DIRECT TESTIMONY

of

JOHN V. STUTSMAN

Reliability Assessment Program
Energy Division
Illinois Commerce Commission

Commonwealth Edison Company

Petition for approval of Alternative Rate Regulation Plan pursuant to Section 9-244 of the Public Utilities Act

Docket No. 10-0527

November 9, 2010

Q. **Please state your name and business address.**

A. My name is John Vance Stutsman. My business address is 527 East Capitol Avenue, Springfield, Illinois, 62794-9280.

Q. **By whom are you employed and in what capacity?**

A. I am employed by the Illinois Commerce Commission ("Commission") as Manager of the Reliability Assessment Program in the Energy Division.

Q. **Please describe your professional experience prior to your employment with the Commission**

A. Prior to joining the Commission Staff ("Staff") in 1991 I was employed as a Project Manager for approximately 2.5 years by the engineering consulting firm BRS Technologies, Inc. where my responsibilities included client engineering and design projects in power generation, transmission, and distribution systems and all client projects in computer and control systems. Additionally, I was employed by Purdue University as a Guest Lecturer where I taught two undergraduate accounting courses at Purdue University-Calumet: Financial Accounting and Managerial (Cost) Accounting. Prior to that I was employed for approximately 2.5 years by the financial consulting firm J.H. Ellwood and Associates, Inc. as Systems Director where I was responsible for the company's management

information systems ("MIS"), MIS personnel, and computer modeling/processing efforts. Prior to that I was employed for approximately 10 years by Northern Indiana Public Service Company ("NIPSCO") where my duties and responsibilities included generation planning, engineering and financial analysis, capital budget estimates, load forecasts, rate studies, acquisition planning, strategic planning, and engineering project management & supervision. Additionally, for three years I represented NIPSCO on the East Central Area Reliability Coordination Agreement Generation Reserve Panel. I am a registered Professional Engineer in the states of Indiana and Illinois. Additionally, I am a registered Certified Public Accountant in the states of Indiana and Illinois. I am a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") and a Member of IEEE Power & Energy Society ("PES").

Q. **Please describe your educational background.**

A. I received a Bachelor of Science in Electrical Engineering degree from Missouri University of Science and Technology. I received my Master of Science degree from Purdue University. While employed in industry and at the Commission, I have attended classes and conferences relevant to utility operations, planning, and power delivery infrastructure reliability.

Q. **What are your responsibilities in this case?**

A. On behalf of Staff, I will present my opinions and recommendations regarding the "Urban Underground Facility Reinvestment" ("UUFR")[1] program proposed by Commonwealth Edison Company ("ComEd" or "Company") ComEd witness Dr. Ross Hemphill, ComEd Ex. 1.0, and described by ComEd witness Michelle Blaise, ComEd Ex. 4.0. This is the same program proposed and briefly described by Dr. Hemphill in ICC Docket No. 10-0467, ComEd Ex. 14.0, lines 601 through 607.

Q. **What is your opinion of the UUFR program?**

A. It is my opinion that the UUFR program shows a definite reliability benefit to customers that will compound into the future from the maintenance program with 38,363 estimated incremental avoided customer interruptions[2] when the work is completed. It is maintenance programs like the UUFR program that, in the aggregate, make great strides in improving and maintaining the reliability of the power distribution system and these programs should be encouraged whenever possible.

Q. **Do you have any concerns about ComEd's dedication to the UUFR program?**

[1] In Docket No. 10-0467 and other places, this project is also referred to as the "Urban Underground Investment Reinvestment" ("UUIR") project.
[2] In ComEd's response to Staff data request JVS 1.02 in Docket No. 10-0467, ComEd showed supporting assumptions that when UUFR program work is completed a calculated expectation of 23,162 Inside Chicago and 15,201 outside Chicago for a total of 38,363 estimated incremental avoided customer interruptions. See Attachment A.

67

68 A. Yes. ComEd has indicated that the UUFR program is a feature only of ComEd's
69 alternative regulation proposal.[3] ComEd indicated that it would continue only the
70 current mainline feeder maintenance program[4] if it did not receive Commission
71 approval of its alternative regulation plan. I am concerned that ComEd is being
72 irresponsible in denying customers reliability improvements if it does not receive
73 its alternative regulation proposal. ComEd has indicated[5] that under the current
74 mainline feeder maintenance program it could take up to 100 years to complete
75 refurbishment of all manholes. Under the current program[6], ComEd refurbishes
76 manholes and related cables opportunistically, as failures occur or new business
77 or capacity expansion projects require.

78

79 Q. **Do you have additional concerns about ComEd's dedication to the UUFR**
80 **program?**

81

82 A. Yes. I was concerned when ComEd witness Dr. Ross Hemphill added additional
83 uncertainty to the UUFR program by conditionally linking the program's
84 implementation to the outcome of the rate case, even if the alternative regulation
85 proposal was approved without limitation.[7]

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[3] See Attachment B, ComEd's response to Staff data request JVS 1.04 in Docket No. 10-0467.
[4] ComEd's current mainline feeder maintenance program is succinctly described by ComEd witness Ms. Blaise, ComEd Ex. 4.0, lines 181-182, "ComEd's current reactive approach, by contrast, spends and invests as little as possible to meet minimum service requirements."
[5] ComEd Ex. 4.0, lines 99-100.
[6] ComEd Ex. 4.0, lines 95-97.
[7] ComEd Ex. 1.0, page 10, lines 212-216; and Docket No. 10-0467, ComEd Ex. 14.0, page 33, lines 670-683.

Q. **Did ComEd assign a dollar value to the 38,363 estimated incremental avoided customer interruptions that the UUFR program is expected to provide?**

A. No, not directly. In Docket No. 10-0467, ComEd witness Terence Donnelly stated (ComEd Ex. 8.0, page 17, lines 318-326):

> Our ability to improve reliability well beyond that minimally required of a utility has major benefits for our customers. Interruptions cost customers money. A study recently commissioned for ComEd concluded that reducing the System Average Interruption Frequency Index ("SAIFI") by approximately 0.1, or approximately 10 percent of total SAIFI, has a financial benefit to customers of between $53.5 and $102.3 million annually, including reducing ComEd's restoration costs by $8.7 to $11.6 million. While no utility can be interruption free, and many causes of interruptions cannot be reasonably controlled, striving to eliminate interruptions whenever we practically can is not only a matter of convenience for customers, but benefits them financially.[8]

In response to a data request[9] ComEd estimated that the 38,363 incremental avoided customer interruptions after the work is complete on the UUIR program equates to a SAIFI reduction of approximately 0.01, which implies that the net financial benefits to customers are significant. In her testimony, ComEd witness Ms. Blaise (ComEd Ex. 4.0, pages 12-14, lines 183-233) listed a number of benefits in addition to expected near-term reliability performance improvements. This included long-term reliability benefits, a number of safety improvements, long-term materials and labor cost reductions and work management efficiency improvements achieved by the scale and scope of the program design. In

[8] Also see Attachment C, Attach 01 to ComEd's response to Staff data request JVS 1.01 in Docket No. 10-0467.
[9] See Attachment D, ComEd's response to Staff data request JVS 1.03 in Docket No. 10-0467.

addition, Ms. Blaise noted that the UUFR would result in number of additional skilled jobs created by the program implementation. Clearly, ComEd believes this is a worthy project for improving the reliability of ComEd's customers.

Q. **What is your recommendation?**

A. In order to address the barriers holding back the start of the UUFR project that would improve the reliability of ComEd customers by 38,363 estimated incremental avoided customers interruptions, I recommend that the Commission order ComEd to undertake the UUFR program irrespective of whether ComEd receives approval of and moves forward with its alternative regulation proposal. Additionally, I recommend that ComEd be ordered to provide status reports to Staff every 6 months and upon completion, on the progress being made on the UUFR program until it is completed. I believe the status reports should involve minimal additional work and could be little more than copies of internal high level summaries[10] that ComEd management would be using to track progress on this program.

Q. **Do you have any concerns about recovering costs for the UUFR program pursuant to the Company's alternative regulation proposal?**

[10] Tracking factors such as number of inspections completed, cable segments tested, cable segments replaced, and manholes repaired or replaced versus plan.

A. Yes. The intense budget driven emphasis in the alternative regulation proposal is problematic for several reasons. (1) The amount of work that is projected needing to be done is highly variable with a variance of 50% in the number of manholes needing repair/replacement, a variance of 51% in the number of circuit miles VLF tested, and a variance of 48% in total cable replacement miles. (2) While the proposed work is highly variable the budget is not and is proposed to be $45 million – after assuming a 10% productivity gain from the budget based on actual historical costs of $49 million. (3) The alternative regulation proposal heavily incentivizes ComEd to come within budget and as close as possible to the bottom range of repairs and work – even at the expense of needed reliability improvements.

Q. **Please explain why a highly variable or flexible activity such as the UUFR program is not appropriately managed with a static budget.**

A. From ComEd Ex. 4.0, when talking about a UUFR program budget we have no idea what activity level it represents, i.e., how many circuit segments tested, how many manholes repaired or replaced, nor do we know the total miles of cables replaced or the number of cable joints replaced. The UUFR program budget number is static for an activity that will be highly variable or flexible depending heavily on how many circuit segments are tested, manholes inspected and what is discovered during those tests and inspections. “From a cost control or management point of view it is total nonsense to compare costs of one activity

158 level with costs at a different activity level."[11] ComEd Ex. 4.0, lines 137-140, on
159 page 9 shows a flexible range of activity for what is a static budget as shown on
160 page 15 of ComEd Ex. 4.0, lines 247-250.
161
162 Q. **How does a static UUFR program budget heavily incentivize ComEd to**
163 **come within budget and as close as possible to the bottom of the flexible**
164 **range of repairs and work?**
165
166 A. The static UUFR program budget coupled with a flexible range of work activity
167 perverts the use of the budget from a work management tool to a revenue
168 generating tool. Dr. Rearden, in ICC Staff Exhibit 1.0, addresses a number of
169 economic and financial issues and incentives in this regard. Because of this new
170 nature associated with the static budget, ComEd managerial personnel can be
171 expected to understand that the Company will have a strong interest in keeping
172 near the bottom of the range of work and repairs. Managers will understand that
173 they are likely to be evaluated based on this objective. This could have the effect
174 of managers potentially moving their reliability programs to budget driven and not
175 reliability driven.
176
177 Q. **What do you mean by reliability programs becoming budget driven over**
178 **reliability driven?**
179

[11] Managerial Accounting – Concepts for Planning, Control, Decision Making; Sixth Edition; Ray H. Garrison, DBA, CPA; c 1991, Page 411.

A. I believe there is the danger that ComEd managerial personnel who are responsible for getting the work done will become so budget-focused that reliability work will become shortchanged in order to beat budget numbers. This concern is legitimate given a past report on ComEd's service reliability by Liberty Consulting. As Liberty Consulting group said in their investigation of ComEd's service reliability problems in the late 1990's:

> It is likely that a root cause of many of the service interruptions experienced by ComEd's customers in recent years relates to less than adequate funding of T&D activities during the 1990s. ComEd should not permit future cost control efforts to inhibit identified repairs and enhancements planned for its T&D systems.[12]

Q. **Does this conclude your direct testimony?**

A. Yes.

[12] Liberty Consulting Group; First Report of the Investigation of Commonwealth Edison's Transmission and Distribution Systems, June 2000, Page III-18.
http://www.icc.illinois.gov/downloads/public/ng/Liberty%20Report.zip

ICC Docket No. 10-0467

Commonwealth Edison Company's Response to
Illinois Commerce Commission ("STAFF") Data Requests
JVS 1.01 – 1.04
Date Received: August 20, 2010
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REQUEST NO. JVS 1.02:

Referring to the program described on pages 29 & 30, lines 601-607, ComEd Ex. 14.0:

a) Please provide all plans, analyses, assessments and other supporting documentation supporting the assertion that about 35,000 customer interruptions would be prevented over 18 months;

b) Please explain how Mr. Hemphill defines "customer interruption" in this context and how this compares to the definition of "interruption" Part 411 of the 83 Illinois Administrative Code;

c) Please explain how this program was reviewed and assessed by the Material Condition Improvement Plan ("MCIP") process as described on pages 43 & 44, Lines 889-915, ComEd Ex. 8.0. Please provide all supporting documentation as well as the "health indexing" score for this program.

Please provide all supporting calculations and workpapers. To the extent applicable, all documents and workpapers should be provided in Excel format with working formulas.

RESPONSE:

a) The analysis and supporting information relating to preventing customer interruption is provided is attached as JVS 1.02_Attach 1.

b) Customer Interruption is defined as the sum of customers affected for each "interruption" or "outage" that is the result of an underground failure. The definition of an interruption or outage is consistent with Section 411.20 of Title 83 of the Illinois Administrative Code.

c) The Material Condition Improvement Plan ("MCIP") process begins by rigorously surveying the system and assessing the material condition of delivery system assets based on a standard repeatable process called "health indexing". Health indices, however, are applied at an asset level, not a program level, and health index scores do not exist for programs.

ICC Dkt. No. 10-0467
JVS 1.02_Attach 1
Avoided Customer Interruptions

Estimated Incremental Avoided Customer Interruptions When Work is Completed	
Inside Chicago	23,162
Outside Chicago	15,201
Total	38,363

	Inside Chicago	Outside Chicago	Total	Basis
Emergent Cable Replacement				
2010 Expected Faults per Year Based on Historic Data	350	400	750	Based on historic outage data
Expected Avoided Outages from Emergent Replacement per 2010 Expectation	15	0	15	Assumes 25% probability that circuits with 2 or more faults the second outage will be avoided
Rate of Avoided Outages from Emergent Replacement per 2010 Expectation	0.04	0		Based on miles touched and program assessment
Current Mainline Testing Program				
2008 Program Circuit Sections Repaired/Replaced after Testing	14	10		From 2008 Program Data
2008 Program Estimated Feet Replaced per Section (on average)	1,000	1,900		From 2008 Program Data
2008 Program Total Feet Touched	14,000	19,000		Calculated based on circuit sections touched
Historic Customers Affected Per Mainline Underground Fault (on average)	900	630		Based on 3 year historic outage data
2008 Program Faults Avoided - based on faults before replacement and faults after on circuit	5	10		From 2008 Program Data - based on performance before and after work was completed
Weather Normalization - to account for better than average weather in 2009	8%	8%		Based on decrease in mainline cable faults in 2009 compared to previous years excluding the circuits in the 2008 program
Estimated Faults Avoided per Foot Replaced	0.0003	0.0005		Calculated based on avoided faults, weather normalization, and feet touched
Current Replacement Only Program (no testing)				
2008 Program Circuits with Cable Replacement	0	20		From 2008 Program Data
2008 Program Estimated Feet Replaced Per Circuit (on average)		1,200		From 2008 Program Data
2008 Program Faults Avoided - based on faults before replacement and faults after on circuit		15		From 2008 Program Data - based on performance before and after work was completed
Weather Normalization - to account for better than average weather in 2009		8%		Based on decrease in mainline cable faults in 2009 compared to previous years excluding the circuits in the 2008 program
Estimated Faults Avoided per Foot Replaced		0.0006		Calculated based on avoided faults, weather normalization, and feet touched
Manhole Refurbish				
Approximate Number of Manholes	24,750	8,400		Based on Passport Equipment Records
Number of Circuits with 2 or More Faults Over 3 Years	243	11		Based on historic outage data
Number of Manholes per Circuit	51	26		Based on Passport equipment records
Total Number of Manholes on Circuits with Historic Faults	12,393	286		Based on Passport equipment records and historic outage data
2010 Expected Faults Per Year Based on Historic Data	350	400		Based on historic outage data
Percent of Total Faults due to Manhole Conditions	63%	2%		Assumption based on discussions with Distribution Standards Equipment Specialist and historic outage data for location of faults
Estimated Faults Related to Manhole Conditions	221	8		Calculated based on historic outage data and assumption for percent of faults manhole related
Estimate of Faults from Manhole Support Condition	25%	25%		Assumption based on discussions with Distribution Standards Equipment Specialist
Estimate of Faults from Joint Issues (CMs)	75%	75%		Assumption based on discussions with Distribution Standards Equipment Specialist
Faults Avoided per Manhole Refurbished	0.0044	0.0070		Calculated based on historic outage data and assumptions on estimate of faults manhole or joint related
Faults Avoided per Joint Issue	0.0400	0.0629		Calculated based on historic outage data and assumptions on percent of faults manhole or joint related
Degradation				
Underground Cable Degredation Rate	3%	3%		Based on historic outage data
Percent of Total Faults due to Manhole Conditions	63%	2%		Assumption based on discussions with Distribution Standards Equipment Specialist and historic outage data for location of faults

Proposed Program (All numbers are total including the existing and proposed program. To get incremental numbers the existing program numbers need to be subtracted from the proposed program numbers.)

Year		**2011**	**2012**	**Total**	
Avoided Faults From Emergent Replacement		15	15	30	
Cable VLF Testing and Replacement					
Inside Chicago					
Feet Replaced Annual		11,200	15,400	26,600	
Avoided Faults Annual*		4	5	9	
Outside Chicago					
Feet Replaced Annual		15,900	25,200	41,100	
Avoided Faults Annual*		8	12	20	
Replace Only					
Feet Replaced Annual		28,000	29,600	57,600	
Avoided Faults Annual*		16	16	33	
Inside Chicago Manhole Rebuilt/Refurbish					
Manholes Touched Annual		817	1,635	2,452	
Avoided Faults Annual		4	7	11	
Feet Replaced Annual		60,800	100,600	161,400	
# of cable joint CMs corrected		69	115	184	
Avoided Faults Annual*		3	4	7	
Outside Chicago Manhole Rebuilt/Refurbish				26	
Manholes Touched Annual		182	366	548	
Avoided Faults Annual		1	2	4	
Feet Replaced Annual		0	0		
# of cable joint CMs corrected		0	0		
Avoided Faults Annual*		0	0	0	
Total	750	722	682	1,405	1,060,473
Inside Chicago	350	335	315	650	585,005
Degradation Reduction		3.000%	2.875%		
Outside Chicago	400	387	368	755	475,468
Degradation Reduction		3.000%	2.997%		

Existing Program

Year		**2011**	**2012**	**Total**	
Avoided Faults From Emergent Replacement		15	15	30	
Cable VLF Testing and Replacement					
Inside Chicago					
Feet Replaced Annual		7,000	7,000	14,000	
Avoided Faults Annual*		2	2	5	
Outside Chicago					
Feet Replaced Annual		6,600	6,600	13,200	
Avoided Faults Annual*		3	3	6	
Replace Only					
Feet Replaced Annual		26,400	26,400	52,800	
Avoided Faults Annual*		15	17	32	
Inside Chicago Manhole Rebuilt/Refurbish					
Manholes Touched Annual		0	0		
Avoided Faults Annual		0	0	0	
Feet Replaced Annual		21,000	21,000	42,000	
# of cable joint CMs corrected		30	30	60	
Avoided Faults Annual*		1	1	2	
Outside Chicago Manhole Rebuilt/Refurbish				7	
Manholes Touched Annual		0	0		
Avoided Faults Annual		0	0	0	
Feet Replaced Annual		0	0		
# of cable joint CMs corrected		0	0		
Avoided Faults Annual*		0	0	0	
Total	750	736	719	1,455	1,098,836
Inside Chicago	350	342	334	676	608,166
Degradation Reduction		3.000%	3.000%		
Outside Chicago	400	394	385	779	490,669
Degradation Reduction		3.000%	3.000%		

* Avoided faults decreases annually based on the proportional decrease in underground faults

ICC Docket No. 10-0467

Commonwealth Edison Company's Response to
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JVS 1.01 – 1.04
Date Received: August 20, 2010
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REQUEST NO. JVS 1.04:

Referring to the program described on pages 29 & 30, lines 601-607, ComEd Ex. 14.0:

a) Please explain why this program has not been implemented and completed and recovery sought under Section 9-201;

b) Please compare and explain the differences between the MCIP assessment and "health indexing" scores referenced in JVS-1.02(c) above and the "health indexing" scores for the programs and projects that are included in the 9-201 filing docket 10-0467;

c) How soon will this program begin and when would it be completed if:
   a. The 9-244 plan for this program is adopted or
   b. The 9-244 plan for this program is not adopted and recovery would only be through a 9-201 filing.
   c. Please explain any differences in the responses and provide any additional explanations as appropriate.

RESPONSE:

ComEd respectfully objects to subparts (a) and (c) to the extent that they seeks discovery of legal advice given to ComEd (including without limitation concerning differences between 9-201 and 9-244 filings) and ComEd's legal strategies in this or other dockets. Such information is privileged and/or protected by the work product doctrine. Subject to this Objection and its General Objections, ComEd states:

a) Underground mainline feeder cable system failures, which often occur in and around manholes, are a leading cause of customer interruptions. However, only a very small proportion of the mainline cable system fails each year. Therefore, ComEd has historically refurbished manholes and related cables opportunistically. There is nothing improper or imprudent about this approach, and work can be performed in this manner consistent with good utility practice. Moreover, because ComEd has performed this work opportunistically in the past, only the costs of that approach have been included in the revenue requirements on which ComEd's tariffs, filed under Section 9-201.

b) The Material Condition Improvement Plan ("MCIP") provides ComEd with two main scoring tools. The first is a tool known as health indexing, which is used to assess the health/material condition of the delivery system on an asset by asset basis. The second component is a prioritization tool known as risk scoring. Health indices are at an asset level not a program level. For this reason, there are no health indexing scores for the programs and projects included in the revenue requirement in this docket or proposed in ICC Docket No. 10-0527.

c) Please see the subsections below.

a. In this case, the Urban Underground Facility Reinvestment ("UURF") program would begin immediately once the proposed alternative regulation plan was approved by the Commission.

b. In this case, ComEd would intend to continue its current mainline feeder maintenance program, subject to adjustments in the future as may be warranted. The UURF program would not be put into effect.

c. As noted above, the UURF program is a feature of ComEd's alternative regulation proposal. The existing programs of cable maintenance are sufficient to meet minimum service standards and additional expenditures are not required. However, additional investments as described in the alternative regulation plan would be beneficial to customers.

NAVIGANT CONSULTING

Value Assessment

Distribution Automation and Conservation Voltage Reduction Programs

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August 2009

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Executive Summary

Distribution Automation (DA) offers a broad range of benefits to electric utilities and its customers, regional power suppliers and society at large. Recognizing these benefits, Commonwealth Edison (ComEd) is proposing to automate several hundred distribution switches and deploy a pilot conservation voltage reduction (CVR) as outlined in a Funding Opportunity Application (FOA) 000058 Recovery Act - Smart Grid Investment Grant Program recently submitted to the Department of Energy (DOE).

Distribution automation provides tangible benefits to its customers via reduced outages and lower restoration costs. Using methods that quantify the value of enhanced reliability, the impact of DA to ComEd customers is expected to be substantial - up to 400,000 fewer customer interruptions with corresponding benefits of over $60 million achieved by avoided disruption of customer load and lost economic opportunity. Conservation Voltage Reduction also provides predictable benefits in the form of reduced customer energy consumption, enhanced grid efficiency, reduced equipment maintenance, lower PJM power supply, and reduced fossil emissions.

Because some of the value of these programs cited above accrue to beneficiaries other than ComEd and its customers, economic benefits are presented for other stakeholders, including Regional Power Supply (PJM) and Society at large for emissions benefits.

Figure 1 presents the annual benefits resulting from distribution automation. Results indicate annual DA benefits will range from over $40 million to over $100 million annually. These ranges are based on the variability in the number of outages that occur annually. All benefits are expected to accrue to ComEd and its customers.

Figure 1: Distribution Automation Total Annual Benefits

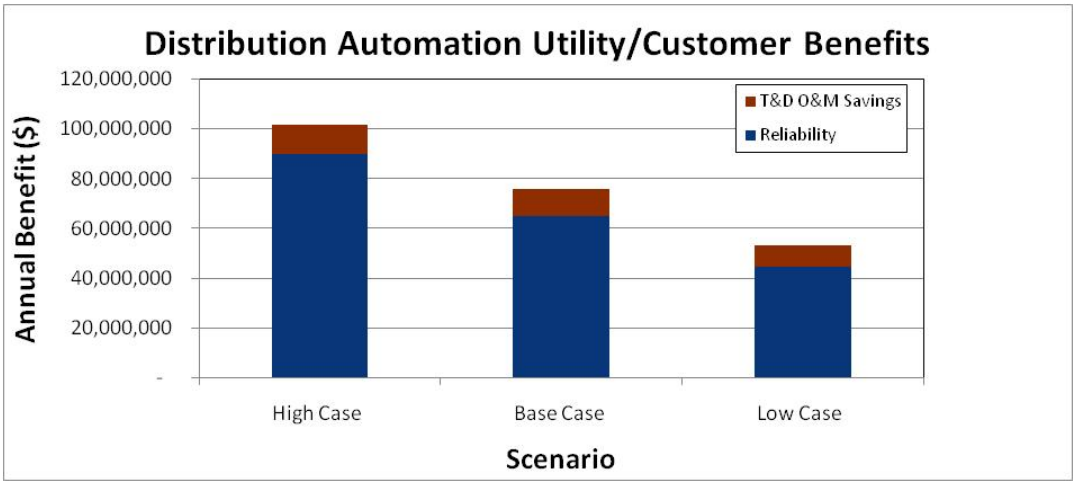
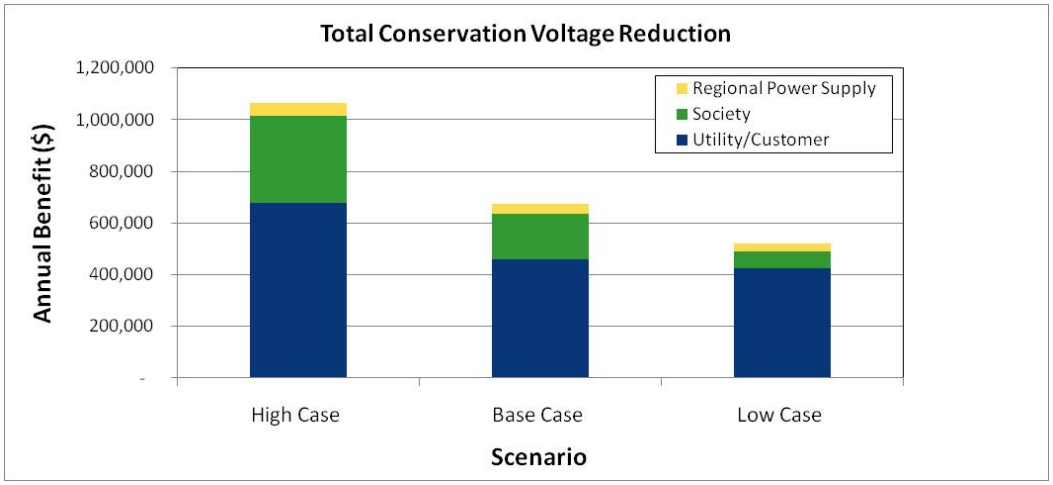


Figure 2 presents the annual savings for CVR, which is expected to range from over $400,000 to over $1 million annually, depending on the price of avoided energy and capacity, and the variability in energy usage reduction. These values translate to an annual benefit of between $71/MWh to $140/MWh. The majority of CVR benefits accrue to ComEd and its customers. However, approximately, 20 to 35 percent accrues to other stakeholders.

Figure 2: Conservation Voltage Reduction Total Annual Benefits by Stakeholder



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Overview

Background

Distribution Automation (DA) offers a broad range of benefits to stakeholders, which include electric utilities and its customers, regional power suppliers and society at large. When DA is targeted to areas of the system most likely to benefit from DA, the value to these stakeholders can be substantial. Recognizing these benefits, Commonwealth Edison (ComEd) is proposing to automate several hundred distribution switches and deploy conservation voltage reduction (CVR) on segments of its system as part of a Smart Grid Investment project outlined in a Funding Opportunity Application (FOA) 000058 Recovery Act - Smart Grid Investment Grant Program recently submitted to the Department of Energy (DOE). The primary objective of the project is to …"stimulate the rapid deployment and integration of advanced digital technology that is needed to modernize the nation's electric delivery network for enhanced operational intelligence and connectivity" and to determine economic value to all beneficiaries.

Numerous prior studies have broadly addressed the benefits of DA and CVR. Some have sought to quantify these benefits, while others assessed benefits qualitatively. Historically, vertically integrated electric utilities were the key stakeholder as they were the recipient of most benefits to the power delivery system; particular, benefits that accrue to the electric distribution system. However, unbundling of power supply from energy delivery companies has blurred the line with regard to which entity actually realizes these benefits.

Navigant Consulting Inc. (NCI) was engaged to identify and quantify the long term benefits of its DA demonstration programs. The benefits analysis is limited to ComEd's automated feeder switching and conservation voltage reduction programs. Other benefits that may be derived from ComEd's Smart Grid program, including those associated with Advanced Metering Infrastructure (AMI), are outside of the scope of this analysis; but nonetheless, enhance the overall value of Smart Grid program implementation. The analysis is limited to evaluating program benefits. It excludes derivation of program costs or an economic comparison of program costs versus benefits.

Program Description

Commonwealth Edison (ComEd) in its application to DOE under FOA 000058 proposes to deploy approximately 600 hundred automated switches on 12.47kV distribution feeders and 90 automated switches on 34.5kV supply lines. For both the 12.47kV and 34.5kV systems, ComEd

will deploy smart devices (Smart Grid) to monitor and control these devices to improve reliability to customers served by these lines. When combined with existing applications, the installation of automated controls on these switches will increase the amount of distribution automation on the ComEd System by about 30%.

ComEd also proposes to implement Conservation Voltage Reduction (CVR) on nineteen 12.47kV feeders served from two substations equipped with intelligent controls. The use of Smart Grid technology in the form of intelligent systems capable of real-time monitoring and control of distributed devices is expected to advance both the commercialization of these technologies and benefits derived.

A detailed description of each of these two programs is highlighted in the following section of this report.

Methodology

The study evaluates the benefits of distribution feeder automation and conservation voltage reduction for all affected stakeholders on an annual basis and estimates sensitivity based on the variability in fuel and pricing assumptions over the expected life of these assets. Program benefits are quantified using economic methods and assumptions for each benefit category, including those deemed to be difficult to quantify, such as enhanced reliability. In most instances, benefit calculations are based on the attributes of the energy delivery assets and customers served by facilities selected by ComEd's for its DA program. For example, expected reliability benefits are based on actual outage histories and the number of customers located on feeders selected for feeder automation. Notably, ComEd has targeted its automated switching program to feeders experiencing the greatest number of sustained interruptions.

The impact and value of the DA programs are derived based on the incremental impacts and savings achieved. For example, demand and energy savings are calculated using marginal prices. Further, economic benefits are derived for all affected stakeholders: (1) the electric utility delivery company and its customers; (2) regional power supply; and (3) society at large.[1]

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[1] Results presented in this study also align with the Energy Independence and Security Act of 2007[1] definition of Smart Grid as defined under Title 13. This title broadly describes the theoretical Smart Grid as maintaining a reliable and secure electricity infrastructure that can meet future demand growth and serve multiple functions including: increased use of digital information and controls; integration of

Results are presented for each stakeholder category, and in aggregate. Where benefits span multiple stakeholder categories, benefits are presented separately for each. For automated feeder switching, values are presented on total dollar. For CVR, economic benefits are presented on both a total dollar, and dollar per megawatt-hour basis.

The methodology and assumptions NCI employed to calculate these benefits are also consistent with several recent DA studies that it has conducted for the Department of Energy, California Energy Commission, and renewable resource/smart grid integration studies for multi-stakeholder groups – several are cited in Appendix A. Most noteworthy is the use of value of service metrics to quantify reliability, the primary benefit derived from automated switching and fault isolation.

Stakeholder Categories

The analysis considers a broad range of operational benefits that are each assigned to one of three stakeholders including Utility/Customers (UC), Regional Power Supply (RP) and Society (SC). Benefits assigned to Utility/Customers bring a direct benefit to ComEd customers such as improved reliability and through reductions in outage time and reductions in interrupted processes. Often, the Utility is defined as the owner and operator of the energy delivery system, but not the service provider of electricity.[2] Because customers ultimately receive the benefits of reduced energy usage and utility operating benefits in rates, the Utility and Customer categories are combined for purposes of this evaluation. Benefits assigned to Regional Power Supply bring a direct benefit to ComEd customers such as lower energy costs, but also benefit other PJM customers outside ComEd's territory. The societal benefits category includes only those benefits that reach beyond local and PJM customers to benefit society at large; for this study, emission reductions were assigned to the societal benefits category.

A distinction is made between Utility/Customer and Regional Power Supply to distinguish between benefits that directly accrue to energy delivery utilities and its customers, versus benefits that are passed through to customers in the form of reduced power supply costs.

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distributed generation, demand response capability, advanced energy storage; and deployment of "smart" meters and appliances with advanced communication and controls.

[2] Many utilities with unbundled service, including ComEd, also provide bundled default service to customers that do not elect to purchase power from third-party suppliers.

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Benefits Evaluation

The following describes ComEd's distribution automation program for automated feeder switching and conservation voltage reduction. It also describes each of the applicable benefits assigned to each of these programs by stakeholder, including the methods and rationale underlying the benefits calculation. The primary benefits associated with automated feeder switching is enhanced reliability and reduced operating costs; whereas, CVR will result in lower line losses, reduced power supply costs, and lower fossil emissions.

Detailed Program Description

ComEd's DA and CVR programs, as filed under FOA 000058 are summarized below:

Distribution Automation (Automated Feeder Switching)

The Project will deploy approximately 700 automated devices on 12kV and 34kV distribution lines that will improve overall reliability and operation of the ComEd distribution system. It includes approximately 400 automated feeder loop schemes and 200 in-line reclosers. The auto-loop schemes and line reclosers will enable ComEd to continuously monitor the distribution system to automatically detect a fault or troubled line section and isolate this section, thereby preventing disruption of electric service to customers on the unfaulted line segment.

- **Cooper NOVA reclosers**: Three-phase, vacuum-interrupting devices for use on the 12kV distribution system
- **S&C Intelli-rupter, utilizing Pulse Closing technology**: ***(next generation technology)*** Used as a mid-circuit and/or tie reclosing device in the 12kV system. Pulse closing devices apply a very fast, low energy pulse to the line to reduce damaging fault currents and voltage sags on the faulted line as well as on adjacent feeders. Intelli-rupter utilizes the Intelli-TEAM II automatic restoration system and provides the ability to track system conditions on overhead and underground distribution systems and provide fast, fully automatic fault isolation and customer service restoration
- **S&C SCADA-Mate Automatic Line Restoration Switches (ALRS**): ComEd will install 90 ALRS on 34kV lines. ALRS switches provide remote feeder monitoring capability and automatic reconfiguration, and employ S&C Intelli-TEAM technology. ComEd will also perform an upgrade of all existing ALRS controllers to Intelli-TEAM 2 technology allowing enhanced sectionalizing and communication ability of teams.

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- **Communication Network:** A highly secure and interoperable Silver Spring Networks mesh radio technology, including point-to-point capability to adhere to the interoperability and cyber security principals established by the National Institute of Standards.

These auto-sectionalizing devices will communicate with the Silver Spring AMI network and serve as collection points for facilitating data storage and outage analysis. They will also utilize the Silver Spring network as part of an overall migration to a cyber secure communications system at ComEd.

ComEd studies indicate automated feeder switching will reduce the number of sustained[3] customer interruptions (CI) between 300,000 to 400,000 annually, resulting in a composite SAIFI reduction of 0.1, almost 8 percent of ComEd's total system SAIFI.

Conservation Voltage Reduction (CVR)

ComEd will deploy CVR on nineteen 12.47kV feeders serving 23,000 customers out of two distribution substations: Oak Park and Berwyn. The composite peak demand projected for these substations in 2010 is about 106 MW. Using smart control algorithms designed for this application, CVR will regulate voltages over a narrower band and at a lower average voltage, but within the ICC limits.[4] For the CVR pilot, ComEd will reduce the substation voltage by 2.5 percent, resulting in a voltage reduction to most customers – voltages for some customers located at the end of the feeder may be at the 113 volt minimum under peak conditions.

To prevent violations of the voltage regulation standard, ComEd will utilize voltage measurements from AMI voltage sensors located near customers at the lowest voltage points, which will initiate switching of feeder capacitors to increase feeder voltages via centralized

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[3] The Institute of Electric and Electronic Engineers (IEEE) Working Group on Reliability defines a sustained outage as a continuous interruption of service of greater than 5 minutes. The automated switching schemes employed in the demonstration will restore service within the 5-minute threshold.
[4] Illinois Commerce Commission Administrative rules require that energy be delivered between 113 and 127 volts, inclusive, for customers taking service at a 120 volt standard; or plus or minus 10 percent for customers taking service at a voltage other than 120 volts. ComEd currently regulates substation bus voltage between 124 to 126V for all load levels.

controls as voltages reach 113 volts. Data from the voltage sensors will be analyzed to validate assumptions presented in ComEd's FOA application and the results presented herein.

CVR also provides monitoring functions for implementation of a condition-based maintenance program for distribution capacitor switch inspection. This deployment seeks to identify other additional benefits and requirements that could result from a broader implementation.

Specific attributes and characteristics of ComEd's CVR program include:

- Micro-processor feeder relays to monitor real and reactive power
- Digital substation transformer tap changer controls
- Digital controls for pole-top capacitor banks
- A central controller that minimizes feeder reactive power flow while maintaining minimum voltage delivered to customers by feeders
- Digital communications between sensors, capacitor controls and the central controller
- Use of highly secure and interoperable mesh radio technology (Silver Spring Networks)

In order to confirm the limits of voltage reduction – a key objective of the project – ComEd will continuously test these algorithms and monitor performance, and make adjustments or changes when needed. AMI voltage sensors will be used to collect data and monitor performance.

ComEd studies indicate CVR will reduce annual energy consumption by 7,205 MWh. In addition, lower distribution losses achieved by reducing feeder and substation reactive loads via optimized capacitor switching will further reduce energy savings by about 180 MWh annually. The combined energy savings results will reduce annual energy consumption by approximately 1.6 percent for the 19 feeders selected for CVR. The reduction in energy consumption also reduces power plant emissions – up to 5000 MT annually of CO_2.

In addition to the above, automated condition monitoring is expected to reduce or eliminate the need to conduct annual field inspection of capacitors.

Assignment of Benefits to Stakeholder Categories

Benefits provided by DA technologies can be assigned to one or more of the three stakeholder groups. A total of 13 discrete benefits were identified as having sufficient economic value to warrant quantification for this study. These 13 benefits were then mapped and grouped into six primary benefit categories.

Table 1 presents the benefits calculation hierarchy in matrix form. It also highlights which benefit applies, by program, and how these are assigned to the three stakeholder groups. The subsections that follow describe the methodology and rationale applied to quantify each of these benefits.

Table 1: Stakeholders and Benefit Categories

Benefit Category	Stakeholder			Benefits Achieved	
	UC	RP	SC		
1. Reliability	✓			1	Reduction in Sustained Outages (DA)
	✓			2	Reduced Equipment Failure (CVR)
2. Energy Savings	✓	✓		3	Reduced Energy Cost (CVR)
3. Line Losses		✓		4	Lower Peak Demand Losses (CVR)
		✓		5	Lower Energy Losses (CVR)
4. PJM Capacity/Delivery Charges		✓		6	Lower Reserve Margin Requirements (CVR)
	✓			7	Reduced Capacity Costs (CVR)
5. T&D Operation & Maintenance	✓			8	Reduced Outage Restoration Cost (DA)
	✓			9	Reduction in LTC Maintenance (CVR)
	✓			10	Lower O&M Cost for Capacitors (CVR)
6. Emissions			✓	11	Lower CO2 Emissions (CVR)
			✓	12	Lower SOx Emissions (CVR)
			✓	13	Lower NOx Emissions (CVR)

Each benefit category is described in the following subsections, including key assumptions and methods employed to derive economic savings. Benefits include operational expenses and capital savings. All savings are projected to recur annually, but should be escalated to account for real cost escalation.

Reliability

Improved reliability accounts for the majority of benefits for automated feeder switching. There is no reliability benefit assigned to CVR, although there may be benefits from reduced equipment failures achieved via voltage stabilization and tighter bandwidth; however, these would likely be small and not materially impact system reliability on such a small scale (19 feeders). Feeder switching does not eliminate line outages. It improves reliability by significantly reducing the length of time – from hours to minutes or seconds – to restore power to customers located on unfaulted line sections. This reduction is achieved via automated switching using control logic and algorithms designed to locate and isolate line faults, and transfer customers on unfaulted line sections to adjacent feeders. It reduces sustained outages

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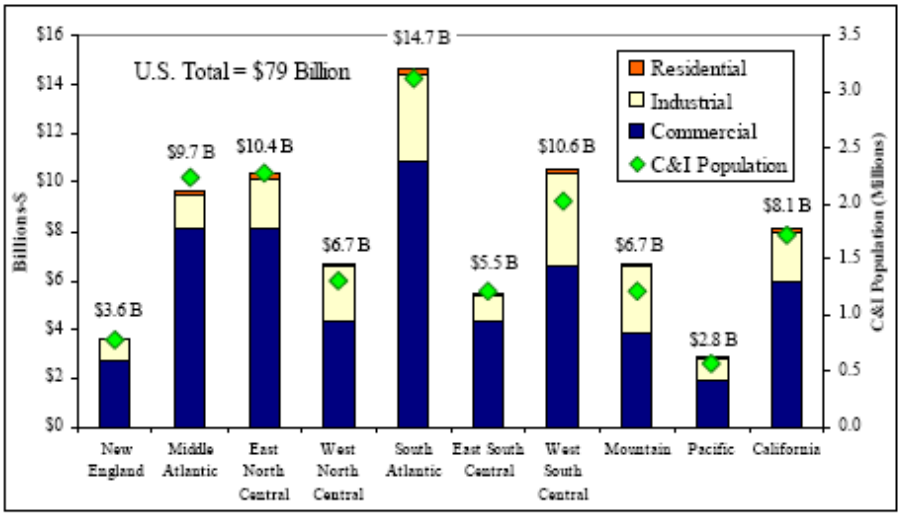
as measured by the System Average Interruption Frequency Index (SAIFI). For example, a feeder loop scheme with two mid-point switches and a single feeder tie serving 4000 customers (2000 on each of the 2 feeders) would see a reduction of 2000 customer interruptions if the main line section of each feeder experiences one outage per year.

Reliability benefits are quantified by multiplying the reduction in customer interruptions, by the weighted customer class value of service (VOS) for sustained outages. Values for VOS vary significantly by customer class, as the impact of customer interruptions is far greater for commercial and industrial customers. Derivation of VOS has been studied extensively over the past several years, as the impact of reliability on utility customers is substantial. Recent studies by the Lawrence Berkeley National Laboratory (LNBL), New York State Energy Research Agency (NYSERDA) and private firms, including NCI, have estimated the cost of reliability to consumers and electric utilities. A recent study conducted by LBNL estimates the impact of outages at over $100 billion annually. The cost of reliability is presented in Figure 3 for regions in the U.S. The estimated annual cost of outages in the region that includes ComEd is over $10 billion.

Figure 3: High Case Estimate of the Cost of Power Interruptions by Region and Customer



[1]Costs shown in U.S. 2002 CPI-weighted dollars

Source: Cost of Power Interruptions to Electricity Consumers in the United States (U.S.); Feb 2006; K. Lawrence Berkeley National Lab, Contract No. DE-AC02-05CH11231; Kristina Hamachi LaCommare and Joseph H. Eto.

For this study, base case values are based on a 2009 study completed by LBNL. Table 2 summarizes weighted value of service costs for a given average Customer Average Interruption Duration Index (CAIDI) value. The 2.5 hour estimate was provided by ComEd based on the outage duration over the past five years. The value of $174 was used for the base case scenario, while $225 and $148 were used for the high and low case scenario respectively.

Table 2: Value of Service for a 2.5 hour outage

Sector	Weighted VOS Rate ($/interruption)
Residential ($)	$4.6
Commercial ($)	$169.4
Total Weighed	**$174.0**

Note that the impact of outages to industrial customers does not apply for automated switching of distribution feeders, as large industrial customers typically are served by dedicated facilities or directly from the transmission system. The percentage split between residential and commercial customers associated with the feeders selected for the demonstration project is approximately 90/10. Based on this percentage split, the weighted VOS applied to each customer interruption is $174. Using an average restoration time of 2.5 hours (CAIDI) and average customer demand of 3.5 kW yields a VOS of approximately $20,000/MWh, a value commonly cited in industry studies.

The second area of potential reliability savings is reduced equipment failure for voltage regulating devices used for CVR; mostly load tap changing (LTC) devices on substation power transformers and voltage regulators. Benefits are derived from the reduction in equipment failures due to fewer LTC operations and stabilized voltages, and from condition monitoring of capacitors. Although tangible, the savings are likely to be very small compared to other benefits. However, if the pilot program for CVR expands to include a greater number of feeders, additional reliability benefits may apply. This could include expanding the condition monitoring program to include devices other than line capacitors. Proactive monitoring of other equipment, particularly those with high failure rates, would enable ComEd to proactively monitor equipment to detect incipient equipment failures, and take corrective action prior to failure.

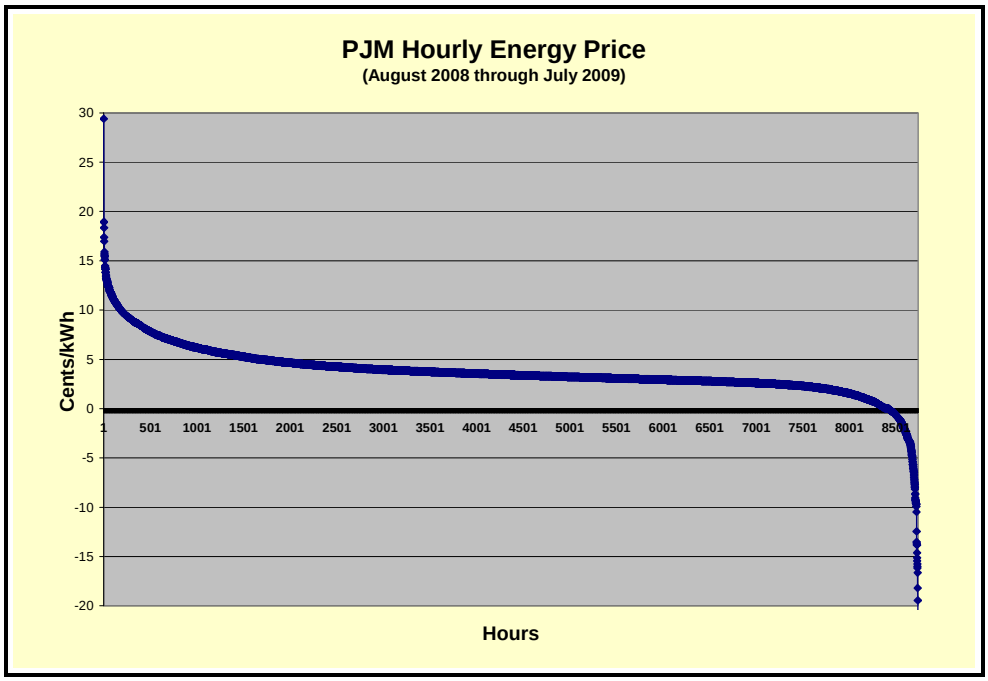
Energy Savings

The Conservation Voltage Reduction (CVR) reduces energy consumption at the customer level is achieved by lowering feeder distribution voltages, yet remain within ICC allowable ranges; particularly line-end customers where the drop typically is greatest. Voltage reduction is

achieved by decreasing voltage at the substation low-side bus; usually via the transformer LTC. For each of the 19 feeders, ComEd proposes to reduce voltages by 2.5 percent for all hours of the year. Customer energy consumption is reduced in an amount proportional to the amount of voltage decrease.

CVR reduces energy deliveries that otherwise would be supplied by ComEd or third-party suppliers. Benefits are assigned to the Utility/Customer stakeholder category, as all energy cost savings are assumed to flow through to the customer, either via third-party suppliers or by ComEd via provision of bundled service. The value of reduced energy consumption is calculated based on the PJM avoided costs for August 2008 through July 2009. Figure 4 presents PJM's avoided cost profile during this time frame. Notably, for most hours of the year – over 7500 hours - the PJM price is below five cents per kilowatt-hour. It increases to over ten cents during peak hours, which is less than 200 hours.

Figure 4: PJM Avoided Cost Profile



Energy savings were allocated over seven time periods based on the avoided PJM energy charges for the time interval. Table 3 presents the analysis, which results in annual energy savings of approximately $272,000 for CVR.

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Table 3: Allocated Energy Savings

Hours	Percent of Hours	PJM Energy Price ($/MWh)	Load Reduction ()kW)	Energy Savings (MWh)	Interval Savings ($)
183	2.1%	119	1,789	150,938	$18,027
280	3.2%	89	1,761	230,943	$20,569
620	7.1%	68	1,718	511,374	$35,025
1819	20.8%	48	1,624	1,500,304	$71,575
4856	55.6%	31	1,348	4,005,210	$125,096
661	7.6%	12	612	545,190	$6,439
317	3.6%	-32	511	261,460	($5,186)
8736	**100%**			**7,205,419**	**$271,545**

Line Losses

Reduced line loss savings are achieved on feeders with CVR controls by optimizing capacitor switching and substation LTC to reduce reactive loads on distribution feeders (i.e., higher power factor). Because losses are greatest when loads are highest, the cost of energy usually is highest during these hours as well. Hence, the average avoided cost of energy production was weighted to the highest load hours. In addition, NCI estimated the loss reduction at peak, which is typically twice the value of average line losses. Because the feeder peak is nearly coincident with the system peak, it is appropriate to apply avoided production capacity credits as well. ComEd feeder simulation studies produced energy loss data for CVR, estimated at 180 MWh annually.

The value of DER loss benefit improvements is estimated by applying avoided generation demand and energy costs to the derived loss savings. These savings are allocated to the Utility/Customer stakeholder category as these benefits ultimately will reduce loss factors used to adjust PJM capacity and energy charges.

PJM Capacity and Delivery Charges

The reduction in energy usage reduction (and line losses) achieved by CVR also decreases costs via reduced PJM generation capacity and delivery charges. Although small (due to the limited size of the CVR demonstration project), system demand on the PJM system is reduced, with the maximum reduction occurring during peak hours. In addition, the lower overall demand also results in a smaller amount of generation capacity needed to meet PJM reserve margins.

The total reduction in peak demand achieved by CVR at peak is about 1800 kW. Combining PJM's $3.21/kW capacity and ComEd's $5/kW delivery charges yields annual savings of about $160,000. These savings are assigned to the Utility/Customer stakeholder group as these charges ultimately are reflected in a reduction in the customer's bill.

As a result of the load reduction achieved by CVR, the amount of capacity needed to meet PJM reserve margin requirements also declines. Assuming a 15 to 20 percent PJM reserve margin requirement, the total demand reduction is about 2500 kW. Using an avoided gas-fired peaking unit as a proxy, the annual value of deferred capacity is estimated at $75/kW-Year. Total annual savings for the reserve margin component is approximately $30,000.

Transmission and Distribution Operations and Maintenance Savings

Discussions with ComEd operations staff revealed several areas where DA could provide operations and maintenance (O&M) benefits. One benefit results from reduced travel time for crew dispatch in response to line outages for automated feeder switching. In general, this benefit provides operational benefits via the crew dispatch time saved by using automated switching to isolate faults and transfer load to unfaulted line sections.

The other primary benefit is the elimination of annual capacitor inspections by utility crews. ComEd's condition-based equipment monitoring program will be used to monitor capacitor switching operations, described above. Maintenance benefits are derived from the reduction in the range of steady-state voltage swings that regularly occur on distribution feeders. In addition, CVR will reduce preventive maintenance (PM) for voltage regulating devices; mostly load tap changing (LTC) devices on substation power transformers and voltage regulators.

Voltage regulation benefits were derived based on estimates of fewer maintenance intervals achieved by reducing the number of tap changing operations resulting from CVR voltage stabilization. Average LTC maintenance costs are estimated at $2200 annually for the Berwyn and Oak Park. Net PM benefits were estimated by assuming the average annual maintenance costs would be reduced by 15 to 25 percent.

Other potential operational expense savings, excluding energy cost reductions captured in other benefit categories, include feeder line maintenance and patrol, supervisory and administrative overhead expense, routine trouble calls including outage events, and customer service. However, these, too, were deemed to be small compared to other benefit categories, and omitted from the study. However, if the pilot program for CVR expands to include a greater number of feeders or to monitor additional equipment such as LTC's and regulators, additional benefits may apply.

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Emissions

This benefit category monetizes emission reductions achieved by energy from reduced energy usage and loss savings. The emissions offset achieved by CVR assumes the emissions offset from generation operating at the margin. For this study, we use ComEd's 2008 environmental disclosure data to estimate the emission rates of ComEd's resource mix. We assumed that nuclear does not operate at the margin and took the emission rate (lbs/kWh) weighted averages of the remaining fuel resources which consist mainly of coal and natural gas. The deployment of CVR, often coincides with peak demand intervals in the PJM system and reduces the need for fossil fueled peaking facilities such as NGCC or other gas-fired generation; for example simple cycle combustion turbines.[5] The value of emission offsets is based on NCI's 2009 fuel and emission price estimates which builds on data from EIA.[6]

Table 4 outlines the emission assumptions made for the four types of gases included in the study.

Table 4: Emission Estimates

Emission Type	Marginal Emission Rate (lbs/MWh)	Value of Emissions ($/ton)	Reference
CO2 Emissions	1,893	10-60	ComEd, EIA, NCI Estimate
SOx Emissions	3.23	300-700	ComEd, EIA, NCI Estimate
NOx Emissions	10.08	400-1,100	ComEd, EIA, NCI Estimate

Project Parameters and Key Assumptions

The assumptions used to derive savings and economic value follows. Wherever possible, DA and CVR data is from ComEd sources or operational experience, supplemented with information from credible sources such as the Energy Information Administration (EIA) and National Laboratory Studies. Study parameters not cited in the individual benefit categories are presented in Table 5.

[5] Senate Bill 1368 also supports this assumption as it requires emissions from new base load generation in California to be less than or equal to the emissions Natural Gas Combined Cycle plants.
[6] EIA Price of CO2 Forecast--Energy Market and Economic Impacts of H.R. 2454--Figure 5 Projection to 2030

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Table 5: Study Parameters

Parameter Type	Unit	Low	Base	High	Source
Avoided Customer Interruptions	Interruptions	300,000	373,000	400,000	ComEd FOA 58
Utility Restoration Costs	$/interruption	29	29	29	Data from ComEd
Avoided Generation Energy Costs to Customer	$ per kWh	0.038	0.038	0.053	Data from ComEd
Annual Energy Loss Reduction due to CVR	MWh/yr.	180	180	180	ComEd FOA 58
Weighted Average Marginal Energy Value	$ per kWh	0.0451	0.0451	0.0631	Data from ComEd
2010 Forecast Feeder Average Peak (KVA)	KVA	5,046	5,046	5,046	Data from ComEd
Voltage reduction	%	2.5%	2.5%	2.5%	Data from ComEd
% power reduction per % voltage reduction	%	75%	75%	75%	Data from ComEd
Marginal Distribution Losses	%	10%	10%	10%	NCI Estimate
Number of Feeders	Feeders	19	19	19	Data from ComEd
Monthly Value of PJM Capacity	$/kW	1.61	3.21	4.82	Data from ComEd
Monthly Value of ComEd Delivery Charges	$/kW	5.00	5.00	5.00	Data from ComEd
Reserve Margin Requirement	%	15%	18%	20%	NCI Estimate
CVR Effective Capacity	kWh/yr	1,789	1,789	1,789	Data from ComEd
ComEd Carbon Dioxide weighted w/o nuclear	lbs/MWh	1,893	1,893	1,893	ComEd 2008 EDI
ComEd NOx weighted w/o nuclear	lbs/MWh	3.23	3.23	3.23	ComEd 2008 EDI
ComEd SO2 weighted w/o nuclear	lbs/MWh	10.08	10.08	10.08	ComEd 2008 EDI
FOA Annual CO2 Emissions	MT	5,000	5,000	5,000	ComEd FOA 58
Annual Energy Reduction—CVR	MWh/yr.	7,205	7,205	7,205	Data from ComEd
Annual O&M cost for capacitors	$ per location	85	100	115	Data from ComEd
Pilot capacitor locations	locations	26	26	26	Data from ComEd
Annual Maintenance Costs	$	2,200	2,200	2,200	NCI Estimate
Percent reduction in Maintenance	%	15%	20%	25%	NCI Estimate

Study Results

This section highlights the results of the benefits analysis for a base case with sensitivity applied to value of service, fuel costs, and emissions cost. The charts and tables that follow illustrate the extent to which each benefit contributes to the total, and how these benefits align with DA and CVR. Finally, the value of CVR is presented on a per megawatt-hour basis. Unless otherwise specified, assume all numbers in the results below are in 2009 dollars.

Distribution Automation (DA) Results

The greatest benefit from DA is derived from enhanced reliability; whereas, for CVR, the greatest benefits are from energy savings, emissions, and capacity benefits. Figure 5 provides an overview of the DA benefit categories and corresponding benefit estimate.

Figure 5: Distribution Automation Total Annual Benefits

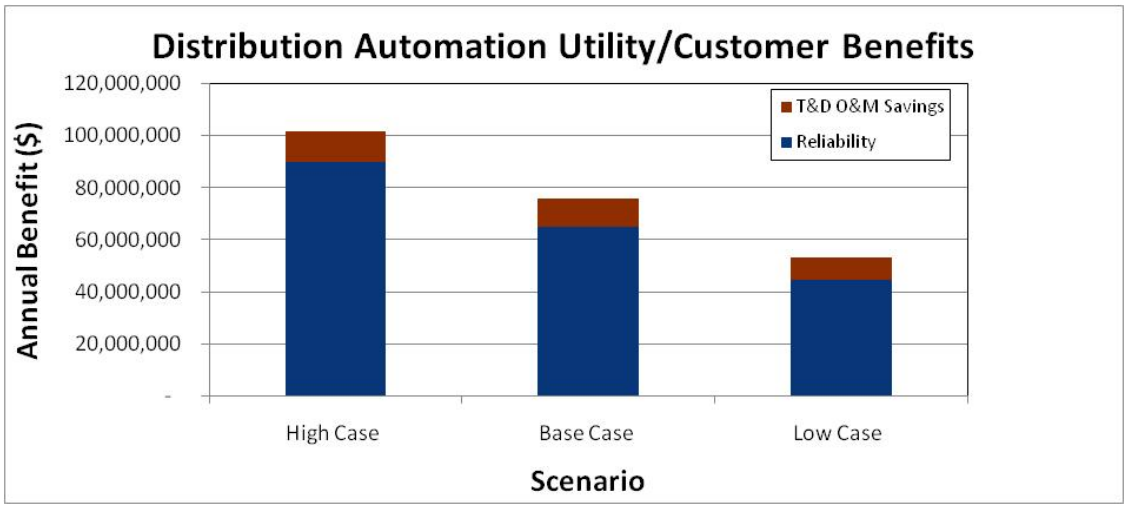

Table 6 summarizes the results for the DA benefits for each scenario. The only relevant benefit categories include reliability, and T&D operations and maintenance savings. All benefits accrue to the Utility/Customer stakeholder group.

Table 6: Distribution Automation Annual Benefits ($)

Benefit Category	Scenario	Utility/Customer
Reliability	High	90,000,000
	Base	64,900,000
	Low	44,400,000
T&D O&M Savings	High	11,600,000
	Base	10,800,000
	Low	8,700,000

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Conservation Voltage Results

Figure 6 summarize the CVR range of benefits by stakeholder. The utility/customer category receives most of the benefit.

Figure 6: Conservation Voltage Reduction Total Annual Benefits by Stakeholder

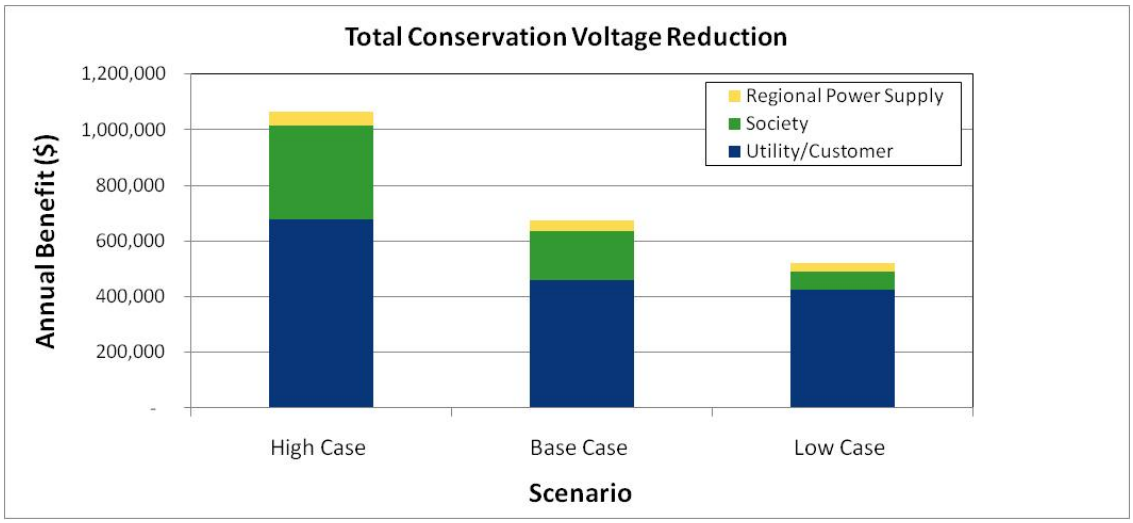

Table 7 estimates the dollar per MWh benefit of CVR for the base case scenario using 180 MWh/yr in line losses and 7,205 MWh/yr in reduced energy consumption.

Table 7: CVR Benefits

Benefit Category	Base Case Totals	$/MWh
Energy Savings	$286,000	$39
Emissions	$175,000	$24
Deferred Generation	$187,000	$25
Losses	$26,000	$3.5
T&D O&M Savings	$3,000	$0.41
Total	**$677,000**	**$92**

Figure 7 provides more detail on the breakdown of each relevant CVR benefit category for the high and low scenarios. Energy savings provides the largest benefit followed by emissions reductions which has a wide range resulting from the current uncertainty of federal regulations (e.g. H.R. 2454) on emissions.

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Figure 7: Conservation Voltage Reduction Annual Benefits by Benefit Category

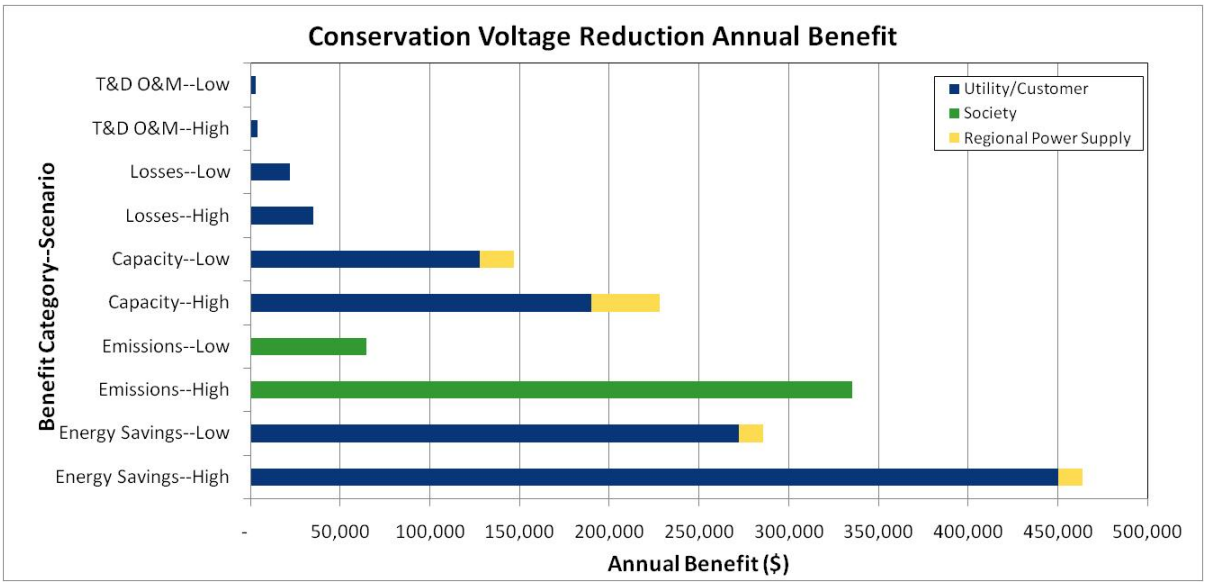

Table 8 lists each CVR benefit category, scenario, stakeholder, and corresponding dollar benefit.

Table 8: CVR Benefits Summary

Benefit Category	Scenario	Utility/Customer ($)	Society ($)	Regional Power Supply ($)	Total ($)
Energy Savings	High	450,000	-	14,000	464,000
	Base	272,000	-	14,000	286,000
	Low	272,000	-	14,000	286,000
Emissions	High	-	335,600	-	335,600
	Base	-	175,000	-	175,000
	Low	-	64,500	-	64,500
Capacity	High	190,000	-	38,000	228,000
	Base	159,000	-	28,000	187,000
	Low	128,000	-	19,000	147,000
Line Losses	High	35,000	-	-	35,000
	Base	26,000	-	-	26,000
	Low	22,000	-	-	22,000
T&D O&M	High	4,000	-	-	4,000
	Base	3,000	-	-	3,000
	Low	3,000	-	-	3,000

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Summary Assessment and Conclusions

The results of ComEd's DA and CVR program assessment, described herein, indicates substantial benefits may be achieved via automation, particularly when stakeholders other than the energy delivery service provider are included in the evaluation. The monetary value of these applications is underscored by the significant reliability benefits associated with reducing the number of sustained customer interruptions

For CVR, the greatest benefits to Utility/Customers derive from reduced energy consumption, followed by avoided regional capacity costs. Although measurable, operating benefits are lower than the displacement of energy and capacity.

Key results and findings include:

1. The composite annual value of ComEd's DA and CVR ranges from $54 to 103 million or roughly $76 million for the base case scenario.

2. Automated feeder switching provides substantial benefits via the reduction of sustained interruptions. When fully implemented, the program has the potential to reduce SAIFI by approximately 0.1 or 8 percent of total SAIFI. The value of avoided interruption to ComEd customers accounts for most of the dollar benefit—approximately $53 to 102 million annually, which includes reduced T&D restoration costs of $9 to 12 million.

3. The collective avoided demand and energy costs associated with CVR produces annual benefits of approximately $680,000 for the base case scenario. On a per unit basis, this value is $92/MWh.

4. The uncertainty of federal emissions regulations results in high variability of CVR societal benefits in the sensitivity analysis.

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Appendix A: References

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ICC Docket No. 10-0467

Commonwealth Edison Company's Response to
Illinois Commerce Commission ("STAFF") Data Requests
JVS 1.01 – 1.04
Date Received: August 20, 2010
Date Served: September 10, 2010

REQUEST NO. JVS 1.03:

Referring to the program described on pages 29 & 30, lines 601-607, ComEd Ex. 14.0:

a) Please quantify the expected reduction in customer interruptions to annual SAIFI & CAIDI improvements;
b) Please explain how you define SAIFI & CAIDI in (a) above and how it compares to SAIFI and CAIDI as defined in Part 411 of the 83 Illinois Administrative Code;
c) Please explain how and when this program was originally proposed and initially designed.

d) Were similar programs proposed within the Company in 1999 or 2000? Please explain.

Please provide all supporting calculations and workpapers. To the extent applicable, all documents and workpapers should be provided in Excel format with working formulas.

RESPONSE:

ComEd respectfully objects to subpart c) and d) to the extent that they seeks discovery of legal advice given to ComEd, and ComEd's legal strategies in this or other dockets. Such information is privileged and/or protected by the work product doctrine. Subject to this Objection and its General Objections, ComEd states:

a) The 18 month program will provide about 30,000 to 40,000 incremental avoided customer interruptions after the work is complete. This equates to a SAIFI reduction of 0.01 on an annual basis upon completion. The program is not expected to have a significant impact on CAIDI therefore it was not included in the analysis.

b) The calculation of SAIFI and CAIDI are consistent with Section 411.20 of Title 83 Illinois Administrative Code.

c) The Urban Underground Facility Reinvestment ("UUFR") program was originally proposed in this docket. It was designed shortly before it was proposed. The design drew upon a 2009 analysis of the underground system in Chicago. The program was designed based on the realization that customers could benefit from increased investment in underground mainline cable testing and maintenance, even through the existing maintenance and replacement protocols was prudent and met operational and engineering standards.

d) No. The proposed UUFR program would accelerate underground maintenance and facility reinvestment. While recommendations from the 1999 Transmission and Distribution investigation also addressed underground maintenance, findings of that investigation have already been implemented and are not part of the UUFR program.