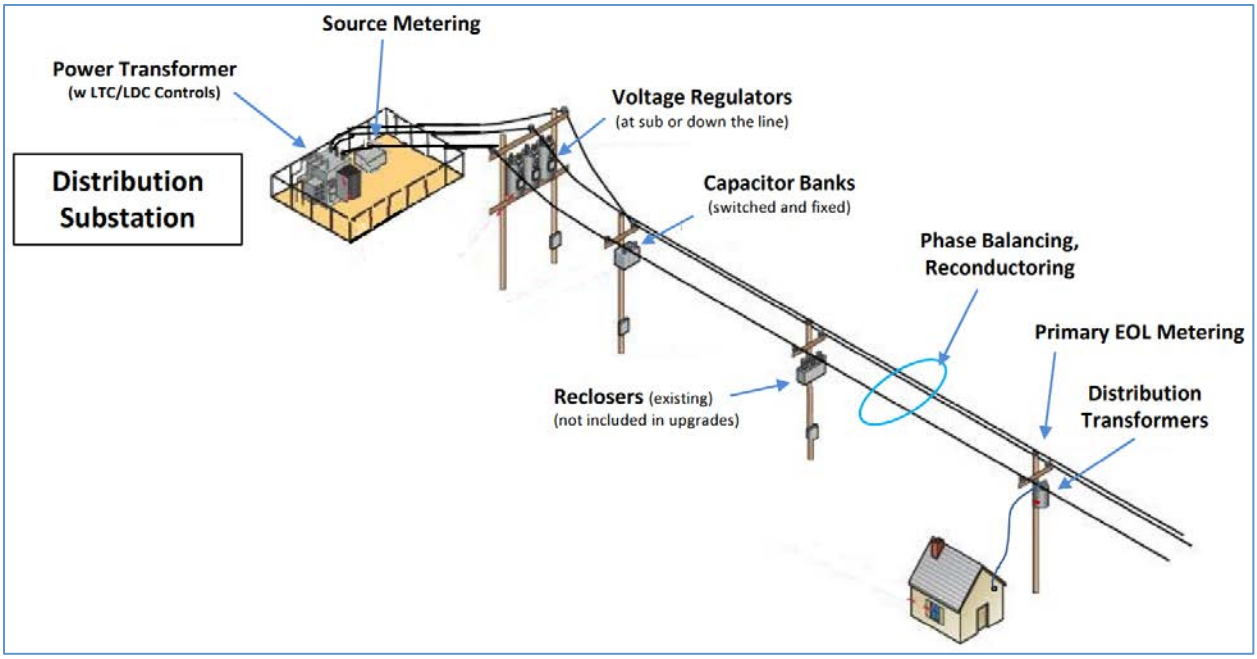

Figure 8 - Illustration of Efficiency Upgrades for Plans A and B

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

Note: 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 System Population:		5655
Less Non-Included Regions	(1898)	
Less Non-Viable Feeders	(1837)	
Total Viable 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.

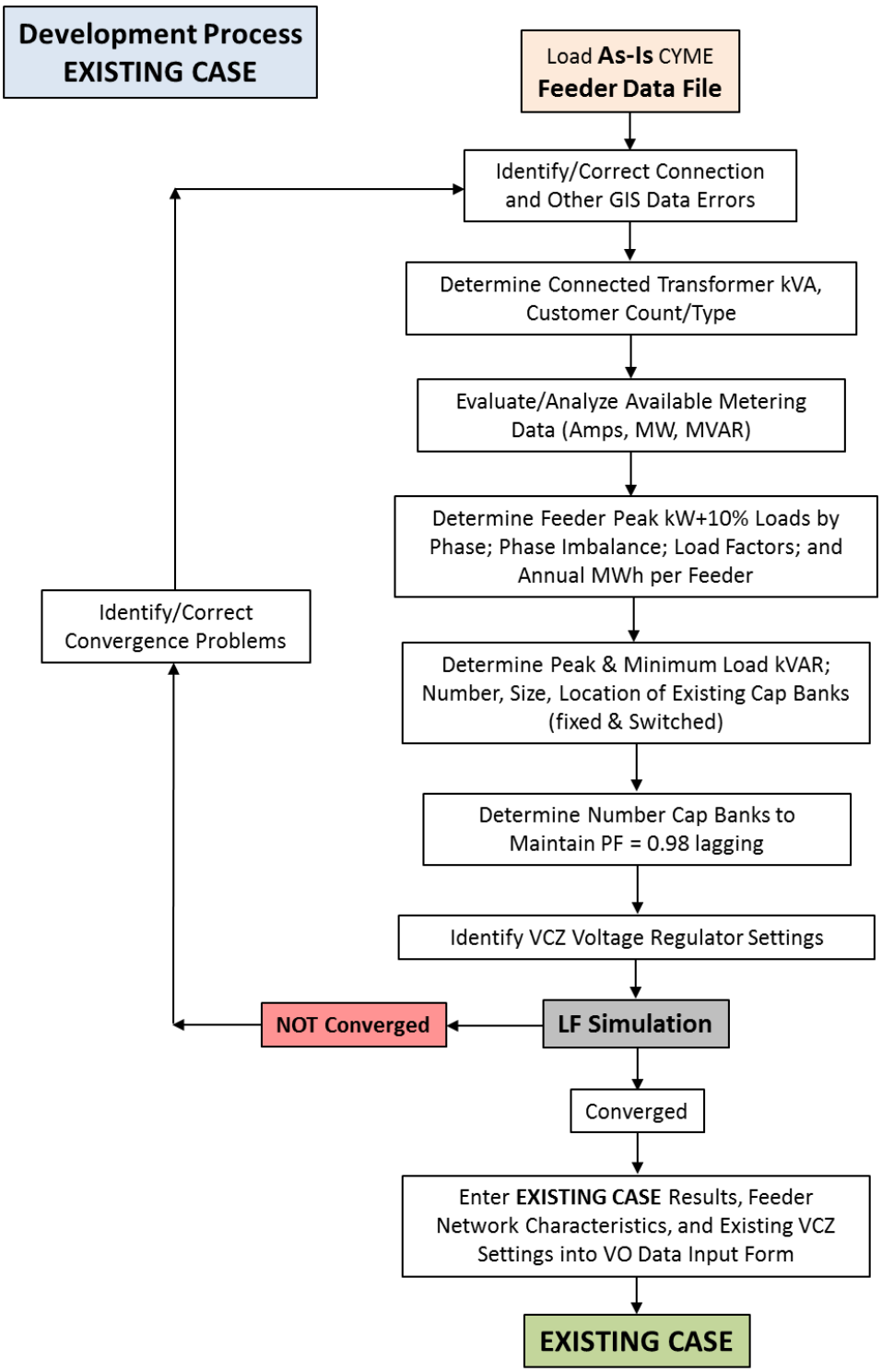

Figure 9 - VO Study Process for Existing Case

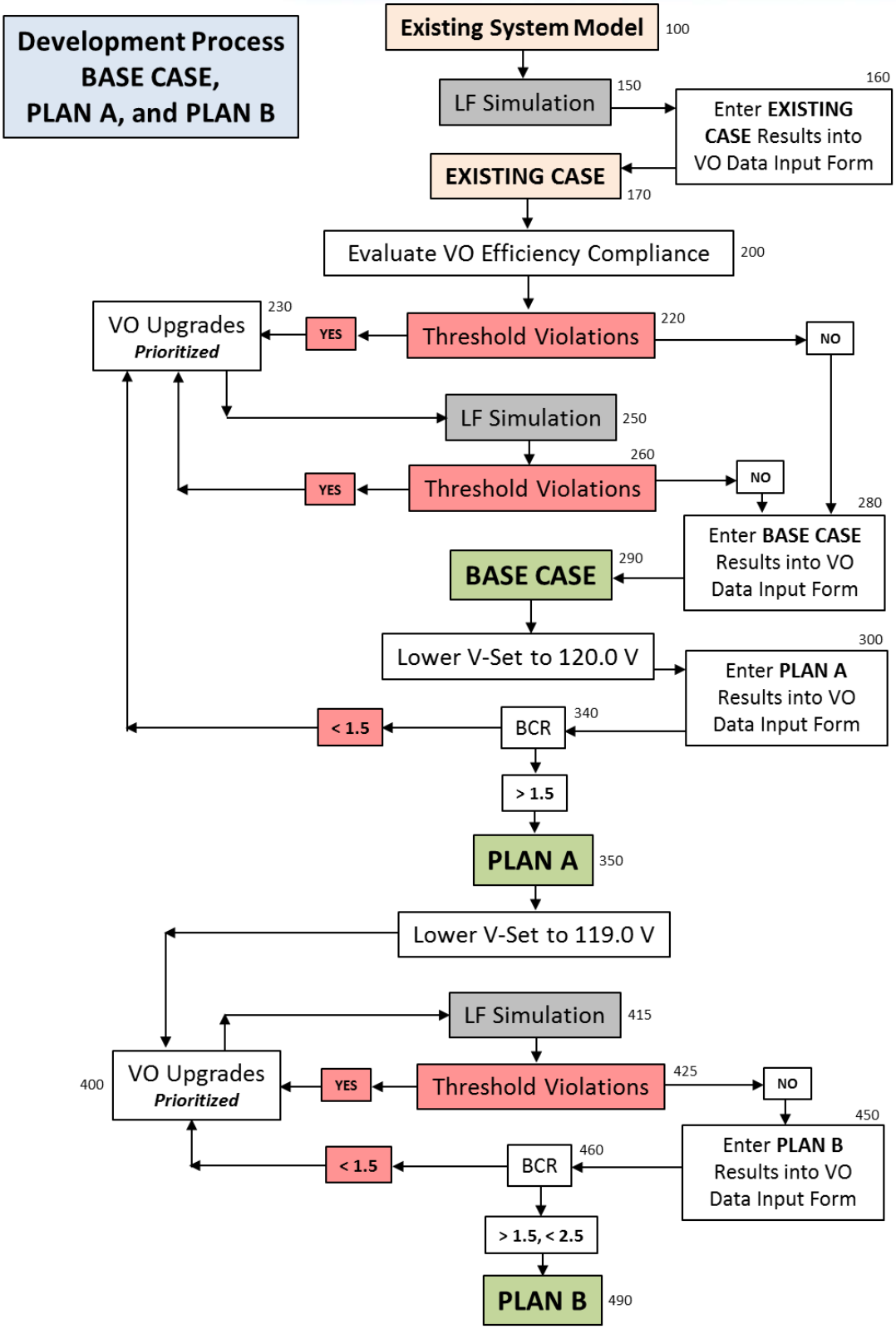

Figure 10 - VO Study Process for VO Simulation Cases

The ten steps 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

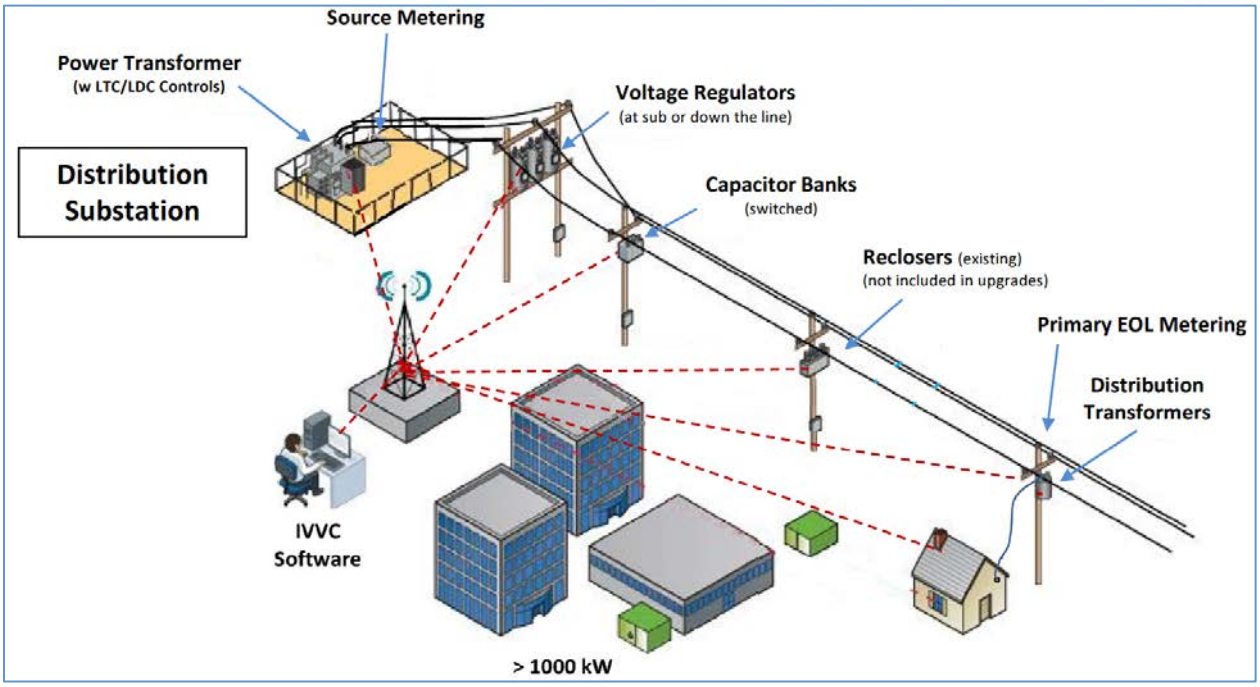

Figure 11 - Typical IVVC Application to Isolate Non-Viable Feeders

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