COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

In the Matter of:

APPLICATION OF DUKE ENERGY KENTUCKY,	)	
INC. FOR (1) A CERTIFICATE OF PUBLIC	)	
CONVENIENCE AND NECESSITY	)	
AUTHORIZING THE CONSTRUCTION OF AN	)	CASE NO.
ADVANCED METERING INFRASTRUCTURE; (2)	)	2016-00152
REQUEST FOR ACCOUNTING TREATMENT;	)	
AND (3) ALL OTHER NECESSARY WAIVERS,	)	
APPROVALS, AND RELIEF	)	

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF DUKE ENERGY KENTUCKY, INC.

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits the following responses to data requests of Duke Energy Kentucky, Inc.

Respectfully submitted,

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Certificate of Service and Filing

Counsel certifies that: (a) the foregoing is a true and accurate copy of the same document being filed in paper medium; (b) pursuant to 807 KAR 5:001 § 8(7)(c), there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and (c) the original and copy in paper medium is being filed with the Commission on August 16, 2016.

I further certify that in accordance with 807 KAR 5:001 § 4 (8), the foregoing is being contemporaneously provided via electronic mail to:

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this 15th day of August, 2016

Assistant Attorney General

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 1
Page 1 of 1

Other than Mr. Alvarez, please identify any persons, including experts whom the Attorney General has consulted, retained, or is in the process of retaining with regard to evaluating the Company's Application in this proceeding.

RESPONSE:

Objection. The question seeks information covered by the Attorney-Client and/or Work Product privileges. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, the Attorney General states Mr. Alvarez is the only expert with whom the Attorney General has consulted for the purpose of evaluating the Company's Application in this proceeding.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 2
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For each person identified in (prior) response to Interrogatory No. 1 above, please state (1) the subject matter of the discussions/consultations/evaluations; (2) the written opinions of such persons regarding the Company's Application; (3) the facts to which each person relied upon; and (4) a summary of the person's qualifications to render such discussions/consultations/evaluations.

RESPONSE:

See response to question no. 1, above. Objection. The question seeks information covered by the Attorney-Client and/or Work Product privileges. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, the Attorney General states that Mr. Alvarez's testimony is of public record in this case.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 3
Page 1 of 1

For each person identified in response to Interrogatory No. 1 above, please identify all proceedings in all jurisdictions in which the witness/persons has offered evidence, including but not limited to, pre-filed testimony, sworn statements, and live testimony. For each response, please provide the following:

(a) the jurisdiction in which the testimony or statement was pre-filed, offered, given, or admitted into the record;

(b) the administrative agency and/or court in which the testimony or statement was pre-filed, offered, admitted, or given;

(c) the date(s) the testimony or statement was pre-filed, offered, admitted, or given;

(d) the identifying number for the case or proceeding in which the testimony or statement was pre-filed, offered, admitted, or given; and

(e) whether the person was cross-examined.

RESPONSE:
Objection. The question is vague and overbroad, and to the extent refers to information that may be publicly available, is overly burdensome in that DEK can conduct such research itself, and accordingly must be seen as intending to harass. Without waiving said objections, to the extent discoverable, and in the spirit of discovery, the Attorney General states this information can be found in Mr. Alvarez's testimony available in the public record of this matter; see also response to DEK data request no. 5.

WITNESS/RESPONDENT RESPONSIBLE:
Counsel as to Objections

QUESTION No. 4
Page 1 of 1

Identify and provide all documents or other evidence that the Attorney General may seek to introduce as exhibits or for purposes of witness examination in the above-captioned matter.

RESPONSE:

Objection. The question: (a) seeks information covered by the Attorney-Client and/or Work Product privileges; (b) is unduly burdensome; (c) is non-sensical; and (d) is not designed to lead to the discovery of admissible evidence, and thus must be seen as an intent to harass.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 5
Page 1 of 2

Please identify all proceedings in all jurisdictions in which Paul Alvarez has offered evidence, including but not limited to, pre-filed testimony, sworn statements, and live testimony and analysis. For each response, please provide the following:

(a) the jurisdiction in which the testimony, statement or analysis was pre-filed, offered, given, or admitted into the record;

(b) the administrative agency and/or court in which the testimony, statement or analysis was pre-filed, offered, admitted, or given;

(c) the date(s) the testimony, statement or analysis was pre-filed, offered, admitted, or given;

(d) the identifying number for the case or proceeding in which the testimony, statement or analysis was pre-filed, offered, admitted, or given;

(e) whether the witness was cross-examined;

(f) the custodian of the transcripts and pre-filed testimony, statements or analysis for each proceeding; and

(g) copies of all such testimony, statements or analysis.

RESPONSE:

As to (a) – (f), see chart on next page.
As to (g), objection. The request seeks information which DEK is just as capable of obtaining as the Attorney General. To the extent this question is duplicative of DEK DR 3, it is overly burdensome and must be seen as an intent to harass. Without waiving this objection, see attached files.

QUESTION No. 5
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A[1]	Case	Date	Type	File	Crossed?
CO PUC	11A-1001E	12-14-11	Exhibit MGL-1	MetaVu_SmartGridCity Evaluation Report – Finalv10_10132011.pdf	No
OH PUC	10-2326-GE	6-30-11	Staff Report	Final_Public_Version_2011-06-30_DEO_Audit_and_Assessment.pdf	No
MD PSC	9361	12-8-14	Written Testimony and Cross-Exam at Hearing	Testimony filed 12-8-14.pdf	Yes
KS CC	15-WSEE-115-RTS	7-9-15	Written Testimony	Paul Alvarez testimony with verification 7 9 15.pdf	No
CA PUC	A-15-09-001	4-29-16	Written Testimony	A1509001_TURN_Alvarez+Stephens_Direct DERIC Testimony FINAL (Public).pdf	Case still open

[1] Jurisdiction, Agency, and Custodian

THE UTILITY REFORM NETWORK

CPUC Docket: A.15-09-001
Exhibit Number: TURN-5
Witness: Paul A. Alvarez
Dennis Stephens

PREPARED TESTIMONY OF PAUL A. ALVAREZ AND DENNIS STEPHENS

ADDRESSING PACIFIC GAS AND ELECTRIC COMPANY'S DISTRIBUTED ENERGY RESOURCE INTEGRATION CAPACITY PROGRAM

Submitted on Behalf of

THE UTILITY REFORM NETWORK

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April 29, 2016

DIRECT TESTIMONY

OF

PAUL J. ALVAREZ AND DENNIS STEPHENS ON BEHALF OF

THE UTILITY REFORM NETWORK

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DIRECT TESTIMONY OF

PAUL J. ALVAREZ AND DENNIS STEPHENS ON BEHALF OF TURN

I. INTRODUCTIONS

Q. PLEASE STATE YOUR FULL NAMES AND BUSINESS ADDRESSES.

A. Paul J. Alvarez and Dennis Stephens. The business we work for is served by Post Office Box 150963, Lakewood, Colorado, 80215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. (Alvarez)

I am the President of the Wired Group, a consultancy specializing in distribution utility performance and value creation.

(Stephens)

I work for the Wired Group as a Senior Technical Consultant, where I specialize in helping clients understand and apply electric distribution grid concepts, technologies, and business processes.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. (Alvarez)

We are testifying on behalf of The Utility Reform Network (“TURN”) regarding the Distributed Energy Resource Integration Capacity Program (the “DERIC” Program) proposed by PG&E in Chapter 13 of its PG&E-04.[1] We recommend that the Commission reject the DERIC Program proposal in its entirety, resulting in disallowances of $22.509 million in capital in 2017 and $99.762 million in capital from 2017-2019.[2] TURN witnesses Eric Borden and Garrick Jones will address other recommended disallowances in distribution capital and O&M spending, respectively.

My testimony will demonstrate that the DERIC Program PG&E proposes is not in the ratepayers' interest. Contrary to the requirements of P.U.C Section 769, I do not believe the proposal delivers net benefits to customers, nor do I believe its associated costs are just or reasonable.

(Stephens)

My testimony will demonstrate that the DERIC Program and its presumptive investment schedule is not necessary to avoid future delays in retail DER integration, and that any risk to continued integration of DERs from rejecting the DERIC Program proposal is low.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUNDS.

A. (Alvarez)

My career in the electric utility industry began 15 years ago with Xcel Energy, one of the largest investor-owned utilities in the U.S. After a series of product management roles of progressive responsibility for large corporations, including Motorola's Communications

[1] PG&E-04, p. 13-29 to 13-35.

[2] These amounts are included in MWC 06 and MWC 46, as specified in PG&E-04, p. 13-35, Table 13-4.

Division (now owned by Google), Baxter Healthcare, Searle Pharmaceuticals, and Walgreens, I served Xcel Energy as product development manager. In this role I oversaw the development of new energy efficiency and demand response programs for residential and commercial and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance.

In 2008 I left Xcel Energy to establish a utility practice for boutique sustainability consulting firm MetaVu, where I utilized my M & V experience to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are the only two comprehensive, unbiased evaluations of smart grid deployment performance completed to date. The results of both were part of regulatory proceedings in the public domain, including an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010,[3] and an evaluation of Duke Energy's Cincinnati deployment for the Ohio Public Utilities Commission in 2011.[4]

I started the Wired Group in 2012 to focus exclusively on distribution utility performance measurement and utility customer value creation. Wired Group clients include consumer and environmental advocates, regulators, utility suppliers, industry associations, and non-profit utilities. I also teach a graduate course on renewable technologies, markets, and policy at the University of Colorado's Global Energy Management Program, and courses

[3] *SmartGridCity™ Demonstration Project Evaluation Summary*. Exhibit MGL-1 to the testimony of Michael G. Lamb in the Matter of the Public Service Company of Colorado Application for Approval of SmartGridCity Cost Recovery. Filed with the Colorado PUC in 11A-1001E on December 14, 2011. Alvarez et al. Report dated October 21, 2011.

[4] *Duke Energy Ohio Smart Grid Audit and Assessment*. Public Utilities Commission of Ohio Staff Report, public version, filed in 10-2326-GE-RDR on June 30, 2011. Alvarez et al.

on distribution utility performance measurement and smart grid value creation at Michigan State University's Institute for Public Utilities (a program dedicated to educating new regulators and staff on utility industry concepts).

Finally, I am the author of <u>Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment</u>. The book describes the challenges of translating smart grid investments into economic benefits for customers, and offers organizational, operational, customer engagement, rate design, and regulatory solutions. I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree in management from the Kellogg School at Northwestern University in 1991. A full CV is provided as Appendix A to this testimony.

(Stephens)

My career began in 1975, when I began work for Xcel Energy (then Public Service Company of Colorado) as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution design, planning, operations management, asset management, and the innovative use of technology to assist with these functions. In many of these roles I had to contend with the impact of distributed energy resources ("DER") on distribution assets and operations. Positions I've held over the years have included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments.

In 2006, my team and I won a national Edison Award for Utility Innovations. In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™ demonstration project in Boulder, Colorado, the first of its kind at the time, covering 46,000 customers. I developed the technical foundations for the project, including the development of all concepts presented to the Xcel Energy Executive Committee for project approval, and including the negotiations with technology vendors on their contributions to the project. As Director of Utility Innovations for Xcel Energy, I also worked with many software providers, including ABB, IBM, and Siemens, helping them develop their distribution automation ideas into practical software applications of value to grid owners and operators. In 2009, I established a DER integration strategy and capability road-map for Xcel Energy. The technical project components focused on Boulder, which had (and still has) the highest concentration of PV solar installations in Xcel Energy's eight-state electric service area.

I retired from Xcel Energy in 2011, and now work for the Wired Group on a part-time basis. I am a veteran of the US Air Force, where I worked on ballistic missile systems. I have a BS degree in Electrical Engineering from the University of Missouri at Rolla. A full CV is provided as Appendix B to this testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. (Alvarez)

Our testimony will demonstrate that the DERIC Program and its presumptive investment schedule is not in ratepayers' interests as described below.

- I summarize relevant elements of California Public Utilities Code Section 769, investor-owned utility (IOU) economic incentives, and the resulting bias I find throughout PG&E's DERIC Program proposal. I believe PG&E is using unfounded reliability concerns allegedly resulting from DER growth to increase capital expenditures more quickly than necessary. I will also discuss the outsized importance of the DERIC Program proposal resulting from its potential to establish inappropriate precedents.

- Mr. Stephens will continue by describing why the DERIC Program and its presumptive investment schedule is not necessary to avoid future delays in retail DER integration, and why the risk of postponing DERIC Program investments until they may become necessary on an as needed basis is low. Mr. Stephens explains that PG&E has successfully used industry standard practices and processes to date to integrate a large amount of DER with no operational problems, and presents evidence that presumptive investments proposed in the DERIC Program are premature.

- I will resume testimony by demonstrating that the DERIC Program is much more costly to ratepayers than the industry standard practices and processes PG&E is already employing successfully. I will also describe why the DERIC Program may benefit wholesale DER owners at ratepayer expense, and present evidence that PG&E's investments would subsidize wholesale DER interconnections in violation of Rule 21. Finally, I will describe how presumptive investment transfers PG&E performance risk into ratepayer economic risk.

- I summarize the above arguments to show that the DERIC Program is not cost-effective, as it fails to provide net benefits to ratepayers, and the cost is far out of proportion to ratepayer and prospective retail DER owner risk reduction. I recommend that the Commission disallow the entire $22.5 million capital forecast for the first year of the DERIC Program (test year 2017), and order PG&E to not make these presumptive investments. I make several additional recommendations designed to promote DER integration on PG&E's distribution system during the course of this rate case.

II. PG&E IS USING THE DERIC PROGRAM TO PROMOTE UNNECESSARY CAPITAL EXPENDITURES THAT DO NOT PRODUCE NET BENEFITS (ALVAREZ)

Q. PLEASE PRESENT YOUR PERSPECTIVE ON THE ROLE OF SECTION 769 IN THE REGULATION OF CALIFORNIA IOUS.

A. I understand that Section 769 of the California Public Utilities Code directs utility investments " . . . to minimize overall system costs and maximize ratepayer benefit from investments in distributed (energy) resources (DER)." However, I view the cost-effective deployment of DER as only one of several goals the Commission advances. Others include the protection of consumers by ensuring utility services are provided safely, reliably, and at just and reasonable rates. The Commission has optimized the balance among these goals for more than a century, adding environmental enhancement as California's needs evolved. TURN and I share the Commission's interest in optimizing the balance among these goals.

For over 100 years, California IOUs have been tasked with finding the most cost-effective solutions to technical and business issues as they arise. The attainment of renewable generation goals, and DER integration in particular, simply represents new technical and business challenges that PG&E must solve in the most cost-effective manner possible. The Commission's role is to establish the governance required to ensure the challenges are met reliably, safely, and at the lowest possible cost to ratepayers, while providing economic incentives to IOU shareholders to do so.

Q. PLEASE SUMMARIZE WHY PG&E'S DERIC PROPOSAL RESULTS IN UNNECESSARY CAPITAL EXPENDITURES

A. Based on extensive evaluation of the components of the DERIC program, I find that the proposed capital investment is unnecessary for the following reasons, which are detailed in the remainder of this testimony:

- The DERIC Program proposes to invest presumptively rather than on an "as needed" basis, despite the fact that there is no evidence that continuing with "as needed" upgrades does not work, and in the face of evidence that presumptive investment will result in unnecessary and costly upgrades on circuits that would experience no problems integrating more DERs;

- The DERIC Program proposes hardware solutions with long depreciable lives over alternative solutions with reduced ratebase impact (such as short-lived software solutions or operational solutions requiring no Company capital);

- The DERIC Program proposes to add, to the ratebase, the cost of upgrades that should have been charged to wholesale DER owners, as well as the cost of upgrades that will benefit yet-to-be-identified wholesale DER owners.

Q. THE DERIC PROGRAM IS A SMALL COMPONENT OF PG&E'S GRC. WHY ARE YOU AND TURN DEVOTING TIME AND RESOURCES TO REJECT IT?

A. As this testimony will demonstrate, presumptive DERIC Program investments are not needed to avoid retail DER integration delays, and the reliability and safety risks associated with traditional "upgrade as needed" approaches is low or zero. While spending any amount of ratepayer funds on upgrades that deliver no ratepayer benefit is sufficient basis for my efforts, I believe the approval of the DERIC Program would set several bad precedents:

- It would force ratepayers to subsidize wholesale DER owners (let alone retail DER owners);

- It would approve presumptive investments to solve problems which will not appear in the near term, can be more effectively addressed on an "as-needed" basis in a more traditional manner, and might result in upgrades on circuits that will not see DER growth;

- It would approve the first phase of a program that targets less than about 16% of PG&E's circuits, and anticipates - without any explanation or justification of the potential size and need for – large future presumptive investments.

The DERIC Program will only upgrade 506 of PG&E's 3200 circuits for $75 million (MWC 06), and 5 of its 900 substations for $25 million (MWC 46).[5] Simple extrapolation of these numbers delivers full deployment cost estimates in the billions of dollars *in PG&E's service territory alone*. In discovery PG&E stated that it would not commit to the additional amount of retail DER capacity it could accommodate if DERIC Program upgrades were implemented as proposed. This means ratepayers don't know what they are getting for their money, and can't assume that more funds won't be needed to integrate DER on these 506 circuits and 5 substations. At some point, DER ceases to become a cost effective approach to reaching California's environmental goals.

Research and demonstration projects to identify more cost-effective DER integration approaches, from DER management software and smart inverters to potential use of electric storage, have not been concluded or not yet begun. In addition, the details and impact of Locational Net Benefits Analysis and associated pricing mechanisms anticipated in the Distribution Resource Planning docket (R.14-08-013) have yet to be determined, making DER growth forecasts suspect. For all of these reasons, the potential precedents that could be established by DERIC Program approval are extremely critical

[5] These amounts are included in MWC 06 and MWC 46, as specified in PG&E-04, p. 13-35, Table 13-4.

and merit careful consideration, despite the relatively minor short-term ratepayer impacts relative to the overall size of the GRC.

III. PRESUMPTIVE DERIC INVESTMENTS ARE NOT NEEDED TO AVOID FUTURE DELAYS IN RETAIL DER INTEGRATION, WHILE THE RISK OF POSTPONING DERIC INVESTMENTS IS LOW (STEPHENS)

Q. PLEASE PREVIEW THE TESTIMONY YOU ARE ABOUT TO PRESENT.

A. My testimony will demonstrate that the presumptive investment schedule of the DERIC Program is simply not needed to avoid retail DER integration delays or to avoid reliability and safety issues related to DER. I will use four arguments:

- The established distribution planning practices and processes PG&E already employs are adequate to identify significant upgrades with sufficient notice such that retail DER integration delays can be avoided, at little to no risk to reliability or safety.

- The established operating practices and processes PG&E already employs are adequate to address local voltage regulation and protective device upgrades as they arise, with little to no risk to reliability or safety.

- PG&E's practices and processes are working as intended, and have avoided reliability and safety issues as well as retail DER interconnection delays; this is true despite a number of circuits which already have very high levels of DER.
- Many if not most of the upgrades are being proposed far in advance of the time they will be required, while others are being proposed to avoid issues with little or no probability to impact distribution customers or DER owners.

Q. PLEASE PRESENT YOUR UNDERSTANDING OF THE DISTRIBUTION PLANNING PRACTICES AND PROCESSES UTILITIES USE TO IDENTIFY SIGNIFICANT UPGRADES IN ADVANCE OF NEED.

A. All utilities monitor growth in customer loads and associated impacts on Transmission, Substation and Distribution systems. They monitor trends in energy use and peak demand over time, by circuit and by substation, as part of the distribution planning discipline. The goal of distribution system planning is typically to identify, at least 2 to 3 years in advance, the need for significant distribution system upgrades. Upgrades are categorized as "significant" when they require both large amounts of capital and long lead times for design and execution. Reconductoring large sections of distribution line, substation capacity upgrades, and some substation protection upgrades can be examples of significant upgrades. They can be capital intensive and may require long lead times – about 12-18 months for some large reconductoring projects, 24-36 months in the case of substation capacity upgrade projects, and 6-12 months for some substation protection upgrades.

In geographies with excellent solar resources and extensive DER adoption such as California, the distribution planning discipline has already begun incorporating DER considerations into its work.[6] Utilities are now monitoring minimum circuit loads as well as additional DER capacity to better predict the possible occurrence of two-way power flow. These are now minimum standards for distribution planning at utilities where DER is growing.

Q. WHAT DOES THIS HAVE TO DO WITH PG&E'S DERIC PROGRAM PROPOSAL?

A. PG&E's DERIC Program proposes investing almost $20 million to reconductor 12 circuits, $19.4 million to increase the capacity of 5 substations ("upgrade substation equipment"), and $3.2 million to upgrade protective devices at the head ends of 22 circuits ("substation protection") from 2017-2019. These upgrades are significant per the definition above, and fall into the domain of distribution planning processes. Typically, distribution planning engineers will examine the entire distribution grid to identify the significant upgrades of greatest priority. PG&E does this using the tools, such as a Load Forecasting Tool, described in its Distribution Resource Plan. In addition, utilities typically asses the projects identified through the planning process with a Risk Assessment Tool. This is used to determine how any one individual project stacks up against other identified projects, from a probability of risk and cost standpoint. The Asset Management Group will then present the list of prioritized projects to management for

[6] "Distribution Planning and Investment and Distributed Generation". PG&E 2014 General Rate Case Appendix C. Section D, "Distribution Capacity Planning and DG", pages C-9 to C-14.

selection to be included in the capital budgets approval process. PG&E uses exactly these processes, and describes them on GRC pages 13-4 and 13-5; PG&E's Risk Informed Budget Allocation process is described on GRC pages 13-11 through 13-14. However, I do not believe the upgrades proposed for the DERIC Program were selected using these processes.

Q. WHY DO YOU BELIEVE STANDARD DISTRIBUTION PLANNING PRACTICES AND RISK ANALYSIS PROCESSES WERE NOT USED TO SELECT THESE DERIC UPGRADES?

A. In discovery TURN requested, for table 13-4, "all workpapers and calculations to support this table." (Table 13-4 presents the 3-year costs for all 7 categories of upgrades proposed for the DERIC Program.) PG&E did not reply with any detail or analysis for substation protective device upgrades or substation capacity upgrades; for reconductoring upgrades, it responded with a few explanatory sentences and some bullet points, with no details or analyses specific to any recommended circuit or upgrade.[7] Had standard distribution planning practices and processes, along with analysis using current risk assessment tools, been used to determine the need for specific upgrades on specific circuits, such detail and analyses would have been readily available. In my experience, the lack of available detail suggests that these specific projects would have failed the test of standard risk analysis, compared to other capital budget items.

[7] PG&E response to DR_TURN_035-Q11

Q. WHAT IS THE IMPLICATION OF NOT UTILIZING STANDARD DISTRIBUTION PLANNING PRACTICES AND PROCESS, ALONG WITH RISK ANALASIS, ON CIRCUITS SELECTED FOR UPGRADE?

A. The implication of not applying common distribution capacity planning processes and risk analysis, is that PG&E's proposed DERIC investments may not be necessary to address system needs.

There is circuit-specific evidence that the reliability and safety issues PG&E predicts from high-DER circuits have not materialized on circuits that already have high DER capacity. To me, this is an indication that PG&E's existing capacity planning practices and processes, as well as risk analysis processes, are working well, and that presumptive DERIC investments are not necessary. This, combined with the fact that retail DER interconnection approval times have fallen from 15 business days in 2012 to 3 business days in 2015, despite a quadrupling of interconnection request volume,[8] is further proof that the DERIC upgrade requests are premature.

The Wired Group compiled Table 1 below from data provided by PG&E in discovery. The data indicates that many of the substations and circuits chosen for significant upgrades in the DERIC Program proposal already exceed PG&E's definition of "High Penetrations of DG". In fact, some substations and circuits chosen already exceed PG&E's definition by significant amounts. (Note that the threshold set by PG&E for taking action in DERIC is 15% of DG capacity as a percentage of peak load, representing

[8] PG&E response to DR_TURN_098-Q02, Attachment 01.

DER interconnect application screen "M" in Rule 21.) *Yet, these circuits have exhibited none of the reliability or safety problems of which PG&E warns in its proposal*. Detailed peak demand and DER capacity data, both current and forecast, on the circuits selected for Reconductoring, Substation Capacity, and Substation Protection upgrades is available in Appendices C, D, and E, respectively.

Table 2: Reliability or safety issues reported to date on circuits/substations selected for significant upgrades[9]

Upgrade category	No. of circuits/subs to be upgraded per DERIC Program proposal	No. of circuits/subs which already exceed high* DER capacity	Reliability or safety issues reported on circuits/subs w/high* DER capacity	Retail DER interconnection delays to date on circuits/subs with high* DER capacity
Reconductoring	12	8[1]	None	None
Substation Capacity	5	5[2]	None	None
Substation Protection	22	13[3]	None	None

* DER capacity (all types) as of 12-31-15 in excess of 15% of 2015 peak demand
[1] One circuit (42891101) has almost 3x the definition of high DER capacity at 43.4%
[2] One substation has almost 10x the definition of high DER capacity at 146.5%
[3] One circuit (252941106) has more than 2x the definition of high DER capacity at 33.6%

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW TRADITIONAL DISTRIBUTION PLANNING APPROACHES CAN BE USED TO INTEGRATE DG?

[9] See Appendices C, D, and E for data to support this table and citations to data sources.

A. Yes. Appendix C of Phase 2 of PG&E's 2014 GRC, entitled "Distribution Planning and Investment and Distributed Generation",[10] provides a perfect example. Consider this quote from sect D. 2. b. "How PG&E's Load Forecast Incorporates DG":

> "Over 99 percent of the DG systems interconnected to PG&E's distribution system are accounted for in the historical peak demands the Company uses to forecast future load. This is because PG&E makes no adjustments to its load forecasting process for small DG systems 8 (i.e., less than 100 kW) which represents nearly all the DG interconnected to the distribution system. In effect, PG&E records the peak load that substation transformers and circuits serve (or "see"). Since substation transformer loads reflect the amount of DG that is interconnected and operating on the peak day, the recorded peak load includes the influence that DG has on the load that the distribution system serves (which is not necessarily the full capacity value of the DG system). Since the load forecast is based on historical peaks, and the historical peaks reflect the contribution that DG makes to the amount of load the system serves, DG is incorporated into the load forecast in terms of both quantity and trend. (Seven years of historical data form the trend, so if DG is growing in a particular area, then that growth is captured to at-least some extent in the forecast.) However, the fact that DG is incorporated in the load forecast does not necessarily mean it is influencing capacity expenditures. What causes capacity expenditures is the relationship of the load forecast relative to available capacity for a specific system component such as a substation transformer, circuit, etc. If there is insufficient capacity (i.e., a deficiency) then a project may be necessary. The ability of DG to influence the capacity expenditure is the confluence of the correct amount and location of DG relative to the deficiency."

This is an excellent description of how to use traditional distribution planning techniques to integrate DG, and it is a method that PG&E is using successfully today to avoid DER integration delays as well as potential reliability and safety issues.

[10] PG&E response to DR_TURN_035-Q04, Attachment 01

Q. WERE YOU ABLE TO DETERMINE HOW PG&E IDENTIFIED THE SUBSTATIONS AND CIRCUITS THAT WERE PROPOSED FOR UPGRADE IN ITS DERIC PROGRAM?

A. PG&E's Distribution Resource Plan Section 2. b., "Integration Capacity Analysis", describes the process that PG&E is proposing to use for DER integration.[11] In discovery, when TURN asked for copies of detailed analyses for picking the identified substations and circuits, PG&E was not able to supply such analysis.[12]

Several of the issues addressed in the DERIC program are associated with "voltage anomalies". However, even if PG&E had used the process described in the "Distribution Resource Plan" they would not have been able to find these voltage problems. The following is a quote from that process section 2. b. i. 3. "Voltage/Power Quality Criteria":

> "PG&E's initial Integration Capacity Analysis cannot directly evaluate all the criteria and subcriteria of voltage / power quality. Currently, only voltage flicker can be assessed."

Voltage flicker is the occurrence of a very short duration of voltage variation, which was not addressed by any of the DERIC solutions. It is apparent that PG&E did not use any of these processes to identify the substations and circuits in its DERIC Program. It appears that the only process that was used was to pick substations and circuits with forecast DER capacity connected by 2020 in excess of 15% of the 2015 peak load on that substation or circuit. Late in the discovery process, PG&E provided a response to DR 94-Q01 that included a method for calculating "Voltage Capacity Limits". However, there is no

[11] PG&E Electric Distribution Resources Plan. Submitted July 1, 2015 in R14-08-013. Pages 22-61.

[12] PG&E response to DR_TURN_035-Q11 and follow-up requests specific to each DERIC upgrade.

indication or evidence that the method was actually used to identify the substations and circuits selected for upgrades in the DERIC Program.

Q. PLEASE DESCRIBE THE OPERATING PRACTICES AND PROCESSES PG&E ALREADY EMPLOYS TO ADDRESS LOCAL VOLTAGE REGULATION OR PROTECTIVE DEVICE UPGRADES AS THEY ARISE.

A. All utilities find it necessary to respond to changes in customer loads on their distribution system on a regular basis. PG&E describes these efforts on page 14-5 of its testimony, including Voltage Complaint Investigation, Troublemen Field Work, and Field Work Plans. Operating practices and processes are quite different from distribution planning, which looks ahead; rather, operating practices and processes generally respond to issues and problems on local distribution circuits as they arise. Solutions are typically identified and implemented within a few days or weeks, rather than the months required for significant upgrades. Solutions such as the capacitor, voltage regulation, and line protection device upgrades proposed in the DERIC Program can and should be dealt with using these standard utility industry approaches, as PG&E has apparently been using to date with good success.

Today, PG&E employs these operating practices to respond to voltage and line protection issues as they arise, whether those issues result from changes in customer loads or from growth in DER, with no apparent reliability or safety problems or delays in retail DER interconnection requests. In fact, until the DER capacity on a circuit reaches 15% of its peak demand, PG&E approves retail DER interconnection requests in technical compliance with its interconnection standards with no examination into distribution system impact.[13] Further, the 15% of peak demand guideline is arbitrary and does not mandate any specific upgrades; it is a screening device only. It is meant to trigger potential investigations, but will not necessarily result in investigations, upgrades, or retail DER integration delays. So it is difficult for me to understand why the proposed DERIC Program upgrades are required to avoid future retail DER integration delays.

Q. WHAT DOES THIS HAVE TO DO WITH PG&E'S DERIC PROGRAM PROPOSAL?

A. PG&E's DERIC Program proposes investing over $11 million to upgrade capacitor banks, and $23.5 million to upgrade other voltage regulating devices, from 2017-2019. The proposal also calls for $11 million to upgrade line protection devices. All of these upgrades would normally be undertaken locally on an "as needed" basis in the course of normal operations. Presumptive upgrades of these devices on the notion that they might be needed some day is simply not consistent with standard utility practices and represents a questionable value proposition for ratepayers.

Q. DO YOU HAVE ANY DATA TO SUPPORT THE NOTION THAT PRESUMPTIVE INVESTMENT OF DEVICES THAT WOULD OTHERWISE BE

[13] "Initial Review Process for Applications to Interconnect Generating Facilities". Rule 21. Accessed via Internet on PG&E website from page "Distribution Interconnection Handbook" at http://www.pge.com/en/mybusiness/services/nonpge/generateownpower/distributedgeneration/interconnectionhandbook/index.page

ADDRESSED ON AN "AS NEEDED" BASIS IN THE COURSE OF NORMAL OPERATIONS ARE OF QUESTIONABLE VALUE?

A. Yes. The Wired Group compiled the table below from data provided by PG&E in discovery. The data indicates that many of the circuits chosen for local upgrades in the DERIC Program proposal meet PG&E's definition of "high penetrations of DG", yet have exhibited none of the reliability or safety problems of which PG&E warns in its DERIC proposal.

Table 2: Reliability or safety issues reported to date on circuits/substations selected for local upgrades [14]

Upgrade Category	No. of Circuits to be upgraded by 2020	No. of Circuits with high* DER capacity as of 12-31-15	Reliability or safety issues reported on circuits with high* DER capacity	Retail DER Interconnection delays to date on circuits with high* DER capacity
Capacitor Banks	348	177[1]	None	None
Voltage Regulating Devices	92	55[1]	None	None
Line Protection Devices	252	157[2]	None	None

* DER capacity (all types) as of 12-31-15 in excess of 15% of 2015 peak demand
[1] One circuit (103491102) had more than 7x the definition of high DER capacity at 98.9%
[2] One circuit (62021101) had more than 8x the definition of high DER capacity at 120.9%

Q. HOW CAN YOU BE CERTAIN EXISTING PRACTICES AND PROCESSES WILL BE SUFFICIENT TO AVOID RETAIL DER INTEGRATION DELAYS, AS

[14] PG&E response to DR_TURN_094-Q02, Attachment 01CONF.

WELL AS RELIABILITY OR SAFETY ISSUES, AS DER CAPACITY CONTINUES TO INCREASE?

A. Of course I cannot be certain there will never be a DER integration delay or DER-related customer voltage complaint. However by looking at 2020 DER capacity forecasts by circuit, and comparing the level of DER capacity currently being managed without reliability or safety problems or DER integration delays, one can get comfortable with the notion that existing PG&E practices and processes, be they distribution planning or operational in nature, can deal effectively with increasing DER capacity. The Wired Group compiled Table 3 below from data provided by PG&E in discovery. The data indicates that presumed DERIC Program upgrades are premature.

Table 3: Number of circuits and substations selected for DERIC upgrades with DER capacity in 2020 that is below the greatest levels being successfully managed today[15]

Upgrade Category	Number of Circuits/Subs to be upgraded by 2020	Greatest DER capacity as % of peak kW being successfully managed today (no reliability or safety incidents or retail DER integration delays)	Number of circuits/subs in 2020 (per PG&E DER forecast) below the greatest DER capacity % being successfully managed today*
Reconductoring	12	43.4%	[redacted]
Substation Capacity	5	146.5%	
Substation Protection	22	33.6%	
Capacitor Banks	348	111.0%	
Voltage Regulating Devices	92	98.9%	
Line Protection Devices	252	120.9%	[redacted]

* Conservatively calculated at 2020 DER capacity forecast as a percent of 2015 peak kW.

This table summarizes data found in Appendices C through H. Using Appendix C, "Reconductoring Circuit Data Detail" as an example, I will illustrate how the data for each of the upgrades indicates that presumptive DERIC investments are premature.

Examining the data in the table in Appendix C, we can see that for circuit 42891101, the "Current DG % of Peak kW" (the 5th column) is 43%. This circuit had the highest percentage of DG as compared to its peak load of all of the circuits identified for reconductoring. Note that the threshold set by PG&E for taking action in DERIC is 15% DG capacity as a percentage of peak load, representing DER interconnect application

[15] PG&E response to DR_TURN_094-Q02, Attachment 01CONF

screen "M" in Rule 21. Despite the fact that current DG percent of peak kW on circuit 42891101 is almost 3 times the PG&E threshold for DERIC upgrades, PG&E reports no reliability or safety issues to date, nor any retail DER integration delays. The last column of the table indicates that [redacted] of the 12 circuits selected for reconductoring in DERIC will not have DG capacity greater than that already experienced without incident on circuit 42891101, even by 2020. Yet, PG&E's DERIC Program insists all 12 reconductoring project should be completed now. It could be many years before the DER capacity achieves a level that would require the reconductoring proposed by PG&E, leading to my conclusion that these upgrades are being proposed far in advance of the time they will actually be required. The same approach can be applied to the other upgrades described in Table 3 above, using Appendices D through H as detail to point out the inconsistencies in PG&E's DERIC Program logic.

Q. SO YOU DO NOT AGREE THAT PG&E SHOULD TAKE PRESUMPTIVE ACTION WHEN DG CAPACITY REACHES 15% OF PEAK LOAD?

A. No, I do not, for two reasons. First, the 15% level is completely arbitrary. There is no research or guideline that suggests grid owners must take presumptive action to prepare for any particular level of DER. The answer is "it depends" on a number of factors: line impedance, the location and characteristics of loads on the line, the location and characteristics of the DER on the line, local circuit design and links with nearby circuits, and others. This is precisely why properly administered, flexible, "as needed" approaches to grid planning and operations – proactively in the case of significant upgrades, and reactively in the case of local upgrades – are well-suited, and perfectly appropriate for, managing increasing levels of DERs.

Second, as I have stated throughout my testimony, I feel that most if not all proposed DERIC Program upgrades would not pass any kind of legitimate Risk Analysis at this time. At some point, as the levels of DERs grow ever-larger, voltage problems and other types of concerns will probably appear, even though none have appeared to date despite some fairly significant DER levels. Any such problems will be minor and infrequent to start, at which point PG&E will begin to gather data. Soon after, there will be enough information for more rigorous incorporation into a proper risk analysis. When the results of such risk analyses warrant action, PG&E should and will take action. With experience and a proper risk analysis in place, PG&E will know the conditions to look for and the type of action best-suited to address anticipated issues in the most cost-effective manner possible. This is a much more pragmatic approach than making presumptive investments to address potential or hypothetical problems that may not materialize, or for which timing is highly variable.

Q. YOUR TESTIMONY HAS YET TO ADDRESS THE DERIC PROPOSAL TO INSTALL RELAYS IN SUBSTATIONS WITH SINGLE-PHASE FUSES ON THE HIGH-VOLTAGE SIDE OF TRANSFORMERS.

A. This issue illustrates a problem that is somewhat common among distribution engineers: a desire for perfection. Much like cybersecurity experts who test system security by identifying and exploiting any and every possible weakness, electrical engineers have been trained to spot and eliminate avoidable problems, no matter how unlikely the probability of occurrence. Distribution engineers have been known to develop solutions at costs that are far out of proportion to the probability an issue they've determined could occur, actually will occur. I believe this solution is an example of one of those instances.

In discovery, TURN verified the chain of events that would need to occur for the problem to be solved by installing relays would actually manifest, and asked PG&E to estimate the probability of each. The individual and collective probabilities PG&E provided are presented in Table 4 below,[16] while I added my own estimates based on my experience.

Table 4: ***Probability that the alleged problem to be solved by installing relays in substations with single-phase fuses on the high-voltage side of transformers will occur***

Link in the Chain of Events Required to Create the Problem	Probability as characterized by PG&E	Probability per witness Stephens' experience
[redacted]	[redacted]	0.006[17]
		1.000
		0.500
[redacted]	[redacted]	0.010
		0.100
		0.000003 (probabilities multiplied)

[16] PG&E response to DR_TURN_094-Q13CONF

[17] Woodcock, David J. *Assessing Health and Criticality of Substation Transformers*. Electric Energy T&D Magazine. Volume 9, No. 3. Pages 27-30.

To summarize, the problem PG&E describes has 1 chance in 333,000 of occurring. I do not believe the probability this problem will occur warrants the $2.3 million investment required to prevent it. And I certainly do not believe the issue identified and proposed solution would pass any type of Risk Analysis Assessment.

Q. ARE THERE OTHER SITUATIONS LIKE THIS IN THE DERIC PROGRAM PROPOSAL?

A. Yes, PG&E describes one other "problem" that is similar for its low probability of occurrence. But this "problem" is also characterized by potential impact to only a very small numbers of customers, as well as relatively minor associated consequences.

One of the idiosyncrasies of some voltage regulation schemes in place in PG&E's distribution grid is the use of open-delta configuration for voltage regulation. The open-delta configuration uses just two of the three phases to accomplish three phase voltage regulation. PG&E claims that under a certain combination of circumstances, high levels of DER on a circuit equipped with open-delta configuration voltage regulation could cause machine-based generators owned by a small minority of customers to trip (shut down). PG&E calls this situation "Nuisance Tripping". While I believe PG&E's claim to be technically accurate, I think the probability of occurrence to be extremely low, as PG&E has not been able to document a single incidence of it on the Company's grid.

In addition, the consequences associated in the event the problem occurs are small. The "Nuisance Tripping" would be a result of the voltage fluctuations on the distribution line. These fluctuations would cause the generator to drop off line when the voltage on the circuit moved out of its required range, as required by IEEE 1547. These trips off line would result in a normal shut down of the generator, should not result in any safety hazards, and are therefore of low consequence. (Such generators can simply be restarted once voltage fluctuations pass.) Low probability of occurrence, combined with the small number of customers who would be affected, and the low consequences associated in the event the problem occurs, make this another problem not worth spending ratepayer funds to prevent. And once again I do not believe this would pass any type of Risk Analysis Assessment.

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. As a summary comment, several of the potential issues PG&E describes in its DERIC Program proposal relate to damage to machine-based DER, or inconvenience to customers which own machine-based DER. There are likely to be only a small number of customers who own machine-based generators, such as microturbines powered by waste gas or industrial process waste heat. Machine-based generators are generally much larger and much more costly to install than rooftop PV solar systems, thus they are found in dramatically smaller numbers on most distribution grids.

Not only are these customers a small minority of all customers, ratepayers are not responsible for the protection of such equipment or for the inconvenience of such customers. Rule 21 clearly requires that customers install equipment that disconnects publicly-owned DERs from the distribution grid in the presence of high voltage. Rule 21 also requires that the facility grounding schemes of customer-owned DER shall not disrupt the coordination of the distribution grid protection scheme. If these rules are strictly adhered to and enforced, even as growth in DER may require changes to equipment installed by DER-owning customers, many of the problems that the DERIC Program proposal attempts to solve at ratepayer cost would not materialize.

IV. THE DERIC PROGRAM WILL NEEDLESSLY INCREASE RATES (ALVAREZ)

Q. WHY DO YOU BELIEVE THE DERIC PROGRAM WILL NEEDLESSLY INCREASE RATES?

A. There are actually several reasons I will cover in the testimony immediately following:

- The DERIC Program is vastly more expensive for ratepayers than the "as needed" approaches used successfully to date;
- The DERIC Program will subsidize wholesale DER owners at ratepayer expense;
- PG&E has already attempted to subsidize wholesale DER owners at ratepayer expense;
- The presumptive DER integration investments proposed in DERIC transfers PG&E performance risk into economic risk for ratepayers.

Q. PLEASE SUPPORT YOUR CLAIM THAT THE DERIC PROGRAM IS VASTLY MORE EXPENSIVE FOR RATEPAYERS THAN THE "AS NEEDED" APPROACHES USED SUCCESSFULLY TO DATE.

A. Certainly. Using PG&E's advice letter 4660-E, and data obtained in discovery, we calculated the average cost of grid upgrades PG&E has incurred to integrate almost 600 MW of retail DER on a "per kW" basis using the traditional, "as needed" approaches described and advocated by Mr. Stephens in his testimony.[18] We calculated an average grid upgrade cost to integrate retail DER using traditional, as needed approaches of $9.45 per kW of DER integrated.

Table 5: Historical cost of integrating retail DER using traditional, "as needed" approaches

Line	Description, 11-1-13 to 5-31-15	Amount	Data Source
A	Distribution Engineering Costs to integrate retail DER	$2,128,980	Advice letter 4660-E, Table 2
B	Facility Upgrade Costs to integrate retail	3,513,511	Advice letter 4660-E, Table 4
C	Total cost to upgrade grid to integrate retail DER	$5,642,491	A + B
D	Capacity (kW) of retail DER kW integrated	597,000	PG&E Response to DR TURN_073_Q03
	Grid upgrade cost per kW to integrate DER 11-1-13 to 5-31-15:	$9.45	C ÷ D

Q. HOW DOES THIS AVERAGE HISTORICAL RETAIL DER INTEGRATION COST PER KW COMPARE TO THE COST OF THE DERIC PROPOSAL?

[18] PG&E response to DR_TURN_073_Q03

A. It's somewhat difficult to say. In discovery, PG&E would not commit to the amount of additional retail DER capacity the Company could reliably and safely integrate if the presumptive grid investments recommended in the DERIC Program proposal were made. For this reason it is difficult to determine the benefit DERIC Program spending is intended to deliver if approved. However, we can assume a worst-case scenario as one indication.

As a conservative assumption, we assumed the retail DER capacity growth forecast PG&E provided by 2020 is the maximum amount that could be integrated for the proposed DERIC Program investment. This may be an overly conservative assumption, but it provides a starting point for comparison. Using DERIC Program cost data from GRC table 13-4, and 2020 retail DER forecast data provided by PG&E in discovery,[19] we calculated the cost of the DERIC Program to be $[redacted] per kW of retail DER capacity integrated.

Table 6: Cost of integrating DER using the presumptive DERIC approach, worst case scenario

Line	Description	Amount	Data Source
A	DERIC Program proposed investment	$99,762,000	Table 13-4, GRC page 13-35
B	Retail DER increase 12-31-15 to 12-31-19 (in kW)	[redacted]	PG&E Response to DR TURN_094_Q02Atch01CONF
	DERIC Program cost per kW of retail capacity integrated (forecast = max)	[redacted]	A ÷ B

[19] PG&E Response to DR_TURN_094-Q02, Attachment 01CONF

While the amount of additional retail DER capacity the proposed DERIC Program could reliably and safely integrate is likely greater than the forecast DER capacity growth, *the DERIC Program would need to integrate more than* [redacted] *times the forecast growth to be as cost-effective as the traditional, as-needed approaches utilized to date.*

Q. DO YOU HAVE ANY THOUGHTS AS TO WHY THE COST OF PRESUMPTIVE INVESTMENT IS SO MUCH HIGHER THAN THE COST OF TRADITIONAL, "AS NEEDED" APROACHES?

A. As described in Mr. Stephens' testimony, presumptive action may result in investment that is not needed, or investment far in advance of the time needed. This is certainly a key contributor to the out-sized cost of the DERIC Program per kW of DER relative to "as needed" approaches. But I know of at least one specific example that is highly illustrative.

In discovery, PG&E estimated that the cost to replace a single voltage regulator is $100,000.[20] PG&E claims such replacement is required to ensure voltage regulators operate properly in the presence of two-way power flow associated with high levels of DER. While Mr. Stephens and I believe this cost estimate to be a bit on the high side, more troubling is the proposal to replace voltage regulators at all. Voltage regulator retrofit kits are available which allow utilities to simply replace the controller module of existing voltage regulators with more advanced controllers able to accommodate two-way power flow. In addition, these advanced controllers are available with communications capabilities that enable SCADA system integration. Advanced controllers cost around

[20] PG&E response to DR_TURN_095-Q02

$2,000, with an installed cost (including all engineering, labor, and commissioning) of about $5,000 per voltage regulator. The fact that PG&E is proposing a $100,000 solution when a $5,000 solution is available is yet another indication that PG&E's DERIC Program proposes investments that are not only unnecessary, but also unreasonable.

Q. WHILE YOUR POINTS ABOUT THE COST OF PRESUMPTIVE INVESTMENT ARE WELL TAKEN, HOW DO YOU RESPOND TO THOSE WHO FEEL THE COST IS WORTH AVOIDING A HAWAII SITUATION?

A. By "a Hawaii situation", I assume you are referring to the idea that failure to sufficiently prepare the distribution grid for increases in DER is now resulting in delays in DER integration in Hawaii. I do not know enough about the specifics of Hawaiian utility preparations to render an opinion on the sufficiency of any such efforts. In addition, as I think Mr, Stephens' testimony makes clear, "as needed" investment may be sufficient to avoid "a Hawaii situation". However, I can tell you with confidence that the level of DER being integrated right now in Hawaii is far beyond what PG&E will experience by 2020, according to PG&E's overall DER growth forecasts.

I prepared Table 7 below from data reported by the Hawaii State Energy Office[21] and a variety of reputable sources as noted below the table. Despite aggressive DER growth forecasts for DERIC substations/circuits ([redacted]),[22] which I then

[21] *Hawaii Energy Facts and Figures*. Hawaii State Energy Office. May, 2015. Pages 2 (system peak) and 18 (installed PV solar capacity).

[22] PG&E response to DR_TURN_094-Q02, Attachment 01CONF, duplicate circuits removed.

applied to all the DER in PG&E's entire service territory (unlikely), the table indicates just how far behind DER integration at PG&E is today compared to Hawaii, and how far behind PG&E still will be by 2020. (Note that differences in "percent of peak" from PG&E's NEM reports is due to PG&E's use of aggregate non-coincident peaks in those reports; coincident system peak is used in Table 7 for consistency with available Hawaii data.)

Table 7: Relative DER capacity comparisons, selected Hawaiian islands' 2014 actuals vs. PG&E service area, 2014 actual and 2020 forecast

Geography/IOU	Year	Coincident System Peak (MW)	DER Capacity (MW)	DER Capacity as % of Coincident System Peak
Hawaii/HELCO	2014	189.0	54.7	28.9%
Maui/MECO	2014	199.0	56.9	28.6%
CA/PG&E	2014	17,638.0[a]	2,002.0[b]	11.4%
CA/PG&E	2020	18,946.6[c]	[redacted][d]	[redacted]%

Notes:
[a] From PG&E's 2014 submission to US DOE on EIA Form 861, Worksheet 2A, Section 6
[b] From PG&E's July 1, 2015 DRP: 1700 MW retail, page 95; 302 MW wholesale, page 98
[c] Calculated at 1.2% compound annual growth rate per CEC demand forecast update, PG&E Planning Area, mid-case, December 2014, page 22.
[d] [redacted] growth rate on DERIC subs/circuits per PG&E response to DR_TURN_094-Q02Atch01CONF, duplicate circuits removed, applied to all DER from PG&E's DRP

Q. WHY DO YOU BELIEVE THE DERIC PROGRAM SUBSIDIZES WHOLESALE DER OWNERS AT RATEPAYERS' EXPENSE?

A. In its DERIC Program proposal PG&E cites many reliability and safety problems it claims will be caused by high levels of DER, including complications associated with two-way power flow. However, these reliability and safety problems, to the extent they might occur, cannot be attributed solely to retail DER. High levels of wholesale DER would contribute to the exact same problems PG&E claims will be caused by retail DER. In fact, wholesale DER may contribute more than its share of these claimed problems relative to retail, as prospective wholesale DER owners may prefer to locate large PV solar systems in sparsely populated areas with lower real estate costs. These locations typically have low native loads, creating a situation more likely to create two-way power flow and any associated problems that might occur. Retail, NEM-eligible systems are, by definition, located where there is load. They are sized so as not to exceed average annual on-site load. The DERIC Program proposes investments that will prepare the grid for future wholesale DER as well as future retail DER,[23] enabling future wholesale DER owners to avoid paying their fair shares of grid upgrade costs.

Q. AND YOU BELIEVE SUCH SUBSIDIES HAVE ALREADY OCCURRED?

A. Yes. The DERIC Program includes $19.4 million – plus escalation – to upgrade 5 substations. In both the DERIC Program proposal and subsequent discovery, PG&E makes clear the proposed spending is intended to accommodate retail DER only. Data secured from PG&E in discovery clearly indicates any requirement to upgrade these 5 substations was caused by wholesale DER, not retail DER. As shown in Table 8 below, wholesale DER comprised 95.1% to 99.9% of all the distributed generation connected to the 5 circuit banks PG&E is proposing to add to or upgrade.[24] PG&E should have

[23] PG&E responses to DR_TURN_098-Q04 and Q05.

[24] PG&E response to DR_TURN_073-Q02, Attachment 02

charged the costs of these upgrades to wholesale DER owners. It is TURN's position that PG&E must now complete these upgrades at shareholder expense.

Table 8: Percent of wholesale Der on the banks of 5 substations selected for upgrades

Sub	12-31-15 DER kW (total)	12-31-19 DER kW (forecast)	12-31-15 Wholesale DER kW	Wholesale DER % of Total DER 12-31-15	Wholesale DER* % of 2020 Forecast DER
A	30,500	32,802	30,000	98.4%	91.5%
B	20,184	21,507	20,000	99.1%	93.0%
C	20,928	21,248	20,000	95.6%	94.1%
D	21,036	22,940	20,000	95.1%	87.2%
E	10,008	23,316	19,000	99.9%	81.5%

*Assumes zero new wholesale DER capacity will be added after 12-31-15

Q. WHAT DO YOU BELIEVE SHOULD BE DONE ABOUT WHOLESALE DER SUBSIDIES?

A. I believe some sort of financial mechanism is needed to allocate the cost of grid upgrades, to the extent they are necessary, between both retail DER and wholesale DER. A wholesale DER owner should be responsible for the cost of the upgrades immediately necessary to integrate his or her DER project per Rule 21. But wholesale DER owners should also be responsible for the cost of any overall preparations made historically, or that might be required in the future, to reliably and safely deliver their products to markets. A recognition that wholesale DER owners' use of the grid creates ongoing costs, as well as ongoing value, for which wholesale DER owners must pay, is critical to avoiding ratepayer subsidies. A manufacturer of widgets would never assume his products would somehow arrive at customers' doorsteps without arranging for, and paying, a shipping company to deliver them. Both parties know that one of them must pay the shipping company for its services, and neither party could imagine a scenario where the shipping company's other customers would pay to ship the widgets. Yet, unless wholesale DER owners are charged for the full cost of the value delivered by PG&E's distribution grid, ratepayers will subsidize wholesale DER integration costs in precisely this manner. I believe it is appropriate and important to address how wholesale DER owners should be charged for ongoing services and value provided by the grid in the Distribution Resource Planning proceeding and/or the Rule 21 proceeding.

Q. WHY IS IT IN PG&E'S ECONOMIC INTEREST TO SUBSIDIZE WHOLESALE DER?

A. When faced with a choice between passing the cost of multi-million dollar upgrades to wholesalers with no mark-up per Rule 21 and PG&E's wholesale distribution tariff, or adding those costs to rate base, PG&E has a financial incentive to choose the latter approach. These assets have useful lives of 20 years or more and will thus earn significant shareholder profits. PG&E's use of DERIC to subsidize wholesale DER integration costs with ratepayer funds is further evidence that the DERIC Program represents an unjust ratepayer impact.

Q. ARE THERE ANY OTHER ISSUES ASSOCIATED WITH PRESUMPTIVE INVESTMENT AT STAKE IN PG&E'S DERIC PROGRAM PROPOSAL?

A. Yes, I believe there is one additional issue. In addition to making investments that may not be needed, or not be needed for several years or more, and are unjust as a result of ratepayer subsidy of wholesale DER owners, the presumptive nature of PG&E's

recommended DERIC Program investments transfers PG&E's performance risk into ratepayer economic risk.

As I testified earlier (Section II) in this testimony, PG&E retains the responsibility for addressing technical and business issues as they arise at the least cost to ratepayers. Mr. Stephens indicated in his testimony that PG&E has successfully been managing this responsibility as it relates to the growth in DER through existing distribution planning and grid operations practices and processes. The reliable and safe integration of growing DER using existing practices and processes represents performance risk that PG&E must manage.

By making the presumptive investments proposed in the DERIC program, PG&E reduces its performance risk. If all upgrades are made far in advance of the time in which they are needed, PG&E no longer need worry about identifying upgrades as the need for them arises. Presumptive investment also allows PG&E to use rate-based, capital-intensive solutions rather than low-cost operating expense solutions. (Consider the capital cost of upgrading a capacitor bank to the incremental operating cost of dispatching a lineman to change the setting on a fixed capacitor bank.) Presumptive investment obviously takes some pressure off of PG&E distribution grid managers. But as demonstrated earlier in my testimony, this reduction in PG&E performance risk comes at a dramatic increase in economic cost (and risk) to ratepayers. I do not believe PG&E should be allowed to transfer its performance risk into ratepayer economic risk.

V. THE DERIC PROPOSAL FAILS TO PROVIDE NET BENEFITS TO RATEPAYERS (ALVAREZ)

Q. WHY DO YOU BELIEVE THE DERIC PROPOSAL FAILS TO PROVIDE NET BENEFITS?

A. There are several reasons why the DERIC Program proposal fails to provide net benefits. For a net benefit test to be favorable from a ratepayer perspective, several conditions must apply:

- The benefits must accrue to ratepayers and result from the proposed investment.
- The size of the benefits and the size of the costs must be known.
- The incremental costs must be reasonable in relation to the incremental benefits.
- There must be no less-expensive method available to secure the anticipated benefits.

Allow me to review, from the testimony presented by Mr. Stephens or myself, how the DERIC Program proposal fails on all of these counts.

As Mr. Stephens' testimony indicates, the presumptive investments proposed in DERIC are not needed to avoid delays in retail DER integration. Not only have PG&E's existing practices and processes managed to avoid delays in retail DER integration, they have avoided the reliability and safety issues PG&E claims will arise despite multiple instances of high DER penetration that already exist in portions of PG&E's service territory. If there are any benefits from DERIC, my testimony indicates they accrue disproportionately to wholesale DER owners, not ratepayers. To summarize, it is not at all clear that ratepayers will receive benefits from the proposed investment.

In discovery, as indicated in my testimony above, PG&E would not commit to the amount of additional retail DER the Company would be able to integrate if the DERIC Program investments were made. This makes it impossible for ratepayers to estimate the size of the benefit they might receive from DERIC. The failure to make a commitment as to the additional retail DER PG&E would be able to integrate for $99 million also implies that additional costs might be required. Without knowing the size of the DER to be integrated nor the ultimate costs of such integration, it is impossible to even complete a net benefits test, let alone to assume the outcome of the net benefits test will be favorable for ratepayers.

Though Mr. Stephens and I believe ratepayer benefits from the DERIC program to be near zero, there are two technical arguments raised by PG&E that we support. Installing relays on the high-side of transformers in substations with single-phase breakers will indeed help avoid a problem in a certain rare set of circumstances. However the probability the problem will occur is so small, and the likelihood of incremental substation equipment damage so remote, that the cost to solve the problem is far out of proportion to the size of the problem. Similarly, we agree that a certain type of voltage regulation configuration (open delta) might, in rare instances, result in nuisance tripping for generation owned by a small number of customers. But this is more accurately categorized as an inconvenience rather than a problem, and does not impact 99% of ratepayers in any event. DERIC Program costs are simply not reasonable in relation to the incremental benefits to ratepayers.

And finally, there must be no less-expensive method available to secure the benefits claimed. To repeat, the low-cost solutions successfully employed today represent one less-expensive method to integrate increasing levels of DER. But there are other solutions that might be less expensive than DERIC, like DER management systems; retrofitting rather than replacing voltage regulators; increased use of smart inverters or electric storage; and pricing signals based on an approach to Locational Net Benefit Analysis that fully incorporates DER integration costs. Tests and demonstration projects utilizing these solutions have either not yet been completed or not yet started, so ratepayers cannot be assured they are getting solutions at the lowest possible costs. PG&E should be required to run risk analyses on all of these proposals and provide their risk assumptions and their risk analysis results as compared to other capital expenditure risk analysis.

Q. DO YOU HAVE ANY ADDITIONAL DATA THAT CALLS INTO QUESTION THE LEGITIMACY OF THE DERIC PROPOSAL?

A. While the DERIC Program is relatively small, the Commission should consider the fact that PG&Es' distribution investments have been larger historically than those of other IOUs in the United States. Using publicly-available data provided by PG&E and other US IOUs in FERC Form 1 filings and EIA Form 861 filings, I have determined that PG&E's distribution assets are 29% higher per customer than the average of all US IOUs ($4,525 vs. $3,500 as of December 31, 2014; n = 126).

There are a few factors that influence the level of assets required to distribute electricity reliably and safely. Two of the more relevant factors for comparison purposes would be peak demand and customer density. PG&E's peak demand per customer (3.7 kW) is only 65% of the average of all US IOUs (5.7 kW; n = 131). (I believe low peak demand per customer in PG&E's service territory may be the result of lower air conditioning penetration and/or less heavy industry relative to other geographies served by U.S. IOUs.) In addition, PG&E's customer density is average (37.8 customers per distribution line mile compared to the US IOU average of 38.0; n = 105). These factors do not, therefore, support PG&E's 29% higher asset quantity.

I also found that PG&E's distribution assets are growing faster than the average rate of US IOUs. From December 31, 2010 to December 31, 2014, PG&E distribution assets per customer grew 25%, while the average for US IOUs for this time period was only 17% (n = 126). Growth in peak demand does not fully explain distribution asset growth, as PG&E's peak demand per customer has only grown from 3.3 kW to 3.7 kW (12%) over this time frame. All of these statistics indicate that PG&E has been spending more distribution capital than other major IOUs, even though its peak load is lower than average. This data is presented in chart form for convenient visualization in Appendix I.

Of course, PG&E has justified some of its spending based on the need to replace "aging infrastructure." I have not had the opportunity to fully evaluate the validity of this claim, but note that almost every US IOU is currently making this claim. I also note that the growth in distributed solar generation in California has been ongoing for some time, notably with the launch of the California Solar Initiative in 2008. To the extent PG&E

has been replacing distribution capital assets, it should have already been making the investments necessary to enable greater DER penetration. The Commission should evaluate whether PF&E's many investments in Grid Reliability and Grid Automation have taken into account the types of issues being addressed in the DERIC Program, and if not, why not?

VI. CONCLUSIONS AND RECOMMENDATIONS (ALVAREZ)

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS CASE?

A. I have five recommendations.

1) TURN recommends the Commission reject the DERIC Program in its entirety based on the arguments supported by this testimony, resulting in a 2017 test year capital reduction of $17.07 million in account MWC 06 and $4.165 million in account MWC 46, plus respective escalations. Similarly, TURN recommends that presumptive DERIC Program investments proposed for 2018 and 2019 be prohibited.

2) TURN recommends the Commission order PG&E to promptly complete the 5 substation capacity upgrades made necessary by installed wholesale DER, but not charged to wholesale DER owners, at shareholder expense.

3) TURN recommends PG&E prioritize, and pursue research funds to complete, demonstration projects to find the most pragmatic and cost-effective approaches to

integrating increased DER capacity. These efforts should focus upon, but perhaps not be limited to:

- Distributed Energy Resource Management Systems
- Accelerated adoption of advanced smart inverter standards (per the recommendations of the Smart Inverter Working Group)
- Expanded use of electric storage to reduce incidence of two-way power flow
- Customer applied technologies that better protect machine-based DER and voltage- and phase-sensitive equipment (rather than asking ratepayers to fund more expensive, grid-based approaches to protecting sensitive customer equipment)

4) TURN recommends the Commission initiate a rulemaking, or add to the scope of existing Rule 21 Rulemaking 11-09-011, to consider the level of the responsibility customers who own sensitive equipment have to protect their equipment. If increasing DER is to become the new reality of the distribution grid, customers who own sensitive equipment, such as machine-based DER and 3-phase motors, may need to take new precautions. This is not unlike the responsibility certain customers take on today regarding grid reliability; customers for whom existing reliability is insufficient to meet particular business needs install back-up generation. The Commission has determined that the needs of a few customers to secure higher-than-average reliability is not cause to demand the same reliability overall, or for the associated costs to be socialized to all ratepayers for the benefit of a few. As DER increases, the assumption

that ratepayers bear responsibility for the cost of grid upgrades that might be needed to protect the sensitive equipment owned by a few is not at all clear or justified.

5) Finally, TURN recommends the Commission prioritize the prompt completion of the DRP proceeding to resolve issues raised in this testimony, including:
   - A resolution as to how DER integration costs should be incorporated into Locational Net Benefit Analysis modeling; and
   - A resolution as to how the cost of any grid upgrades made presumptively to accommodate anticipated increases in wholesale DER be socialized to as-yet-unidentified wholesale DER projects; and
   - Defined expectations of California IOUs regarding the incorporation of DER integration into existing distribution planning and operations, incorporation into existing risk analysis methods, and that DER integration be reliably and safely completed at least cost to ratepayers while avoiding subsidies of wholesale DER owners.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDICIES

A. Alvarez Curriculum Vitae

B. Stephens Curriculum Vitae

C. Reconductoring Circuit Data Detail (CONFIDENTIAL)

D. Substation Capacity Data Detail (CONFIDENTIAL)

E. Substation Protective Device Circuit Data Detail (CONFIDENTIAL)

F. Capacitor Bank Circuit Random Sample Data Detail (CONFIDENTIAL)

G. Voltage Regulating Device Circuit Random Sample Data Detail (CONFIDENTIAL)

H. Line Protective Device Circuit Random Sample Data Detail (CONFIDENTIAL)

I. Distribution Assets per Customer Benchmark Data Charts

Notes regarding Appendices C-H

Data for tables in Appendices C-H is sourced from PG&E responses to the TURN data requests listed below.

Column "2015 Rated Capacity" (in kW or KVA as indicated): Circuit capacity in amps (DR_TURN_73-Q02ATCH01) X Circuit Voltage (DR_TURN_94-Q03Atch01) X √3

Columns "2015 Peak kW", "Current DG Capacity 12-31-15", and "Forecast DG Capacity 12-31-19": DR_TURN_94-Q02Atch01CONF

Column "2015 Minimum Load at Noon (kW)": PGE_DRP_Profiles_Workbook_20150701.xls available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5139

All forecast columns related to demand growth over time: In all cases, forecast growth in demand was estimated at 1.2% compounded annually from 2015 to 2020. This is consistent with the mid-case estimate for the PG&E Planning Area 2014-2024 developed by the California Energy Commission in its recent California Energy Demand Forecast Update.[25]

[25] Kavalec, Chris. *California Energy Demand Updated Forecast, 2015-2025.* California Energy Commission Staff Draft Report CEC-200-2014-009-SD. December, 2014. Page 22.

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

Research Projects, Thought Leadership, Regulatory Appearances

Arguments to Reject Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Best Practices in Grid Modernization Capability Optimization: Visioning, Strategic Planning, and New Capability Portfolio Management. Top-5 US utility; client confidential. 2014.

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. Filed December 14, 2011 as Exhibit MGL-1. Report dated October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. First edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 327 pages. 2014.

Noteworthy Publications

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Notable Presentations

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Keynote. Toronto, Canada. January 23, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us.* Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012.

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25, 2012.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23, 2012.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators.* St. Louis. November 13, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master of Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Accounting, Finance, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Marketing and Finance.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

Curriculum Vitae – Dennis Stephens EE

Wired Group, PO Box 150963, Lakewood, CO 80215 dstephens@wiredgroup.net 303.434.0957

Profile

Mr. Stephens has over 35 years' experience in electric distribution grid planning, design, operations management, asset management, and the innovative use of technology to assist with these functions. He spent his entire career at Xcel Energy subsidiary Public Service Company of Colorado, an electric (and gas) distribution business serving over 1.2 million customers. In a series of electrical engineering and management roles of increasing responsibility, Mr. Stephens served as Director, Electric and Gas Operations for the City and County of Denver; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments (for all of Xcel Energy's 8-state service territory). Mr. Stephens retired from Xcel Energy in 2011, and now works for the Wired Group on a part-time basis.

Noteworthy Projects

Smart Grid Solutions Development, 2010. Worked with several large solution providers to develop and implement technical distribution grid solutions and innovations, including IBM, ABB, and Siemens**.**

DER Integration Strategy and Roadmap Development, 2009. Established DER integration strategy and road-maps for Xcel Energy, including technology and capability roadmap for high DER penetration geographies in Boulder, Colorado.

SmartGridCity™ Project Development, 2008. Developed the technical foundations for the SmartGridCity project in Boulder, Colorado (46,000 customers).

Distribution Automation Design, 2007. Worked with ABB Corporation to design software to identify and locate failures in underground cable. The ABB Smart Analyzer™ was programmed with three traps to capture detailed information using Oscillography/Digital Fault Records (O/DFR).

Utility Innovations Program Development, 2006. Led the development of Xcel Energy's Utility Innovations program, for which Mr. Stephens' team receive a national Edison Award.

Distribution Asset Optimization Process, 2005. Taking advantage of SPL's Centricity Outage Management Program and Itron's Real Time Performance Management system (RTPM), developed a Distribution Asset Optimization process by mining AMI meter data and asset utilization information in the development of an enhanced asset loading forecasting process. The process took advantage of the systems' abilities to forecast sudden changes in usage patterns to take proactive mediation of equipment overloading.

Distribution Asset Optimization Software Development, 2004. Worked with Itron on the development of a Distribution Asset Optimization software program.

Fixed AMI Communications Network Development, 2003. Worked with Itron to pilot one of the first applications of a fixed wireless radio network to collect data from customer meters.

Electric Asset Management Strategy Development, 2002. Developed Xcel Energy's Electric Distribution Asset Management Strategy

Automated Switching System Deployment, 2001. Worked with S&C Electric Corporation on to deploy its Intelliteam™ devices on Xcel Energy's distribution grid to reduce the number of customers impacted by an outage by isolate faults through automated switching routines.

Regulatory Appearances

General Novelty vs. Public Service Company of Colorado. Testimony in Colorado PUC Case 6609 on behalf of Public Service regarding restitution for customer equipment damage resulting from transformer failure. Public Service Company of Colorado prevailed as a result of Mr. Stephens' testimony.

Notable Presentations

DistribuTECH 2010, Tampa, Florida. "Realizing the Benefits of DER, DG and DR in the Context of Smart Grid"

OSI 2008 User's Conference, Denver, Colorado; DistribuTECH 2007, San Diego, California. "Smart Grid City: A blueprint for a connected, intelligent grid community"

ABB 2007 World Conference, Jacksonville, Florida. "Use of Distribution Automation Systems to identify Underground Cable Failure"

North American T&D Conference 2005, Toronto, Canada; Itron 2005 User Conference, Boca Raton, Florida. "Xcel Energy Utility Innovations and Distribution Asset Optimization"

DistribuTECH 2005, San Diego, California. "How Advanced Metering Technology is Driving Innovation at Xcel Energy"

Education

Bachelor of Science Degree in Electrical Engineering, 1975, University of Missouri at Rolla.

Awards

National Edison Award for Utility Innovations, 2006.

APPENDIX C – RECONDUCTORING CIRCUIT DATA DETAIL

CONFIDENTIAL

APPENDIX D – SUBSTATION CAPACITY DATA DETAIL

CONFIDENTIAL

APPENDIX E – SUBSTATION PROTECTIVE DEVICE CIRCUIT DATA DETAIL

CONFIDENTIAL

Note: 20 of 348 circuits identified by PG&E for Capacitor Bank Upgrades were selected at random using a random number generator. Data from the 20 randomly-selected circuits obtained in discovery is presented in the table below.

CONFIDENTIAL

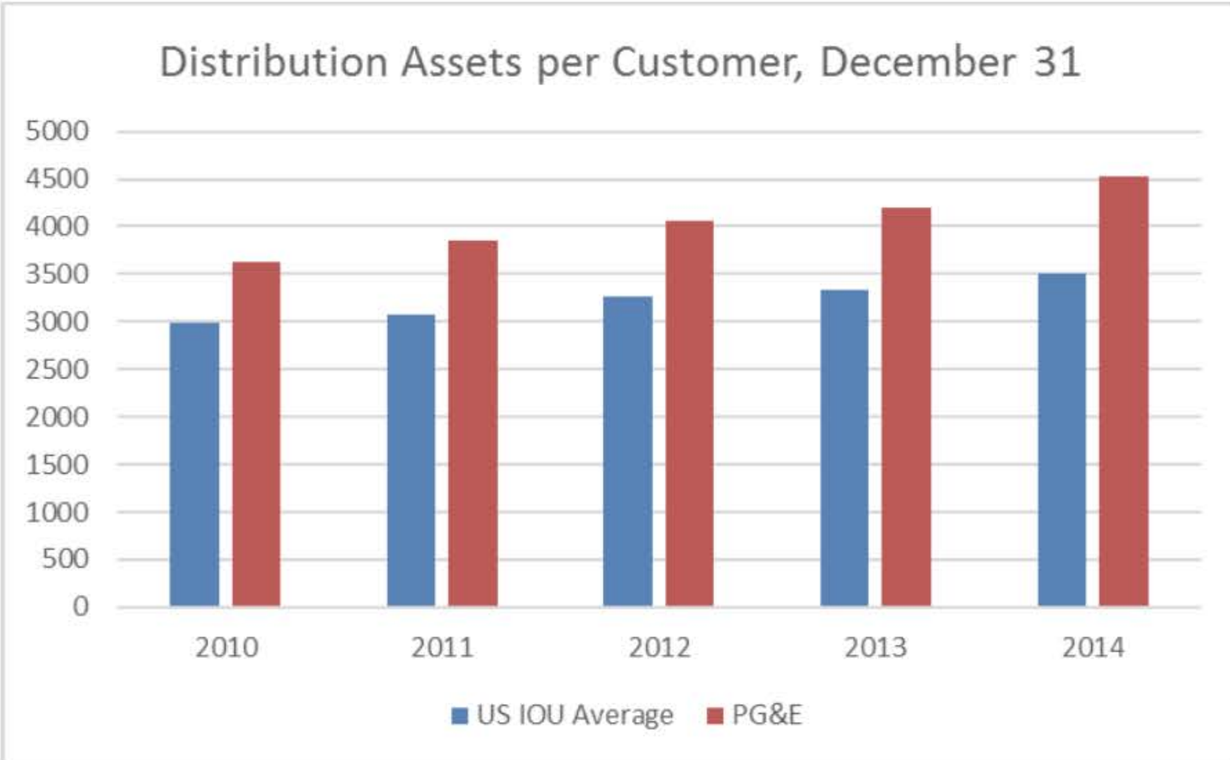
Note: 10 of 93 circuits identified by PG&E for Voltage Regulating Device Upgrades were selected at random using a random number generator. Data from the 10 randomly-selected circuits obtained in discovery is presented in the table below.

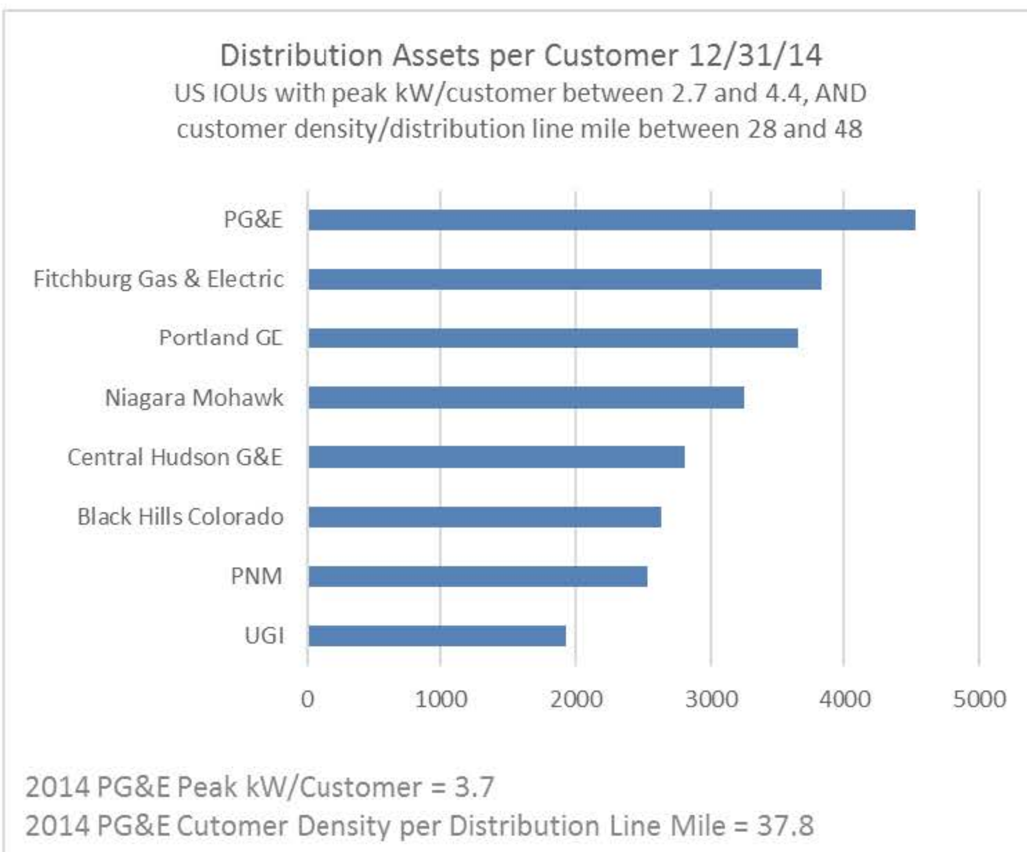
CONFIDENTIAL

Note: 20 of 253 circuits identified by PG&E for Line Protective Device Upgrades were selected at random using a random number generator. Data from the 20 randomly-selected circuits obtained in discovery is presented in the table below.

CONFIDENTIAL

APPENDIX I – DISTRIBUTION ASSETS PER CUSTOMER BENCHMARK CHARTS





Duke Energy Ohio Smart Grid Audit and Assessment

June 30, 2011

Prepared for:
The Staff of the Public Utilities Commission of Ohio
PUBIC VERSION WITH CONFIDENTIAL INFORMATION REDACTED

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PREFACE

The U.S. electric distribution grid is considered by many to be the largest machine ever built. Despite its size, the distribution grid has limitations that will likely be tested soon. Today's grid incorporates the same basic designs of grids constructed 100 years ago. It was designed to reliably distribute electricity uni-directionally, from generators to customers, in a manner that optimized capital investment and operating costs. In the future electric customers will likely expect new capabilities, and the distribution grid must be prepared to deliver. New demands are likely to include:

- Bi-directional power flow (large numbers of customers generating as well as using electricity).
- Advanced pricing plans (providing customers with cost management opportunities).
- Higher distribution energy efficiency (minimizing line losses).
- Improved customer service levels and new services.
- Ability to accommodate large numbers of electric vehicles.

Grid operators are also likely to require new services to facilitate management of many new objectives at the lowest possible cost, including:

- Maintenance or improvement of reliability in the face of new demands.
- Reliable incorporation of intermittent renewable generation sources.
- Improved utilization of generation, transmission, and distribution system capacity.

Duke Energy (and in particular Duke Energy Ohio) was among the first utilities to propose making significant investments to prepare its distribution grid for future demands through the use of advanced monitoring, information and communications technologies (the 'smart' grid). The Public Utilities Commission of Ohio (Commission) was among the first public utility commissions to approve a full smart grid deployment, and was also among the first to authorize its staff to conduct an audit and assessment of the deployment and of economic benefits delivered.

This report details the results of the authorized audit and assessment, as conducted by MetaVu, Inc. (MetaVu) under the direction of the Staff of the Public Utilities Commission of Ohio (Staff) from January to June, 2011. MetaVu employed the services of specialty project partners Alliance Calibration, Inc. (Alliance Calibration) and OKIOK Data, Ltd. (OKIOK) to complete the audit and assessment and prepare this report. The intended audiences for the report include the Commission, Duke Energy, various stakeholders that are generally parties to Duke Energy Ohio regulatory proceedings and the people of the state of Ohio.

MetaVu would like to thank the management and employees of Staff, project partners, and Duke Energy, without whom the audit and assessment could not have been successfully completed.

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About MetaVu

MetaVu is a recognized leader in sustainable business development, delivering the solutions companies need to innovate products, services and business models to manage energy, social and environmental risk throughout the value chain. In the utility sector, MetaVu helps clients integrate customer, technology and regulatory strategies into profit-generating products and business models including demand side management, renewable energy development, and smart grid evaluation and deployment.

Disclaimer

MetaVu served as a Staff resource for the Audit and Assessment described in this report and used best efforts to collect and analyze relevant information from Duke Energy. Report users should consider that the veracity and precision of Audit and Assessment findings are based on representations provided by Duke Energy. MetaVu recommends that experienced professional advisors be consulted in the event the information herein is intended to be used for a particular purpose.

1 EXECUTIVE SUMMARY

This report documents the results of a mid-deployment audit and assessment of the Duke Energy Ohio grid modernization project by the Staff of the Public Utilities Commission of Ohio (Staff). Duke Energy Ohio agreed to a mid-deployment audit and assessment as part of regulatory proceedings associated with the Duke Energy Ohio Electric Security Plan Case No. 08-920-EL-SSO. Staff selected MetaVu, Inc. (MetaVu) to support Staff's audit and assessment through a competitive bidding process.

The purpose of the audit and assessment was to verify and quantify the value of smart grid deployment to Duke Energy Ohio customers and to identify any appropriate changes or revisions to the smart grid deployment plan. The audit and assessment was structured into several sub-components including:

- An Operational Audit
- A Systems Integration Assessment
- A Guidelines and Practices Conformity Assessment
- An Operational Benefits Assessment

1.1 Audit and Assessment Background

On July 31, 2008, Duke Energy Ohio filed an application for approval of an Electric Security Plan (ESP), Case No. 08-920-EL-SSO. The application included a business case for the deployment of a smart grid in Duke Energy's Ohio service territory. Many of the parties in the Duke ESP Case entered into a stipulation that provided for the implementation of smart grid technologies, established a rider for the recovery of smart grid deployment costs, and called for a mid-deployment review of progress in the second quarter of 2011. The Commission issued an opinion and order approving the stipulation on December 17, 2008.

The stipulation required Duke Energy Ohio to file applications in the second quarter of each year to recover smart grid expenditures from the previous year. The stipulation entered into as part of Duke Energy Ohio's application (09-543-GE-UNC) to recover 2009 smart grid costs, approved by the Commission on May 13, 2010, stated in pertinent part:

> *"In order to provide Staff and interested stakeholders ample opportunity to verify and ensure value to customers, and in preparation for the midterm review Duke Energy Ohio will provide Staff with such data and information as may be necessary to understand any revisions or changes to its business case for Smart Grid as set forth in Case No. 08-920-EL-SSO including information pertaining to revised projected costs, and revised projected operational benefits for the period of the business case. Duke Energy Ohio commits to provide such information prior to the midterm review described in Case No. 08-920-EL-SSO."*

Staff developed and issued a Request for Proposal EE10-OA-1 that solicited support to conduct the Audit and Assessment authorized by the Commission. MetaVu and its project partners were awarded the bid after a competitive solicitation process. The scope of the Audit and Assessment is described below.

1.2 Audit and Assessment Scope

Staff developed an Audit and Assessment Scope that guided MetaVu's project planning and execution efforts and those of its project partners. The Audit and Assessment scope included an Operational Audit, a Systems Integration Assessment, a Guidelines and Practices Conformity Assessment, and an Operational Benefits Assessment as described below.

Operational Audit

The Operational Audit consisted of a review of installed equipment and systems, an analysis of their functionality, and a mapping of deployment status against implementation plans. Operational Audit activities included:

- A field audit of Duke Energy Ohio's smart grid deployment to date
- An analysis of the degree to which deployed components function as they should (e.g., are the smart meters accurate)
- A comparison of deployment status to date with overall deployment plans and a determination of the extent of deployment remaining for completion

Systems Integration Assessment

The Systems Integration Assessment consisted of an analysis of the degree to which smart grid components work together with other components and systems. Systems Integration Assessment activities included:

- An analysis of the degree to which components deployed are systemically integrated with one another, including communications from meters through the creation of customers' bills
- A test of the accuracy of billed data for customers participating in time-differentiated pricing pilots
- An analysis of the degree to which deployed components are integrated with other Duke Energy Ohio business systems such as outage management, work force deployment, asset management, and other information systems

Guidelines and Practices Conformity Assessment

The Guidelines and Practices Conformity Assessment focused on how, and the degree to which, Duke Energy Ohio's smart grid systems and their deployment conform with emerging guidelines and best practices. The Guidelines and Practices Conformity Assessment included:

- A review of the guidelines development process ongoing at the National Institute of Standards and Technology (NIST)
- An assessment of conformity with evolving guidelines
- The identification of potential risks of non-conformity and the implications of such risks
- The identification of best practices and characterization of Duke Energy Ohio practices in that context
- The identification of practices that pose significant risks associated with having to fix or redeploy components and systems

Operational Benefits Assessment

The Operational Benefits Assessment focused on estimating the net present value of benefits to Duke Energy Ohio resulting from smart grid deployment. The activities included:

- An assessment of 23 Operational Benefits included in Duke Energy Ohio's smart grid business case including those anticipated to reduce operations and maintenance costs, increase revenue, avoid fuel costs, or defer capital expenditures
- The identification of two Operational Benefits that Duke Energy Ohio did not include in its smart grid business case
- An estimation of the dollar value and timing (net present value) of the 25 Operational Benefits

The scope of work did not include any estimation or valuation of customer or societal benefits attributable to smart grid deployment nor did it include a financial audit for cost recovery purposes. The overall objective was to assist Staff in examining Duke Energy Ohio's smart grid deployment to date and its business case on a going-forward basis, and to document those findings for the record in Case No. 08-920-EL-SSO.

1.3 Audit and Assessment Findings

MetaVu facilitated the inquiry, assessment and analysis phase of the Audit and Assessment through collaboration with subject and domain experts of project partners and Staff. The resulting analysis is documented in the following sections:

Operational Audit Findings

Meter Tests

- A test of a statistically significant number of smart electric meters revealed that the smart meters' measurement accuracy is well within manufacturer's specifications and better than the traditional meters they are replacing.
- A test of gas meter data transmitters revealed that they accurately communicate gas meter readings to Duke Energy Ohio meter data management systems.
- A test of gas meter data transmitters' Radio Frequency (RF) emissions indicated field strengths within FCC guidelines and lower than many electric devices commonly used by consumers.

Field Equipment Audit

As of December 31, 2010:

- Smart meter deployments were found to be 46% complete compared to a planned deployment of 85%, with corresponding delays of associated Operational Benefits.
- The installation of 'smart' equipment intended to reduce outage extent (the number of customers impacted by an average outage) is on schedule with approximately 60% remaining to complete.
- The installation of 'smart' equipment in Duke Energy Ohio's Cincinnati substations is slightly behind plan with 69% remaining to complete.
- The economic benefits of 'smart' equipment intended to improve electric distribution efficiency is largely dependent on software, with completion anticipated in 2013.
- A comparison of readings displayed on devices in the field to data available in Duke Energy Ohio's Electric Management System and historical data repository revealed no significant differences, indicating that all installed equipment was functioning as intended when inspected.

Systems Integration Assessment Findings

The Systems Integration Assessment found:

- Usage data from 47 smart electric meters and 47 gas meters equipped with wireless data transmitters was traced through communication infrastructures and a number of Duke Energy data processing systems used to generate customer bills. No data integrity issues were identified, indicating that systems used to communicate and manage billing data are adequately integrated.
- Bills from a randomly selected sample of customers on time-differentiated rates (12 on rate TDAM and 13 on rate TDLITE) were audited from source energy usage data collected in 15 minute intervals. No errors in the calculation of customer bills were found.
- A review of the usage data Validation, Editing, and Estimation (VEE) routines utilized by the two data processing systems (EDMS and MDMS) used to prepare usage data for customer bill generation, including those used to prepare time-differentiated rate bills, found that they were adequate to identify errant billing data and functioning properly at the time they were inspected.
- MetaVu reviewed the capability of Duke Energy Ohio's Advanced Metering Infrastructure (AMI) to measure MAIFI (Momentary Average Interruption Frequency Index) as defined by the IEEE (Institute of Electrical and Electronics Engineers). MetaVu's review concluded that there is no readily available approach to measuring MAIFI as defined by the IEEE from existing AMI capabilities, although some reasonable approximations could be made available with significant effort and cost.
- MetaVu reviewed the planned integration of the yet-to-be-deployed Distribution Management System (DMS) that Duke Energy Ohio intends to use as the centerpiece of distribution

automation. MetaVu found that detailed plans and budgets for completing extensive integration of the DMS with existing systems, including SCADA, Outage Management, Workforce Management, data historian, are in place. MetaVu recommends that a thorough and formal change management plan be designed and executed as part of the DMS implementation to maximize DMS value.

- MetaVu also reviewed business process integration as part of the Systems Integration Assessment and found several opportunities to make better use of meter data including:
  - Use of meter status to proactively detect smaller and localized outages
  - Use of meter power quality data to improve voltage monitoring capabilities
  - Use of meter data for capacity planning purposes
  - Use of meter data to enhance customer DSM program effectiveness (such Power Manager®)
- Though outside Duke Energy Ohio's deployment plan scope, MetaVu noted opportunities to incorporate advanced substation monitoring and reporting as part of a future phase of smart grid development.

Guidelines and Practices Conformity Assessment Findings

The Assessment of Conformity with Guidelines and Practices found:

- The NIST guidelines against which Duke Energy Ohio's smart grid was evaluated are a superset from which utilities are expected to select as applicable. As such, utilities are not expected to comply with the complete set of requirements defined in the NIST guidelines.
- Instances of low conformity with NIST guidelines does not necessarily imply that Duke Energy does not have valid security practices in place, only that they do not meet some of the very specific requirements called for in the NIST guidelines.
- Duke Energy was found to be in full or partial conformity with five of the "families" of the NIST guidelines but was found to conform to less than half of the requirements of four other families of guidelines.

[redacted]

- [redacted].
- Some families were identified as both non-conforming and associated with a high potentiality of a security breach.
- [redacted]
- The Duke Energy Personal Information Privacy Policy describes the requirements for protecting the privacy of personal information but does not explicitly protect energy data collected and processed by smart grid information systems.
- Electric smart meters [redacted]:
  - [redacted]
  - [redacted]
- Gas meter data transmitters [redacted]

[redacted].

- Electric smart meters [redacted]

  [redacted]

Operational Benefits Assessment Findings

MetaVu estimated the Net Present Value (NPV) of Operational Benefits available from Duke Energy Ohio's smart grid deployment at $382.8 million in the base case with a low case of $325.8 million and a high case of $447.5 million. Summary findings are provided below:

- About 90% of the benefits can be traced to two smart grid capabilities: Advanced Metering Infrastructure (AMI) and Integrated Voltage/VAR Control (IVVC).
- Operations and Maintenance costs avoided from the implementation of AMI represent about 45% of the total benefits and include avoided labor and vehicles costs from remote meter reading and diagnostic capabilities (the vast majority), as well as improved meter accuracy and power theft detection (which increase billed sales volumes).
- Fuel (and purchased power) costs avoided from IVVC capabilities represent another 45% of the total benefits. Improved control of Voltage and VAR increases the efficiency of the distribution grid and therefore the amount of power delivered to customers per unit of power generated.
- Though a variety of grid capabilities combine to help defer capital investments, this type of value is smaller than the others analyzed (Avoided Operations and Maintenance Costs, Avoided Fuel Costs, and Increased Revenues). This is particularly true when one considers that customers realize the value of deferred capital over long periods of time.
- The most significant drivers of smart grid benefit NPV include assumptions about:
  - Cost growth rates
  - Software and hardware deployment rates
  - Projected distribution grid performance improvements post deployment
  - Impact of automation on labor and capital
  - Discount rate

1.4 Report Organization

This report is organized into four Sections, one for each of the primary scopes. Each Section follows the following outline:

- An **Introduction** that provides background and general information on the specific audit or assessment
- A description of the **Methodologies** used to complete the specific audit or assessment
- **Findings** for detailed components examined within the specific audit or assessment

In addition, an extensive **Appendix** includes details and clarifications that were segregated to ensure smooth presentation of report content.

2 OPERATIONAL AUDIT

2.1 Introduction

The Staff of the Public Utilities Commission of Ohio (Staff) asked MetaVu and Alliance Calibration[1] to conduct an operational audit of installed smart grid equipment and systems and an analysis of their functionality. The Operational Audit was conducted to answer two primary questions:

1. Are deployed components of the smart grid functioning as they should?
2. What is the deployment status relative to completion as defined by original implementation plans?

The Operational Audit was prompted in part by concerns about meter accuracy and health impacts by electric customers in Texas and California. MetaVu executed the Operational Audit with the assistance of Cincinnati-based Alliance Calibration through three primary means:

1. Lab-testing of samples of smart electric meters, gas meter wireless data transmitters, and traditional electric meters.
2. Review and observation of meter lot testing and installation procedures.
3. Field audits of a sample of smart grid equipment installed throughout Duke Energy's Ohio distribution grid.

Alliance Calibration employed a purpose-built environmental chamber to test electric meters under a variety of simulated weather conditions. Gas meter data transmitters were tested in a semi-Anechoic Radio Frequency Chamber to test RF emissions. The lab tests and field audit also afforded opportunities to inform other aspects of the assessment (Systems Integration, Guidelines and Practices, and Operational Benefits).

This Introduction concludes with diagrams that illustrate the physical layouts of Duke Energy Ohio's Advanced Metering Infrastructure (AMI) and Distribution Automation (DA) system. The balance of the Operational Audit section includes descriptions of audit methodologies and is followed by audit findings organized into Metering and Distribution Automation components:

Metering Audit

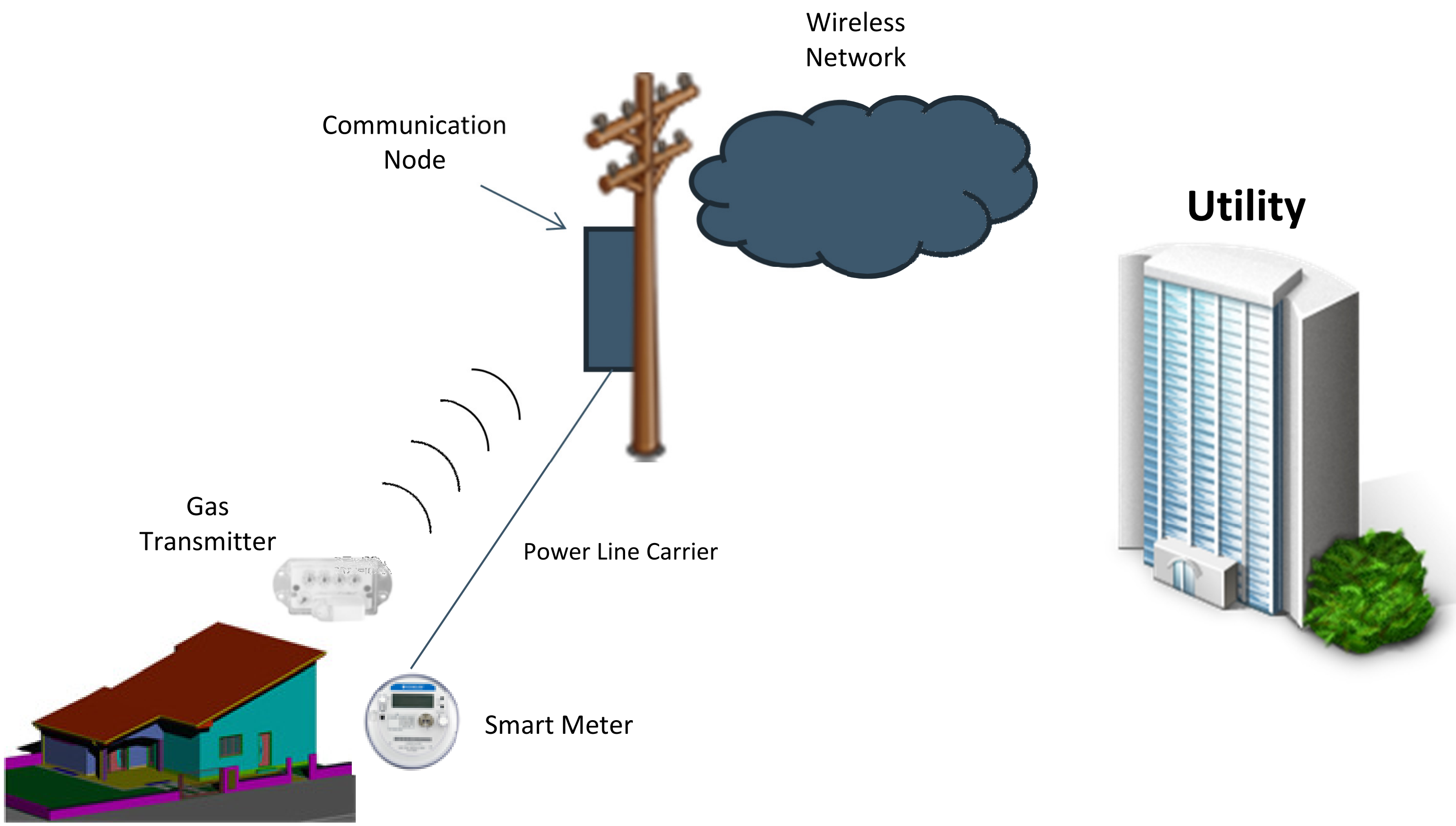
- Tests of smart electric meters
- Tests of traditional electric meters
- Tests of gas meter wireless data transmitters
- Review and observation of meter installation and meter lot testing procedures

Distribution Automation Audit

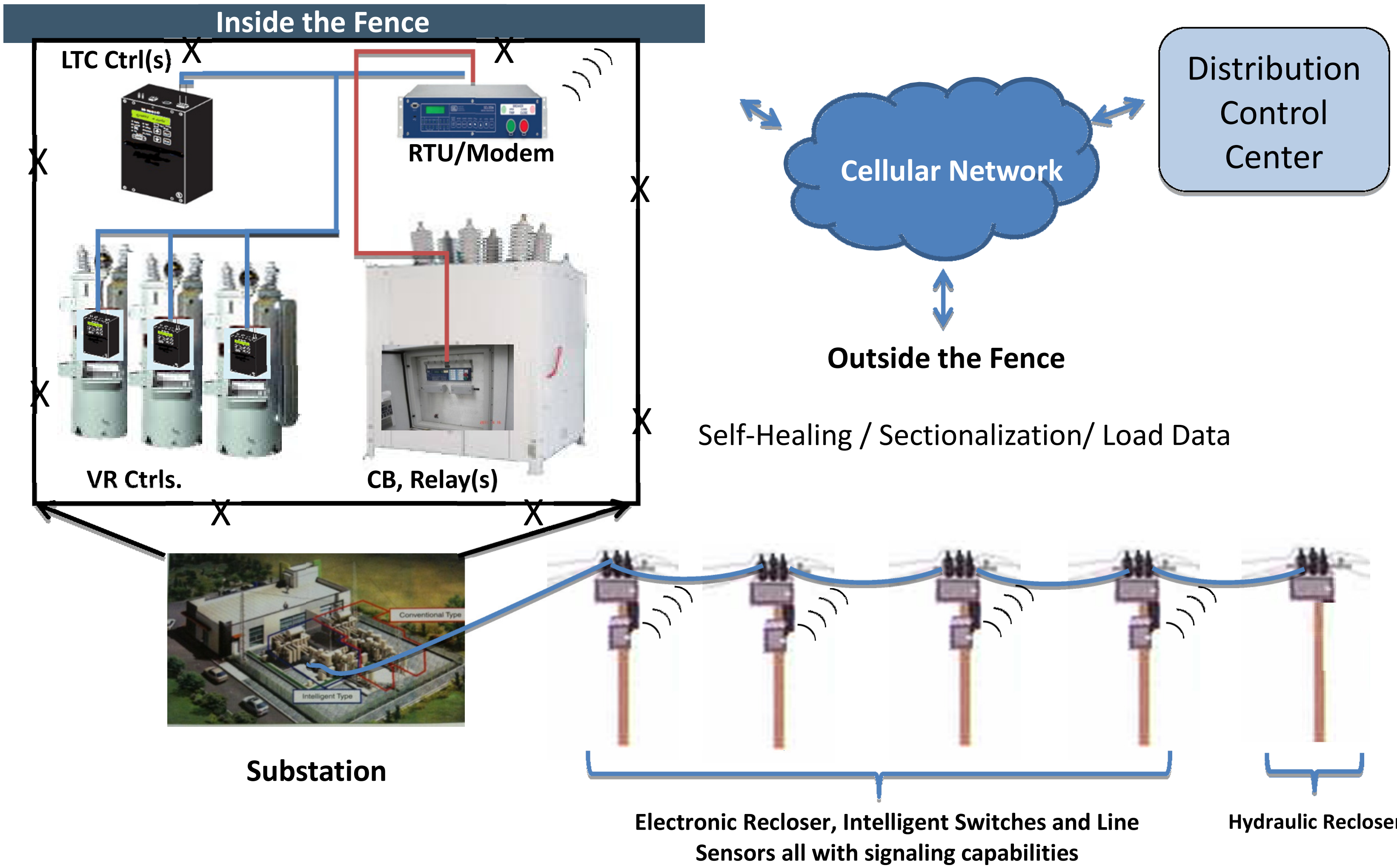
- Substations
- Feeders/Laterals

[1] Alliance Calibration is an ISO/IEC 17025:2005 accredited laboratory with staffers credentialed by the American Society of Quality in Calibration Technology. Alliance Calibration staffers also hold certifications as Internal Auditors for ISO/IEC 17025 and in measurement uncertainty training.

The following diagram illustrates the AMI architecture of Duke Energy Ohio. As exemplified below, electric smart meters and gas meter transmitters send data to communication nodes located throughout the smart meter service area. Those communication nodes then transmit customer data to the utility for analysis.



The diagram below depicts architecture of the Distribution Automation (DA) system of Duke Energy Ohio. Within the fence of the substation, load tap changer controllers, voltage regulator controls, circuit breakers, relays, and Remote Terminal Units (RTU) automate the substation and communicate critical data to the utility. On the distribution line, various reclosers and recloser controllers, intelligent switches, and other devices work automatically to improve grid state operations.



2.2 Methodologies

MetaVu and Alliance Calibration were careful to create and document measurement methodologies appropriate to achieve the goals of the Operational Audit. Measurement methodology overviews are provided below for:

- Electric Meter Tests
- Gas Meter Data Transmitter Tests
- Distribution Automation Equipment Audits

Additional test details are available in Appendix 1: Meter Test Inspection.

Electric Meter Tests – Standards and Procedures

Electric Meter Tests included tests of smart meters in-service for at least 90 days, tests of inventoried smart meters not yet deployed in the field, and tests of traditional meters. Tests consisted of meter accuracy under a variety of weather conditions and loads. Initially, it was anticipated 48 smart meters in-service for 90 days would be tested but the inability to access one customer premise precluded testing of one smart meter. The tests for inventoried (not yet placed into service) smart meters and traditional meters included 48 meters of each type.

The meter under test is then read by the tester to determine the meter's accuracy compared to the standard. The testing device used was the TransData 2130 which allows for the testing of various types of electrical meters (electromechanical, digital and smart) with an internal accuracy standard of ±0.025% (a far higher accuracy rate than the meters tested). For more information see Appendix 1-A: Electric Meter Test Plan.

Electrical meters were tested with a variety of known loads that are typical of consumer usage. Meters were tested at ambient room temperature, at -40^{o}C, and +40^{o}C (temperatures recommended according to American National Standards Institute (ANSI) standards). Traditional meters consisting of both mechanical and digital types from 6 different manufacturers were tested along with the smart meters.

The testing of electric meter measurement accuracy is a mature field governed by process and quality standards set by several recognized organizations. The National Institute of Standards and Technology, commonly referred to as NIST, is one such organization. NIST is a non-regulatory federal agency with a mission to promote U.S. innovation and industrial competitiveness by advancing measurement science, standards, and technology. The calibration of the test equipment utilized in the electric meter test is traceable to NIST.

A second relevant standard-setting body is the American National Standards Institute which governs the creation, use, and ongoing development of thousands of norms and guidelines. ANSI is also actively engaged in accrediting programs that assess conformance to standards – including globally-recognized, cross-sector programs such as the International Organization for Standardization or ISO 9000 (quality) and ISO 14000 (environmental) management systems. The methods used to test electric meters were in compliance with the C: 12.20-2010 American National Standard for Electricity Meters 0.2 and 0.5 Accuracy Classes.

The International Organization for Standardization is the world's largest developer and publisher of "International Standards" and serves as a network of the national standards institutes of 160 countries**.** Alliance Calibration is accredited to ISO/IEC 17025:2005 by the Laboratory Accreditation Bureau.

Electrical Meter Tests – Sampling and Statistical Significance

The mathematical field of statistics governs the process of "sampling." Properly applied, statistical principles can be used to evaluate and describe the degree to which the results of a sample can be assumed to represent the results of an entire population. Factors that determine the size of a statistically significant sample include:

- What is the failure rate for the devices being tested?
- What is the accuracy of the testing equipment relative to the devices being tested?
- What is the desired degree of confidence that the sample results reflect those of the entire population?

- What is the performance variability (margin of error) of the devices being tested?
- What is the size of the population?
- Are the meters being tested a representative (i.e., randomly selected) sample of the population?

Assumptions used to determine the appropriate sample size for Electrical Meter Tests include:

- Failure rate = 0.15%
- Smart Meter manufacturer stated accuracy of ± 0.5% from -40^{o}C to + 85^{o}C
- Traditional meter regulated minimum accuracy of ± 2.0%
- Testing equipment accuracy of ±0.05%
- Confidence level and confidence interval is set such that there is 95% confidence that the population results would be within ±5.0% of the sample results
- Device performance variability (margin of error) is 1%
- The total population of devices is greater than 20,000
- Meters to be tested were selected at random

Based on the above data a sample size of 58 meters was calculated as the minimum acceptable to ensure statistically significant results. In fact, 95 smart meters were tested so that there could be no doubt about the statistical validity of the results. The 95 smart meters tested included 47 in-service for at least 90 days as well as 48 from manufacturer-delivered lots that had been approved for installation by Duke Energy Ohio's meter lab. In addition, 93 traditional electric meters were selected at random for comparative testing. The tests for gas meter data transmitters included tests of radio frequency used to communicate gas meter data to data concentrators. The electric meter tests did not consist of such testing as electric meters use power line carrier to communicate meter information to the data concentrators.

Unlike the gas meter data transmitters (see below), electric meters were not tested for RF emissions. The smart electric meters installed by Duke Energy Ohio communicate through the power lines themselves using a protocol known as Power Line Carrier or PLC. The Duke Energy Ohio smart meters do not communicate wirelessly and therefore generate no RF emissions.

Gas Meter Data Transmitter Tests

Gas meters were not replaced as part of Duke Energy Ohio's smart grid deployment. Instead, wireless data transmitters were retrofitted to existing gas meters to enable remote meter reading. Accordingly, gas meter accuracy was not tested as part of this audit. Gas data transmitter tests consisted of RF emissions testing as well as data transmission accuracy (covered in Section 2, "Systems Integration"). Forty-eight gas meter data transmitters were selected at random from an inventory of data transmitters about to be installed. The photograph below illustrates a typical gas data transmitter installation, with the device (box with black dials affixed with red screws) retrofitted onto an existing gas meter.

It is noteworthy that the data transmitters do not modify the function or accuracy of the gas meter but merely repeat and transmit gas meter data readings.

Gas meter data transmitters emit RF as part of normal operations. RF emissions from electronic equipment are regulated by The Code of Federal Regulations (CFR) 47, part 15. This Federal Communication Commission (FCC) regulation sets specific requirements so that various electronic devices do not interfere with each other's operation. In today's modern society exposure to radio frequency waves is a common occurrence. Light switches, cellular telephones, cordless home telephones, garage door openers, microwave ovens, wireless data modems, and FM radio station transmitters represent a few of many examples.

In fact, RF-emitting devices are so prevalent that testing RF emissions is difficult without special equipment to minimize extraneous RF signals. Alliance Calibration utilized a semi-Anechoic (RF) Chamber (a soundproof room similar to a music recording studio) to minimize ambient RF and enable accurate gas meter data transmitter testing.

Duke Energy provided gas meters to facilitate data transmitter testing. A known volume of gas was pumped through the gas meters and both the physical readings on the dials and the signal sent from the meter data transmitters was recorded. An Alicat gas calibration unit with an accuracy of ± 0.4 % was used to measure the known volume of gas; like the electric meter testing equipment, the calibration of the Alicat unit is traceable to NIST.

Wide band RF characterization measurements were taken from data transmitters at rest and while transmitting to determine the frequencies at which significant RF emissions occurred. The measurements were taken at a distance of 3.0 meters. A variety of transmitter positions were tested and both horizontal and vertical field components were measured. The output of the antenna was connected to the input of the receiver and emissions were measured in the range from 30MHz to 1GHz. The values up to 1GHz with a resolution bandwidth of 120 kHz are quasi-peak readings made at 3.0 meters. The raw measurements were corrected to allow for antenna factor and cable loss. For detailed gas transmitter test plans please see Appendix 1-B: Gas Meter Test Plan and Appendix 1-C: Gas Transmitter Chamber Test Plan.

Distribution Automation Equipment Audit

The objective of the Distribution Automation Equipment Audits was to determine deployment status relative to completion as defined by the Duke Energy smart grid implementation plan approved by PUCO. MetaVu designed an audit that involved physical inspection of 'smart' equipment installed throughout the distribution grid and verification of equipment readings in Duke Energy's Energy Management System (EMS) system found in the Supervisory Control and Data Acquisition (SCADA) system. Those same readings were also compared to corresponding data found in the data historian. The results of the audit (based on a random sample) were extrapolated to estimate the Substation and Feeder/Lateral deployment levels as a percent of the total project.

Duke Energy provided a list of installed smart equipment from its asset management system. MetaVu selected 25% of all substations that underwent smart grid upgrades in 2009 or 2010 as a random sample set "inside the fence." Of this sample set a Physical Field Audit was completed for all the smart grid-enhanced hardware, including Circuit Breaker Protective Relays (CB Relays), Voltage Regulators (VR) and Transformer Load Tap Changer Controllers and the respective communication transceivers.

A random sample set of smart switching equipment "outside the fence", laterally from the substations, was also selected and audited. This sample of lateral feeder equipment was all located on poles and/or overhead and consisted of electronic re-closing, self-healing, sectionalizing, and fault-isolating disconnectors, switches or circuit breakers.

An Alliance Calibration technician supported the physical inspection and documentation aspects of the field equipment audit. Accompanied by a MetaVu electrical engineer, the technician participated in Duke Energy substation and field safety training. MetaVu instructed the technician on audit requirements and protocols, which included:

- Documentation of the street address of selected assets
- Photographs of selected assets

- Documentation of manufacturers, models, serial numbers, and installation dates of selected assets
- Date and timestamp of the inspection
- For a subset of applicable equipment:
  - A time-stamped display reading or a switch position indication
  - A real-time call to the EMS operator to compare equipment display readings or switch position according to the EMS system
  - Duke provided information from the data repository for MetaVu to compare equipment display readings or switch position to readings in the field

The technician's day to day activities were guided by Alliance Calibration management with oversight from MetaVu. The technician, accompanied by Duke Energy personnel, completed the field inspection over several weeks in late March and early April.

2.3 Findings

Metering Audit

The metering audit concluded as follows:

- Smart electric meters are significantly more accurate in all weather conditions, offering significantly smaller measurement variability than traditional electric meters.
- Smart electric meter deployment lags planned deployment levels, ratably delaying anticipated economic benefits.
- Gas meter data transmitters accurately report gas meter measurements.
- Gas meter data transmitter RF emission levels are lower than the RF emission levels of other devices commonly used by consumers and meet FCC standards.
- Duke Energy meter lot testing and change-out procedures are adequate and consistently applied.

These findings are described in detail in the sections below.

Smart electric meters are significantly more accurate in all weather conditions, offering significantly smaller measurement variability than traditional electric meters.
Detailed tests of smart and traditional electric meters indicate that smart meters are much more accurate and offer reduced measurement variability than traditional meters. The table below summarizes the findings:

Average Meter Accuracy Results

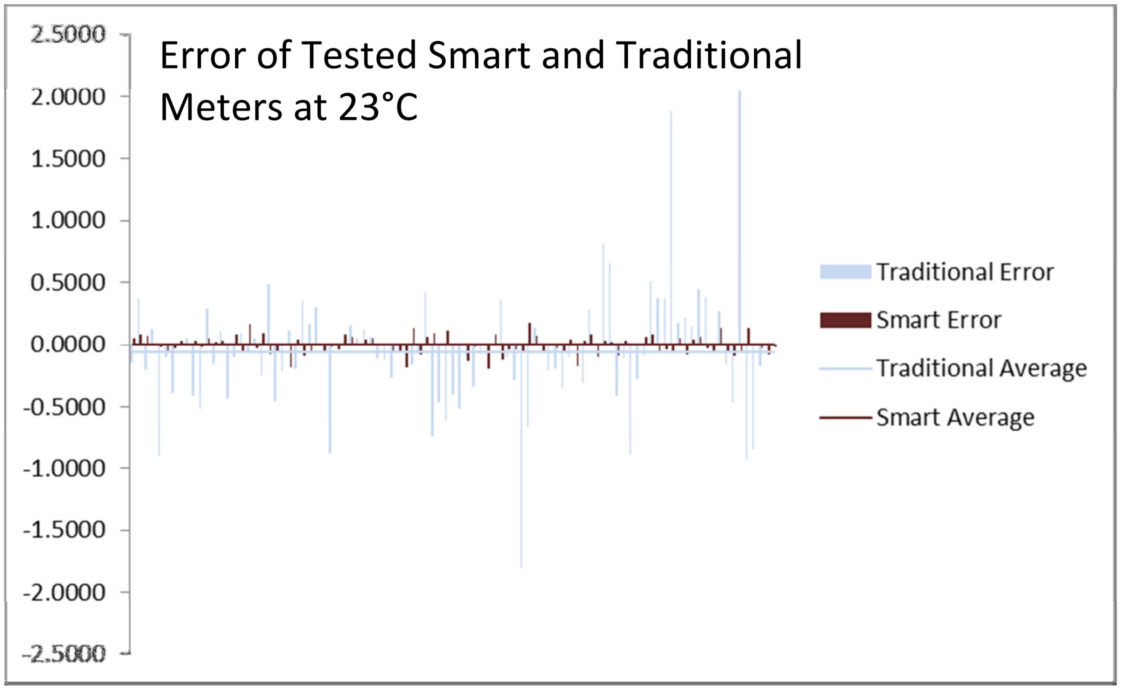
	Smart Meters, Passed Lots	Smart Meters in service 90 days+	Traditional Meters
+23°C Average % Error	0.004	-0.014	-0.061
+23°C Standard Deviation	0.073	0.079	0.494
+40°C Average % Error	0.442	0.455	-0.904
+40°C Standard Deviation	0.282	0.248	1.009
-40°C Average % Error	0.094	0.110	-0.178
-40°C Standard Deviation	0.105	0.122	0.541

"Error" is defined as the difference between actual load and the load indicated by the meters tested.

Graphical representations can help make the dramatic improvements in meter accuracy more apparent:

NOTES:

- Average Smart Meter Error: +.004%
- Average Traditional Meter Error: -.061%
- Smart meter sample size: 95
- Traditional meter sample size: 93
- Results of tests conducted at 23℃, average of 3 current loads tested
- ”Error” is defined as the difference between actual load and the load indicated by the meters tested.



While the tests show improvements in smart meter accuracy over traditional meters, it should be noted that the magnitude of these numbers is very small. Customers are not likely to notice a difference on their bills as a 0.004% error rate on a $50 bill is less than 20 cents. In the aggregate, however, the improvement in meter accuracy should increase billed sales volumes for Duke Energy Ohio. This is addressed in Section 4, ‘Operational Benefits’ under Benefit 8,”Meter Accuracy Improvement.”

Smart electric meter deployment lags planned deployment levels, ratably delaying anticipated economic benefits.
Several types of economic benefits associated with smart meters, from the aforementioned meter accuracy improvements to dramatic reductions in meter reading costs, are driven by the level of meter deployment. Due to a variety of factors, smart meter deployments have lagged planned deployments. These factors include:

- Difficulty accessing some meters, particularly those located within customer premises.
- Time required for the initial learning curve of meter installation.
- Difficulty in identifying a smart meter solution appropriate for some commercial/industrial customers.
- The need to upgrade premise meter facilities that have been made unsafe over time.
- Start-up delays associated with communications node design and production.

Operational Benefit estimates, utilizing meter deployment as a significant variable, have been adjusted accordingly.

Gas meter data transmitters accurately report gas meter measurements.
Data from 47 in-service gas meters was tracked in real-time from the meter to Duke Energy’s central gas meter data collection and management systems without error. Please see the Systems Integration Assessment section for more information.

Gas meter data transmitter RF emission levels are lower than the RF emission levels of other devices commonly used by consumers and meet FCC standards.
RF emission level testing of gas meter data transmitters revealed that RF emission levels are lower than FCC limits for such devices.

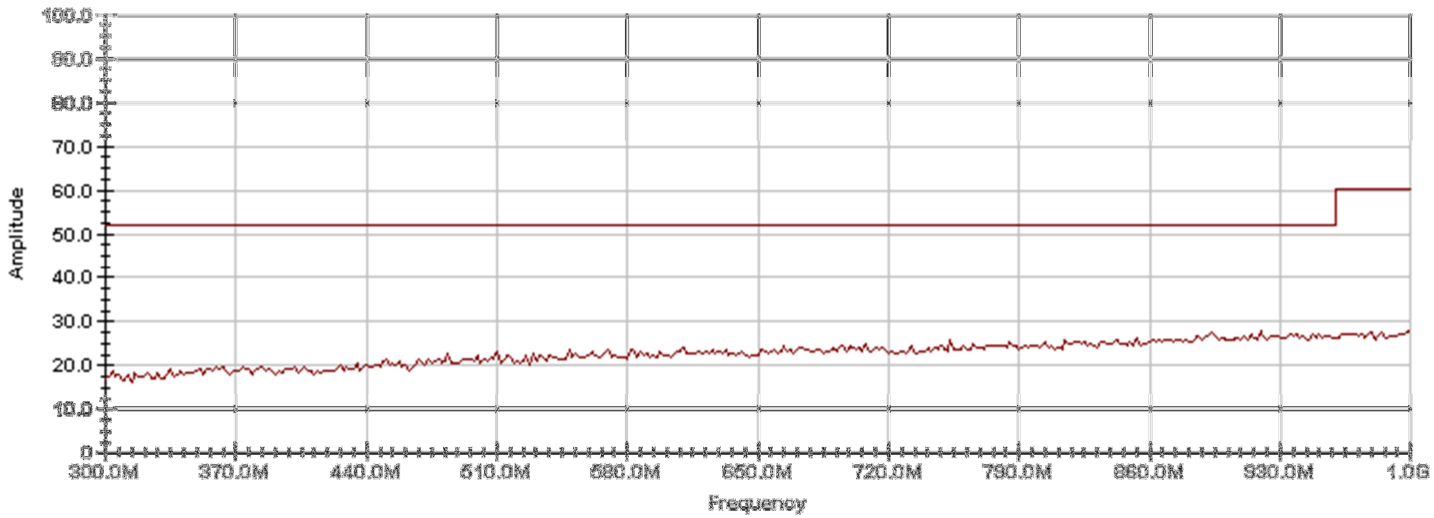
The chart below indicates the results of the test relative to the FCC limit (represented by the straight red line): RF signal strength was measured from a variety of locations to understand if the signal varied from different positions around the data transmitter, and no significant differences were found.

In some instances, such as apartment buildings, multiple data transmitters are installed tightly together. Alliance Calibration tested 12 co-located data transmitters to examine this scenario and found that RF signal strength was not additive. The gas meter data transmitter manufacturer has tested its equipment in a similar manner and submitted its findings to the FCC in compliance with CFR 47, part 15. Alliance Calibration examined the filing and found it to be consistent with findings of this audit.

F-Squared Laboratories

Spectrum Analyzer Trace Data

Corrected Graph



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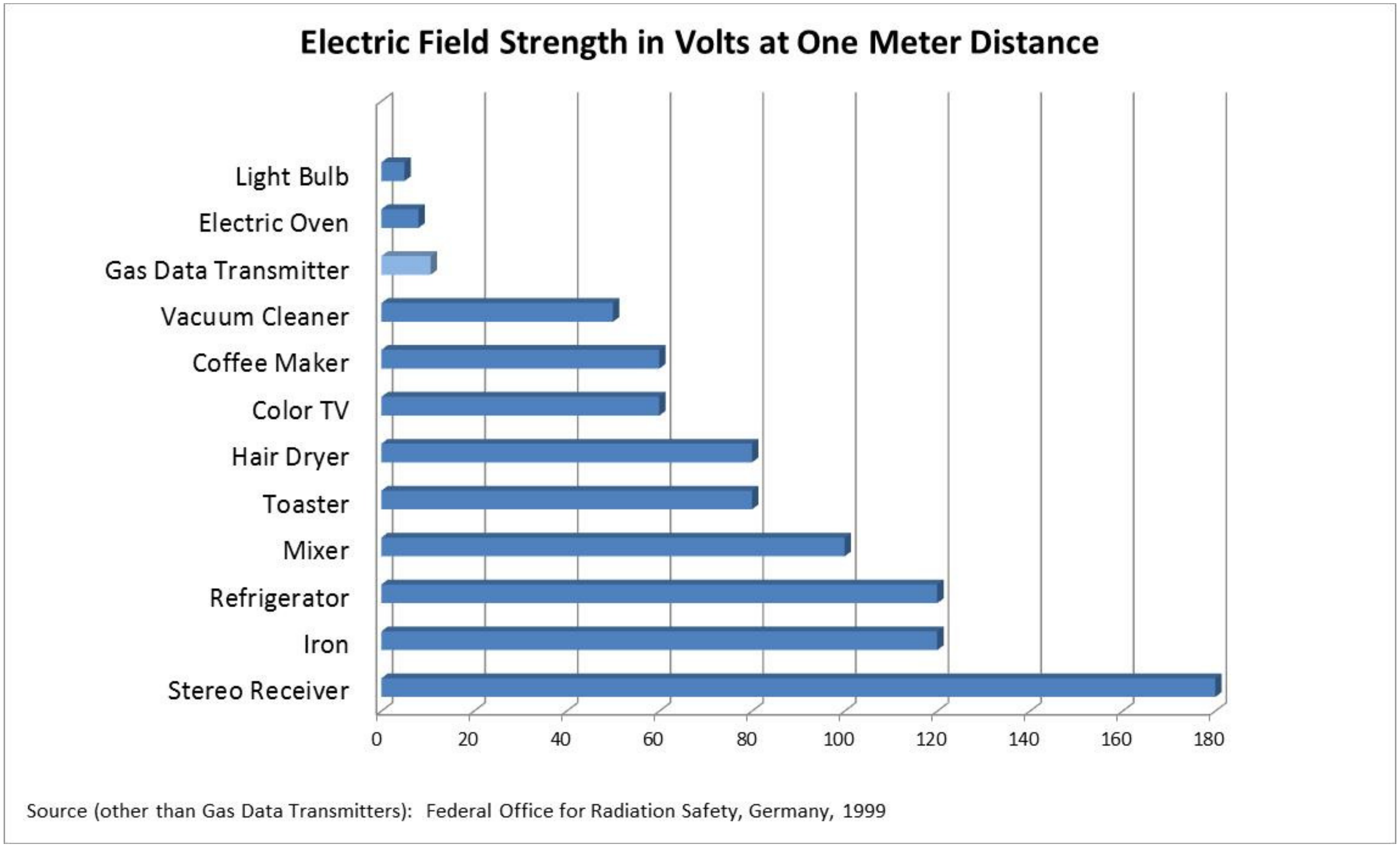
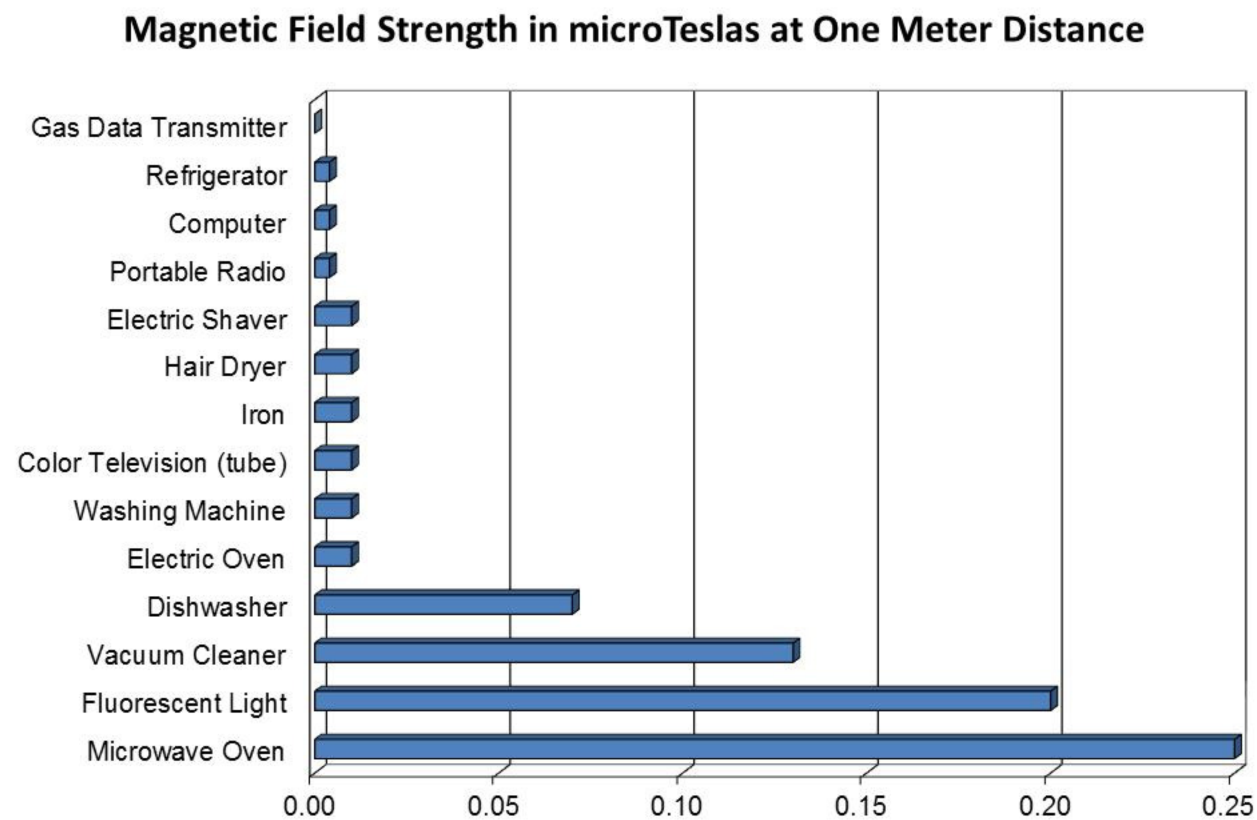
Company: Alliance Calibration

Duke Energy's Ohio customers may be interested to know that many of the devices consumers use on a daily basis emit significantly stronger Electro-Magnetic Frequencies (EMF) than the gas meter data transmitters. The following charts compare the gas meter data transmitters' findings by Alliance Calibration to the findings of a separate study of common household devices on electric and magnetic field strength at one meter distance.





Source (other than Gas Data Transmitters): Federal Office for Radiation Safety, Germany, 1999

Duke Energy meter lot testing and change-out procedures are adequate and consistently applied.
Alliance Calibration reviewed and observed processes employed at Duke Energy's electric and gas meter testing facility in Cincinnati as part of the Operational Audit. Alliance Calibration found the processes to be in compliance with electric and gas meter testing standards as described above. Duke Energy is currently testing 10% of the meters in a manufacturer's lot before approving the meters in the lot for installation. This is in excess of the amount required for minimum statistical significance. Alliance Calibration tested a random sample of meters from two lots approved by Duke Energy and found them suitable for installation.

Alliance Calibration also reviewed and observed the process by which traditional meters were removed and smart meters installed. Ninety-three instances of the process were observed as executed by eight different installers. These observations indicated that the new meters present no installation challenges. Meter mount modifications were not necessary and the swap-out process is described simply as "pull the old one out and plug the new one in."

All installers observed made consistent efforts to contact customers while on site and answer any customer's questions. All customers that were contacted by installers were advised to turn off any electrical devices such as computers. All installers observed waited for customers to turn off electrical devices before installing meters and consistently employed industry-standard safety procedures and installation methods.

Distribution Automation Audit

- The installation of "smart" equipment intended to reduce outage extent is on schedule with approximately 40% complete as of December 31, 2010.
- The installation of "smart" equipment in Duke Energy's Cincinnati substations is slightly behind plan with 31% complete as of December 31, 2010.
- The economic benefits of "smart" equipment intended to improve electric distribution efficiency is largely dependent on software with completion anticipated by 2013.
- The comparisons of device readings and data found in EMS and the data repository were found to be sufficiently accurate.

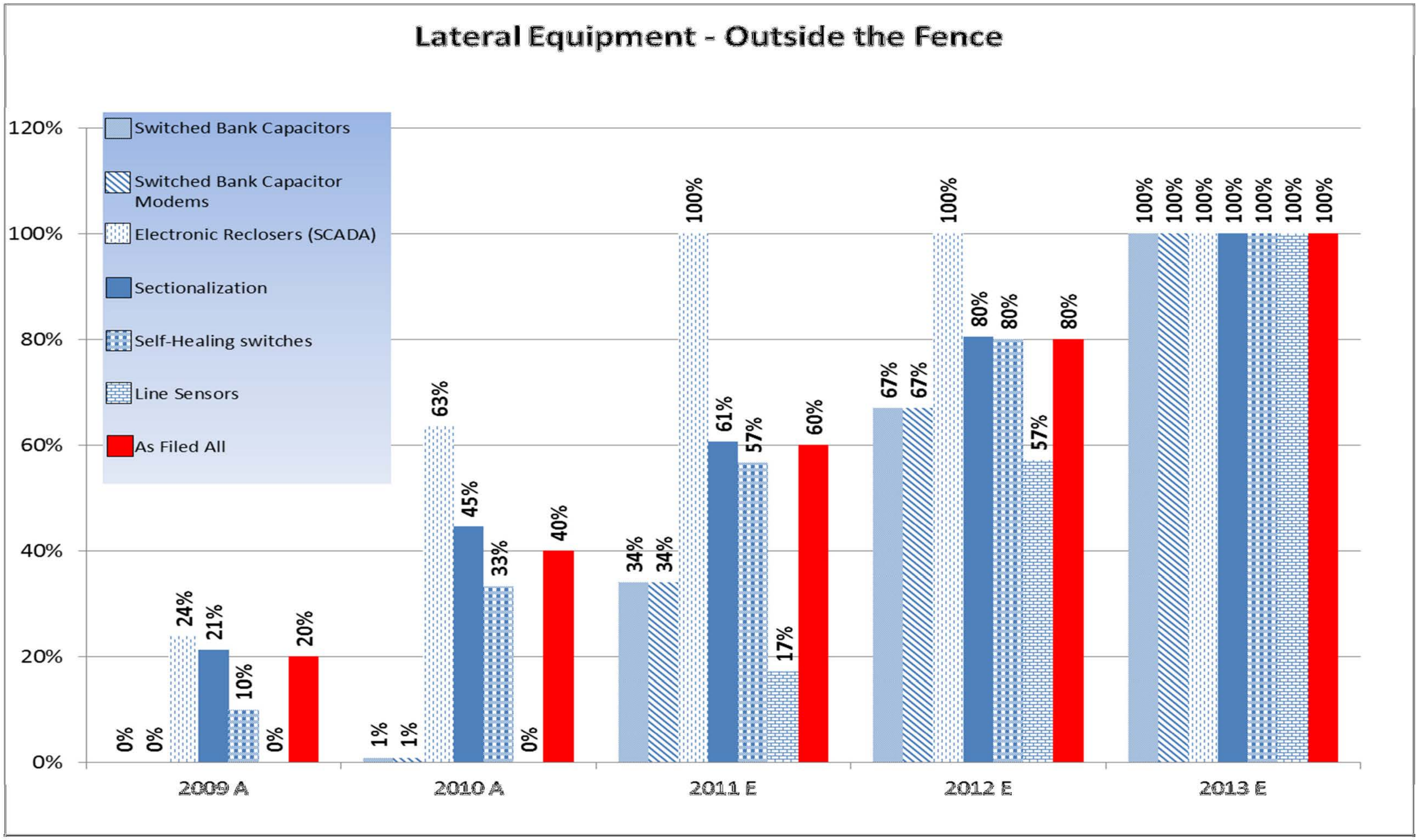
These findings are described in detail in the sections below.

The installation of "smart" equipment intended to reduce the length and extent of outages is on schedule with approximately 40% complete as of December 31, 2010.

Several types of smart equipment installed in the distribution grid are specifically designed to reduce the number of customers impacted by an outage or reduce the time required to locate the source of an outage (known as "Fault Isolation and Outage Detection"). The use of these devices, including reclosers, sectionalizers, and switches, has been commonplace for some time, but the number of devices installed and the extent to which they communicate data and operate automatically is significantly greater in smart grid applications.

"Smart" versions of these devices are more effective than traditional versions at reducing "Customer Minutes Out", a common measure of grid reliability. MetaVu's audit of these devices indicated that the installation of such devices is on schedule, and that approximately 40% are installed as of December 31, 2010.

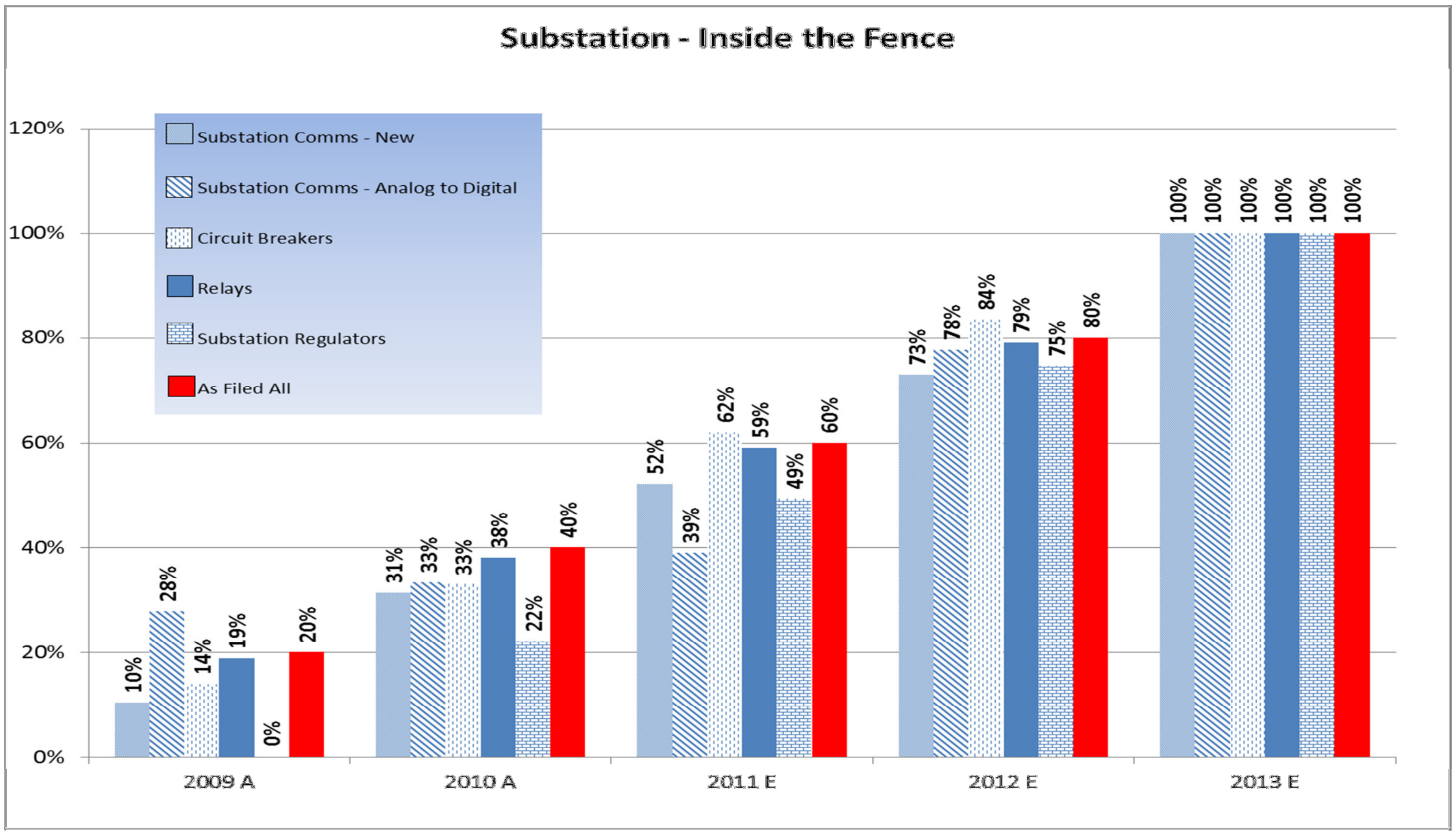
MetaVu's audit of smart substation equipment indicates that upgrades are on schedule, and that about 31% of the work and spending to finish the approved implementation plan relative to substations is complete as of December 31, 2010. The chart below describes MetaVu's audit findings for substation equipment installation rates, including historical actuals and future projections based on actuals:



The installation of "smart" equipment in Duke Energy's Cincinnati substations is slightly behind plan with 31% complete December 31, 2010.

Substations play a critical role in the smart grid and house a great deal of the smart equipment required to secure anticipated reliability and economic benefits including communications, circuit breakers, relays, and voltage regulators.

MetaVu's audit of smart substation equipment indicates that upgrades are on schedule and that about 31% of the work and spending to finish the approved implementation plan relative to substations is complete as of December 31, 2010. The chart below describes MetaVu's audit findings for substation equipment installation rates, including historical actuals and future projections based on actuals:



The economic benefits of "smart" equipment intended to improve electric distribution efficiency is largely dependent on software with completion anticipated by 2013.

The reader may have noted from the "Lateral Equipment – Outside the Fence" chart above that installation of some on the smart equipment has just begun. This equipment, including capacitor bank controllers/ communications as well as line sensors, are specific to Duke Energy's Distribution Management System, or DMS, which is currently being installed and is scheduled for full operation in 2013. The "de-prioritization" of the installation of this equipment is therefore appropriate, as associated benefits are not anticipated to be significant until the DMS is fully operational.

The fact that the DMS and associated hardware will not be fully operational until 2013, however, does have implications for economic benefits. The DMS application that will make greatest use of the capacitor bank controllers/communications and line sensors is IVVC. Currently, Duke Energy Ohio is conducting IVVC pilots and has yet to select the technology and algorithm to be integrated into DMS. IVVC offers significant economic benefits in terms of distribution efficiency as it helps reduce voltage and associated power generation within the lowest tolerances according to standards and improves the VAR (power factor). Improving the power factor increases the amount of usable power available to customers for every unit of power generated.

These improvements in distribution efficiency are among the larger economic benefits available from smart grid implementations. Operational Benefit estimates, associated with IVVC operation calculated elsewhere in this report, have been assumed to begin in 2013.

The comparison of device readings and data found in EMS and the Data Historian was found to be sufficiently accurate.

All the equipment selected for Audit was found to be installed. All display readings and switch position indicators matched up with EMS in real-time. All display readings also matched subsequent examination of the Data Historian but for one switch position exception. It is reasonable to conclude that the switch position not matching the Data Historian could be attributed to "noise" in the measurement because everything matched up in real-time. The cause of this is most likely a human error and can be attributed to one or more of the following:

- The time stamps captured were inaccurate
- The switch position was written down incorrectly
- The switch was operated within a minute of the physical audit (time stamp was rounded to nearest minute)
- Duke operator may accidently have given inaccurate switch position from the data historian

Therefore, MetaVu determined that data from DA field devices is being communicated to the EMS and Data Historian accurately.

3 SYSTEMS INTEGRATION ASSESSMENT

3.1 Introduction

Staff asked MetaVu to review Systems Integration in terms of "the degree to which Smart Grid components work together with other components and systems." MetaVu interpreted this definition somewhat broadly, incorporating both information technology systems and associated business processes into its assessment.

The Systems Integration Assessment findings are organized into areas of investigation specified by the Staff:

- Electric Data Audit
- Gas Data Audit
- Time-Differentiated Billing Data Audit
- Billing Data Validation, Estimation, and Editing
- Meter Outage Data integration for MAIFI Reporting
- Distribution Automation Integration
- Meter Data Integration

This Introduction concludes with diagrams that illustrate the data paths and information systems of Duke Energy Ohio's Advanced Metering Infrastructure (AMI) and smart distribution grid. The balance of the Systems Integration section includes descriptions of audit methodologies and is followed by audit findings organized into Advanced Metering Infrastructure and Distribution Automation components.

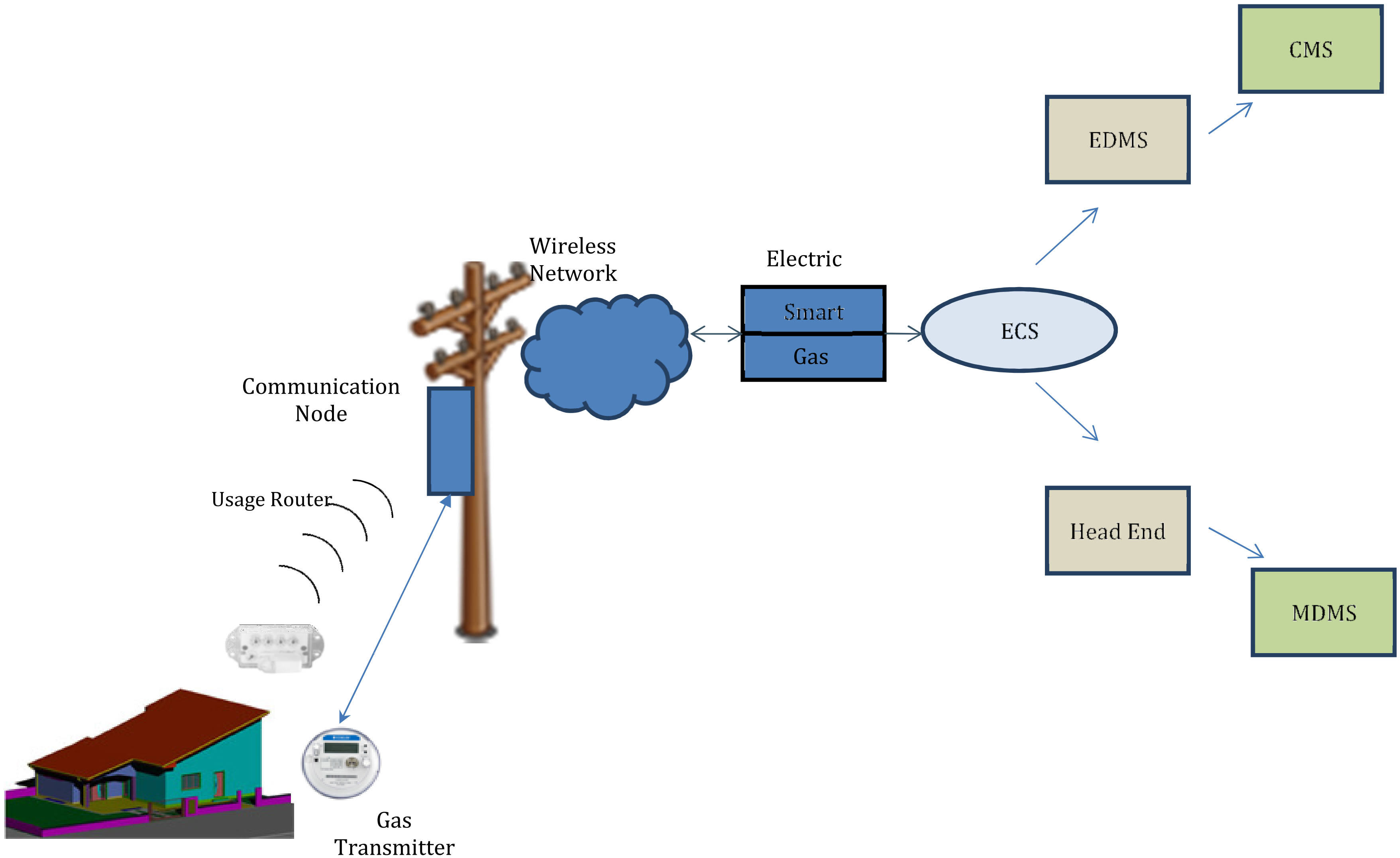
An appreciation of system architectures is helpful to understanding the System Integration findings presented in this Assessment. Though there are opportunities for integration, smart grid system architecture can be simplified by considering distinctly the two primary smart grid systems, Advanced Metering Infrastructure and Distribution Automation.

Advanced Metering Infrastructure

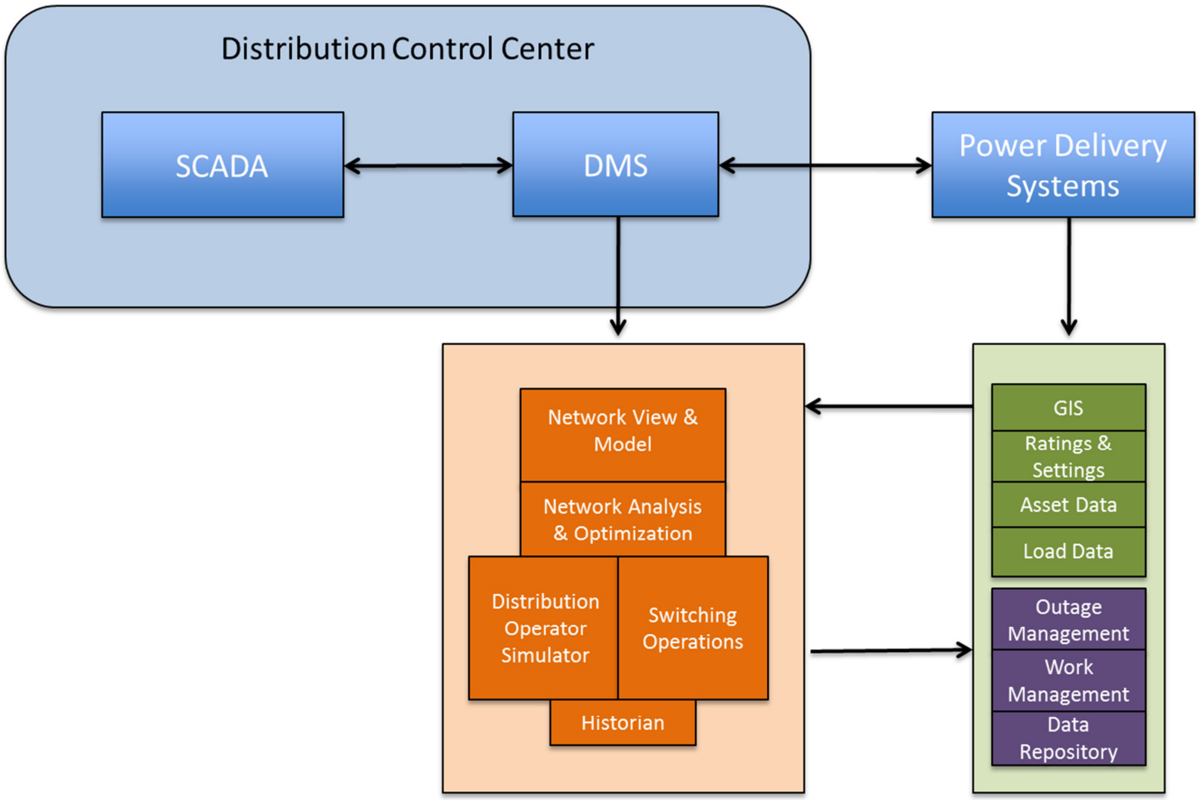
Duke Energy's Ohio AMI begins with customers' smart meters where usage data is recorded, and ends at the customers' bills where usage data is reported. A diagram of the manner in which meter data is collected, analyzed, and processed is shown below. Aspects of the metering system not associated with "smart" metering have been omitted for clarity.

Distribution Automation

Duke Energy's Distribution Automation (DA) system is the application of automated and sensing technology equipped with bi-directional communication throughout the distribution system, combined with application software, to improve energy efficiency and reliability. The Duke Energy Ohio DA system is currently being implemented.


CMS
EDMS
Wireless
Network
Electric
Smart
Gas
ECS
Communication
Node
Usage Router
Head End
MDMS
Gas
Transmitter

The plan is to deploy smart grid devices to produce operating characteristic data, such as voltage, current, etc. throughout the distribution grid. The data will be analyzed and processed in real-time to assist in grid operation and will be stored for retrospective analysis. A diagram of the planned collection, analysis, processing, and storage of grid operating data is shown below.



3.2 Methodology

The evaluation of Systems Integration consisted of both data collection efforts from a series of System Integration specific data requests and general observations made while collecting data for other components of the Assessment project. The data collection efforts specifically focused on Systems Integration consisted of the following steps:

- Inventory distribution field hardware to be installed as part of the deployment
- Inventory information systems that utilize data generated by field hardware
- Document information systems' roles in business processes, functions, usage, and data flows
- Review information systems' implementation plans (for systems not yet fully functional)
- Examine detailed customer usage data (for meter data and time-differentiated billing audits).

These data collection efforts were pursued through documentation provided by Staff and through interviews with Duke Energy personnel, information provided by Duke Energy in response to specific data requests, and a structured investigation of information technology systems, including software demonstrations and desktop research.

Inventory Distribution Automation Field Hardware to be Installed as Part of the Deployment

Staff provided a list of field hardware to be installed as part of the deployment, which was subsequently updated by Duke Energy in response to a specific data request. The updated field hardware list served as the list used for physical verification of devices and for devices used to track data from the field into EMS and the data repository.

The list of data-generating field hardware included both metering and distribution grid devices:

Advanced Metering Infrastructure Devices

- Smart (electric) Meters
- Meter (Gas) Wireless Data Transmitters

Distribution Automation Devices

- Line Sensors
- Recloser Controllers
- Capacitor Bank Controllers
- Self-healing Switches
- Voltage Regulators and Load Tap Changer Controllers
- Circuit Breaker Relays
- Remote Telemetry Units (RTUs)
- Communications Equipment

Inventory Information Systems that Utilize Data Generated by Field Hardware

MetaVu utilized a structured interview process to create an inventory of information systems that utilize or are envisioned to utilize, data generated by smart field hardware. The list of information systems included both AMI and DA systems:

Advanced Metering Infrastructure

- Electric meter data head end (the system for collecting data from smart electric meters)
- Gas meter data head end (the system for collecting data from gas meter wireless data transmitters)
- Energy Data Management System (EDMS, used to store data for use by the Customer Management System)
- Meter Data Management System (MDMS, used to store data for use by the Enterprise Customer System)
- Customer Management System (CMS, the primary customer billing system)

- Enterprise Customer System (ECS, the billing system used to create time-differentiated bills for the Duke Energy Ohio residential pilot rates).

Distribution Automation

- SCADA (Used by Duke Energy's Distribution Control Center personnel to monitor and manage the grid today)
- EMS (similar to SCADA, but focused primarily on substations and transmission)
- DMS (the epicenter of the smart grid, automating many new distribution capabilities and providing new levels of visibility and control of the distribution grid beyond the capabilities of SCADA)
- Data Historian (used as a repository of operational data)

Document How Information Systems Are Used in Business Processes and Functions

MetaVu documented how information systems are used in business processes and functions as part of the Systems Integration assessment. This documentation was accomplished through 4 primary means:

- Interviews with managers and users of various systems
- Live "white boarding" sessions with managers and users
- System demonstrations
- System documentation reviews

Review information systems' implementation plans (for systems not yet functional)

Various information systems associated with Duke Energy's Ohio smart grid deployment are being implemented over several years. While the AMI systems are already integrated and being used to bill customers today, Duke Energy plans to integrate multiple new systems into its existing distribution grid architecture by 2013. The centerpiece of these integration efforts for the DA system is the DMS.

MetaVu reviewed Duke Energy's DMS implementation plans and previewed the DMS in a test environment in order to render opinions on related System Integration. The reader is cautioned that MetaVu's assessment of systems that have yet to be implemented (such as DMS) is based on implementation plans which may change over time.

Examine detailed customer usage data (for meter data and time-differentiated billing audits)

MetaVu submitted specific data requests to Duke Energy to collect the information needed to audit billing data. Examples of such data requests include:

- Historical data from smart electric meters removed from the field for testing and corresponding historical data from various information systems associated with the smart metering infrastructure
- Remote meter reads of gas meter values simultaneous to physical inspection as part of the gas meter wireless data transmitter testing
- Real-time queries of field data from distribution grid equipment
- Historical data from the MDMS and corresponding customer bills of those participating in Duke Energy Ohio residential rate pilots.

3.3 Findings

Electric Data Audit

Staff requested that MetaVu evaluate the quality of the smart grid deployment's data communications processes and customer bill accuracy. MetaVu did this by auditing the data from specific meters and comparing it with corresponding data in the EDMS and the CMS. By examining data on both sides of a communication node, the audit tests the quality and accuracy of the communications node itself.

As part of the meter accuracy test described in Section 1, "Operational Audit", Duke Energy removed 47 smart meters that had been in operation for over 90 days. These meters were selected at random from a list provided by Duke Energy. Meter removal was observed and meter testing conducted by Alliance Calibration. Historical data available from these meters' on-board memory was downloaded by Duke Energy and provided to MetaVu for analysis. The primary data sets evaluated included energy usage measured in 15-minute intervals ("interval" data) as well as energy usage measured on a daily basis (known as "scalar" reads).

Simultaneously, MetaVu requested 15-minute interval meter data from Duke Energy's electric head end and EDMS systems. In addition, daily scalar data was requested for the electric head end, EDMS and CMS systems. MetaVu then compared the data downloaded from the meters' on-board memory to the data stored in the electric head end, EDMS and CMS system for each of the meters. (Interval data was not tracked to CMS, as CMS is not utilized for customers choosing to be billed on time-differentiated rates.) The comparison indicated that 100% of 15-minute interval and scalar data from the evaluated smart meters was accurately reflected in both the electric data head end and EDMS systems, and that scalar data was accurately reflected throughout all the systems. This result indicates that all of the components between the smart electric meter and billing system are functioning effectively:

- PLC communications from smart meters to electric data collectors
- Electric data collectors within the communications nodes located throughout Duke Energy's Ohio service territory
- Cellular telecommunications infrastructure between the communications nodes and electric data head end system
- The interface between the electric data head end system and the EDMS meter data management system
- The interface between EDMS and the CMS

Gas Data Audit

MetaVu also evaluated the quality of the data communications processes and customer bill accuracy for the gas wireless gas data transmitters installed on existing gas meters. A different process was used to evaluate the gas transmitter data communications as the equipment and data collection process is different from those employed by the smart electric meters.

The comparison of physical meter reads to the on-demand meter reads available in the gas meter data head end system revealed that the physical readings taken from the 47 meters were 100% accurately reflected in the gas meter data head end system and the EDMS system. This indicates that all of the components between the gas meter and the gas data meter head end system are functioning effectively. This includes:

- Gas meter wireless data transmitters on customers' meters
- Gas data collectors within communications nodes
- Cellular telecommunications infrastructure between the communications nodes and the gas data head end system
- The interface between the gas data head end system and the EDMS meter data management system

Time-Differentiated Billing Data Audit

MetaVu was asked to verify the accuracy of customer bills calculated under time-differentiated rates. This was accomplished by retrieving interval data from the MDMS, the last stop for interval data prior to the creation of a time-differentiated customer bill. Twenty five customer bills on the Ohio Time-of-Use pilot program were selected for analysis. Interval data corresponding with those selected customer bills was extracted from the MDMS and used to calculate billed kWh amounts by hand according to published tariffs. Hand calculations were then compared to the kWh totals in customer bills to verify accuracy. The comparison of hand calculations from MDMS 15-minute interval data to customer bills was entirely accurate for every bill on both rates.

Of the 25 customer bills, 12 consisted of TD-AM rates and 13 of TD-LITE rates.

TD-AM rating periods as defined by Duke Energy:

- Summer On-Peak Period – 12:00 p.m. to 7:00 p.m. Monday through Friday, excluding holidays
- Summer Shoulder Period – 9:00 a.m. to 12:00 p.m. and 7:00 to 10:00 p.m. Monday through Friday, excluding holidays
- Winter On-Peak Periods – 7:00 a.m. to 1:00 p.m. and 5:00 p.m. to 10:00 p.m. Monday through Friday, excluding holidays
- Winter Shoulder Period – 6:00 a.m. to 7:00 a.m. and 1:00p.m. to 5:00 p.m. Monday and Friday, excluding holidays
- Off-Peak Period – All hours Monday through Friday not included above plus all day Saturday and Sunday as well as all says designated as national holidays

TD-AM Billing Periods

- Summer period is June 1 through September 30
- Winter period is October 1 through May 31

TD-LITE rating periods as defined by Duke Energy:

- Summer On-Peak Period – 2:00 p.m. to 7:00 p.m. Monday through Friday, excluding holidays
- Winter On-Peak Period – 7:00 a.m. to 1:00 p.m. Monday through Friday, excluding holidays
- Off-Peak Period – All hours Monday through Friday not included above plus all day Saturday and Sunday as well as all days designated as national holidays

TD-LITE Billing Periods

- Summer period is June 1 through September 30
- Winter Period is defined as December 1 through February 28 (29^{th} if Leap Year)
- All other days are defined as Spring/Fall

The 12 TD-AM bills included an On-Peak, Off-Peak and Shoulder rating periods. For each period, all kWh totals were accurate for all 12 customer bills.

The data for TD-LITE rates was extracted during the spring season. Therefore, no On-Peak period was used. As a result, only Off-Peak kWh was calculated and verified as accurate in all 13 customer bills.

Billing Data Validation, Estimation, and Editing

MetaVu was asked to review the adequacy of high/low meter reading validations utilized by Duke Energy in the bill preparation process. All utilities, including Duke Energy, utilize Validation, Estimation, and Editing (VEE) routines to identify customer bills that may be incorrect prior to issue. Customer bills identified as potentially incorrect are researched and edited if necessary; bills that cannot be readily researched and edited are estimated and issued. Estimated bills are reconciled at a later date as issues (missing meter read data, for example) are resolved.

Duke Energy uses a variety of data and communications checks throughout its smart meter data collection and processing procedures. These checks appear to be appropriate and effective at identifying, raising, and resolving data collection and communication issues. The checks through and including the electric and gas data head end systems are used to evaluate the presence and integrity of the data and do not evaluate the data for reasonableness. MetaVu concentrated its evaluation on the formal VEE routines utilized in Duke Energy's EDMS and MDMS meter data management systems that do perform reasonableness testing as part of the billing process.

The VEE routines in the EDMS system, which serves as the data source for bills calculated by CMS, focus on single, daily customer energy usage reads. These daily reads are called "scalar" reads which the CMS system uses for billing purposes. Thirty-two distinct VEE routines have been developed to evaluate data from various types of customers and meter configurations. Examples of the types of evaluations that are conducted within each of these VEE routines are "Compare energy usage to corresponding meter read yesterday" or "Compare energy usage to corresponding meter read last week". In the time period examined, 1.3% of meter reads violated established EDMS VEE parameters.

The VEE routines in the MDMS system, which serves as the data source for bills calculated by ECS, focus on both scalar reads and 15-minute interval data. Evaluation comparisons similar to those conducted in EDMS are also employed by MDMS VEE routines, but are configured for and applied to interval as well as a scalar data. These enhancements are important and appropriate, as accurate interval data is critical to the accuracy of bills calculated on time-differentiated rates. In the time period examined, 2.1% of meter reads violated established MDMS VEE parameters. The increase in violation ratio is a result of tighter VEE controls established for MDMS data and higher levels of data relative to EDMS. This is an intentional measure which Duke Energy intends to use to manage the new and more detailed time-differentiated rates billed from the MDMS system.

MetaVu's review of the EDMS and MDMS VEE routines indicates that meter data validations and associated business processes are adequate and appropriate for billing purposes. However, it should be noted that the larger volume of data evaluated by the MDMS VEE routines will invariably lead to larger volumes of VEE violations in MDMS, all else being equal. As MDMS is currently utilized to generate a relatively tiny portion of residential customer bills today, this has not yet presented a significant issue. However, as more customers participate in time-differentiated rates continuous refinement of MDMS VEE routines is advised so that the volume of bills violating parameters remains manageable. In effect, MDMS VEE routines must be held to a higher standard of accuracy than those in EDMS; failure to do so may result in higher staffing levels and/or an increase in the number of estimated bills. Duke Energy is aware of this situation and is monitoring it closely for potential process improvements as MDMS billing volumes increase.

Meter Outage Data Integration for MAIFI Calculations

Staff asked MetaVu to evaluate the capability of Duke Energy's AMI system to detect and transmit data in order to calculate MAIFI (Momentary Average Interruption Frequency Index), one of several measures of grid reliability. MetaVu conducted its assessment subsequent to a Commission docket on the issue. MetaVu's MAIFI assessment included both a review of information supplied by Duke Energy Ohio as part of the docket as well as MetaVu's own investigation of MAIFI measurement options within the Duke Energy Ohio smart grid.

$MAIFI_E$ is the industry metric for average frequency of momentary service interruption events (defined as less than 1 to 5 minutes depending on the utility) and is to be calculated as follows per IEEE Standard 1366-2003:

$$\frac{Total\ Number\ of\ Customer\ Momentary\ Interruption\ Events\ (voltage = 0)}{Total\ Number\ of\ Customers\ Served}$$

Data that could be used to support the MAIFI calculations could conceivably come from two sources: the DA system or the AMI system. MetaVu's evaluation of the MAIFI issue indicates that neither approach offers a measurement that strictly complies with the IEEE calculation and that each offers pros and cons. A third option is not to measure MAIFI.

AMI-Oriented MAIFI Calculation

The smart meters Duke Energy Ohio selected for its deployment are able to count and store the number of momentary outages experienced by the meter. Duke Energy Ohio could conceivably retrieve this data on a periodic basis to calculate MAIFI. However, the meter manufacturer has verified that its meters define momentary outages as any instance in which voltage drops below 72% of nominal voltage (110 volts) for more than 12 cycles. If Duke Energy Ohio were to retrieve meter MAIFI counts, it would obtain MAIFI measures that reflected the meter manufacturer's definition and not the IEEE definition. Including the voltage drops in the MAIFI calculation introduces a number of drawbacks:

- Comparisons of Duke Energy Ohio MAIFI performance to that of utilities using the IEEE definition are difficult
- Customer activity can cause low voltage situations that would be counted in MAIFI inappropriately (as customer activity is a condition beyond Duke Energy Ohio's control)
- There are significant costs to collecting MAIFI meter data, to designing and developing software to organize and report the

MAIFI data, and for human resources to analyze and explain MAIFI report data.

Duke Energy estimated the costs associated with collecting and reporting quasi-MAIFI measures as part of the MAIFI docket. MetaVu reviewed the cost estimates and believes them to be reasonably accurate:

1. A one-time programming project - $241,515
2. Data gathering from the smart meter
   a. Daily basis - annually $524,954
   b. Weekly basis - annually $76,018
   c. Monthly basis - annually $18,646

In the event an AMI-oriented MAIFI calculation project is ordered by the Commission, MetaVu recommends that a formal project scoping and chartering exercise be completed to develop more formal project development and ongoing cost budgets. Additional ongoing costs would also be incurred such as analysis of MAIFI data, production of reports to communicate the data, and any follow-up efforts surrounding data questions or concerns.

Distribution System-Oriented MAIFI Calculation

Many of the devices to be placed on the distribution grid as part of Duke Energy Ohio's Distribution Automation effort present an alternative to AMI-Oriented MAIFI data collection, albeit with drawbacks. Many devices are intentionally designed to help avoid sustained outages, but may cause momentary interruptions in the process. Many of these devices, including reclosers, switches, and sectionalizers, will communicate operational data to a centralized data repository (the Data Historian) in Duke Energy Ohio's distribution automation design. This device operating data could be matched to the quantity of customers impacted by device operations as indicated by Duke Energy Ohio's Geographic Information System (GIS) and queried to collect the data needed for MAIFI calculations.

Unfortunately this approach to MAIFI data collection also suffers from drawbacks, including:

- Not all of the devices described above will be "smart", i.e., communicate operational data. Operating data associated with devices that don't communicate will not be available in the Data Historian and therefore would not accurately report MAIFI.
- There are significant costs to measuring MAIFI via this approach as well.

Discontinue MAIFI Reporting

The "do-nothing" alternative is also available. MetaVu does not render an opinion on this option, but did collect Duke Energy Ohio's perspectives on this issue:

- As customers prefer momentary outages to sustained outages, Duke Energy Ohio believes that System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are more appropriate measures of reliability than MAIFI.
- Duke Energy Ohio believes that improvements in SAIDI and SAIFI performance are often accompanied by deteriorating MAIFI performance. As evidence the Company cites that an outage that would have affected 2,500 customers for 2 hours in a traditional grid environment might impact 1,000 customers for 2 hours and 1,500 customers for only 1-5 minutes in a smart grid environment.

Distribution Automation Systems Integration

Duke Energy plans to implement a DMS to serve as the centerpiece of its distribution automation effort. DMS is critical to the achievement of distribution automation objectives. While smart grid field hardware generates large amounts of data, economic and reliability benefits stem from the manner in which the DMS translates the data into actionable information and automated execution. Note that some reliability benefits are available upon installation and do not require a DMS to deliver value. Duke Energy plans to interface many systems that currently operate independently to the DMS. A detailed 3-year deployment plan has been developed and execution is well underway. Resources and project management appear to be sufficient to execute the plan as scheduled. These observations indicate that the DMS deployment plans reviewed by

MetaVu are likely to be followed and that findings based on the deployment plans are relevant and valuable. This determination was made by MetaVu at the time of publishing this report and changes to future deployment plans may alter MetaVu's determination.

The deployment plans indicate that the following utility systems are to be integrated fully with the DMS:

- SCADA
- Distribution Outage Management System (DOMS)
- Workforce Management System (WMS)
- Data Historian

The plans also call for the DMS to make use of several types of data generated by systems that are not fully integrated, including:

- Geographic data
- Ratings and Settings data
- Capacity
- Asset data
- Load data

While many distribution automation economic benefits are based largely on a functioning DMS, much of the smart hardware being installed by Duke Energy today has immediate reliability benefits that are not DMS-dependent. Examples include automated sectionalizers and reclosers that isolate faults and reduce the number of customers affected by an outage.

As the DMS is being deployed, MetaVu suggests that a corresponding change management plan be developed and executed. The DMS (and the smart grid in general) offers new capabilities and multiple opportunities to create value for customers. Many organizational changes may be required to capture value for customers and some are already underway. Examples are numerous but include:

- Resource requirements may drop in some departments, such as meter reading, but increase in others, such as information technology.
- Distribution Control Centers may need to develop new processes for field crew dispatch as outage management and sectionalization become more automated.
- Field crews may need to develop new skills to be able to configure and troubleshoot the more sophisticated field hardware critical to DMS performance.
- Distribution capacity planning and reliability engineering have access to extremely large quantities of historical data which may help prioritize and optimize grid development.
- Reliability performance metrics and incentives may need to change as increases in some metrics (such as MAIFI) are necessary to enable improvements in other, more important metrics (such as SAIDI and SAIFI as described above).

A comprehensive change management plan oriented to smart grid capabilities can be extremely valuable in maximizing the value of smart grid investments and should address a variety of organizational and operational enhancement opportunities. These include:

- Changes to organizational strategy, structure, and resources suggested by smart grid efficiencies and opportunities (some of which are currently being evaluated by Duke Energy)
- Changes to operational processes, governance, policies, incentives, and performance metrics as dictated by smart grid capabilities
- Changes to information systems and tools to take advantage of new data types and characteristics
- Changes to organizational and human capabilities as existing capabilities are made redundant and new capabilities are required

Meter Data Integration

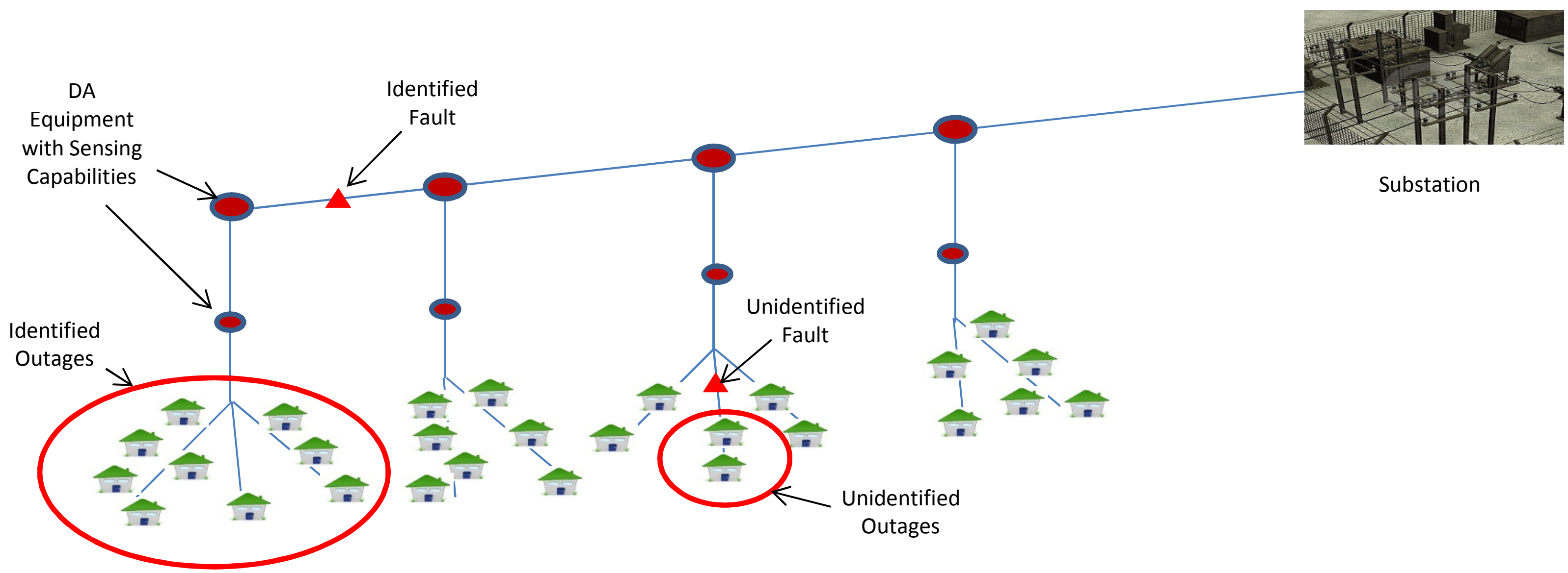
MetaVu found that the Duke Energy smart grid deployment is characterized by a distinction between smart metering systems, such as AMI and DA and the associated systems like DMS as described above. While MetaVu has found that this is typical among U.S. smart grid deployments it has examined, increased integration of meter data into the DMS and other systems nonetheless offers opportunities to increase the value of smart grid investments. Smart grid capabilities also present more general opportunities to improve the integration of business processes to maximize benefits. Although the size of the benefits and associated deployment costs vary widely between smart grid deployments, a few examples of potential meter data and business process integration include:

- Meter status for proactive outage detection
- Meter data for power quality (voltage)
- Meter data for capacity planning
- Meter data for load management verification
- Substation condition monitoring (such as oil temperature, pressure, and gas levels).

Meter status for proactive outage detection

One of the benefits commonly touted for the smart grid is that the utility, historically dependent on customer phone calls to identify outages, is now able to proactively identify outages without customer assistance. MetaVu's examination of the Duke Energy smart grid deployment indicates that the proactive outage notification capability will be available with the DMS deployment and the planned integration with DOMS with some limitations.

MetaVu's review of DMS deployment plans indicates that DA equipment will monitor and report data in real-time and that a combination of software and hardware will automatically take appropriate actions to minimize the number of customers impacted, alert repair crews, and alert the distribution control center. Outages must occur within the footprint monitored by smart devices for them to be identified. Outages that occur outside a DA-enabled area of the distribution grid will not be detected automatically.



(See the diagram above for an illustration of an outage outside the footprint of a smart device.) In these instances Duke Energy Ohio will still need to rely upon customers to report outages.

This issue is common to most smart grid deployments. Duke Energy is addressing the issue to some extent by deploying battery back-ups in selected communications nodes which enables exception reporting when the power goes out. There may be several ways to address this issue if deemed sufficiently important to customers, but all involve costs and tradeoffs. Additional cost/benefit analyses would be required to evaluate options and compare to customer-perceptions of value.

Meter data for power quality (voltage)

A similar situation exists for voltage reduction and management. The IVVC module in the DMS automatically adjusts the voltage of a feeder to ensure voltage is no higher than necessary yet still meets customer performance expectations. Reducing voltage in this manner avoids large amounts of electric generation and reduces customer fuel costs over the course of a year. Various smart grid designs employ different methods to determine a level that is no higher than necessary.

In traditional distribution grid designs, voltage is measured and controlled at the substation and in these designs customer complaints represent the feedback mechanism to let a utility know if voltage settings are too low. Utilities traditionally err on the side of caution, setting voltage higher than necessary to avoid complaints.

In the planned Duke Energy smart grid deployment, voltage is (generally) controlled at the substation but measured by the line sensors closer to customer premises at the “end of the line” (the location on a feeder where voltage issues are most prevalent). This can present a significant improvement as the DMS adjusts substation voltage continuously, in real-time, to a level with less safety margin. This reduces the amount of electric generation required for a given level of energy usage. A safety margin, though smaller, must still be employed as the voltage between the line sensors and customer premises must still be estimated.

In some smart grid deployments voltage measurements utilized by a DMS are taken at customer meters. This permits an even smaller safety margin, but comes with increased data collection costs. One solution may lie in identifying those customer premises located at the end of the line. Regular monitoring of voltage data from only these customers could serve as proxies for all the other customers on the line, reducing associated data collection costs. One limitation of this solution is that grid operating decisions based on a small customer subset (with potentially greater voltage variation) may be sub-optimal. Duke Energy is currently conducting several IVVC tests to better quantify the pros and cons of various approaches.

Meter Data for Capacity Planning

Historically, detailed meter data from individual customer premises can be aggregated by feeder, lateral, or transformer to dramatically improve the understanding of capacity needs. A better understanding of capacity “needs” can lead to improved transformer sizing and improved investment prioritization which can create beneficial delays in capital spending, improvements in reliability, and reductions in line losses.

In the course of MetaVu’s assessment there were many instances in which Duke Energy employees mentioned how meter data could be used in a Circuit Modeling Tool (CMT), a software tool which simulates various circuit load scenarios, to achieve these benefits. However, the effort to integrate meter data into the CMT appears to be in a very preliminary evaluation stage. MetaVu recommends that Duke Energy continue to pursue this potentially valuable integration effort.

A utility’s overall approach to data integration is important to maximizing smart grid value and merits some discussion. Some utilities are resolving the need for multiple applications to use the data generated by smart grid components through the use of a data “bus”. In traditional IT architectures, individual interfaces are built between an application and each of the other applications with which it must share data; this can result in higher maintenance costs and operational complexities. In bus architecture, applications send data to the bus, and other authorized applications pull data from the bus. Bus systems can reduce the effort required to integrate systems due to the relative ease of configuration and reductions in ongoing maintenance relative to traditional IT architectures. Of course, these benefits must be weighed against the considerable cost of implementing bus architecture.

Duke Energy IT policies state a clear preference for bus architectures, and MetaVu did find an example of bus architecture being used to integrate electric and gas meter data head end systems with the EDMS and MDMS meter data management systems. MetaVu believes the benefits of increased use of bus architectures within smart grid environments are potentially significant and likely worthwhile when viewed with a long-term perspective.

Meter Data for Customer Product and Program Optimization

Duke Energy's Power Manager® program helps the Company better manage peak loads by cycling participating customer's air conditioning compressors during peak demand periods through the use of wirelessly controlled switches. One drawback of such programs is that communication with the switches is unidirectional; that is, utilities can signal control intentions to the switches but there is no feedback to ensure the controls were implemented. A number of factors, from AC replacement to radio communications interference, can explain the difference between expected and actual load reductions from such programs.

Interval data collected from smart meters can be used to help confirm the accurate operation of Power Manager switches. This is only one of a number of examples in which smart grid capabilities can be employed to enhance energy efficiency and load management programs and portfolios. Another example is Duke Energy's use of customer interval data to establish usage baselines for Peak Time Rebate rate incentive calculations.

Substation Monitoring, Exception Reporting, and Forensic Analysis

Substation failures are rare, but result in widespread and sometimes extended outages as well as significant expenditures for repair. The upgrade of communication and data processing capabilities at the substation is a significant component of smart grid deployments and provides new opportunities for substation condition monitoring, exception reporting, and forensic analysis.

Although it is outside the scope of Duke Energy's initial smart grid business case, the monitoring of substation transformer oil characteristics, voltages, and other metrics in real-time offers a wealth of information to substation operators. MetaVu has observed that the incremental cost of monitoring devices is fairly minimal once enabling communications and data processing capabilities are installed in substations as part of smart grid designs. Forensic analysis can also be applied to historical monitoring data in the event of substation failure to facilitate root cause analysis in support of ongoing reliability improvement efforts. Software that analyzes the data and makes it actionable is necessary for these applications and increased employee costs may also apply.

4 GUIDELINES AND PRACTICES CONFORMITY ASSESSMENT

4.1 Introduction

Staff asked MetaVu to assess the degree to which the Duke Energy Smart Grid has been deployed in a manner consistent with the NIST Smart Grid guidelines and industry best practices as well as to identify the potential areas of improvement for complying with the guidelines and best practices.

The Assessment was conducted by MetaVu project partner OKIOK, an information technology (IT) and infrastructure security consultancy firm with specific expertise in secure data transfer, encryption and IT security compliance. The Assessment focused on the degree to which “Guidelines for Smart Grid Cyber Security” (NISTIR 7628) are addressed by the Duke Energy Ohio Smart Grid architectural design, implementation, and functions as well as Duke Energy corporate policies, standards, and procedures.

In addition to the conformity with the NISTIR 7628 that identifies high-level security requirements, privacy recommendations, and common vulnerabilities, OKIOK assessed whether Duke Energy adopted the guidelines identified and selected by the NIST Smart Grid Interoperability Panel (SGIP) and whether Duke Energy acknowledged industry security best practices. Thus the guidelines and practices included in the Assessment consisted of:

- NISTIR 7628 Volume 1 – High-level Security Requirements
- NISTIR 7628 Volume 2 – Privacy
- NISTIR 7628 Volume 3 – Common Vulnerabilities
- SGIP Interoperability
- Security Best Practices

About the NISTIR 7628

The security, privacy, and vulnerability issues covered by the NISTIR 7628 are a work in progress, scheduled to be updated every 18 months. They were chosen by the Cyber Security Working Group (CSWG) from existing standards documents such as NIST Special Publication 800-53 Recommended Security Controls for Federal Information Systems, DHS Catalog of Control Systems Security: Recommendations for Standards Developers, and NERC CIPs (1-9).

The NISTIR uses the word “requirement” to refer to security measures that are generally considered best practices or required to protect against well-known attack scenarios. *The use of the word “requirement” does not in any way imply that a specific measure is required in order to meet a given standard*. This document retains the “requirement” nomenclature utilized by the NISTIR 7628 for consistency.

How the NISTIR 7628 Was Used in the Assessment

Following the assessment of conformity with the NISTIR 7628, the families of controls and the practices associated with high risk were analyzed in more detail. Along with a brief description of the weaknesses identified, OKIOK provided hypothetical security break scenarios as well as high-level recommendations for Duke Energy to consider in order to mitigate the risk.

The NISTIR 7628 recommends that the organization perform a risk assessment on each individual smart grid information system in order to evaluate the impact level of a security breach and to decide which security requirements are to be selected. A risk assessment of this nature can only be performed by the organization itself and was not in the scope of this Assessment.

The Guidelines and Practices Conformity Assessment is valuable as it not only provides a mapping of the NISTIR 7628 security requirements with Duke Energy smart grid security controls but also evaluates the level at which the identified controls satisfy these requirements. The results provided by this assessment illustrate the conformity, alignment or congruity of the Duke Energy Smart Grid with the NISTIR 7628 and present to the reader a snapshot of the security controls in place in the Duke Energy Smart Grid.

Although the Assessment identified which existing controls from the Duke Energy smart grid conform with the NISTIR 7628 and to what level, it does not include evaluation of the effectiveness of the Duke Energy controls. Particularly, technical verifications on production systems such as penetration testing, having the purpose of identifying potential weaknesses of the Duke Energy security controls, were not within the scope of this Assessment.

Section Organization

A description of the Methodologies used to complete the Assessment follows this Introduction. Findings are organized into areas of investigation specified by Staff:

- The NIST Standards Development Process
- Conformity with Evolving Standards or Guidelines
- Risks of Nonconformity
- Practices Posing Redeployment Risks

4.2 Methodology

This section describes the methodology that was followed throughout the Guidelines and Practices assessment.

Review of the NIST Guidelines Development Process

Prior to assessing the conformity with evolving standards, the process used by the NIST Smart Grid Interoperability Panel to develop smart grid related guidelines and frameworks was reviewed.

In particular, OKIOK's review covered the two principal deliverables of the SGIP Cyber Security Working Group "Guidelines for Smart Grid Cyber Security" or NISTIR 7628 and "Standards for Consideration by Regulators". All five "families" of standards selected from those established by the International Electrotechnical Commission (IEC), were analyzed in order to observe current and potential future enforcement of recommended practices.

Assess Conformity with Evolving Standards and Guidelines

Following the identification of standards, guidelines, and best practices to be used as a reference for the assessment, recommended practices were analyzed resulting in a checklist of conformity items that covered all security requirements and recommendations within the scope of the assessment.

In order to correctly assess the conformity of the Duke Energy smart grid, data requests were placed with the purpose of receiving the documentation necessary for the Assessment. In the case where the responses to the data requests were not clear or incomplete, more specific data requests were placed. Overall, more than 600 documents were provided by Duke Energy and analyzed during the Guidelines and Practices Assessment.

Upon receipt of the responses to the data request, the documentation provided by Duke Energy was analyzed and the conformity of an item on the checklist was evaluated to one of the following values:

- *Fully conforms* – the documentation provided shows evidence and provides reasonable assurance that the security requirements or recommendations assessed are satisfied by security controls in place
- *Partially conforms* – the documentation provided shows evidence that some aspects of the security requirements or recommendations assessed are satisfied by security controls in place
- *Does not conform* – evidence providing reasonable assurance that the requirements and recommendations are addressed by existing security controls was not observed

Conformity items for which OKIOK did not observe either positive or negative evidence of satisfaction of the security requirements or recommendations by controls, were evaluated as "Does not conform".

Preliminary results were provided to Duke Energy in the form of working papers in order to provide feedback and stimulate discussions. These discussions typically resulted in additional supporting documentation being provided by Duke Energy which was considered and evaluated during the assessment.

- Ideally, a security assessment would evaluate the satisfaction of all the security requirements and recommendations on each logical interface between the various smart grid information systems. Such an approach was infeasible within a reasonable timeframe and effort, due to the large number of smart grid logical interfaces and requirements and recommendations assessed and, was beyond the scope of work specified by Staff. A more practical methodology used to assess the conformity with items originating from the various sources is described below.

NISTIR 7628 Volume 1 – High level requirements

The NISTIR 7628 Volume 1 provides three types of security requirements:

- Governance, risk and compliance (GRC) requirements
- Common technical requirements
- Unique technical requirements

GRC requirements were evaluated against existing governance objects, i.e. internal policies, standards or guidelines applying either specifically to the Duke Energy smart grid or to the entire organization. For these types of requirements, evidence was sought that 1) governance objects addressing the GRC requirements exist and 2) that they are applied in practice. Documentation was accepted in various formats, such as internal policies, standards, procedures, reports, presentations, meeting notes, and emails.

Common technical requirements were evaluated against security controls in place for all smart grid information systems. For these types of requirements, evidence was sought that procedures, guidelines or tools to implement security controls were available and in use for smart grid information systems.

Finally, unique technical requirements were evaluated against security controls in place for specific smart grid information systems within the logical interface category to which the requirements are assigned. Similar to the common technical requirements, evidence of the controls being in place for systems assigned to the corresponding interface type, was sought.

Throughout the NISTIR 7628 Volume 1, requirements are allocated to impact levels, i.e. low, medium or high. The organization is expected to perform a risk assessment in order to evaluate the impact associated with a cyber security breach affecting the smart grid information systems and to select those requirements that apply to the evaluated impact level for each component of the smart grid information system. Performing an impact assessment on all of the Duke Energy smart grid information systems was not within the scope of this project. In addition, the requirements that were not allocated to any impact level were not evaluated during this assessment as they are provided as guidance for organizations that seek security requirements necessary to address specific risks and needs.

The objective of the NISTIR 7628 Volume 1 assessment was to provide a quantitative statement of conformity with proposed requirements. Because some proposed requirements are composed of several conformity items these items were assessed individually, as described previously, and evaluated to the following numerical scores:

- Items in Full Conformity were assigned a score of 100%
- Items in Partial Conformity were assigned a score of 50%
- Items in Not in Conformity were assigned a score of 0%

Following the evaluation of individual items, scores were aggregated and averaged to classify requirement conformity into one of the following categories:

- Requirements with an average score between 75% and 100% were assessed as Fully Conforming
- Requirements with an average score between 25% and 74% were assessed as Partially Conforming
- Requirements with an average score between 0% and 24% were assessed as Not Conforming

NISTIR 7628 Volume 2 – Privacy

The NISTIR 7628 Volume 2 – Privacy identifies potential privacy issues and provides recommendations based on the consumer-to-utility Privacy Impact Assessment (PIA) performed by the NIST SGIP privacy subgroup.

Similar to the GRC security requirements, privacy recommendations were evaluated against existing governance objects, i.e. written internal policies, standards or guidelines, applying either specifically to the Duke Energy smart grid or to the entire organization. For these types of requirements, evidence was sought that 1) governance objects addressing the GRC requirements exist and 2) that they are applied in practice. Documentation was accepted in various formats, such as internal policies, standards, procedures, reports, presentations, meeting notes, and emails.

The objective of the NISTIR 7628 Volume 2 assessment was to provide a quantitative statement of conformity with privacy recommendations.

NISTIR 7628 Volume 3 – Common vulnerabilities

The NISTIR 7628 Volume 3 presents analyses and references supporting the high-level security requirements described in Volume 1. In particular, chapter 6 presents a list of identified vulnerabilities that could adversely impact the operation of the electric grid. Therefore, the vulnerabilities presented in this section are matched to the security requirements described in Volume 1. The purpose of this list of potential vulnerabilities is to feed the risk analysis process for the smart grid information systems.

The objective of the NISTIR 7628 Volume 3 assessment was to identify whether the common technical vulnerabilities described are "acknowledged" by Duke Energy. For example, if a particular type of vulnerability was identified or tested by Duke Energy or by a third-party performing testing on behalf of Duke Energy on smart grid information systems, that certain type of vulnerability is considered to be acknowledged by Duke Energy for the purpose of this assessment.

It is important to note that if a vulnerability is assessed as being acknowledged by Duke Energy, it does not necessarily mean that all occurrences of that vulnerability have been detected or even that the identified occurrences of the vulnerability have been fixed. It simply signifies that Duke Energy is aware that the type of vulnerability in question can occur within the smart grid.

The approach used for the assessment of the NISTIR 7628 Volume 3 was also selected for the assessment of conformity with the recommendations from technical best practices, including NIST Physical Security Guidelines and Open Web Application Security Project (OWASP) Top 10 Web Application Security Risks.

Interoperability Standards

The Duke Energy Ohio smart grid deployment was assessed to evaluate the current and planned usage of interoperability standards selected by NIST. These standards generally describe communication protocols and data representation formats and are used to achieve logical interoperability. The approach selected was to identify and report on any reference to interoperability in the form of architecture and planning guidelines, specification and development requirements, or Request for Information / Proposal (RFI / RFP) criteria.

Risks of Nonconformity

One of the objectives of the Guidelines and Practices Conformity Assessment was to identify potential risks of nonconformity with emerging national guidelines and best practices. OKIOK performed an analysis of the NISTIR 7628 guidelines in order to identify the impact that each security requirement has on the potentiality of a security breach to occur. The security requirements described in the NISTIR 7628 Volume 1 were grouped into three categories:

- High Potentiality
- Medium Potentiality
- Low Potentiality

The logic supporting the grouping of requirements in categories of potentiality of a security breach to occur is presented above. It is important to note that this grouping was performed by OKIOK based on its experience in the field of information security and on actual or theoretical security breaches observed throughout the various projects it performed over the years.

High Potentiality

Requirements that have a direct and immediate impact on the probability of a security breach to occur, such as access control and prevention against malicious code, were grouped in the High Potentiality category. For example, access controls that prevent unauthorized access to critical systems are placed in this category.

Medium Potentiality

Requirements that have a medium-term impact on the probability of a security breach to occur, such as mechanisms that allow for the detection of security breach attempts by using monitoring and logging or requirements that address the response and restoration is case of a breach, were grouped in the Medium Potentiality category.

These requirements are considered to be at a lower level than the High Potentiality requirements because the absence of a detection mechanism by itself does not allow an attacker to modify the behavior of a system. However, an attacker might attempt to breach a certain system for a period of time without success until a particular context arises that allows the attacker to successfully attack the system. In this example, having a detection mechanism in place would allow the organization to detect that breach attempts are occurring and react accordingly.

Low Potentiality

Finally, requirements that have a long-term impact on the probability of a security breach to occur, such as policies, procedures, and standards ensuring that the security mechanisms are effective, updated, tested, and implemented throughout the organization when required, are grouped in the Low Potentiality category. Once again, these requirements are considered of a lower level than the High and Medium Potentiality requirements in the sense that the absence of security policies does not represent an immediate risk if the appropriate security controls are in place.

However, as the smart grid environment evolves, existing security controls might be deactivated in order to satisfy compatibility and operational needs, new systems might not have the security controls in place, and evolving systems might not have their security controls updated to address the changes that occur. In this context, the presence and enforcement of governance objects in the form of policies, procedures, and standards ensures the homogeneity and adequacy of security controls in place.

For the purpose of identifying risks of nonconformity with emerging guidelines, OKIOK analyzed the conformity of the current Duke Energy Ohio smart grid implementation with the NISTIR 7628 security requirements versus the potentiality of a security breach of each of these requirements.

The families of requirements that were found to have 25% or more of requirements associated with a high potentiality of a security breach **and** found to be in non-conformity were considered *High Risk*.
These families were analyzed in more detail by describing the weaknesses identified and presenting risk scenarios that illustrate the potential consequences of a security breach.

Finally, for each high risk family analyzed, OKIOK offers high-level recommendations for Duke Energy to consider in order to mitigate identified risks.

Identify Practices Posing Risks of Redeployment

Based on documentation analyzed during the security conformity assessment and on industry best practices, OKIOK identified practices that pose a risk that, if deemed unacceptable, may result in having to fix or redeploy components and systems.

Similar to the presentation of non-conformity risks, practices posing significant risks are analyzed in more detail by describing the weaknesses identified and presenting risk scenarios to illustrate the potential consequences of a security breach.

Finally, OKIOK considered countermeasures that could be put in place to mitigate identified risks. OKIOK recommends that Duke Energy perform a detailed and quantitative risk assessment for each of these risk scenarios to evaluate the potential cost associated with the security breach as well as the cost of implementing countermeasures. Based on OKIOK's analysis, Duke Energy might choose to accept the risk, implement the proposed countermeasures, or implement alternative countermeasures.

4.3 Findings

Findings are organized into areas of investigation specified by Staff.

- The NIST Standards Development Process
- Conformity with Evolving Guidelines
- Risks of Nonconformity
- Practices Posing Redeployment Risks

The NIST Standards Development Process

As outlined in the Energy Independence and Security Act of 2007 (EISA), NIST has been given "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems."[2]

NIST initiated the SGIP to fulfill its responsibility to coordinate standards development for the Smart Grid. Established in 2009, the SGIP is a public/private partnership comprised of over 600 member organizations representing 22 stakeholder categories, including federal agencies as well as state and local regulators.

[2] Public Law 110 - 140, *Energy Independence and Security Act of 2007*, available at http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/content-detail.html.

Figure 4.3.1 illustrates the SGIP structure, as presented on the SGIP Wiki Collaborative Site.[3]

In 2009, NIST created the Cyber Security Coordination Task Group which was renamed the Cyber Security Working Group or CSWG, as part of the SGIP. The two major work efforts that have been completed by the CSWG are discussed in this section

- "Guidelines for Smart Grid Cyber Security" (NISTIR 7628)
- Standards Review

As discussed previously, the EISA assigns NIST with the responsibility of developing a framework for smart grid protocols and standards. The EISA also gives the Federal Energy Regulatory Commission (FERC) the authority to adopt smart grid standards:

> *"At any time after [NIST's] work has led to sufficient consensus in the [FERC's] judgment, the [FERC] shall institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets"*[4]

However, as identified by the Government Accountability Office (GAO), FERC does not have the authority to enforce smart grid related standards:

> *"While EISA gives FERC authority to adopt smart grid standards, it does not provide FERC with specific enforcement authority. This means that standards will remain voluntary unless regulators are able to use other authorities—such as the ability to oversee the rates electricity providers charge customers—to enforce them."*[5]

The remainder of this section describes the two major work efforts that have been completed by the CSWG as well as its three-year plan.

[3] NIST Smart Grid Wiki Collaboration Site, http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPAbout. .

[4] Public Law 110 – 140, *Energy Independence and Security Act of 2007*, available at http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/content-detail.html.

[5] GAO Report 11-117, *Electricity Grid Modernization: Progress Being Made on Cybersecurity Guidelines, but Key Challenges Remain to Be Addressed*, available at http://www.gao.gov/products/GAO-11-117.

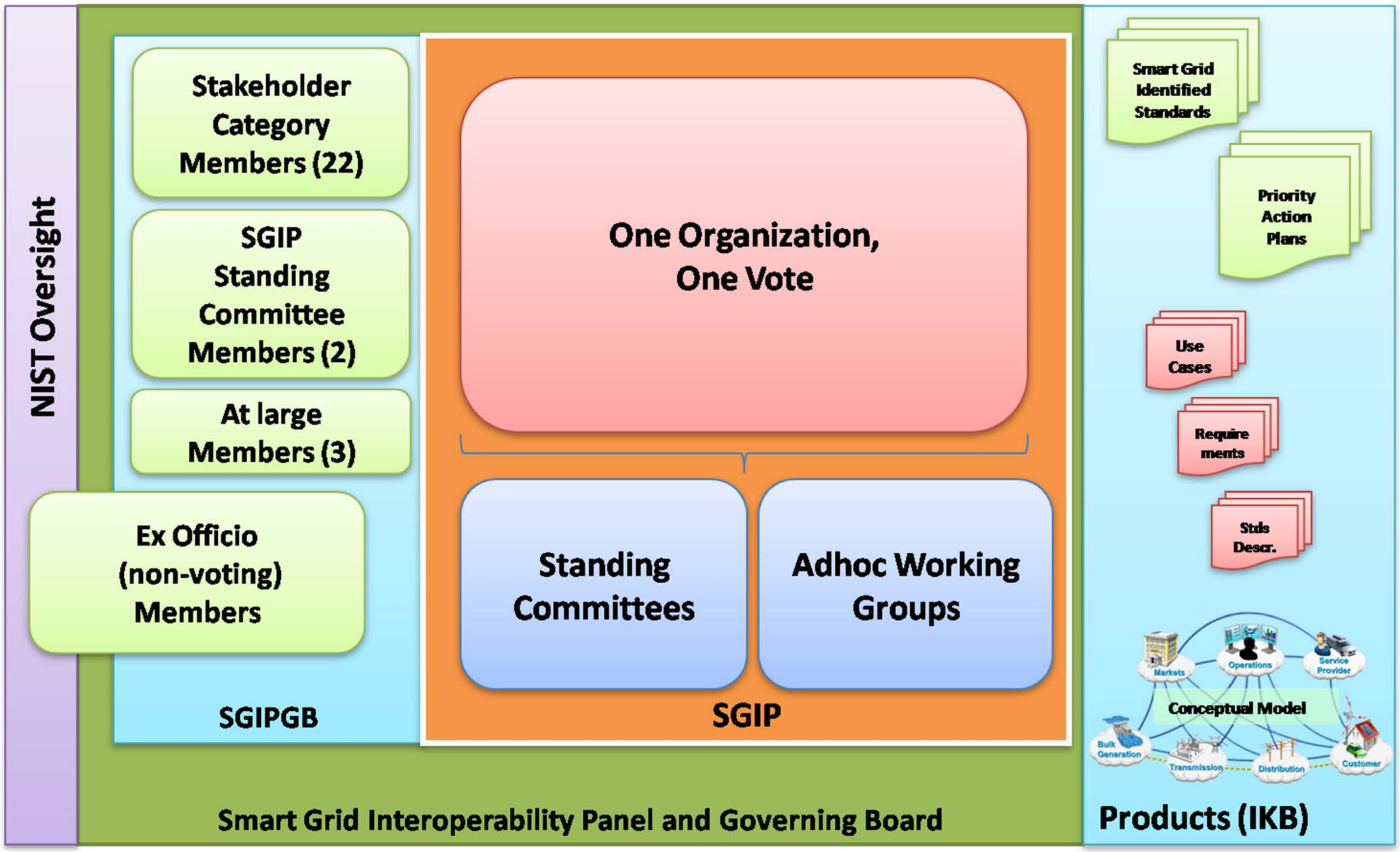


Figure 4.3.1 - NIST Smart Grid Interoperability Panel (SGIP) structure

Guidelines for Smart Grid Cyber Security

The "Guidelines for Smart Grid Cyber Security" (NISTIR 7628) is both a starting point and a foundation for developing a smart grid security strategy. As described in the CSWG 3-Year Plan[6], the first installment of the smart grid cyber security guidelines - NISTIR 7628 v1.0 is:

- An overview of the cyber security strategy used by the CSWG to develop the high-level cyber security Smart Grid requirements
- A tool for organizations that are researching, designing, developing, implementing, and integrating smart grid technologies—established and emerging
- An evaluative framework for assessing risks to smart grid components and systems during design, implementation, operation, and maintenance
- A guide to assist organizations as they craft a Smart Grid cyber security strategy that includes requirements to mitigate risks and privacy issues pertaining to Smart Grid customers and uses of their data.

The NISTIR 7628 defines a smart grid logical reference model by associating smart grid actors to 22 logical interface categories and identifying the interactions between elements in each category. It then presents a set of high-level security requirements, each of these being associated with some or all of the logical interface categories. In addition, the document matches each security requirement to one or more impact levels (i.e. low, moderate, high) resulting from the loss of a component or service.

The organization designing, implementing, or operating smart grid information systems is expected to develop a specific smart grid security architecture and allocate security requirements to each smart grid information system, using the NISTIR 7628 as a starting point. Because of the uniqueness of each smart grid deployment, the organization must take into account particularities of its smart grid systems such as constraints posed by the device and network technologies used, co-habitation with legacy systems, regulations and policies and cost criteria when selecting the smart grid security requirements. In addition, the organization is expected to perform a risk assessment in order to evaluate the impact associated with a cyber security incident affecting the smart grid information systems and to select those requirements that apply to the evaluated impact level for each component of the smart grid information system.

Finally, the NISTIR 7628 was not written in a way in which conformity can be easily assessed or enforced. Instead, as described previously, it is suggested as a toolkit for organizations developing a smart grid security strategy.

Standards Review

In January 2010, NIST published the "Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0"[7]. The report identifies existing technical standards likely to be applicable to a smart grid and prioritizes future action. In addition, in October 2010, NIST advised the FERC that five families of standards fundamental for smart grid interoperability were "ready for consideration by regulators"[8]:

- IEC 61970 and IEC 61968: Provide a Common Information Model (CIM) necessary for exchanges of data between devices and networks, primarily in the transmission (IEC 61970) and distribution (IEC 61968) domains.
- IEC 61850: Facilitates substation automation and communication as well as interoperability through a common data format.

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[6] *CSWG Three-Year Plan*, The Smart Grid Interoperability Panel – Cybersecurity Working Group, April 2011, available at http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/CSWGRoadmap/CSWG_three_year_plan_final_April2011.doc.

[7] NIST SP - 1108, NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0, available at http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf.

[8] NIST -identified Standards for Consideration by Regulators, Release 1.0, October 6, 2010, available at http://www.nist.gov/public_affairs/releases/upload/FERC-letter-10-6-2010.pdf.

- IEC 60870-6: Facilitates exchanges of information between control centers.
- IEC 62351: Addresses the cyber security of the communication protocols defined by the preceding IEC standards.

In January 2011, FERC held a technical conference on Smart Grid Interoperability Standards[9] to aid determination of whether there is "sufficient consensus" that the five families of standards are ready for the Commission's consideration in a rulemaking proceeding. The statements presented at the FERC technical conference argued that an insufficient number of experts in cyber security have been involved in selecting the standards and that there has not been sufficient consensus.

Emerging Standards

In April 2011, the CSWG published its three-year plan[10] identifying future activities, which are listed in this section:

- Participate in the Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) public-private initiative to develop a harmonized energy sector enterprise-wide risk management process, based on organization missions, investments, and stakeholder priorities.
- Identify cyber and physical vulnerabilities, threats, and the potential impact on the current power grid and augment the NISTIR 7628 high-level requirements to address the combined cyber-physical attacks.
- Expand coordination with the SGTCC to develop guidance and recommendations on smart grid conformance, interoperability, and cyber security testing.
- Update the NISTIR 7628 every 18 months to reflect evolving standards, regulations, threats and risks.
- Continue outreach activities to explain how the NISTIR 7628 can be used.
- Coordinate CSWG activities with federal agencies and industry groups.
- Continue face-to-face meetings for technical working sessions, planning and coordination activities.
- Maintain liaison with Priority Action Plans (PAP) to ensure cyber security is covered where required.

In addition, the following milestones have been proposed for standards review reports:

- Smart Meter / AMI – related standards (Q2 FY11)
- Institute of Electrical and Electronics Engineers (IEEE) 1547 and other standards related to renewable energy sources (Q3 FY11)
- IEEE 1686 and other standards related to substation intelligent electronic devices (IEDs) (Q3 FY 11)
- Demand Response (DR) and HAN-related standards (Q3 FY11)
- Electric vehicle-related standards (Q4 FY11)
- Cyber security-related standards (Q1 FY12)
- New standards developed (Q1 FY11 – Q4 FY13)

Conformity with Evolving Guidelines

For the purpose of identifying conformity with evolving guidelines, OKIOK assessed the conformity of the Duke Energy smart grid with the "Guidelines for Smart Grid Cyber Security" (NISTIR 7628), interoperability standards and best practices.

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[9] FERC Technical Conference on Smart Grid Interoperability Standards, January 31, 2011, http://www.ferc.gov/eventcalendar/Files/20110114074853-1-31-11-agenda.pdf.

[10] *CSWG Three-Year Plan*, The Smart Grid Interoperability Panel – Cybersecurity Working Group, April 2011, available at http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/CSWGRoadmap/CSWG_three_year_plan_final_April2011.doc.

The NISTIR 7628 was released by NIST in August 2010. Duke Energy has initiated work with a third-party consultancy firm to better understand how the NISTIR 7628 applies to its smart grid environment and how it relates to its existing security guidelines.

NISTIR 7628 Volume 1 – High Level Requirements

This section presents the quantitative evaluation of conformity with the NISTIR 7628 volume 1 – high-level requirements.

Figure 4.3.2 illustrates the families of requirements described in the NISTIR 7628 volume 1 and the number of requirements from each family that are in full, partial or non-conformity. Although the families with longer bars in Figure 4.3.2 do not explicitly represent the importance of one family over another, the longer bars are associated with a greater number of requirements listed for that particular family.

The families with the highest number of requirements in full conformity are [redacted]

The families with the lowest number of requirements in conformity are [redacted]

In order to better visualize the alignment with the NISTIR 7628 requirements we group requirements in full and partial conformity and illustrate the conformity percentages associated with such requirements in Figure 4.3.3.

[redacted]

[redacted]

[redacted]

Finally, Figure 4.3.4 illustrates the percentage of requirements in full or partial conformity compared to those not in conformity based on the category of requirements, i.e., GRC, Common Technical, or Unique Technical.

The detailed list of NISTIR 7628 volume 1 requirements as well as the evaluation of conformity for each requirement is presented in Appendix 3-A – Conformity with the NISTIR 7628.

Figure 4.3.2 – Number of requirements in full, partial and non conformity, per family

Figure 4.3.3 - Percentage of requirements in full, partial and non conformity, per family

Figure 4.3.4 - Percentage of requirements in full, partial and non conformity, per category

NISTIR 7628 Volume 2 – Privacy

This section presents the qualitative evaluation of conformity with the NISTIR 7628 volume 2 – privacy recommendations.

Main Alignment Points:

- Duke Energy has enterprise-wide privacy and procedures in place.
- Notification is provided by the Peak Time Rebate Pilot program informing the consumer that personal consumption baselines will be created.
- The Peak Time Rebate Pilot and the Time of Use Rate Plans are opt-in pilots.
- Evidence of restricting the data collected by the residential electric meter to only that which is necessary, although driven by data transmission costs, was found.
- Evidence of a draft Customer Data Management document including privacy requirements for managing smart grid specific data was found. Although the Customer Data Management document assessed had not been approved by management, it shows Duke Energy's intent of augmenting the current privacy policy and standards to address smart grid data.

Main Gaps:

- The current Personal Information Privacy Policy describes the requirements for protecting the privacy of personal information, for example, health information, social security number, consumer report, and first and last name. The policy does not make reference to energy data collected and processed by smart grid systems as being private or as being protected by the same measures as the Personal Information.
- Evidence of notification being sent to customers, prior to the time of collection describing what data is being collected, the intended use, retention, and sharing of the data, when and why data items are being collected and used without obtaining consent, when and how information may or may not be shared with law enforcement officials, whether new data is being collected, whether there are new information use purposes, and the consumer options was not found.
- Explicit policies, procedures, and guidelines limiting the association of energy data with individuals to only when and where required, de-identifying data when possible, and excluding private information from internal and external research were not found.

NISTIR 7628 Volume 3 – Common Vulnerabilities

This section examines the degree to which the common vulnerabilities listed in the NISTIR 7628 volume 3 are acknowledged by Duke Energy.

Evidence of acknowledgement of the majority of the technical vulnerabilities listed in the NISTIR 7628 volume 3 was found. It is important to note that evidence indicates that Duke Energy employs tools and techniques or has processes and procedures in place that allow it to detect or prevent these vulnerabilities from occurring. However, acknowledgement does not necessarily imply that Duke Energy addressed all occurrences of the vulnerabilities.

The list of vulnerabilities is presented in Appendix 3-C – Evaluation of Common Vulnerabilities Acknowledgement.

Interoperability Standards

This section presents the qualitative evaluation of conformity with interoperability standards.

Main Alignment Points:

- Duke Energy currently implements or follows several open standards and standard families:

  [redacted]

  [redacted]

  [redacted]

[redacted]

- Duke Energy acknowledges the importance of the NIST SGIP and the selection by NIST of the five smart grid interoperability standard families: IEC 61970, IEC 61968, IEC 61850, IEC 60870 and IEC 62351.
- Architecture guidance to give preference to solutions implementing the Common Information Model (CIM) related standard is in place.
- Documentation proposing the implementation of open standards facilitating interoperability at the network, syntactic and semantic levels between the various smart grid components was found.

Main Gaps:

- Formal documentation of management commitment for ensuring the adoption of interoperability standards was not observed.
- Evidence of the five families of standards selected by NIST (IEC 61970, IEC 61968, IEC 61850, IEC 60870 and IEC 62351) being part of Smart Grid solutions requirements was not found.
- A roadmap for adopting interoperability standards was not found.

Security Best Practices

This section presents the qualitative evaluation of conformity with industry security best practices.

Main Alignment Points:

[redacted]

Main Gaps:

[redacted]

Risks of Nonconformity

For the purpose identifying risks of nonconformity with emerging standards, OKIOK analyzed the conformity of the current Duke Energy smart grid implementation with the NISTIR 7628 security requirements versus the potentiality of a security breach of associated with each of these requirements.

Figure 4.3.5 illustrates all of the security requirements assessed from the NISTIR 7628. The horizontal axis represents the level of conformity of Duke Energy smart grid with the requirements assessed. The leftmost column in Figure 4.3.5 represents Full Conformity and is illustrated in green signifying that there is no significant risk associated with the requirements listed in this column. The vertical axis represents the impact on the potentiality of a security breach. The upper row represents a high potentiality, which translates to an immediate impact on the probability that a security breach will occur. For this reason, the upper rightmost cell is illustrated in red to represent the highest risk.

For the detailed results of conformity with the NISTIR 7628 requirements the reader is invited to see Appendix 3-A – Conformity with the NISTIR 7628.

Similarly, the detailed results of the impact on the potentiality of a security breach to occur for the NIST 7628 requirements are presented in Appendix 3-B – Potentiality of a Security Breach.

In the rest of this section the families of requirements that are associated with a high risk are analyzed. The following families were found to have [redacted] of requirements in non-conformity and with high potentiality of a security breach:

[redacted]

For each family identified above, risk scenarios that illustrate the potential consequences of a security breach are presented. Note that the risk scenario presented is not exhaustive and variations of the scenario or other scenarios might be feasible. Finally, for each family a high level recommendation describing the type of countermeasure that could potentially be put in place to mitigate the risk is proposed.

For a detailed quantitative description of the percentage of requirements in full, partial or non-conformity in each family as well as a mapping with the evaluation of the potentiality of a security breach see Appendix 3-D – Potentiality of a Security Breach vs. Conformity.

Figure 4.3.5 - Mapping of the security requirements with the conformity level and the potentiality of a security breach

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5 OPERATIONAL BENEFITS

5.1 Introduction

The Staff asked MetaVu to evaluate and assess the operational benefits from smart grid implementation. Staff defined these as benefits that have either accrued to the benefit of Duke Energy or may reasonably be expected to accrue to Duke Energy in the future. Staff provided information on Duke Energy's original smart grid business case to MetaVu on a confidential basis. MetaVu used the original business case as a starting point for its assessment.

Thirty Operating Benefits were identified by Duke Energy in its original business case. Several of these benefits were consolidated into others, some were determined to be out of scope as defined by Staff, and a few new benefits were identified, resulting in a total of twenty five Operating Benefits evaluated by MetaVu and presented here. Each benefit was classified into one of four saving types based on how the benefit is likely to be recognized in existing rate making processes. These savings categories include:

- Avoided Operations and Maintenance Cost
- Avoided Fuel Cost
- Deferred Capital
- Increased Revenue.

Several benefits identified by Duke Energy Ohio in the original business case as customer benefits (such as time-differentiated rate and reliability) or societal benefits (such as environmental) were defined as out of scope for the Audit and Assessment.

The Operational Benefits section begins with a description of the methodology used to estimate the Net Present Value or NPV of the twenty five Operating Benefits. A "Benefits Summary" presents analyses of synthesized Operational Benefit estimates. Finally, each of the twenty five Operating Benefits is presented individually including:

- The estimated 20-year net present value of the individual benefit and the percentage of the total that the Benefit represents
- Savings Category to which the benefit relates
- Background on how the benefit results from smart grid capabilities
- The drivers that most significantly impact the size of each benefit
- Modeled economic benefits by year until steady state is achieved

Charts are used to illustrate key points. Supporting details and methodologies are available in the Appendix as indicated.

5.2 Methodology

MetaVu completed multiple calculations to evaluate and forecast potential benefits from Duke Energy's Ohio smart grid deployment. In 2008, Duke Energy provided a business case outlining the various benefits anticipated from its Ohio Smart grid deployment. MetaVu considered the business case and approaches employed by Duke Energy to calculate various benefits in light of other MetaVu experience and available information, including:

- MetaVu's experience in evaluating Xcel Energy's SmartGridCity™ demonstration project
- Measurement frameworks and performance benchmarks from the Electric Power Research Institute
- American Recovery and Reinvestment Act smart grid evaluation metrics
- Information from the regulatory dockets of other utilities pursuing smart grid projects (including Oklahoma Gas and Electric and Baltimore Gas and Electric).

After considering such inputs MetaVu developed revised versions of benefit calculations to be applied to the Ohio smart grid deployment.

To better understand how calculations could be accurately applied and to validate various calculation inputs, a series of data requests were submitted to Duke Energy. These data requests resulted in formal responses and meetings with Subject Matter Experts (SMEs). Data captured from data request responses and SME meetings allowed MetaVu to accurately estimate and forecast smart grid benefits. As data was provided to MetaVu for analysis, additional data and meetings with SMEs were requested to refine and supplement previously delivered information and provide a robust understanding of the Duke Energy smart grid's capabilities.

After evaluating data request responses, SME meeting notes, and supplemental information, MetaVu forecast annual benefits from 2009 to 2028 (20 years) to estimate the NPV of each. For some larger or more highly variable benefits, MetaVu calculated high case, base case, and low case estimates. Results presented in this report are base case estimates unless otherwise indicated.

5.3 Benefits Summary

In total, MetaVu estimated the NPV of smart grid benefits at $382.8 million. A series of summary tables and charts are presented to facilitate conclusions about detailed Operational Benefit estimates:

- Summary of Base Case Estimate Data by Operational Benefit
- Chart of Relative NPV Size by Operational Benefit
- Low-, Base-, and High-Case NPV Comparison Chart
- Chart of NPV by Savings Category
- Chart of NPV by Investment Type (AMI vs. DA)
- Operational Benefit Ranking by NPV Size Chart

Figure 5.3.1 lists the Operating Benefits and details the 5-year total, 20-year total, and 20-year NPV of each.

Figure 5.3.2 indicates the relative size of NPV by Operational Benefit.

Figure 5.3.3 illustrates the summary of benefits in high, mid, and low cases. Some benefits were calculated with varying assumptions, providing low-, base- and high-case scenarios to provide the reader insight on the possible variances of the benefit calculation.

Figure 5.3.4 represents the breakdown of benefits by accounting categories Avoided O&M Cost, Avoided Fuel Cost, Deferred Capital, and Increased Revenue. It should be noted benefits 4 and 13 create value for two different categories.

Figure 5.3.5 compares the total benefits provided by the Distribution Automation (DA) and Advance Metering Infrastructure (AMI) systems.

Figure 5.3.6 sorts all the benefits by value based total 20-year NPV totals.

Figure 5.3.1 Summary of Base Case Estimate Data by Operational Benefit

Benefit Number	Infrastructure Category	Benefit	Savings Category	5-Year NPV BASE	20-Year Total BASE	20-Year NPV BASE
1	AMI	Regular meter reads	Avoided O&M Cost	$ 3.75	$ 125.28	$ 49.86
2	AMI	Off-cycle / off-season meter reads	Avoided O&M Cost	$ 8.33	$ 123.43	$ 53.96
3	AMI	Remote meter diagnostics	Avoided O&M Cost	$ 0.74	$ 16.07	$ 6.53
4 & 5[11]	AMI	Power theft (4) - Recovery Costs (5)	Increased Revenue	$ 0.92	$ 19.47	$ 7.94
6	AMI	Meter operations – Avoided capital costs	Capital Deferment	$ 2.03	$ 40.28	$ 16.58
7	AMI	Meter operations – Decreased annual expenses	Avoided O&M Cost	$ 0.29	$ 5.91	$ 2.43
8	AMI	Meter accuracy improvement	Increased Revenue	$ 0.98	$ 20.87	$ 8.51
9	AMI	Meter Salvage Value	Increased Revenue	$ 0.45	$ 0.93	$ 0.66
10	AMI	Outage Detection	Avoided O&M Cost	$ 0.07	$ 1.44	$ 0.59
11	AMI	Outage Verification	Avoided O&M Cost	$ 0.64	$ 12.68	$ 5.22
12	AMI	Outage – Incremental Revenue	Increased Revenue	$ 0.62	$ 14.96	$ 5.64
13	DA	24/7/365 System Voltage Reduction Strategy	Mostly Avoided Fuel Cost	$ 7.48	$ 389.92	$ 155.57
14	DA	Power Shortage Voltage Reduction	Capital Deferment	$ 0.07	$ 2.15	$ 0.86
15	DA	Continuous Voltage Monitoring	Avoided O&M Cost	$ 0.06	$ 4.37	$ 1.71
16	DA	VAR Management	Capital Deferment	$ 0.87	$ 22.54	$ 9.26
17	DA	Asset Management	Capital Deferment	$ -	$ 3.00	$ 1.89
18	DA	System Fine-tuning	Mostly Avoided Fuel Cost	$ 0.03	$ 18.74	$ 7.17
19	DA	Capacitor Inspections	Avoided O&M Cost	$ 0.05	$ 3.57	$ 1.39
20	DA	Circuit Breaker Inspections	Avoided O&M Cost	$ 0.10	$ 1.86	$ 0.77
21	AMI	Call center efficiency	Avoided O&M Cost	$ 0.14	$ 2.75	$ 1.13
22	AMI	Increase in safety	Avoided O&M Cost	$ 0.10	$ 2.28	$ 0.93
23	AMI	Billing savings – Shortened billing cycle	Avoided O&M Cost	$ 0.12	$ 1.78	$ 0.74
24	AMI	Vehicle Management	Avoided O&M Cost	$ 1.22	$ 24.83	$ 10.21
25	DA	Fuel Cost Reduction through VAR reduction	Avoided Fuel Cost	$ 0.18	$ 9.31	$ 3.73
26	DA	Wholesale sales due to freed-up capacity	Increased Revenue	$ 0.05	$ 81.54	$ 29.52
TOTAL				$ 29.29	$ 949.96	$ 382.79

[11] Benefits 4 & 5 have been combined as one benefit.

Figure 5.3.2 Chart of Relative NPV Size by Operational Benefit - Base case in millions

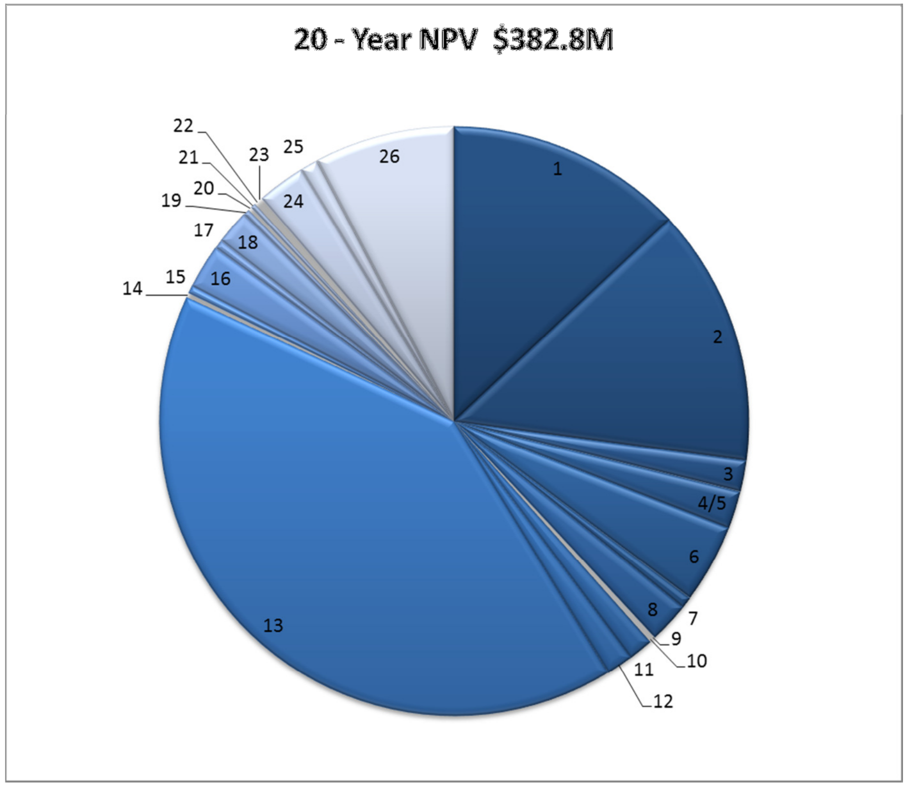


Figure 5.3.3 Low-, Base-, and High-Case NPV Comparison Chart

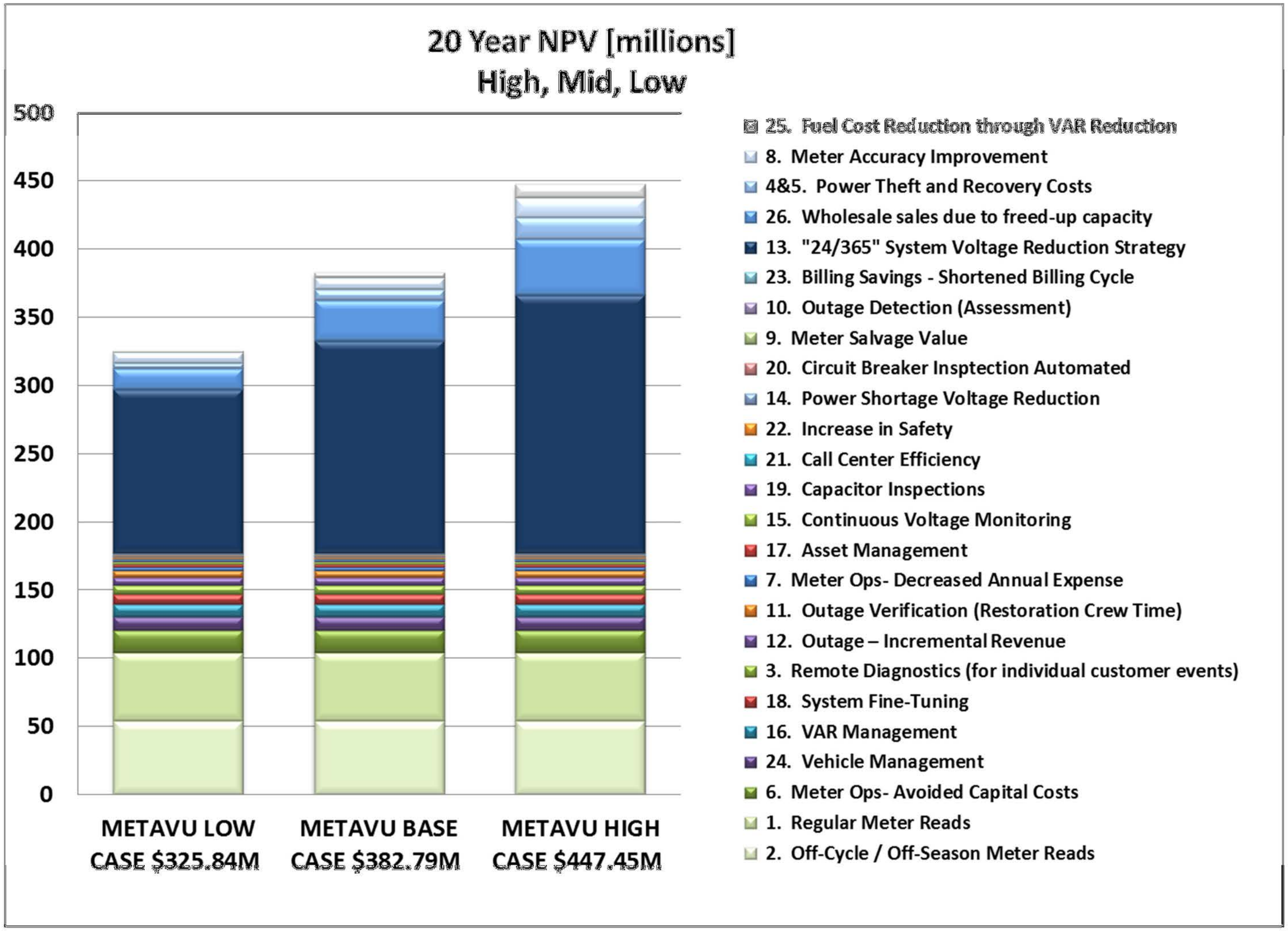


Figure 5.3.3 illustrates the summary of benefits in low, base, and high cases. Some benefits were calculated with varying assumptions, providing low, base, and high scenarios to provide the reader insight on the possible variances of the Operational Benefit estimates.

Figure 5.3.4 Chart of NPV by Savings Category

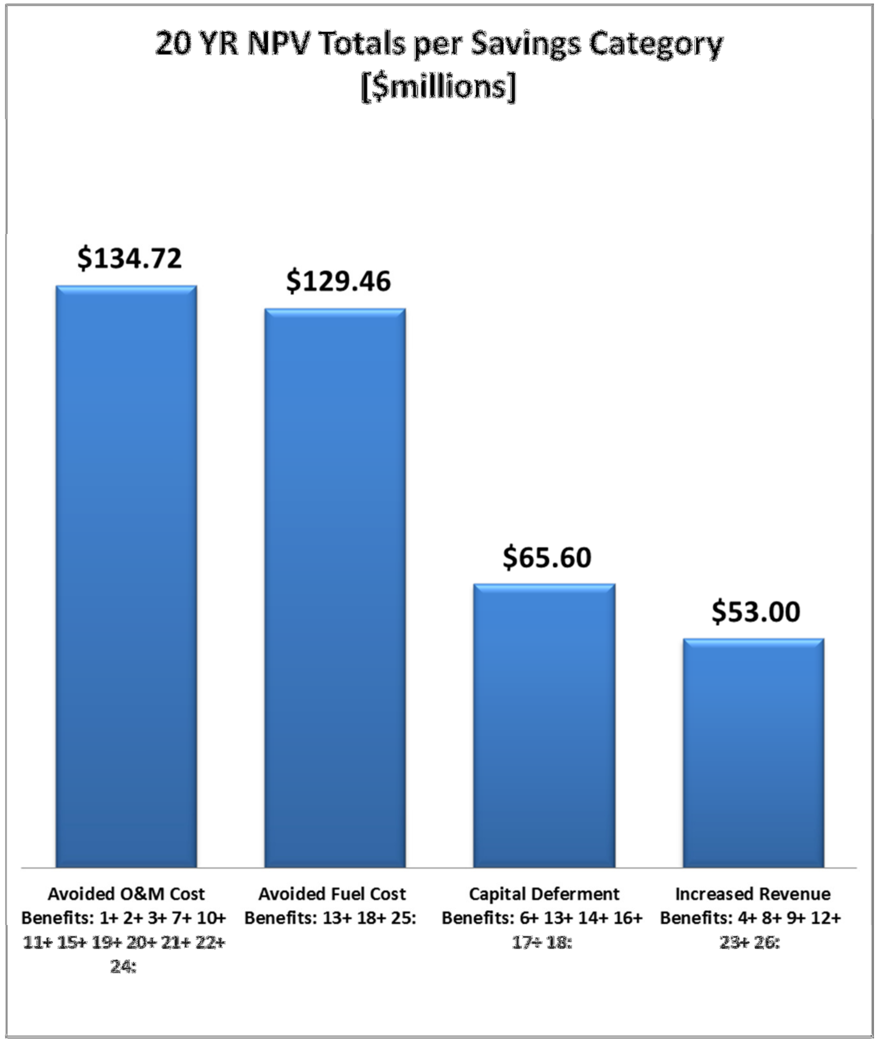


Figure 5.3.4 represents the breakdown of benefits by Savings Categories: Avoided O&M Cost, Avoided Fuel Cost, Deferred Capital and Increased Revenue. Note that A) Benefits 13 and 18 create value for two different categories; B) Lost Margins have been netted out of Benefit 26; and C) Theft recovery costs have been netted out of Benefit 4

Figure 5.3.5 Chart of NPV by Investment Type (DA = Distribution Automation; AMI = Advanced Metering Infrastructure)

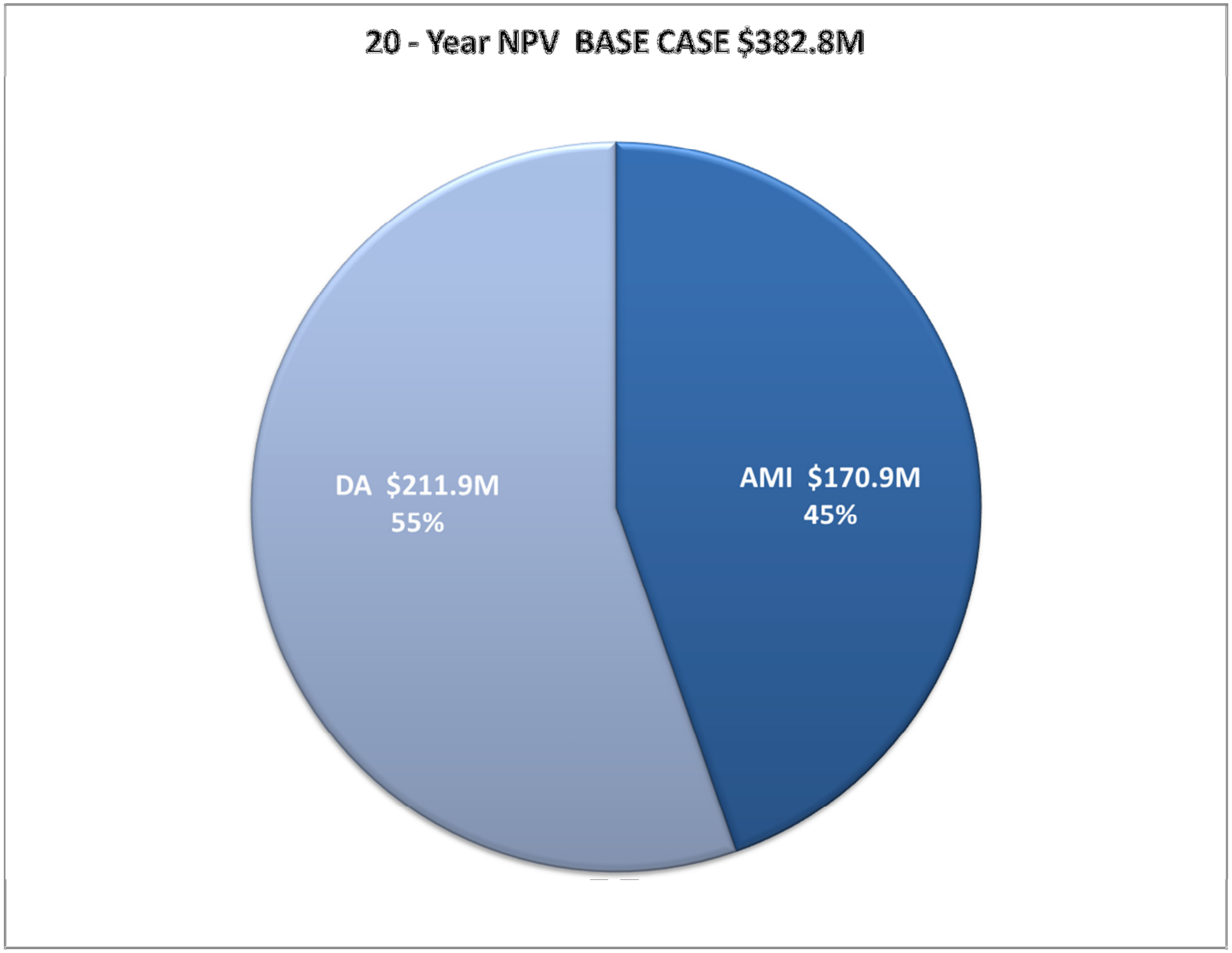


Figure 5.3.5 compares the total benefits provided by the Distribution Automation (DA) and Advanced Metering Infrastructure (AMI) investments. Note that outage-related benefits are provided by a combination of DA and AMI.

Figure 5.3.6 Operational Benefit Ranking by NPV Size

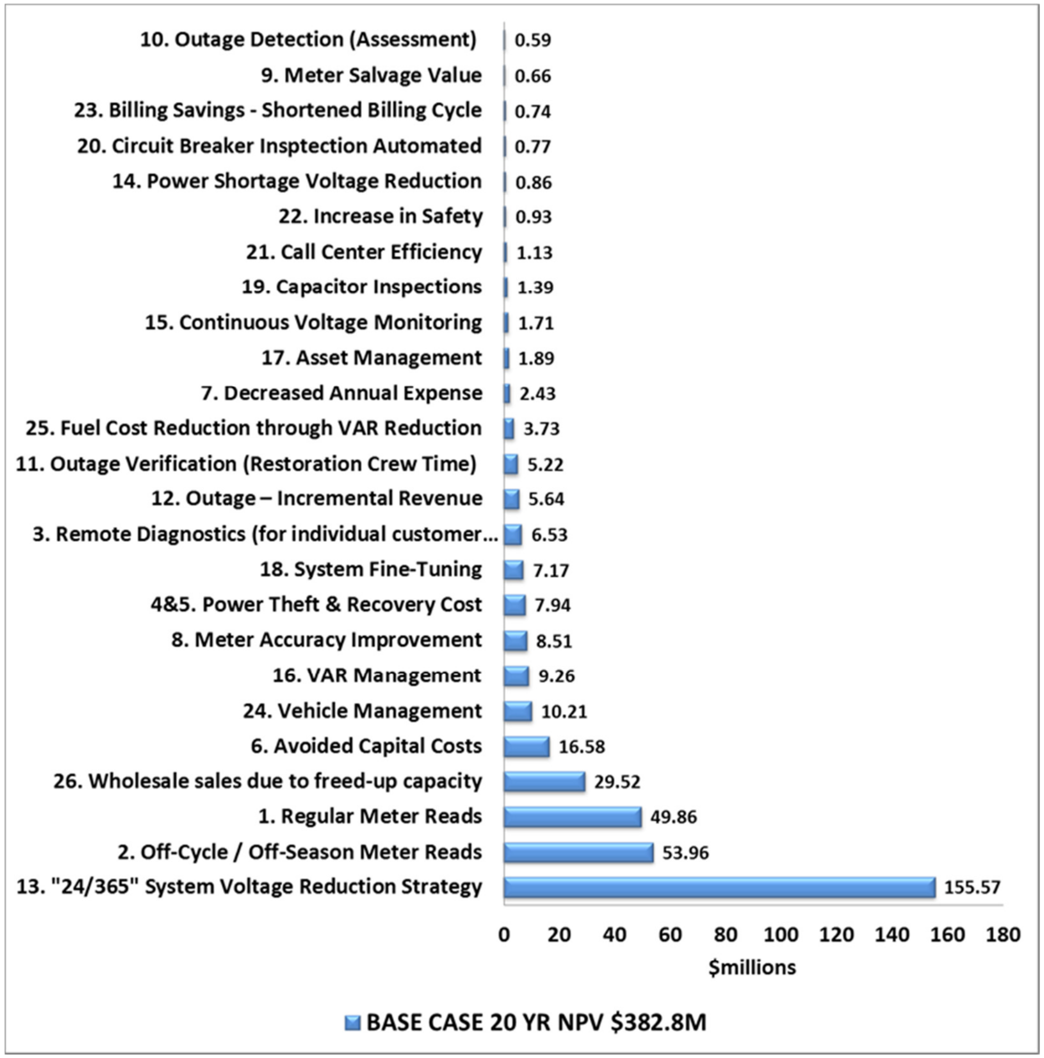
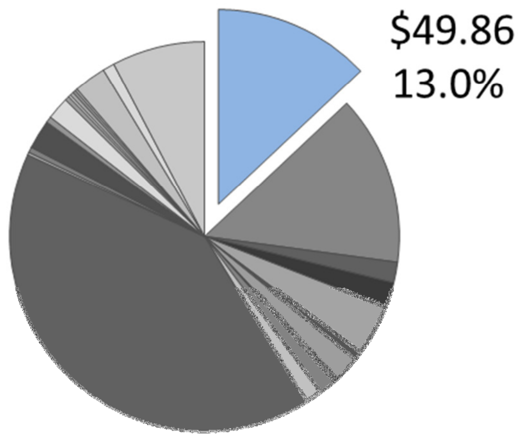


Figure 5.3.6 ranks Operational Benefits by base case 20-year NPV.

5.4 Findings

Regular Meter Reads (Benefit 1)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

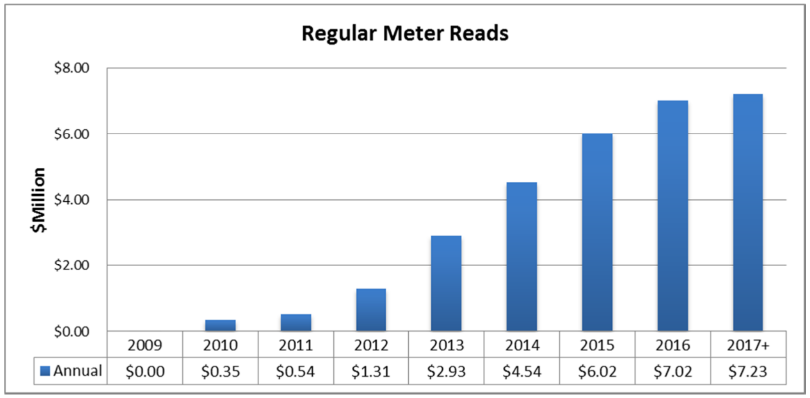
- AMI technology will eliminate the majority of on-cycle manual Meter Reading as smart meters are deployed. The benefit value consists of a labor cost reduction from Meter Reading staff. The benefits from reducing Meter Reading vehicles is captured in benefit number 25.
- Duke Energy in Ohio has traditionally employed Meter Readers to manually read meters on a monthly basis. This process consists of individuals walking from house to house to capture electric and gas meter data with handheld equipment. Meter Readers then provide meter data to the utility for billing purposes. With the deployment of smart meters, metering data is communicated via a wireless network to the utility. As data is sent directly to the utility, the need for most manual meter reads will be eliminated with corresponding reductions to Meter Reading staff. It is anticipated some staff will be required to occasionally read meters manually for potential failure of smart meters or smart meter communications and for periodic gas safety checks of gas meters.
- Relative to other U.S. geographies, manual meter reading is particularly expensive in Duke Energy's Ohio territory as a significant number of meters are located within customers' premises. To access the meters, Meter Readers may need to schedule and reschedule appointments which is resource intensive, cumbersome, and inconvenient to customers.
- Electric smart meters capture energy usage data on a 15 minute basis. Communications nodes placed on distribution transformers collect meter data. Wireless data transmitters are placed upon traditional gas meters and regularly provide gas readings to the same communication nodes. The communications nodes transmit electric and gas meter data wirelessly on a daily basis to Duke Energy for bill processing.
- It is anticipated the Meter Reading department that covers Duke Energy's Ohio footprint will be reduced. Approximately half of remaining Meter Reader time will be allocated to meter reading activities. The other half will address gas meter safety inspections which regulatory rules require every 3 years.
- Smart meter data provides granular data that can be accessed through a "Customer Portal", providing customers with insights on usage, including historical analysis and usage compared to weather temperatures.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

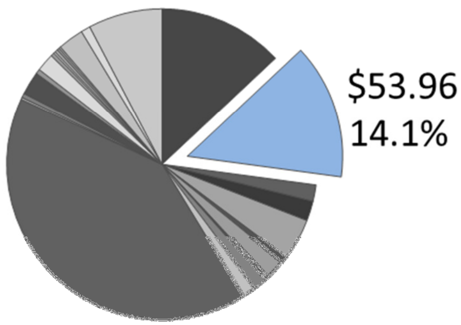
- The deployment rate of smart electric meters and gas modules
- Annual meter reading labor costs for Duke Energy Ohio
- Meter Reader reduction resulting in meter reading route consolidation and Full-Time-Equivalent (FTE) reduction
- Labor inflation rates

Modeled Economic Benefits



Off-Cycle/Off-Season Meter Reads (Benefit 2)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

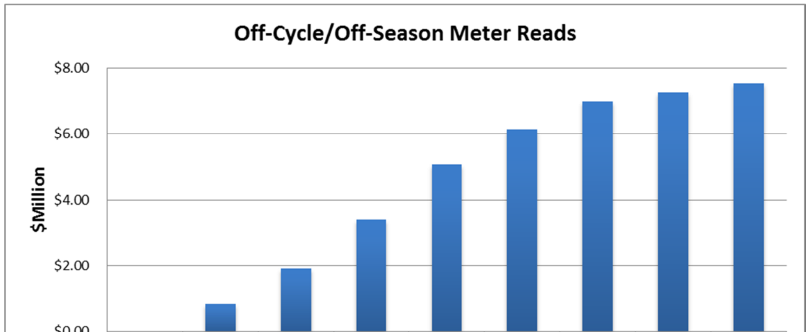
- AMI technology will eliminate a portion of the meter reads not associated with regular monthly reads. These reads, classified as Off-Cycle / Off-Season Reads, are more accurately defined as "Meter Orders". Meter Orders include meter reads outside the typical billing cycle such as move-ins and move-outs, customer requested service additions, and cancellations. The feasibility of remote disconnects for non-payment were also evaluated as providing potential value. This benefit measures the labor costs associated with these meter order activities.
- Duke Energy in Ohio has traditionally employed field technicians to physically read meters outside of the standard billing cycle window, generally when customers move-in or move-out of a residence. In addition, customers often request energy to be turned on or shut off, which requires a field technician to physically turn off service. These voluntary Meter Orders can now be conducted remotely with smart meter deployment. If a customer calls to indicate they are moving to or leaving a premise, the call center can arrange a remote meter read for that date. For activation or deactivation of service (often due to move-ins or move-outs), a customer can call and indicate when service should be turned on or off remotely. Remote shut off of service is not available for gas meters for safety reasons.
- Smart electric meters and gas modules have the capability to be read through a real-time meter read. This allows the utility to conduct an instantaneous read outside of the standard billing cycle. Smart electric meters have remote connect/disconnect capabilities at the customer request that allow the utility to activate or deactivate service without sending an individual to do it manually. (Note that gas meters do not have remote connect/disconnect capabilities and field technician visits are required.)
- Traditionally, service disconnects due to non-payment have been completed physically by a field technician. It was originally anticipated that remote disconnect capabilities could create value by not deploying a field technician to manually disconnect the electric meter for reason of non-payment. However, regulations require a Duke Energy employee to physically notify the customer of an upcoming involuntary electricity disconnect by leaving a door hanger at the customer's premise. This regulation requiring a person to visit the premise prior to disconnecting service eliminates the benefit for remote disconnects due to non-payment.
- Benefits for non-payment remote disconnects could be achieved if changes to current regulatory rules were enacted. Reductions in uncollectible account write-offs might also be available.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- The deployment rate of smart electric meters and gas modules
- Annual Meter Order labor costs for Duke Energy Ohio
- Reductions in FTE positions
- Regulatory requirements for disconnections of service
- Labor inflation rates
- Vehicle and fuel costs

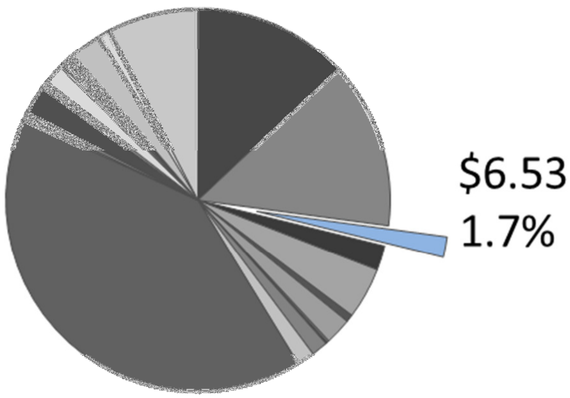
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.84	$1.92	$3.41	$5.07	$6.14	$6.98	$7.25	$7.52

Remote Meter Diagnostics (Benefit 3)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

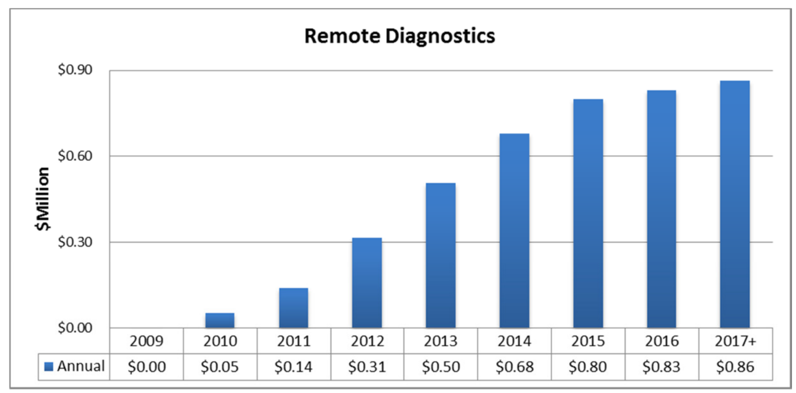
- With the ability to conduct real-time remote diagnostics of smart meters, smart grid technology provides system dispatchers with the ability to reduce trouble dispatches that end up being unnecessary when the problem is determined to exist on the customer's side of the meter. A reduction in the number of these dispatches translates into a reduction of labor needed to address these calls.
- With traditional meters, Duke Energy did not have the capability to understand if a customer issue was on the utility or customer-side of the meter until after a field technician physically investigated the problem. If the issue was on the customer-side, no further action was required by the utility and the customer would need to contact an electrician. AMI technology allows for the utility to conduct a real-time remote diagnostic to determine if the meter is operating normally. If the meter is receiving voltage, no field personnel are sent to investigate.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

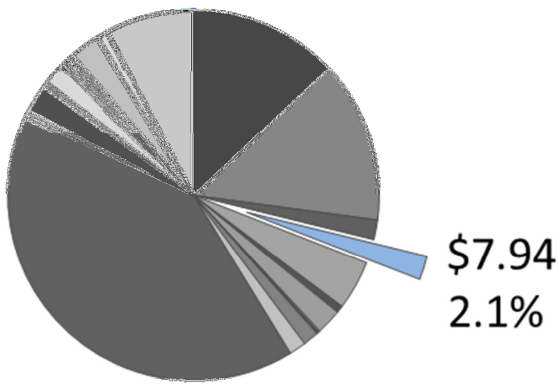
- The deployment rate of smart electric meters
- Annual cost to investigate individual customer events
- Reduction of labor hours dedicated to investigating customer-side issues
- Labor inflation rates can fluctuate over the years which could impact the 20-year savings
- Vehicle and fuel costs

Modeled Economic Benefits



Power Theft/Theft Recovery Costs (Benefits 4 and 5)

$ NPV in millions/% of total benefits



Savings Category – Increased Revenue

Background on Benefit

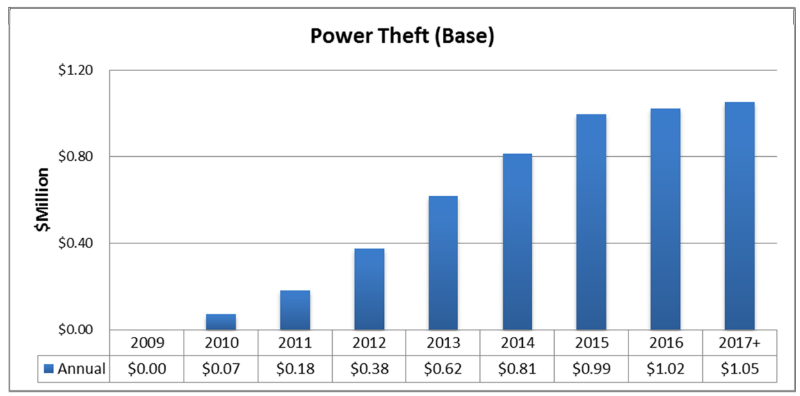
- Power theft in the United States has been hard to quantify, and in the literature it has been assumed to be 0.5-1.0 percent of any utility's overall revenue.
- Traditional meters do not offer capabilities to detect tampering, meters installed up-side down, or intentionally mis-wired or bypassed meters.
- Electric smart meters can generate tampering alarms and detect mis-wiring. VEE processes employed by Duke Energy take advantage of smart meters' 15 minute interval data availability to monitor and track consumption registration on meters to identify possible theft. By adding investigation and prosecution process steps, a reduction in theft will result in lower losses and increased revenue.
- By the end of 2009 Duke Energy had replaced 8% of all meters classified as residential or commercial/industrial <500kW. In 2010, an increase in revenue due to power theft from Electric smart meters was quantified and realized in Ohio. The increased revenue gives an early indication that power theft from electric smart meters is in the range 0.25-0.5 percent of overall revenue, assuming VEE processes are detecting and reducing previously unbilled/stolen energy by 50 percent.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

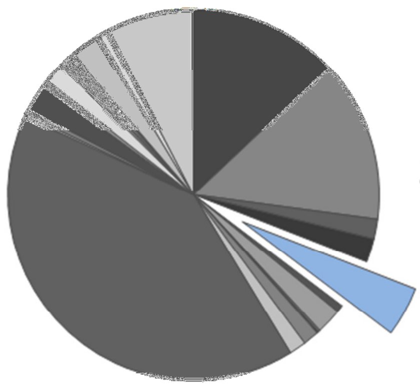
- Estimated Power Theft as a percentage of overall revenues
- Estimated Reduction in Power Theft due to smart grid
- Incremental Investigation Cost. (Source: United Illuminating, eSource conference presentation, September 2010. $15 billed for every $1 spent on investigation, less 55% uncollectible.)

Modeled Economic Benefit



Meter Operations Capital (Benefit 6)

$ NPV in millions/% of total benefits



Savings Category – Deferred Capital

Background on Benefit

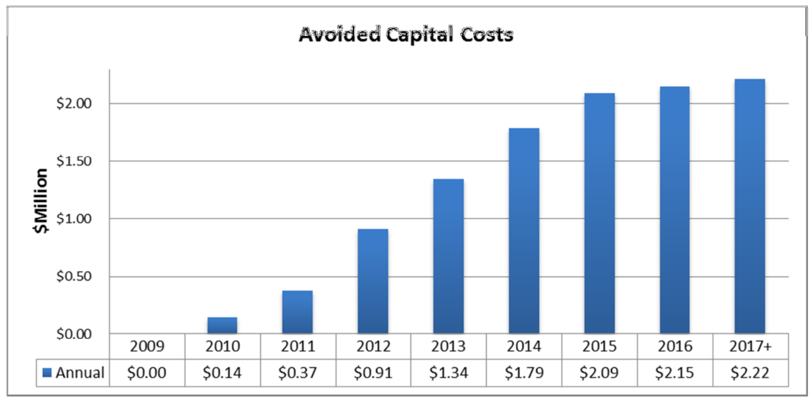
- With the deployment of AMI technology, capital costs associated with the replacement of traditional meters and related equipment will be significantly reduced.
- Without AMI deployment, traditional meters, and other related equipment, such as handheld devices, would have to be replaced over time resulting in regular capital costs. As penetration of smart meters increases, the need to replace traditional meters and other manual meter reading equipment will decrease significantly.
- Smart meters do not require the use of equipment related to manual meter reads such as handheld devices, resulting in reduced costs.
- It must be noted that smart meters will also need to be replaced after life cycle completion, estimated to be 20 years.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

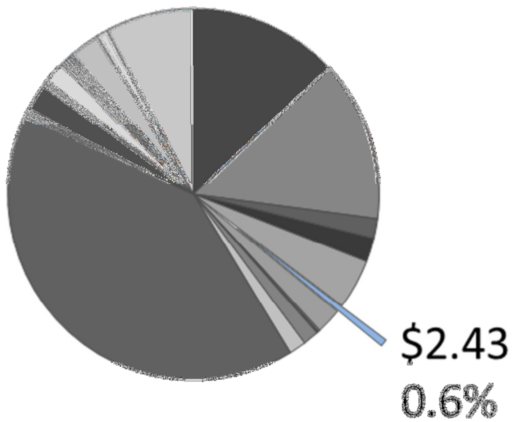
- The deployment rate of smart electric meters and gas modules
- The meter and equipment purchase and installation labor budgets for Duke Energy Ohio
- Labor and material inflation rates

Modeled Economic Benefits



Meter Operations Costs (Benefit 7)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

- AMI technology will utilize smart meters which will not require the same testing and refurbishment as traditional meters. Instead, smart meters will require very little testing or refurbishment as they will be replaced upon failure. This will reduce labor costs in the meter operations department.
- Traditional meters and associated handheld equipment decrease in accuracy over time, requiring routine testing and occasional refurbishment to function properly. Traditional meters may speed up or slow down over time, impacting the integrity of readings.

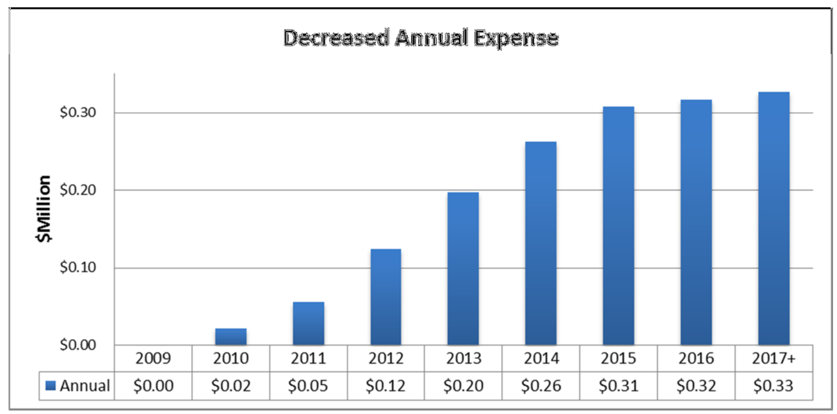
Due to their digital nature, smart meters do not require regular testing to ensure accuracy. In addition, refurbishment is not required of smart meters as they generally maintain accuracy until failure, at which time they will be replaced.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

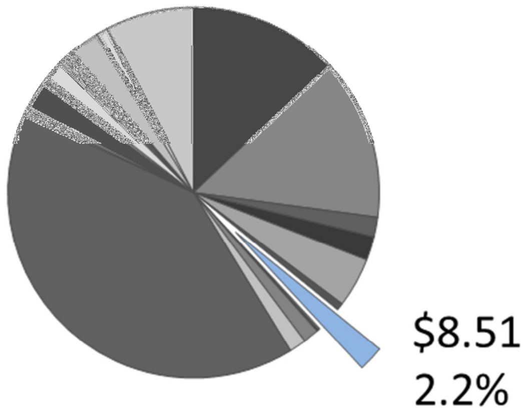
- The deployment rate of smart electric meters and gas modules
- Annual meter testing costs
- Annual meter refurbishment costs
- Labor inflation rates

Modeled Economic Benefits



Meter Accuracy Improvement (Benefit 8)

$ NPV in millions/% of total benefits



Savings Category – Increased Revenue

Background on Benefit

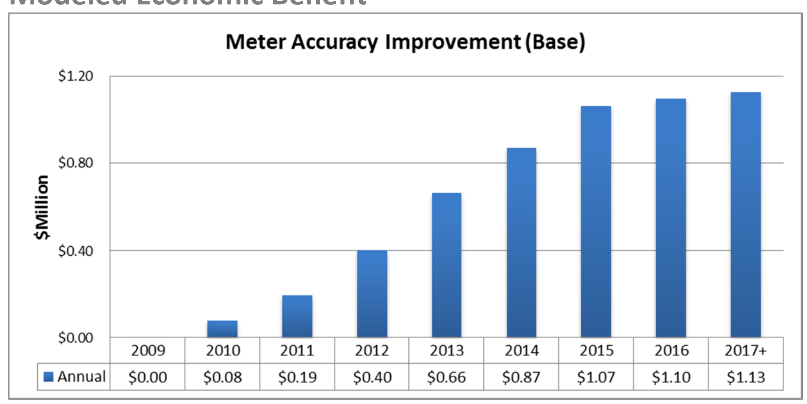
- The meter tests conducted as part of this project (see the Operational Audit section) indicated that Duke Energy Ohio's traditional meters, on average, register a slightly lower energy use reading than actual consumption. This can be attributable to:
  - Increased friction between moving parts over time
  - Sensitivity to tilted (not level) installations
  - Uncorrected temperature-related errors in the traditional meter instrumentation
- The electric smart meters do not have moving parts and can correct temperature-related error with simple algorithms, making them inherently more accurate.
- The meter tests indicated that the electric smart meters:
  - Will register energy use within the manufacturer's specified tolerance, which is far more accurate than traditional meters
  - Do not suffer from under-reported usage.
- Because the traditional meters under-report usage on average, replacing them with more accurate smart meters will result in increased billings and collections.
- The meter tests indicated that an average electric smart meter was expected to increase accuracy by 0.06-0.065% over that of an average traditional meter.
- With weighting, this translates into increased billed revenue of 0.17-0.18% (after weighting to create "usage over time" estimates from "point-in-time" meter accuracy tests).
- A Duke Energy study attributes 0.3-0.35% revenue gains for deployed electric smart meters in 2010 to improved accuracy.

Benefit Drivers

"Percent Accuracy Improvement" is the largest single driver of this benefit. Conservatively weighted (0.17%), realistically weighted (0.18%) and Duke study (0.30%) estimates were used to calculate revenue increases in low case, base case, and high case values, respectively.

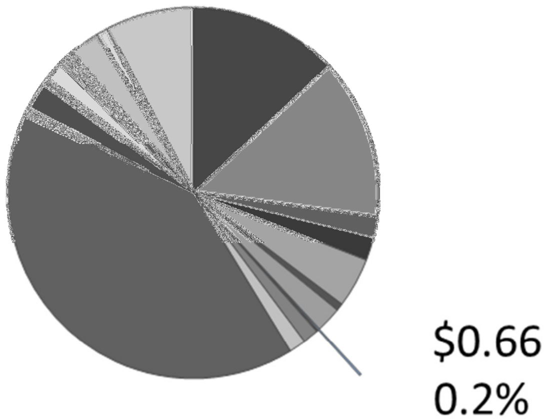
Meter Deployment Rate is also an important benefit driver.

Modeled Economic Benefit



Meter Salvage Value (Benefit 9)

$ NPV in millions/% of total benefits



Savings Category – Increased Revenue

Background on Benefit

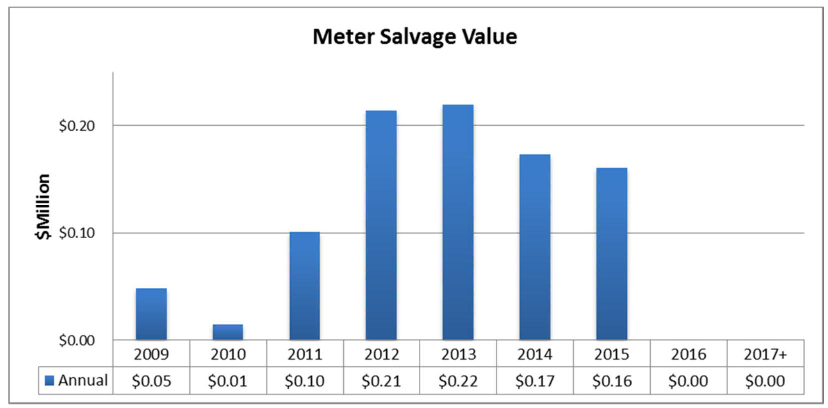
- For traditional meters exchanged for smart meters, those that cannot be refurbished and redeployed within Duke Energy's footprint will be salvaged. Salvaging meters for scrap metal will increase Duke Energy revenues.
- As gas modules are deployed there are instances in which the entire gas meter must be replaced. Gas meters removed and salvaged cannot be considered a smart grid related benefit according to Staff, and therefore were not considered in this benefit calculation.
- This benefit begins to accrue after the first year of deployment and will end after all smart meters have been deployed.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

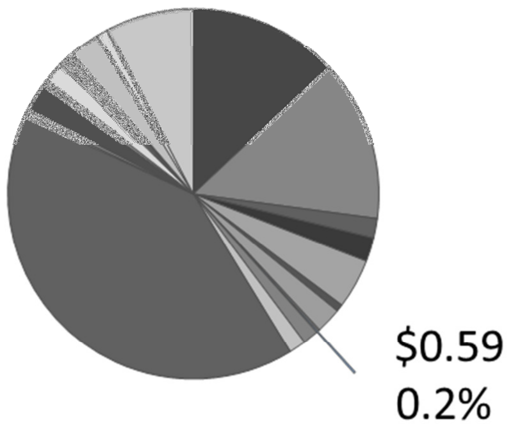
- The rate at which smart electric meters are deployed.
- The rate of traditional meter refurbishments. As more refurbished traditional meters are redeployed there is the possibility of saturation. Duke Energy may not require additional refurbished traditional meters as more smart meters are deployed. Therefore, fewer refurbished meters will result in an increase in the level of meters salvaged.
- The salvage value of meters and inflation of materials during the deployment period.

Modeled Economic Benefits



Outage Detection (Benefit 10)

$ NPV in millions/% of total benefit



Savings Category – Avoided O&M Cost

Background on Benefit

- The deployment of AMI and DA technology provides the capability to detect the extent of customer outage, with sensing technology and on-demand readings of smart meters. This allows assessors to correctly determine which areas of an outage are restored and which are still experiencing an outage. This benefit reduces assessor labor hours.
- During storms that cause outages, a Storm and Natural Disaster plan is activated. Duke has defined 4 severity levels:
  - Level 1: Various localized damage
  - Level 2: Moderate damage over large area or heavier damage over small area
  - Level 3: Heavy damage over large area or extensive damage over small area
  - Level 4: An overwhelming amount of damage over major or all service territory anticipated to take several days to fully restore
- Outages caused by "Level 1 storms" or with "Level 1 Severity" are handled by distribution operators. For levels 2, 3 and 4, when the number of customers and number of storm outage cases escalates and becomes unmanageable for the distribution operator, field assessors are activated.
- Assessors investigate and call in from the field to assign appropriate restoration resources. Historically, many trouble tickets relate to areas where service has already been restored.
- Electric smart meters have remote diagnostic capabilities that can be used to avoid "already restored" tickets and reduce assessor labor.
- As illustrated in figure 10.1 all assessors' combined number of hours per year is estimated to be reduced by 20 percent.
- In addition, smart grid DA equipment such as circuit breaker relays and electronic reclosers can calculate approximate fault locations, which may further reduce the time spent in assessment.
- Duke Energy's IT-plans indicate that the outage management system (OMS) will fully integrate data from interruption equipment, line sensors, electric smart meters and GIS, and will be able to automatically map out outages and pinpoint fault locations. This will accelerate the scouting process and effectively reduce/improve the total customer outage time. Duke has already deployed and integrated a significant amount of DA hardware. In addition, a project charter has been approved that would marry electric smart meter data into the OMS for additional improvements if implemented.

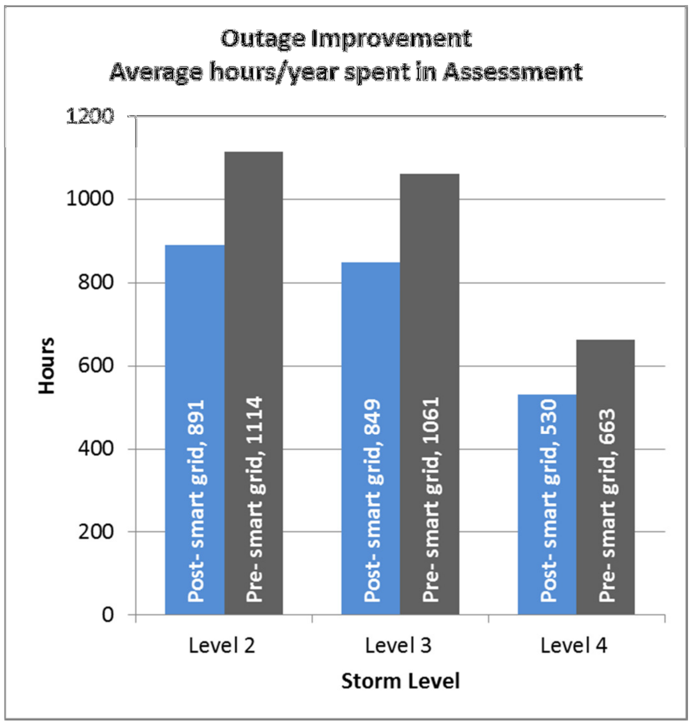
Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

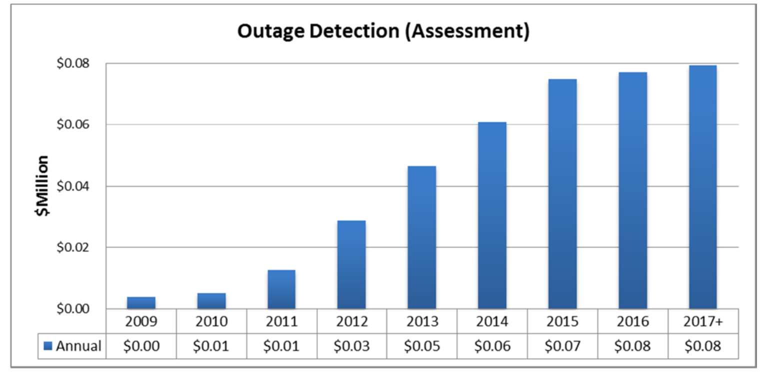
- Average Annual Number of Outage Events and Duration
- Average Number of Assessors per Outage Event

- Percent of Outage Spent in Assessment
- Cumulative Meter Deployment Rate
- Percent Reduction in Assessment Time
- Hourly Labor Rate and Labor Rate Inflation

Fig.10.1 Reduction in Assessors' combined hours

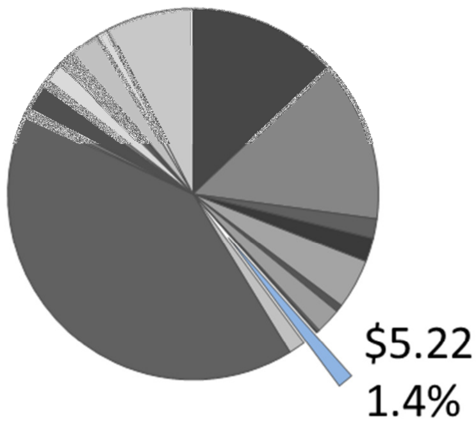


Modeled Economic Benefits



Outage Verification (Benefit 11)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M cost

Background on Benefit

- During storms and OCB/recloser failures, it is critical for maintenance / outage crews to quickly identify and verify failure and repair locations. As a result of installed smart grid relay equipment, there is a reduction on time spent locating failures reducing crew labor and associated costs.

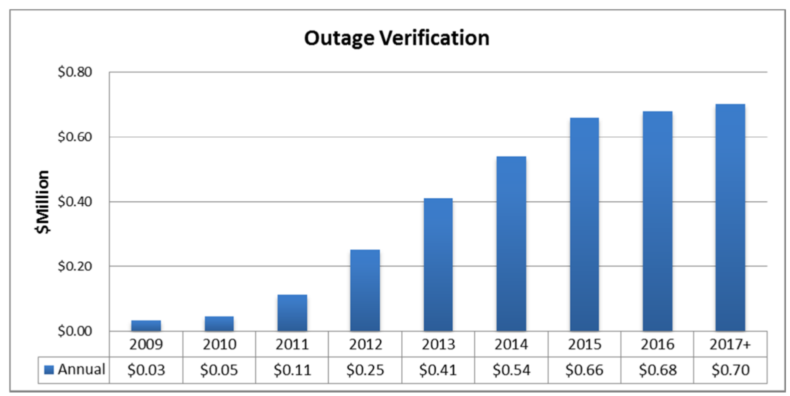
Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Number of Outages (reduction reflected in Benefit 12)
- Outage Duration (reduction reflected in Benefit 12)
- Hourly Labor Rate (varies by resource and storm type)
- Labor Inflation
- Non-labor Restoration Costs (out-of-area crews and travel)
- Number of Restoration Crew Members
  - 15% Crew Time Reduction for level 1 storms
  - 10% Crew Time Reduction for level 2,3,4 storms
  - 20% Crew Time Reduction for OCB/Reclosers

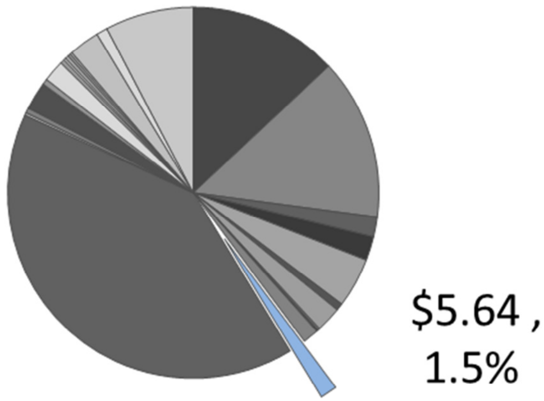
These values were just a consensus judgment from several Duke Energy SMEs with experience in storm and service restoration based on having more precise and immediately available data on which customers are still out of service and the ability to determine if any customers fed by a device are still out after Duke Energy thinks the outage caused by that device is restored.

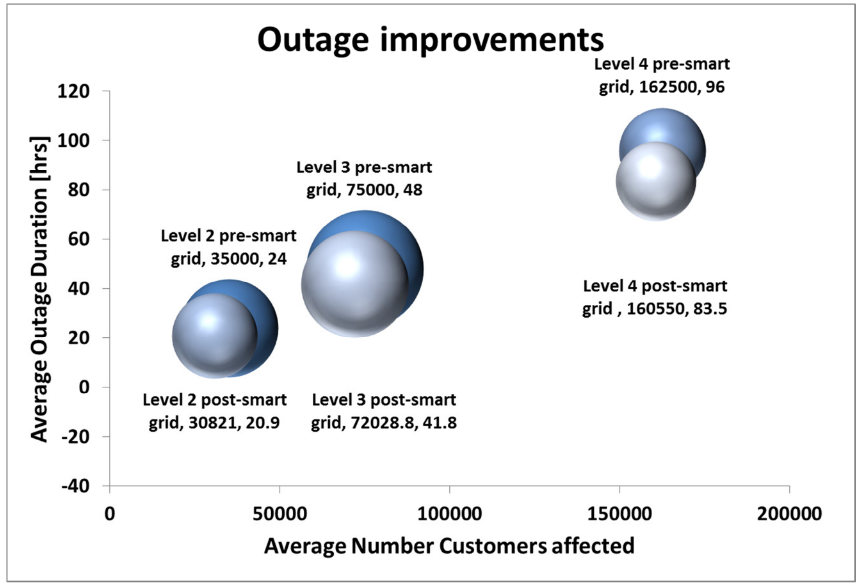
Modeled Economic Benefit



Outage Reductions – Revenue Impact (Benefit 12)

$ NPV in millions/% of total benefit





Savings Category – Increased Revenue

Background on Benefit

- The smart grid's outage restoration reporting functionality can be expected to reduce total time for service restoration, thus increasing Duke Energy Ohio's revenue associated with customers whose service has been severed during outage events.
- The smart grid's improved "sectionalization" capabilities help utilities isolate faults better and reduce the number of customers impacted by an outage. Self-healing teams are a more sophisticated means of accomplishing the same objective using a combination of circuit breakers, reclosers, self-healing team switches, sectionalizers, and fuses. In either case, Duke Energy Ohio's revenue increases when the average number of customers impacted by each outage decreases.

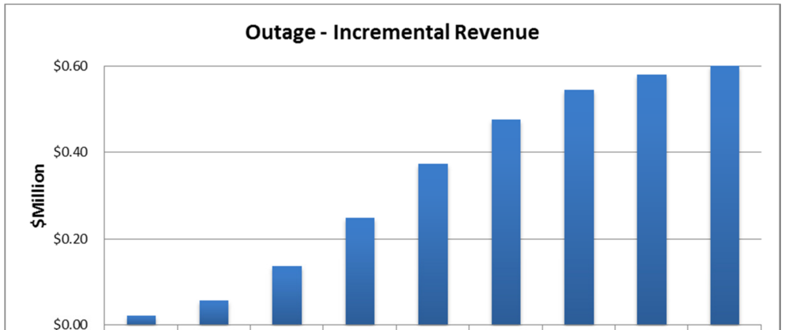
Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Number of Outages
- Outage Duration (hrs.)
- Average Number of Customers Affected
- % of Outage Spent in Assessment (Assessors)
- Reduction in Assessment Time (See benefit 10)
- Average Customer Hourly Power Consumption
- Reduction in Customers Affected Due to Self-Healing
  - 60% Reduction for level 2 storms
  - 20% Reduction for level 3 storms
  - 0% Reduction for level 4 storms
- Number of Circuits with Self-Healing Teams

- Reduction in Customers Effected Due to Sectionalization
  - 25% Reduction for level 2 storms
  - 8% Reduction for level 3 storms
  - 4% Reduction for level 4 storms
- Number of circuits with Sectionalization

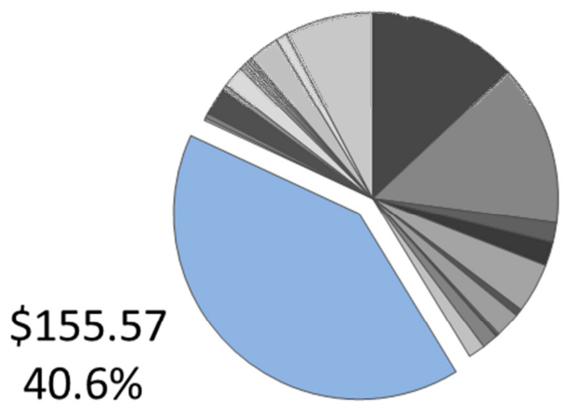
Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.02	$0.06	$0.14	$0.25	$0.37	$0.48	$0.54	$0.58	$0.60

24/365 System Voltage Reduction Strategy (Benefit 13)

$ NPV in millions/% of total benefits



Savings Category – Avoided Fuel Cost

Background on Benefit

Smart grid "Voltage Reduction Strategy" is based on the same principle as a light dimmer. It's intuitive that when a light dimmer is turned down, the energy usage is reduced. Energy reduction is the objective of Voltage Reduction Strategy. But to do this in a meaningful manner for a grid, several issues need to be addressed. For example and hypothetically speaking, if one dimmer was controlling all the lights in a city on one very long wire, the lights at the end of the wire would not be as bright as the closer ones. This issue is due to a phenomenon called "voltage drop", and is fixed by activating "capacitor banks", which have similar properties as batteries, along the length of the power line. These "batteries" supply just enough additional power to counteract the voltage drop so the lights at the end of the line are as bright as those closer to the dimmer.

An interesting thing happens if every other light on the long line were turned off; the voltage drop is reduced. So a smarter way to operate the dimmer and batteries would be to turn down the dimmer a little bit and deactivate the batteries when unnecessary while continuously monitoring that all the lit lights are still as bright as they are specified to be. Even if the dimmer is only turned down slightly, the total energy savings from all the lights combined is substantial.

"System Voltage Reduction" is often named Conservation Voltage Reduction (CVR) or Integrated Volt VAR Control (IVVC), and results in avoided fuel cost and some distribution capital deferment. IVVC is typically enabled by smart grid equipment such as Voltage Regulators/Load Tap Changers (very large dimmers), capacitor banks, and sophisticated software applications in the DMS.

An IVVC algorithm has two distinct but related functions:

- Reduce the voltage drops over the length of a feeder/circuit by activating capacitor banks
- Lower the voltage while maintaining a safety margin from minimum allowable levels

Algorithms in the DMS software alternates five minute periods of voltage flattening and voltage reduction and continually make control decisions based on real-time voltage readings from the capacitors, substation equipment, and line sensors on the feeder/circuit.

Load Tap Changers and capacitors play important roles in traditional grids as well, but their operation is not as automated or coordinated:

Step 1: Reduce voltage drop along the line.

Step 2: Lower the voltage-while maintaining a safety margin from minimum allowable levels).

Determining Energy Savings of a Hypothetical 2% Voltage Reduction

The amount of energy saved from a given level of voltage reduction is a matter of debate and varies from feeder to feeder based on several factors. In summary, some types of loads do not react to changes in voltage, while other types of loads "work harder" in response to voltage reductions.

As a result, there is not a one-for-one relationship between voltage reductions and energy reductions. Studies indicate energy savings from

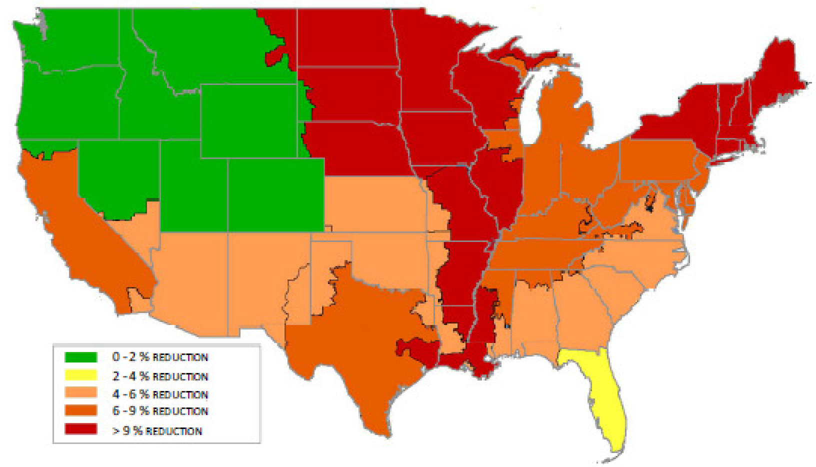
0.50% to 0.79% for a 1.0% drop in voltage, with common mode values of 0.65%. The ratio between energy savings and voltage reduction is becoming known as the CVR factor. MetaVu used these 3 values (0.50%, 0.65%, and 0.79%) in low case, base case, and high case estimates, respectively.

Impact of CO2-related EPA regulations on Operating Benefit Fuel Cost Assumptions

Assumptions on the cost of future EPA carbon regulation compliance are relevant to all Operational Benefits with a fuel cost component. The topic is addressed here because the impact is greater in this Operational Benefit than the others if future regulations are implemented.

- If the EPA is successful in implementing new CO2 emissions standards as currently outlined, NERC estimates that 6-9% of Ohio capacity will become economically obsolete. (Source: NERC Special Reliability Scenario Assessment, October 2010, page 13+.)
- Replacing a conservative estimate of 5% of Duke Energy's Generating Capacity with modern/up-to-CO2-standard power plants can be translated into a 4% one-time increase in fuel cost/LCOE. MetaVu has accounted for the one-time increase in the modeling under the assumption that EPA regulations will take effect in 2016.
- An energy efficiency savings modeling tool popular with many utilities, DSMore from Integrated Analytics, was used to model the value of fuel cost savings (including capacity value) from voltage reductions. Duke Energy provided proprietary system-wide hourly load profiles for the DSMore modeling.

Figure 5: 2018 Reduction in Adjusted Potential Capacity Resources due to the Combined EPA Regulation Scenario

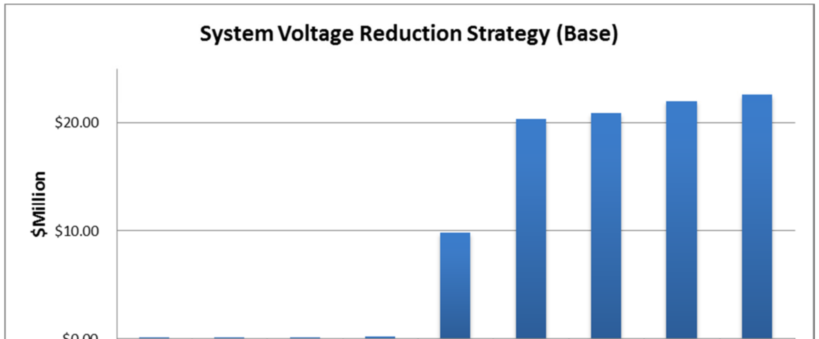


Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Cost Avoided Production (Energy/Fuel)
- Cost Avoided Production (Capacity)
- CVR-Factor
- Purchased Power/Fuel Cost Escalation Single Year (2016)
- DMS Deployment Schedule

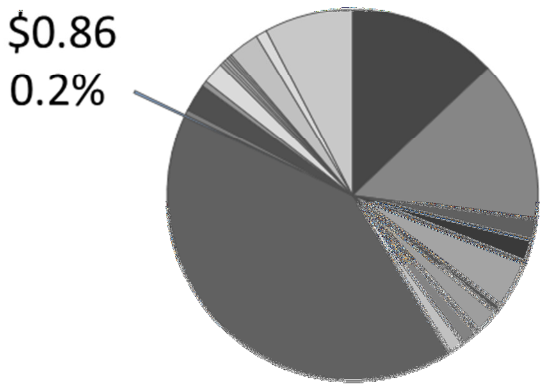
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.18	$0.18	$0.19	$0.19	$9.90	$20.32	$20.87	$22.08	$22.67

Power Shortage Voltage Reduction (Benefit 14)

$ NPV in millions/% of total benefits



Savings Category – Capital Deferment

Background on Benefit

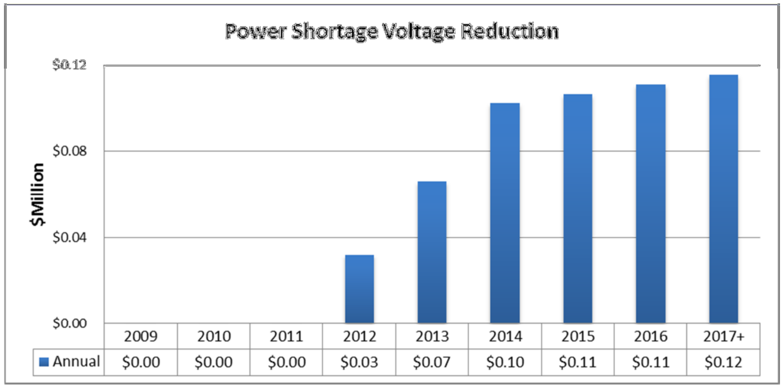
- Improved voltage control (i.e., stable distribution voltage profiles) enables voltage levels to be reduced in the distribution system for load reduction without impacting customer service, resulting in reduced capital investment as a result of mitigating peak loads and lower operating expenses during peak load conditions.
- An energy efficiency savings modeling tool popular with many utilities (DSMore from Integrated Analytics) was used to model the value of capacity avoided through voltage reductions. Duke Energy provided proprietary system-wide hourly load profiles for the DSMore modeling.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

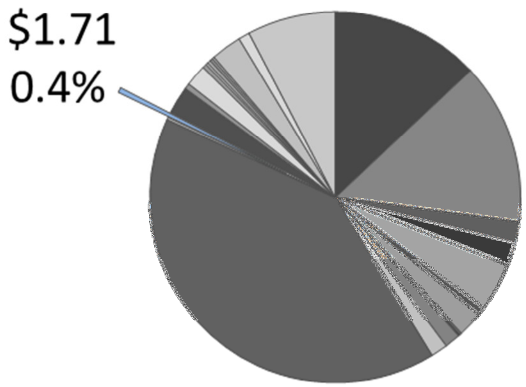
- Cost of avoided Capacity
- CVR Factor: 0.65%/1.0%

Modeled Economic Benefit



Continuous Voltage Monitoring (Benefit 15)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

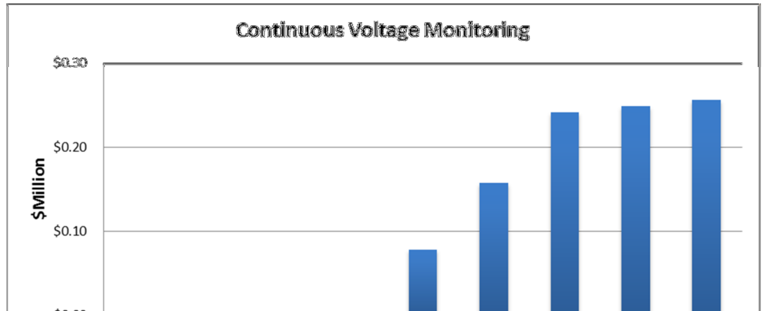
- Improved capability in automated monitoring of voltage for low voltage situations allows for a major reduction in the time field employees currently spend performing this function.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Number of FTEs Checking Low Voltage Issues
- Cost per FTE
- Labor inflation rates
- Estimated Savings Percentage
- Meter Deployment Rate

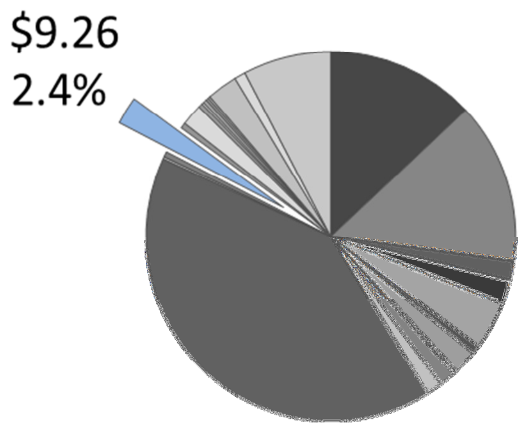
Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.00	$0.00	$0.00	$0.08	$0.16	$0.24	$0.25	$0.26

VAR Management (Benefit 16)

$ NPV in millions/% of total benefits



Savings Category – Capital Deferment

Background on Benefit

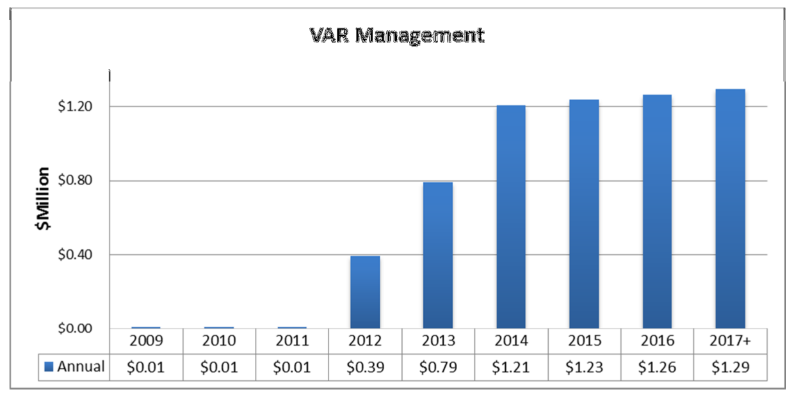
- Capacitors improve the power factor (VAR) of energy and increase the effective carrying capacity of existing plants and distribution equipment.
- Duke Energy's smart grid deployment plans include equipment that monitors and reports the status of capacitors. With this feature, faulty capacitors can be identified and repaired or replaced immediately.
- Prior to smart grid deployment, capacitors might be offline for a year before being detected. Rapid detection and repair improves capacitor effectiveness and enables the avoidance/deferral of capital expenditures.

Benefit Drivers

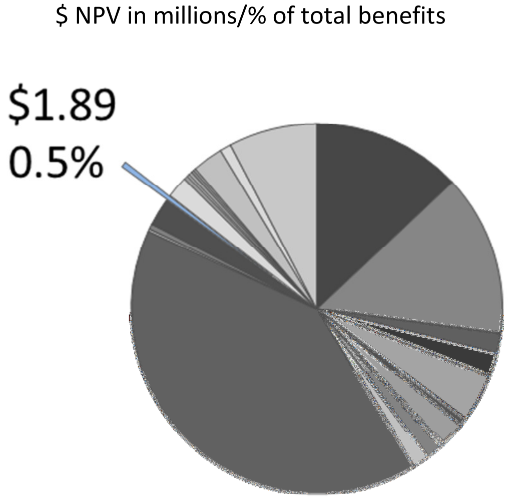
The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Distribution Peak Load
- VAR Improvement %
- Percent Capacitors Offline
- Carrying Cost of Plant
- DA Deployment Schedule

Modeled Economic Benefit



Asset Management (Benefit 17)



Savings Category – Capital Deferment

Background on Benefit

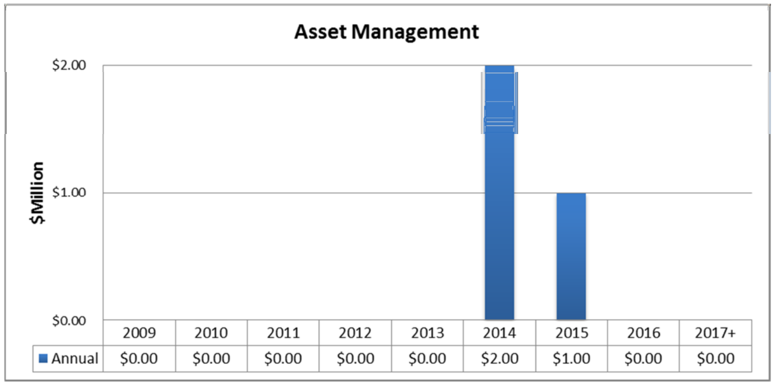
- Distribution equipment, including substations and feeders, must be upgraded from time to time to increase capacity as dictated by customer demand.
- Smart grid enhancements offer improved grid data access and analysis capabilities that can be used to switch loads from one feeder or substation to another.
- Optimized load switching can be used to relieve grid assets that are approaching capacity. It is possible to delay capacity upgrades one-two years by better distributing loads across available assets, deferring capital expenditures.
- Based on this, the resulting assumption is that two substation upgrades could be delayed per year, one substation by one year and the second substation by two years.

Benefit Drivers

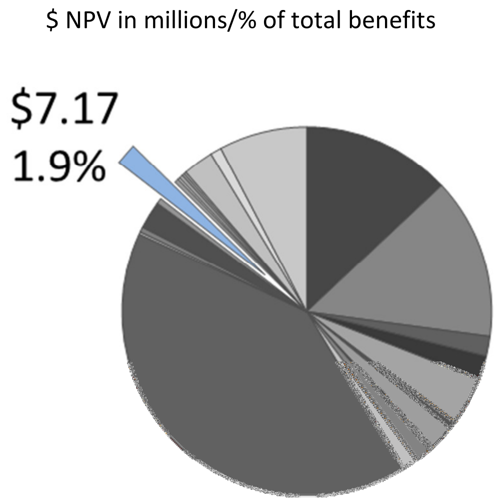
The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Cost of one substation
- Load Growth
- Load Shifting/Reconfiguration opportunity

Modeled Economic Benefit



System Fine Tuning (Benefit 18)



Savings Category – Avoided Fuel Cost and Capital Deferment

Background on Benefit

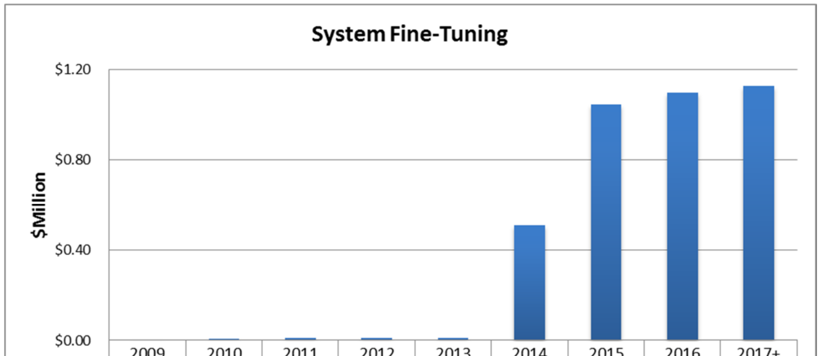
- Fine tuning enables more efficient distribution of power (e.g., reduced line losses in the medium voltage three phase portion of the distribution). This results in the need for less capital investment (in distribution, transmission, and generation assets) for handling peak load and improved overall operating expenses (i.e., less power needs to be generated or purchased to service the load) – on an ongoing, real-time basis.
- DMS software must be engaged to activate fine tuning and to enable this benefit.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Main Line Loss (% of Power)
- Reduction in Losses (% of losses)
- Annual Retail Sales
- Total Electric Loss (T&D)
- Cumulative Residential Energy Growth
- Weighted Average Fuel Cost (an average based on a mix of fuel types)
- Annual Fuel Cost Escalation
- Fuel Cost Escalation Single Year (2016)
- Carrying Cost of Plant

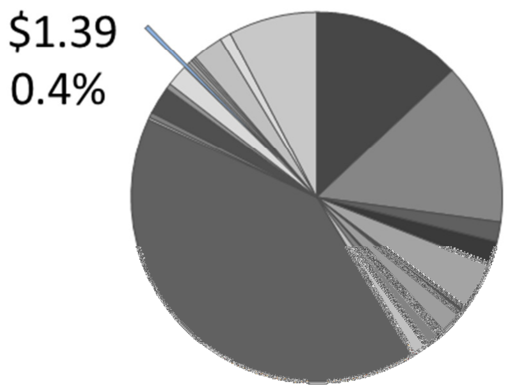
Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.01	$0.01	$0.01	$0.01	$0.51	$1.04	$1.10	$1.13

Capacitor Inspection Costs (Benefit 19)

$ NPV in millions/% total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

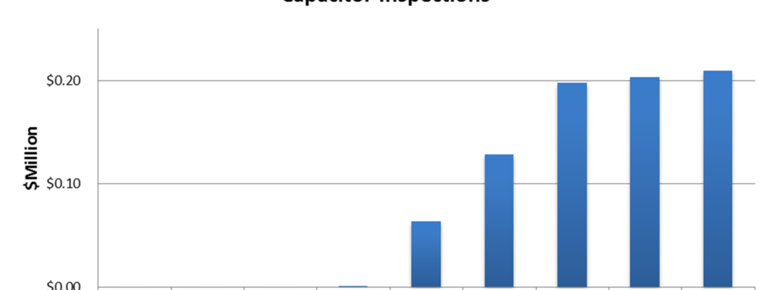
- New capacitor bank controllers and communication modems will be leveraged to produce alarms and exception reports when issues arise at each capacitor bank. These alarms will be near real-time, which will greatly reduce the need for onsite inspections.
- Prior to the smart grid, each capacitor bank was inspected annually. Going forward one fifth of the capacitor banks will be inspected annually. Therefore, smart grid technology reduces visual walk-by inspections by eighty percent with associated savings in labor and operations costs.
- For this benefit to take effect an approval for waiver of existing regulatory rules associated with applicable capacitor inspection frequency would be required.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Planned Reduction in Capacitor Bank Inspections
- Labor Inflation Rate
- Cumulative Cap Bank Controller & Modem Deployment
- Number of Capacitor Banks
- Cumulative Growth in Capacitor Banks
- Hourly Labor Rate
- Average Number of Hours per Capacitor Bank Inspection Including Field Work and Back-Office Logging and Reporting

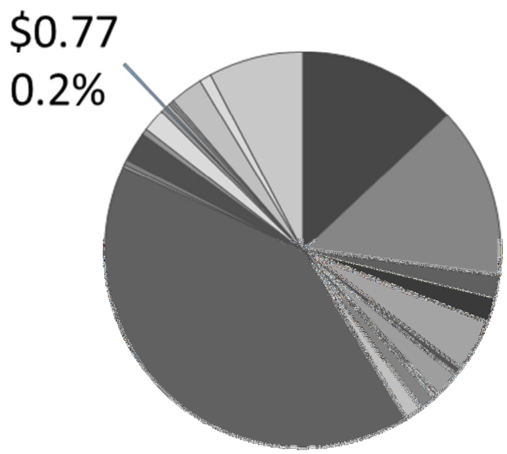
Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.00	$0.00	$0.00	$0.06	$0.13	$0.20	$0.20	$0.21

Circuit Breaker Inspection Costs (Benefit 20)

$NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

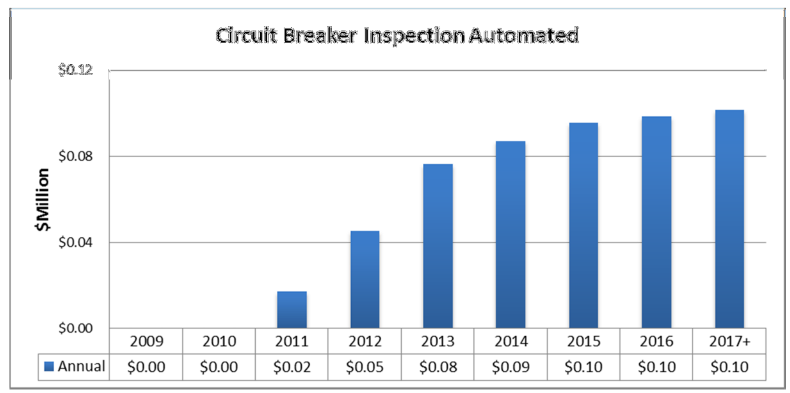
- Legacy reclosers inside substations without communication capability are being replaced by modern circuit breakers that are smart and integrated. Ultimately, the condition of the new circuit breakers will be available remotely in the new DMS and eliminate the need for circuit breaker inspections.
- During the first half of deployment, the circuit breaker data is being tagged in the existing Energy Management System (EMS) interface and stored in the data archive. Partial benefits could therefore be available in advance of DMS deployment.
- For this benefit to take effect an approval for waiver of existing regulatory rules associated with applicable circuit breaker inspection frequency would be required.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

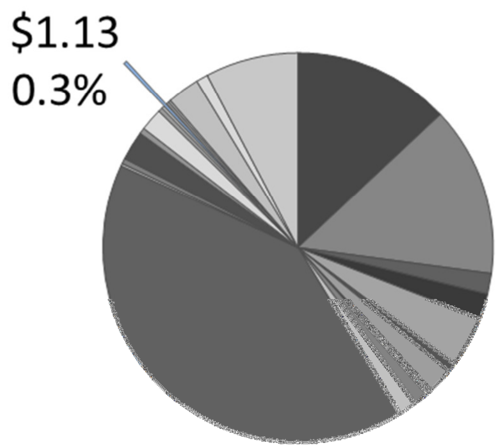
- Projected Annual Labor Cost Savings
- Labor Inflation Rate
- Cumulative Hardware & Communications Deployment

Modeled Economic Benefit



Call Center Efficiency (Benefit 21)

$ NPV in millions/% total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

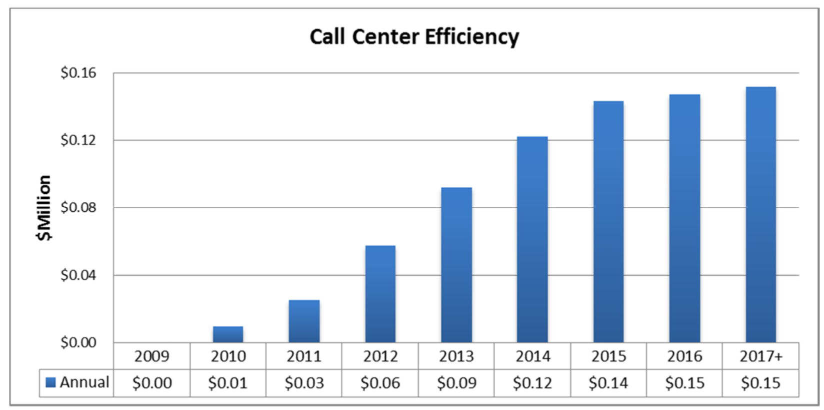
- With greater capabilities associated with AMI technology, such as remote meter reads, remote diagnostics, and more granular historical data, the number of customer calls is expected to decrease over time. Calls related to credit and billing issues, move orders, and trouble calls for both gas and electric are anticipated to be reduced.
- Traditionally, the utility had access to only monthly meter reads which provided call center employees little information to handle customer calls. With AMI technology, call center employees can use granular historical data to help resolve questions or complaints. In addition, reductions in estimated bills also reduce the number of customer calls. Remote diagnostic meter reads can assist in resolving trouble calls as mentioned in Benefit 3 and reduce the number of meter order calls that occur from rescheduling appointments for indoor or other hard-to-access meters.
- Customers with access to the Customer Portal will have the capability to view their detailed usage online. Customers with smart meters can access this data and resolve questions prior to calling the call center.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

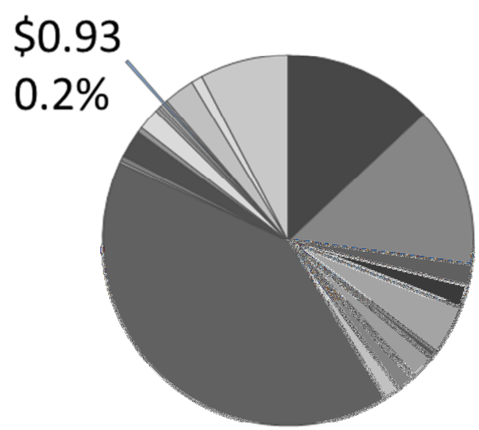
- The deployment rate of smart electric meters and gas modules
- Reduction in credit, billing, move order and trouble calls
- Labor inflation rates

Modeled Economic Benefits



Increase in Safety (Benefit 22)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

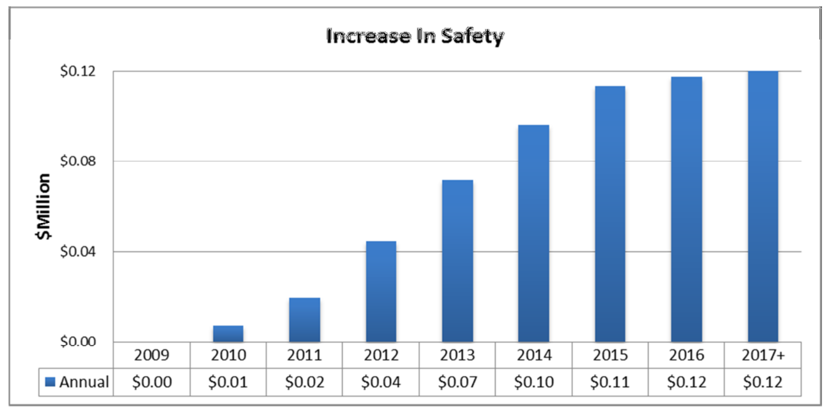
- As AMI technology reduces staff in the Meter Reading department, labor costs will drop. Worker's compensation costs, which are assessed based on labor costs, will drop as well.
- In addition, Duke Energy Ohio may experience reductions in workers' compensation insurance rates, though this impact is difficult to quantify. The reduction of maintenance/inspections on distribution equipment and remote operation of field devices, for example, will result in reduced exposure to field hazards and greater levels of safety for field crews and linemen. Over time, reduced frequency of safety incidents should result in lower worker's compensation insurance rates.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

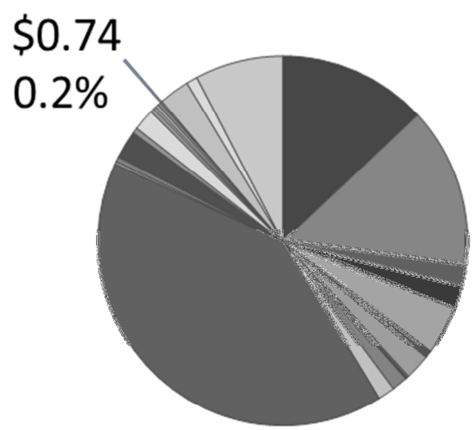
- The deployment rate of smart electric meters and gas modules
- Annual cost workman's compensation for Meter Reading
- Annual cost of vehicle accident claims
- Meter reader reduction resulting in meter reading route consolidation and meter reader staff reduction

Modeled Economic Benefits



Billing Savings – Shortened Billing Cycle (Benefit 23)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Costs

Background on Benefit

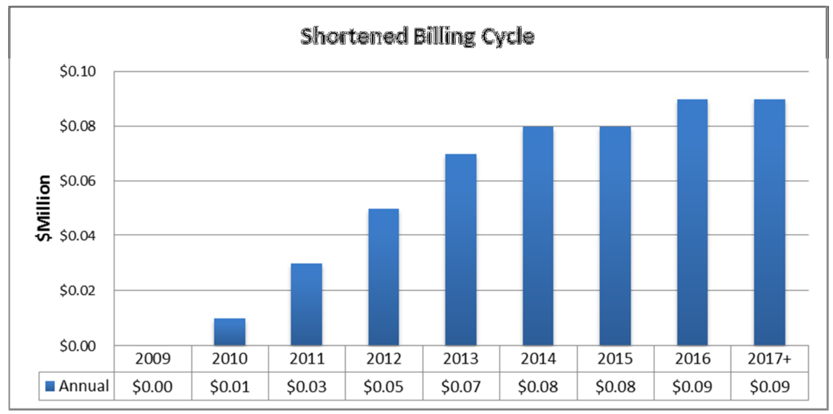
- Smart meters will almost always provide billing data on the scheduled read day, allowing the bills to be made available on the first day of the billing cycle.
- Traditionally, some bills are not issued on the first day of the billing cycle. Most of these are estimated, delaying billing by as much as 2 days.
- By reducing the number of bills issued on a delayed basis, cash collections will be accelerated and interest expense can be reduced.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

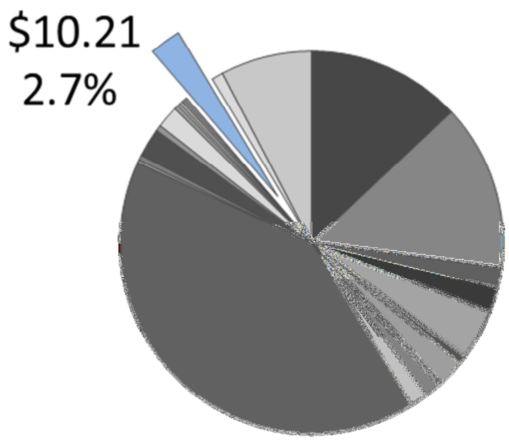
- The deployment rate of smart electric meters and gas modules
- Duke Energy's discount rate
- Electric and gas load growth rates
- Electric and gas price inflation
- The number of estimated bills

Modeled Economic Benefits



Vehicle Management Costs (Benefit 24)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

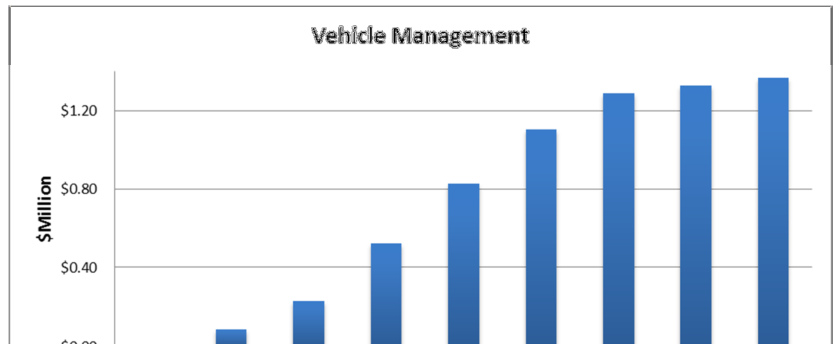
- Smart meters will result in the reduction of vehicles used for meter reading.
- Duke Energy in Ohio has traditionally employed Meter Readers to manually read meters on a monthly basis. This process consists of individuals capturing electric and gas meter data in the field. Meter Readers then provide meter data to the utility for billing purposes.
- With the deployment of smart meters, metering data is communicated via a wireless network to the utility. This reduces the need for most manual meter reads, meter readers, and meter reading vehicles.
- It should be noted, despite a significant decrease in vehicles used for meter reading, the average miles driven per remaining meter reader will increase. Traditionally, Meter Readers walked door-to-door routes. With AMI technology, very few meters will need manual meter reads, and distance between manual meter read locations will be much further.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- The deployment rate of smart electric meters and gas modules
- Cost of insurance premium per vehicle
- Total meter reading vehicles
- Average miles driven per year
- Inflation rate of materials

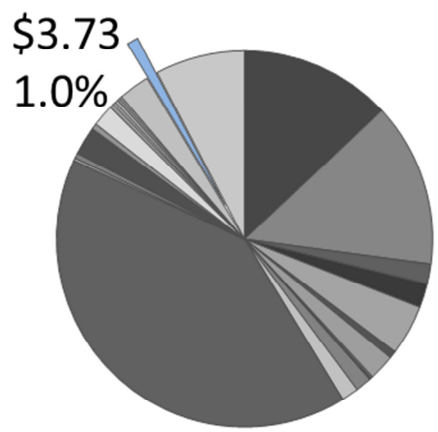
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.09	$0.23	$0.52	$0.83	$1.10	$1.29	$1.33	$1.37

Fuel Cost Reduction through VAR Improvement (Benefit 25)

$ NPV in millions/% of total benefits



Savings Category – Avoided Fuel Cost

Background on Benefit

- Improved Power Factor (VAR) performance from DMS-enabled IVVC and VAR management will reduce line losses, resulting in fuel cost reductions.

Line loss improvements due to VAR improvements were not captured in the other benefits that relate to IVVC and VAR management (13 and 18)

Benefit Drivers

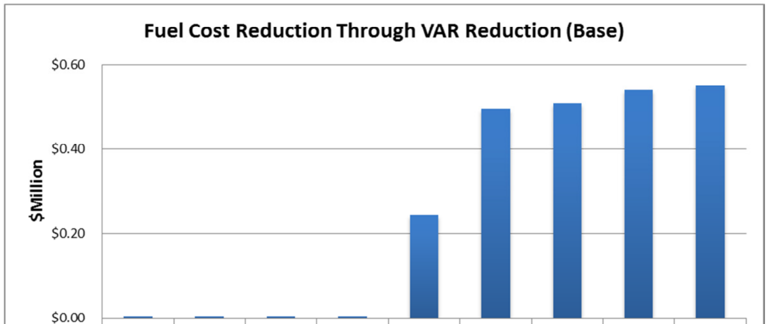
The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Percent of Feeders with relatively poor VAR performance
- Amount of line loss improvement available from VAR improvement
- Amount of line losses as a result of poor VAR

Assumptions:

	Low Case	Base Case	High Case
Poor-performing Feeders	25%	50%	75%
PF improvement	From .85 to .99	From .96 to .985	From .96 to .985
Line Loss	1%	3%	5%

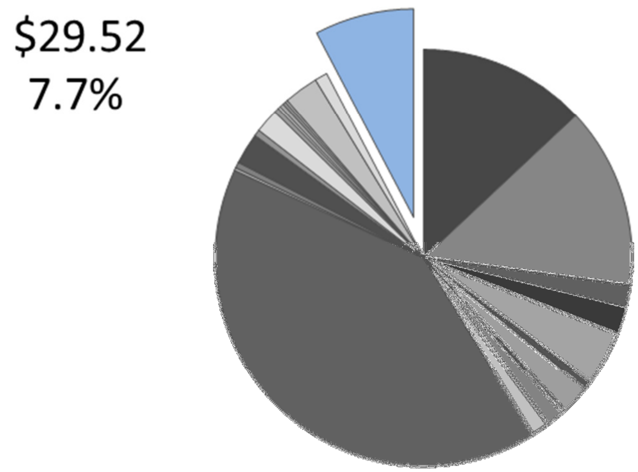
Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.00	$0.00	$0.00	$0.24	$0.50	$0.51	$0.54	$0.55

Wholesale Energy Sale of Capacity Made Available (Benefit 26)

$ NPV in millions/% of total benefits



Savings Category – Increased Revenue

Background on Benefit

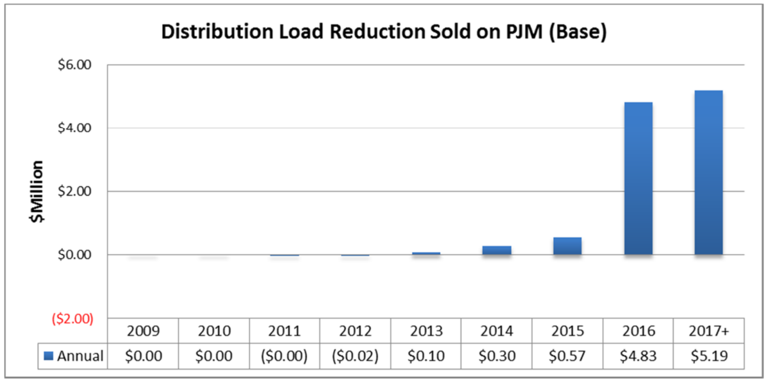
- Freed up capacity from smart grid-related distribution load reductions in Ohio may be used to produce energy that can be sold into the wholesale market (PJM). Historical PJM Locational Marginal Prices (LMP) shows that there are opportunities for profitable sales when market prices exceed the Cost of Energy (COE).
- The ability of Duke to sell into the wholesale market depends on whether they are long or short on generation to serve Standard Service Offer (SSO) load ("native" or "non-shopping" load).
- Whether Duke is long or short depends on shopping levels.
- Sales volumes are anticipated to fall as a result of smart grid deployment, all else being equal. Lost margins associated with this reduction have been netted against this benefit.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Annual Energy Saved from Benefit 13, System Voltage Reduction 24/365
- Annual Energy Saved from Benefit 18, System Fine Tuning
- Annual Energy saved from Benefit 25, VAR Improvement
- Energy Used Benefit 12, Incremental Revenue from Reduced Outage time
- Low Case: Assume cost at $61.10; Wtd Ave LMP $81.98
- Mid Case: Assume cost at $47.10; Wtd Ave LMP $63.15
- High Case: Assume cost at $28.10; Wtd Ave LMP $47.41
- Percentage of Time when price is above cost
  - Low: 13.8% (1,213 hours)
  - Mid: 35.7% (3,124 hours)
  - High: 87.3% (7,649 hours)
- Fuel Cost Escalator
- Weighted Average Fuel Cost
- Transmission Losses to PJM/MISO
- Duke Ohio Total Retail Sales 2010
- Effective Date of Next Rate Case (Jan. 1st 2016)
- Lost Margins Estimate ($12.30/MWh T&D Margin per Case No. 09-1999-EL-POR, Jim Ziolkowski testimony Attachment 1, Feb. 15, 2011.)

Modeled Economic Benefit



Operational Benefits Summary table ($ millions)

Assessment ID	20-Year NPV	Year 1 NPV 2009	Year 2 NPV 2010	Year 3 NPV 2011	Year 4 NPV 2012	Year 5 NPV 2013	5-Year NPV Total	Year 6 NPV 2014	Year 7 NPV 2015	Year 8 NPV 2016
1(b) Base	$ 49.86	$ -	$ 0.31	$ 0.43	$ 0.98	$ 2.03	$ 3.75	$ 2.93	$ 3.61	$ 3.90
2(b) Base	$ 53.96	$ -	$ 0.72	$ 1.54	$ 2.55	$ 3.52	$ 8.33	$ 3.96	$ 4.18	$ 4.03
3(b) Base	$ 6.53	$ -	$ 0.05	$ 0.11	$ 0.23	$ 0.35	$ 0.74	$ 0.44	$ 0.48	$ 0.46
4(b) Base	$ 7.94	$ -	$ 0.06	$ 0.15	$ 0.28	$ 0.43	$ 0.92	$ 0.52	$ 0.60	$ 0.57
6(b) Base	$ 16.58	$ -	$ 0.12	$ 0.30	$ 0.68	$ 0.93	$ 2.03	$ -	$ -	$ -
7(b) Base	$ 2.43	$ -	$ 0.02	$ 0.04	$ 0.09	$ 0.14	$ 0.29	$ 0.17	$ 0.18	$ 0.18
8(b) Base	$ 8.51	$ -	$ 0.07	$ 0.16	$ 0.30	$ 0.46	$ 0.98	$ 0.56	$ 0.64	$ 0.61
9(b) Base	$ 0.66	$ 0.05	$ 0.01	$ 0.08	$ 0.16	$ 0.15	$ 0.45	$ 0.11	$ 0.10	$ -
10(b) Base	$ 0.59	$ 0.00	$ 0.00	$ 0.01	$ 0.02	$ 0.03	$ 0.07	$ 0.04	$ 0.04	$ 0.04
11(b) Base	$ 5.22	$ 0.03	$ 0.04	$ 0.09	$ 0.19	$ 0.28	$ 0.64	$ 0.35	$ 0.40	$ 0.38
12(b) Base	$ 5.64	$ 0.02	$ 0.05	$ 0.11	$ 0.19	$ 0.26	$ 0.62	$ 0.31	$ 0.33	$ 0.32
13(b) Base	$ 155.57	$ 0.17	$ 0.16	$ 0.15	$ 0.14	$ 6.86	$ 7.48	$ 13.10	$ 12.50	$ 12.29
14(b) Base	$ 0.86	$ -	$ -	$ -	$ 0.02	$ 0.05	$ 0.07	$ 0.07	$ 0.06	$ 0.06
15(b) Base	$ 1.71	$ -	$ -	$ -	$ 0.00	$ 0.05	$ 0.06	$ 0.10	$ 0.14	$ 0.14
16(b) Base	$ 9.26	$ 0.01	$ 0.01	$ 0.01	$ 0.29	$ 0.55	$ 0.87	$ 0.78	$ 0.74	$ 0.70
17(b) Base	$ 1.89	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.29	$ 0.60	$ -
18(b) Base	$ 7.17	$ -	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.03	$ 0.33	$ 0.62	$ 0.61
19(b) Base	$ 1.39	$ -	$ -	$ -	$ 0.00	$ 0.04	$ 0.05	$ 0.08	$ 0.12	$ 0.11
20(b) Base	$ 0.77	$ -	$ -	$ 0.01	$ 0.03	$ 0.05	$ 0.10	$ 0.06	$ 0.06	$ 0.05
21(b) Base	$ 1.13	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.06	$ 0.14	$ 0.08	$ 0.09	$ 0.08
22(b) Base	$ 0.93	$ -	$ 0.01	$ 0.02	$ 0.03	$ 0.05	$ 0.10	$ 0.06	$ 0.07	$ 0.07
23(b) Base	$ 0.74	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.05	$ 0.12	$ 0.05	$ 0.05	$ 0.05
24(b) Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25(b) Base	$ 10.21	$ -	$ 0.08	$ 0.18	$ 0.39	$ 0.57	$ 1.22	$ 0.71	$ 0.77	$ 0.74
26 Base	$ 3.73	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.17	$ 0.18	$ 0.32	$ 0.30	$ 0.30

6 APPENDICES

1. Meter Test Plans

2. Field Audit Results

3. Guidelines and Practices Detail

4. TOU Billing Data

5. Smart Meter Data Audit

6. References

7. Inputs and Assumptions

8. Meter Accuracy Weighting

9. Glossary

10. Project Partner Qualifications

7 APPENDIX 1: METER TEST INSPECTION

Meter Testing

Testing of meters was carried out by Alliance Calibration, an accredited test laboratory in the Greater Cincinnati Area, in accordance with a subset of the meter type testing standards, ANSI C12.20. Sample selection of meters undergoing test (MUT), the testing and the test results are documented in a test report which was then reviewed by MetaVu and prepared for the smart grid report by Alliance Calibration.

MetaVu has assessed that the tests have been carried out in accordance with the appropriate test procedures and that they properly document the aspects required for this evaluation.

Load Measurements

Electric load measurements were required for accuracy evaluation. The tests were conducted according to the minimum requirements given below. The purpose of "Load Testing" was to provide data to enable MetaVu to estimate accuracy. For Load Testing, the specific load and consumption registration listed in ANSI C12.20 were measured.

Test Results Attestation

MetaVu attests that the necessary tests have been carried out by Alliance Calibration in accordance with relevant international standards.

Bench-testing was conducted by the staff of Alliance Calibration at the Alliance Calibration testing facility. The test engineer prepared a test plan which was inspected by the MetaVu staff and is additionally agreed to by both MetaVu and Alliance Calibration. This test plan conforms to the industry standard requirements including the descriptions for quality assurance of the testing process. The tests were conducted according to the test plan as attested to by the MetaVu staff. This attestation is, at a minimum, based on high level inspections of the following:

- All instrument calibrations required in the procedures described in the test plan
- All instrument model and serial numbers relevant to calibrations
- Representative Smart Meters under test
- Instrument electrical connections
- The quality of at least 48 passed lot MUTs test data

Test Reports

Test reports prepared by Alliance Calibration conform to the relevant standard used to define the test requirements. Each test report includes, at a minimum:

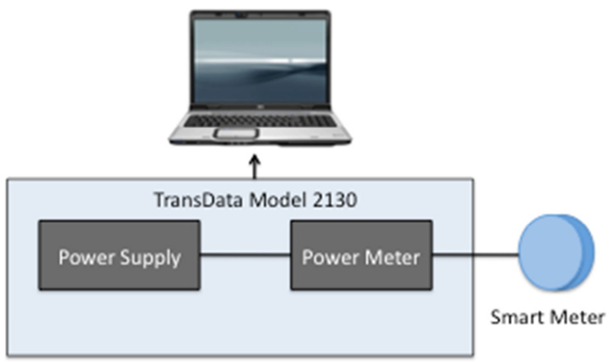
- A description of the MUT samples
- Lot including the serial number, and differences between the lot and the in-service meters
- A description of the test site
- Instrumentation
- Test procedure
- Test conditions
- Data analysis procedure

- Uncertainty analysis
- Results

7.1 Appendix 1-A: Electric Meter Test Plan

TransData Meter Testing Procedure

Simplified Test Layout



Meters were tested in our Laboratory and in an environmentally controlled chamber.

- All meters were tested as follows:
  - 240 Volts
  - 30 Amps
  - 3 Amps
  - Unity Power Factor
  - 50% Power Factor
- The Alliance Calibration Laboratory is maintained at 23°C ±5°and 20-30% Relative Humidity.
- The TransData 2130 Serial # 10502638 and Serial# 110504888 allows for the testing of various types of meters (electromechanical, digital and smart meters) and contains an internal Standard with an accuracy of +-0.025%.
- Proof of calibration traceable to NIST provided by Manufacturer.
- Refer to TransData technical specifications for specific details.
- A bar code scanner was used to read the unique meter identifier and this number is used as the identifier for test results.
- It is identified on the actual test report.
- The Test report also shows:
  - The Date the test was performed
  - The Technician who performed the test
  - The Test Constant
  - The Instrument Transformer Constant
  - The Meter Form
  - The Test setup name
  - The measured Quantity
  - The test report is generated as a PDF document that contains a time and date stamp.

Environmental Chamber Testing Conditions

- All meters were tested at -40°C±0.5° and + 40°C±0.5°.
- All meters were allowed to acclimate to temperature in the chamber for at least 24 hours before testing.
- The meter base was placed inside the chamber and TransData tester placed outside the chamber for all testing.
- These temperature ranges were selected as they represent the extreme range of temperatures on record from −25 to 109 °F (-32 to 43 °C) on January 18, 1977 and July 21, 1934, respectively by the National Weather Service.

Alliance Calibration	**Revision 1.0**
Procedure: P-114A	**Revision Date: 03/14/2011**
Title: 2S Watt Meters	

1.0 Purpose

1.1 The purpose of this document is to establish and maintain the procedure for calibration of 2S Watt Hour Meters

2.0 Scope

2.1 This procedure covers calibrations performed on all 2S Watt Hour Meters owned by Alliance Calibration or a customer contracting the services of Alliance Calibration

3.0 Authorization

3.1 Alliance Calibration Quality Manual

4.0 References

4.1 ISO 17025:2005

4.2 Manufacturer's specifications

4.2.1 Tolerance

4.2.2 Range

4.2.3 Limitations

5.0 Reference Standards and Equipment Used

5.1 Watt Hour Calibration Standard (TransData Model 2130 and computer with TransData software or equivalent)

5.2 2S Meter Socket

5.3 Associated wire leads as needed

Note: Before proceeding with the calibration the technician(s) must be familiar with the operation of the UUT, reference standards, and other equipment used in the calibration. In addition, safety considerations need to be taken into account to protect the UUT, reference standards, equipment, laboratory or the technician(s) from harm.

6.0 Detailed Procedure

6.1 Disconnect unit under test (UUT) from any external power source.

6.2 Disconnect voltage link located on rear of UUT.

6.3 Use an ohm meter to determine the correct terminal and connect opened voltage link to standard V-. Install meter into 2S meter socket.

6.4 Connect calibration standard to 2S meter socket as seen in attached diagram.

6.5 Affix optical pick up to meter. Use disk sensor for electromechanical meters of the Infra-red sensor for solid state meters.

6.6 Open the TransData software select “meter test” and then select the appropriate calibration program from the calibration computer software and ensure Kwh values match the value printed on the meter face.

6.7 When using the electromechanical disk sensor pick up apply full voltage and amperage and adjust the pick-up position and or sensitivity as required.

6.8 Fill in the meter identification number, the customer, and any additional information required in the software fields.

6.9 Click the “Begin As Found Test” button. The computer will control the testing of the meter. The meter will be tested on phase A and C for high current (30A @ unity power factor) power factor (30 @ 0.5 power factor) and light load (10% of full load test @ unity power factor). Phases A & C are tested separately to ensure any calibration deficiencies that may go unnoticed during series testing would be identified. Phase B is used only when calibrating 3-phase watt hour meters. The software will use the data from the optical pick up to calculate the value reported by the UUT and compare it to the calibration standard as a percentage value.

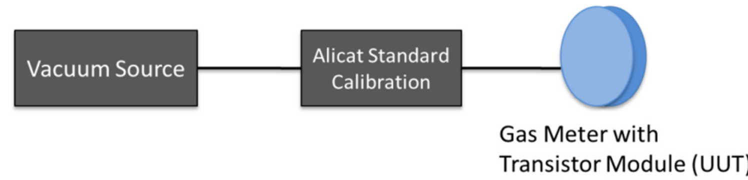
6.10 When calibration is complete the TransData standard will emit a series of beeps signaling the completion of testing for the UUT. Use the print button to generate a report of the calibration results.

6.11 Create certificate.

7.2 Appendix 1-B: Gas Meter Test Plan

Badger Transmitter Testing:

- Badger Transmitter connected to Gas Meter
- Known flow was applied at 23°C ±5°C at 20-30% relative humidity
- Readings were taken with a Trimble Ranger handheld meter reader Firmware5.0.3 serial #ss75c29567 and compared to known flow.



Alliance Calibration	**Revision 1.00**
Procedure: P-104A	**Revision Date: 5/2/2011**
Title: Calibration of Gas Flow Totalizers	

1.0 Purpose

1.1 The purpose of this document is to establish and maintain the procedure for the calibration of gas flow totalizing meters. Gas flow totalizing meters are intended to measure the amount of a gas that has been used over the course of time.

2.0 Scope

2.1 This procedure covers calibrations performed on all gas flow totalizing meters owned by Alliance Calibration or a customer contracting the services of Alliance Calibration

3.0 Authorization

3.1 Alliance Calibration Quality Manual

4.0 References

4.1 ISO 17025:2005

4.2 Manufacturer's specifications

4.2.1 Tolerance

4.2.2 Range

4.2.3 Limitations

4.2.4 General operation of unit under test (UUT)

4.2.5 Safety considerations

4.3 Customer specifications

4.3.1 Tolerance

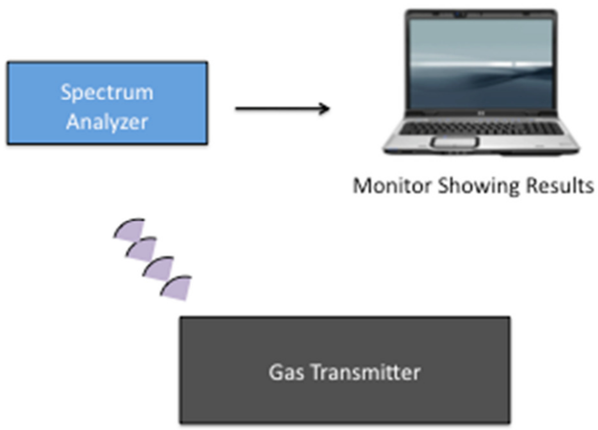
4.3.2 Range

4.3.3 Limitations

5.0 Reference Standards and Equipment Used 5.1 Electronic mass flow meter with a totalize function of appropriate range for the unit under test (UUT) to be calibrated. (Typically Alicat Flow model PCU) 5.2 Tubing, hose, and fittings required to make necessary connections 5.3 Vacuum source Note: Before proceeding with the calibration the technician(s) must be familiar with the operation of the UUT, reference standards, and other equipment used in the calibration. In addition, safety considerations need to be taken into account to protect the UUT, reference standards, equipment, laboratory or the technician(s) from harm.
6.0 Detailed Procedure 6.1 Connect the outlet of the UUT to the calibration standard inlet port. 6.2 Ensure the UUT inlet is free from obstructions. 6.3 Connect the outlet of the calibration standard to regulated vacuum source. 6.4 Turn on the calibration standard, and enter the device's totalize function. 6.5 Turn on the vacuum source and adjust the flow rate to be stable and representative of the UUT normal operating conditions. 6.6 Turn off the vacuum source and use the tare function of the calibrator and UUT. If the UUT does not have a tare function record the numerical readings prior to testing. 6.7 Turn on the vacuum source. Allow air to flow until a representative reading can be obtained. 6.8 Turn off vacuum source, record and compare readings. In the case of devices that do not have a tare function subtract the reading obtained in step 6.5 from the final reading to achieve the corrected reading for the UUT. 6.9 Repeat steps 6.1-6.7 for additional calibration points as required. 6.10 Create Calibration certificate.
Alicat Portable Calibration Unit: • Serial # 60216-60217-60218 • See Alicat Portable Calibration Manual for Specifications

7.3 Appendix 1-C: Gas Transmitter Chamber Test Plan

Simplified Test Layout



Technical

The Federal Communications Commission (FCC) requires that all digital devices (including information Technology, Industrial, Scientific, and Medical Equipment) that operate with internal clock rates over 9 kHz be tested under one of more of the sections outlined in CFR Title 47, Parts 15, 18, 68, and 90.

Declaration of Conformity

In May 1996, the FCC allowed manufacturers of personal computer and peripherals to issue Declarations of Conformity (DoC's) in order to proclaim compliance of their products to Part 15. This was introduced as a way for manufacturers to get their products to market faster. Once the test report has been issues by an accredited test laboratory, the manufacturer can sell products immediately.

Certification

Some products, such as transmitters, are required to be certified by the FCC. Certification requires that an application be made to the FCC. The product may not be sold/marketed until the approval process is completed and the Certification is granted by the FCC.

Verification

Verification is a self-approval process. The equipment must be tested and the manufacturer must then maintain the test report and submit it to the FCC upon request. This process is typically used for Class A products such as business computers, TV and FM receivers, and Industrial, Scientific, and Medical Equipment.

Radio Frequency Overview

- FCC Registration Number (FRN): 0002723575
- Filing the FCC states device as low power transmitter
- 3rd party test firm recorded in filing
- Filing states frequency of 916.45 MHz

Radiated Emissions

The Badger Transmitter was initially placed in a semi-Anechoic RF Chamber, and wide band characterization measurements were performed to determine the frequencies at which significant emissions occurred.

The Badger Transmitter was tested at a distance of 3.0 meters. The emissions were maximized by rotating the table and raising/lowering the antenna mounted on a 4.0 meter mast. Cable and peripheral positions were also varied to produce maximum emissions. Both horizontal and vertical field components were measured. The output of the antenna was connected to the input of the receiver and emissions were measured in the range of 30MHz to 1GHz. The values up to 1GHz with a resolution bandwidth of 120 kHz are quasi-peak reading made at 3.0 meters. The raw measurements were corrected to allow for antenna factor and cable loss.

Conducted Emissions

The Badger Transmitter was placed on a 1.0 x 1.5 meter non-conductive table, 0.8 meter above a horizontal ground plane and 0.4 meter from a vertical ground plane. Power was provided to the EUT through a LISN bonded to a 3 x 2 meter ground plane. The LISN and peripherals were supplied power through a filtered AC power source. The output of the LISN was connected to the input of the receiver via a transient limiter, and emissions in the range 150 kHz to 30 MHz were measured. The measurements were recorded using the quasi-peak and average detectors as directed by the standard, and the resolution bandwidth during testing was 9kHz. The raw measurements were corrected to allow for attenuation from the LISN, transient limiter and cables.

Radiated Emission Testing

The EUT was positioned on an 80cm non-metallic table and tested on an Open Area Test Site, (OATS) at a distance of 3.0 meters. The emissions were maximized by rotating the table 360 degrees and raising/lowering the antenna mounted on a 4.0 meter mast. Cable and peripheral positions were also varied to produce maximum emissions. Both horizontal and vertical field components were measured. The output of the antenna was connected to the input of the receiver and emissions were measured in the range 30MHz to 1GHz. The values up to 1GHz with a resolution bandwidth of 120 kHz are quasi-peak readings made at 3.0 meters. The measurements above 1GHz with a resolution bandwidth of 1MHz are peak readings at a distance of 3.0 meters. The raw measurements were corrected to allow for antenna factor and cable loss.

Calculation of Data-Radiated Emission

The antenna factors of the antennas used, and the cable losses are added to the field strength reading recorded from the measurement receiver. The resultant field strength can then be compared to the FCC limits in dBµV/m. The following equation is used to convert to µV/m:

EµV/m = antilog (EdBµV/m /20)

Sample of Field Strength Calculation:

Ea =Va + AF + Ae

Where: Ea = Field Strength (dBµV/m)

Va= 20 x log10 (Measure RF voltage, µV)

Ae= Cable Loss Factor, dB

AF= Antenna Factor dB (m-1)

8 APPENDIX 2: FIELD AUDIT

8.1 Methodology

MetaVu randomly selected various pieces of Distribution Automation Equipment deployed by 2010 for the Audit. Selections were based on a list of deployed equipment that was provided in Duke's response to Data Request 39. Within a week, Duke had mapped out the selections on a GPS device, provided one-line diagrams and assigned a Duke employee to guide Alliance Calibration to the physical locations. The Physical Field Audit took place between February 22nd 2011 and April 6th 2011.

Checklist

The following information was captured for each piece of equipment:

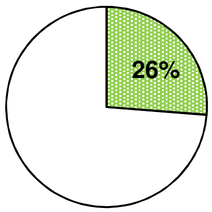
- Audit Date
- Unique identifier and circuit number labeled on equipment and used as tag in EMS(D-SCADA/DMS)
- Picture of Equipment/Enclosures/Unique Identifier
- For a subset of applicable equipment:
  - A time-stamped display reading or a switch position indication
  - A real-time call to the EMS operator checking that the EMS control center was reading the same on-screen
  - In follow-up at a later date Duke provided archived data for MetaVu to check system integration end-to-end

8.2 Result/Conclusion

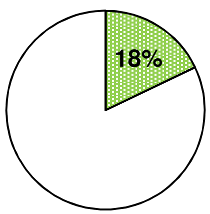
- All the Equipment selected for Audit was found to be installed. *(See Figures A2.1 and A2.2 below)*
- All display readings and switch position indicators matched up with EMS in real-time. *(See Figure A2.3 below).*
- All but one (Team 6 Montgomery Circuit 45 ID #29903) switch position matched the PI data. *(See Figure A2.4 below).* It is reasonable to conclude that the one that did not match is attributed to "noise" in the measurement because everything matched up in real-time. The cause of this is most likely a human error and can be attributed to one or more of the following:
  - The time stamp as captured was inaccurate
  - The switch position was written down incorrectly
  - The switch was operated within a minute of the physical audit (time stamps are rounded to nearest minute)
  - Duke operator may accidently have given inaccurate switch position from archived data

8.3 Outside the Fence Audit Selections

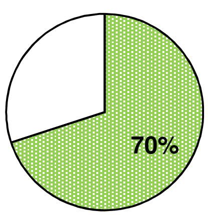
Electronic Reclosers
audited=21 of 80



Sectionalization
audited=36 of 201

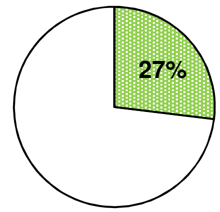


Self-Healing teams audited=7
of 10

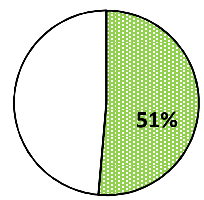


8.4 Inside the Fence Audit Selections

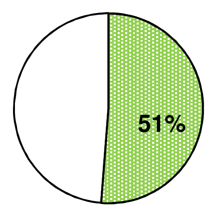
Circuit Breakers
audited=7 of 26



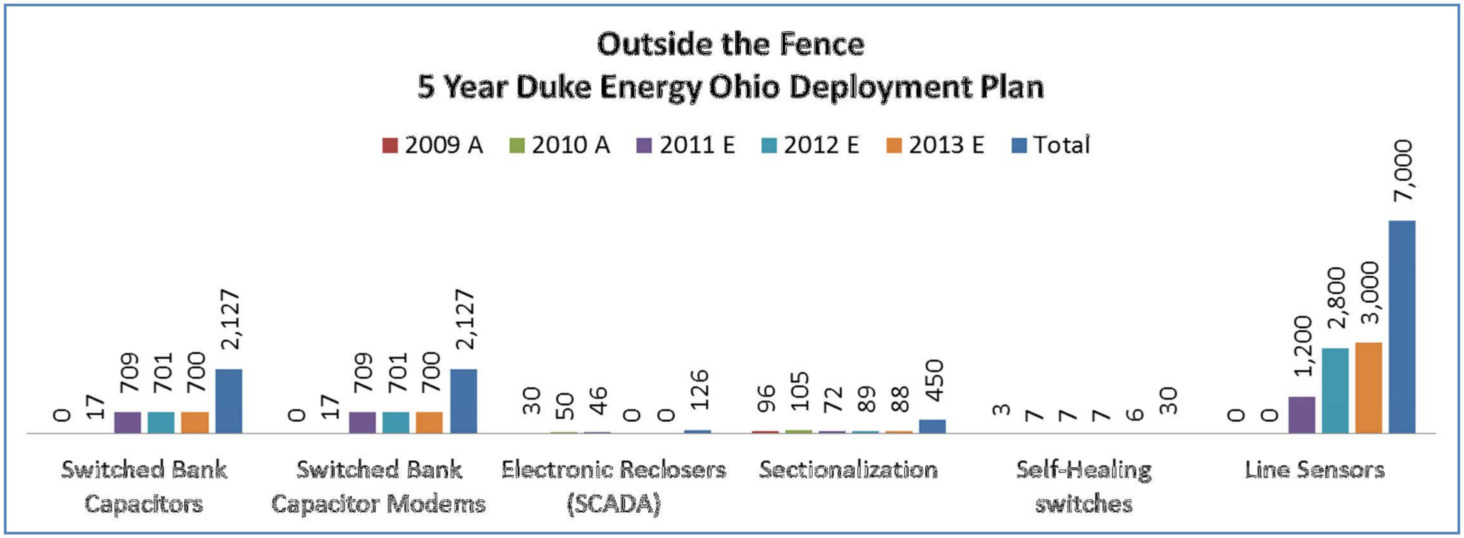
Relays
audited=74 of 144



Substation Regulators
audited=62 of 121



Figures A2.1 and A2.2 Field Audit Findings Actual deployment numbers for 2009 and 2010 - Estimates for 2011-2013



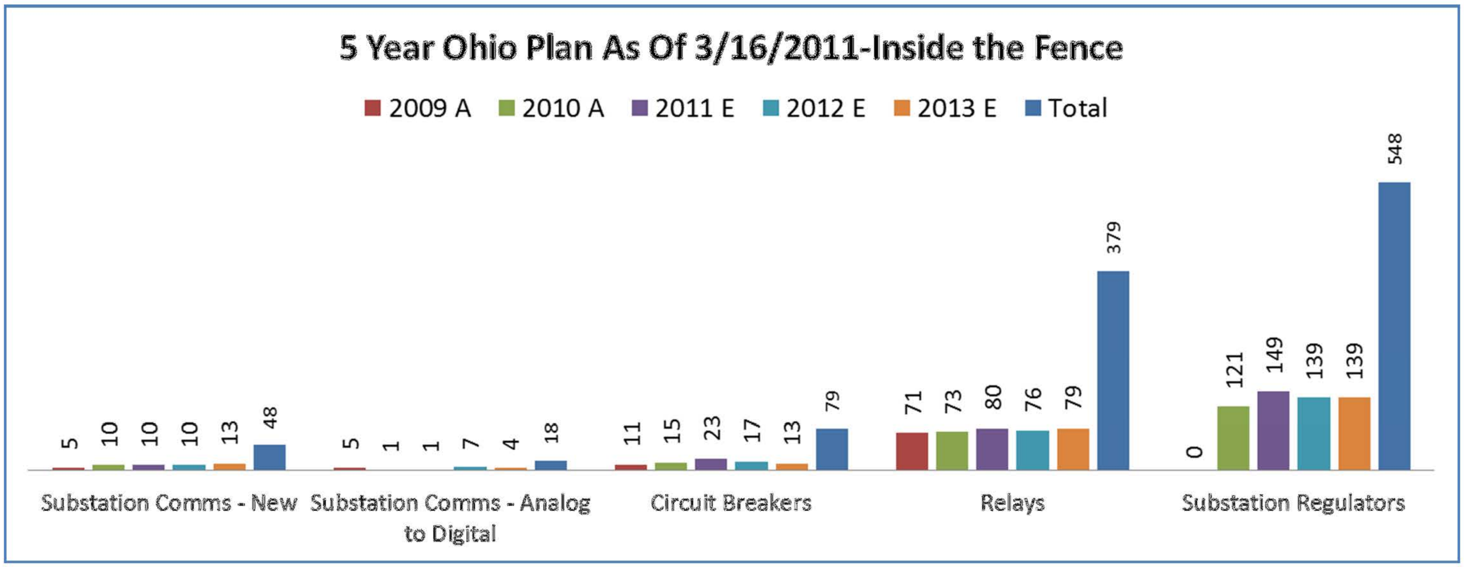


Figure A2.3 Field Audit Findings. Display readings from field (in blue) match archived data (in red)

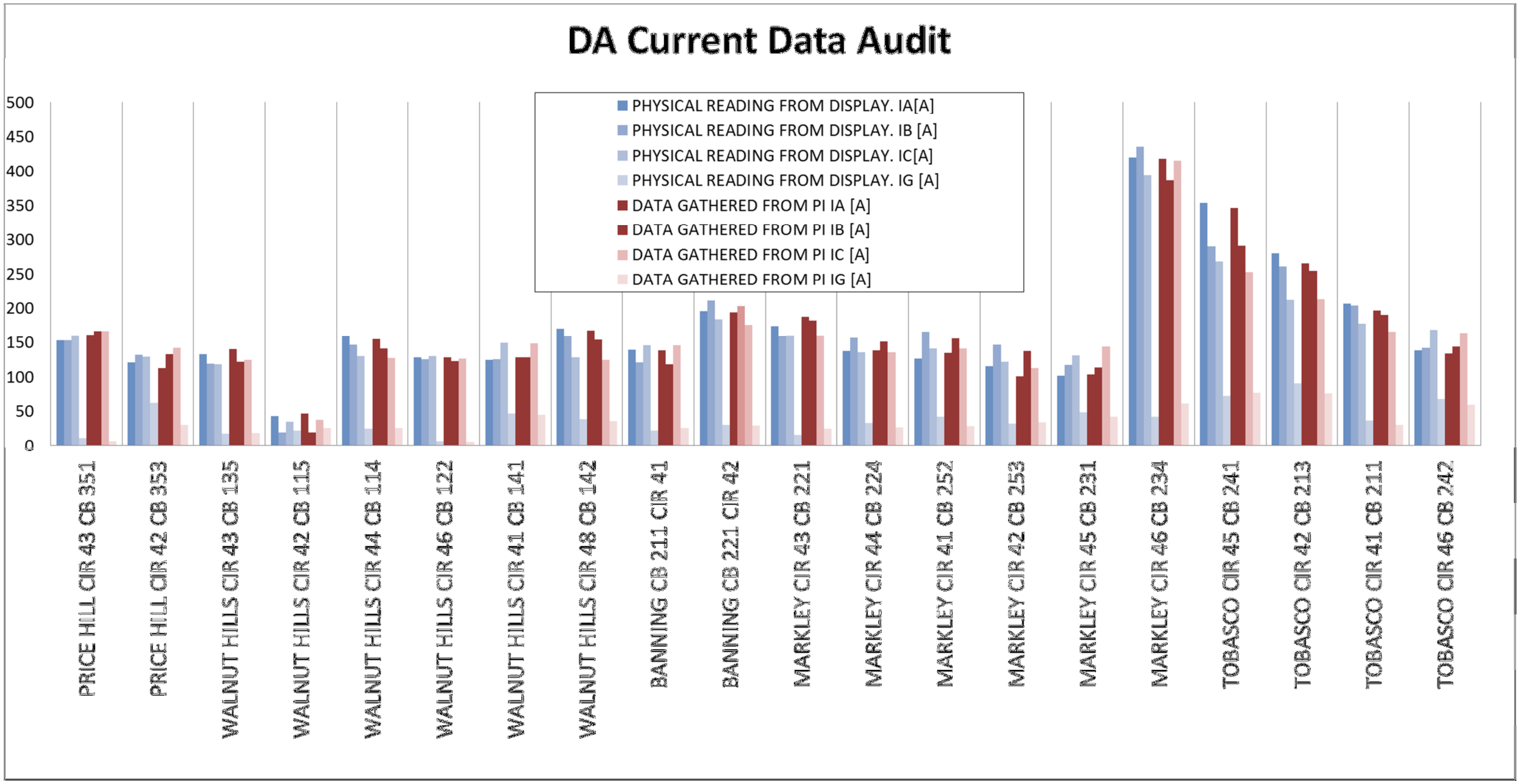
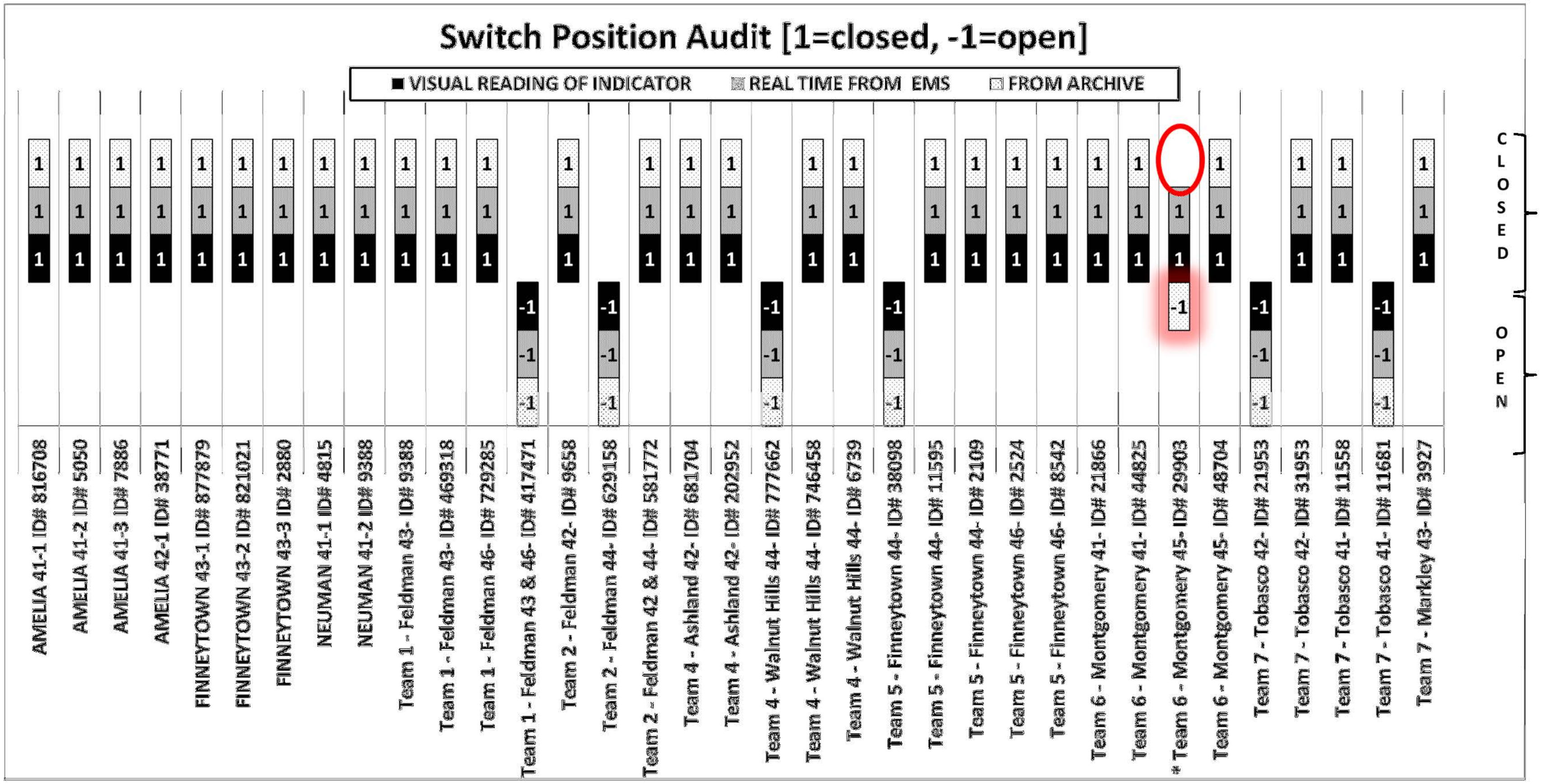


Figure A2.4. Field Audit Findings. All but one indicator reading match archived data



9 APPENDIX 3: GUIDELINES AND PRACTICES

9.1 Appendix 3-A – Conformity with the NISTIR 7628

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Requirement	Impact Level Allocation	Conformity Level
Access Control		
SG.AC-1 Access Control Policy and Procedures	Low / Moderate / High	…………………………………
SG.AC-2 Remote Access Policy and Procedures	Low / Moderate / High	…………………………………
SG.AC-3 Account Management	Low / Moderate / High	…………………………………
SG.AC-4 Access Enforcement	Low / Moderate / High	…………………………………
SG.AC-6 Separation of Duties	Moderate / High	…………………………………
SG.AC-7 Least Privilege	Moderate / High	…………………………………
SG.AC-8 Unsuccessful Login Attempts	Low / Moderate / High	…………………………………
SG.AC-9 Smart Grid Information System Use Notification	Low / Moderate / High	…………………………………
SG.AC-11 Concurrent Session Control	Moderate / High	…………………………………
SG.AC-12 Session Lock	Moderate / High	…………………………………
SG.AC-13 Remote Session Termination	Moderate / High	…………………………………
SG.AC-14 Permitted Actions without Identification or Authentication	Low / Moderate / High	…………………………………
SG.AC-15 Remote Access	Low / Moderate / High	…………………………………
SG.AC-16 Wireless Access Restrictions	Low / Moderate / High	…………………………………
SG.AC-17 Access Control for Portable and Mobile Devices	Low / Moderate / High	…………………………………
SG.AC-18 Use of External Information Control Systems	Low / Moderate / High	…………………………………
SG.AC-19 Control System Access Restrictions	Low / Moderate / High	…………………………………
SG.AC-20 Publicly Accessible Content	Low / Moderate / High	…………………………………
SG.AC-21 Passwords	Low / Moderate / High	…………………………………
Awareness and Training		
SG.AT-1 Awareness and Training Policy and Procedures	Low / Moderate / High	…………………………………
SG.AT-2 Security Awareness	Low / Moderate / High	…………………………………
SG.AT-3 Security Training	Low / Moderate / High	…………………………………

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
SG.AT-4 Security Awareness and Training Records	Low / Moderate / High	…………………………………
SG.AT-6 Security Responsibility Testing	Low / Moderate / High	…………………………………
SG.AT-7 Planning Process Training	Low / Moderate / High	…………………………………
Audit and Accountability		
SG.AU-1 Audit and Accountability Policy and Procedures	Low / Moderate / High	…………………………………
SG.AU-2 Auditable Events	Low / Moderate / High	…………………………………
SG.AU-3 Content of Audit Records	Low / Moderate / High	…………………………………
SG.AU-4 Audit Storage Capacity	Low / Moderate / High	…………………………………
SG.AU-5 Response to Audit Processing Failures	Low / Moderate / High	…………………………………
SG.AU-6 Audit Monitoring, Analysis, and Reporting	Low / Moderate / High	…………………………………
SG.AU-7 Audit Reduction and Report Generation	Moderate / High	…………………………………
SG.AU-8 Time Stamps	Low / Moderate / High	…………………………………
SG.AU-9 Protection of Audit Information	Low / Moderate / High	…………………………………
SG.AU-10 Audit Record Retention	Low / Moderate / High	…………………………………
SG.AU-11 Conduct and Frequency of Audits	Low / Moderate / High	…………………………………
SG.AU-12 Auditor Qualification	Low / Moderate / High	…………………………………
SG.AU-13 Audit Tools	Low / Moderate / High	…………………………………
SG.AU-14 Security Policy Compliance	Low / Moderate / High	…………………………………
SG.AU-15 Audit Generation	Low / Moderate / High	…………………………………
SG.AU-16 Non-Repudiation	High	…………………………………
Security Assessment and Authorization		
SG.CA-1 Security Assessment and Authorization Policy and Procedures	Low / Moderate / High	…………………………………
SG.CA-2 Security Assessments	Low / Moderate / High	…………………………………
SG.CA-4 Smart Grid Information System Connections	Low / Moderate / High	…………………………………
SG.CA-5 Security Authorization to Operate	Low / Moderate / High	…………………………………
SG.CA-6 Continuous Monitoring	Low / Moderate / High	…………………………………
Configuration Management		
SG.CM-1 Configuration Management Policy and Procedures	Low / Moderate / High	…………………………………
SG.CM-2 Baseline Configuration	Low / Moderate / High	…………………………………
SG.CM-3 Configuration Change Control	Moderate / High	…………………………………
SG.CM-4 Monitoring Configuration Changes	Low / Moderate / High	…………………………………
SG.CM-5 Access Restrictions for Configuration Change	Moderate / High	…………………………………
SG.CM-6 Configuration Settings	Low / Moderate / High	…………………………………
SG.CM-7 Configuration for Least Functionality	Low / Moderate / High	…………………………………
SG.CM-8 Component Inventory	Low / Moderate / High	…………………………………
SG.CM-9 Addition, Removal, and Disposal of Equipment	Low / Moderate / High	…………………………………
SG.CM-10 Factory Default Settings Management	Low / Moderate / High	…………………………………

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
SG.CM-11 Configuration Management Plan	Low / Moderate / High	....
Continuity of Operations		
SG.CP-1 Continuity of Operations Policy and Procedures	Low / Moderate / High	....
SG.CP-2 Continuity of Operations Plan	Low / Moderate / High	....
SG.CP-3 Continuity of Operations Roles and Responsibilities	Low / Moderate / High	....
SG.CP-4 Continuity of Operations Training	Low / Moderate / High	....
SG.CP-5 Continuity of Operations Plan Testing	Low / Moderate / High	....
SG.CP-6 Continuity of Operations Plan Update	Low / Moderate / High	....
SG.CP-7 Alternate Storage Sites	Moderate / High	....
SG.CP-8 Alternate Telecommunication Services	Moderate / High	....
SG.CP-9 Alternate Control Center	Moderate / High	....
SG.CP-10 Smart Grid Information System Recovery and Reconstitution	Low / Moderate / High	....
SG.CP-11 Fail-Safe Response	High	....
Identification and Authentication		
SG.IA-1 Identification and Authentication Policy and Procedures	Low / Moderate / High	....
SG.IA-2 Identifier Management	Low / Moderate / High	....
SG.IA-3 Authenticator Management	Low / Moderate / High	....
SG.IA-4 User Identification and Authentication	Low / Moderate / High	....
SG.IA-5 Device Identification and Authentication	Moderate / High	....
SG.IA-6 Authenticator Feedback	Low / Moderate / High	....
Information and Document Management		
SG.ID-1 Information and Document Management Policy and Procedures	Low / Moderate / High	....
SG.ID-2 Information and Document Retention	Low / Moderate / High	....
SG.ID-3 Information Handling	Low / Moderate / High	....
SG.ID-4 Information Exchange	Low / Moderate / High	....
Incident Response		
SG.IR-1 Incident Response Policy and Procedures	Low / Moderate / High	....
SG.IR-2 Incident Response Roles and Responsibilities	Low / Moderate / High	....
SG.IR-3 Incident Response Training	Low / Moderate / High	....
SG.IR-4 Incident Response Testing and Exercises	Low / Moderate / High	....
SG.IR-5 Incident Handling	Low / Moderate / High	....
SG.IR-6 Incident Monitoring	Low / Moderate / High	....
SG.IR-7 Incident Reporting	Low / Moderate / High	....
SG.IR-8 Incident Response Investigation and Analysis	Low / Moderate / High	....
SG.IR-9 Corrective Action	Low / Moderate / High	....
SG.IR-10 Smart Grid Information System Backup	Low / Moderate / High	....
SG.IR-11 Coordination of Emergency Response	Low / Moderate / High	....

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Requirement	Impact Level Allocation	Conformity Level
Smart Grid Information System Development and Maintenance		
SG.MA-1 Smart Grid Information System Maintenance Policy and Procedures	Low / Moderate / High	....
SG.MA-2 Legacy Smart Grid Information System Upgrades	Low / Moderate / High	....
SG.MA-3 Smart Grid Information System Maintenance	Low / Moderate / High	....
SG.MA-4 Maintenance Tools	Low / Moderate / High	....
SG.MA-5 Maintenance Personnel	Low / Moderate / High	....
SG.MA-6 Remote Maintenance	Low / Moderate / High	....
SG.MA-7 Timely Maintenance	Low / Moderate / High	....
Media Protection		
SG.MP-1 Media Protection Policy and Procedures	Low / Moderate / High	....
SG.MP-2 Media Sensitivity Level	Low / Moderate / High	....
SG.MP-3 Media Marking	Moderate / High	....
SG.MP-4 Media Storage	Low / Moderate / High	....
SG.MP-5 Media Transport	Low / Moderate / High	....
SG.MP-6 Media Sanitization and Disposal	Low / Moderate / High	....
Physical and Environmental Security		
SG.PE-1 Physical and Environmental Security Policy and Procedures	Low / Moderate / High	....
SG.PE-2 Physical Access Authorizations	Low / Moderate / High	....
SG.PE-3 Physical Access	Low / Moderate / High	....
SG.PE-4 Monitoring Physical Access	Low / Moderate / High	....
SG.PE-5 Visitor Control	Low / Moderate / High	....
SG.PE-6 Visitor Records	Low / Moderate / High	....
SG.PE-7 Physical Access Log Retention	Low / Moderate / High	....
SG.PE-8 Emergency Shutoff Protection	Low / Moderate / High	....
SG.PE-9 Emergency Power	Low / Moderate / High	....
SG.PE-10 Delivery and Removal	Low / Moderate / High	....
SG.PE-11 Alternate Work Site	Low / Moderate / High	....
SG.PE-12 Location of Smart Grid Information System Assets	Low / Moderate / High	....
Planning		
SG.PL-1 Strategic Planning Policy and Procedures	Low / Moderate / High	....
SG.PL-2 Smart Grid Information System Security Plan	Low / Moderate / High	....
SG.PL-3 Rules of Behavior	Low / Moderate / High	....
SG.PL-4 Privacy Impact Assessment	Low / Moderate / High	....
SG.PL-5 Security-Related Activity Planning	Moderate / High	....
Security Program Management		
SG.PM-1 Security Policy and Procedures	Low / Moderate / High	....
SG.PM-2 Security Program Plan	Low / Moderate / High	....

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
SG.PM-3 Senior Management Authority	Low / Moderate / High	....
SG.PM-4 Security Architecture	Low / Moderate / High	....
SG.PM-5 Risk Management Strategy	Low / Moderate / High	....
SG.PM-6 Security Authorization to Operate Process	Low / Moderate / High	....
SG.PM-7 Mission/Business Process Definition	Low / Moderate / High	....
SG.PM-8 Management Accountability	Low / Moderate / High	....
Personnel Security		
SG.PS-1 Personnel Security Policy and Procedures	Low / Moderate / High	....
SG.PS-2 Position Categorization	Low / Moderate / High	....
SG.PS-3 Personnel Screening	Low / Moderate / High	....
SG.PS-4 Personnel Termination	Low / Moderate / High	....
SG.PS-5 Personnel Transfer	Low / Moderate / High	....
SG.PS-6 Access Agreements	Low / Moderate / High	....
SG.PS-7 Contractor and Third-Party Personnel Security	Low / Moderate / High	....
SG.PS-8 Personnel Accountability	Low / Moderate / High	....
SG.PS-9 Personnel Roles	Low / Moderate / High	....
Risk Management and Assessment		
SG.RA-1 Risk Assessment Policy and Procedures	Low / Moderate / High	....
SG.RA-2 Risk Management Plan	Low / Moderate / High	....
SG.RA-3 Security Impact Level	Low / Moderate / High	....
SG.RA-4 Risk Assessment	Low / Moderate / High	....
SG.RA-5 Risk Assessment Update	Low / Moderate / High	....
SG.RA-6 Vulnerability Assessment and Awareness	Low / Moderate / High	....
Smart Grid Information System and Services Acquisition		
SG.SA-1 Smart Grid Information System and Services Acquisition Policy and Procedures	Low / Moderate / High	....
SG.SA-2 Security Policies for Contractors and Third Parties	Low / Moderate / High	....
SG.SA-3 Life-Cycle Support	Low / Moderate / High	....
SG.SA-4 Acquisitions	Low / Moderate / High	....
SG.SA-5 Smart Grid Information System Documentation	Low / Moderate / High	....
SG.SA-6 Software License Usage Restrictions	Low / Moderate / High	....
SG.SA-7 User-Installed Software	Low / Moderate / High	....
SG.SA-8 Security Engineering Principles	Low / Moderate / High	....
SG.SA-9 Developer Configuration Management	Low / Moderate / High	....
SG.SA-10 Developer Security Testing	Low / Moderate / High	....
SG.SA-11 Supply Chain Protection	Low / Moderate / High	....
Smart Grid Information System and Communication Protection		
SG.SC-1 Smart Grid Information System and Communication Protection Policy and Procedures	Low / Moderate / High	....

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
SG.SC-3 Security Function Isolation	Low / Moderate / High	....
SG.SC-5 Denial-of-Service Protection	Low / Moderate / High	....
SG.SC-6 Resource Priority	High	....
SG.SC-7 Boundary Protection	Low / Moderate / High	....
SG.SC-8 Communication Integrity	Moderate / High	....
SG.SC-9 Communication Confidentiality	Moderate / High	....
SG.SC-11 Cryptographic Key Establishment and Management	Low / Moderate / High	....
SG.SC-12 Use of Validated Cryptography	Low / Moderate / High	....
SG.SC-13 Collaborative Computing	Low / Moderate / High	....
SG.SC-15 Public Key Infrastructure Certificates	Low / Moderate / High	....
SG.SC-16 Mobile Code	Moderate / High	....
SG.SC-17 Voice-Over Internet Protocol	Moderate / High	....
SG.SC-18 System Connections	Low / Moderate / High	....
SG.SC-19 Security Roles	Low / Moderate / High	....
SG.SC-20 Message Authenticity	Low / Moderate / High	....
SG.SC-21 Secure Name/Address Resolution Service	Low / Moderate / High	....
SG.SC-22 Fail in Known State	Moderate / High	....
SG.SC-26 Confidentiality of Information at Rest	Moderate / High	....
SG.SC-29 Application Partitioning	High	....
SG.SC-30 Smart Grid Information System Partitioning	Moderate / High	....
Smart Grid Information System and Information Integrity		
SG.SI-1 Smart Grid Information System and Information Integrity Policy and Procedures	Low / Moderate / High	....
SG.SI-2 Flaw Remediation	Low / Moderate / High	....
SG.SI-3 Malicious Code and Spam Protection	Low / Moderate / High	....
SG.SI-4 Smart Grid Information System Monitoring Tools and Techniques	Low / Moderate / High	....
SG.SI-5 Security Alerts and Advisories	Low / Moderate / High	....
SG.SI-6 Security Functionality Verification	Moderate / High	....
SG.SI-7 Software and Information Integrity	Moderate / High	....
SG.SI-8 Information Input Validation	Moderate / High	....
SG.SI-9 Error Handling	Low / Moderate / High	....
Cryptography and key management		
Key material and cryptographic operations protection	Moderate / High	....
Key material generation	Low / Moderate / High	....
Key material provisioning	High	....
Key material uniqueness, (e.g., key derivation secrets, managing secrets, pre-shared secrets)	Moderate / High	....
Revocation management	Low / Moderate / High	....
Credential span of control	Moderate / High	....

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Requirement	Impact Level Allocation	Conformity Level
Key and crypto lifecycles (supersession / revocation)	Low / Moderate / High	[redacted]
Key material Destruction	Moderate / High	[redacted]
Local autonomy (Availability Exclusively)	Moderate / High	[redacted]
Privacy		
Accuracy and Quality	N/A	[redacted]
Choice and Consent	N/A	[redacted]
Collection and Scope	N/A	[redacted]
Disclosure and Limiting Use	N/A	[redacted]
Individual Access	N/A	[redacted]
Management and Accountability	N/A	[redacted]
Notice and Purpose	N/A	[redacted]
Openness, Monitoring, and Challenging Compliance	N/A	[redacted]
Security and Safeguards	N/A	[redacted]
Use and Retention	N/A	[redacted]

9.2 Appendix 3-B – Potentiality of a Security Breach

The evaluation of the potentiality of a security breach to occur for each security requirement was performed by OKIOK based on its experience in the field of information security and on actual or theoretical security breaches observed throughout the various projects it performed over the years. This evaluation is unrelated to the Duke Energy Smart Grid deployment.

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
Access Control		
SG.AC-1 Access Control Policy and Procedures	GRC	[redacted]
SG.AC-2 Remote Access Policy and Procedures	GRC	[redacted]
SG.AC-3 Account Management	GRC	[redacted]
SG.AC-4 Access Enforcement	GRC	[redacted]
SG.AC-6 Separation of Duties	Common technical, Integrity	[redacted]
SG.AC-7 Least Privilege	Common technical, Integrity	[redacted]
SG.AC-8 Unsuccessful Login Attempts	Common technical, Integrity	[redacted]
SG.AC-9 Smart Grid Information System Use Notification	Common technical, Integrity	[redacted]
SG.AC-11 Concurrent Session Control	Unique technical requirement	[redacted]
SG.AC-12 Session Lock	Unique technical requirement	[redacted]
SG.AC-13 Remote Session Termination	Unique technical requirement	[redacted]
SG.AC-14 Permitted Actions without Identification or Authentication	Unique technical requirement	[redacted]
SG.AC-15 Remote Access	Unique technical requirement	[redacted]
SG.AC-16 Wireless Access Restrictions	Common technical, Confidentiality	[redacted]
SG.AC-17 Access Control for Portable and Mobile Devices	Common technical, Confidentiality	[redacted]
SG.AC-18 Use of External Information Control Systems	GRC	[redacted]
SG.AC-19 Control System Access Restrictions	GRC	[redacted]
SG.AC-20 Publicly Accessible Content	GRC	[redacted]
SG.AC-21 Passwords	Common technical, Integrity	[redacted]
Awareness and Training		
SG.AT-1 Awareness and Training Policy and Procedures	GRC	[redacted]
SG.AT-2 Security Awareness	GRC	[redacted]
SG.AT-3 Security Training	GRC	[redacted]
SG.AT-4 Security Awareness and Training Records	GRC	[redacted]
SG.AT-6 Security Responsibility Testing	GRC	[redacted]
SG.AT-7 Planning Process Training	GRC	[redacted]
Audit and Accountability		
SG.AU-1 Audit and Accountability Policy and Procedures	GRC	[redacted]
SG.AU-2 Auditable Events	Common technical, Integrity	[redacted]

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
SG.AU-3 Content of Audit Records	Common technical, Integrity	[redacted]
SG.AU-4 Audit Storage Capacity	Common technical, Integrity	[redacted]
SG.AU-5 Response to Audit Processing Failures	GRC	[redacted]
SG.AU-6 Audit Monitoring, Analysis, and Reporting	GRC	[redacted]
SG.AU-7 Audit Reduction and Report Generation	GRC	[redacted]
SG.AU-8 Time Stamps	GRC	[redacted]
SG.AU-9 Protection of Audit Information	GRC	[redacted]
SG.AU-10 Audit Record Retention	GRC	[redacted]
SG.AU-11 Conduct and Frequency of Audits	GRC	[redacted]
SG.AU-12 Auditor Qualification	GRC	[redacted]
SG.AU-13 Audit Tools	GRC	[redacted]
SG.AU-14 Security Policy Compliance	GRC	[redacted]
SG.AU-15 Audit Generation	Common technical, Integrity	[redacted]
SG.AU-16 Non-Repudiation	Unique technical requirement	[redacted]
Security Assessment and Authorization		
SG.CA-1 Security Assessment and Authorization Policy and Procedures	GRC	[redacted]
SG.CA-2 Security Assessments	GRC	[redacted]
SG.CA-4 Smart Grid Information System Connections	GRC	[redacted]
SG.CA-5 Security Authorization to Operate	GRC	[redacted]
SG.CA-6 Continuous Monitoring	GRC	[redacted]
Configuration Management		
SG.CM-1 Configuration Management Policy and Procedures	GRC	[redacted]
SG.CM-2 Baseline Configuration	GRC	[redacted]
SG.CM-3 Configuration Change Control	GRC	[redacted]
SG.CM-4 Monitoring Configuration Changes	GRC	[redacted]
SG.CM-5 Access Restrictions for Configuration Change	GRC	[redacted]
SG.CM-6 Configuration Settings	GRC	[redacted]
SG.CM-7 Configuration for Least Functionality	Common technical, Integrity	[redacted]
SG.CM-8 Component Inventory	Common technical, Integrity	[redacted]
SG.CM-9 Addition, Removal, and Disposal of Equipment	GRC	[redacted]
SG.CM-10 Factory Default Settings Management	GRC	[redacted]
SG.CM-11 Configuration Management Plan	GRC	[redacted]
Continuity of Operations		
SG.CP-1 Continuity of Operations Policy and Procedures	GRC	[redacted]
SG.CP-2 Continuity of Operations Plan	GRC	[redacted]
SG.CP-3 Continuity of Operations Roles and Responsibilities	GRC	[redacted]
SG.CP-4 Continuity of Operations Training	GRC	[redacted]

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
SG.CP-5 Continuity of Operations Plan Testing	GRC	[redacted]
SG.CP-6 Continuity of Operations Plan Update	GRC	[redacted]
SG.CP-7 Alternate Storage Sites	GRC	[redacted]
SG.CP-8 Alternate Telecommunication Services	GRC	[redacted]
SG.CP-9 Alternate Control Center	GRC	[redacted]
SG.CP-10 Smart Grid Information System Recovery and Reconstitution	GRC	[redacted]
SG.CP-11 Fail-Safe Response	GRC	[redacted]
Identification and Authentication		
SG.IA-1 Identification and Authentication Policy and Procedures	GRC	[redacted]
SG.IA-2 Identifier Management	GRC	[redacted]
SG.IA-3 Authenticator Management	GRC	[redacted]
SG.IA-4 User Identification and Authentication	Unique technical requirement	[redacted]
SG.IA-5 Device Identification and Authentication	Unique technical requirement	[redacted]
SG.IA-6 Authenticator Feedback	Unique technical requirement	[redacted]
Information and Document Management		
SG.ID-1 Information and Document Management Policy and Procedures	GRC	[redacted]
SG.ID-2 Information and Document Retention	GRC	[redacted]
SG.ID-3 Information Handling	GRC	[redacted]
SG.ID-4 Information Exchange	GRC	[redacted]
Incident Response		
SG.IR-1 Incident Response Policy and Procedures	GRC	[redacted]
SG.IR-2 Incident Response Roles and Responsibilities	GRC	[redacted]
SG.IR-3 Incident Response Training	GRC	[redacted]
SG.IR-4 Incident Response Testing and Exercises	GRC	[redacted]
SG.IR-5 Incident Handling	GRC	[redacted]
SG.IR-6 Incident Monitoring	GRC	[redacted]
SG.IR-7 Incident Reporting	GRC	[redacted]
SG.IR-8 Incident Response Investigation and Analysis	GRC	[redacted]
SG.IR-9 Corrective Action	GRC	[redacted]
SG.IR-10 Smart Grid Information System Backup	GRC	[redacted]
SG.IR-11 Coordination of Emergency Response	GRC	[redacted]
Smart Grid Information System Development and Maintenance		
SG.MA-1 Smart Grid Information System Maintenance Policy and Procedures	GRC	[redacted]
SG.MA-2 Legacy Smart Grid Information System Upgrades	GRC	[redacted]
SG.MA-3 Smart Grid Information System Maintenance	GRC	[redacted]
SG.MA-4 Maintenance Tools	GRC	[redacted]
SG.MA-5 Maintenance Personnel	GRC	[redacted]

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
SG.MA-6 Remote Maintenance	GRC	[redacted]
SG.MA-7 Timely Maintenance	GRC	[redacted]
Media Protection		
SG.MP-1 Media Protection Policy and Procedures	GRC	[redacted]
SG.MP-2 Media Sensitivity Level	GRC	[redacted]
SG.MP-3 Media Marking	GRC	[redacted]
SG.MP-4 Media Storage	GRC	[redacted]
SG.MP-5 Media Transport	GRC	[redacted]
SG.MP-6 Media Sanitization and Disposal	GRC	[redacted]
Physical and Environmental Security		
SG.PE-1 Physical and Environmental Security Policy and Procedures	GRC	[redacted]
SG.PE-2 Physical Access Authorizations	GRC	[redacted]
SG.PE-3 Physical Access	GRC	[redacted]
SG.PE-4 Monitoring Physical Access	GRC	[redacted]
SG.PE-5 Visitor Control	GRC	[redacted]
SG.PE-6 Visitor Records	GRC	[redacted]
SG.PE-7 Physical Access Log Retention	GRC	[redacted]
SG.PE-8 Emergency Shutoff Protection	GRC	[redacted]
SG.PE-9 Emergency Power	GRC	[redacted]
SG.PE-10 Delivery and Removal	GRC	[redacted]
SG.PE-11 Alternate Work Site	GRC	[redacted]
SG.PE-12 Location of Smart Grid Information System Assets	GRC	[redacted]
Planning		
SG.PL-1 Strategic Planning Policy and Procedures	GRC	[redacted]
SG.PL-2 Smart Grid Information System Security Plan	GRC	[redacted]
SG.PL-3 Rules of Behavior	GRC	[redacted]
SG.PL-4 Privacy Impact Assessment	GRC	[redacted]
SG.PL-5 Security-Related Activity Planning	GRC	[redacted]
Security Program Management		
SG.PM-1 Security Policy and Procedures	GRC	[redacted]
SG.PM-2 Security Program Plan	GRC	[redacted]
SG.PM-3 Senior Management Authority	GRC	[redacted]
SG.PM-4 Security Architecture	GRC	[redacted]
SG.PM-5 Risk Management Strategy	GRC	[redacted]
SG.PM-6 Security Authorization to Operate Process	GRC	[redacted]
SG.PM-7 Mission/Business Process Definition	GRC	[redacted]
SG.PM-8 Management Accountability	GRC	[redacted]

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
Personnel Security		
SG.PS-1 Personnel Security Policy and Procedures	GRC	[redacted]
SG.PS-2 Position Categorization	GRC	[redacted]
SG.PS-3 Personnel Screening	GRC	[redacted]
SG.PS-4 Personnel Termination	GRC	[redacted]
SG.PS-5 Personnel Transfer	GRC	[redacted]
SG.PS-6 Access Agreements	GRC	[redacted]
SG.PS-7 Contractor and Third-Party Personnel Security	GRC	[redacted]
SG.PS-8 Personnel Accountability	GRC	[redacted]
SG.PS-9 Personnel Roles	GRC	[redacted]
Risk Management and Assessment		
SG.RA-1 Risk Assessment Policy and Procedures	GRC	[redacted]
SG.RA-2 Risk Management Plan	GRC	[redacted]
SG.RA-3 Security Impact Level	GRC	[redacted]
SG.RA-4 Risk Assessment	GRC	[redacted]
SG.RA-5 Risk Assessment Update	GRC	[redacted]
SG.RA-6 Vulnerability Assessment and Awareness	GRC	[redacted]
Smart Grid Information System and Services Acquisition		
SG.SA-1 Smart Grid Information System and Services Acquisition Policy and Procedures	GRC	[redacted]
SG.SA-2 Security Policies for Contractors and Third Parties	GRC	[redacted]
SG.SA-3 Life-Cycle Support	GRC	[redacted]
SG.SA-4 Acquisitions	GRC	[redacted]
SG.SA-5 Smart Grid Information System Documentation	GRC	[redacted]
SG.SA-6 Software License Usage Restrictions	GRC	[redacted]
SG.SA-7 User-Installed Software	GRC	[redacted]
SG.SA-8 Security Engineering Principles	GRC	[redacted]
SG.SA-9 Developer Configuration Management	GRC	[redacted]
SG.SA-10 Developer Security Testing	Common technical, Integrity	[redacted]
SG.SA-11 Supply Chain Protection	Common technical, Integrity	[redacted]
Smart Grid Information System and Communication Protection		
SG.SC-1 Smart Grid Information System and Communication Protection Policy and Procedures	GRC	[redacted]
SG.SC-3 Security Function Isolation	Unique technical requirement	[redacted]
SG.SC-5 Denial-of-Service Protection	Unique technical requirement	[redacted]
SG.SC-6 Resource Priority	Unique technical requirement	[redacted]
SG.SC-7 Boundary Protection	Unique technical requirement	[redacted]
SG.SC-8 Communication Integrity	Unique technical requirement	[redacted]
SG.SC-9 Communication Confidentiality	Unique technical requirement	[redacted]

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Security Requirement	Category	Potentiality of a Security Breach
SG.SC-11 Cryptographic Key Establishment and Management	Common technical, Confidentiality	[redacted]
SG.SC-12 Use of Validated Cryptography	Common technical, Confidentiality	[redacted]
SG.SC-13 Collaborative Computing	GRC	[redacted]
SG.SC-15 Public Key Infrastructure Certificates	Common technical, Confidentiality	[redacted]
SG.SC-16 Mobile Code	Common technical, Confidentiality	[redacted]
SG.SC-17 Voice-Over Internet Protocol	Unique technical requirement	[redacted]
SG.SC-18 System Connections	Common technical, Confidentiality	[redacted]
SG.SC-19 Security Roles	Common technical, Confidentiality	[redacted]
SG.SC-20 Message Authenticity	Common technical, Integrity	[redacted]
SG.SC-21 Secure Name/Address Resolution Service	Common technical, Integrity	[redacted]
SG.SC-22 Fail in Known State	Common technical, Integrity	[redacted]
SG.SC-26 Confidentiality of Information at Rest	Unique technical requirement	[redacted]
SG.SC-29 Application Partitioning	Unique technical requirement	[redacted]
SG.SC-30 Smart Grid Information System Partitioning	Common technical, Integrity	[redacted]
Smart Grid Information System and Information Integrity		
SG.SI-1 Smart Grid Information System and Information Integrity Policy and Procedures	GRC	[redacted]
SG.SI-2 Flaw Remediation	Common technical, Integrity	[redacted]
SG.SI-3 Malicious Code and Spam Protection	GRC	[redacted]
SG.SI-4 Smart Grid Information System Monitoring Tools and Techniques	GRC	[redacted]
SG.SI-5 Security Alerts and Advisories	GRC	[redacted]
SG.SI-6 Security Functionality Verification	GRC	[redacted]
SG.SI-7 Software and Information Integrity	Unique technical requirement	[redacted]
SG.SI-8 Information Input Validation	Common technical, Integrity	[redacted]
SG.SI-9 Error Handling	Common technical, Integrity	[redacted]
Cryptography and key management		
Key material and cryptographic operations protection	N/A	[redacted]
Key material generation	N/A	[redacted]
Key material provisioning	N/A	[redacted]
Key material uniqueness, (e.g., key derivation secrets, managing secrets, pre-shared secrets)	N/A	[redacted]
Revocation management	N/A	[redacted]
Credential span of control	N/A	[redacted]
Key and crypto lifecycles (supersession / revocation)	N/A	[redacted]
Key material Destruction	N/A	[redacted]
Local autonomy (Availability Exclusively)	N/A	[redacted]

9.3 Appendix 3-C – Evaluation of Common Vulnerabilities Acknowledgement

[redacted]

9.4 Appendix 3-D – Potentiality of a Security Breach vs. Conformity

Family	[redacted]
Access Control	[redacted]
Awareness and Training	[redacted]
Audit and Accountability	[redacted]
Security Assessment and Authorization	[redacted]
Configuration Management	[redacted]
Continuity of Operations	[redacted]
Identification and Authentication	[redacted]
Information and Document Management	[redacted]
Incident Response	[redacted]
Smart Grid Information System Development and Maintenance	[redacted]
Media Protection	[redacted]
Physical and Environmental Security	[redacted]
Planning	[redacted]
Security Program Management	[redacted]
Personnel Security	[redacted]
Risk Management and Assessment	[redacted]
Smart Grid Information System and Services Acquisition	[redacted]
Smart Grid Information System and Communication Protection	[redacted]
Smart Grid Information System and Information Integrity	[redacted]
Cryptography and key management	[redacted]

10 APPENDIX 4: TIME-DIFFERENTIATED BILL DATA

In the evaluation of Time Differentiated Bill accuracy, bill types TDAM and TD-LITE were evaluated.

TDAM rates consist of On Peak, Shoulder and Off Peak pricing tiers for both winter and summer periods. The TDAM summer period is defined as June 1 through September 30. The TDAM winter period is defined as October 1 through May 31.

TD-LITE rates consist of On Peak and Off Peak pricing tiers for both winter and summer periods and Off Peak rates for spring and autumn periods. The summer period is defined as June 1 through September 30. The winter period is defined as December 1 through February 28 (29th if Leap Year). All other days are defined as spring or autumn. During the time TD-LITE rates were analyzed, all customer bills occurred during the spring period

.

Service Point	Bill Type	Off-Peak KWH Bill	Off-Peak KWH Data	On-Peak KWH Bill	On-Peak KWH Data	Shoulder KWH Bill	Shoulder KWH Data
68	TDAM	208.742	208.742	203.463	203.463	89.055	89.055
2	TDAM	227.098	227.098	131.953	131.953	54.391	54.391
12	TDAM	228.773	228.773	121.759	121.759	49.428	49.428
13	TDAM	340.961	340.961	232.956	232.956	71.576	71.576
23	TDAM	171.621	171.621	89.764	89.764	28.773	28.773
42	TDAM	293.806	293.806	130.626	130.626	46.33	46.33
52	TDAM	236.803	236.803	106.598	106.598	42.187	42.187
53	TDAM	73.398	73.398	35.603	35.603	15.36	15.36
54	TDAM	128.544	128.544	57.984	57.984	22.512	22.512
55	TDAM	131.473	131.473	74.009	74.009	21.86	21.86
56	TDAM	295.971	295.971	132.631	132.631	47.657	47.657
57	TDAM	233.531	233.531	123.025	123.025	43.9	43.9
1000277	TD-LITE	657.822	657.822	NA	NA	NA	NA
1000278	TD-LITE	967.989	967.989	NA	NA	NA	NA
1000279	TD-LITE	356.167	356.167	NA	NA	NA	NA
1000282	TD-LITE	1151.372	1151.372	NA	NA	NA	NA
1000284	TD-LITE	339.568	339.568	NA	NA	NA	NA
1000288	TD-LITE	1519.229	1519.229	NA	NA	NA	NA
1000290	TD-LITE	1252.964	1252.964	NA	NA	NA	NA
1000292	TD-LITE	801.402	801.402	NA	NA	NA	NA
1000302	TD-LITE	569.051	569.051	NA	NA	NA	NA
1000313	TD-LITE	297.537	297.537	NA	NA	NA	NA
1000374	TD-LITE	397.371	397.371	NA	NA	NA	NA
1000377	TD-LITE	479.79	479.79	NA	NA	NA	NA
1000382	TD-LITE	163.69	163.69	NA	NA	NA	NA

11 APPENDIX 5: SMART METER DATA

The following meters were selected for the change out process. Load profile and scalar data was downloaded from each meter and compared to the electric meter data head end, EDMS and CMS systems. The time stamped usage data from every meter was accurate in each system for both load profile and scalar data.

Meter Serial Numbers	Head End		EDMS	CMS	
	Load Profile	Scalar	Load Profile	Scalar	Scalar
1N5100055531GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000022457GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047752GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047082GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000021200GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000025105GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000015357GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100036623GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026309GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100099638GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100053077GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026398GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011223GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011815GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000013766GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011577GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100037075GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000022556GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100037411GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047803GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100054149GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100056126GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100040684GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100044234GZ008	Accurate	Accurate	Accurate	Accurate	Accurate

Meter Serial Numbers	Head End		EDMS	CMS	
	Load Profile	Scalar	Load Profile	Scalar	Scalar
1N5000012893GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011233GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100057176GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000015622GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011822GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100053330GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100042933GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100040818GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100044275GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000012084GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000022690GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047772GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100045662GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047716GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026092GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026091GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100036702GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100039844GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100038865GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100056272GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026321GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100056250GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100049983GZ008	Accurate	Accurate	Accurate	Accurate	Accurate

12 APPENDIX 6: REFERENCE LIST

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13 APPENDIX 7: INPUTS AND ASSUMPTIONS

Input/Assumption	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Average hourly consumption per customer	kWh	3.4457		3.2689							
Annual electric energy growth rate	%	[redacted]									
Annual electric demand growth rate	%	[redacted]									
Weighted average electric price/kWh (non-fuel)	$/kWh	[redacted]									
Weighted average fuel price/kWh	$/kWh	[redacted]									
Fuel price annual growth rate	%	[redacted]									
COE impact by EPA regulations	%	0	0	0	0	0	0	0	0	4	0
Electric Meter Accuracy Improvement (Smart vs. Traditional)	%	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180
Cumulative Residential Electric Meter Deployment	%	6	8	19	42	66	84	100	100	100	100
Annual Electric Meter Deployment	%	6	2	11	23	23	18	16	NA	NA	NA
Cumulative Gas Meter/Module Deployment	%	5	9	22	47	70	93	100	100	100	100
Annual Gas Meter/Module Deployment	%	5	4	13	25	23	23	7	NA	NA	NA
Cumulative IVVC hardware/communications Deployment*	%	0	1	1	1	34	67	100	100	100	100
Cumulative DMS software phases/Deployment*	%	0	1	1	1	1	50	100	100	100	100
Cumulative Self-Healing Deployment	%	0	0	10	33	57	80	100	100	100	100
Cumulative Sectionalizing Deployment	%	0	0	21	45	61	80	100	100	100	100
Weighted Average Cost of Capital	%	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60
Annual Inflation Rate '09-'17	%		2.50	2.50	2.50	2.50	3.00	3.00	3.00	3.00	3.00

*VR/LTC/Capacitor Bank hardware/communications and IVVC Algorithms are being tested in three unique IVVC pilots (i.e. 1% in 2009-2012).

14 APPENDIX 8: METER ACCURACY WEIGHTING

The determination of the average percentage registration involves the characteristics of the meter and the loading. The percentage registration of a watt-hour meter is, in general, different at light loads than at full loads. The accuracy of meters is more closely associated with the full load (30 amps) because that is when most power is consumed. The light load (3 amps) test for accuracy is only representative of the meter's performance at very small load conditions. Therefore, when making accuracy calculations one uses a weighted average since it is more indicative of customer usage patterns and in-service meter performance.

This method of calculating average accuracy complies with The American National Standard Code for Electricity Metering ANSI C12.1-2001 (section 5) is the standard method for calculating average accuracy based on a generic load. This method is consistent with the reporting data to the Staff.

14.1 Operational Benefit 8) Meter Accuracy Improvement Assumptions:

Average percentage registration is the weighted average of the percentage registration at light load (LL) and at full load (FL). The Accuracy improvement is the difference between weighted average percent registration for smart meters and traditional meters.

- High Case: 0.3% increase with smart meters
- Giving the FL registration a weight of 4X: Weighted Percentage Registration = (4*FL + LL)/5
- Duke Accuracy Measurements, generic load (ANSI C12.1)
- Mid Case: 0.18% increase with smart meters
- Giving the FL registration a weight of 6.48X: Weighted Percentage Registration = (6.48*FL + LL)/7.48
- MetaVu Accuracy Measurement, Duke Energy Ohio Average Load
    - Low Case: 0.17% increase with smart meters
    - Giving the FL registration a weight of 6.48X: Weighted Percentage Registration = (4*FL + LL)/5
    - MetaVu Accuracy Measurement, Duke Energy Ohio Average Load

See Table A9.1, Calculations A9.1 and Fig. A9.1 for a description of how MetaVu derived the average weighting based on an average hourly consumption of 3.2689kWh for Duke Energy Ohio. See Table A9.2 and Calculations A9.2 for a description of how MetaVu utilized meter accuracy measurements to derive the mid- and low case meter accuracy improvement.

Table A9.1

Average Hourly Consumption	I[A]	Voltage[V]	Power [kW]	Hours/day	Energy[kWh]/day	Weighting
[redacted]	13.62	240	3.2689	24	78.45	1
Full Test Load 1	30	240	7.2	9.44	67.97	6.48
Low Test Load 2	3	240	0.72	14.56	10.48	1.00
Test Load 1+2	NA	NA	NA	24	78.45	NA
Ave.(Load 1 and 2)	13.62	240	3.2689	NA	NA	NA

Calculations A9.1

Deriving Weighting

$$Hours_{Full\ Test\ load\ per\ day} = \frac{(Power_{Typical\ Average} - Power_{Test\ 3Amps}) \cdot 24hrs}{(Power_{Test\ 30Amps} - Power_{Test\ 3Amps})} = \frac{(3268.9W - 720W) \cdot 24hrs}{(7200W - 720W)} = 9.44hrs$$

$$Hours_{Low\ Test\ Load\ per\ day} = 24 - Hours_{Full\ Test\ load\ per\ day} = 24 - 9.44 = 14.56hrs$$

$$Energy_{Low\ Test\ Load\ per\ day} = Power_{Test\ 3Amps} \cdot Hours_{Low\ Test\ Load\ per\ day} = 0.72 * 14.56 = 10.48kWh$$

$$Energy_{Full\ Test\ Load\ per\ day} = Power_{Test\ 30Amps} \cdot Hours_{Full\ Test\ Load\ per\ day} = 7.2 * 9.44 = 67.97kWh$$

$$Weighting_{Full\ Test\ Load} = \frac{Energy_{Full\ Test\ Load\ per\ day}}{Energy_{Low\ Test\ Load\ per\ day}} = \frac{67.97}{10.48} = 6.48$$

Full Load (30Amps) Weighting	**6.48**

Figure A9.1

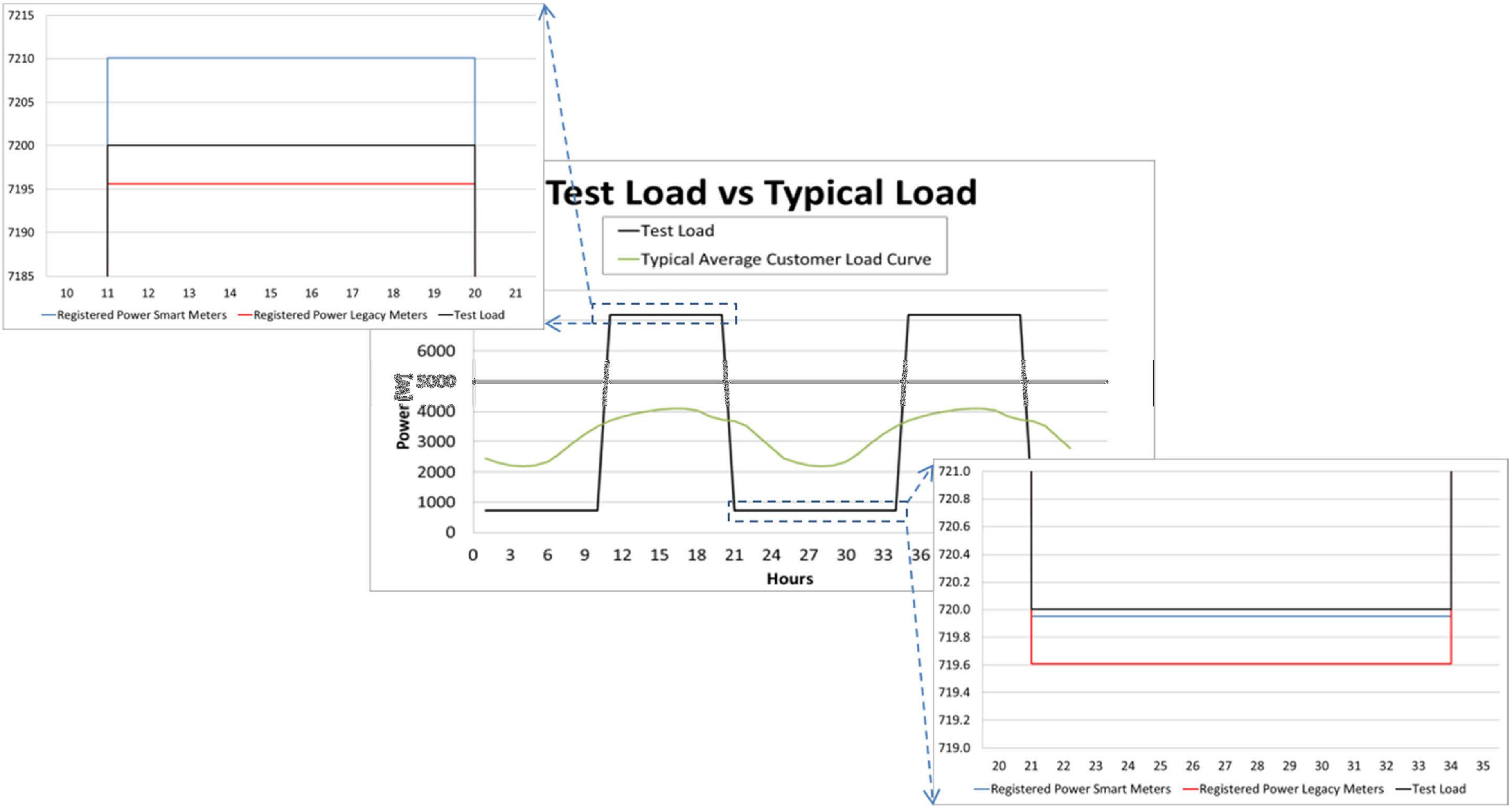
7215
7210
7205
7200
7195
7190
7185
10 11 12 13 14 15 16 17 18 19 20 21
Registered Power Smart Meters
Registered Power Legacy Meters
Test Load
Test Load vs Typical Load
Test Load
Typical Average Customer Load Curve
Power [W]
6000
5000
4000
3000
2000
1000
0
0 3 6 9 12 15 18 21 24 27 30 33 36
Hours
721.0
720.8
720.6
720.4
720.2
720.0
719.8
719.6
719.4
719.2
719.0
20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35
Registered Power Smart Meters
Registered Power Legacy Meters
Test Load

Table A9.2

	New Echelon, 23 Deg, Average Registration of 48			Old Traditional, 23 Deg, Average Registration of 48		
TEST LOAD [A]	TEST A	TEST C	Ave. (TEST A, TEST C)	TEST A	TEST C	Ave. (TEST A, TEST C)
30	100.118	100.161	100.139	99.943	99.935	99.939
3	99.973	100.013	99.993	100.062	99.830	99.946

Calculations A9.2

MID CASE % INCREASE

$$\frac{Weight_{30A} \cdot (Smart\ Reg_{30A} - Legacy\ Reg_{30A}) + Weight_{3A} \cdot (Smart\ Reg_{3A} - Legacy\ Reg_{3A})}{(Weight_{30A} + Weight_{3A})}$$

$$= \frac{6.48 \cdot (100.139 - 99.939) + 1.00 \cdot (99.993 - 99.946)}{(6.48 + 1.00)}$$

= 0.18%

LOW CASE % INCREASE

$$\frac{Weight_{30A,ANSI\ C12.1Duke} \cdot (Smart\ Reg_{30A} - Legacy\ Reg_{30A}) + Weight_{3A} \cdot (Smart\ Reg_{3A} - Legacy\ Reg_{3A})}{(Weight_{30A,Duke} + Weight_{3A})}$$

$$= \frac{4.00 \cdot (100.139 - 99.939) + 1.00 \cdot (99.993 - 99.946)}{(4.00 + 1.00)}$$

= 0.17%

15 APPENDIX 9: GLOSSARY

Advanced Metering Infrastructure (AMI): A metering system equipped with advanced two-way communications for electric and gas meters. The two-way communication allows for obtaining remote meter reads as well as the capability to perform certain remote operations. Duke's AMI allows remote off-cycle meter reading as well as remote connection/disconnection of service.

Assessors: Utility field technicians who investigate issues on the distribution grid.

Carrying Cost of Plant: The annuity or levelized cost of a system or plant, which may include depreciation expense, taxes and return on equity.

Capacitor bank: A collection of individual capacitor units that can be connected to or disconnected from each of the three phases; used to counteract reactive power from inductive loads.

Circuit Breaker (CB): An electrical switch typically found in substations utilized to protect a circuit from overloads or short circuits.

Circuit Breaker Protective Relays (CB Relays): Same as relays (See Relay).

Conservation Voltage Reduction (CVR): Reduces voltage and automatically improves power delivery efficiency and within required specifications.

Dispatchers: Utility distribution center staff members who delegate tasks to field technicians for the investigation and repair of issues involving the distribution grid.

Distribution Automation (DA): Automation of distribution devices, including two-way communications to some existing electronic devices on the distribution system and the addition of new electronic devices with two-way communications. DA consists of equipment both deployed on the distribution grid and within the substation.

Distribution Management System (DMS): DMS is a generic term for a software tool that consists of many integrated applications or plugins. DMS is an Energy Management System (EMS) that has the capability to monitor, control and automate the distribution portion of a power system. (See Energy Management System)

DSMore: A software package that takes inputs regarding specific supply costs (operating and purchase), demand within the specific jurisdiction, forecasted costs increases, and other factors and calculates the annual savings (energy, capacity, and CO_2) associated with modeled changes, such as lowering the voltage on the system.

Electric Load: The amount of power consumption on a circuit.

Energy Management System (EMS): An EMS is a generic term for a software tool that has the capability to monitor, control and automate an energy system. EMS may include transmission, generation and/or distribution portions. (See: Distribution Management System)

Electric Recloser: A circuit breaker enhanced with power quality measurements, analysis and communications.

Feeder: A physical conductor that feeds or supplies power to electric loads. The term feeder is used for the outgoing conductors from a substation. (See Electric Loads, Substation and Circuit)

Full-Time-Equivalent (FTE): The number of employees on full-time schedules plus the number of employees on part-time schedules converted to a full-time basis.

Hydraulic Recloser: Short for Circuit Breaker with hydraulic time delay. Some types of circuit breakers incorporate a *hydraulic time delay* feature using a viscous fluid.

Integrated Volt VAR Control (IVVC): Combined control of grid devices such as Load Tap Changer controllers and capacitor banks to provide unified voltage regulation and reactive power (VAR) flow control throughout the distribution line. (See System Voltage Reduction Strategy)

Intelligent Switches: An automated sectionalization device equipped with bi-directional communication capabilities.

Load Tap Changer (LTC): A device that can connect to the windings of a transformer to change the ratio of primary to secondary windings; changes the voltage relationship between the high and low sides of the transformer.

Load Tap Changer Controller (LTC Controller): A device that controls the load tap changer to allow for remote operation.

MAIFI: Momentary Average Interruption Frequency Index.

Oil-insulated Circuit Breaker (OCB): Traditional circuit breaker without smart grid capabilities.

OVR: Acronym for Overhead Recloser: (See Recloser)

Off-Cycle Reads: Meter readings conducted outside the typical monthly meter reading schedule. Off-cycle meter reads can be due to customers moving locations, requiring the utility to read the meter prior to the scheduled meter reading.

On-Cycle Reads: Meter readings conducted according to predetermined meter reading schedules.

Power Factor: The ratio of real power to apparent power in an AC system. It is considered the percent of total usable power.

Recloser: A circuit breaker equipped with a mechanism that can automatically close, open and reclose the breaker after it has been opened due to a fault. (See Electric Recloser).

Relay: A relay in the smart grid context refers to circuit breaker or switchgear controls that typically enhance a circuit breakers interrupting/reliability capability with protective features such as power quality measurements, analysis and communications.

Remote Terminal Unit (RTU): Microprocessor device that interfaces equipment in the field (such as DA equipment) with SCADA.

SCADA: See Supervisory Control and Data Acquisition

Sectionalization: The use of switching equipment to isolate circuits that have been damaged or contain faults.

Sectionalizer: Refers to the function of a switch, namely sectionalizing. Sectionalizers are typically overheard interrupting devices that increase the reliability metrics by isolating faults. Sectionalizers may be equipped with communications, but this is not a standard feature.

Self-Healing: A functionality of a Distribution Automation system, which utilizes automated switching to reconfigure the distribution grid and minimize the impact of outages.

Single Phase: One of three phases in an AC system. Single Phase portions of a distribution grid often refer to the 240V secondary side of a line transformer (see Tap Line).

Substation: A substation typically consists of one or more high-to-medium voltage transformers, circuit breakers and other switchgear. Smart grid-enhanced substations typically have one or more Voltage Regulators and/or Load Tap Changers with embedded Controls, and/or Protective Relays with Controls and Communications.

Supervisory Control and Data Acquisition (SCADA): A computer system used to monitor and control utility equipment.

Switch: A sectionalization device utilized in the distribution grid.

System Voltage Reduction Strategy: System (Distribution Grid) Voltage Reduction is often named Conservation Voltage Reduction (CVR) or Integrated Volt VAR Control (IVVC)

Tap Line: Low Voltage 240V line of the distribution grid.

Validation, Editing and Estimating (VEE): Processes to analyze and validate interval customer usage data.

Voltage Regulators: A "dimmer switch" in a substation that controls the voltage going to a feeder.

Voltage Regulator Controls: A device that remotely operates a Voltage Regulator and reports voltage regulator data.

16 APPENDIX 10: PROJECT PARTNER QUALIFICATIONS

16.1 MetaVu, Inc.

Meta Vu is a management, strategy, and valuation consulting firm that has been in practice since 2002. The Company has developed specific competencies and skill sets by helping clients understand the value of sustainable business practices and corresponding client performance as measured objectively against both defined and emerging standards and market-based best practices.

MetaVu has been particularly active in the Oil and Gas and Utility Sectors, focusing on energy's unique and central role as the nexus and barometer of operational efficiency and environmental performance. The Company's expertise in the utility industry is focused on renewable energy strategy, energy efficiency strategy, and the enabling capabilities of the smart grid. MetaVu's smart grid experience stems from recent and relevant project work:

- Benefit and Cost analyses of various AMI and DA components of a demonstration project of 46,000 premises
- Estimation of energy and demand benefits associated with various time-differentiated rates and advanced demand response devices in a study of 7,000 participants using enrollment mechanisms to simulate both voluntary and "default rate" implementation options
- Qualitative and quantitative research of electricity customers' perspectives on various smart grid capabilities and benefits, from time-differentiated rates and demand response to improved reliability and customer services
- Identification of opportunities to maximize smart grid benefits through organizational and operational change management practices, including strategy and structure, governance and process, data systems and tools, and resource development
- Meta-analysis of smart grid performance evaluation frameworks, including EPRI, PNNL, and NETL
- Examination of ARRA grant awards and smart grid applications from U.S. utilities BG&E, Duke Energy, OG&E, PG&E, SCE, and Xcel Energy

For more information on MetaVu, please visit the company's website at www.metavu.com.

16.2 Alliance Calibration

Alliance Calibration serves the aeronautical, defense, automotive, government, research, medical, pharmaceutical, energy, and power industries. Alliance Calibration is a mutual held trade name for Toolroom, Inc. and Raitz Services, Inc. Toolroom focuses on Mechanical and Dimensional services while Raitz specializes in the Process and Test market.

Alliance Calibration’s services include dimensional & mechanical as well as process & test equipment calibration. Examples of dimensional & mechanical include gages, calipers, indicators, micrometers, plates, scales, rings, hardness testers, CMM' s, comparators, plugs, blocks, & protractors. Process & test equipment calibration services include pressure, vacuum, frequency, AC/DC power supplies, humidity, pH & conductivity, controllers, recorders, meters, meggers, hipots, thermocouples, RTD' s, timers, oscilloscopes, ovens, scales, & guns.

Alliance Calibration is ISO/IEC 17025:2005 accredited by Laboratory Accreditation Bureau (LAB) in the disciplines described, and all calibration staff holds certifications from the American Society for Quality. Alliance Calibration offers clients access to calibration results 24 hours per day, 365 days per year through its eTracking service.

16.3 OKIOK Data, Ltd.

OKIOK has been dedicated to the field of IT security since 1983 and has developed a unique expertise in designing, building and evaluating complex, secure systems involving communications, embedded software, cryptography, remote firmware upgrades etc. Over the years, OKIOK has pioneered several key concepts and developed strong competencies related to the core technologies that are the very foundation of modern AMI infrastructures.

Few firms can claim to be entirely dedicated and specialized within the field of information security and consequently, OKIOK, with close to 50 specialists and engineers, is recognized as one of the leading North American companies in this space. The diversity of OKIOK engagements and the expertise garnered over the years demonstrates a thorough knowledge of the challenges, problems, best-practices and solutions associated with security technologies.

OKIOK has successfully provided vision and project leadership for two major initiatives that led to the definition of corporate security architecture along with a 5 year security master plan for Hydro Quebec. These initiatives will help Hydro-Québec adopt a proactive security stance and meet the challenge of its upcoming AMI infrastructure deployment (potentially reaching 4.5 million units) as well as compliance to internal security standards, ISO 27002 and NERC CIP 02 to 09.

SmartGridCity™ Demonstration Project
Evaluation Summary

October 21, 2011

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PREFACE

Electric distribution grids across the U.S. consist of aging infrastructure in need of upgrades. Coincidentally, customers are demanding greater efficiency and services from the grid at the same time that reliability challenges – from distributed generation such as PV Solar and demanding loads such as Electric Vehicles – loom on the horizon. U.S. utilities are considering how best to modernize their grids in a manner that optimizes investments and maximizes associated benefits, thereby creating value for customers for the least cost and risk.

In 2008 Xcel Energy, through its subsidiary Public Service Company of Colorado ("PSCO"), designed the most comprehensive smart grid demonstration project in the U.S. integrating generation, transmission, and distribution through grid data collection and analysis. The project was the Company's approach to comprehensively understand how best to modernize its grid. The Company was interested in learning which capabilities were feasible, which were advisable, and which were ill-advised.

The purpose of this report is to review the outcomes of the evaluation phase of the demonstration project. While designed primarily to serve as an input to PSCO grid development strategy, it is intended that the document proves useful for all readers, including policy makers, customer advocates, the electric utility industry, and technology providers.

Throughout the evaluation phase MetaVu was offered full access to PSCO people, processes, and data. The evaluation phase could not have been completed without dedicated efforts from PSCO employees and business functions too numerous to mention. MetaVu would also like to recognize the supporting contributions from SmartGridCity™ technology partners Accenture, Current Group, GridPoint, OSIsoft, SEL, and Ventyx.

About MetaVu

MetaVu is a recognized leader in sustainable business evaluation and advisory services, delivering the solutions companies need to innovate their products, services and business models to manage energy, social and environmental risk throughout the value chain. MetaVu's clients in the energy industry benefit from the firm's deep experience in business model valuation and strategy development. MetaVu helps utilities integrate customer, technology and regulatory strategies into profit-generating products and business models including demand side management, renewable energy development, and smart grid evaluation and deployment.

Disclaimer

The information contained herein is of a general nature and is not intended to be used for decision support. This evaluation is retrospective in nature and is not intended to be used solely as a means to determine the value of future projects in isolation from necessary technical evaluations. No one should act on such information without appropriate professional advice after thorough examination for a particular use.

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INTRODUCTION

In March 2008 Public Service Company of Colorado ("PSCO") and a consortium of the smart grid industry's most advanced technology companies announced their intention to build the nation's first fully integrated smart grid demonstration project, known as SmartGridCity™.

The SmartGridCity™ demonstration project in Boulder, Colorado was specifically designed to help the utility understand which grid investments best improve electric distribution efficiency and reliability; facilitate expansion of customer energy efficiency and demand response; inform future investments; and help the utility manage reliability challenges from higher penetrations of new technologies.

The smart grid industry was in its infancy at the time. No truly comprehensive smart grid technology tests had been completed; no U.S. government grants were available; standards were fragmented and many technologies reaching the market today were still in development stages.

MetaVu was commissioned to perform a third-party evaluation of the SmartGridCity™ demonstration project to identify lessons learned and document reference information for future grid modernization strategy development, business case development, and implementation planning.

MetaVu's evaluation indicates that the anticipated contributions were indeed delivered, and that specific demonstration project goals were satisfied by the SmartGridCity™ demonstration project. Accomplishments include:

- A comprehensive suite of smart grid technologies that could be employed to manage anticipated changes in the retail electric market has been designed, built, and is currently in operation.
- A real-world laboratory in which new utility and consumer technologies can be deployed and evaluated on an ongoing basis has been created and is currently in use.
- A 'body of knowledge' to inform future deployment strategy and business case development has been established, and contributions to it continue.

In the satisfaction of these goals, PSCO has learned many lessons that will help it optimize investments in the grid and make the organizational and operational changes required to maximize the benefits of those investments for customers. The Company learned which capabilities were likely to deliver value and, just as importantly, which capabilities did not. The Company also learned about barriers to, and the conditions that support, customer value creation through grid modernization.

This report summarizes the lessons learned and illustrates how the project created value for SmartGridCity™ customers, PSCO customers, and the utility while challenging conventional wisdom and providing guidance to industry suppliers, regulators, and policy makers.

Evaluation Overview

This evaluation phase of the SmartGridCity™ demonstration project began with the development of a measurement and reporting framework based on emerging standards. Primary inputs included The Electrical Power Research Institute's (EPRI) Benefit Measurement Framework and the Department of Energy/National Energy Technology Laboratory/Carnegie Mellon Smart Grid Maturity Model. MetaVu adapted the emerging standards to SmartGridCity™ learning objectives and supplemented the framework with customer and business model considerations. Eighty reference sources were consulted in the course of the evaluation.

The framework was employed to accomplish three goals established by PSCO:

- Evaluate the benefits of 61 value propositions pre-defined by PSCO and SmartGridCity™ partners at the onset of the project.

- Document measurement methods so that Company managers may use them in future business planning.
- Identify relevant risks and operational and strategic considerations identified through the evaluation process.

The evaluation process consisted of interviews, data collection and analysis, specific peer-level research, and documentation of findings. This work provides PSCO with critical data points to employ as inputs to grid development strategy. Additional input from regulators and customers, combined with some scenario analyses and inputs from SmartGridCity™ research already underway, should provide PSCO managers the information needed to facilitate grid modernization strategy and business case development, customized for specific capabilities, operating conditions, and assumptions.

Report Preview

This report consists of three sections, each with a progressively greater level of detail. The Executive Summary is primarily strategic, describing value created by the project and themes that transcend any individual smart grid component or capability. The second section describes the value created by individual smart grid components. A highly detailed Appendix follows and includes evaluations of specific value propositions and a reference list.

1. Executive Summary

The Executive Summary begins by documenting the value created by the demonstration project

- For SmartGridCity™ Customers
- For PSCO Customers.

The Executive Summary continues with descriptions of themes identified in the course of evaluation that transcend more than one value proposition or SmartGridCity™ system and can serve as additional inputs into grid development strategy:

- Grid Modernization is a strategic planning process.
- Stakeholder and Customer Engagement is a platform for risk mitigation and value creation.
- Change Management is critical to maximizing the benefits of many smart grid systems.

2. Value Creation by Smart Grid System

The pre-determined value propositions were evaluated in relation to the smart grid systems that enable them. Smart grid systems are defined as a set of hardware and software that could conceivably be installed in isolation to create or support value for customers. Six distinct smart grid systems and two infrastructure systems were defined as actionable investment opportunities. By organizing lessons learned into systems, PSCO can best understand how to optimize grid modernization investments, maximize customer benefits, and reduce risks.

The systems defined include:

- Distributed Energy Resource Control/Demand Response
- Advanced Metering Infrastructure
- Distribution Monitoring
- Distribution Automation
- Integrated Volt/VAr Control
- Smart Substation Monitoring and Protection
- Communications Infrastructure
- Information Technology Infrastructure

The section begins with summary descriptions of the measurement framework, the systems themselves, and benefit, cost, and risk findings by system. Details by system follow, including descriptions of the primary goal, function, value creation, and business case considerations for each system.

3. Appendices

The Appendices provide detailed information on specific value propositions and lessons learned. A list of references that helped inform evaluation frameworks and validate evaluations of specific value propositions is also provided.

EXECUTIVE SUMMARY

An objective evaluation of PSCO's SmartGridCity™ demonstrates that the project created significant and specific value

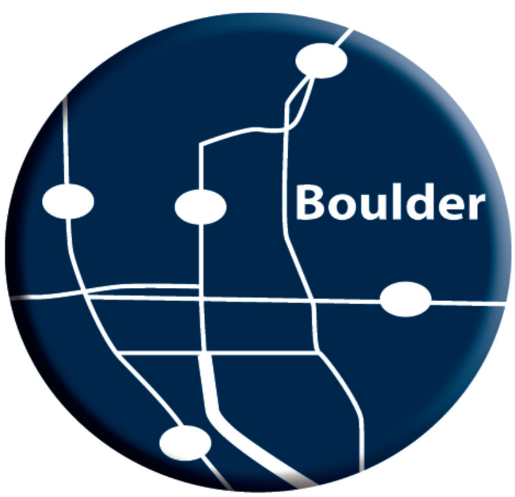
- For SmartGridCity™ customers
- For PSCO customers.

The evaluation process also identified three fundamental themes that transcend more than one value propositions or smart grid system and can serve as additional inputs into grid development strategy:

- Grid Modernization is a strategic planning process.
- Stakeholder and Customer Engagement present a platform for risk mitigation and value creation.
- Change Management can help maximize the benefits from many smart grid systems.

Value Creation

MetaVu's evaluation found that the demonstration project investment created significant value for both SmartGridCity™ and PSCO customers. 'Value' is defined as capabilities, options, assets, or knowledge not available prior to the project that are currently delivering benefits or that will ultimately benefit customers.



The Project Created Value For SmartGridCity™ Customers

Customers residing within the SmartGridCity™ footprint obtained (and will continue to receive) direct benefits from the project in several areas, including energy use reductions, reliability improvements, new rate options, new service options, and customer service level improvements. Some benefits are available only to subsets of SmartGridCity™ customers, such as those located on certain feeders or those with smart meters.

Energy Use Reductions

The average residential customer located on one of the two feeders treated with Integrated Volt/VAr Control (IVVC) experienced usage reductions resulting in annual bill savings of approximately $18 with no reduction in service level (For more information please see Value Proposition 1.9a, 'Reduce Energy Consumption through IVVC' in Appendix 1).

Reliability Improvements

Reliability improved in SmartGridCity™ in terms of both Customer Minutes Out (CMO) and Power Quality. The Distribution Automation system, which reduces the number of customers impacted by a given outage, is estimated to have reduced CMO by over 28,000 minutes annually on each of the two feeders on which it has been installed. (For more information please see Value Proposition 4.1, 'Distribution Automation to Reduce Outage Extent' in Appendix 1.)

Distribution Monitoring, which helps utilities locate fault sources faster, is estimated to have reduced outage durations by 382,000 minutes throughout SmartGridCity™. Distribution Monitoring also offers exception reporting that proactively identifies Power Quality issues; as a result, Power Quality complaints dropped to zero annually after deployment from a baseline of over 30 complaints annually. (For more information please see Value Propositions 4.3, 'AMI to restore power faster'; 4.4, AMI to detect outages'; and 4.6, 'Proactively Fix Power Quality Issues' in Appendix 1.)

New Rate Options

PSCO offered three new rate options that make use of smart meter capabilities, including a Critical Peak Price rate, a Peak Time Rebate rate, and a traditional Time-Of-Use rate. Approximately 4,000 SmartGridCity™ customers are taking service under one of these rates as part of a study of the impact of rate design on customer usage and behavior. In a study conducted by PSCO in 2006 and 2007, highly motivated customers taking service under time differentiated rates reduced annual electricity spending up to $200 each*. (For more information please see Value Proposition 6.1, 'Increase Customer Ability to Manage Energy Bill' in Appendix 1.)

New Service Options

SmartGridCity™ customers taking part in one of the three new rate options are being offered the opportunity to participate in a study of additional impacts on demand and energy use offered by In-Home Smart Devices. In-Home Smart Device systems are currently being installed in SmartGridCity™ residences, with a total targeted installation of 1,264 systems. The In-Home Smart Device systems will allow the utility to understand and help customers manage participation in the new rates through remote operation of thermostats and plug loads.

Customer Service Level Improvements

SmartGridCity™ customers with smart meters (about half of the 46,000 premise SmartGridCity™ footprint) received two types of improved service.

- Detailed (15 minute) energy usage data is updated daily on a secure website, marking a significant improvement over traditional usage data availability. Daily updates of detailed usage data can help customers better understand and reduce energy use and even project the amount of a monthly bill.

- Real time, remote access to meter status improves responsiveness to customers in the event of an outage. Smart meters provide the customer care center with immediate indication about whether an outage has occurred on the utility side or customer side of a meter. This capability was rated highly important in a survey of 800 PSCO customers. (Reports of outages for premises with traditional meters always prompt on-site investigations by utility personnel; in a full roll-out, associated O&M savings could be significant.)

In summary, the demonstration project created specific value and valuable options for SmartGridCity™ customers.

The Project Created Value for Public Service Company of Colorado Customers

The demonstration project also created value for all 1.36 million Public Service Company of Colorado (PSCO) electric customers. The project informed both capabilities the Company should consider, but just as importantly, those that it may want to disregard (at least presently). In doing so the Company may have avoided hundreds of millions of dollars in investments (and associated rate increases) that would have created insufficient value for customers relative to costs. In addition, PSCO electric customers will receive ongoing benefits and cost savings from the SmartGridCity™ infrastructure through ongoing testing of emerging technologies.

* This result should not be extrapolated to an entire population

Lessons Learned will Optimize Future Investments and Maximize PSCO Customer Value

The SmartGridCity™ demonstration project stands in stark contrast to smart grid deployments prompted by investment grants from the U.S. Government's American Recovery and Reinvestment Act (ARRA) smart grid program. Smart Grid Investment Grant awards stipulated that the grants and matching funds had to be spent quickly to stimulate the economy. Accordingly, smart grid deployments were driven by the ARRA grants' prioritization of investment over learning. The SmartGridCity™ demonstration project, however, prioritized learning over investment. A review of publicly available smart grid business cases indicates that IOUs completing full deployments are investing from $500 to $700 per electric customer (outliers discounted). By contrast, PSCO elected to spend approximately $33 per electric customer to help ensure that any large investments it chooses to make in its grid will be as cost-effective as possible.

More to the point, and as described below, the actionable lessons learned in SmartGridCity™ provide real value to PSCO customers by optimizing future grid investments. Informed by the lessons from SmartGridCity™, PSCO is prepared to develop business cases with confidence and knowledge to share with stakeholders as part of a structured and informed grid strategy development and investment decision process.

Lessons from the project that help optimize smart grid investments are illustrated throughout this document, but some of the more valuable technology- and capability-specific lessons are described below. For more information on such lessons, please see the 'Value Creation by Smart Grid System' section below or even more detailed descriptions in the Appendix 1 – Value Proposition Evaluation.

Distributed Energy Resource Control (DERC)/Demand Response (DR)

'Distributed Energy Resource Control' as implemented in SmartGridCity™ consists primarily of advanced capabilities to control customer loads through home area networks, or HANs. PSCO has plans in place to complete 1,264 HAN installations from October 2011 to May 2012 in the residences of customers participating in the time-differentiated pricing pilot. Top lessons learned about HANs include:

- HANs offer significant features beyond those available from traditional Demand Response technologies, but the impact of these features on effectiveness is not yet known and is currently under study.
- For the foreseeable future, an impractical number of pre-requisites exist for HAN technology to be effectively used to increase the utilization of renewable generation.
- HAN technology is extremely expensive and evolving rapidly, presenting high capital and technological obsolescence risk; it can also present additional utility system security risks if not carefully managed.

Advanced Metering Infrastructure (AMI)

Advanced meters offer many types of upgrades over traditional meters, facilitating time-differentiated rates, communicating with the utility in real-time, automating meter reading, sensing grid conditions, and other optional features. The options, benefits, and roles are specific to each utility and driven by existing operations, customer priorities, distribution grid strategy, rate designs, cost structures, and other factors. AMI investment choices are therefore highly complex and lessons learned are therefore very important to investment decisions. Further, since the service life of this equipment is typically 20 years or more, short term decisions have long term implications. Advanced meters have been installed in about half of the customer premises in SmartGridCity™. Top lessons learned about AMI include:

- Advanced meters offer extremely long customer payback periods if meter reading has already been automated (as it has in PSCO) and/or time-differentiated rates are adopted slowly by customers.
- Advanced meters offer capabilities likely to improve the satisfaction of some customers through the increase in ability to control energy usage and better Call Center responsiveness.
- Advanced meter and relevant communication technologies are still evolving rapidly and associated costs are dropping.
- Advanced meters can also serve as sensing

devices, reducing the need for transformer-based line sensors used in Distribution Monitoring and Integrated Volt/VAr Control.

- Enabling customer/representative access to meter functions (i.e., using meters as a home gateway) increases utility cyber security risks.

Distribution Monitoring (DM)

Distribution Monitoring (DM) provides real-time visibility into distribution grid conditions between substations and customer premises. This visibility enables more efficient operations than traditional, substation-only monitoring provides. The capabilities of DM -- primarily more efficient troubleshooting and fault locating -- have been clearly demonstrated in SmartGridCity™. DM is operating throughout SmartGridCity™ and currently benefits 46,000 customers. Top lessons learned about DM include:

- Selective deployment of DM (for example, based on reliability and geographic needs) will increase value created per dollar of invested capital relative to universal deployment. For example, benefits are greater when deployed in areas of relatively lower reliability or time-consuming troubleshooting (i.e. rural, underground) compared to other deployment options.
- DM provides the Distribution Capacity Planning function with data to optimize upgrades and transformer sizing, which may become increasingly important as customer adoption of PV Solar and Electric Vehicles increases.

Distribution Automation (DA)

Distribution Automation (DA) consists of a set of field hardware and software that automatically reconfigures the grid, primarily to isolate the impact of a service outage to the smallest number of customers possible. This effectively "self-heals" portions of the distribution system to minimize customer minutes out (CMO). DA provides automated control logic and remote operation capabilities not available in traditional SCADA (System Control and Data Acquisition) systems used by grid operators. DA is operating on two feeders in SmartGridCity™. Top lessons learned about Distribution Automation include:

- Selective DA deployment based on reliability and geographic needs will improve value created per dollar of invested capital relative to universal deployment. For example, DA deployment could be limited to geographies with relatively low reliability.
- DA benefits are primarily related to reliability; economic benefits (such as capital referral resulting from improved load balancing) did not appear to justify costs in preliminary analyses when compared to reliability benefits.
- Of all smart grid systems, DA has the lowest tolerance for failure as it controls critical grid equipment and therefore must communicate accurately and regularly with internal systems.
- DA functions at the substation and feeder level and does not require centralized data processing. 'Distributed processing' in substations could serve as an alternative to centralized data processing and offers benefits in data latency and management.
- Reliability improvement from DA is generally a function of the number of sectionalizing devices installed; incremental improvements in reliability must be balanced against the incremental cost of devices.

Integrated Volt/VAr Control (IVVC)

IVVC regulates feeder voltage and power factor (VAr) continuously and automatically to reduce energy usage between the substation and customer loads. Voltage is monitored near customer premises to ensure voltage levels are within requirements, while VAr is optimized through the coordinated operation of capacitor banks located throughout the grid. IVVC is functioning on two feeders in SmartGridCity™. Top lessons learned about IVVC include:

- IVVC offers high potential economic benefits to customers relative to cost through voltage optimization.
- IVVC can be deployed selectively, for example on feeders with the greatest load and voltage/VAr improvement opportunity. Though full deployment offers greater benefits relative to selective deployment, selective deployment can improve customer payback periods.

- Though IVVC benefits are significant in the aggregate and relative to cost of implementation, individual customer benefits are small enough that they will be difficult to perceive.

- IVVC investments are similar to DSM programs in that utility spending delivers benefits directly to customers but reduces a utility's opportunity to earn authorized rates of return. DSM-type mechanisms can help address this issue.

Smart Substation Monitoring and Protection (SSMP)

Smart Substation Monitoring and Protection (SSMP) offers real-time visibility into substation operating conditions, providing detailed data that can be used proactively to identify equipment malfunctions prior to failure and forensically to investigate abnormal substation events. It is functioning in four substations in SmartGridCity™. Top lessons learned about SSMP include:

- Substation-level failures are rare but have a disproportionate impact on CMO when they occur.

- Substation data may help predict substation transformer and breaker failure, but insignificant experience is available to prove or disprove such a claim due to the infrequency of such failures.

- Substation data can potentially be used forensically to evaluate failure root causes.

- Analytical tools and business process changes will be needed if substation data is to be used to predict equipment failure and reduce outage time.

Communications Systems Infrastructure

For smart grid equipment to function, a system to support the communication between smart grid technologies is required. The communications system utilized in SmartGridCity™ was designed to be reliable, robust, secure, and fast to allow for a variety of capabilities to demonstrate and test. SmartGridCity™ was equipped with a high bandwidth and low latency communications network so that current and future application testing could proceed relatively unconstrained. These capabilities were established through a variety of communications technologies, including Broadband over Power Line (BPL), fiber optic cable, 3G Cellular, DSL, and microwave. Top lessons learned about Communications Systems Infrastructure include:

- Competing approaches to communication systems offer pros and cons in a variety of decision criteria, including Build vs. Buy; Upfront Capital Cost vs. Ongoing O&M Cost; Grow Competence vs. Hire Expertise; Accountability for Security; Bandwidth and Latency; future flexibility; and Reliability/Quality Control, to name a few.

- No single communications infrastructure type will be adequate for all geographies or capabilities. For example, SmartGridCity™ primarily utilized broadband over power line and fiber, but in locations where such infrastructure was unavailable, wireless technology was employed.

- The Geographic Information System (GIS) must be adequately detailed to support communication design and operation.

- Communications with field devices yields safety benefits (by reducing field crew exposure to hazardous conditions) as well as operating expense reductions.

Information Technology Systems Infrastructure

PSCO developed a new IT infrastructure for SmartGridCity™, maximizing the use of readily-available technology and IT best practices. The IT systems facilitate the communication and processing of smart grid data. The systems are readily scalable and can be leveraged to support future smart grid investments within PSCO. Top lessons learned about smart grid IT infrastructure include:

- Data and cyber security must be built into IT designs. Simply applying legacy policies, processes, and protocols to smart data environments can add administrative burdens, particularly in employee access management and credentialing.

- The distribution operations function may need to acquire new IT skills, while the business systems function may need to adopt new electrical engineering skills.

- Smart grid systems produce significant amounts of data. Strategies and tools should be developed to maximize the value of available data and the benefits of smart grid investments.

- Strategies to minimize data collection, including exception reporting and, in particular, distributed (vs. centralized) data processing in the substations, are advised. Lower latency is an added benefit of distributed data processing.
- Though grid modernization offers operating cost reductions in several functions, IT support, software maintenance, and data management costs are likely to increase.

Ongoing Benefits from SmartGridCity™ Infrastructure

In addition to optimized investments from lessons learned, PSCO customers are receiving benefits from the infrastructure installed as part of SmartGridCity™. Four examples are discussed below:

- A real-world laboratory is being used to study distribution technologies and customer behaviors.
- The SmartGridCity™ customer data portal improved access to historical usage and billing data for all PSCO customers.
- IT application software is being used to support expansion of select smart grid systems to other PSCO service areas.
- IT architecture is being used to support PSCO-wide software applications.
- More uses for smart grid data will be found over time; changes in data needs may entail changes to communications requirements (speed, latency, etc.).

A real-world laboratory is being used to study distribution technologies and customer behaviors

One of the primary goals of the demonstration project was to establish a real-world laboratory to study distribution technologies and customer behaviors. The combination of line sensors, smart meters, software, and communications systems integrated into SmartGridCity™ is ideal for putting new technologies and customer program designs to the test. In addition to the aforementioned pricing and In-Home Smart Device study, PSCO is using the laboratory for a study on the impact of Electric Vehicles (EV) on the grid in conjunction with Toyota and the University of Colorado. The pilot will gain greater understanding on EV performance, EV impact on electricity usage, and customer interaction with such technology. Other studies using the laboratory are being considered. The laboratory is available to test promising new technologies, approaches, and programs as they become available. Test results will be used to benefit all PSCO customers by optimizing capital investments and maximizing associated benefits. The laboratory is already being used to answer the questions that inform technology deployment investment decisions such as:

- What impact does a technology or program have on operations, costs, or customer behavior?
- What is the value of the impact? How does value compare to cost, and how is it likely to change over time?
- What are the drivers of value, and how can they be influenced?
- What organizational and operational changes are required to maximize benefits from the technology or program?

With answers to such questions PSCO can make the informed choices regarding studied technologies and programs and their implementation, maximizing the value of investments made on behalf of PSCO customers.

The SmartGridCity™ Customer Data Portal Improves Access to Historical Usage and Billing Data

A website portal was installed to provide smart-metered customers secure access to daily updates of detailed energy usage data. Current efforts are underway to provide energy usage data in near real-time. The portal includes enhancements that improved the user experience of all PSCO customers who access historical energy usage data from the Xcel Energy website.

IT Application Software Is Being Used To Support Expansion of Select Smart Grid Systems

The software installed to support many SmartGridCity™ systems (Open Grid, which supports Integrated Volt/VAr Control, Distribution Automation, and Distribution Monitoring) is scalable. PSCO may consider expanding these capabilities to other parts of its Colorado distribution system without significant incremental application software cost or effort.

The Company has already used Open Grid to expand Integrated Volt/VAr Control to a feeder in Englewood, Colorado and is currently considering other expansions.

SmartGridCity™ IT Architecture Is Being Used to Support PSCO-wide Software Applications

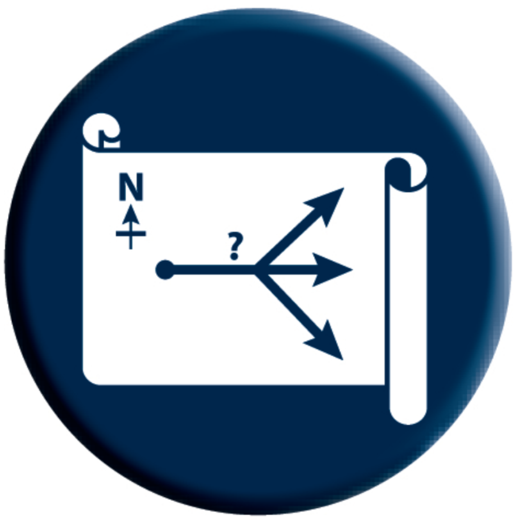
The Bus architecture employed for the first time in PSCO as part of the SmartGridCity™ demonstration project is being used to integrate data from other systems that serve PSCO customers. The Bus architecture facilitates data integration and utilization and features reduced interface maintenance costs for the Business Systems function.

Transcendent Themes

In addition to benefits for SmartGridCity™ and PSCO customers, the demonstration project provided three themes that will serve as additional inputs to PSCO's grid modernization strategy. These themes transcend multiple value propositions and smart grid systems, but do not necessarily apply to all value propositions or smart grid systems. The three themes include:

- Grid Modernization Is a Strategic Planning Process.
- Stakeholder and Customer Engagement Is a Platform for Risk Mitigation and Value Creation.
- Change Management Can Help Maximize Benefits from Many Smart Grid Systems.

These themes are described fully below.



Transcendent Theme: Grid Modernization Is a Strategic Planning Process

The electric distribution grid is an asset that utilities, including PSCO, continuously modernize; utilities have extensive experience in evaluating the benefits of new technologies relative to costs. The primary difference between grid modernization today relative to past decades is demand curve volatility related to unknown customer adoption of potentially disruptive technologies such as PV Solar generation and electric vehicles. Considering rapid technology development, market and regulatory evolution, and the significant investments required to prepare the grid for the future, the requirement to rigorously apply strategic planning processes to govern grid modernization becomes readily apparent.

Through the perspective of an ongoing strategic planning process, the demonstration project delivered lessons that will provide exceptional value to PSCO customers in terms of optimizing future investments:

- Value is greatest on the utility side of the grid and drops as components approach premises.
- Two competing approaches to deployment speed, 'Big Bang' and 'Incremental', offer very different trade-offs in benefits, costs, and risk.

Value is greatest on the utility side of the grid and drops as components approach premises.

From an economic perspective, SmartGridCity™ data (supplemented by data from other studies as appropriate) seems to indicate that the most reliable and least controversial economic paybacks for PSCO's customers lie within the grid and not on its periphery (A full and formal Business Case must be developed to prove this hypothesis and is outside the scope of the evaluation phase).

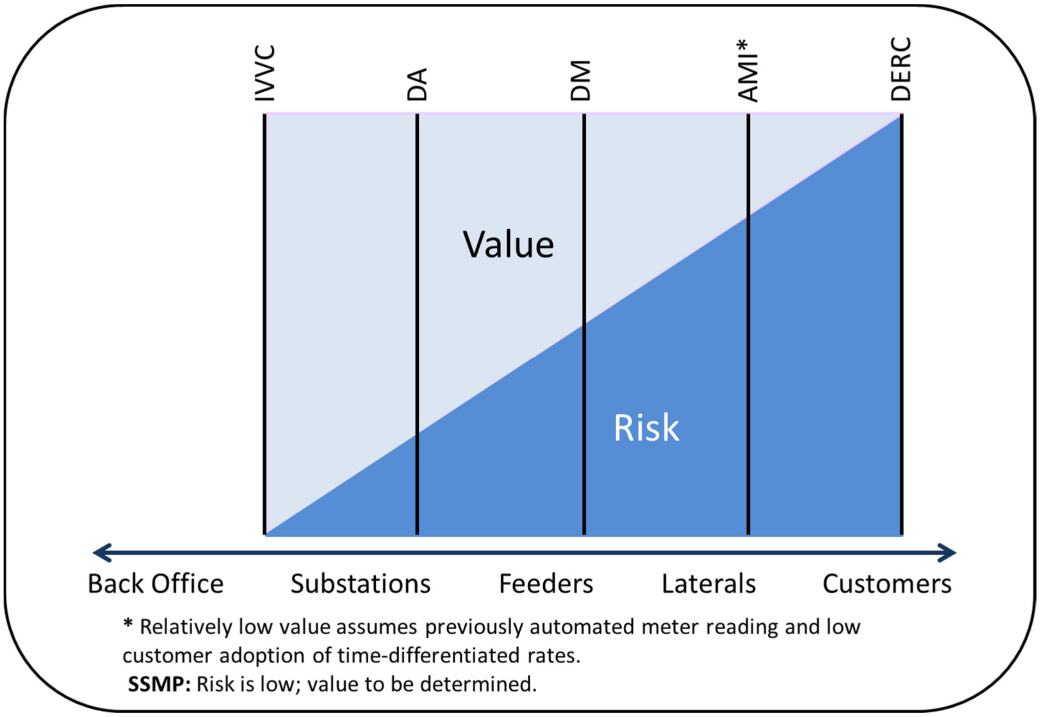
Through careful mapping of value propositions and benefit types to SmartGridCity™ systems, and by comparing summary benefit information to investment costs and technological obsolescence risk by system, informal estimates about the value of various grid capabilities can be made. For more detailed information on benefits, cost, and risk by smart grid system please see 'Value Creation by Smart Grid System' below.

The idea that value appears to be greatest on the utility side of the grid assumes circumstances that may be unique to PSCO and cannot be extrapolated to other utilities' deployments:

- Meter reading has already been automated, making associated savings low from AMI investments.
- Without the savings from automated meter reading, high customer adoption of time-differentiated rates would be needed to provide a reasonable payback period on AMI deployment. Aggressive implementation of time-differentiated rates carries significant customer satisfaction risk.

Figure 1 illustrates how value is greatest on the utility side of the grid and risk appears to be greatest on the customer side of the grid.

Figure 1 – Relationship Between Asset Location, Value, and Risk



Two competing approaches to deployment speed, 'Big Bang' and 'Incremental', offer very different trade-offs in costs and benefits

Some utilities are pursuing a 'Big Bang' approach to grid deployment, characterized by rapid implementation of significant grid upgrades over large areas, requiring extensive capital investment. The increased cost of accelerated grid upgrades stems from both premium acquisition prices for the latest technologies as well as accelerated replacement schedules for currently adequate equipment. (Generally Accepted Accounting Principles require that any book value of equipment retired before the end of its useful life be written down to zero.)

Alternatively, the 'Incremental' approach is achieved through selective (as opposed to universal) deployment of smart technologies, as well as the simple practice of upgrading grid equipment as retired. Advantages of a planned and concerted pace include potentially lower overall costs, effort, and risk as technologies continue to develop. (Note that under the incremental approach, communication and IT infrastructure investments will be required at some point to support incremental grid upgrades, and that these costs may represent a significant investment at that point.)

SmartGridCity™ taught that benefits from smart grid technologies can vary by feeder based on asset condition. For example, a feeder with higher voltages and loads will yield greater benefits from Integrated Volt/VAr Control than feeders with lower voltages and loads. This finding implies that some grid technologies can be most cost-effectively deployed on a selective, vs. universal basis. A utility need not upgrade its grid all at once, but over time based on logically prioritized geographies. The lesson is that incremental modernization is a realistic alternative to 'all or nothing' deployments.

The Big Bang approach does have some advantages. For example, reducing meter reading routes can only be achieved through large deployments of smart meters. In addition, lower per-unit prices are likely for equipment purchased in large quantities. Conversely, incremental deployment takes advantage of the premise that competition will drive technology prices down while capabilities improve over time.

Either deployment approach will require significant and careful consideration of the implications for communications and IT Infrastructure design. If large scale or incremental deployment is pursued, a forward looking IT and communication strategy should be put in place to support smart grid development.

Transcendent Theme: Stakeholder And Customer Engagement is a Platform for Risk Mitigation and Value Creation

Utilities have always been challenged by competing interests among stakeholders (e.g. customers, regulators, advocacy groups, etc.) and have long been dependent on stakeholder to maximize the benefits of investments in programs such as Demand Side Management. Not surprisingly, smart grid investments only 'up the ante' on the value of stakeholder engagement. With regards to grid modernization, stakeholder engagement can help mitigate regulatory risk for some grid investments and maximize the benefits created by others:

- Definition of appropriate 'Grid Preparedness' levels varies by stakeholder and creates regulatory and cost recovery risk due to unknowable customer technology adoption.
- Clear rules must be established if utility development of certain smart grid capabilities is to be encouraged.
- Customer engagement is critical to the maximization of benefits from several systems.

Definitions of appropriate 'Grid Preparedness' levels vary by stakeholder and create regulatory risk based on unknowable customer adoption of electric technologies.

The Evaluation indicated that current adoption rates of new electric technologies such as PV solar and Electric Vehicles presents little threat to reliability. In the future, however, rapid and/or geographically concentrated adoption of these electric technologies could present reliability challenges. As challenges to reliability increase, the value from systems designed to improve reliability (such as Distribution Monitoring and Automation) will likely increase.

While SmartGridCity™ proved these systems do indeed provide reliability benefits today, policymakers should understand that the most valuable aspects of reliability-oriented smart grid investments relate to management of anticipated future challenges. Currently, much of PSCO is experiencing high levels of reliability. Stakeholders will need to help determine the value of preparedness for anticipated (but unknowable) reliability challenges. PSCO could then use this value determination as an input into Distribution Monitoring and Automation investment decisions. Investment decisions about other smart grid systems, such as Integrated Volt/VAr Control, may involve virtually zero uncertainty and require no customer engagement.

Customer adoption of PV solar and electric vehicles is beyond utilities' control and is highly unpredictable as to timing and extent. Given this variability it is difficult for utilities to determine the appropriate level of readiness with which to prepare the grid. Historical distribution grid planning horizons require utilities to begin preparing for such changes far in advance, but early actions expose utilities to technology, financial, regulatory and reputation risk. Utilities are understandably concerned that hindsight will be used to judge the accuracy of their forecasts and deny cost recovery. Stakeholder engagement can be used to reduce this risk. Figure 3 illustrates the challenge utilities face in preparing for and meeting unknown levels of customer adoption of potentially disruptive technologies.

Figure 3: Illustration of Market Adoption Rate Risk

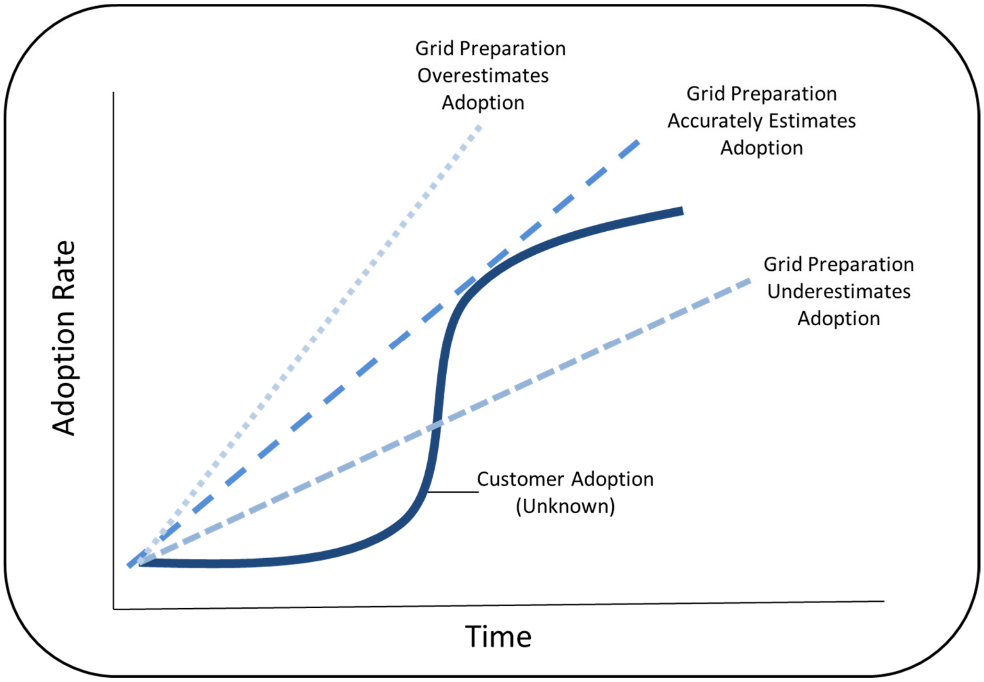


Figure 3 is intended to illustrate two points. First, classic utility planning horizons may be insufficient for customer adoption rates of new technologies. Second, it is difficult for utilities to plan for uncertain customer adoption.

In Figure 3 the lowest dashed line represents a classic utility planning and grid development horizon. The solid dark curve represents customer adoption of technologies (PV solar or Electric Vehicles) that are likely to present reliability challenges at higher penetration rates. For example, high penetration of Electric Vehicles could damage transformers due to large electricity demand. In the event customer adoption follows the curve, a grid modernized at traditional grid development rates is unlikely to be prepared for reliability challenges. Given the potential discrepancy between grid preparation and customer adoption rates, utilities may need to anticipate reliability challenges by preparing the grid with Distribution Monitoring and Automation in advance. The question is for what rate of adoption should a utility prepare the grid?

By preparing the grid at a rate represented by the middle dashed line, the utility will reduce reliability risk for the least amount of investment. But what if the utility guesses incorrectly? The adoption curve is unknown; it is just as likely that a utility prepares the grid for an aggressive adoption rate (the top dashed line in Figure 3) that does not materialize. In such a situation, the utility has over-prepared (and over-invested in) its grid.

To summarize, the timeline of utility grid upgrades combined with the uncertainty of customer adoption presents inherent challenges to utility planners and policy makers. In many respects, investments in Distribution Monitoring and Adoption (though there are other examples) can be considered a hedge against potential reliability risks for customers. Stakeholder engagement can help establish consensus on the value of such a hedge, which PSCO can use as an input into investment decisions and to reduce associated regulatory risk.

Clear rules must be established if utility development of certain smart grid capabilities is to be encouraged.

Regulators play a particularly critical role in the development of smart grid capabilities. Certain capabilities present increased risks to utilities, particularly investor-owned utilities. Utilities will likely want to be protected from these risks before investing in or enabling such capabilities. A few examples may help illustrate this issue.

Consider the concept of proactive customer outage notification. Smart grid capabilities could facilitate automated execution of telephone, text, and e-mail messages to customers about outages, including validation of outage awareness by the utility and time-to-restoration estimates. While these services might be appreciated by customers, they could increase utility risk. Customers may rely on such information over time, and use it to inform certain actions or alter established plans. In the event the information the utility provides proves to be incorrect, or is not received by a customer due to a technical issue, customers might hold the utility accountable for associated economic harm. "I was on vacation, and all my food spoiled. Had the utility's new notice system worked, I'd have called a relative to empty my refrigerator and freezer. The utility owes me $800."

This is only one illustrative example of many smart-grid related capabilities that could increase utility risk. The example illustrates that utilities are likely to increase their risk exposure if they add services that might one day prove to become a customer satisfaction issue or increase costs for all customers.

Another smart grid capability that illustrates the concept of increased utility risk is Integrated Volt VAr Control. IVVC improves distribution efficiency, increasing the usable power delivered to customers for a given level of electric generation. But as voltage is reduced to accomplish this objective, customers use less energy. This reduces electricity sales volumes below the levels assumed in the most recently completed ratemaking process, and results in a reduced opportunity for the utility to earn its authorized rate of return. In this regard, IVVC is much like a Demand-Side Management (DSM) program. The utility makes all of the investment and incurs the rate or return risk, while the customers enjoy all of the economic benefits. Regulatory mechanisms would need to be created like those employed for DSM programs to provide equitable economic treatment in such situations and encourage utilities to invest in certain capabilities.

Customer engagement is critical to the maximization of benefits from several systems

Customers play a key role in grid modernization -- taking advantage of opportunities, driving certain types of benefits, and adopting new technologies that make the smart grid both necessary and valuable. Some smart grid capabilities and benefits affect customers directly, some indirectly, and others require customer participation in order to maximize anticipated benefits.

As just one example, time-differentiated rates present both opportunities and risks to customer satisfaction. On one hand, many customers appreciate opportunities to manage energy use and cost and may be more likely to embrace options like time-differentiated rates and Demand Response. Many other customers, however, may participate in such programs and be dissatisfied by the inconvenience required to participate, or be disappointed by the size of the economic incentives their efforts delivered.

In addition, research into other utilities' time-differentiated rate programs indicates that the manner in which these rates are introduced is critical to perception and satisfaction impact and very dependent on utility base rates. From a customer's perspective, rate *options* will generally be perceived favorably relative to rate *mandates*. This is particularly true in the electric utility industry, in which simplicity and relatively low cost have created a product category characterized by extremely low engagement and interest.

Focus groups of customers within SmartGridCity™ identified multiple educational opportunities to help manage associated satisfaction risk. An informal takeaway is that customers have a long way to go to become fluent in, let alone embrace, advanced rate designs.

The benefits associated with time-differentiated rates and advanced demand response capabilities are driven largely by customer behavior change and program participation levels. While rate designs, convenience services, communications, and education are critical to the success of these programs, an understanding of the drivers of average customer participation and response to such programs is critical to pricing, program, and promotion designs. Behavior change will vary with program design, incentive offer, and implementation scenarios (mandatory, default/opt out, and opt in), and rigorous research is required to accurately inform deployment strategy development. A set of extensive, multi-year pilots are underway in SmartGridCity™ to obtain the thorough understanding of customer response and behavior change required.

A review of the results of PSCO's 2006-2007 time-of-use pricing study indicates that the benefits of time-differentiated rates are potentially significant. The time-of-use and in-home smart device pilot currently underway will validate the size of the opportunity.

To summarize, stakeholder engagement activities should accommodate the evolving role and contributions of customers in concert with regulatory changes (i.e. establishment of clear rules).

<u>Transcendent Theme: Change Management Can Help Maximize the Benefits from Many Smart Grid Systems</u>

As part of its SmartGridCity™ evaluation MetaVu examined the extent to which PSCO had integrated smart grid capabilities into routine operations. The examination identified examples in which the application of change management best practices could maximize the benefits of some smart grid systems. These examples are summarized into the observations listed below. In addition, MetaVu has observed that the experiences associated with operating SmartGridCity™ have institutionalized a motivating vision for grid modernization among PSCO management and individual contributors.

- The roles played by certain key assets change with smart capabilities and may require modifications to organizational structure and strategy.
- Functional areas and personnel will require new systems and tools to maximize the value of data and capabilities made available by the smart grid.
- Increased use of sophisticated equipment and capabilities enabled by the smart grid will require new and different organizational and human resource skills and capabilities if the benefits are to be maximized.

These observations are fully discussed below.

The roles played by certain key assets change with smart capabilities and may require modifications to organizational structure and strategy.

The increasing sophistication of many distribution grid assets implies that they will serve a greater number of purposes and business areas. The discussion below will address three of the grid assets for which changes will likely be greatest: operations centers, smart meters, and smart substations.

Control and Operations Center(s) Example. In a traditional utility structure, Transmission Control Center (TCC) staff and Distribution Control Center (DCC) staff are in regular contact to achieve operational tasks. IT served as a support function for both the TCC and DCC. The advancements of smart grid technology will require more integrated IT role, for example in troubleshooting smart grid technologies in the field and back office. Consequently, future integration and interaction of the TCC and DCC with the IT department's Information Operation Center (IOC) and the communications systems' Network Operating Center (NOC) will be required to optimize business functionalities. Going forward the TCC and DCC may need to consider the IOC and NOC as peers, maintaining regular communication and developing common processes and procedures to create a more interconnected environment.

For example, DCC staff may send field technicians to address faulty field equipment and determine the problem may be due to IT or communication issues. Field technicians must then ask for IT assistance resulting in extended troubleshooting time. Merging the DCC, IOC and NOC ticketing systems to create greater alignment of troubleshooting procedures could be implemented to increase the coordination and integration of the two business areas. Greater integration could correctly identify which teams should address equipment and system issues to optimize troubleshooting.

Smart Meter Example. In the transition from traditional to smart meters, the meter evolves from simple measurement device to a sophisticated multifunctional instrument, incorporating data and communications technologies, diagnostic capabilities, exception reporting capabilities, and in some cases control functions. Traditionally, meters have logically been the responsibility of utilities' revenue cycle team as a result of meters' central role in revenue determination and collection.

In their new role, smart meters are valuable to many departments, including:

- Customer Care (remote meter function testing and in some cases control)
- Area Engineering (to diagnose Power Quality issues)
- Distribution Capacity Planning (to identify capacity increase needs)
- Distribution Control Center (to identify fault locations)
- Marketing (to provide services and information of value to customers)

In a smart grid deployment, organizational changes may be required to align new technical capabilities with organizational responsibilities. Questions to be answered include 'Which organization should maintain responsibility for meter operation and functionality?' and 'Are smart meters a corporate IT asset?' Utilities will need to consider which organizational structures may need to change in order to optimize benefits.

Substation Example. Substations offer another good example. Formerly responsible for stepping down transmission voltage and meeting power factor standards at the transmission voltage entrance, substations can play many new roles in a modernized grid and serve new internal customers. Depending on capabilities and system design, substations can serve as field data centers and communications hubs. SmartGridCity™ illustrated that substations can also effectively house many new types of equipment such as remote controllers, data servers, sensing devices, and other components that will become critical to Distribution Operations in a modernized grid. For example, as future loads become less stable, systems will increasingly need to react to grid issues in a timely and effective manner, requiring lower latency communication capabilities for faster response. The shorter distance from field devices to data centers in substations will allow for lower latency and can serve as a collection and processing point to provide pertinent information to central, back office systems.

In summary, much of the equipment required to modernize the distribution grid resides in substations. The need to install, maintain, repair, and upgrade this equipment suggest that new substation physical designs, operating processes, and organizational changes be considered as part of grid modernization strategies.

Functional areas and personnel will require new systems and tools to maximize the value of data and capabilities made available by the smart grid.

Systems and tools can play a pivotal role in helping business areas and personnel to maximize the value of available data. Enhancements to existing software applications, development of free-standing applets and subroutines, and exception reporting can be useful approaches to accessing the data made available by smart grid capabilities. Systems and tools can help business areas manage practical issues that serve to reduce the adoption of new capabilities, from the complex (making sense of extremely large data sets) to the simple (user hardware upgrades).

This is particularly critical during the period of transition from a traditional grid to a smart grid, which may be lengthy. Due to its large size, smart grid upgrades can take years to complete (or even decades in the event the 'incremental' approach to grid modernization as described earlier is selected.) This implies that employees in many business functions will be forced to manage two operating models – traditional and smart – simultaneously. Information systems and tools can be designed to help employees accommodate this challenge efficiently and effectively. As just one example, the SCADA systems in use in the Distribution Control Center could be modified to let an operator know which feeders have been enabled with Distribution Automation capabilities, and to notify the operator when Distribution Automation has instituted a configuration change.

Increased use of sophisticated equipment and capabilities enabled by the smart grid will require new and different organizational and human resource skills and capabilities if benefits are to be maximized.

There are many examples in which smart grid capabilities will require business functions to acquire new capabilities. In the field, smart grid systems are more sophisticated than existing equipment, and consequently require more effort and knowledge to install, maintain, and support. 'Smart' field devices are no longer simple electromechanical systems, but complex computer-driven devices. Troublemen and linemen will need enhanced communications and information technology skills. For example, Troublemen may have to repair communications equipment not previously used in distribution activities, requiring an entirely new skill set. Also, Information Technology help desks will require more resources and skills to support many new types of computerized field devices.

In addition to field and IT capability enhancements, Distribution Control Centers (DCC) will also need to acquire new skills, as the management of grid operations becomes more complex. The distribution of power past the substation has historically been unidirectional. In the future, higher penetrations of customer-owned generation and storage may require Dispatchers to manage multidirectional power flow (PV Solar and Electric Vehicles) as transmission operators do currently. Dispatchers have traditionally instructed field crews to make on-location changes; smart grid technologies will allow them to perform the actions remotely, or perhaps simply monitor automated system instructions. The role is changing as the technology develops, and Distribution Control Center managers may wish to consider how Dispatcher skills and competencies will need to change to maximize the value of smart grid technologies.

Even Customer Care Center skill sets may need to change. In a smart grid scenario, the nature of support customers might want to obtain from their utility is likely to change. As just one example, access to detailed usage information is likely to prompt customer questions on how to interpret the information, how to identify the drivers of home energy consumption, and how best to save money on time-differentiated rates. These types of calls will require new skills and competencies from Call Center agents.

In Marketing and Product Development, the smart grid will change the types of Demand Side Management (DSM) programs utilities offer, the features and capabilities of such programs, and the manner in which DSM programs will be promoted. And the introduction of time-differentiated rates presents particularly challenging marketing issues. Utility marketing organizations will want to cultivate the types of creative and self-driven personality types required to identify and seize opportunities to maximize the benefits of smart grid investments.

In summary, MetaVu examined the extent to which PSCO integrated smart grid capabilities into routine operations as part of MetaVu's SmartGridCity™ evaluation. The examination documented many examples in which the application of change management best practices could maximize the benefits of smart grid capabilities in the event of future expansions. In addition, MetaVu observed that the experiences associated with operating SmartGridCity™ have institutionalized a motivating vision for grid modernization among PSCO management and individual contributors.

VALUE CREATION BY SMART GRID SYSTEM

This section provides more detailed descriptions of the value created by various SmartGridCity™ systems. It begins with information on the measurement framework used to evaluate the systems, describes each system, and summarizes findings on economic benefits, costs, and risks by system. Each system is then described in detail:

- System objectives and functions
- Types of benefits offered by the system
- Value created for SmartGridCity™ and PSCO customers
- List of important considerations when developing a business case for the system.

Summary

Measurement Framework

PSCO executives and demonstration project leaders established three goals to maximize the value of the evaluation phase. These goals included:

- Evaluate the benefits of 61 value propositions and take other steps as necessary to inform deployment strategy and future business case development.
- Document measurement methods so that Company managers can use them as appropriate in future business planning.
- Identify relevant risks and operational and strategic considerations identified through the evaluation process.

The SmartGridCity™ evaluation framework was designed to collect, organize, and analyze data to transform a collection of findings into a usable and actionable information set and satisfy the following criteria:

- Identify lessons learned and information gleaned from the SmartGridCity™ demonstration project.
- Provide valuable quantification and perspective to inform the development of deployment strategies and business cases by PSCO managers.
- Document the measurement frameworks, assumptions, and calculations for application to specific deployment scenarios as part of future planning efforts.

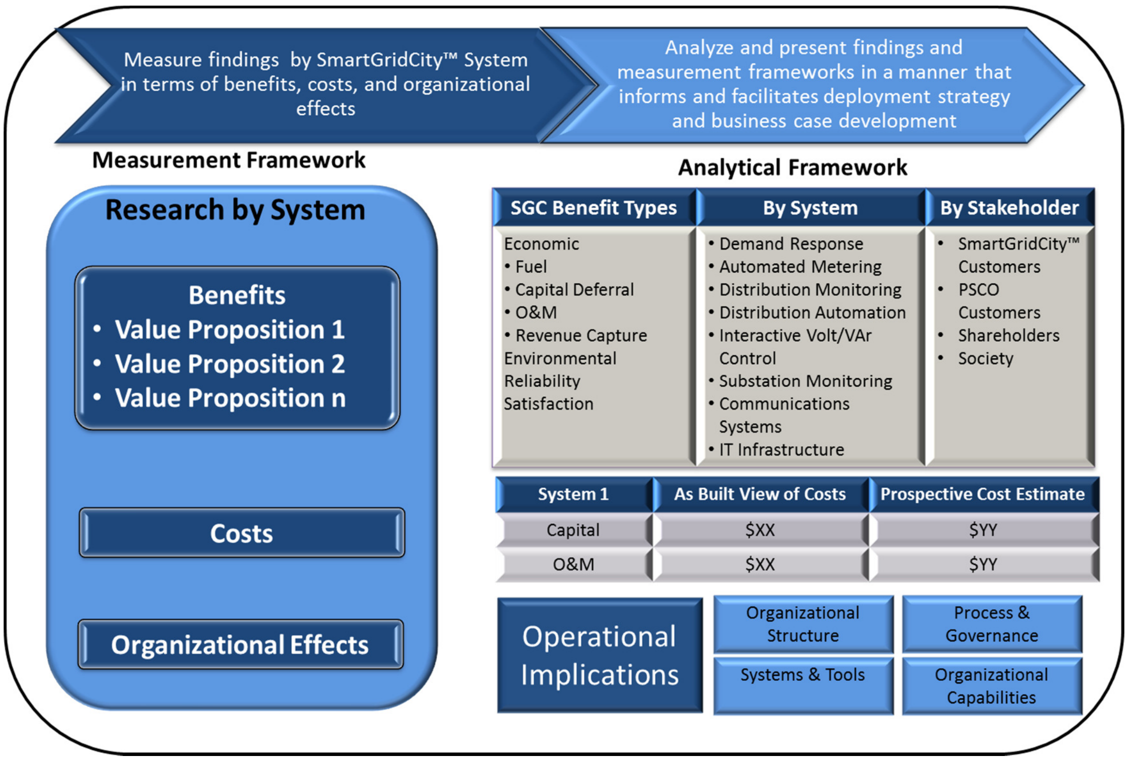
Because of the developing and emerging nature of smart grid technologies and assessments, measurement standards are not yet universal. However, the various grid modernization pilots, deployments, evaluations, and assessment guidelines that have been completed or are underway were analyzed as part of the SmartGridCity™ evaluation framework development process. MetaVu completed an analysis of 12 value measurement methodologies (EPRI, NETL, DOE, etc.) and smart grid deployments (BG&E, OG&E, SCE, etc.) to inform the measurement framework used to evaluate the SmartGridCity™ demonstration project. Fifty-two additional external references (studies, papers, articles, etc.) were used to validate and/or support specific calculations for value proposition benefits. Sixteen other sources were used to develop context and application frameworks for demonstration project evaluations and findings.

The resulting evaluation framework adapted emerging standards to SmartGridCity™ learning objectives; specifically, 61 value propositions established by the project leadership team to inform business case development. (To facilitate analysis and simplify the use of value proposition findings in future business planning, MetaVu split some value propositions and added a few others, ending up with 68 value propositions in total.)

No standards exist to address the potential effects of grid modernization on customer satisfaction or utility business models, though these issues were within the scope of the evaluation phase. In these two cases, MetaVu used best practices in market research and organizational development to establish appropriate measurement frameworks. The evaluation team made extensive use of market research to measure customer perceptions and value attribution related to grid capabilities and benefits. Utility organizational and operational implications were informed by interviews and collaboration with subject matter experts of varying responsibility levels both within and external to PSCO.

MetaVu provided additional support for future business case development by quantifying 'as built' and 'prospective' deployment costs and identifying operational and strategic deployment considerations. MetaVu also synthesized evaluation findings in the context of its experience with grid modernization projects. Many transcendent themes described in the Evaluation Summary were the result of discussions of the findings with PSCO project leaders and Business Area managers. Figure 4 illustrates the evaluation framework MetaVu developed for the SmartGridCity™ evaluation.

Figure 4 -- Illustration of Evaluation Framework



System Descriptions

Value Propositions are not actionable in and of themselves; benefits are delivered by SmartGridCity™ systems. In the Value Proposition analysis, at least one SmartGridCity™ system is identified as responsible for delivering the potential benefits available. A SmartGridCity™ system is defined as "a set of hardware and software that could conceivable be installed in isolation to accomplish SmartGridCity™ value propositions."

- **Distributed Energy Resource Control (DERC):** Controls energy resources throughout the distribution grid to optimize utility operations and support time-differentiated pricing programs. Components include in-home smart device (IHSD), smart meters, and demand response management system (DRMS) software.

- **Advanced Metering Infrastructure (AMI):** Records high-resolution usage data that is communicated automatically to the utility for billing and analysis purposes and provided to customers to enable them to change consumption behaviors. Components include smart meters, online account management (OAM), OpenGrid software, and the billing system.

- **Distribution Monitoring (DM):** Provides real-time visibility into distribution network status. Components include voltage sensors on overhead transformers, current and voltage sensors on underground transformers, Power Quality meters, synchrophasors, and OpenGrid software.
- **Distribution Automation (DA):** Reconfigures the distribution grid automatically based on electrical conditions. Components include sectionalizing devices, and DA controllers.
- **Integrated Volt/VAr Control (IVVC):** Reduces voltage and optimizes power factor automatically to improve power delivery efficiency. Components include distributed capacitor banks and controllers, line sensors, load tap changers and controllers, and a centralized data processor utilizing OpenGrid, a server-based software application.
- **Smart Substation Monitoring and Protection (SSMP):** Provides real-time visibility into substation operating conditions. Components include microcontroller-based relays, automation controllers, communications equipment, analysis engines and OSI Soft software.

Benefits

A summary table of benefits by SmartGridCity™ system is offered below, rated relative to the benefits available from other systems. The values in Table 1 are defined as follows:

High: Substantial potential for benefit

Med: Moderate potential for benefit

Low: Minimal, if any potential for benefit

Blank: Benefits of a specific type were not anticipated from a particular system

TBD: Benefit level is dependent on a high number of variables

Please note that the table below describes relative benefits, not value. Value considers the benefits against costs and risks. The following ratings do not take into account costs or risk involved in realizing the benefits (see next section).

Table 1: Relative Benefits by System and Benefit Type

	Inside Systems ←-----------------------------→ Outside Systems					
	Smart Substation Monitoring and Performance (SSMP)	Integrated Volt VAr Control (IVVC)	Distribution Automation (DA)	Distribution Monitoring (DM)	Advanced Metering Infrastructure (AMI)	Demand Response (DR or DERC)
Capital Deferral		High	Low	Low	High/ Low*	High
O&M	TBD			Med	Low	
Revenue Capture					Low	
Energy / Environment* **		High	Low	Low	High/ Low*	Med
Reliability	TBD		High	High	Low	Low
Safety				Med	Low	
Satisfaction**		Low	Low	Low	TBD	High

Table 1 notes:

* With (High) and without (Low) high customer adoption of time-differentiated rates enabled by Smart Metering

** Many benefits offered by smart grid systems are not readily apparent to customers and therefore offer low satisfaction benefit

*** Green signals were not implemented as they were not shown to increase utilization of renewable energy

Note: The "Inside" systems, notably Integrated Volt/VAr Control, deliver some types of economic benefits at high and medium potential levels; the reader will observe that these capabilities require relatively little capital to implement in the next section. Conversely, the "Outside" systems, notably smart metering, offers relatively low customer benefits unless high customer adoption of time-differentiated rates is realized; the reader will observe that metering requires a great deal of capital to implement. For additional information, please see value proposition evaluation detail in Appendix 1.

Costs and Risks

Prospective estimates of capital costs relevant to future deployment were developed from detailed analyses of 'as built' costs as incurred in the SmartGridCity™ demonstration project. Prospective estimates by system incorporate likely design changes recommended by construction managers, project managers, and project leaders as a result of lessons learned through the demonstration project. Prospective estimates also reflect the fact that partner support to the extent contributed in SmartGridCity™ is not likely to be available in the future. Feeders are used as the basis of analysis as they represent a useful common-denominator. The figure below describes the likely capital costs of various systems in any future deployment.

Risk was estimated by system based on the relative technological obsolescence risk related to each system. Technology Obsolescence risk was estimated in relative terms by observing grid technology and supplier business model changes from 2007 to 2010. During this time many technologies and supplier business models evolved; some technology price points dropped, some technology features improved, and other technologies were ultimately determined to be sub-optimal. Home Area Networks were identified as particularly immature technologies in the SmartGridCity™ demonstration project, though meter technologies evolved rapidly during the evaluation period as well. The results of relative technology risk evaluations by system are presented in the chart.

Figure 5 - Capital and Technology Risk by System

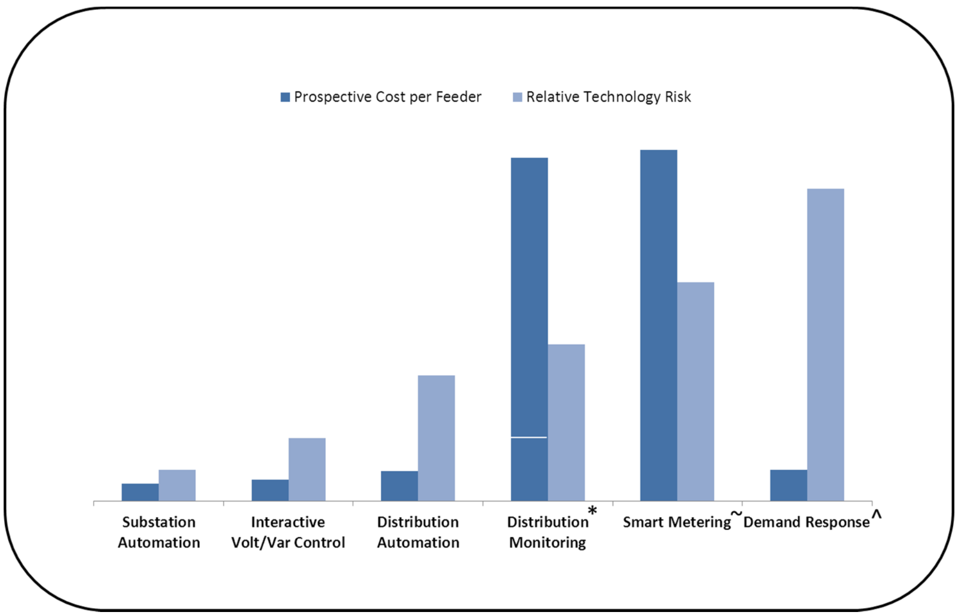


Figure 5 notes:

° Amounts indicated do not include fixed infrastructure capital costs.

* Distribution Monitoring capital cost estimate assumes transformer-based sensing; the portion above the break indicates capabilities and costs that might be duplicated with the installation of smart meters with certain sensing capabilities. (Note that the use of meters as sensing devices is contingent upon readily- and cost effectively-available data, which is in turn based on communications infrastructure design choices.)

~ Smart Metering capital cost estimates include communications-enabled meter and premise-variable communications costs per premise.

^ Demand Response capital cost estimates assume that customers purchase home energy management equipment; amounts indicated consist of equipment rebates likely paid by utility.

Figure 5 illustrates that the size of investment required to deploy smart grid capabilities per feeder and the technology risk associated with each system grows as the physical and logical location of associated hardware approaches the grid periphery.

Smart Grid System Value Creation Detail

This section provides more detailed descriptions of the value created by the demonstration project for SmartGridCity™ customers and PSCO customers. Value creation detail is organized by distinct SmartGridCity™ system and presented in order of the physical location of capital investments, from the customer premise to the utility substation and through data processing.

- Distributed Energy Resource Control/Demand Response (DR)
- Advanced Metering Infrastructure (AMI)
- Distribution Monitoring (DM)
- Distribution Automation (DA)
- Integrated Volt/VAr Control (IVVC)
- Smart Substation Monitoring and Protection (SSMP)

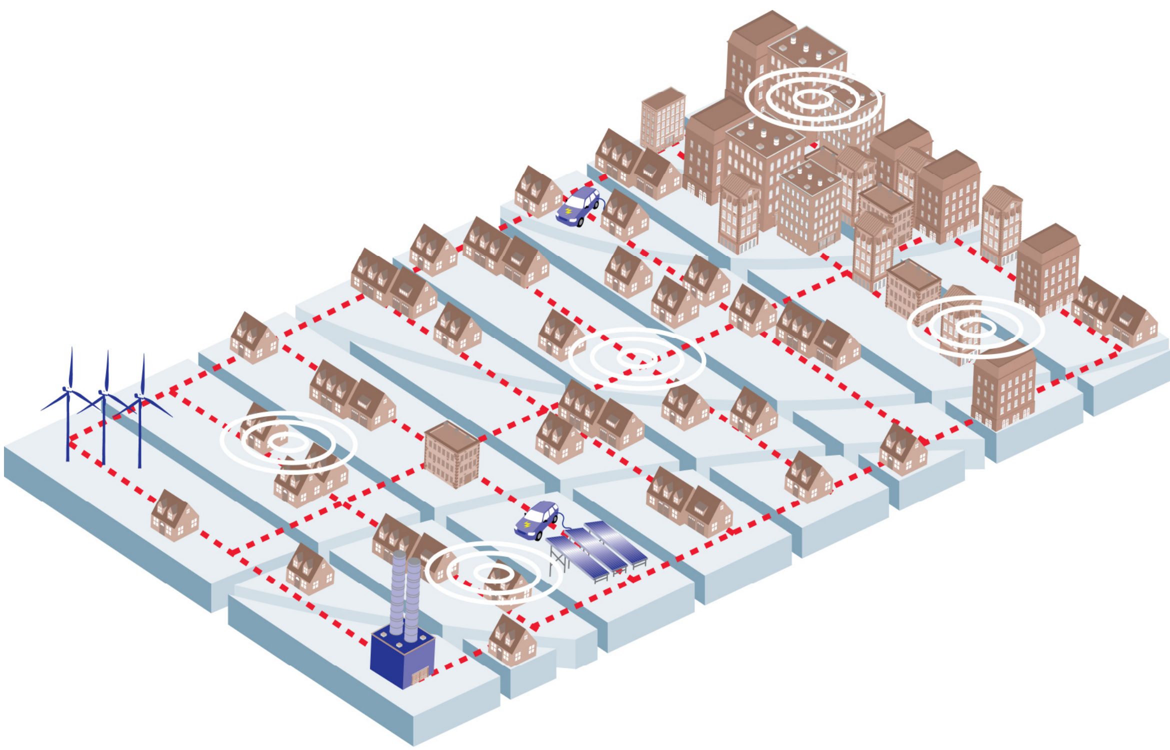
The value created by infrastructure systems is also presented:

- Communications Systems
- Information Technology Systems

Each system is described in detail in the following format:

- System objectives and functions
- Types of benefits offered by the system
- Value created for SmartGridCity™ customers and PSCO customers
- List of important considerations when developing a business case for the system

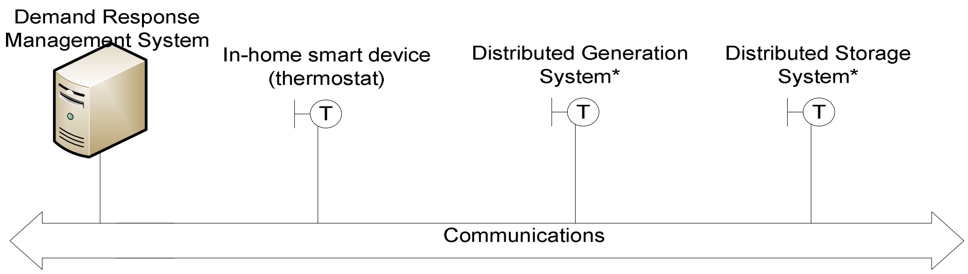
For even greater detail about lessons learned, please see Appendix 1.



1. Distributed Energy Resource Control (DERC)

Though envisioned to control customer loads as well as many types of distributed resources (including customer-owned equipment such as electric vehicles and PV Solar) in time, 'Distributed Energy Resource Control' as implemented in SmartGridCity™ consisted primarily of advanced capabilities to control customer loads through home area networks, or HANs. The table below summarizes value created by the demonstration project for SmartGridCity™ customers, PSCO customers, and the utility (in the form of lessons learned).

Figure 1 Distributed Energy Resource Control (DERC) System



System Dashboard

The following table describes the relative value provided by DERC from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for DERC.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
High	**-**	**-**	**Med**	**Low**	**-**	**High**

Capital Deferral - DERC can result in significant capital deferral for generation, but opportunities to defer distribution capacity expansion are limited.

Energy / Environment – DERC (Demand Response) is much more valuable as a capacity management tool than an energy efficiency tool. Because customer satisfaction will likely limit the number of Demand Response events that can be called, the events must be employed judiciously (i.e., on high demand days). It should be noted that DERC technology improvements offer demand response program design options that could enable changes to event flexibility, thus altering event assumptions.

Reliability – High customer adoption of DERC (Demand Response) is required before it can be counted on as an effective response to local distribution emergencies.

Satisfaction - DERC is likely to improve customer satisfaction through lower bills, as customers are likely to be paid incentives to participate.

Summary Analysis: Distributed Energy Resource Control

The table below summarizes value created by Distributed Energy Resource Control in the demonstration project:

Value to SmartGridCity™ Customers	Value to PSCO Customers
• SmartGridCity™ Customers were offered the opportunity to participate in a pilot of In-home Smart Devices	Lessons learned that will optimize investments for PSCO customers: • Home Area Networks (HAN) offer customers significant capability enhancements over traditional DR programs. • DR offers significant generation capacity deferral value ($170/yr.) but little in the way of distribution capital deferral or energy efficiency value. Lessons learned that minimized risk for PSCO customers: • HAN technology is extremely expensive and evolving rapidly, presenting high capital and technological obsolescence risk. • HAN technology, when deployed such that it is interconnected with advanced utility meters, presents additional utility system security risks if not carefully managed. Lessons learned that will maximize benefits through operational changes: • Providing customers with a green energy signal when renewable energy is high will not increase the amount of renewable generation on the system; increases in electric load that result from such signals are generally satisfied with natural gas-fired generation. Improvements in storage technologies may require this lesson to be revisited in the future. • DR as designed could be called locally to help address distribution emergencies, but only at high customer adoption rates. • HAN could be a valuable enabler of time-differentiated rates for customers. A test lab exists that will help optimize investments and maximize benefits into the future: • The degree to which HAN technology increases the effectiveness of Demand Response over traditional residential Demand Response technologies is not yet known.

DERC Business Case Considerations

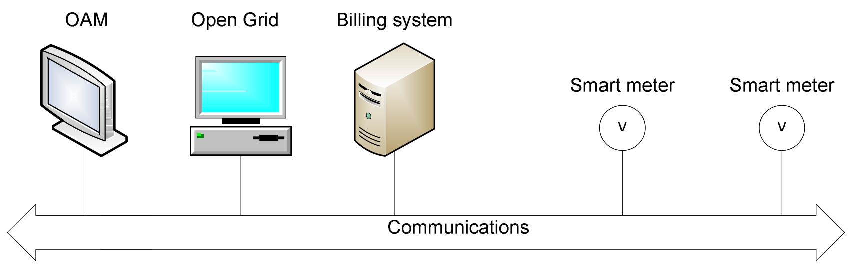
When developing the business case for DERC, PSCO is advised to consider:

- Customer Participation Levels
- Customer Behavior Change
- Comparisons to Existing DR Technologies (Saver's Switch)
- Value of Capacity
- Technology Obsolescence Risk

2. *Advanced Metering Infrastructure*

Smart Meters record high-resolution interval data that is communicated automatically to the utility for billing and analysis purposes. This data can also be provided to customers to enable them to manage energy use. Other smart meter capabilities include two-way communications and the measurement of metrics beyond usage. Though there are alternative approaches available, smart meter capabilities can facilitate time-differentiated pricing programs. Based on external research and historic studies, MetaVu believes the time-differentiated pricing methods facilitated by smart metering could offer significant opportunities to defer capital and reduce energy usage. However, the overall impact will depend on a large number of factors, including customer participation rates and behavior change levels, system load growth, and pricing program structures.

Figure 2 Smart Metering System



System Dashboard

The following table describes the relative value provided by Smart Meters from among those types of benefits available through grid modernization:

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
High/Low	**Low**	**Low**	**High/Low**	**Low**	**Low**	**TBD**

Capital Deferral – If time-differentiated rates are widely adopted by customers, significant reductions in peak demand can decrease asset stress and defer capital investments. If time-differentiated rates are not widely adopted by customers, smart metering is unlikely to experience capital deferral benefits.

O&M – As meter reading has already been automated (and is extremely cost effective) in almost all of the PSCO service area, smart metering offers little in the way of meter reading savings. Other, smaller O&M reductions are available through reductions in troubleshooting truck rolls and shorter customer call length in the Call Center.

Revenue Capture – Residential theft and commercial meter configuration and equipment errors can be detected with a smarter grid, but the net increase in revenue capture is expected to be relatively small.

Energy / Environment - Like Capital Deferral, in order for Smart Metering to achieve significant Energy / Environmental benefits, rapid customer adoption of time-differentiated rates must be secured.

Reliability – Smart meters could help identify, classify and locate outages, but data levels required to complete this functionality are high. As a result, most smart grids manage outages at the neighborhood (vs. premises) level, though smart meters' meter pinging capability can reduce over/ under estimations of outage extent.

Safety – Smart meters can reduce truck rolls and hazardous field investigations that positively impact safety.

Summary Analysis: Smart Meters

The table below summarizes value created by Smart Meters in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
• SmartGridCity™ Customers have the opportunity to participate in time-differentiated rate programs. • In a 2006-2007 PSCO study of time-differentiated rates, motivated customers saved as much as $200 on their bills annually • Customers with smart meters can view detailed usage data throughout the month via a secure website. • In the event of an outage, the customer care center can remotely diagnose smart meter operation, immediately determining if the outage is PSCO's responsibility or the customer's responsibility to repair. (This capability was rated highly important in a survey of SmartGridCity™ Customers).	Lessons learned that will optimize investments for PSCO customers: • Advanced meters offer long customer payback periods if meter reading has already been automated and/or time-differentiated rates are adopted slowly by customers. Payback periods could improve if the technology is paired with high customer adoption of time-differentiated rates and as advanced meter prices drop. • Smart metering can reduce O&M costs by decreasing truck rolls and customer care center call times. • Advanced meters can double as sensing devices, reducing the need for transformer-based line sensors used in Distribution Monitoring and Integrated Volt/VAr Control. Lessons learned that will minimize risk for PSCO customers: • Smart meter and relevant communication technologies are still evolving and associated costs are dropping. • Enabling customer/representative access to meter functions (i.e., using meters as a home gateway) increases utility cyber security risks. Lessons learned that will maximize benefits through operational changes: • Historical smart meter data can help the distribution Capacity Planning function 'right size' transformers and other grid components. A test lab exists that will help optimize investments and maximize benefits into the future: • Smart meters are one of the most critical components of the test lab as they provide detailed measurements at the customer level.

Smart Metering Business Case Considerations

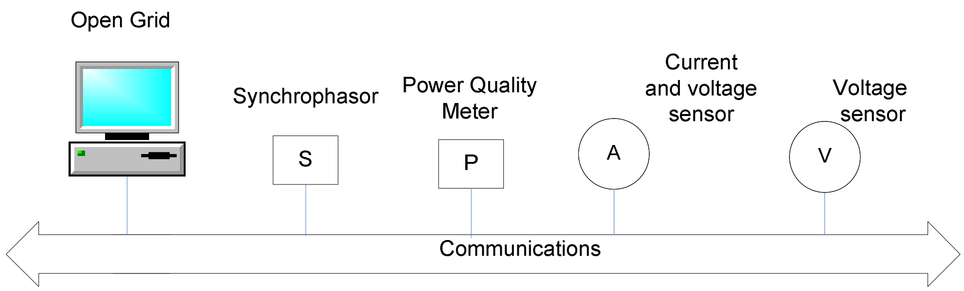
When developing the business case for Smart Metering, PSCO is advised to consider:

- Value of customer service enhancements
- Time Differentiated Rate Participation
- Customer Behavior Changes Due to Time Differentiated Rates
- Value of Meter Reading Cost Reduction
- Distribution Monitoring designs and capabilities
- Cost of Smart Meters and associated communications

3. Distribution Monitoring

Distribution monitoring provides real-time visibility into distribution grid conditions between substations and customer premises. This visibility enables more efficient faster problem troubleshooting and fault locating, which have been clearly demonstrated in SmartGridCity™.

Figure 3 Distribution Monitoring System



System Dashboard

The following table describes the relative value provided by Distribution Monitoring from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for DM.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
Low	Med	-	Low	High	Med	Low

Capital Deferral - DM will only minimally reduce capital expenditures as a result of better access to load information because current legacy tools are considered to be highly accurate.

O&M - O&M cost reductions are available from potential outage notification programs and reduced maintenance requirements, but such reductions are anticipated to be small.

Energy / Environment - The ability to properly size transformers through access to better load information can improve distribution efficiency but payback periods are fairly long.

Reliability - Greater visibility into the distribution grid significantly speeds fault location and Power Quality issue troubleshooting. This is particularly true for underground faults.

Safety – DM will dramatically improve troubleshooting and consequently the number of truck rolls and exposure to hazardous field conditions.

Satisfaction – Despite increases in reliability from DM, customer satisfaction will not likely improve as most PSCO customers already experience high levels of reliability.

Summary Analysis: Distribution Monitoring

The table below summarizes value created from Distribution Monitoring in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
• Power Quality issues that typically required days or weeks to accurately identify using traditional techniques are diagnosed in minutes in SmartGridCity™. • Faster fault identification capabilities are reducing Customer Minutes Out (CMO) by 385,000 CMO annually. • Exception reporting enables proactive identification and resolution of Power Quality issues; complaints dropped from 37 annually pre-deployment to zero post deployment.	Lessons learned that will optimize investments for PSCO customers: • Selective deployment of DM based on reliability and geographic needs will improve value created per dollar of invested capital relative to universal deployment. • As PV and EV penetration grow, DM can identify and prioritize needed grid upgrades. • DM fault location value is greater on underground conductors than it is on overhead conductors. • DM can be used in place of AMI for outage management and Power Quality issue identification; there are valid arguments for either approach. Lessons learned that will minimize risk for PSCO customers: • Sensors used in DM are sensitive, with failure rates in excess of that experienced with most grid equipment. Lessons learned that will maximize benefits through operational changes: • Proactive outage notification is achievable through the implementation of DM. • DM data can help the distribution Capacity Planning function 'right size' transformers and other grid components. • When paired with AMI data, troubleshooting time can be further reduced.

Distribution Monitoring Business Case Considerations

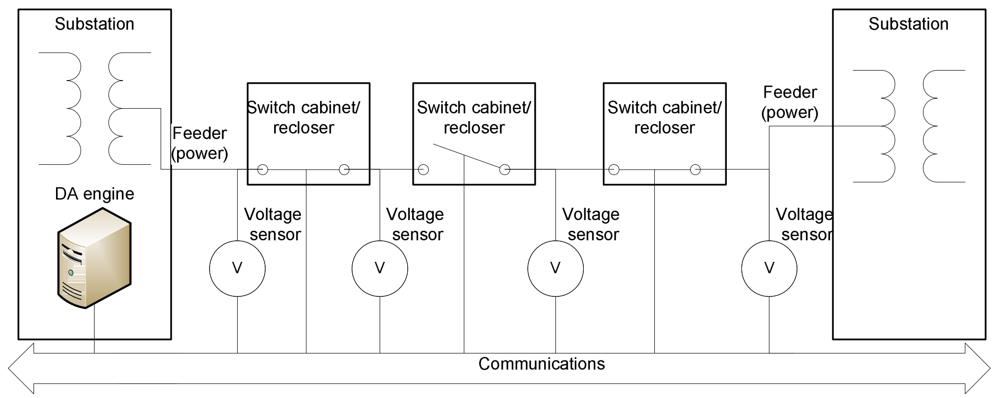
When developing the business case for Distribution Monitoring, PSCO is advised to consider:

- Value of Improved Reliability/Impacts of Deteriorating Reliability
- Feeders/Geographies Most Likely to Benefit
- Communication Requirements Necessary for Desired Level of Monitoring
- Asset Life of DM Equipment
- Cost and Risks of DM Equipment
- Value of Faster Problem Identification and Resolution

4. Distribution Automation (DA)

DA is a set of field hardware and software that automatically reconfigure the grid, primarily to isolate the impact of a service outage to the smallest number of customers possible. DA provides automated control logic and remote operation capabilities not available in traditional SCADA (System Control and Data Acquisition) systems used by grid operators. The table below summarizes value creation from benefits to the participating customers in the demonstration project:

Figure 4 Distribution Automation System



System Dashboard

The following table describes the relative value provided by Distribution Automation from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for DA.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
Low	**-**	**-**	**Low**	**High**	**-**	**Low**

Capital Deferral – DA is unlikely to impact capital deferral as opportunities to shift load were found to be minimal.

Energy / Environment – Current high-voltage switching technologies cannot accommodate the frequent load shifting that would be required to balance phases dynamically and reduce line losses. Opportunities are generally small but should be re-examined as solid state switching technologies advance.

Reliability - Distribution Automation reduces CMO by isolating the outages automatically shortly after a fault occurs; customers not on the isolated segment will have power restored almost immediately.

Satisfaction – Distribution Automation can shorten outage extent but is unlikely to significantly increase customer satisfaction as reliability in PSCO is currently high.

Summary Analysis: Distribution Automation

The table below summarizes value creation from Distribution Automation in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
• Increased reliability from a fully functioning DA system resulting in a reduction of 28,125 CMO *per feeder* per year (Installed on 2 feeders.).	Lessons learned that will optimize investments for PSCO customers: • Selective deployment of DA based on reliability and geographic needs will improve value created per dollar of invested capital relative to universal deployment greater value. • Significant reliability benefits are available from DA, though economic benefits (resulting from improved load balancing, for example) did not appear sufficient to justify costs in preliminary analyses. (MetaVu did not attempt to estimate the economic value customers obtain from improved reliability.) Lessons learned that will minimize risk for PSCO customers: • Reliability improvement is generally a function of the number of sectionalizing devices installed; improvements in reliability must be balanced against the cost of the devices. Lessons learned that will maximize benefits through operational changes: • Of all smart grid systems, DA has the lowest tolerance for failure as it controls critical grid equipment. • Firmware and software upgrades are critical to continuous and reliable DA functionality. • DA functions at the substation and feeder level and does not require centralized data processing. 'Distributed processing' could serve as a model for other smart grid systems.

Distribution Automation Business Case Considerations

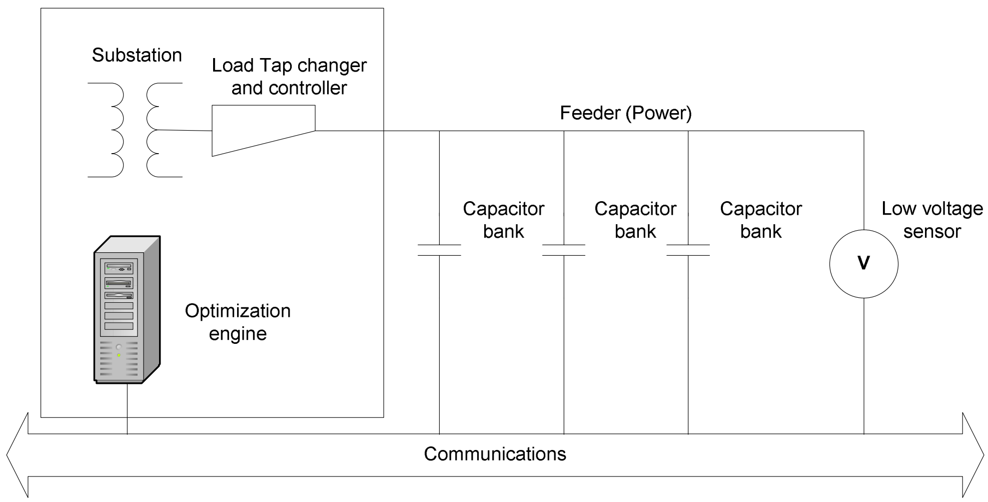
When developing the business case for Distribution Automation, PSCO is advised to consider:

- Level of Reliability Desired
- The Value Customers Assign to Reliability
- Feeders/Geographies Most Likely to Benefit
- Cost of Switching/Sectionalizing Equipment

5. *Integrated Volt VAr Control (IVVC)*

IVVC regulates feeder voltage and power factor (VAr) continuously and automatically to reduce line losses between the substation and customer loads. Voltage is monitored near customer premises to ensure satisfaction of minimums, while VAr is optimized through the coordinated operation of capacitor banks located throughout the grid. The table below summarizes value creation from benefits to the participating customers in the demonstration project:

Figure 5 Integrated Volt VAr Control System



System Dashboard

The following table describes the relative value provided by IVVC from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for IVVC.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
High	-	-	**High**	-	-	**Low**

Capital Deferral – In order for IVVC to delay distribution capital, feeders must be operating near capacity and be experiencing slow growth. High growth feeders are likely to be upgraded despite IVVC, and feeders not near capacity are unlikely to be upgraded at all. Generation capital deferral can be significant if a large number of feeders are treated.

Energy / Environment - Initial SmartGridCity™ investigations suggest IVVC may reduce end-user energy usage by up to 2.5%.

Satisfaction – Although significant in the aggregate, the energy usage reductions obtained by any one customer will be difficult for a customer to perceive.

Summary Analysis: Integrated Volt VAr Control
The table below summarizes value creation from Integrated Volt VAr Control in the demonstration project:

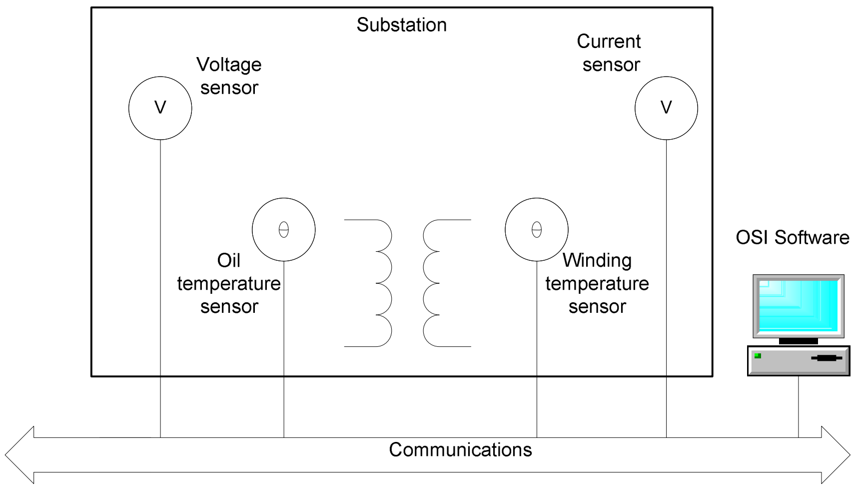
Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
• For customers served by feeders 1554 and 1556, bill reduction of \$18 per customer per year was achieved due to full-time voltage reduction strategy. • IVVC on feeders 1554 and 1556 is reducing CO_2 equivalent output by 430 tons per year through energy savings.	Lessons learned that will optimize investments for PSCO customers: • IVVC offers high potential economic benefits to customers relative to cost. • IVVC can be deployed selectively, for example on feeders with the greatest load and voltage/VAr improvement opportunity. Though full deployment offers greater benefits relative to selective deployment, selective deployment can improve customer payback periods. • Capital deferral from IVVC is anticipated from deferred generation capacity due to demand reduction. Lessons learned that will reduce risk for PSCO customers: • The technology risk of IVVC is low. Lessons learned that will optimize benefits through operational changes: • Though significant relative to costs and significant in the aggregate, the economic benefits to any individual customer from IVVC will be difficult to perceive. • IVVC investments are similar to DSM program investments in that they deliver direct benefits to customers but reduce the utility's opportunity to earn its authorized rate of return. • Advanced meters can also function as sensing devices, serving as voltage end points for IVVC.

Integrated Volt/VAr Control Business Case Considerations
When developing the business case Integrated Volt/VAr Control, PSCO is advised to consider:
- Energy per KWh
- Incremental cost to add IVVC to a feeder
- Engineering Analysis to determine feeder-specific IVVC value
- Incentives similar to DSM programs to mitigate lost margins

6. Smart Substation Monitoring and Protection

Smart Substation Monitoring and Protection (SSMP) offers real-time visibility into substation operating conditions, providing detailed data that can be used proactively to identify equipment malfunctions prior to failure and forensically to investigate abnormal substation events. It is functioning in four substations in SmartGridCity™.

Figure 6 Smart Substation Monitoring and Protection System



System Dashboard

The following table describes the relative value provided by Smart Substation Monitoring and protection from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for SSMP.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
-	TBD	-	-	TBD	-	-

O&M - Less than 1% of substation transformers fail per year. But when failures occur, many customers are left without power for long periods of time and are very costly to repair. Failures are so infrequent that more experience with the SSMP system is required before any conclusions can be determined.

Reliability – SSMP may be able to predict substation transformer and breaker failure and reduce CMO. It may also be able to be used forensically post-failure, adding to best practices and helping to avoid future substation outages through a continuous quality improvement process. However, failures happen very infrequently and additional experience with the SSMP system is required before any conclusions can be made.

Summary Analysis: Smart Substation Monitoring and Protection

The table below summarizes value creation from Smart Substation Monitoring and Protection in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
• Data from four SmartGridCity™ substations is being collected.	Lessons learned that will optimize investments for PSCO customers: • Substation-level failures are rare but have a disproportionate impact on CMO when they occur. • Substation data may help predict substation transformer and breaker failure, but insignificant experience is available to prove or disprove such a claim. • Substation data can potentially be used forensically to evaluate failure root causes. Lessons learned that will optimize benefits through operational changes: • Analytical tools and business process changes will need to be developed to make use of substation data.

Substation Monitoring and Protection Business Case Considerations

When developing the business case for Substation Monitoring and Protection, PSCO is advised to consider:

- Value Customers Place on Reliability
- Value of Greater Substation Data to Improve Reliability
- Changes in Business Processes, Resources and Management Systems to make use of Data Available
- Costs of Substation Monitoring Equipment

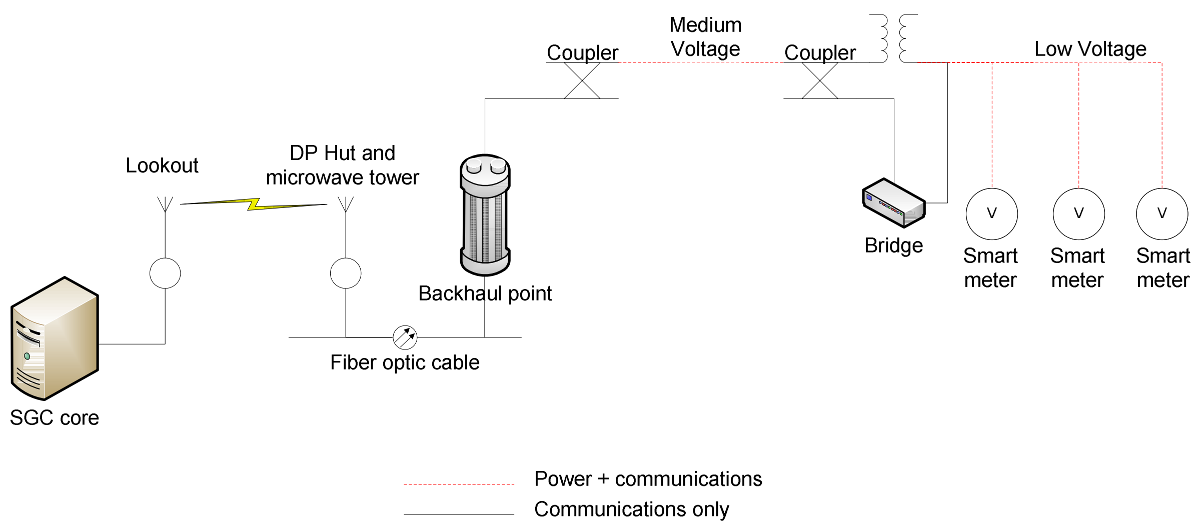
Smart Grid Infrastructure System Detail

7. Communication Systems

For smart grid equipment to function, a system to support the communication between smart grid technologies is required. The communications system utilized in SmartGridCity™ was designed to be reliable, robust, secure, and fast to allow for a variety of capabilities to demonstrate and test. It was equipped with a high bandwidth and low latency communications network so that current and future application testing could proceed effectively. This capability was established through a variety of communications technologies, including Broadband over Power Line (BPL), fiber optic cable, 3G Cellular, DSL, and microwave.

The system was designed to accommodate any standard internet protocol, allowing almost any type of system to be implemented over the SmartGridCity™ communications network. Since most emerging technologies use standard internet protocols, they all are able to use the existing communications infrastructure provided they can be connected to BPL or fiber optic cable.

Figure 7 Communications System



System Dashboard

Infrastructure systems provide no direct value but enable other systems to deliver value. Accordingly, no system dashboard of relative value is required.

Summary Analysis: Communication Systems

The table below summarizes value creation from Communication Systems in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
• A robust and effective communication system exists in SmartGridCity™ which supports and enables the smart grid technologies and associated benefits.	Lessons learned that will optimize investments for PSCO Customers • Competing approaches to communication systems offer pros and cons in a variety of decision criteria. o Build vs. Buy a System o Upfront Fixed Cost vs. Ongoing Variable Cost o Grow Competence vs. Hire Expertise o Accountability for Security o Bandwidth and Latency o Future flexibility o Reliability/Quality Control • Communications with field devices yields safety benefits (by reducing field crew exposure to hazardous conditions) as well as operating expense reductions. • No single communications infrastructure will be adequate for all geographies or capabilities. • GIS must be adequately detailed to support communication design and operation. • Grid automation design must be deployed with ongoing consideration to the amount of data that it will generate and its impact. For example, line sensor report exceptions are provided instead of all data that can be measured. • More and better uses for smart grid data will be found over time. Communication systems may be called upon to support those needs. A test lab exists that will help optimize investments and maximize benefits into the future: • Communications Systems are some of the most critical components of the test lab as they have been designed to allow large amounts of test data to be communicated frequently with no latency.

Communication System Business Case Considerations

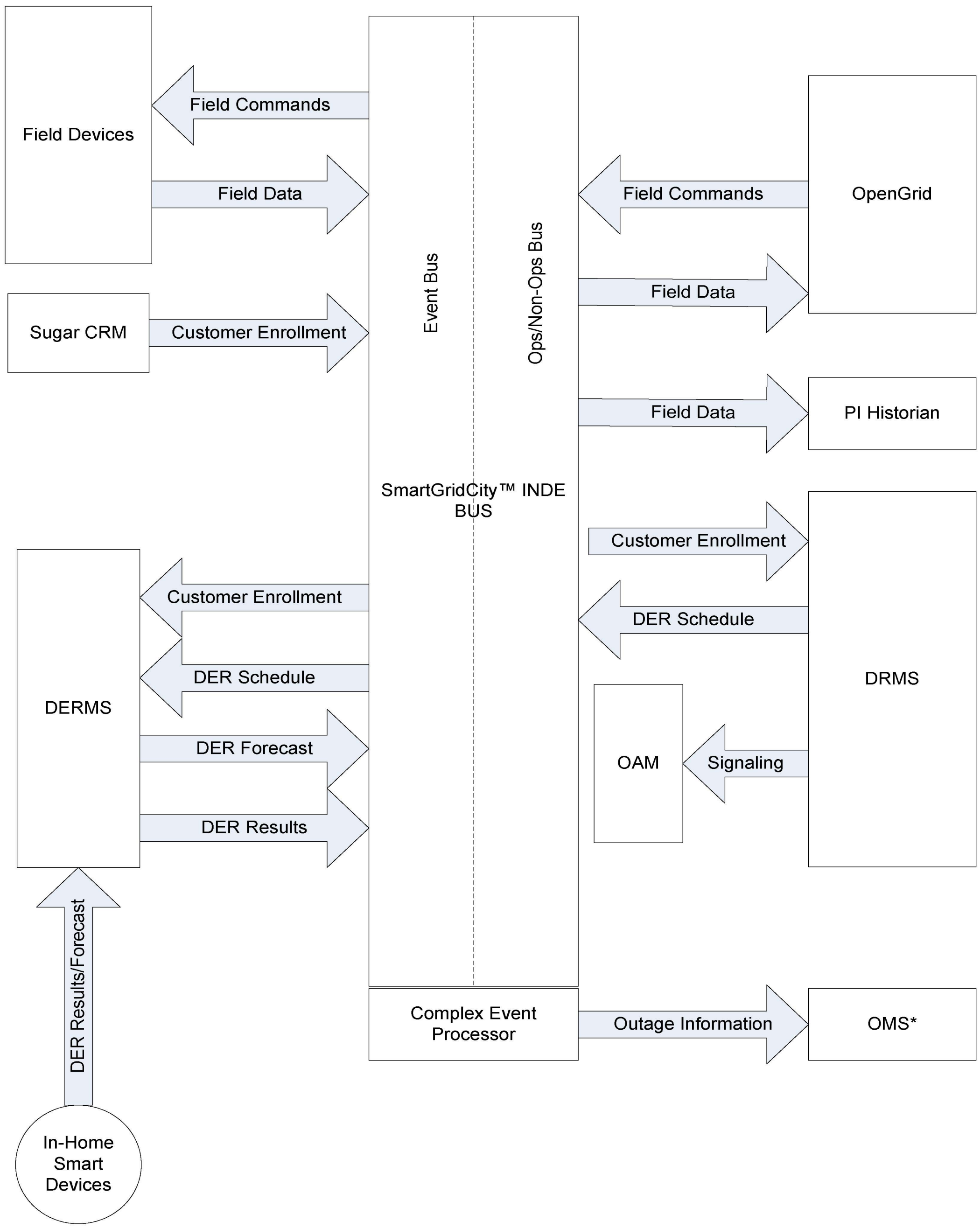
When developing the business case for a communication system for smart grid investments, PSCO is advised to consider:

- The latency and bandwidth requirements of smart grid technologies today and in the future.
- The investment and ongoing costs of various communication systems.
- Geographic capabilities and limitations of various communication infrastructures.
- Economic and technical constraints of various communication infrastructure types initial and ongoing.

8. *Information Technology Systems*

PSCO developed a new design of the IT infrastructure for SmartGridCity™, maximizing the use of readily-available technology, and systems and IT best practices. The IT systems facilitate the communication and processing of smart grid data. The systems are readily scalable and can be leveraged to support future smart grid investments within PSCO.

Figure 8 IT Systems



System Dashboard

Infrastructure systems provide no direct value but enable other systems to deliver value. Accordingly, no system dashboard of relative value is required.

Summary Analysis: Information Technology Systems

The table below summarizes value creation from IT Systems in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
• A robust and effective suite of information technologies exists in SmartGridCity™ which supports and enables the smart grid technologies and associated benefits.	Lessons learned that will optimize investments for PSCO customers: • The SmartGridCity™ Information Technology infrastructure is readily scalable, reducing the capital requirements and maintenance costs associated with any broader roll-out of smart grid applications in PSCO. Lessons learned that will maximize benefits through operational changes: • Security should be built into IT designs. It may be difficult to apply legacy policies, processes, and protocols to smart data environments. • The distribution operations function may need to acquire new IT skills, while the business systems function may need to adopt new electrical engineering skills. • Smart grid systems produce significant amounts of data. Strategies and tools should be developed to maximize value of data and benefits of smart grid investments. • Strategies to minimize data collection, including exception reporting, are advised. Lower latency is an added benefit of distributed data processing. • Though grid modernization offers operating cost reductions in several functions, IT support, software maintenance and data management costs are likely to increase. • The infrastructure must be designed to accommodate both existing systems and newer systems simultaneously. • Information from new and old systems must be integrated as seamlessly as possible to the user. A test lab exists that will help optimize investments and maximize benefits into the future: • Information Technology systems are some of the most critical components of the test lab as they enable processing and analysis of large volumes of test data. IT infrastructure investments made in SmartGridCity™ are being leveraged to benefit all PSCO customers: • A dual bus architecture optimized for differing data transfer needs was utilized to support various SmartGridCity™ systems. The bus approach was so successful it has been leveraged into other IT designs and platforms that support delivery of service to PSCO customers. • The bus architecture employed in SmartGridCity™ is anticipated to incur lower IT maintenance costs over time relative to traditional architectures, in which systems are integrated through maintenance-intensive 'point to point' system interfaces.

<u>IT System Business Case Considerations</u>

When developing the business case for an IT system for smart grid investments, PSCO is advised to consider:

- The Interoperability of Systems with the Current Bus Architecture
- Costs of Software Licensing, Maintenance and Potential Scalability
- Obsolescence Risk of IT Systems
- Initial and Ongoing Security Requirements
- Cost of Field and Central Hardware Support

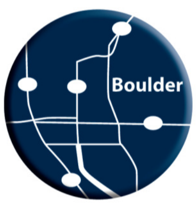
CONCLUSION

MetaVu's evaluation of the SmartGridCity™ demonstration project indicates that PSCO accomplished stated project objectives:

- A comprehensive suite of smart grid technologies that could be employed to manage anticipated changes in the retail electric market has been designed, built, and is currently in operation.
- A real-world laboratory in which new utility and consumer technologies could be deployed and evaluated at scale on an ongoing basis has been created and is currently in use.
- A 'body of knowledge' to inform future deployment strategy and business case development has been established, and contributions to it continue.

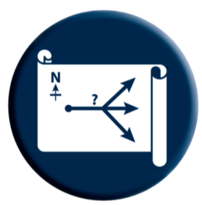
In addition, as described throughout this report, the SmartGridCity™ demonstration project provided benefits to SmartGridCity™ customers. The project also greatly benefited PSCO customers by providing insights that can be used to optimize grid investments and maximize economic, reliability, and satisfaction benefits for PSCO customers in the future. As such the demonstration project provided critical input into the Utility's grid modernization strategy and may have avoided hundreds of millions of dollars in sub-optimal grid investments.

Readers are encouraged to review the information in the Appendices for more details in support of the top five findings of the evaluation phase:



The project created value for SmartGridCity™ customers

The project created value for PSCO customers



Grid Modernization is a strategic planning process

Stakeholder and customer engagement is a platform for risk mitigation and value creation

Change management can help maximize the benefits from many smart grid systems

Now that the evaluation phase is complete, PSCO is in possession of valuable inputs to its grid modernization strategic planning process. The findings in this document, combined with inputs from Company managers, executives, stakeholders, customers, and regulators, should enable PSCO to develop grid modernization strategies, business cases, and implementation plans that maximize customer benefits while minimizing costs and risk. SmartGridCity™ will continue to serve as an ongoing test bed platform for future technologies and continue to inform and help optimize investments. As a result, the SmartGridCity™ demonstration project will be perceived by many to deliver lasting value in principle and in practice. In addition, Boulder customers within the SmartGridCity™ footprint have been equipped with a robust system that provide benefits now and into the future.

APPENDICES

Appendix 1 – Value Proposition Evaluation

Appendix 2 – Bibliography

Appendix 1 – Value Proposition Evaluation

Background and overview

The SmartGridCity™ (SGC) Value Proposition (VP) evaluation was completed during the fourth phase of the demonstration project, as one component of MetaVu's broader third-party research, evaluation and value measurement process. The VP evaluation is intended to be utilized by PSCO as inputs to create business cases for various smart grid system implementations.

The information presented in Appendix 1 is based largely on MetaVu's evaluation of the SGC VPs as established by industry partners, PSCO managers and Subject Matter Experts during the first phase of SGC in 2008. In general, evaluating a VP is based on a review and analysis of the benefits, costs and value that an organization can deliver to its customers, prospective customers, and other stakeholders within and outside the organization, or in this instance, within and outside of SGC. External research, where appropriate and relevant, supplemented analysis of internal data sources.

MetaVu developed and followed a standardized process to research and measure the benefits and lessons learned associated with each VP, adding custom calculation frameworks as appropriate to facilitate the measurement of specific VPs. The VP Analysis provides valuable insights into suitability of technologies, costs, benefits, and documented lessons learned associated with these technologies and related deployments.

The SGC VP evaluation provides a summary of quantified benefits, measurement methodologies and lessons learned to enable peer review and to advance the understanding of grid modernization value, including specific, targeted smart grid system applications.

MetaVu has prepared this work product for PSCO to be used for educational purposes and as input into specific decision scenarios. The data provided and lessons learned are intended to inform the ongoing decision-making process rather than provide detailed business cases.

Appendix 1 is organized by the following:

- Value Propositions List
- SGC Field Systems and Benefits Type
- Value Proposition Analysis Sheet Template
- Value Proposition Analysis Sheets

Value Propositions List

A summary and analysis of each of the 68 value propositions is included here in Appendix 1. The value propositions are organized by the following customer benefits types:

- Economic (32)
    - Fuel Cost (9);
    - Capital Deferral (12);
    - Operations and Maintenance (10); and
    - Revenue Capture (1).
- Environmental (3)
- Reliability (11)
- Customer Satisfaction (13)
- Strategic (9)

The complete value proposition analysis sheets are included in this section in a chronological order.

Economic (Fuel Cost, Capital Deferral, Operations and Maintenance, Revenue Capture)

Through targeted smart grid investments and implementation of smart grid systems, PSCO has gained invaluable knowledge that can be leveraged to benefit customers and its grid operations. 32 value propositions were evaluated that held potential economic impacts. Each of the four Economic categories is listed below.

Economic – Energy

Nine value propositions were evaluated that held potential impacts for reduced energy usage.

VP #	Description
1.7	Use Demand Response as a Virtual Power Plant
1.9a	Reduce energy consumption through CVR
2.4	Fuel cost reduction through VAr reduction
2.5	Line loss optimization through remote switching
3.4	Time-of-Use and Other Intraday pricing Programs
3.5	Utility can reduce GHG compliance costs through Green Signals
3.6	Support bi-directional integration of Distributed Energy Storage
5.2a	Proactively replace transformer with smaller size
5.2b	Avoid oversizing replacement transformers

Economic – Capital Deferral

Thirteen value propositions were evaluated that held potential for appropriate deferral of capital spending.

VP #	Description
1.1	Capital Deferment through VAr reduction
1.2a	Capital Deferment through DER/PHEV
1.2b	Transmission/Distribution Capital Deferment through DR
1.2c	Capital Deferment through Pricing
1.2d	Capital Deferment through load balancing
1.3	Capital Deferment with grid state monitoring
1.4	Avoiding asset overloads with demand response
1.5	Classify Demand Response as Operating Reserves
1.6	Use Demand Response as Planning Reserves
1.9b	Peak Capacity Reductions through Voltage Reduction
2.3	Replace meters with in-home equipment
4.2	Use DR to assist load management during outage
4.5	Use DR to avoid overloading during normal operations

Economic – Operations and Maintenance

Ten value propositions were evaluated that held potential for reducing Operations and Maintenance costs.

VP #	Description
1.8	Dynamically load circuits to avoid overtime
2.1	Reduced OKOA through outage verification
2.2	Reduce Meter Reading Cost
2.6	Proactive notification of outages
2.8	Use AMI to reduce the number of ‘special’ meter reads
2.9	GIS update from grid state connectivity
4.8	Measure phase balance remotely
4.9	Troubleshooting voltage issues remotely
4.11	Remotely verify dispatch commands
6.6	Use Meter Interval Data to Reduce O&M

Economic – Revenue Capture

One value proposition was evaluated that held potential impacts for Revenue Capture.

VP #	Description
2.7	Detect diversions

Environmental

Three value propositions were evaluated that held potential Environmental benefits in terms of CO2 reduction.

VP #	Description
3.1	Encouraging customer adoption of Renewable DG
3.2	Enable customers to maximize use of renewable energy through generation mix signals
3.3	Carbon reduction through T&D loss reduction

Reliability

Eleven value propositions were evaluated that held potential reliability benefits, including fault isolation, more rapid service restoration, outage prevention, and Power Quality issue reduction.

VP #	Description
4.1	Distribution automation to reduce outage extent
4.3	AMI to restore power faster
4.4a	AMI to avoid outage overprediction
4.4b	AMI to identify nested outages
4.4c	AMI to avoid outage underprediction
4.6	Proactively fix Power Quality issues
4.7	Islanding using DER during outages
4.10	DR for frequency regulation
5.1	Predict transformer failure
5.3	Measure substation transformer stress to predict failure
5.4	Measure substation breaker stress to predict failure

Customer Satisfaction

SmartGridCity™ provided technologies that enabled new capabilities that provided insights in customer interests and motivations, responsiveness to dynamic prices, and empowers the customer to monitor and manage energy use. Thirteen Customer Satisfaction value propositions were evaluated.

VP #	Description
6.1	Increase customer ability to manage energy bill
6.2	Ability to reduce energy use through usage data access
6.3	Participation in an online green energy community
6.4	Reduce Customer Minutes Out (CMO)
6.5	Use Meter Pinging to Avoid Investigation-related Delays
6.7	Proactive Monitoring of Selected Customer Premise Circuits
6.8	Customer confident that Utility will be aware of outages
6.9	Customer confident that Utility can perform remote meter diagnostics
6.10	Customer feels empowered to manage personal energy use
6.11	Customer feels empowered to use renewable energy
6.12	Customer feels partnership with utility rather than dependency
6.13	Customer sees utility as progressive and interested in customer well-being
6.14	Use Prepaid Program as a financial controlling tool by customers

Strategic

SmartGridCity™ provided a pilot project platform to monitor and test how the strategic nature of various smart grid field systems and technologies impacted the planning process. Nine value propositions were evaluated that were designed to inform strategic, organizational considerations.

VP #	Description
7.1	Alternative to Meter Based Business Models
7.2	Encoding Institutional Knowledge
7.3	Framework for Integrating Acquisitions
7.4	Higher Asset Utilization
7.5	Higher Share Price through Commitment to Stakeholders
7.6	Relationship with Regulators
7.7	Visible Activity in Green Technologies
7.8	Integration of new technologies into utility systems
7.9	Carbon management technologies to improve carbon output

SmartGridCity™ Field Systems and Benefit Types

Value Propositions are not actionable in and of themselves; benefits are delivered by SmartGridCity™ systems. In the Value Proposition analysis, at least one SmartGridCity™ system is identified as responsible for delivering the hypothetical benefits available from each Value Proposition. MetaVu defined a SmartGridCity™ system as "a set of hardware and software that could conceivably be installed as a standalone function to accomplish value propositions." This is not meant to imply that the systems are not integrated in SmartGridCity™. Within SmartGridCity™, these discrete systems are interoperable contributing data to and pulling data from a variety of systems connected by communications and IT platform infrastructures. The systems are:

- **Distributed Energy Resource Control (DERC):** Controls energy resources throughout the distribution grid to optimize utility operations and support time-differentiated pricing programs. Components include in-home smart device (IHSD), smart meters, and demand response management system (DRMS) software.

- **Advanced Metering (AMI):** Records high-resolution usage data that is communicated automatically to the utility for billing and analysis purposes and provided to customers to enable them to change consumption behaviors. Components include smart meters, online account management (OAM), OpenGrid software (DMS), and the billing system.
- **Distribution Monitoring (DM):** Provides near real-time visibility into distribution network status. Components include voltage sensors on overhead transformers, current and voltage sensors on underground transformers, Power Quality meters, and DMS software.
- **Distribution Automation (DA):** Reconfigures the distribution grid automatically based on electrical conditions. Components include sectionalizing devices, and a DA controller with communication.
- **Integrated Volt/VAr Control (IVVC):** Reduces voltage and improves power factor automatically to make electricity distribution more efficient. Components include distributed capacitor banks and controllers, line sensors, load tap changers and controllers, and a centralized data processor utilizing DMS software, a server-based software application.
- **Smart Substation Monitoring and Protection (SSMP):** Provides real-time visibility into substation operating conditions. Components include microcontroller-based relays, automation controller, communications equipment, analysis engines and OSI Soft database software.

Value Propositions

TEMPLATE VP X.X TITLE

Benefit Category

Type of benefit envisioned: economic, environmental, reliability, etc.

Enabling Field System

Field system required to create the Value Proposition's benefits

Hypothesis

It is a description of the value proposition and how technical factors were envisioned to result in benefits. It is an explanation of the value proposition and associated benefit opportunity in lay terms.

Environment outside SmartGridCity™

A listing of how the business process or technical objective is executed traditionally/outside of SmartGridCity™, including examples that illustrate implementations outside SmartGridCity™ that have similar technical goals.

Environment within SmartGridCity™

An explanation of how the implementation was executed or intended in SmartGridCity™ to achieve the business or technical goal, including examples of differences from implementations outside of SmartGridCity™.

Actions Taken

The deployment and status of associated systems in SmartGridCity™.

Lessons Learned

- Detailed lessons learned about the value proposition and considerations for implementation.

Conclusion

Summary of anticipated benefits (economic unless otherwise indicated) from the value proposition.

VP 1.1 Capital Deferment through VAr Reduction

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Integrated Volt/VAr Control

Hypothesis
Distribution Capacitor Banks decreases reactive power drawn from the transmission system, i.e. improving power factor in distribution and reducing the unusable amount of energy that must be generated, transmitted and distributed. If the reduction is significant at peak, and on lines near capacity, capital may be deferred or delayed.

Environment outside SmartGridCity™
Autonomous capacitor banks reacting to local conditions; actions uncoordinated between banks; Manual capacitor banks set annually or semi-annually.

Environment within SmartGridCity™
Centralized control of distributed capacitor banks communicating over BPL and fiber; adds additional optimization beyond autonomous capacitor banks.

Actions Taken
Integrated Volt/VAr Control (IVVC) is active on two feeders: 1554 and 1556

Lessons Learned
- Value realized from fuel reduction is greater than value realized from capital deferral (Note: Fuel cost reduction through VAr reduction is addressed in VP 2.4).
- As an automated system, VAr reduction involves no adoption or business process issues and is therefore ideal for selective application.
- Distribution capital deferral only occurs on feeders near capacity that are experiencing low load growth.
- Distribution capacity is added in increments of 5 MVA minimum and usually 16 MVA (new feeder). Incremental capacity improvements, such as those offered via VAr reduction, are not generally sufficient to alter decisions to add distribution capacity.
- Capacitor Bank installations is less beneficial on underground feeders than on overhead feeders because of the higher inherent capacitance in these cables, i.e. better power factor under typical peak load conditions and also less voltage drop per unit length.
- With further development, sensors at the end of feeders could be replaced with smart meters to support IVVC.

Conclusion
Capital benefits likely, but relatively low. Capital can be deferred in specific situations. In SmartGridCity™, due to load configurations, minimal capital delay found. Theoretical capital deferral of up to two years can be achieved in ideal, feeder-specific situations.

VP 1.2a Capital Deferment through DER/PHEV

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
Distributed energy resources located near demand will reduce the amount of energy that must be distributed through the feeders. If these resources can be relied upon, capital for increased capacity may be deferred or delayed.

Environment outside SmartGridCity™
Capacity planning done a few years out based on historical capacity, growth expectations.

Environment within SmartGridCity™
Same as outside SGC; however SGC will enable better decisions from more data available about demand.

Actions Taken
DERC systems are being utilized to manage Demand Response systems in SGC.

Lessons Learned
- No capacity deferral because DERs not shown to generate power reliably during peak load (e.g., solar PV sometimes generates no power during system peak, especially if peak falls at 6 or 7 PM).
- PHEV storage is not likely to be a reliable or economically feasible source of capacity for many years.
- Increased DER penetration and utility control reliant on marketing and program communications.
- Distributed Generation (DG) can "mask" true system demands, complicating operating decisions by Distribution Control Center and Commercial Operations at high penetration levels and possibly impacting local reliability if not appropriately planned.
- Installed DG capacity was 4% of demand as of 2009 in Boulder.
- Learned that many types of Distributed Energy Resource (DER) are not sufficiently reliable or correlated with peak load to enable reduced capacity in distribution design.

Conclusion
Benefits are unlikely. MetaVu recognizes regulatory requirements and yet inconclusive NERC effort to count capacity value from variable generation (IVGTF). Per current requirements, capacity (generation, transmission, and distribution) must be designed for peak load and capacity; therefore intermittent resources are insufficiently reliable to permit reductions in capacity designs at this time. This will likely change if the availability of PV solar and distributed storage increases dramatically.

VP 1.2b Transmission and Distribution Capital Deferment through DR

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
The utility can reduce the demand during peak periods by controlling customer loads. If this reduction is significant and reliable, capital for increased capacity may be deferred or delayed.

Environment outside SmartGridCity™
In the existing Saver's Switch program demand response is primarily limited to large, industrial customers and requires significant payments by the utility to enroll customers; primarily focused on generation capacity.

Environment within SmartGridCity™
Demand response at the customer level is primarily controlling air conditioner loads during hot days. Currently, few numbers of other devices are being controlled.

Actions Taken
DR as implemented in SmartGridCity™ offers additional functionality and convenience for customers over the existing Saver's Switch program. Installation of 1,264 in-home smart devices as part of the time-differentiated rate pilot has already begun.

Lessons Learned
- Generation benefits from Demand Response (See Value Proposition 1.6) are much larger and more certain than the transmission and distribution benefits of Demand Response.
- Distribution capacity expansions are generally planned in increments of 5 MW or greater; to realistically defer T&D capacity expansion, DR penetration of ~1 MW or more per feeder (about 1,000 participants, or 70% of the customers with central air conditioning) is required.
- DR as implemented in SGC offers additional functionality and convenience for customers over existing Saver's Switch program. Next generation DR will require bidirectional communications, while the existing Saver's Switch program consists of unidirectional communications.
- Product development historically worked with generation and commercial operations; may need to start working with distribution capacity planning and Distribution Control Center (DCC) to design DR programs of benefit to DCC.

Conclusion
Generation capacity deferral benefits are likely, but less certain for T&D capacity expansion. With high customer penetration rates, capital deferral of up to $32.75 per DR participant with central air conditioning per year may be possible.

VP 1.2c Capital Deferment through Pricing

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
By implementing critical peak pricing (CPP) or other similar pricing schemes, the utility can incent customer to reduce demand during peak periods. If this reduction is significant and reliable, capital for increased capacity may be deferred or delayed.

Environment outside SmartGridCity™
Pricing programs not done for residential customers due to high cost of interval meters.

Environment within SmartGridCity™
Smart meters with interval data enable time of use pricing; pilot pricing programs are evaluating customer behavior in response to different tariffs.

Actions Taken
Pricing pilot began in October 2010 to increase understanding of various program characteristics on impact.

Lessons Learned
- Billing services will need to accommodate interval data and be able to produce accurate bills for complex pricing programs.
- Time-differentiated rate benefits are highly variable and driven by participation levels, degree of behavioral change, program and incentive designs, and other factors such as capacity costs.
- Based on the PSCO 2006-2007 TOU-CPP Pricing Study, it was learned that pricing programs are likely to have significant impact on system demand at peak.
- Difference in behavior change between voluntary and mandatory program implementation is critical to the calculation of this value proposition and is among the issues being tested in the current pricing pilot.

Conclusion
Benefits are likely and potentially high based on PSCO 2006-2007 TOU-CPP Pricing Study; however, customer adoption rates must be high and/or behavior change must be significant if implementation is to be cost-effective. Research showed generation, transmission and distribution capacity cost reduction of $33.62 per customer per year. (Research also showed significant energy reductions from participating customers; please see Value Proposition 3.4 for additional benefits.)

VP 1.2d Capital Deferment through Load Switching

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distribution Automation

Hypothesis
At system peak, some feeders are operating near capacity while others have significant capacity available. If some of the load can be reliably shifted from the highly utilized feeder to the lower utilized, capital for increased capacity may be deferred or delayed.

Environment outside SmartGridCity™
Configurations are set a few times per year based on load profiles from previous years and are re-evaluated based on distribution models.

Environment within SmartGridCity™
Same as outside SmartGridCity™; no new activities are being done. Better information from actual data may be used to make different decisions on load shifting.

Actions Taken
Distribution Automation is functioning as designed on two feeders in SGC.

Lessons Learned
- Requires reliably uncorrelated loads on nearby feeders to alter capacity planning decisions.
- Capability would require many switches on multiple feeders in order to achieve balanced loads during peak.
- Distribution capital deferral only occurs on feeders near capacity that are experiencing low load growth.
- Distribution capacity is added in increments of 5 MVA minimum and usually 16 MVA (new feeder). Incremental capacity improvements, such as those offered via load switching, are not generally sufficient to alter decisions to add distribution capacity.

Conclusion
Benefits are unlikely due to the absence of required conditions.

VP 1.3 Capital Deferment with Grid State Monitoring

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distribution Monitoring
Smart Substation Monitoring

Hypothesis
Higher resolution models and more information will allow the capacity planning teams to make better decisions and not over-build unnecessarily. This will delay or defer capital dollars in system capacity.

Environment outside SmartGridCity™
Generation, transmission and substation systems are monitored and voltage, load and other data is stored. The distribution system is modeled based on expected characteristics. The data and model are used for planning for system capacities.

Environment within SmartGridCity™
Higher resolution data about the distribution system (i.e. underground loads, all transformer voltages and customer usage data in 15-minute intervals) is collected. This additional information can be used to make better capacity decisions.

Actions Taken
Data is being collected from the distribution system for single phase underground circuits and smart meters (throughout SmartGridCity™). Distribution data is also being collected from four substations.

Lessons Learned
- Electric Distribution Engineering will have more data available to determine the optimum investment plans that will maximize reliability and performance and optimal cost.
- Distribution Asset Analysis (DAA) software is used for capacity planning outside SmartGridCity™ and is sufficiently accurate for distribution operations and capacity planning decisions; SmartGridCity™ data could be integrated into DAA for maximum benefit.
- The standard for all new XE substation monitoring is 3-phase voltage and load; in this regard SmartGridCity™ offers no new capabilities at the substation or beyond for capacity planning purposes.
- Feeder capacity upgrade decisions are made in step increments of 5 – 16 MW; additional information will not affect distribution capacity decisions based on increment sizing.

Conclusion
Grid state monitoring benefits are primarily related to reliability. Capital deferral benefits unlikely to justify grid state monitoring investment from an economic perspective. For more on grid state monitoring's reliability benefits, please see Value Propositions 4.3, 4.6, 5.1, 5.3, and 5.4.

VP 1.4 Avoiding Asset Overloads with Demand Response

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
Demand response (DR) events can be called when assets are in (or approaching) overload conditions. Avoiding overload conditions can significantly extend the life of assets because overloading is a primary driver of failure.

Environment outside SmartGridCity™
Demand response is primarily limited to large, industrial customers with ISOC programs. Residential and small commercial customers can participate in Saver's Switch program which cycles air conditioner compressors.

Environment within SmartGridCity™
Demand response is at the residential level, primarily controlling air conditioner loads during hot days. Few numbers of other devices are being controlled. This control can be done at the system level and is capable of handling asset specific programs.

Actions Taken
DR programs are not yet established for feeder level control because low penetration will make such implementation infeasible. Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available in 2012.

Lessons Learned
- There are no baseline measurements outside of SGC to evaluate transformer overloads. Transformer overloads are estimated based on monthly usage data and load modeling.
- To achieve this value proposition, the Distribution Control Center (DCC) must have the capability to call DR events for the premises attached to the overloaded asset.
- If implemented, the DCC and Power Operations will need to coordinate DR events to minimize potential impact to customer satisfaction.
- Exceptionally high customer penetration rates are required to avoid asset overloads with DR. (1000 Gen kW, i.e. 971 participants)
- This benefit would need to have the capability to identify and aggregate DR potential by asset.
- Benefits are greater with underground (UG) rather than overhead (OH) feeders because of (i) heat dissipation on OH vs. UG and (ii) cost and time of repairs.
- If DR reaches sufficient scale and penetration, programs will need to be developed to enable events by distribution asset. Current programs are only designed at the substation level or transmission area.

Conclusion
Capital deferral is plausible, but difficult to quantify due to high variability in correlating overloading to impact on asset life.

VP 1.5 Classify Demand Response as Operating Reserves

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
The value (and opportunity cost) of spinning reserves is much greater than the value of non-spinning reserves. Improved responsiveness and verification of DR made available through smart grid capabilities makes it possible to call upon, and verify, load reductions within the 10 minute window required for classification as spinning reserves. Two-way communications also enable customer override options, which can reduce DR impact.

Environment outside SmartGridCity™
DR is currently available for residential customers through the Saver's Switch program.
It may be possible to upgrade Saver's Switch technology to provide some SmartGridCity™-related attributes once smart meters are installed.

Environment within SmartGridCity™
SGC's in-home smart devices (IHSDs) are essentially the same as Saver's Switch, but with several beneficial features:

- Faster response and two-way communications (to verify load reduction).
- Customer control via Internet (for convenience).
- Improved customer service (AC temp settings, override options, plug loads, etc.).

Actions Taken
DERC is available to execute DR events within the 10-minute time frame required to qualify for spinning reserves.

Lessons Learned
- Modification of WECC regulations to enable DR to be classified as spinning reserves is required.
- Many regional transmission authorities already accept DR to qualify as spinning reserves.
- Saver's Switch technology cycles A/C compressors on and off from a population of participating customers in cycles, while IHSDs change the thermostat settings of A/C units for all participating customers at once. This can offer greater responsiveness but increased volatility.
- Customers do take advantage of override options; an SCE study of small commercial customers indicated that 20% of events are overridden even when penalties are assessed.
- PSCO DR study underway in SmartGridCity™ will examine the change in impact resulting from differences between Saver's Switch and IHSDs.

Conclusion
Benefits likely and high assuming regulatory hurdles cleared. $9.55 per year in reserve reduction value can be avoided per customer with central air conditioning controlled by the utility.

VP 1.6 Use Demand Response as Planning Reserves

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
Public utility commissions require regulated utilities to submit Integrated Resource Plans periodically to indicate how capacity needs will be met. To the extent DR can be used to reduce capacity needs, generation increases can be delayed or avoided.

Environment outside SmartGridCity™
DR is currently available from residential customers through the Saver's Switch program.
It may be possible to upgrade Saver's Switch technology to provide some SmartGridCity™-related attributes.

Environment within SmartGridCity™
SmartGridCity™'s IHSDs have several beneficial features that might increase market penetration above Saver's Switch levels:

- Customer control via Internet (for convenience)
- Improved service levels (AC settings, override options, plug loads)

Actions Taken
Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available by year-end 2012.

Lessons Learned
- SmartGridCity™ did not attempt to quantify the benefits of DR on commercial customer demand.
- Commercial customers with smaller controllable loads (roughly under 25 kW) can find it difficult to overcome the start-up costs for DR participation (other than Saver's Switch). DR as implemented in SmartGridCity™ may provide opportunities to access this market segment.
- A significant customer penetration rate is required for DR to be valuable for use as planning reserves. This is particularly true of residential premises as a result of typically smaller loads.
- Commercial Operations requires approximately 20 MW minimum controllable load to represent practical value in power operations.

Conclusion
Benefits are likely and high. Capital benefits of $159.65 per customer per year with central air conditioning controlled by an in-home smart device (IHSD) can be realized.

VP 1.7 Use Demand Response as a Virtual Power Plant

Benefit Category
Economic (Energy)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
Commercial Operations utilizes extremely sophisticated software and decision support algorithms to identify least cost resources as it makes generation utilization decisions on a real time basis. Large scale Demand Response programs could be quantified and incorporated into the list of resources available to call upon. In theory, Demand Response could serve as a resource that is cheaper than traditional generation on a per MW or per MWh basis. Power Operations would make the determination to use Demand Response within criteria established by Marketing and Regulators.

Environment outside SmartGridCity™
Today Commercial Operations uses Demand Response to manage load, not to manage energy.

Environment within SmartGridCity™
In-home smart devices enable the utility to control various loads within the customers' premises, primarily central air conditioning, by adjusting the thermostat. These events can be called by commercial operations as a source of energy, providing opportunities for trading profits.

Actions Taken
Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available by year-end 2012.

Lessons Learned
- There is a practical limit to the number of DR events customers will tolerate. Further study is needed to quantify this effect since it depends on a number of factors such as the type of DR event and duration (increasing thermostats one degree versus turning off a compressor).
- With limited opportunities to use DR, it is best to employ DR for capacity reductions (relatively larger financial benefit) than for energy reductions.
- While DR works well as a demand (kW) management tool it is not a strong energy (kWh) management tool.
- Increased availability data available from SGC capabilities creates new DR product and business models. For example, today's limitations on DR events (i.e. 15 per year/5 degrees A/C) could be modified to hundreds of events at 1 degree
- Commercial Operations requires approximately 20 MW minimum controllable load to represent practical value in power operations.
- Using DR as a source of energy when economic conditions warrant is likely to exhaust customer patience.
- A/C units use a great deal of energy to restore desired room temperatures at the conclusion of a control event (rebound).
- Controlling plug loads yields energy savings many times smaller than the energy savings from A/C control.

Conclusion
Benefits are available but relatively small. Purchased power/fuel cost savings per customer with central air conditioning controlled by IHSD = $1.13/year.

VP 1.8 Dynamically Load Circuits to Avoid Overtime

Benefit Category
Economic (O & M Cost)

Enabling Field System
Distribution Monitoring

Hypothesis
Effective capacity ratings are a function of temperature because at colder temperatures more heat is dissipated and assets can handle higher loads. When an asset fails, the dispatch team will restore customers however possible, including overloading circuits. If circuits are loaded beyond their specified ratings, a field crew will be dispatched to repair the failure and relieve the overloaded assets, incurring overtime if necessary to do so.

If the actual capacity of a line is higher than a specified rating due to weather, the Distribution Control Center (DCC) can intentionally overload a circuit beyond its specified rating. This would allow a field crew to repair the failure during the course of normal operations rather than during overtime.

Environment outside SmartGridCity™
Some assets (substations) have summer and winter ratings. Most devices have a single set of ratings (warning, alarm). When an asset is being used in the warning or alarm condition, the situation causing the overload is repaired as quickly as possible including having crews work in off-hours.

Environment within SmartGridCity™
The assets can have real time ratings based on current temperatures and loads. Crews will only dispatched in off-hours to repair the cause if the assets are in "real-time" warning or overload, and not if they are below these thresholds even if they are above the nominal thresholds.

Actions Taken
Load data is being captured in real time, making the capability of dynamically loading circuits feasible.

Lessons Learned
- Operators have different styles for operating equipment: some will be more aggressive and others are more cautious; specific standards do not exist or may not be followed.
- The DCC will need to adjust to real-time dynamic ratings instead of the static ratings currently in use.
- The described capability is only required when operating near thresholds or in overload conditions; occurs very rarely in Boulder due to excess capacity, though frequently in Denver Metro.
- Benefits are unlikely to be a significant as highest loads most often occur when temperatures are high, limiting the availability of conditions required for this benefit to be likely.
- The DCC frequently overloads circuits beyond nameplate during outages to minimize customer impact.

Conclusion
Benefits are likely but relatively low. Estimated overtime costs savings of $1,200 per year in Denver Metro; no savings in Boulder because feeder overloading rarely occurs, therefore rarely requiring overtime.

VP 1.9a Reduce Energy Consumption through Voltage Reduction

Benefit Category
Economic (Energy)

Enabling Field System
Integrated Volt/VAr Control

Hypothesis
Voltage is set at the feeder level to maintain customers' voltage well above the minimum threshold of 114 V. Traditionally voltage must be set at levels with a high safety margin to ensure that the voltage does not drop below the threshold during peak load conditions. Due to practical constraints this voltage setting stays fixed for longer time periods. However, today the powerful communication infrastructure of SmartGridCity™ allows better monitoring throughout the line, especially near the customer premises, effectively reducing the safety margin required. As voltage is reduced, there is a proportional reduction in energy usage. This control function is often referred to as Conservation Voltage Reduction (CVR).

Environment outside SmartGridCity™
Voltage is set at the substation transformer by *manually* configuring the load tap changer. The LTC setting is based on the measured voltage at the feeder and the *estimated* voltage throughout the distribution system. Traditionally, load tap changers and switched capacitor banks are operated as completely independent (stand-alone) devices, with no direct coordination between the individual controllers and there are minimal feedback loops to ensure customer voltage is within specification.

Environment within SmartGridCity™
The feeder voltage is dynamically regulated up or down *automatically* based on near real-time voltage *measurements* throughout the distribution system. Approximately 10-12 sensors per feeder are used, and these are located at strategic points where customer voltage is expected to be most varied from feeder voltage.

Actions Taken
Integrated Volt/VAr Control (IVVC) is functional on 2 feeders, 1554 and 1556.

Lessons Learned
- Distribution Control Center will utilize additional information provided by the IVVC system to set the ideal voltages.
- IVVC has high potential benefits relative to cost.
- SGC's Distribution Monitoring system was utilized to identify the ideal locations for IVVC system sensors.
- Moderately accurate model of the distribution system required to determine sensor locations and voltage drop between sensors and premises.
- Targeted customer voltage 115V, but not all customers will be at that level due to variations on the feeder.
- IVVC investments are similar to DSM program investments as they are delivered by the utilities but benefit customers by reducing energy usage.

Conclusion
Benefits are likely and high. Significant energy usage and fuel cost reduction noted. Reducing the average voltage from 121 to 116 full-time yields energy reductions of approximately 2.7% on average, or 207kWh per residential customer annually (worth $8 per residential customer in avoided fuel to the utility, and $18 in savings annually per residential customer served by an equipped substation assuming $.087 per kWh).

VP 1.9b Peak Capacity Reductions through Voltage Reductions

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Integrated Volt/VAr Control

Hypothesis
During power shortage voltage is set at the feeder level near the minimum threshold of 114 V. This is done in extreme cases to avoid outages, but will also compliment HB 1037 demand reduction requirement. Better monitoring throughout the line, especially near the customer premises will reduce the safety margin required. As voltage is reduced during peak demand months July and August, there is a proportional reduction in generation capacity

Environment outside SmartGridCity™
Voltage is set at the substation transformer by changing the load tap changer (LTC). The LTC setting is based on the measured voltage at the feeder and the estimated voltage throughout the distribution system. There are minimal feedback loops to ensure customer voltage is within specification.

Environment within SmartGridCity™
The substation voltage is set automatically based on voltage measurements throughout the distribution system. Approximately 10-12 sensors per feeder are used, and these are located at strategic points where customer voltage is expected to be most varied from feeder voltage.

Actions Taken
Integrated Volt/VAr Control (IVVC) is functional on 2 feeders, 1554 and 1556.

Lessons Learned

- Distribution Control Center will utilize additional information provided by the IVVC system to set the ideal voltages.
- IVVC has high potential benefits relative to cost.
- SGC's Distribution Monitoring system was utilized to identify the ideal locations for IVVC system sensors.
- With further development, smart meters could serve as IVVC system sensors.
- Moderately accurate model of the distribution system required to determine sensor locations and voltage drop between sensors and premises.
- Target Customer Voltage could be reduced to 114V during power shortage and still be within ANSI C84 limit

Conclusion
Benefits are likely and high. A 5% reduction in voltage during critical peak will reduce demand by 3.25%. (A prospective benefit of $14M in deferred Generation Capacity if deployed on 40% of PSCO's substations.)

VP 2.1 Reduced OKOA through Outage Verification

Benefit Category
Economic (O & M Cost)

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Smart meters can report in their status both on a regular basis and on demand, when pinged. This can be used to verify that an outage has occurred. When a customer reports an outage, the Customer Care Center (CCC) can ping the meter and determine if the meter has power. If so, the outage is the customer's responsibility to fix and a truck roll can be avoided. This will significantly reduce the number of OK on arrivals (OKOAs).

Environment outside SmartGridCity™
If customer reports an outage, the CCC or Distribution Control Center (DCC) dispatches a troubleman.

Environment within SmartGridCity™
When a customer calls in to report an outage, the CCC or DCC can "ping" a meter to verify power is out. If the meter appears to have power, the CCC or DCC informs the customer that the problem is inside the customer's premises.

Actions Taken
SmartGridCity™ consists of 23,000 customers with smart meters; all are 'pingable' by the DCC or CCC.

Lessons Learned
- SGC systems that impact a small percentage of a user's responsibility are not being readily adopted or being integrated into existing systems or processes. For example, DCC and CCC do not fully utilize "pinging" capability due to small percentage (5% and 0.5%, of customers with smart metering capability, respectively).
- In extremely rare circumstances (<2% of SGC outages), a faulty meter connection block causes an outage for which PSCO is responsible to fix that a meter ping would indicate is a customer's responsibility to fix, according to PSCO.
- Integration with IVR system could enable customers to self-serve meter pinging to reduce number of live calls.
- Smart meters introduced new point of failure: connection block between meter and premise wiring, according to PSCO.
- It is very easy for customers to report an outage; but hard to get customers to cancel outage reports when service is restored. Meter pinging can help with this situation.
- Only saves O&M if someone had to be called in for overtime; assumed that someone's OT costs would have been saved during escalated operations.
- Learned that meter pinging capabilities are likely to reduce OKOAs.
- Reductions in field time investigating outages will result in increased safety.

Conclusion
Economic benefits are likely but small. A reduction of 110 OKOAs for SGC per year are possible. $2,700 savings for 23,000 smart meters ($0.12/customer) per year.

Customer satisfaction benefits are significant; the ability of the CCC or DCC to let a customer know immediately whether or not the problem was the customer's responsibility to fix (rather than waiting for a troubleman to investigate) was rated second highest capability in importance (next to energy use and cost) in a survey of 800 PSCO customers.

VP 2.2 Reduce Meter Reading Cost

Benefit Category
Economic (O&M Cost)

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Reduce manual or drive-by meter reading with fully automated meter reading. This Value Proposition relates to the capability of communicating remotely with meters. Among many other benefits, remote meter communication offers the opportunity to read electric meters without pedestrian manual meter readers or radio-equipped drive-by meter reading vehicles.

Environment outside SmartGridCity™
PSCO: In general, meters read via radio-equipped vehicles.
NSP: In general, meters read via CellNet (fixed wireless network).
SPS: In general, meters read via manual meter readers.

Environment within SmartGridCity™
Smart meters in areas with remote communications capabilities can be read remotely without meter readers or drive-by meter reading vehicles.

Actions Taken
Within SmartGridCity™ 23,000 meters are being read remotely on a daily basis with accuracy in excess of 99.5% monthly, the best of any meter data collection method employed by PSCO.

Lessons Learned
- Ideally, all meters within a meter reading route must be upgraded to reduce meter reading costs and to allow for modeling of such things as transformer loading.
- Improvements in process efficiency gained in one area may require a review of processes, resources and budget allocations in others.
- Staffing levels in meter reading may reduce as meter reading is conducted remotely.
- Savings are highly dependent on existing meter reading approach. For example, PSCO's already low meter reading costs (drive-by radio system) would yield less savings versus replacement of more expensive pedestrian meter reading.
- Battery-powered, under-glass upgrades that permit gas meters to communicate once monthly with smart electric meters are now available. This capability enables remote gas meter reading through electric meters with remote communications capabilities.

To enable savings via elimination of meter reading routes:
- Meter change-out should be implemented 100% within a defined geography.
- In geographies with overlapping gas service, gas meter communications capabilities should be installed simultaneously with electric meter communications to optimize meter reading savings.

Conclusion
Benefits are likely but relatively small. O&M expenses reduced $0.84 per premise per year.

VP 2.3 Replace Meters with In-Home Equipment

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
A complex, home area network that measures all electrical usage inside the premises could replace meters attached outside the premises. This would reduce the costs of installing and replacing meters.

Environment outside SmartGridCity™
Electrical use is measured via meters connected between the service and the premises. The meters are primarily located outside the premises and exposed to significant weather and other forces.

Environment within SmartGridCity™
Not implemented in SmartGridCity™ as in-home technology is not sufficiently mature to utilize as envisioned.

Actions Taken
Not implemented in SmartGridCity™.

Lessons Learned
- Interoperability of systems, including a lack of standards, guidelines and related data security measures discourage replacement of revenue-grade metering hardware.
- Updates to regulatory rules required, such as Colorado PUC Rules 3300-3306 governing the ownership, accuracy, location, testing, and servicing of meters, in order to realize the benefits of this VP.
- Technology has not yet matured to the point where meters can be replaced by in-home equipment. Meters could be moved to the transformer since manual meter reading may no longer be required; however, this has other issues such as accessibility for repairs or replacement.
- Learned that maturity of in-home technologies is inadequate for usage measurement.

Conclusion
Benefits are unlikely due to limitations in existing technologies, resulting in excessive risk. It was not practical or prudent to pursue in SmartGridCity™.

VP 2.4 Fuel Cost Reduction through VAr Reduction

Benefit Category
Economic (Energy)

Enabling Field System
Integrated Volt/VAr Control (IVVC)

Hypothesis
IVVC decreases reactive power, improving power factor and reducing the unusable amount of energy that must be generated. This reduction in generation requirements saves fuel costs or purchased power costs.

Environment outside SmartGridCity™
Autonomous capacitor banks reacting to local conditions; actions uncoordinated between banks; Manual capacitor banks set annually or semi-annually.

Environment within SmartGridCity™
Centralized control of distributed capacitor banks communicating over BPL and fiber; adds additional optimization beyond autonomous capacitor banks.

Actions Taken
Active on 2 feeders, 1554 and 1556 and is controlling power factor.

Lessons Learned
- As an automated system, VAr reduction involves no adoption or business process issues and is therefore ideal for selective application relative to universal deployment.
- Opportunity for benefits is a function of both energy usage and power factor.
- Learned that power factor improvement is a simple and cost effective way to reduce fuel cost. Active on 2 feeders, 1554 and 1556 and is controlling power factor.

Conclusion
Benefits are likely and high. Fuel costs savings of approximately $ 4,800 per feeder per year on average; not applicable to all feeders. (This is worth $1.92 per customer in operational benefits assuming 2500 customers per feeder)

VP 2.5 Line Loss Optimization Through Remote Switching

Benefit Category
Economic (Energy)

Enabling Field System
Distribution Automation

Hypothesis
Redistributing system load can reduce system losses by balancing the I^2R losses. Since I^2R losses are proportional to the square of the current, balancing the currents to have them equal on lines of similar resistance will optimize losses. This can be done through frequent grid reconfigurations based on better load information.

Environment outside SmartGridCity™
Grid configuration is set approximately twice per year based on historical load profiles. Grid reconfiguration is done in real time only for outages or other unusual events; it is not done for line loss optimization.

Environment within SmartGridCity™
Using better load information and remote switching capabilities, grid reconfiguration can be done in real time to minimize line losses. Capability to switch loads remotely and automatically based on electrical characteristics has been proven using the DA system.

Actions Taken
Distribution Automation is implemented and active on 2 feeders, 1554 and 1556.

Lessons Learned
- Remote operation switches are expensive and have a limited number of switch operations, thus are not frequently activated; further, line balancing could require many switches to be activated along many different feeders to optimize losses.
- This value proposition should be re-evaluated in the event of significant switching equipment technology developments.
- The Distribution Control Center (DCC) is primarily focused on reliability; therefore monitoring line loss optimization in real time is not a priority.
- Most of the decisions that are made regarding configuration perform reasonably well to minimize losses over the year; lines are generally well balanced with minimal switching.
- Whenever a switch is made, there is extra current through the line which causes stress on all the components.
- DA has the lowest tolerance for failure of the smart grid systems as it controls critical grid equipment and therefore must communicate accurately and regularly with internal systems.
- Redistribute system load through remote grid reconfiguration.

Conclusion
Benefits are unlikely. Fuel savings ($2,700 per feeder) did not justify incremental investments in large number of switches necessary to realize benefits.

VP 2.6 Proactive Notification of Outages

Benefit Category
Economic (O&M)

Enabling Field System
Distribution Monitoring

Hypothesis
Smart meters, combined with remote, real-time communications, enable the capability for the utility to become aware of an outage before a customer has an opportunity to call the utility. The concept is to pair this capability with automated customer outreach to let a customer know that the utility has become aware that power to the customer's premise is out. Benefits include improvements in customer satisfaction and reduced customer contact center call volumes and O&M expenses.

Environment outside SmartGridCity™
Traditionally, utilities have only been alerted to outages as a result of customers' calls (with the exception of large outages such as feeder lockouts).

Environment within SmartGridCity™
In SGC, transformer sensors can send a "last gasp" signal when power is lost.
The utility is aware of the outage without the customer calling in, and Call Center resources may be used to proactively contact affected customers.

Actions Taken
Not implemented in SGC as a result due to the high cost of outbound telephone calling. PSCO is currently evaluating the use of recently available technologies (e.g. digital, social network, etc.) to realize this capability in a more cost effective manner.

Lessons Learned
- A formal program with optional registration would be required to enable customers to set their own preferred parameters (media, rules, hours, etc.).
- Customers interested in this capability scored middle of the pack compared to other SGC capabilities on 'willingness to pay' in survey.
- This feature would ideally be established as part of OAM (online account management) so that customers could self-maintain preferred parameters; the execution of this capability via telephone yielded unfavorable cost/benefit analysis.
- Recruiting would ideally be included as part of the process of establishing new service for customers.
- Meters may lose power intermittently or may occasionally be unresponsive to communications; to prevent false positives, there must be a delay or secondary check before an outage is verified.
- Estimated that accurate cell phone numbers are available for about 38% of PSCO customers.
- Learned that execution of this capability via telephone yielded unfavorable cost/benefit analysis.

Conclusion
Benefits are unlikely by phone. Estimated benefits are $0.09 per smart metered customer per year. Customer satisfaction benefits may also be available from this capability.

VP 2.7 Detect Diversions

Benefit Category
Economic (Revenue Capture)

Enabling Field System
Distribution Monitoring
Advanced Metering Infrastructure

Hypothesis
Most businesses utilize inventory controls to compare the amount of product supplied to the amount of product billed as a check. The SGC concept is to measure kWh at the transformer level and compare it to kWh billed at meters associated with the transformer to identify missed billings.

Environment outside SmartGridCity™
There are currently no checks to routinely compare kWh supplied against kWh billed. The meter reading team currently audits about 2,000 (commercial) electric meters annually in PSCO, finding an error rate of 5% (100 meters) and additional revenues of about 0.15% of billings ($1.5 million) annually.

Environment within SmartGridCity™
Cumulative totals of energy usage for all meters on a transformer can be compared to the energy through that transformer; major discrepancies may be diversions or metering errors and can be investigated. In addition, for smaller premises such as residential, unusual usage patterns can be detected from interval data and investigated.

Actions Taken
Shifted focus to commercial customers' metering errors as a larger revenue capture opportunity relative to cost.

Lessons Learned
- The most common forms of residential theft - failing to report a move-in and unauthorized re-establishment of service after credit cut-off - do not require grid upgrades to enable them to be recognized.
- Larger opportunities are available from detecting billing errors for commercial customers (wrong scaling factor, one phase not being measured, etc.) than from detecting residential theft.
- Implementation of this feature can also improve the accuracy of the GIS database.
- Two options are available for identifying commercial meter errors :
    - Traditional kWh meters on transformers with software to compare transformer readings to associated premise readings; or
    - Increase use of transformer sensors over current SGC design (add current and voltage sensors to all 3 phases).
- For residential diversion, software that can 'read' premise interval data and check for anomalies that might indicate theft could be developed.
- Learned that incremental costs required to identify low levels of residential theft did not justify implementation.

Conclusion
Benefits are likely but relatively low. Estimated benefits are $95.46 per metered commercial transformer per year.

VP 2.8 Use AMI to Reduce the Number of 'Special' Meter Reads

Benefit Category
Economic (O&M)

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Smart meters, combined with remote, real-time communications, enable the capability for the utility to read meters for billing purposes 'at will'. This capability was envisioned to reduce O&M costs by reducing in-person meter reads for move-ins and move-outs. However in-person meter reads are rarely used for move-ins and move-outs (see below). This Value Proposition was therefore modified to examine the value of remote meter reading to reduce any type of in-person meter reads, for example to investigate suspected meter tampering or malfunctions.

Environment outside SmartGridCity™
In most jurisdictions utilities are permitted to pro-rate a customer's bill based on the number of days (out of a meter reading cycle) that the customer occupied a premise. Thus no 'in person' meter reads are required for move-ins and move-outs.

Environment within SmartGridCity™
With remote, real-time meter reading capabilities it is possible to bill the customer for the usage actually consumed by the customer prior to moving out to the nearest interval (15 minutes in SGC). While this capability offers no opportunity for O&M savings today, it could provide increased customer satisfaction opportunities.

Actions Taken
Remote, real-time meter reading capabilities are available for approximately 23,000 premises equipped with smart meters in SGC.

Lessons Learned
- Call Center personnel have successfully used available customer interval data to resolve high bill complaint calls without having to order a special meter read (via identification of past usage patterns to help customers recognize potential consumption explanations).
- Interval data from meters could provide insight to users in regards to malfunctioning equipment or tampering.
- Through traditional metering methods, pro-rating for move-ins and move-outs was necessary. Meter reading as implemented in SGC enables actual usage calculations to the nearest day for move-ins and move-outs and may represent a customer satisfaction improvement opportunity.
- Learned that Colorado rules allow utilities to pro-rate bills for move-ins and move-outs to avoid special meter reads. As a result, special meter reads consist mainly of meter investigations from high bill complaints.

Conclusion
Benefits are likely but relatively low.

VP 2.9 GIS Update from Grid State Connectivity

Benefit Category

Economic (O&M)

Enabling Field System

Distribution Monitoring
Advanced Metering Infrastructure

Hypothesis

The electrical network topology can be verified using the communications infrastructure. This information can be used to update the GIS systems or alert GIS operators to discrepancies, to ensure that the mapping is an accurate representation of the electrical grid.

Environment outside SmartGridCity™

GIS information is input or updated when new electrical installations are installed. Changes are made in the field or field personnel identify a discrepancy between the actual installation and the mapping representation. Updates are performed manually by the GIS team

Environment within SmartGridCity™

The connectivity between the transformers and the smart meters is verified based on the signal strength of the meter communications. If this connectivity differs from the GIS database, an update or alert is triggered.

Actions Taken

Dig-it project updated GIS with include new communications information. SGC demonstrated that the cost of integrating DM with GIS far exceeded the benefits. Not implemented in SGC as a result.

Lessons Learned

- Numerous GIS errors found during SGC implementation due to high number of installations; not a feature of SGC specifically, but coincidental benefit.
- Learned that the GIS system needs to contain information on communications assets in addition to the electric grid assets traditionally maintained in GIS. This is necessary for trouble-shooting, maintenance and expansion of the intelligent grid. It also assumes that the systems used in conjunction with the GIS system (e.g. design tools) are updated to support this enhanced environment.
- SGC highlighted the fact that GIS data was insufficiently detailed to be used as basis for field communications designs that utilize electrical infrastructure.
- Automating the GIS update process is risky because primary source for all geographic information; automated alerts to discrepancies is a very good method.

Conclusion

Benefits are unlikely as very little is spent on GIS updates annually.

VP 3.1 Encouraging Customer Adoption of Renewable DG

Benefit Category
Environmental

Enabling Field System
Distribution Monitoring
Advanced Metering Infrastructure
Integrated Volt/VAr Control

Hypothesis
Extensive penetration of renewable DG such as PV Solar presents opportunities and challenges. The potential opportunities include reduced capacity, energy, and environmental costs, while the observed challenges include: 1) economic equity to those customers who do not own DG; and 2) potential reductions in both generation and distribution grid reliability.

Environment outside SmartGridCity™
Customer DG is accounted for via net metering, an approach that provides 'hidden' subsidies from customers to DG owners under current rules/rates. Distribution grid reliability can be affected at high levels of DG penetration, including harmonic distortion and exacerbation of any frequency dips that might occur.
Net metering 'masks' the actual demand a customer would require should DG production drop, providing no visibility to Power Operations.

Environment within SmartGridCity™
- Dual metering combined with SGC communications-enabled controls could help Distribution Control override PV inverter shut-off in appropriate situations.
- Grid upgrades such as Volt/VAr control (VP 1.9 and 2.4) can help manage high levels of DG penetration and maintain distribution grid reliability.
- Dual metering 'unmasks' potential system demand.

Actions Taken
Insufficient penetration of renewable DG existed in SGC to enable full quantification of this capability.

Lessons Learned
- The role of DCC will become much more challenging as renewable DG penetration grows. Previously concerned only with 1-way power flow, DCC capabilities will need to adopt the skill sets of transmission operations.
- Grid upgrades facilitate (but are not required for) dual metering of customer-owned generation that could eliminate hidden subsidies.
- Relatively minor grid events, such as momentary voltage or frequency dips, can cause large scale drops in DG production as DG inverters 'trip off' (as designed).
- Existing inverter/interconnection standards must be modified to allow automated response to grid disturbances based on extended grid state awareness. This is required to maintain reliability and worker safety as DG penetration increases.
- Distributed Storage (See VP 3.6) can also help manage DG.
- Learned that several SGC capabilities increase PSCO's ability to reliably accommodate increased penetration of renewable DG.

Conclusion
Environmental benefits are likely. Economic benefits are unlikely as current tariffs result in "hidden" subsidies of renewable DG owners, estimated at $6 million annually by 2015.

VP 3.2 Maximize Customer Use of Renewable Energy Through Generation Mix Signals

Benefit Category
Environmental

Enabling Field System
Distributed Energy Resource Control

Hypothesis
The concept is to provide customers with signals -- Green/Use for times when renewable generation is a relatively high portion of the total and Red/Conserve for times when renewable generation is relatively low. In theory customer response to these signals could conceivably reduce a utility's CO_2 output.

Environment outside SmartGridCity™
Energy Mix signals could be provided to customers without SmartGridCity™ capabilities (for example through text messages, e-mails, etc.).
There is a reduced ability for a utility to control a customers' loads as indicated by energy mix absent SmartGridCity™ capabilities; see VP 1.5-1.7.

Environment within SmartGridCity™
Customers' In Home Smart Devices could be used to display energy mix signals.
Customers' In Home Smart Devices could be used to control customers' loads as indicated by energy mix.

Actions Taken
Green signals were not implemented in SGC.

Lessons Learned
- Signal design is not as easy as is commonly supposed and can lead to unanticipated consequences if not properly done. For example, green signaling could create demand that may outstrip renewable generation, requiring fossil fuel generation to fill gaps renewables could not meet.
- Providing energy mix signals in real time would provide confidential information that energy traders/generators could use to manipulate market prices, raising costs per kWh for all customers.
- Several conditions are required for customers to 'switch' usage to times when renewable energy is plentiful:
    - The green signal must be preceded by a 'red signal' to create pent-up demand.
    - The customer must be aware of the signals and act accordingly, though analysis of historical data indicates most signaling would occur at night.
    - Under current regulatory framework a utility will not be allowed to increase customer loads (during green signal) due to a conflict of interest.
- Research indicates that some customers (42%) are interested in receiving Green Signals, though this was the lowest interest level recorded among SGC capabilities surveyed.

Conclusion
Benefits are unlikely as increased usage during periods of high renewable energy mix does not result in a decrease of fossil fuel-fired generation.

VP 3.3 Carbon Reduction through T&D Loss Reduction

Benefit Category
Environmental

Enabling Field System
Integrated Volt/VAr Control (IVVC)

Hypothesis
If line losses are reduced, the amount of energy production required will also be reduced, and there will be a commensurate reduction in carbon dioxide equivalent (CO2e) emissions.

Environment outside SmartGridCity™
Autonomous capacitor banks react to local conditions. Of which, actions are uncoordinated between capacitor banks. Manual capacitor banks are set annually or semi-annually. Voltage levels are set at the feeder with minimal feedback from distribution system. Grid configuration is set approximately twice per year to minimize I^2R losses.

Environment within SmartGridCity™
Centralized control of distributed capacitor banks communicating bi-directionally over BPL and fiber; adds additional optimization beyond autonomous capacitor banks. Feeder voltage is set automatically based on voltage measurements throughout the distribution system. Using better load information and remote switching capabilities, grid reconfiguration can be done in real time to minimize line losses.

Actions Taken
IVVC is particularly effective at reducing energy use and is implemented on 2 feeders, 1554 and 1556.

Lessons Learned
- Environmental benefits are closely correlated to fuel usage, especially on the margins.
- See VPs 1.9 and 2.4.

Conclusion
Benefits are likely and high. CO2e reduction of approximately 500 tons per feeder for IVVC per year is feasible (3.1% total reduction vs. untreated feeder).

VP 3.4 Time-of-Use and Other Advanced Pricing Programs

Benefit Category
Economic (Energy)

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Increasing the transparency of costs to the retail level as those costs vary to the utility by time of day/day of year has been proven through various studies to reduce peak demand and in some cases overall energy usage. Smart meters enable advanced pricing through their ability to record energy use by the time over which it is used.

Environment outside SmartGridCity™
Traditional meters only measure energy used on a monthly basis. This level of granularity is insufficient for most advanced pricing programs.

Environment within SmartGridCity™
Smart meters can measure and record individual customer usage down to 15, 10, or even five minute increments (15-minute intervals are currently used in SGC).

Actions Taken
Advanced pricing pilot began in October 2010 as a separate effort.

Lessons Learned
- TOU program benefits vary dramatically with participation rates, program designs, incentives, and climate.
- Smart meters are not absolutely necessary for TOU rates; some meter collections methods using existing meters may be viable options. Investigation of these options may be advisable.
- The pilot is not attempting to quantify benefits of advanced TOU pricing on commercial customer demand and usage. As a large customer subset, the benefits from commercial customer participation in advanced pricing programs are expected to be significant.
- As the links between individual customer usage extends back to Energy Supply and strengthens over time, it may make sense to employ retail measurement intervals that are important to Energy Supply and Commercial Operations. For example, since Commercial Operations is held to a 10 minute generation availability standard, the measurement of customer usage in 10 minute intervals could support advanced rate designs and Demand Response incentives that prove more valuable to Energy Supply and Commercial Operations.
- Self-selection bias inherent in voluntary advanced pricing study designs makes it difficult to generalize findings to full roll out.

Conclusion
Benefits are likely and potentially high. Estimated benefits are expected to be $86.11 per participating customer per year. Benefits highly variable based on customer adoption rate and degree of behavior change.

VP 3.5 Utility Can Reduce Carbon Compliance Costs through Green Signal

Benefit Category
Economic (Energy)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
Green Signals would not create RECs. However, a Green Signal program might be effective at getting people to shift energy usage to times when renewable energy is plentiful. In rare instances, this will reduce costs (but not carbon). When renewable energy is "plentiful" is defined as an *instance in which no peaking plants are operating AND base load + renewable > energy demand.* This condition means energy is being dumped. It only occurs rarely for a few hours at a time, as base load cannot be ramped down further or fast enough for short timeframes. By selling extra power, rather than 'dumping' extra power, purchased renewable power waste costs can be reduced and wind production tax credits (PTC) can be taken.

Environment outside SmartGridCity™
Energy Mix signals could be provided to customers without SGC capabilities (for example through text messages, e-mails, etc.). There is a reduced ability for a utility to control a customers' loads as indicated by energy mix absent SGC capabilities; see VP 1.5-1.7.

Environment within SmartGridCity™
Customers' In-home smart devices could be used to display energy mix signals.
Customers' In-home smart devices could be used to control customers' loads as indicated by energy mix.

Actions Taken
Not implemented in SmartGridCity™.

Lessons Learned
- Providing energy mix signals in real time would provide confidential information that energy traders and generators could use to manipulate market prices, leading to higher costs per kWh for all customers.
- Several conditions are required for customers to 'switch' usage to times when renewable energy is "plentiful":
  - The green signal must be preceded by a 'red signal' to create pent-up demand.
  - The customer must be aware of the signals and act accordingly, though analysis of historical data indicates most signaling would occur at night.
  - Under current regulatory framework a utility will not be allowed to increase customer loads (during green signal) due to a conflict of interest.
- Research indicates that some customers (42%) are interested in receiving Green Signals, though this was the lowest interest level recorded among SGC capabilities surveyed.
- Learned that the opportunity to reduce carbon compliance costs is rare and that significant practical impediments to implementation exist.

Conclusion
Benefits are unlikely due to practical considerations. Provision of real-time energy signals could result in market manipulation and higher kWh costs.

VP 3.6 Support Bi-Directional Integration of Distributed Energy Storage

Benefit Category
Economic (Energy)

Enabling Field System
Integrated Volt/VAr Control

Hypothesis
Distributed Energy Storage (DES), owned by customers or a utility, offers significant potential benefits in distribution system reliability and increased utilization of renewable generation. While the cost of DES is generally prohibitive today, technology improvements & manufacturing economies of scale may make integration economically viable in the future. Smart capabilities will be needed to integrate DES into the grid.

Environment outside SmartGridCity™
Occasionally, renewable generation is so plentiful that base load generation must be 'backed down' (or run superfluously) at great expense. DES could store this 'excess' generation for later use.
High penetrations of renewable distributed generation can introduce reliability issues (See VP 3.1) that DES can help manage.

Environment within SmartGridCity™
SGC communications capabilities and software enable:

- Automated optimization of DES.
- Placement of DES farther 'down the grid' than otherwise available (generally limited to substations in absence of SGC)
- Optimized use of PHEVs as DES

Actions Taken
Not implemented in SmartGridCity™.

Lessons Learned
- DES may make it easier for utilities to comply with Renewable Energy Standards (RES).
- Recognition/classification of energy from DES that has been charged by renewable generation as renewable energy will be important.
- The cost effectiveness of DES may improve as its use in RES compliance is considered. Rather than 'dump' power from base load plants as a result of temporary renewable energy surpluses, surpluses could be stored for later use, offsetting power that would otherwise be generated by natural gas plants.
- While centralized, large-scale storage may have cost benefits over DES, DES offers important distribution system reliability benefits that centralized storage does not offer.
- DES may also offer benefits unrelated to renewable generation, such as deferring capital associated with substation upgrades.
- DES from PEVs (plug-in electric vehicles) are anticipated to be extremely small for many years to come due to several factors:
    - PEV availability (in total and at specific times) is likely very low.
    - PEV owners are likely to demand high compensation levels, but a solution might be utility PV battery ownership/leasing.
- Learned through peer-level research, and to limited extent SGC, that economic benefits were small relative to the likely cost of acquiring power from PHEVs. Conservation voltage reduction (VP 1.9), Power Factor improvement (VP 2.4), and communications capabilities would support DES integration in the future.
- Regulatory protection would be required if the utility generated signal model is used.

Conclusion
Benefits are unlikely due to unfavorable economics. 500 MWh of storage capacity (10% of the storage of 500,000 PHEVs) would be needed to save $ 500,000 per year in wind curtailment costs.

VP 4.1 Distribution Automation to Reduce Outage Extent

Benefit Category
Reliability

Enabling Field System
Distribution Automation

Hypothesis
The distribution automation system senses a fault, and changes the state of switches, reclosers and switch cabinets to isolate as much of the line as possible surrounding the fault and restore power to those customers not in the isolated area.

Environment outside SmartGridCity™
Distribution automation systems are installed in numerous, high trouble or high value locations. These systems are primarily Intelliteam system made by S&C using radio communications.

Environment within SmartGridCity™
Distribution automation system uses SEL controller equipment and logic, and fiber communications.

Actions Taken
Within SmartGridCity™ eight sectionalizing devices are installed on four feeders to create two loops are currently active.

Lessons Learned
- Manufacturer recommended firmware and software updates should be implemented as specified. Early in the demonstration project, the DA system reported a switch closed that was in fact open, leading to customer service interruption. This issue has since been corrected via firmware upgrades.
- Smart grid field hardware should go through same the standards qualification process as traditional hardware. SEL equipment did not go through normal standards qualification process. As a result, replacement parts and test equipment present logistical challenges.
- Alerts for Distribution Control Center (DCC) staff regarding the operating status of the DA system would provide benefits. It is difficult for DCC staff to determine whether lack of response from a DA controlled asset is hardware-, software- or communications-related.
- Learned that the technology was practical but data accuracy is essential to the functionality of the system.
- Selective deployment of DA in less accessible areas or geographies with low reliability will improve value created per dollar of invested capital relative to universal deployment.

Conclusion
Reliability benefits are likely and high. DA is anticipated to reduce 28,125 CMO per year per feeder in SmartGridCity™.

VP 4.2 Use DR to Assist Load Management During Outage

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
During outage conditions, dispatchers will find a way to restore power as quickly as possible. This sometimes results in overloading circuits temporarily or making other sub-optimal configuration decisions.

Environment outside SmartGridCity™
During outage conditions, dispatchers will find the best configurations to accommodate existing loads. This may involve stressing equipment beyond normal or ideal operating conditions.

Environment within SmartGridCity™
During outage conditions, dispatchers can call Demand Response (DR) events to reduce loads, which give them more flexibility in configuring the grid and reducing equipment stress.

Actions Taken
DR programs are not yet established for feeder level control because low penetration will make such implementation infeasible. Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available in the autumn of 2011.

Lessons Learned
- Changes to regulations (to allow for isolated DR events) or operations protocols (to call PSCO wide events during isolated outages) are required to make use of DR for localized load management.
- Dispatch does not currently engage commercial operations to call DR events nor does it have control over events. Coordination with commercial operations or control would be required.
- There is a practical limit to the number of DR events customers will tolerate.
- Frequent use of DR as a reliability tool may exhaust customer willingness to participate.
- Increased availability data available from SGC capabilities creates new DR product and business models. For example, today's limitations on DR events (i.e. 15 per year/5 degrees A/C) could be modified to hundreds of events at 1 degree.
- DCC requires approximately 1 MW minimum controllable load per feeder to represent practical value in distribution operations. This typically represents as much as 100% penetration of customer with central air conditioning (CAC) on some feeders.
- With limited opportunities to use DR, it is best to employ DR for capacity reductions (relatively larger financial benefit) than for reliability improvements.
- Learned that exceptionally high customer penetration rates are required per feeder to avoid asset overloads with DR.

Conclusion
Benefits are plausible but low for DR to assist in improving reliability.

VP 4.3 AMI to Restore Power Faster

Benefit Category
Reliability

Enabling Field System
Distribution Monitoring

Hypothesis
When an underground fault occurs, Troublemen will know which segment of line is faulted. This will save the troubleshooting time and the number of fuses used to isolate the problem.

Environment outside SmartGridCity™
Troublemen isolate a segment of line by disconnecting surrounding transformers and replacing a fuse; if it holds, the problematic line has been identified; if it blows, a fuse is installed in another location. This is repeated until the location is confirmed. In some areas and situations, the troubleman uses fault finding equipment for this purpose.

Environment within SmartGridCity™
Sensors between the feeder and fault will see the current spike. Those downstream of the fault will not. By looking at these feeder reports, the troubleman will know immediately which segment of line is faulted and can isolate it.

Actions Taken
Line sensors are active and in use on underground feeders and transformers.

Lessons Learned
- With optional upgrades smart metering can deliver most of the benefits of line sensors, although with pros and cons.
- Smart meter and related communication costs are dropping, which may increase the feasibility of using smart meters as line sensors.
- With appropriate communications infrastructure, smart meters with optional equipment upgrades, might be able to replace line sensors' fault locating capabilities with software that maps meters to transformers and phases.
- In SGC, current sensors were only installed on underground lines. It is typical to identify fault location on overhead lines due to visible problems.
- This saves time by reducing troubleshooting time, and also saves fuses because line testing by blowing a fuse will decrease. Extra fuses are used in approximately 10% of underground primary faults and cost approximately $130 per fuse, including truck fuel savings.
- There is value in monitoring all three phases. Underground sensors often installed on 1/3 phases with the expectation that a fault on any one phase will occur on all three phases. This was found not to be the case as faults are often only on one phase.
- Learned that line sensors on underground feeders are highly effective at identifying underground fault locations and that transformer-based line sensors are an alternative to AMI-based fault detection.
- Reducing time to troubleshoot in the field will significantly improve employee safety by decreasing exposure to daily hazards.

Conclusion
Reliability benefits are likely and high. Greater than 30 minutes of savings can be achieved per underground outage leading to a reduction of 160,000 CMO in Boulder, or a 20% decrease in CMO from underground fuse outages.

VP 4.4a AMI to Avoid Outage Overprediction

Benefit Category
Reliability

Enabling Field System
Distribution Monitoring
Advanced Metering Infrastructure

Hypothesis
AMI and grid sensors provide information which can be used to determine exactly which sections of line are live and which ones are experiencing an outage. This information can be used to avoid incorrect predictions by OMS (specifically assuming multiple small outages are a single large outage), and send the trouble crews to the correct location.

Environment outside SmartGridCity™
If multiple small outages occur near each other, OMS assumes it was a larger outage. Crews are often sent to the wrong locations and have to spend additional time identifying the correct locations.

Environment within SmartGridCity™
Detailed knowledge of the grid state shows exactly which lines are out and will not over predict the outage. Even if OMS over predicts, the dispatcher or field crew can quickly see the mistake in OpenGrid and identify the correct locations.

Actions Taken
DM and AMI are active within SGC.

Lessons Learned
- This capability improved remote fault reporting and dispatch efficiency.
- Troubleman effectively utilized mobile data terminals to verify where the problem exists during the troubleshooting process.
- This capability would be more beneficial in the areas where distance between devices can be quite far than in Denver Metro where devices are close together.
- Learned that smart meters and DM do offer improvements in outage extent determination over OMS.
- Selective deployment of DM in more rural, less accessible geographies may provide greater troubleshooting value per dollar invested relative to universal deployment.

Conclusion
Reliability benefits are likely and relatively low. A reduction of 22,500 CMO per year in SmartGridCity™ is anticipated*.*

VP 4.4b AMI to Identify Nested Outages

Benefit Category
Reliability

Enabling Field System
Distribution Monitoring
Advanced Metering Infrastructure

Hypothesis
AMI and grid sensors provide information which can be used to determine if power has been restored to all customers in a given area. During storms and escalated operations, a large outage may be fixed while the small outage behind it may still need attention, however the field crews may not know about the small outage and assume power has been fully restored.

Environment outside SmartGridCity™
When a large outage is fixed, dispatch will attempt to call a sampling of customers to verify that power has been restored; however, it cannot always be verified due to customers who are picking up the phone, work load in the operations center, etc.

Environment within SmartGridCity™
When a large outage is fixed, OpenGrid shows where power has and has not been restored. Dispatchers or trouble crews can then ping meters to check status and verify that there are no nested outages or alert crews if there are.

Actions Taken
DM and AMI are active within SGC.

Lessons Learned
- Repair crews prioritize largest outages during escalated operations. Some identified nested outages may not be fixed while a crew is in a nearby area if there are other large or high priority outages.
- AMI and DM provide improvements in outage extent determination over OMS.
- There have been 20 nested outages in Boulder since July 2008, nine of which caused by a single storm in April 2009.
- Reducing time to troubleshoot in the field will significantly improve employee safety by decreasing exposure to daily hazards.
- Selective deployment of DM in more rural, less accessible geographies may provide greater troubleshooting value per dollar invested relative to universal deployment.

Conclusion
Reliability benefits are likely and high. Potential CMO reduction of up to 200,000 minutes in SGC, or approximately nine minutes per customer per year is achievable.

VP 4.4c AMI to Avoid Outage Underprediction

Benefit Category
Reliability

Enabling Field System
Distribution Monitoring
Advanced Metering Infrastructure

Hypothesis
AMI and grid sensors provide information which can be used to determine exactly which sections of line are live and which ones are experiencing an outage. This information can be used to avoid incorrect predictions by OMS. Specifically assuming single customer calls are isolated, rather than wide-spread problems, and can send trouble crews to the correct location

Environment outside SmartGridCity™
During some off-hour outages (such as overnight), few people may call in to report problems. OMS may identify the outage as small and isolated when in fact it is larger and more widespread. The troubleman will start investigations at the wrong location and restoration will be slower.

Environment within SmartGridCity™
All meters that are without power will report the outage even if no customer calls in and the correct isolation device will be identified.

Actions Taken
DM and AMI are active within SGC.

Lessons Learned
- This capability improved remote fault reporting and dispatch efficiency.
- AMI and DM provide improvements in outage extent determination over OMS.
- Troubleman effectively utilized mobile data terminals to verify where the problem exists during the troubleshooting process.
- Underprediction occurs almost exclusively in overnight outages when most customers are asleep; at other times there are sufficient calls to identify the larger outage.
- Reducing time to troubleshoot in the field will significantly improve employee safety by decreasing exposure to daily hazards.
- Selective deployment of DM in more rural, less accessible geographies may provide greater troubleshooting value per dollar invested relative to universal deployment.

Conclusion
Reliability benefits are likely but relatively low. CMO Reduction of 1,500 minutes in SGC.

VP 4.5 Use DR to Avoid Overloading During Normal Operations

Benefit Category
Economic (Capital Deferral)

Enabling Field System
Distributed Energy Resource Control

Hypothesis
During outage conditions, dispatchers will find a way to restore power as quickly as possible. This sometimes means overloading circuits temporarily or making other sub-optimal configuration decisions.

Environment outside SmartGridCity™
During outage conditions, dispatchers will find the best configurations to accommodate existing loads. This may involve stressing equipment beyond normal or ideal operating conditions.

Environment within SmartGridCity™
During outage conditions, dispatchers can call Demand Response (DR) events to reduce loads, which give them more flexibility in configuring the grid and reduce equipment stress.

Actions Taken
DR programs are not yet established for feeder level control because low penetration does not warrant effort. Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available in the autumn of 2011.

Lessons Learned
- Dispatch does not currently engage commercial operations to call DR events nor does it have control over events; coordination with commercial operations or control would be required.
- There is a practical limit to the number of DR events customers will tolerate.
- Frequent use of DR as an asset overloading avoidance tool may exhaust customer willingness to participate.
- Increased availability data available from SGC capabilities creates new DR product and business models. For example, today's limitations on DR events (i.e. 15 per year/5 degrees A/C) could be modified to hundreds of events at 1 degree.
- DCC requires approximately 1 MW minimum controllable load per feeder to represent practical value in distribution operations; this represents 100% penetration of customer with central air conditioning (CAC) on some feeders.
- With limited opportunities to use DR, it is best to employ DR for capacity reductions (relatively larger financial benefit) than for asset overloading avoidance.
- Learned that exceptionally high customer penetration rates are required per feeder to avoid asset overloads with Demand Response (DR).

Conclusion
Benefits are plausible but low for DR to avoid overloading during normal operations.

VP 4.6 Proactively Fix Power Quality Issues

Benefit Category
Reliability

Enabling Field System
Distribution Monitoring
Advanced Metering Infrastructure

Hypothesis
Grid sensors and smart meters collect data on a regular basis. With automated analytics and pre-defined threshold conditions, Power Quality issues can be identified and corrected before they become problematic.

Environment outside SmartGridCity™
The following process occurs:

- A customer complains about Power Quality issue.
- The service investigation team attaches diagnostic tools to measure Power Quality and returns later to retrieve tools and download data.
- The engineering team analyses data and determines resolution.

Environment within SmartGridCity™
The following process occurs:

- OpenGrid alerts engineering team to conditions outside tolerances.
- Engineering team retrieves and analyses data from OpenGrid and determines a resolution.

Actions Taken
AMI and DM are actively used in SmartGridCity™.

Lessons Learned
- Voltage distribution problems that typically required days or weeks to properly identify using traditional techniques are diagnosed in minutes in SGC.
- Service investigations is an internal, salaried team, and no O&M savings will be realized in the near term; a larger rollout could affect staffing levels and increase O&M savings.
- Daily exception reporting from OpenGrid requires minimal effort to identify problems, and only moderate effort to determine solution.
- Thresholds to determine “abnormal” conditions require iteration to find balance between false positives and missed issues.
- DM reporting reliably and proactively identifies voltage issues.

Conclusion
Reliability benefits are likely and high. Voltage complaints dropped from an average of 30 per year to 0 in SGC after implementation.

VP 4.7 Islanding Using DER During Outages

Benefit Category
Reliability

Enabling Field System
Distribution Automation

Hypothesis
When an outage occurs, micro grids can be created by isolating a group of premises in which there are Distributed Energy Resources (DER). These resources can provide power to the neighboring premises restoring power faster.

Environment outside SmartGridCity™
Normal outage restoration procedures to bring power to as many people as possible as quickly as possible. Most areas use manual switching and distribution automation in very few areas.

Environment within SmartGridCity™
Knowledge of fault location, loads and distributed resources allows operators to create islands using remote switching. DER could possibly be engaged to provide power to neighboring premises.

Actions Taken
Not implemented in SGC as a result of this issue and current IEEE 1547 standard.

Lessons Learned
- DER penetration is not nearly significant enough to provide power to surrounding premises during an outage (penetration must be greater than 20% to enable islanding in residential areas).
- Standards (IEEE 1547) preclude this capability because DER is required to disengage during outages to protect worker safety.
- Field crew processes need to be drastically changed if DER is able to provide power during outages.
- Rates and regulations may need modification because individuals are currently only permitted to sell to the utility and not to other customers.
- Further analysis required as penetration increases to incident generation and load as both are highly dependent on time of day and time of year.

Conclusion
Reliability benefits are unlikely. Minimal benefits are possible at the current penetration levels. DG penetration of 20% or higher is required.

VP 4.8 Measure Phase Balance Remotely

Benefit Category
Economic (O&M)

Enabling Field System
Distribution Monitoring

Hypothesis
Every district performs phase balance adjustments on a number of feeders every year, typically seven-eight per district. In order to do this, power measurements must be taken throughout the feeder to determine which loads to shift.

Environment outside SmartGridCity™
Circuits for balancing are determined from feeder SCADA data. Crews are sent to attach sensors to various points on the phases to determine loads to move to restore balance.

Environment within SmartGridCity™
SGC data, including customer load and sensor data, can provide the information required for phase balancing without sending crews to attach and retrieve meters.

Actions Taken
Measurements are being taken as part of normal SGC operations in OpenGrid.

Lessons Learned
- DM could proactively identify load balancing issues such as voltage sags and I^2R losses, but further study is needed to determine whether transformer sensor or meter aggregation is the best approach.
- Further research is required to determine the size of the opportunity.
- Since proactive DM measurement is a new capability, effective use of this information requires new business process to proactively rebalance phases prior to customer experiencing Power Quality issues.
- Can use load data from customer meters to determine phase balance and any need to improve it.
- Depending on who would be doing the phase balance measurements and what other duties they have, this may not impact O&M savings in the near term.

Conclusion
Benefits are likely but relatively low. $1,500 O&M cost reduction per division per year that can avoid sending crews by using smart grid data.

VP 4.9 Troubleshooting Voltage Issues Remotely

Benefit Category
Economic (O&M)

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Many customer Power Quality issues can be detected and investigated using smart meters and/or line sensors.

Environment outside SmartGridCity™
The following process occurs:

- A customer calls complaining of Power Quality issues (light flicker, spikes and sags, etc.).
- A Troubleman responds to call and if he can't identify the problem service investigation (SI) gets involved.
- The service investigation team attaches diagnostic tools to measure Power Quality and returns later to retrieve tools and download data.
- SI attaches a Power Quality meter to the premises and then retrieves it about a week later, and downloads data.
- Engineer analyses data and determines problem and resolution.

Environment within SmartGridCity™
The following process occurs:

- OpenGrid alerts engineering team to conditions outside tolerances.
- Engineering team retrieves and analyses data from OpenGrid and determines a resolution.

Actions Taken
Smart meters and line sensors are collecting data and can be used for Power Quality analysis.

Lessons Learned
- Service investigations is an internal, salaried team, and no O&M savings will be realized in the near term. A larger rollout could affect staffing levels and increase O&M savings.
- Voltage complaint frequency in SGC was extremely low (approximately 30 per year prior to implementation), but was reduced to 0 following implementation of intelligent technology.
- Learned that voltage issues can be proactively identified and investigated using remote technologies and effectively eliminated complaints.
- Reducing need to troubleshoot in the field will significantly improve employee safety by decreasing exposure to daily hazards.

Conclusion
Voltage complaints dropped to 0 after SGC implementation. O&M benefits are likely but relatively low. O&M savings of $650 per year in SmartGridCity™ could be achieved if staffing levels are changed or resources can be redeployed to other tasks.

VP 4.10 DR for Frequency Regulation

Benefit Category
Reliability

Enabling Field System
Distribution Energy Resource Control

Hypothesis
Momentary imbalances between supply and demand will cause changes in system frequency. Actions will be taken to re-balance supply and demand balance and restore the frequency back to normal. Demand Response (DR) could be used to reduce demand and Distributed Storage (DS) could be used to increase supply when balancing is needed.

Environment outside SmartGridCity™
Standard tools, such as increasing generation in real time, are used to manage supply and keep the system in balance.

Environment within SmartGridCity™
Additional tools, such as load reduction from DR and increasing supply from DS, to keep the system in balance could be possible. As demand outpaces supply, DR events can be called to increase demand on the system or energy from DS could be supplied.

Actions Taken
Preliminary results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available in the autumn of 2011.

Lessons Learned
- DR has a 15-minute response time; frequency regulation requires 4-6 second response time or shorter. DR as implemented in SGC will be insufficient for regulating frequency.

Conclusion
Benefits are unlikely as implemented. PSCO is currently considering distributed data processing infrastructure designs that may enable this capability.

VP 4.11 Remotely Verify Dispatch Commands

Benefit Category
Economic (O&M)

Enabling Field System
Distribution Monitoring
Advanced Metering Infrastructure

Hypothesis
Commands sent from the distribution control center do not always reach the target and the field hardware does not always operate. Confirmation that the operation took place is sometimes required and can be done from remote sensing or visual inspection.

Environment outside SmartGridCity™
After a dispatcher sends a command, if there is evidence that the operation failed, a field crew will be sent to the relevant location to verify operation success or failure

Environment within SmartGridCity™
After a dispatcher sends a command, there will be evidence in line sensor and smart meter data that the operation succeeded or failed, and no crews will need to be sent

Actions Taken
Smart meters and DM are actively collecting data in SGC that can be used to verify dispatch commands.

Lessons Learned
- Field crews are only sent if there is evidence that the command failed to operate the device; this happens very rarely.
- Data to determine if a switch worked is generally available in SCADA.
- Selective deployment of DM in more rural, less accessible geographies may provide greater troubleshooting value per dollar invested relative to universal deployment.

Conclusion
Benefits are likely but relatively low. Minimal benefits expected due to the rare occurrences where crews are sent to verify an event.

VP 5.1 Predict Transformer Failure

Benefit Category
Reliability

Enabling Field System
Distribution Monitoring

Hypothesis
Historical load information and up-to-date transformer performance characteristics can identify transformers that are close to failure. These transformers can be replaced before causing an unplanned outage.

Environment outside SmartGridCity™
Transformers are used until failure, or until the thermal protection element trips. When either event happens an unplanned outage occurs. The transformer is then replaced immediately or within 24 hours.

Environment within SmartGridCity™
Transformer load information can be used to estimate effective age of the transformer and estimated time to failure. Transformer characteristics change before failure, and analytics evaluating characteristics and comparing to transformers nearby can alert to incipient failure

Actions Taken
DM is actively collecting data in SmartGridCity™. Transformers failures are 0.4% per year.

Lessons Learned
- Transformer replacement program effective in previous years, but was phased out. In the event of broader deployment, it may be beneficial to re-examine the practice using smart grid data.
- Predicting transformer failure produces the following types of benefits: increase in reliability numbers because an outage is planned; reduction in O&M cost because overtime is not needed; shorter outages because no waiting is required for a truck roll; increase in customer satisfaction because of knowledge of planned outage and timing of outage.
- Process for identifying incipient failure not a specific algorithm, but instead, a troubleshooting analysis of over or under voltage on the transformer, which is found to be caused by shorting between nearby windings.
- Learned that this capability did proactively identify transformers in need of replacement in SGC.

Conclusion
Reliability benefits are plausible but relatively low. Total CMO reduction estimated at 1,650 minutes for SGC per year.

VP 5.2a Identify and Replace Oversized Transformers

Benefit Category
Economic (Energy)

Enabling Field System
Distribution Monitoring

Hypothesis
No load losses are approximately proportional to the size of the transformer. By reducing the size of the transformer to slightly larger than the required capacity as opposed to much larger sizing, no-load losses can be reduced.

Environment outside SmartGridCity™
Standard distribution transformers (50 kVA) are installed for all residential situations. Transformers are only replaced after failure or when a thermal element cutoff occurs. Then they are up-sized. Transformers are never resized proactively.

Environment within SmartGridCity™
Load on a transformer is examined. If peak demand is found to be significantly lower than the transformer size, it can be replaced with a lower transformer size to reduce no-load losses.

Actions Taken
Load measurement is currently active in SmartGridCity™. Transformers are not being replaced based on this information.

Lessons Learned
- Improved granularity of data through DM provides more accurate guidance on transformer sizing and reduces incidence of oversizing.
- Requires engineering analysis on all transformers to determine candidates for proactive replacement. It may be possible to automate initial transformer candidate screening to identify the best transformers.
- Commercial transformers are sized to customer specifications, which often grossly overestimate demand and increase no-load losses (commercial customers base transformer size on system capacity which is usually more than double highest demand).
- Learned that while retroactive replacement of oversized transformers was not cost effective (See VP 5.2b), benefits exist for right sizing transformers at routine replacements.

Conclusion
Benefits are plausible going forward, but savings of reduced transformer size does not match cost of replacement. The payback period is approximately 35-70 years.

VP 5.2b Avoid oversizing replacement transformer

Benefit Category
Economic (Energy)

Enabling Field System
Distribution Monitoring

Hypothesis
When a transformer fails, the field crew replaces it with the next larger standard size. If this is oversized, no-load losses are increased unnecessarily.

Environment outside SmartGridCity™
When a transformer fails, or the thermal protection element cuts out, the element is replaced immediately to restore power. The transformer is replaced soon after with the next larger standard sized transformer.

Environment within SmartGridCity™
When a transformer fails or the thermal protection element cuts out, the historical load on the transformer can be examined to determine the appropriate replacement size.

Actions Taken
Load measurement is active in SmartGridCity™. Transformers are not being replaced based on this information.

Lessons Learned
- Field crews performing transformer replacement will need to refer to OpenGrid to analyze data before sizing replacement.
- Algorithms for determining appropriate transformer replacement size needs to be developed and implemented.
- Material and labor are approximately equal for transformer installation.
- Losses occur every year of transformers use. It can be 30 years or more for distribution transformers before they are replaced.
- Learned that while retroactive replacement of oversized transformers was not cost effective, benefits exist for right sizing transformers at routine replacements.

Conclusion
Benefits are plausible but small. Energy savings of $4,200 are possible in PSCO per year, accumulating each year over the life of transformers.

VP 5.3 Measure Substation Transformer Stress to Predict Failure

Benefit Category
Reliability

Enabling Field System
Smart Substation Monitoring and Protection

Hypothesis
Substation transformer failures are rare, but when they do happen, they are large events causing long outages for many customers. By using SGC data, it may be possible to predict and prevent substation transformer outages through proactive maintenance.

Environment outside SmartGridCity™
Many different generations of equipment are in use because of long life of substation equipment. Primarily equipment that is monitoring electrical and temperature information and sending to SCADA for use in real time alarms. Many components of the equipment are electro-mechanical.

Environment within SmartGridCity™
Devices are microcontroller based, collecting more data at higher frequency rates. Such equipment can perform complex analyses on microcontroller based information using external equipment.

Actions Taken
Four substations and eight substation transformers have been upgraded in SGC to use Smart Substation Monitoring and Protection (SSMP) equipment.

Lessons Learned
- Small footprint, only 4 substations in all of PSCO, makes process changes difficult to handle new data.
- Substation data can potentially be used forensically to evaluate failure causes and predict failure. The validity of this VP should be evaluated in the future as additional study is required.
- Substation transformer failures are very rare (0.8% per year).
- When failures do happen, very large impact on CMO, number of customers, etc.
- Analytical tools and business process changes will need to be developed to make use of substation data and to predict equipment failure to reduce outage time.
- Reducing time to troubleshoot substation equipment will significantly improve employee safety by decreasing exposure to hazards.

Conclusion
Reliability benefits are plausible. 1,320 CMO per transformer monitored and 0.6% chance of predicting a failure per transformer monitored; capital savings of $8,400 per year per transformer failure avoided.

VP 5.4 Measure Substation Breaker Stress to Predict Failure

Benefit Category
Reliability

Enabling Field System
Smart Substation Monitoring and Protection

Hypothesis
Substation breaker failures are rare, but when they do happen, they are large events causing long outages for many customers. By using SGC data, it may be possible to predict and prevent substation breaker outages through proactive maintenance

Environment outside SmartGridCity™
Many different generations of equipment are in use because of long life of substation equipment. Primarily equipment that is monitoring electrical and temperature information and sending to SCADA for use in real time alarms. Many components of the equipment are electro-mechanical.

Environment within SmartGridCity™
Devices are microcontroller based, collecting more data at higher frequency rates. Such equipment can perform complex analyses on microcontroller based information using external equipment. Measuring breaker characteristics including wear is one form of analysis conducted by such equipment.

Actions Taken
Implemented on four substations in SmartGridCity™ with approximately 28 distribution breakers actively monitored.

Lessons Learned
- Small footprint, only 4 substations in all of PSCO were equipped with SSMP, therefore it was difficult to change existing processes to optimize the use of new data, including different methods for data management.
- Substation data can potentially be used forensically to evaluate failure causes and validate the feasibility of this value proposition in the future, but additional study is required.
- Substation breaker failures are very rare (0.5% per year), but if they do occur, can have significant impact on customers CMOs.
- Reducing time to troubleshoot substation equipment will significantly improve employee safety by decreasing exposure to hazards.

Conclusion
Reliability benefits are plausible. 25 CMO reduction per breaker monitored per year is achievable.

VP 6.1 Increase Customer Ability to Manage Energy Bill

Benefit Category
Customer Satisfaction

Enabling Field System
Advanced Metering Infrastructure
Distributed Energy Resource Control

Hypothesis
SGC capabilities enable customers to better manage their energy bill, primarily through better knowledge and to support participation in real time pricing plans. Demand Response technologies help customers manage usage billed through Time of Use (TOU) pricing plans more conveniently. In addition, use of DR technologies is an excellent way to increase the energy and money saved beyond participation in advanced pricing plans.

Environment outside SmartGridCity™
Flat energy rates (¢/kWh) do not offer customers an opportunity to reduce their energy bill simply by modifying when they use energy. The Saver's Switch program offers customers a basic but effective way to reduce their energy bill using DR via an annual $40 incentive.

Environment within SmartGridCity™
SGC capabilities (specifically, smart meters) provide customers with the opportunity to reduce their energy bills by participating in TOU pricing plans (non-SGC enabled customers can also participate in TOU pricing plans). Customers billed through TOU pricing can reduce their bills simply by modifying when they use energy. SGC capabilities also enable DR technologies that are more advanced than the current Saver's Switch.

Actions Taken
23,000 smart meters installed in SGC to facilitate advanced pricing, including Web-based portal technology and DR.

Lessons Learned
- The convenience and simplicity of the presentation of energy data and tools to customers impacted their willingness to participate.
- Only customers who actively manage their usage will experience larger bill reductions in the short term. Less diligent customers will experience reduced bill changes.
- Bill impact benefits will be mitigated somewhat over time through future rate cases. To the extent sales volumes drop for an entire population with access to dynamic pricing, fixed costs are spread over fewer kWh, increasing the rate per kWh.
- Customers are able to employ some level of DR technology without SGC capabilities (Saver's Switch).
- Customers are able to employ DR technology with or without the utility's involvement.
- Cyber security issues must be addressed at the meter and with the IHSD to protect customers.

Conclusion
Economic (electric bill) benefits are potentially high for motivated customers. Based on PSCO's 2006-2007 study of time-differentiated rates, voluntary participants in a Critical Peak Pricing program saved an average of approximately $200 annually over standard rates and baseline usage. (Critical Peak Pricing rates are different in SmartGridCity™, and the current time-differentiated rate study was designed to approximate a default, as opposed to voluntary, introduction of time-differentiated rates. SmartGridCity™ participant savings are likely to be different as a result of these changes.)

VP 6.2 Ability to Reduce Energy Use Through Usage Data Access

Benefit Category
Customer Satisfaction

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
SGC capabilities provide customers with next-day access to their energy usage in 15-minute intervals through a secure internet website (portal). It is anticipated that such access will better help customers understand how much energy is used to operate various home equipment. It is further anticipated that this understanding will lead to appropriate changes in behavior that will reduce energy usage and corresponding carbon dioxide equivalent (CO2e) emissions.

Environment outside SmartGridCity™
Customers today have little understanding of how equipment and usage impact energy bills. Historically, usage detail has been limited to a single figure (kWh for the month). This level of detail is insufficient to help customers understand what actions they can take, or which specific equipment usage modifications to make, to reduce energy usage and corresponding CO2e emissions.

Environment within SmartGridCity™
The combination of smart meters with advanced meter communications enables 15-minute interval usage data to be uploaded to a secure, customer-accessible website on a daily basis. Customers can access their data from any internet-accessible computer to view historical usage from the previous day clear back to the same day the previous year.

Actions Taken
15-minute interval usage data from smart meters is being collected and updated daily to a secure website. Current PSCO studies underway to refine impact estimate.

Lessons Learned
- Customers responded better when metrics were presented in terms they could easily relate to (e.g. miles driven per year vs. tons of CO2e; dollars saved vs. kWh saved).
- Customer Care Center employees are using 15-minute interval data to reduce call handle time and frequency of meter tests for customers with high bill complaints. For more information please see VP 6.6, 'Use meter interval data to reduce O&M expenses'.
- Web portal implementation choices (using Flash software to present 15-minute interval data quickly, securely, and efficiently to customers) do not readily enable tracking of the pages users have visited, user visit frequency, or user visit duration. This information would be helpful in evaluating the impact of usage data access more precisely.
- Cyber security at the meter will be important to protect customer usage data.

Conclusion
Benefits are plausible. External research indicates 8% reduction in energy use per customer per year is possible.

VP 6.3 Participation in an Online Green Energy Community

Benefit Category
Customer Satisfaction

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Customers with Smart Meters have the opportunity to take advantage of many new capabilities, including the ability to view electricity usage data in 15-minute intervals via a secure website. The online green energy community is a supportive tool for these capabilities, enabling users to share success stories and best practices in energy conservation with each other. It's also an opportunity for the utility to post its own energy conservation tips and promote energy efficiency and demand response programs.

Environment outside SmartGridCity™
Customers today have little understanding of how equipment and usage impact energy bills. Historically, usage detail has been limited to a single figure (kWh for the month). This level of detail is insufficient to help customers understand what actions they can take, or which specific equipment usage modifications to make, to reduce energy usage and corresponding carbon dioxide equivalent (CO_2e) emissions. The reliability of related information sources, particularly on the internet, is often questionable.

Environment within SmartGridCity™
Customers with Smart Meters are able to access 15-minute interval usage data through a secure website on a one-day delay. The online green energy community adds to this capability by providing an opportunity for customers to educate each other, share successes and best practices, and compare results in order to maximize the value of interval data access in reducing energy usage.

Actions Taken
Numerous independent networking sites already exist today; therefore the online green energy community was not implemented.

Lessons Learned
- An online energy community would require dedicated resources to promote the community, monitor user interactions, identify educational opportunities, and execute promotional efforts associated with energy efficiency and demand response.
- To encourage customer adoption and involvement in the community, Marketing will likely need to allocate resources and effort towards educating customers on the benefits of using such a community.
- Based on findings from a 2006-2007 PSCO study of time-differentiated rates, very few customers would utilize a PSCO online green energy community.

Conclusion
Benefits are unlikely. Customer survey results indicate that very few customers would currently utilize an online green energy community. In SGC, 17% of customers surveyed indicated they would use such as service; 12% in PSCO.

VP 6.4 Improved Satisfaction via Reduced Customer Minutes Out (CMO)

Benefit Category
Customer Satisfaction

Enabling Field System
Distribution Monitoring
Distribution Automation
Substation Monitoring

Hypothesis
A variety of SGC Systems (Distribution Monitoring, Distribution Automation, and Substation Monitoring) offer improvements in CMO as part of their value propositions. CMO improvements should translate to improved customer satisfaction. Customer research was conducted to understand how much residential customers value reliability improvements.

Environment outside SmartGridCity™
Reliability is a top priority for PSCO distribution and substation operations. A significant amount of resources are dedicated to measuring and analyzing reliability and identifying and resolving reliability issues. PSCO's Outage Management System (OMS) is a valuable tool in reliability improvement efforts. PSCO customers have an expectation of reliability (i.e. it is a cost of doing business vs. a perceived added benefit).

Environment within SmartGridCity™
A variety of SGC systems provide additional capabilities to reduce outage frequency and duration (see VPs 4.1, 4.3, 4.4, 4.7, 5.1, 5.3, and 5.4).

Actions Taken
CMO has reduced 30% after SGC systems implementation.

Lessons Learned
- Most (residential) customers appear to be satisfied with the existing level of reliability.
- Compared to other smart grid capabilities, customers place a relatively low value on additional improvements in reliability.
- If risks to reliability (PV solar, Electric Vehicles, etc.) are not managed well and reliability decreases, then customer interest in reliability would likely be dramatically greater.
- Service in Boulder was already extremely reliable before SGC, with SAIDI figures in the top quartile of US cities (IEEE, 2006).
- Though CMO did improve 30% after implementation of SGC systems, a 30% improvement translates to a relatively short improvement in total time when viewed in the context of already exceptional reliability performance (25 minutes per year).
- Greater value per dollar of investment may be achieved with selective deployment of DM and DA in low reliability or less accessible geographies.
- As greater DG penetration creates instability on the grid, DA and other systems may require faster processing which could lead to distributed processing compared to the current centralized processing model to address latency.

Conclusion
Benefits are unlikely. In a survey of 800 PSCO customers regarding the relative importance of various smart grid benefits, reduced duration and frequency were scored as 8^{th} and 10^{th} lowest out of 11 benefits measured.

VP 6.5 Use Meter Pinging to Avoid Investigation-related Delays

Benefit Category
Customer Satisfaction

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
The SGC implementation included the capability to communicate with smart meters remotely in real time. This capability ('pinging the meter') can be used to determine power status at the meter, including voltage, current, and other conditions. Pinging can be used to let a customer know immediately if an electrical problem is the customer's responsibility or PSCO's responsibility to fix.

Environment outside SmartGridCity™
Traditionally the only way to determine whether or not a customer's service issue is within the home (on the customer's side of the meter/customer responsibility) or outside the home (on PSCO's side of the meter/PSCO's responsibility) is to send a qualified electrician to investigate.

Environment within SmartGridCity™
With meter pinging a Customer Contact Center (CCC) or Distribution Control Center (DCC) employee can determine whether or not a customer's service issue is PSCO's responsibility without having to roll a truck.

Actions Taken
Both the CCC and DCC have the capability to ping all 23,000 smart meters in Boulder.

Lessons Learned
- The pinging capability is not likely utilized as fully in the SGC pilot as it would be in a full roll out.
- While CCC and DCC employees can take steps to identify whether or not a premise has a pinging capability, no alert exists that indicates if a premise has a pinging capability. About 50% of the premises in Boulder have pinging capabilities, or about 2% of PSCO electric meters. This penetration level is insufficient to justify large scale process changes in the CCC or DCC.
- Pinging capability is not generally as valuable in widespread outages as it is in single premise trouble reports.
- In extremely rare circumstances (<2% of SGC outages), a faulty meter connection block caused an outage for which PSCO was responsible to fix, that a meter ping would indicate is a customer's responsibility to fix.
- Learned that this capability is highly valued by customers.

Conclusion
While O&M benefits are likely and relatively low, a survey of 800 PSCO customers regarding the relative importance of various smart grid benefits, "Knowing the responsible party to fix an outage" scored 2nd highest out of 11 benefits measured (Energy Use and Cost).

VP 6.6 Use Meter Interval Data to Reduce O&M

Benefit Category
Economic (O&M Cost)

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Smart meters are used to collect usage data over specific (e.g. 15 minute) time intervals. While this data is generally intended to be used for advanced pricing programs such as Time of Use (TOU) and Critical Peak Pricing (CPP), there are other benefits. For example, Call Center agents can access and review this detailed usage data to help a customer understand why his or her electric bill might be higher than normal (house guests, introduction of new loads, weather-induced extensive AC usage, etc.). Helping a customer identify why a specific electric bill might be high is expected to 1) reduce the time required to handle a high bill complaint call; 2) increase the number of high bill complaint calls resolved without a 2nd call; or 3) reduce the number of meter tests ordered.

Environment outside SmartGridCity™
Traditionally usage data is not very granular, available only on a monthly basis. Neither customers nor Call Center employees have visibility to interval usage data. High bill complaints are typically resolved only after extensive time on the phone, elevation to a supervisor, or through a meter test requiring a truck roll.

Environment within SmartGridCity™
With access to interval data a Call Center employee can identify dates and even hours of high usage and suggest potential explanations. A customer might respond with "Oh, that's when we got our hot tub" or "Right, my sister's family was here and we used the space heater".

Actions Taken
Historical 15-minute interval data is available for all 23,000 smart meters in SGC.

Lessons Learned
- The access to interval data is not likely utilized as fully in the SGC pilot as it would be in a full roll out.
- While Call Center employees can take steps to identify whether or not interval data is available for a given premise, no alert that the data is available for a given premise is routinely provided through CRS.
- Approximately 50% of the premises in Boulder have available interval data, or about 2% of PSCO electric meters. These penetration levels are insufficient to fully change Call Center processes or employee behaviors. As a consequence SGC pilot results likely underestimate the true O&M reductions that result from the availability of interval data.
- Learned that the Call Center can use interval data to better manage high bill complaint calls.
- Call Center employees may need to spend more time with customers to evaluate usage data. Currently, Call Center employees have incentives to take high numbers of calls per day and not to lengthen call time.
- There will be a need to rebalance the budget to ensure increased costs for the Call Center are fully covered.

Conclusion
Benefits are likely but relatively low. O&M Costs reduced are anticipated to be $0.013 per smart metered customer per year.

VP 6.7 Proactive Monitoring of Selected Customer Premises Circuits

Benefit Category
Customer Satisfaction

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Advanced DR devices in customers' premises can be used to investigate the health of appliances and circuits into which they are incorporated. These capabilities could lead to the utility offering a new service to customers.

Environment outside SmartGridCity™
There are no capabilities for a utility to check on the health of an appliance or circuit within a customer's premise.

Environment within SmartGridCity™
SGC communications capabilities, combined with customers' advanced DR devices, enable the utility to investigate the health of appliances and circuits into which these devices are incorporated.

Actions Taken
Not broadly implemented due to security-related delays in release of in-home smart devices required to enable this capability.

Lessons Learned
- Appliance-based monitoring is more practical in residential environments than circuit-based monitoring and a high number of customers are willing to pay for this type of service.
- Software would need to be developed to periodically collect premise circuit data, store it for future use, compare it to new data as collected, identify troubling variations, and report exceptions to the Call Center (for proactive outreach to customer) or customer via automated communications.
- These capabilities have not been broadly tested. A formal product development investigation of this potential service is indicated.

Conclusion
Benefits are plausible. 65% of customers surveyed (Denver Metro) were highly interested in this service, above the median compared to other services/benefits measured. The service also scored the highest on a 'willingness to pay' measure of all other services/benefits measured; 52% would pay up to $1.00 per month.

VP 6.8 Customer Confident That Utility Will Be Aware of Outages

Benefit Category
Customer Satisfaction

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Customer knows that utility can detect outages automatically.

Environment outside SmartGridCity™
Without smart grid capabilities, utilities are dependent upon customers calling in to report outages.

Environment within SmartGridCity™
In SGC, current and voltage sensors in the field, combined with grid communications capabilities and back-office software, enable the utility to be notified of outages at the transformer level without customer intervention.

Actions Taken
Within SGC, 4,700 transformers are being monitored 24/7 for outages. Identified transformer-level outages are automatically posted to OMS.

Lessons Learned
- The meter pinging capabilities available to the Customer Care Center for 23,000 meters in SGC could be utilized to identify single-premises outages. An automated pinging program could be employed to contact the meters on a periodic basis (15-minute intervals) and report unfavorable findings to OMS when encountered.
- Transformer-level outage monitoring works, but is expensive given the ratio of customers per transformer and is not adequate to replace premises-level outage detection.
- Distribution transformer-level outages are accurately reported by existing line sensor technology.
- Single-premises outages on distribution transformer phases with more than one premise are not reported to OMS in real-time today (though these meters can be pinged to verify if they are receiving electricity).

Conclusion
Benefits are likely. 73% of customers surveyed rated PSCO's capability to detect outages without any intervention as highly important. This capability was one of the highest-rated SGC capabilities measured in the survey (top quartile).

VP 6.9 Customer Confident that Utility Can Perform Remote Meter Diagnostics

Benefit Category
Customer Satisfaction

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
The customer will be aware of the of utility's ability to perform remote diagnostics and understand whether the issue is the responsibility of the customer or the utility. This awareness could positively impact the satisfaction of the customer.

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Environment outside SmartGridCity™
Troublemen must be dispatched to investigate outages reported by customers. It can take 30 minutes or longer for a troubleman to travel to a premise and determine the party responsible to repair an outage.

Environment within SmartGridCity™
Smart Meters, combined with grid communications capabilities and back office software, allow Call Center agents the ability to remotely determine whether or not an outage is the customer's responsibility to fix or the utility's.

Actions Taken
Both the CCC and DCC have the capability to ping all 23,000 smart meters in Boulder.

Lessons Learned
- The pinging capability is not likely utilized as fully in the SGC pilot as it would be in a full roll out.
- While Call Center and Dispatch employees can take steps to identify whether or not a premise has a pinging capability, no alert that the pinging capability is available for a given premise is routinely provided through the systems they use. About 50% of the premises in Boulder have pinging capabilities, or about 2% of PSCO electric meters. These penetration levels are insufficient to justify large scale process changes in Call Center or Dispatch.
- Pinging capability is not generally as valuable in widespread outages as it is in single premise trouble reports.
- In extremely rare circumstances (<2% of SGC outages), a faulty meter connection block causes an outage for which PSCO is responsible to fix that a meter ping would indicate is a customer's responsibility to fix.
- Learned that this capability is highly valued by customers.

Conclusion
Benefits are likely. A survey of 800 PSCO customers regarding the relative importance of various smart grid benefits, "knowing the responsible party to fix an outage" scored 2nd highest out of 11 benefits measured.

VP 6.10 Customer Feels Empowered to Manage Personal Energy Use

Benefit Category
Customer Satisfaction

Enabling Field System
N/A

Hypothesis
SmartGridCity™ offers many capabilities – dynamic pricing, demand response, and access to detailed usage data, among others – to help customers feel empowered to manage personal energy use.

Environment outside SmartGridCity™
Customers feel they have little influence over their electric bills. They have no provider choice and don't understand the actions they can take to reduce their use and cost.

Environment within SmartGridCity™
Capabilities offered through grid upgrades offer customers increased opportunities to manage personal energy use. It is believed that enhanced ability to control energy use (and cost) will help customers feel more empowered and satisfied with their utility.

Actions Taken
AMI capabilities have been implemented for 23,000 customers in SGC to facilitate time-of-use rates. A survey was completed about customer interest in, and willingness to pay for such capabilities.

Lessons Learned
- As customer electricity options evolve, the importance of customers' utility perceptions to the utility's business model increases.
- 64% of PSCO customers expressed an interest in participating in time-of-use rates.
- To encourage greater customer awareness and involvement in smart grid programs, Marketing will have to allocate resources and effort in communicating the customer and utility's role in the steps necessary to empowering the customer to manage their personal energy use.
- Customers' experience with a capability must be in large enough numbers for a sufficient-enough length of time to measure the impact on perceptions (for example, of increased empowerment).
- Customer usage of personal consumption data falls off rapidly under current rate structures.

Conclusion
Benefits are likely. A survey of 800 PSCO customers indicated that capabilities to help manage energy use and cost scored the highest in importance among all SGC capabilities queried.

VP 6.11 Customer Feels Empowered to use Renewable Energy

Benefit Category
Customer Satisfaction

Enabling Field System
N/A

Hypothesis
SmartGridCity™ capabilities – including demand response, in home devices, and grid communications – enable opportunities to incorporate greater levels of renewable generation. It is thought these capabilities will provide customers with an increased perception of empowerment to manage the environmental impact of their energy use.

Environment outside SmartGridCity™
Customers feel they have little influence over their environmental impact.

Environment within SmartGridCity™
The capabilities required to offer green signaling and control of customer loads is available in SGC.

Actions Taken
Green signaling was not implemented in SGC as a result of issues around its feasibility. A survey of customers that included testing of the concept was completed.

Lessons Learned
- Providing real-time information on renewables mix was impractical in present regulatory environment and could be counterproductive in both environmental impact and cost reduction.
- Relative to other smart grid capabilities and benefits, the interest in this concept was one of the lowest surveyed outside of Boulder (second only to participating in an online green energy community) and below the median even among Boulder customers.
- As customer electricity options evolve, the importance of customers' utility perceptions to the utility's business model increases.
- Customers' experience with a capability must be in large enough numbers for a sufficient-enough length of time to measure the impact on perceptions (for example, of increased empowerment).
- Providing green signals in environments such as entire neighborhoods could potentially provide benefits.

Conclusion
Short-term benefits are unlikely for a macro environment. In addition to the challenges described in VP 3.2 and 3.5, green signaling scored very low in importance compared to all smart grid benefits queried.

VP 6.12 Customer Feels Partnership with Utility Rather Than Dependency

Benefit Category
Customer Satisfaction

Enabling Field System
N/A

Hypothesis
SmartGridCity™ offers many capabilities – dynamic pricing, demand response, and access to detailed usage data, among others – to help customers feel a partnership with their utility rather than dependent upon their utility.

Environment outside SmartGridCity™
Customers feel they have little influence over their utility. They can't use provider choice to register their preferences and perceive that they are dependent on their utility.

Environment within SmartGridCity™
Capabilities offered through grid upgrades offer customers increased opportunities to manage personal energy use. It is believed that enhanced ability to control energy use (and cost) will help customers feel more like a partner with, and less like a dependent of, their utility.

Actions Taken
AMI and smart portal capabilities have been implemented for 23,000 customers in SGC to facilitate time-of-use rates.

Lessons Learned
- As customer electricity options evolve, the importance of customers' utility perceptions to the utility's business model increases.
- Customers' experience with a capability must be in large enough numbers for a sufficient-enough length of time to measure the impact on perceptions (for example, increased partnership).
- A key issue for the utility for building a partnership with the customer is managing expectations.
- Learned that while smart grid technologies can provide the customer with many options, expectations must be properly established and maintained if the customer is to feel partnership with utility.

Conclusion
Benefits are likely based on overall research findings. Capabilities to help manage energy cost scored the highest among all SGC capabilities investigated in a survey of 800 PSCO customers. Customer experience with smart grid capabilities is insufficient to measure impact on partnership perception at the time of this analysis.

VP 6.13 Customer Sees Utility as Progressive and Interested in Customer Well-Being

Benefit Category
Customer Satisfaction

Enabling Field System
N/A

Hypothesis
SmartGridCity™ and future smart grid deployments may indicate to customers its commitment to its community, customers and the environment and consequently improve customer satisfaction.

Environment outside SmartGridCity™
Due to the nature of the electric and gas utility business, Xcel Energy is not a highly environmentally friendly organization.

Environment within SmartGridCity™
Pursuing smart grid upgrades which can lead to environmental improvements and customer well-being, such as reduced customer bills.

Actions Taken
N/A

Lessons Learned
- PSCO has the opportunity to communicate positive investments in smart grid technologies and related benefits. As customers have more time to become comfortable with the systems and understand their benefits, customer overall satisfaction may improve.
- To encourage greater customer awareness and involvement in smart grid programs, Marketing will have to allocate resources and effort in communicating to the customer the environmental and customer benefits available from deployed smart grid technologies.
- PSCO has not taken full advantage of the SGC demonstration project in this manner.

Conclusion
Benefits are plausible. Approximately 88% of SmartGridCity™ participants surveyed rated overall satisfaction with Xcel Energy as 'positive' or 'neutral' while the same figure for PSCO at-large customers is 83%.

VP 6.14 Use Prepaid Programs as a Financial Controlling Tool by Customers

Benefit Category
Customer Satisfaction

Enabling Field System
Advanced Metering Infrastructure

Hypothesis
Prepaid programs enable customers to pay their energy consumption in advance via pay stations located throughout a service area or using an Internet based software. Payment options will provide participants better control of their energy usage/bill and facilitate better management of their bills. High visibility of customer energy usage and remaining account balances will help participants keep from getting behind in their electricity bills and may motivate them to save energy.

Environment outside SmartGridCity™
Utilities deal with a certain segment of customers who regularly have difficulty paying their bills, resulting in costly write-offs for utilities. Under pressure to reduce those write-offs, some utilities established large deposits for new accounts and high fees for disconnections and subsequent reconnections.

Environment within SmartGridCity™
Smart meters report data to the utility on a daily basis, making prepayment a viable option. Prepaid programs allow payment challenged customers to pay as they go without having to make any large deposits in advance. By reviewing their daily energy usage and remaining balance, customers may also feel more conscientious and conservative about their electricity consumption resulting in less energy consumption.

Actions Taken
15-minute interval usage data is being collected and updated to a secure website daily for customers with smart meters.

Lessons Learned
- Contrary to conventional wisdom, customers who use prepaid programs are extremely satisfied with their participation.
- Multiple benefits extend to all customers from such programs, including reduced bad debt, collections and interest expenses.
- 24/7 billing system in order to process ongoing customers' payments as well as near real-time payment process may be necessary to support the prepaid program demand.
- Key factors for prepaid programs success is ease of access to forms of payment such as Internet, kiosks, phone, etc. Infrastructure and capabilities from SmartGridCity™ are suitable for a prepaid program to be implemented in the future.
- Definition of a standard policy for the program including shut offs, debt accounts, repayment plans, etc. helps to set the limits and rules for the program.

Conclusion
Benefits are plausible. External research indicates that it may be possible to achieve up to 12% energy savings in the first year a program is implemented.

VP 7.1 Alternative to Meter Based Business Models

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
The utility may be able to operate different business models than in the past. Where historically the utility has delivered power and charged customers, smart grid technologies can enable alternative business models. These business models are still being envisioned and developed, but smart grid technologies, specifically AMI and Distributed Energy Resources, will likely play a role in any new business models.

Environment outside SmartGridCity™
Meters are located outside of customers' premises and must be read monthly by drive-by or manual meter readers. Saver's Switch or other programs are available to residential or commercial customers respectively that allow the utility to control loads in exchange for payments or rebates.

Environment within SmartGridCity™
Smart meters record interval data and communicate it to the utility automatically. Loads can be controlled with the customer's consent in exchange for rebates or payments through in-home smart devices. Distributed Generation and Storage systems can be monitored and controlled in real time.

Actions Taken
No alternatives to meter-based business models have been implemented within SmartGridCity™.

Lessons Learned
- While a utility considers these new business models, it must also take into account the chance that regulators could require the utility to share the infrastructure or information with other businesses, meaning the utility could be participating in an unregulated market and face tough competition. The utility may be able to manage this issue, but it could be different than existing business models and experience.
- Learned that lack of maturity in the in-home smart device (IHSD) industry precludes many such business models at present.

Conclusion
MetaVu's preliminary analysis of alternative business model-markets indicates that significant opportunities and risks could exist in the future. Given PSCO's existing capabilities with traditional energy delivery, management, conservation and related programs, MetaVu believes that participation and success within alternative business models based on energy data utilization and two-way customer communications is highly plausible. Timing considerations and extent of preparation to enter alternative business model-based markets are strategic corporate decisions and fall outside the scope of SGC. Opportunities will exist for PSCO to develop alternative business models that utilize smart grid technologies.

VP 7.2 Encoding Institutional Knowledge

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
The installation of SmartGridCity™ and the systems within it could codify knowledge that has been historically retained by employees. This could result in making other employees more effective, especially as staff change jobs.

Environment outside SmartGridCity™
Many processes are done specific ways because employees have experience and knowledge. For example, a dispatcher may know the operating range for a given measurement although it is not explicitly written. This can lead to a knowledge gap when the employee moves to a different role and a new employee begins. It may take a long time for the new employee to learn these facts, and mistakes are likely in the interim.

Environment within SmartGridCity™
In SmartGridCity™, some of the nuances are encoded in the systems. For example, the operating range may be part of the software checks being performed and will not require an operator to instinctively know if the asset is out of tolerance.

Actions Taken
Systems that contributed to this capability in SGC include: Geographic Information System (GIS) enhancements, Distribution Monitoring (DM) and Distribution Automation (DA).

Lessons Learned
- A vast amount of institutional knowledge that resides within PSCO employees is not necessarily documented. This increases the time to train new employees when existing people change roles or leave the company, which could become more significant as many employees are approaching retirement age.
- In certain cases, increased automation also requires higher levels of data accuracy versus manual processes (e.g. pole location and customer by phase).
- Learned that SGC capabilities do improve documentation of grid designs and management processes.

Conclusion
Examples of how SmartGridCity™ and smart grid technologies can be used to standardize knowledge and processes include:

- DM system assists in troubleshooting efforts and requires less institutional knowledge. For example, detailed mapping of the distribution grid can be accessed through OpenGrid requiring less experience to fully understand the geography of the grid.
- The engineers estimate peak loading on feeders based on the current on one phase and calculations. Within SmartGridCity™, the actual peak loading is measured and no calculations or technical knowledge is required.
- In the substations, step-down transformers are used so that measurements can be taken at low voltage levels. However the ratios for the step-down transformers are not documented within SCADA and it is the responsibility of the operators to know if the voltages are within acceptable ranges. Using the SmartGridCity™ systems and hardware, the actual voltage can be shown or appropriately scaled, and it is not required to rely on operator knowledge.

VP 7.3 Framework for Integrating Acquisitions

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
SmartGridCity™ could provide valuable experience for understanding how to best integrate the technologies and processes that would accompany an acquisition. This would give Xcel Energy more strategic flexibility in pursuing acquisitions because the subsequent integration would be less intrusive and expensive.

Environment outside SmartGridCity™
Past mergers and acquisitions by the entities that make up Xcel Energy have been slow and expensive, such as the merger between NSP and New Century Energies.

Environment within SmartGridCity™
SmartGridCity™ provides an experience base and set of documentation to facilitate integration of acquisitions. It was envisioned that the efforts required to integrate a brand new set of systems in SmartGridCity™ would be similar to those of acquired company.

Actions Taken
Examples of processes and capabilities improved within SGC include those found in distribution capacity planning, DR program designs and distribution engineering, to name a few.

Lessons Learned
- Since there was minimal legacy data imported as part of the SGC demonstration project, experience in importing legacy data from an acquired grid's operations is limited.
- The framework for maximizing process integration was not developed as part of the SGC demonstration project because of the low likelihood of an Xcel Energy acquisition in the near-term.
- Learned that the improvement in processes and capabilities that grid modernization offers could conceivably provide benefits when integrating distribution grids of acquired entities.

Conclusion
The potential for having an acquisition integration framework based on the SmartGridCity™ experience does not appear to MetaVu to be overly significant. MetaVu expects that if Xcel Energy were to acquire another utility, the company would want to integrate the systems as much as possible. Due to the fact SmartGridCity™ systems run in an isolated environment, and that utility distribution grids are highly heterogeneous in composition and character, the demonstration project experience may not be directly applicable to a utility acquisition.

VP 7.4 Higher Asset Utilization

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
By having better visibility and control of distribution loads, Xcel Energy can maximize the use of its generation facilities and contracts. This will reduce its desirability as an acquisition target. If the assets were vastly underutilized, a competitor or other utility may want to purchase Xcel Energy and use increased profits by improving asset utilization.

Environment outside SmartGridCity™
Real time load data is available for the substation and feeders, but there is no real-time information about the distribution system or customer loads. The utility can control some loads, including the residential Saver's Switch program which turns off customers' air conditioning compressors.

Environment within SmartGridCity™
With real-time visibility and control through programs such as Demand Response (DR), the utility will be able to reduce the difference between demand peaks and normal usage, and thereby increase generation asset utilization. This reduction between peak and normal times will require less excess capacity for safety margins.

Actions Taken
N/A. Existing PSCO asset utilization is not significantly underutilized relative to other utilities and therefore would not be a contributing factor in a potential acquisition.

Lessons Learned
- Underutilized distribution assets would never be enough reason for one utility to acquire another. However, if there is excess generation capacity either through owned plants or from contracts, it may make a utility an acquisition target.
- With the exception of DR and generation, smart grid systems were not found to significantly improve asset utilization.
- The DR program instituted in SGC is similar to the Saver's Switch program. Data from the pilot program will be available in 2012 and beyond to confirm any differences. MetaVu expects the incremental capabilities of Demand Response over Saver's Switch will not be significant enough to materially change utilization levels to the point where it will affect takeover strategies.
- Use of sufficiently greater consumption data along with analytics developed as part of the SGC project showed that existing Saver's Switch locations with defective equipment, and that they could be remotely identified, allowing for targeted maintenance.

Conclusion
MetaVu believes the strategic benefit of this value proposition is low. Xcel Energy uses sophisticated algorithms to predict demand based on historical loads, new developments, consumption trends and more. In addition, there is accurate load data available from nearly all substations in PSCO. MetaVu does not feel that the additional distribution grid information will make a material difference and significantly change capacity utilization.

VP 7.5 Higher Share Price through Commitment to Smart and Green Technologies

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
The SmartGridCity™ demonstration project and other smart grid activities will demonstrate to stock analysts and other relevant parties that Xcel Energy is committed to maximizing overall stakeholder value which will increase share price.

Environment outside SmartGridCity™
Xcel Energy has invested or participated in many projects that demonstrate its commitment to all stakeholders. These include high levels of wind-sourced energy, a battery storage project, and others.

Environment within SmartGridCity™
The SmartGridCity™ demonstration project was an illustration of Xcel Energy's commitment to preparing for the future while addressing the needs of many different stakeholders. The perception on the link between environmental performance and stock valuation is mixed.

Actions Taken
N/A. The exact impact on share price is dependent on the specific mix selected.

Lessons Learned
- Knowledge and experience gained from SmartGridCity™ may improve operations or investment strategies and increase returns to shareholders.
- As with other utility investments regulatory alignment is critical to achieving desired results, particularly since regulatory policies are still evolving.
- Learned that the proper mix of technologies and implementation strategies are likely to result in favorable economic benefits.

Conclusion
MetaVu does not feel that the SmartGridCity™ project will significantly increase share price because of the demonstration project. There are many other corporate characteristics that have immediate and direct influence on share price versus integrating smart gird systems and green technologies. MetaVu believes that the "commitment to stakeholders" will not significantly impact share prices in the short-term.

VP 7.6 Relationship with Regulators

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
With the experience gained from SmartGridCity™, PSCO can help shape state and federal policies and regulations. This could improve relationships with regulators and potentially lead to more favorable treatments.

Environment outside SmartGridCity™
PSCO has invested or participated in many renewable energy and carbon abatement projects. These include high levels of wind-sourced energy, a battery storage project, and others

Environment within SmartGridCity™
The SmartGridCity™ demonstration project, in part, explored the potential beneficial environmental impact from smart grid systems and customer facing programs. This is an additional environmental project in PSCO's portfolio.

Actions Taken
N/A. This shared vision may reduce regulatory risk associated with stranded costs.

Lessons Learned
- Because PSCO operates in a regulated environment, improved relationships with regulators that may result from grid modernization might help increase a utility's opportunity to earn its authorized rate of return.
- PSCO can use the SmartGridCity™ experience to provide details for testimony or other discussions to support investment and operational decisions.
- Learned that early and frequent interaction with regulators throughout the grid modernization development process is necessary to create a shared vision for the grid and associated value, as well as develop the most effective regulatory framework.

Conclusion
With the experience gained in SmartGridCity™, PSCO has the information necessary to develop a business case for regulatory review while identifying smart grid investments and how such investments will benefit customers and grid operations.

VP 7.7 Visible Activity in Green Technologies

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
If PSCO takes positive, visible steps to demonstrate its commitment to green technologies, relationships with customers and the community could be improved. This could lead to less resistance and opposition, and provide PSCO with more flexibility in meeting its corporate goals.

Environment outside SmartGridCity™
PSCO has invested or participated in many renewable energy and carbon abatement projects. These include high levels of wind-sourced energy, a battery storage project, and others.

Environment within SmartGridCity™
The SGC demonstration project was an illustration of PSCO's commitment to green technologies. There were many aspects of the demonstration project that were designed to reduce energy usage or carbon dioxide equivalent (CO2e) emissions.

Actions Taken
As implemented in SGC, systems such as power factor improvement and conservation voltage reduction have shown to have positive environmental impacts such as fuel efficiency.

Lessons Learned
- Many SGC capabilities offer direct customer participation opportunities, such as DR, time-of-use pricing and increased access to energy use data, may improve relationships with the customer and community-at-large.
- PSCO has not taken full advantage of the SGC demonstration project in this manner.
- Learned that the SmartGridCity™ demonstration project has contributed to PSCO's position as an environmental leader.

Conclusion
Improved reputation among the community could be moderately beneficial through lower resistance to regulatory proposals. If customers and other community members are satisfied with the products and services that PSCO provides, including those provided in an environmentally responsible manner, they may be less critical of the utility.

VP 7.8 Integration of New Technologies into Utility Systems

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
The SmartGridCity™ demonstration project experience will help PSCO determine how to implement and integrate new technologies to drive fundamental changes to the business.

Environment outside SmartGridCity™
Power is generated at centralized facilities, transmitted to the substations and distributed throughout the grid. Power flow on the distribution network is primarily unidirectional, from the substation to the customer. Premises with distributed generation systems are mostly treated as normal loads with reduced demand and consumption.

Environment within SmartGridCity™
Increased information will allow the utility to monitor power flows more accurately, and enable the utility to move away from the vertically integrated model. Power can be sourced from a variety of facilities, including traditional centralized generation plants as well as distributed generation and storage systems. Distributed generation sites are not just a reduced load, but a partner in delivering energy.

Actions Taken
The implementation of a ubiquitous communications infrastructure serving both overhead and underground facilities is a key factor to SGC and all other future activities.

Lessons Learned
- Systems changes required to integrate SGC technologies are known to many of the relevant employees and business areas.
- The data gathered from smart grid technologies can be used to understand how the business model and operations could change and prepare the utility for the future.
- Learned that the environment SGC created is ideal for technology and implementation testing that will continue to facilitate the integration of new technologies into utility systems and that personnel are generally very accepting of the new technologies.
- Legacy and new technologies will need to be integrated and function seamlessly during implementation.

Conclusion
The SmartGridCity™ experience could be valuable in integrating new systems and processes into the existing business as the utility prepares for new opportunities. The primary example of SGC technologies that have been leveraged into utility processes and systems is the INDE BUS architecture.

VP 7.9 Carbon Management Technologies to Improve Carbon Output

Benefit Category
Strategic

Enabling Field System
N/A

Hypothesis
The SmartGridCity™ systems could be used to track, measure and manage carbon dioxide equivalent (CO2e) emissions and related characteristics.

Environment outside SmartGridCity™
CO2e emissions are measured at the generation stations. Some emissions changes are difficult to attribute to specific programs, specifically residential programs because there is insufficient data.

Environment within SmartGridCity™
Additional data about customer consumption patterns and response to smart grid programs can be used to attribute emissions reduction to specific programs. SmartGridCity™ provides the capabilities to track reductions of overall consumption or loads shifted to different time periods. These capabilities can be used to evaluate emissions reduction programs.

Actions Taken
As implemented in SGC, systems such as power factor improvement and conservation voltage reduction have shown to have positive environmental impacts such as fuel efficiency.

Lessons Learned
- Without the customer-level CO2e emission tracking capabilities provided by SGC, many program benefits would be estimated using basic estimation tools, leading to sub-optimal investment strategies.
- PSCO's recently implemented environmental management information system (EMIS) was designed to track emissions for all operating sources.
- Learned that SmartGridCity™ systems provide the capabilities to track reductions of overall consumption or loads shifted to different time periods.

Conclusion
Benefits plausible, the effectiveness of existing tools and processes are sufficient to prepare the utility to measure and manage CO2e emissions and related characteristics. Programmatic reporting benefits may be utilized at the customer-level that would enhance programs that result in carbon dioxide equivalent (CO2e) emissions reduction.

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BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

DIRECT TESTIMONY

OF

PAUL ALVAREZ

ON BEHALF OF

ENVIRONMENTAL DEFENSE FUND

DOCKET NO. 15-WSEE-115-RTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul Alvarez. My business address is PO Box 150963, Lakewood, CO 80215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the President of the Wired Group, a consultancy specializing in the optimization of distribution utility businesses and operations as they relate to grid modernization, demand response, energy efficiency, and renewable generation.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am testifying on behalf of the Environmental Defense Fund (EDF).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports EDF witness Munns' testimony that additional research and stakeholder participation is reasonable in response to Westar Energy's application to establish specific rates for customers who own Distributed Generation (DG).

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. After presenting my qualifications, I will describe how regulators in other states have addressed utility requests for changes in rate design to deal with increases in distributed solar generation, including both typical processes and various outcomes. I will explain the wide variation in regulatory outcomes by introducing the factors that impact the value of distributed solar generation, which is a critical component to be considered in related rate design changes. I will use these factors to identify the data required to design appropriate rates specific to distributed generation owners, highlighting the opportunity to use such data to address many potential subsidy issues within the residential class, and between customer classes, that likely exist today. Finally, I will describe the potential consequences of implementing rates specific to distributed generation owners without adequate research and stakeholder engagement.

II. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now Android/Google), Baxter Healthcare, Searle Pharmaceuticals (now owned by Pfizer), and Option Care (now owned by Walgreens). My combined aptitude for finance and marketing were well suited for innovation and product development, leading to my first job in the utility industry in 2001 with Xcel Energy, one of the largest investor-owned utilities in the U.S. At Xcel Energy I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential, commercial, and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance (including distributed solar incentive program design). As product development manager I learned the economics of traditional monopoly ratemaking and associated utility economic incentives, as well as the impact of self-generation, energy efficiency, and demand response on utility shareholders and management decisions. I also learned a great deal about utility program impact measurement and verification (M & V).

I left Xcel Energy to lead the utility practice for boutique sustainability consulting firm MetaVu in 2008, where I utilized my M & V experience to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are the only two comprehensive, unbiased evaluations of smart grid deployment performance completed to date. The results of both were part of regulatory proceedings in the public domain and include an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010, and an evaluation of Duke Energy's Cincinnati deployment for the Ohio Public Utilities Commission in 2011.

In 2012 I started the Wired Group to focus exclusively on distribution utility businesses and operations as they relate to grid modernization, demand response, energy efficiency, and renewable generation. Wired Group clients include utilities, regulators, consumer and environmental advocates, and industry associations. In addition I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I have also taught at Michigan State University's Institute for Public Utilities, where I educated new regulators and staff on grid modernization and distribution utility performance measurement.

Finally, I am the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment, a book that helps laypersons understand smart grid capabilities, optimum designs, and post-deployment performance optimization. I received an undergraduate degree in Finance from Indiana University's Kelley School of Business in 1983, and a master's degree in Management from the Kellogg School at Northwestern University in 1991. My Curriculum Vitae is attached as Appendix A to this testimony.

Q. WHAT IS YOUR EXPERIENCE TESTIFYING BEFORE STATE UTILITY REGULATORY COMMISSIONS?

A. I have testified before state utility regulatory commissions on the issues of grid modernization, demand response, energy efficiency, and renewable generation in Colorado, Maryland, and Ohio.

III. OTHER STATES' ACTIONS ON RATES SPECIFIC TO DISTRIBUTED GENERATION

Q. CAN YOU DEFINE "RATES SPECIFIC TO DISTRIBUTED GENERATION?"

A. Most utilities offer a variety of rate designs from which customers within a class may choose. Increasingly, utilities are attempting to restrict distributed generation owners' rate choices to a limited number designed specifically for distributed generation owners, as Westar Energy is attempting to do in the present rate case.

Q. WHY ARE UTILITIES ASKING TO IMPLEMENT RATES SPECIFIC TO DISTRIBUTED GENERATION OWNERS?

A. Distributed generation reduces utility sales volumes, and utilities are understandably concerned about the associated reduction in revenues. So as distributed generation grows, more utilities are asking regulators for permission to implement rates that stem revenue erosion. Utilities also allege that rates specific to distributed generation owners are necessary to control cost shifts to customers without distributed generation. But utility-sponsored solutions to this issue also have the effect of slowing the adoption of distributed generation, and are therefore controversial. Distributed generation advocates say that specific rates should not be imposed to recover costs without considering the associated benefits that distributed generation provides.

Q. ARE YOU AWARE OF OTHER STATES' RECENT ACTIVITIES RELATED TO RATE DESIGNS SPECIFIC TO DISTRIBUTED GENERATION?

A. Yes. In the past few years regulators in Arizona, California, Idaho, and Louisiana have concluded proceedings dedicated to distributed generation-specific rate design. These cases have been processed outside general rate cases either through legislative direction (California, Louisiana) or because utilities' proposed rate changes are technically categorized as revenue neutral and allowed to proceed as single issue ratemaking proceedings (Arizona, Idaho). Rates specific to distributed generation are also an issue in the broader regulatory reform effort currently underway in New York, which has been characterized by a high level of informal stakeholder engagement.[1] In addition, informal initiatives are underway in several states with the support of regulatory Staff to consider how to manage

[1] Reforming the Energy Vision. New York Public Service Commission. Case 14-M-0101 initiated April 24, 2014.

distributed generation within the broader context of the changing utility business models, including Hawaii, Massachusetts, and Minnesota. Finally, almost every traditional utility rate case now being filed includes requests for higher fixed charges and/or specific rates for distributed generation owners in response to the revenue threat posed by distributed generation.

Q. WHAT PROCESSES ARE TYPICALLY EMPLOYED IN PROCEEDINGS DEDICATED TO DISTRIBTED GENERATION-SPECIFIC RATES?

A. In California (Assembly Bill 327) and Louisiana (Act 653), legislation directed regulators to establish rates and rules to compensate distributed generation owners for the energy they produce. In Arizona and Idaho, utilities (Arizona Public Service and Idaho Power) applied for permission to institute rates specific to distributed generation. In all these cases regulators established issue-specific dockets to allow impacted stakeholders to participate in the process.

Q. CAN YOU SUMMARIZE SOME OF THE APPROACHES ADOPTED BY COMMISSIONS THAT HAVE CONSIDERED RATES SPECIFIC TO DISTRIBUTED GENERATION?

A. Summarizing is difficult, as these proceedings have resulted in a wide variety of conclusions. For example, Idaho regulators determined that no special rates should apply to distributed generation owners, though they did agree that credit for energy produced by distributed generation systems should be limited to the owner's energy consumption.[2] In Arizona, regulators determined that a small fixed charge – $0.70 per kW of distributed generation capacity per month for existing systems, $3.00 per kW per month for future systems – was appropriate to

[2] Idaho Public Utilities Commission, Case No. IPC-E-12-27, Order No. 32846. July 3, 2013.

address the difference between solar system costs and benefits in that state, at least as an interim measure before the next APS rate case.[3]

The Arizona Commission Corporation's order in the case was particularly informative regarding the issue of cost shifting related to distributed generation. The order noted, "APS' application focuses on the costs associated with increasing levels of DG installations. However, integral to the discussion of DG is the question of what *value* DG offers to APS' electric system and thereby to the customers serviced by that system."[4] I observe that Westar Energy's request to implement rates specific to distributed generation owners suffers from the same omission; in particular, Dr. Faruqui's testimony does not consider the value of solar in avoiding energy purchases during high-cost periods. The importance of quantifying this value is critical to the design of rates specific to distributed generation, and the need is underscored by the Southwest Power Pool's recent (March 1, 2014) transition to a day-ahead energy market. In a day-ahead energy market, distributed generation will make more energy available for Westar Energy to sell while reducing the price of energy it must acquire; both are good for its ratepayers and any actions that might restrict distributed generation deployment should consider this value.

In a California PUC docket established in response to the ratification of AB 327, regulators determined that the rates at which distributed generation owners should be compensated were sufficiently important to justify conducting

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[3] Arizona Commerce Commission, Docket No. E-01345A-13-0248, Decision No. 74202. December 3, 2013

[4] Ibid, page 7.

cost-benefit analyses at the circuit level, whereby rates would vary to serve as price signals to prospective distributed generation owners.[5] In the California approach, these price signals are intended to encourage distributed generation on some circuits (to avoid transmission bottlenecks or substation upgrades, for example) while discouraging it on others (in cases where such economic opportunities were not available). The California PUC's approach is intended to ensure the most cost-effective deployment of distributed generation, and the New York commission appears to be headed down the same path in its aforementioned regulatory reform proceeding.

In Louisiana, though Staff recommended the implementation of rates specific to distributed generation owners (including an increase in fixed fees), the Louisiana PSC did not permit the implementation of such rates.[6] However the PSC did elect to reduce any potential impact of distributed generation by limiting the capacity from which each utility is required to purchase energy at 1/2% of each utility's peak demand. I understand that less than 300 Westar Energy customers own solar systems;[7] I estimate the associated amount of solar capacity among Westar Energy's customers to be far below this very low limit deemed by the Louisiana commission to be acceptable. Moreover, I note Westar Energy fails to quantify the dollar amount of the alleged subsidy to distributed generation owners in its rate case.

[5] California Public Utilities Commission. Order Instituting Rulemaking Regarding Policies, Procedures, and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. Rulemaking 14-08-013. August 14, 2014.

[6] Louisiana Public Service Commission. Net Energy Metering Rule-making. Docket R-27558. November 9, 2005.

[7] Springe, David. Interview with Andy Marso, KHI News Service. June 11, 2015. Posted at www.kcur.org.

Q. WHAT DOES AVAILABLE RESEARCH SAY ABOUT THE COSTS AND BENEFITS OF SOLAR SYSTEMS?

A. The results of "value of solar" systems research varies with the types of economic benefit taken into account. Some utilities, like Arizona Public Service[8] and Public Service Company of Colorado[9] offer studies indicating that solar system value is less than the retail rates at which energy from distributed generation is reimbursed; other utilities like Austin Energy[10] and solar energy industry associations like TASC[11] offer studies indicating that solar system value is greater than retail rates. But perhaps of more practical value is a research review completed by the Interstate Renewable Energy Council specifically for regulators which recommends that all of the following sources of economic value be investigated when considering rates specific to distributed (solar) generation:

- Avoided energy costs
- Line losses avoided when generation is sited next to loads
- Some amount of generation capacity provided from solar systems in aggregate
- Avoided transmission and distribution capacity upgrades
- Distribution grid support (notably, voltage and possibly power factor)

[8] SAIC Energy, Environment & Infrastructure LLC. *2013 Updated Solar PV Value Report.* May 10, 2013.

[9] Xcel Energy. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System.* Docket 11M-426E. May 23, 2013.

[10] Clean Power Research LLC. *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin.* March 17, 2006 and subsequent updates.

[11] Crossborder Energy. *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service.* May 8, 2013.

- Distributed generation as a long-term hedge against fuel price volatility
- Reductions in market prices for energy (and perhaps capacity in Kansas' future)
- Improvements in reliability and resiliency
- Reduced environmental regulation compliance costs
- Local employment and economic development.[12]

Q. DOES DR. FARUQUI TAKE INTO ACCOUNT ANY OF THESE POTENTIAL BENEFITS IN HIS TESTIMONY ON BEHALF OF WESTAR ENERGY REGARDING THE UTILITY'S PROPOSAL FOR RATES SPECIFIC TO DISTRIBUTED GENERATION OWNERS?

A. No.

IV. DATA REQUIRED FOR ADVANCED RATE DESIGN PROCESSES

Q. CAN YOU EXPLAIN WHY A STATE-SPECIFIC INQUIRY IS INDICATED EACH TIME RATES SPECIFIC TO DISTRIBUTED GENERATION OWNERS ARE PROPOSED?

A. First, each utility's avoided energy costs are different; for example, some utilities are more exposed to natural gas price volatility, while others are more exposed to coal costs or day-ahead energy market prices than others. Second, solar resources vary by geography; note that solar resource maps from National Renewable Energy Laboratories indicate solar resources in eastern Kansas are better than those available to more than half the US population.[13] Third, different studies use different assumptions for timeframes, discount rates, and other financial

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[12] Interstate Renewable Energy Council, Inc. *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* October, 2013.

[13] Derived from average annual direct normal irradiance map available at http://maps.nrel.gov/prospector

projection inputs. Finally each geography's customer base is different, marked by different customer type ratios (agricultural vs. industrial vs. commercial vs. residential), different customer loads (for example, the relative penetration of central air conditioning or electric heating among residential customers), and different load shapes and capacity factors (the ratio of average demand to peak demand).

Q. YOUR LAST OBSERVATION SUGGESTS THERE MAY BE ADDITIONAL REASONS TO LOOK MORE CLOSELY AT THE EQUITY OF RATE DESIGN BEYOND THE IMPACT FROM DISTRIBUTED GENERATION.

A. Yes, I believe there are. Consider central air conditioning, which is a significant driver of utility investment in generation, transmission, and distribution capacity. Business and low-income advocates have long claimed that residential customers with central air conditioning have been subsidized by these advocates' constituents; recent efforts by many regulators to correct this situation through inclining block rates seem to validate these claims.

Q. WHY DO YOU BELIEVE OTHER POTENTIAL SOURCES OF COST SHIFTING WITHIN THE RESIDENTIAL CLASS HAVE NOT PROMPTED UTILITY ACTION TO THE DEGREE THAT DISTRIBUTED GENERATION HAS?

A. Distributed generation advocates believe, with some justification, that the type of residential electric equipment they support, solar PV systems, is being unfairly singled-out and targeted by utilities as a source of cost shifting that requires immediate attention. They cite that other types of residential electric equipment could be argued to also shift costs within the residential class, such as air central conditioning or electric heat. However, the addition of these kinds of loads, particularly air conditioning, have not been challenged by utilities on the basis of ratepayer equity, nor have they been aggressively cited by the industry as a reason to impose onerous rate designs that will impede adoption of solar by customers. One explanation is that central air conditioning and electric heat increase electric loads, utility investment, and utility profits, while distributed generation reduces electric loads, utility investment, and utility profits.

Q. WHAT DO YOU RECOMMEND THE COMMISSION CONSIDER AS IT REVIEWS THE DISTRIBUTED GENERATION-SPECIFIC RATES WESTAR ENERGY HAS PROPOSED?

A. I recommend the Commission reject Westar Energy's proposal for rates specific to distributed generation for now, taking the discussion of rate design related to distributed generation out of the rate case to a broader, less formal proceeding where more stakeholders can participate. This could be a statewide forum, with time parameters, where the issue can be addressed for all utilities. A distinct, informal proceeding would offer time for research and stakeholder input that would result in a more optimum Commission decision on needed rate design changes.

Q. HOW DO YOU SUGGEST THE COMMISSION RESEARCH THE COST SHIFT ISSUE?

A. I understand Westar Energy has installed almost 100,000 smart meters for residential customers. These meters collect data that could prove very valuable in quantifying all aspects of system use, costs, and benefits within the residential class. With such a large sample size, which I understand is growing every day, Westar Energy has the data the Commission could use to investigate all potential source of cost shifting – not just the impact of the residential customer who generates some of his own electricity – with a high degree of accuracy and confidence. This data includes:

- Hourly production profile data for solar systems in eastern Kansas
- Hourly usage profile and peak demand data for residential customers with central air conditioning
- Hourly usage profile and peak demand data for residential customers with pools or hot tubs
- Hourly usage profile and peak demand data for residential customers with electric heat
- Hourly usage profile and peak demand data for residential customers without central air conditioning, pools/hot tubs, or electric heat
- Hourly usage profile and peak demand data for low-use customers
- Hourly usage profile and peak demand data for low income customers
- Hourly usage profile and peak demand data for residential square footage (e.g. urban apartments, suburban homes)

This data could be analyzed in conjunction with usage profile and peak demand data long available from larger agricultural, commercial and industrial customers' meters to accurately and confidently measure the relative impacts of various customers' equipment and operations on generation, transmission, and distribution systems. In fact, the detailed data made available by smart meters could be used to establish a full catalog of customer types distinguished by load shape and characteristics. In addition to rate design, this data could be used for integrated resource planning, for preparation of Kansas' response to the Environmental Protection Agency's Clean Power Plan, transmission and distribution system planning, demand response program potential and impact studies, and energy efficiency program potential and impact studies to name just a few.

VI. <u>POTENTIAL CONSEQUENCES OF INADEQUATE RESEARCH AND INPUT</u>

Q. WHAT COULD HAPPEN IF THE COMMISSION MAKES A DECISION WITHOUT THE RESEARCH AND STAKEHOLDER INPUT YOU SUGGEST?

A. While it is certainly possible the Commission could make an appropriate decision without the research and stakeholder input I recommend, I think it unlikely due to the number and variability of associated determinants presented in this testimony. If the Commission makes an inappropriate decision on this issue, a number of unintended and potentially significant consequences could result.

If the solar-specific rates are approved in a way that sets high rates for entry and under-estimates solar system benefits:

- Solar generation that could have delivered value to all Westar Energy customers will not be installed

- The option for Westar Energy customers to install solar systems will be needlessly restricted

- An equitable opportunity for economic development in Kansas through the solar energy industry will be missed

On the other hand, if the Commission does not fairly assign costs to customers who own distributed generation, all Westar Energy customers who do not own distributed generation will pay higher prices for electric service than they otherwise would have paid.

VII. <u>CONCLUSION</u>

Q. COULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Certainly. In summary, I do not believe Westar Energy has completed the necessary research to craft a fair rate design specific to distributed generation owners. Further, the data to accurately and confidently measure the impact of various types of customer equipment on generation, transmission, and distribution systems is now readily available from smart meters. And finally, the consequences of setting the wrong precedent at this time could be significant and have unintended consequences. For all these reasons, it seems appropriate that the Commission remove the discussion of rate design specific to distributed generation from the rate case and place it in a broader, less formal proceeding offering opportunities for research and stakeholder input.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Appendix A: Curriculum Vitae of Paul J. Alvarez MM, NPDP

3667 Evergreen Pkwy, Ste. E, Evergreen, CO 80439 palvarez@wiredgroup.net 720.308.2407

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement in 2001. He has since designed renewable portfolio standard compliance and distributed generation incentive programs. These experiences led to unique projects involving the measurement of grid modernization benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience) and costs, which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving utilities, regulators, staffs, advocates, and other stakeholders.

Research Project and Thought Leadership

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Best Practices in Grid Modernization Capability Optimization: Visioning, Strategic Planning, and New Capability Portfolio Management. Top-5 US utility; client confidential. 2014.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. First edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 327 pages. 2014.

Noteworthy Publications

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Notable Presentations

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators.* St. Louis. November 13, 2011.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando. November 17, 2013.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando. November 18, 2013.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16.

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Keynote. Toronto, Canada. January 23.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us.* Chicago. September 26, 2012.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master of Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Accounting, Finance, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Marketing and Finance.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

STATE OF COLORADO
COUNTY OF Jefferson

VERIFICATION

Paul Alvarez, being duly sworn upon his oath, deposes and says that he is a designated expert witness for the intervenor Environmental Defense Fund, that he has read and is familiar with the foregoing direct testimony, and that the statements contained therein are true and correct to the best of his knowledge, information and belief.

Paul Alvarez

Subscribed and sworn to before me this 8th day of July, 2015.

Notary Public

ERIC K OLSEN
Notary Public
State of Colorado

My appointment expires: 1/27/2016

Gaithersburg

December 8, 2014

David J. Collins
Executive Secretary
Maryland Public Service Commission
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, MD 21202-6906

Re: Case No. 9361

Dear Executive Secretary Collins,

Enclosed for filing in the above reference matter are the original and seventeen (17) copies of the **PUBLIC** Direct Testimony of Paul Alvarez on behalf of the Coalition for Utility Reform. The City of Gaithersburg is jointly sponsoring this testimony. The Coalition's response to Joint Applicants' Data Request 1 is provided in an exhibit following Mr. Alvarez's testimony.

Please feel free to contact our offices should you have any questions regarding this filing.

Respectfully submitted,

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

IN THE MATTER OF THE MERGER	*	
OF EXELON CORPORATION AND	*	
PEPCO HOLDINGS, INC.	*	CASE NO. 9361
	*	

DIRECT TESTIMONY

OF

PAUL J. ALVAREZ

FOR THE COALITION FOR UTILITY REFORM

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Paul J. Alvarez. My business is served by post office box 150963, Lakewood, Colorado, 80215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the President of Alvarez and Associates LLC, which does business as the Wired Group.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I am testifying on behalf of the Coalition for Utility Reform ("The Coalition") regarding Exelon Corporation's proposed acquisition of distribution utilities serving the citizens of Maryland. My testimony will support the Coalition's assertion that the merged entity's return on equity should be based in significant part on the achievement of outcomes-based performance metrics if the proposed merger is to be in the public interest.

Q. **PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.**

A. My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now owned by Google), Baxter Healthcare, Searle Pharmaceuticals (now owned by

Pfizer), and Option Care (now owned by Walgreens). My combined aptitude for finance and marketing were well-suited for innovation and product development, leading to my first job in the utility industry in 2001 with Xcel Energy, one of the largest investor-owned utilities in the U.S. At Xcel Energy I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential and commercial and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance. Here I learned the economics of traditional monopoly ratemaking and associated utility economic incentives. I also learned a great deal about energy efficiency and demand response program performance measurement and verification (M & V).

In 2008 I left Xcel Energy to establish a utility practice for boutique sustainability consulting firm MetaVu, where I utilized my M & V experience to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are the only two comprehensive, unbiased evaluations of smart grid deployment performance completed to date. The results of both were part of regulatory proceedings in the public domain and include an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010 (11A-1001E), and an evaluation of Duke Energy's Cincinnati deployment for the Ohio Public Utilities Commission in 2011 (10-2326-GE-RDR).

In 2012 I started the Wired Group to focus exclusively on distribution utility performance measurement and improvement. Wired Group clients include utilities, regulators, consumer and environmental advocates, and industry associations. In addition I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach a course on electric technologies, markets, and policy; I also teach at Michigan State University's Institute for Public Utilities, where I educate new regulators and staff on distribution utility performance measurement and the smart grid.

Finally, I am the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment, a book that makes a case for performance-based compensation for distribution utilities. I received an undergraduate degree from Indiana University's Kelley School of Business in 1983, and a master's degree in management from the Kellogg School of Management at Northwestern University in 1991.

Q. **HOW IS YOUR TESTIMONY ORGANIZED?**

A. I will begin by describing how the Maryland General Assembly has defined the public interest as it relates to electric generation and distribution through legislation over the past decade. I will then identify several aspects of Exelon's business interests that conflict with many aspects of the public interest, describing how Exelon has historically (and rationally) prioritized its business interests over the public interest in the past. I will also cite examples indicating that the current utility compensation model has failed the public interest. Finally, I will describe a performance-based compensation model that would better align the interest of the merged entity with the public interest in Maryland, and recommend that the Public Service Commission (MPSC) condition merger approval, should it decide to grant such approval, in part on the implementation of such a compensation model.

Importantly, please note that my testimony is not meant to suggest that performance-based compensation should be the only requirement the MPSC must assess in order for the merger to be in the public interest, nor should my testimony be construed to imply that performance-based compensation alone can assure the merger is in the public interest.

II. THE MARYLAND GENERAL ASSEMBLY HAS DEFINED THE PUBLIC INTEREST AS IT RELATES TO ELECTRIC GENERATION AND DISTRIBUTION

Q. WHAT ROLE DOES THE PUBLIC INTEREST PLAY IN A MERGER APPLICATION SUBMITTED BY A REGULATED UTILITY IN MARYLAND?

A. Public Utility Article 6-105 governs the MPSC's review of regulated utility merger applications. Paragraph 3(i) of subsection g states: "If the Commission finds that the acquisition is consistent with the public interest, convenience, and necessity, including benefits and no harm to consumers, the Commission shall issue an order granting the application." Paragraph 3(ii) continues: "The Commission may condition an order authorizing the acquisition on the applicant's satisfactory performance or adherence to specific requirements." Subsection g goes on to state the MPSC can deny such applications if it does not find the acquisition is in the public interest (Paragraph 4), and places the burden of proof on the applicant (Paragraph 5). My testimony will focus on the public interest aspect of the MPSC's merger application review, and recommends the MPSC use its authority to make any merger approval conditional by finding performance-based compensation models a requirement in the public interest.

Q. HOW HAS THE MARYLAND GENERAL ASSEMBLY DEFINED THE PUBLIC INTEREST AS IT RELATES TO ELECTIC GENERATION AND DISTRIBUTION IN MARYLAND?

A. The Maryland General Assembly has seen fit to pass a great deal of legislation in the public interest as it relates to electric generation and distribution in Maryland in the past decade:

- *Renewable Generation.* In 2004, Governor Ehrlich signed HB 1308, which amended the Public Utilities Article *of the Maryland Code* to add *Sections 701-713* that established renewable energy portfolios for public utilities. Of particular value in the public interest are the favorable carbon reduction and environmental stewardship characteristics of renewable generation.
- *Energy Efficiency (EmPower Maryland Energy Efficiency Act of 2008).* This legislation set a statewide standard of a 15 percent reduction in per capita electricity consumption and demand from 2007 to 2015. Of particular value in the

public interest are the favorable carbon reduction and environmental stewardship attributes of energy efficiency.

- *Distributed Energy Resources (Facilitated through the addition of Chapter 9, "Small Generator Interconnection Standards" to Title 20, Subtitle 50 of the Maryland Code).* In 2007, the legislature passed SB 595, which required the creation of a small generator interconnection working group. The Small Generator Interconnection Standards Rule (COMAR 20.50.09) became effective as of June 2008 and created standards for interconnection in line with other national best practices. Of particular value in the public interest are the favorable customer choice attributes associated with distributed energy resources, as well as carbon reduction and environmental stewardship attributes (to the extent that distributed energy resources are often renewable, such as with photovoltaic solar panels).
- *Greenhouse Gas Emissions Reduction Act of 2009.* The Act requires Maryland to reduce greenhouse gas emissions 25 percent by 2020, relative to 2006 levels. (Maryland is one of 10 states currently participating in the Regional Green House Gas Initiative, a multi-state cap-and-trade program meant to reduce carbon dioxide emissions from electricity generating plants.)
- *Electric Service Quality and Reliability Act of 2011.* The reliability performance of PHI utilities in Maryland, and Pepco in particular, has been very poor. In fact, Montgomery County and Prince George's County have experienced some of the worst reliability performance in the U.S. since 2006.[1] Pepco's reliability on so-

[1] *See* Report of the Montgomery County Pepco Work Group. April 20, 2011. Pages 6-9.

called "sunny days" was so poor, and the consequences so severe, that it prompted the Montgomery County Council and others to urge the MPSC to open an investigation into the matter. The Commission did so, and discovered that Pepco's reliability was in the lowest quartile in the nation for five years in a row. That finding led to the introduction and passage of the Electric Service Quality and Reliability Act of 2011. The Act imposed monetary penalties on Maryland utilities for failing to meet reliability performance standards, representing the first use of performance-based utility compensation in Maryland. My testimony builds on the existing legislation, recommending that it be applied more broadly to incorporate additional performance metrics in the public interest, thereby improving the alignment of public and merged entity interests.

In summary, the Maryland General Assembly has made it clear that renewable generation, energy efficiency, distributed energy resources, greenhouse gas emission reductions, and reliability are in the public interest. The public interests cited by the Maryland General Assembly for these laws include long-term decreases in electric generation emissions, a healthier environment, increased energy security, and decreased reliance on and vulnerability from imported energy sources. And in addition, the US Environmental Protection Agency's proposed Clean Power Plan rule would require Maryland to reduce greenhouse gas emissions by 36.5% from 2012 levels by 2030.[2] It is likely renewable energy, energy efficiency, and distributed energy resources will all need to be increased as part of a least-cost plan to comply with such a rule. The Clean Power

[2] Environmental Protection Agency, 79 Fed. Reg. 117, (proposed Wednesday, June 18, 2014) (to be codified at 40 C.F.R. pt. 60). Page 34895.

Plan rule would therefore confirm and increase the level of public interest associated with the Maryland legislation cited above, as low-cost rule compliance would clearly be in the public interest.

III. SEVERAL ASPECTS OF EXELON'S BUSINESS INTERESTS CONFLICT WITH THE PUBLIC INTEREST AS DEFINED BY THE MARYLAND GENERAL ASSEMBLY

Q. WHY ARE EXELON'S BUSINESS INTERESTS RELEVANT TO THE MERGER APPLICATION?

A. It is estimated the merged entity would distribute electricity to 85% of Maryland's citizens.[3] In instances in which Exelon's business interests conflict with the public interest, it is possible Exelon could use its control of Maryland distribution utilities to prioritize business interests over the public interest. This problem is compounded by the current utility compensation model, which (with one exception)[4] would not penalize the merged entity for poor performance in the public interest, nor reward the merged entity for exceptional performance in the public interest. I'll return to this topic later in my testimony.

[3] Seltzer, Rick. "Exelon-Pepco deal would hurt consumers and the environment, opponents say." *Washington Business Journal.* October 2, 2014.

[4] The joint merger application does anticipate performance-based compensation for reliability measures in compliance with existing legislation. Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, and Delmarva Power & Light Company (the Joint Application). August 19, 2014. Page 4.

Q. CAN YOU BE MORE SPECIFIC ABOUT THE EXELON BUSINESS INTERESTS YOU CONTEND CONFLICT WITH THE PUBLIC INTEREST AS DEFINED BY THE MARYLAND GENERAL ASSEMBLY?

A. Certainly. Exelon owns 24 generating plants in the mid-Atlantic region. The value of these assets is dependent in large part on the market price and quantity of the electricity each generates; market price and quantity are determined by the supply of and demand for electricity in the region. As the public interests (as defined by the General Assembly) of increased renewable energy, energy efficiency, and distributed energy resources will directly reduce the demand for electricity from these plants, they reduce electric price and quantity and therefore the profitability and value of generation assets owned by Exelon. This conflict between public and merged entity interests can be successfully managed through performance-based utility compensation models, but not through current utility compensation models.

Q. DO YOU HAVE ANY INFORMATION INDICATING THAT EXELON TAKES ACTION TO PROTECT THE VALUE OF ITS GENERATION ASSETS IN CONFLICT WITH THE PUBLIC INTEREST?

A. It would be irresponsible for any company not to take action to protect the value of its assets in the interest of its shareholders. As just one example, Exelon has actively supported clean-air and carbon dioxide reduction legislation introduced in the US Congress, as such legislation increases the value of the company's large fleet of nuclear-fueled generation stations (which produce no particulate emissions or carbon dioxide). Simultaneously, Exelon has opposed renewable generation subsidies such as the expired Production Tax Credit,[5] despite the fact that renewable generation also produces no particulate emissions or carbon dioxide. This apparent contradiction can only be explained by the fact that renewable generation threatens the value of owned nuclear assets, while clean-air and carbon dioxide reduction legislation enhances the value of these assets. Said company spokesman Paul Adams, "the company supports wind, but federal policies, including the now expired wind PTC, subsidize billions of dollars in inherently unreliable energy sources and severely distort energy markets, causing some otherwise profitable clean generators to operate at a loss."[6] In referring to "clean generators", the spokesman was likely referring in part to Exelon's extensive fleet of nuclear generation plants, including 4,690 MW of capacity (by the Company's estimate, enough to power 3.6 million homes) it owns in Pennsylvania, New Jersey, and Delaware. Exelon spokesman Adams has also argued that renewable energy standards should be replaced with "clean energy standards,"[7] which presumably would apply to the company's nuclear generating assets and thereby increase (or at least maintain) their value.

[5] Snyder, Jim and Johnsson, Julie. "Exelon Falls from Green Favor as Chief Fights Wind Aid." *Bloomberg* April 1, 2013.

[6] Nathans, Aaron. "Exelon opposes renewal of wind subsidy." *The Delaware News-Journal*, August 29, 2014.

[7] Ibid.

In addition, Exelon is reportedly lobbying the Illinois legislature to support the value of nuclear generating plants there. According to an article in the Chicago Tribune describing the aftermath of a published interview with Exelon CEO Chris Crane, "…that led to speculation at the Illinois statehouse that the company was looking for a legislative fix to prop up its nuclear plants. Insiders had said a deal to fix the state's renewable portfolio standard was being held up until it was clear what kind of handout Exelon was seeking."[8]

Indeed, it can be deduced from public comments that Exelon's primary goal for the PHI acquisition is to reduce earnings volatility from Exelon's generation business. In a conference call for investors announcing the proposed acquisition, Chris Crane stated the acquisition will " . . . add further sources of stable regulated cash to our portfolio"[9] and " . . . increase Exelon's utility derived earnings and cash flows, providing a solid base for the dividend."[10] These sentiments were reinforced by perceptions of the investment community, and the comments of Edward Jones equity analyst Andy Pusateri were typical: "the added exposure to regulated utilities should add more stable earnings to a company heavily exposed to non-regulated generation."[11] "Disruptive" technologies – such as rooftop solar and microgrids and other clean energy distributed energy resources

[8] Wernau, Julie. "Exelon CEO: 'We are not asking the state for a bailout.'" *The Chicago Tribune*. April 30, 2014

[9] Morningstar. "Exelon Corp Q1 2014 Earnings Call Transcript." April 30, 2014. Accessed via Internet at http://www.morningstar.com/earnings/PrintTranscript.aspx?id=66289361

[10] "Exelon Announces Acquisition of Pepco Holdings, Inc." Presentation. April 30, 2014. Slide 4.

[11] Tomich, Jeffery and Kuckro, Rod. "Exelon doubles down on regulated assets with Pepco buy." Energy Wire. Thursday, May 1, 2014.

-- are seen as a threat to the "stable earnings" that Exelon's CEO has said is an important motivation for this merger. Therefore it is logical to assume that the merged entity would take actions that are consistent with preventing such "disruptive technologies" from increasing in its service territory.

To summarize, significant Exelon business interests do conflict with the public interest in Maryland, and the Company is likely to prioritize these business interests over the public interest in the absence of performance-based compensation models.

IV. THE CURRENT UTILITY COMPENSATION MODEL HAS FAILED THE PUBLIC INTEREST AS DEFINED BY THE MARYLAND GENERAL ASSEMBLY

Q. WHY DO YOU BELIEVE THE CURRENT UTILITY COMPENSATION MODEL HAS FAILED THE PUBLIC INTEREST AS DEFINED BY THE MARYLAND GENERAL ASSEMBLY?

A. As a general rule, a utility will not pursue a course of action that conflicts with its economic self-interest. Indeed, it would be ill-advised for the managers of any corporation to do so, as federal securities law requires managers to serve the interests of shareholders. The current compensation model encourages utility managers to focus on inputs, such as investment, rather than outcomes, such as performance in the public interest. In my experience, even in cases in which a utility's economic self-interest is not threatened – as in reliability performance – a lack of management attention and focus on outcomes can lead to poor performance. A performance-based compensation model would both manage the conflict inherent in Exelon's specific business interests and improve the focus of the merged entity's management team on outcomes and performance in the public interest.

Q. CAN YOU CITE ANY EXAMPLES OF HOW THE CURRENT COMPENSATION MODEL HAS FAILED THE PUBLIC INTEREST IN MARYLAND?

A. Yes. If we examine the performance record of regulated Maryland utilities to date on issues in which the public interest – such as for increased renewable energy and energy efficiency – conflict with incumbent generation owners' interests, we observe performance deficiencies.

- *Renewable Generation.* Since the aforementioned renewable energy standard was passed in Maryland, the renewable portion of electricity generated by renewable means grew from less than six percent to slightly over eight percent.[12] This represents 35% growth through the end of 2013, a pace that is woefully insufficient to meet the standard of 20% by 2022. To meet the standard, renewable energy will need to grow in Maryland by more than 300% from 2004 to 2022 (less than 6% to at least 20%). Half-way through the performance period, only about 10% of the required renewable energy growth has been achieved.

[12] StateStat (Maryland state government website). "Are we meeting our goals?" Presented on the website's renewable energy page at https://data.maryland.gov/goals/renewable-energy. Accessed 11/22/2014.

- *Energy Efficiency.* The MPSC's most recent standard annual progress report for the aforementioned EmPower Maryland Act suggests energy efficiency goals will not be met. "Looking ahead to the remaining year of the 2012-2014 EmPOWER Maryland plan cycle and the initiation of a new cycle, the Commission acknowledges the possibility that the currently approved programs may fall short of the energy reduction goals for 2015."[13]

Q. ARE THERE OTHER EXAMPLES IN MARYLAND?

A. Yes. The poor reliability performance of PHI utilities that resulted in the Electric Service Quality and Reliability Act of 2011 is likely the most prominent example. Prior to the act, PHI was not penalized for poor reliability performance. With no adverse consequences, PHI reliability performance in Montgomery and Prince George's Counties remained in the bottom quartile of the nation for years as described earlier in my testimony. Significantly, since passage of the Act, reliability has improved, demonstrating that when there are financial consequences for failing to meet important aspects of utility service, a utility will respond.

Q. WHAT OTHER EVIDENCE INDICATES THE CURRENT UTILITY COMPENSATION MODEL NEEDS TO BE MODIFIED?

[13] Public Service Commission. "The EmPOWER Maryland Energy Efficiency Act STANDARD REPORT of 2013." April 2014. Page 36.

A. After Hurricane Sandy, Governor O'Malley recognized that further reforms were necessary to ensure greater reliability, and established a Task Force on Grid Resiliency. On the Task Force's very first day of taking input from stakeholders, the Task Force invited a presentation from the Energy Future Coalition, a nationally recognized, bi-partisan, non-profit public policy initiative that seeks to speed the transition to a new energy economy. The Energy Future Coalition argued, in part, "The electric utility industry of the United States is facing a dramatic transformation over the coming two decades. The lack of reliability and resiliency in Maryland's utility services reflect some of the challenges in that transformation, and Maryland's response to these recent episodes should be shaped by the longer-term foundational forces that will reinvent the nation's electric sector… Across the nation, utilities will contend in the next two decades with destabilizing challenges to their current way of doing business from innovative smart technologies, environmental requirements, new economic realities, and the constraints of a fixed institutional structure . . . . Utilities' economics and business models will change with a new customer ability to respond to price signals, third-party entrants in utility services, huge potential for additional cost-effective efficiency in electricity use, consequent flat or declining overall power demand, and greater attention to (and perhaps willingness to pay for) reliability and power quality . . . . Their regulatory and institutional realities, other than an increased potential for utility mergers, are likely to remain relatively stable and to constitute a constraint on the flexibility that would otherwise be optimal."[14]

[14] Testimony of John W. Jimison, Managing Director of Energy Future Coalition, at the Electric Feedback Forum on

Importantly, the Governor's Task Force concurred with this analysis. "The Task Force concurs with the analysis offered by the Energy Future Coalition, that ***this is a transformative time in Maryland's energy future, and that big, bold thinking is required.***"[15] To facilitate that process, the Task Force requested that the Energy Future Coalition develop a pilot proposal for Utility 2.0 in Maryland. The Energy Future Coalition did just that in a report entitled, "Utility 2.0: Piloting the Future For Maryland's Electric Utilities and Their Customers," filed with this Commission on May 14, 2013.[16] Among the report's principal recommendations, which my participation helped to inform, is that performance-based ratemaking be adopted for the outcomes that the Energy Future Coalition posits are most important for ratepayers today.

Q. HOW HAS PHI RESPONDED TO THESE DEVELOPMENTS?

A. PHI has been receptive to the concept of performance-based ratemaking. In his deposition to the Commission on November 3, 2013, PHI President and CEO Joseph M. Rigby indicated Pepco was "open to the concept of new compensation models

Improving Maryland's Electric Distribution System. August 21, 2012.

[15] Office of Governor Martin O'Malley. "Weathering the Storm: Report of the Grid Resiliency Task Force." September 24, 2012. Page 89.

[16] *See* Councilmember Roger Berliner's "The Energy Future Coalition's Report and Recommendations in Response to the Request of the Governor's Grid Resiliency Task Force" before the Public Service Commission of Maryland. May 14, 2013. Addendum to Maillog 145759: Councilmember Berliner's "Petition to Open Investigation into Utility 2.0 – The Future of Maryland's Grid." March 5, 2013.

incorporating performance-based component."[17] However, the Exelon merger proposal interrupted the progress that was being made. I suggest the proposed merger should not be the basis upon which the advance of new utility compensation models is stalled; rather, it should be the basis upon which the advance of new utility compensation models is accelerated.

Q. HAVE OTHER REGULATORS, STAKEHOLDERS, AND RESEARCHERS RECOGNIZED DEFICIENCIES IN THE CURRENT UTILITY COMPENSATION MODEL?

A. Yes. Many regulators, stakeholders, and researchers have recognized deficiencies in the current utility compensation model; some are even going about rectifying them. Farthest along is the implementation of the RIIO utility compensation model by the UK regulator Ofgem. The RIIO model (**R**evenues will be set using **I**ncentives to deliver **I**nnovation and **O**utputs) was developed jointly by utilities, regulators, researchers, and stakeholders and incorporates a significantly-sized performance-based compensation component. (In the RIIO model, exceptionally poor performance can result in utility compensation below the cost of its debt.)[18] In the US, the New York State Department of Public Service (NYSDPS) has initiated a docket, named "Reforming the Energy Vision" (14-M-0101) to conduct "a fundamental reconsideration of our regulatory paradigms and markets, examining how policy objectives are served both by clean energy programs and by the

[17] Ibid, Maillog 160177.

[18] Ofgem. "RIIO – new way to regulate energy networks." Factsheet 93. April 10, 2010. https://www.ofgem.gov.uk/ofgem-publications/64031/re-wiringbritainfs.pdf

regulation of distribution utilities."[19] Though the docket is in the early stages of development, it appears a significantly-sized performance-based compensation component will be part of the outcome.

The NYSDPS's objectives are aggressive. In addition to modifying distribution utility compensation, it seeks to establish an entirely new vision for electric generation and distribution in the public interest. The NYSDPS coined the phrase "Distributed System Platform Provider" to describe the new roles and capability sets that will be required to enable the new vision.[20] While the Coalition for Utility Reform's objectives in this proceeding are more modest, it is hoped the performance-based compensation models recommended in my testimony would encourage Maryland utilities to voluntarily (and profitably) adopt the roles and capability sets the NYSDPS believes to be in the public interest, and as confirmed in legislation passed by the Maryland General Assembly described earlier in my testimony.

In addition to the aforementioned Energy Futures Coalition, many other respected organizations and researchers have issued pronouncements for changes to the current

[19] "Reforming the Energy Vision". Staff Report and Proposal to the New York State Department of Public Service. April 24, 2014. Case 14-M-0101. Page 1.

[20] Ibid, Page 11.

utility compensation model, generally in favor of performance-based compensation in the public interest.

- *The Environmental Defense Fund*: "It is time . . . to reward results, not spending. Erasing the distinction between rewards for prudent capital investment and effective operations will require a shift in deeply-rooted practices. Changing to a performance-based model will take great care to establish optimal outcomes and performance metrics. The outcomes must still be tied to traditional objectives of adequacy and reliability of service, as well as new outcomes tied to clean energy, customer engagement, system efficiency, and transparency that open the door to energy service innovations from others. This requires fundamental changes in the reward system."[21]
- *The Rocky Mountain Institute*: ". . . there is a looming disconnect between the rapidly evolving new world of distributed energy technologies and the old world of electricity pricing, where relatively little has changed since the early 20th century. By changing electricity pricing to more fully reflect the benefits and costs of electricity services exchanged between customers and the grid, utilities and regulators can unleash new waves of innovation in distributed energy resource investment that will help to reduce costs while maintaining or increasing system resilience and reliability."[22]

[21] *See* Environmental Defense Fund. "Comments Re: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision" filed with the New York Public Service Commission. July 18, 2014.

[22] Rocky Mountain Institute. "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future." August 2014.

- *The Perfect Power Institute*: " . . . our research determined . . . the (specified) improvements made must be held accountable to producing significant, measurable improvements to reliability, efficiency, and the environment"[23]
- *MIT Energy Initiative*: "Performance measures should include progress on any policy goals imposed on distribution systems, as well as more traditional system quality and cost measures . . . . If measurement is to have an impact, the results should be made public, and regulators should provide explicit incentives for good performance . . . . State regulators . . . should design mechanisms for risk allocation and compensation to balance incentives for innovative, risky investment with efficiency gains and ensure that the results . . . are shared with customers".[24]
- *Utility of the Future Center, Arizona State University (America's Power Plan)*: ". . . What is the significance and urgency of these (specified) trends and their possible negative impact on utilities? How will utilities adapt to these changes under the current regulatory framework? What potential changes to regulatory frameworks are warranted in response?"[25]
- *The National Regulatory Research Institute*: "Utility personnel need clear, consistent signals about performance expectations, which will ensure resolute

[23] Perfect Power Institute. "Investing in Grid Modernization: The Business Case for Empowering Consumers, Communities, and Utilities." February, 2013. Page i.

[24] Massachusetts Institute of Technology. "The Electric Grid of the Future: An Interdisciplinary Study". Page 194.

[25] Aggarwal, Sonia and Eddie Burgess. "New Regulatory Models." America's Power Plan, Energy Innovation, and Utility of the Future Center. March 2014.

focus on achieving performance goals and maintaining acceptable performance over time."[26]

Finally, several other state legislators and regulators have required utilities to submit plans to meet new requirements in the public interest (as described in my testimony immediately below), though such proceedings have not yet considered new utility compensation models. These include:

- California Assembly Bill 327, "Energy Utility Rate Reform";
- Massachusetts Department of Public Utilities docket 12-76, "Investigation by the DPU on its own Motion into Modernization of the Electric Grid"; and
- Hawaii Public Utilities Commission docket 2011-0206, "A proceeding to investigate the implementation of reliability standards for HECO, Inc."

Q. YOU'VE MADE A STRONG CASE FOR PERFORMANCE-BASED UTILITY COMPENSATION. IS THE MERGER APPLICATION THE BEST PLACE TO ADDRESS THIS ISSUE, OR IS IT BETTER ADDRESSED IN A FUTURE RATE CASE?

A. As my testimony highlights, there are significant inherent conflicts between the merged entity's private financial and business interests and the broader public interest as has been defined by the Maryland General Assembly. The Commission is required to find that the

[26] National Regulatory Research Institute. "Smart Grid Strategy: How Can State Commission Procedures Produce the Necessary Utility Performance? February, 2011. Page iv.

merger is in the public interest. In the absence of reconciling this conflict, I don't know how the Commission could conclude that the merger meets the public interest test. In my judgment, performance based rewards and penalties that address these core values are the most effective means at the MPSC's disposal to more closely align the conflicting interests.

V. A PERFORMANCE-BASED DISTRIBUTION UTILITY COMPENSATION MODEL WILL ALIGN THE INTERESTS OF THE MERGED ENETITY AND MARYLAND PUBLIC AND SHOULD BE A CONDITION OF MERGER APPROVAL

Q. YOUR TESTIMONY REFERENCES PERFORMANCE-BASED UTILITY COMPENSATION MODELS MANY TIMES. PLEASE DESCRIBE A COMPENSATION MODEL THAT WOULD ALIGN THE INTERESTS OF THE MERGED ENTITY AND MARYLAND PUBLIC

A. I would like to begin by describing the public interests I believe should be measured as part of a performance-based compensation model. In addition to those already recognized by the Maryland General Assembly, I concur with the suggestions found in the Coalition for Utility Reform's petition to intervene in this docket:

- Cost Minimization
- Reliability
- Customer Satisfaction
- Carbon Reduction & Environmental Stewardship
- Distributed Energy Resources
- Customer Control
- Innovation
- Safety

I'll describe the public interest supported by each of these performance metrics individually.

Cost Minimization. While cost minimization in electric distribution is clearly in the public interest, today's compensation model predisposes investor-owned utilities to find capital-intensive solutions to operating challenges. This bias can result in higher prices (and/or sub-optimal performance) for customers, as distribution utilities are encouraged to select over-engineered and/or proprietary solutions over simpler solutions and/or outsourcing to qualified, non-utility service providers. I have also seen this bias, when combined with other deficiencies of today's compensation model described in my testimony, result in utility failure to deliver the full potential value of grid modernization benefits to customers.

Today's compensation model also discourages utilities from initiating rate cases when costs are falling, as rate cases transfer cost reduction benefits from shareholders (in the form of higher profits) to customers (in the form of lower rates). And finally, "cost minimization" could be defined to include distribution efficiency, another key performance indicator today's compensation model fails to address. (Distribution efficiency includes reducing grid losses and optimizing grid voltage and power factor, all of which reduce customer costs.)

Reliability. While utility customers in Maryland affected by poor utility performance on this metric can describe its impact clearly, poor reliability is associated with a broader public interest impact that extends well beyond the experience of affected customers. Community economic impact was a key motivation behind the Electric Reliability and Service Quality Act and the Governor's Task Force on Grid Resiliency, but its' importance to the public interest is confirmed by experts. In a landmark study conducted for the U.S. Department of Energy, Lawrence Berkeley National Labs found significant community-wide economic impacts from electric service interruptions. Consider the community-wide economic impacts the study estimated from a single service outage on a summer weekday afternoon *per customer* (based on outages ranging from momentary to 8 hours):

- Average medium-to-large commercial or industrial customer: $11,756-$93,890;
- Average small commercial or industrial customer: $439-$4,768;
- Average residential customer: $2.70 to $10.70.[27]

Of course longer outages entail larger economic impacts. Further, the Perfect Power Institute cites the economic disadvantages to which the U.S. economy is subjected through utility reliability that is substandard relative to that of other nations:[28]

[27] Lawrence Berkeley National Laboratory. "Estimated value of Service Reliability or Electric Utility Customers in the United States". June, 2009. Page xxi.

[28] Perfect Power Institute. "Investing in Grid Modernization: The Business Case for Empowering Consumers, Communities, and Utilities." February, 2013. Page 19.

Country	System Average Interruption Duration Index (minutes/year)
Germany	23
Denmark	24
Netherlands	33
Italy	58
France	62
Austria	72
United Kingdom	90
Spain	104
United States	240

In fact, reliability is so critical to Maryland quality of life, economic productivity, and the public interest, the Coalition for Utility Reform recommended a performance objective of top quartile reliability performance (i.e., better than 75% of utilities) within 3 years in its petition to intervene in this proceeding. Given that Exelon cites reliability improvement as a post-merger public interest benefit in its Application,[29] I recommend the Coalition's objective and timeframe be incorporated into any performance-based compensation model the MPSC orders.

Customer Satisfaction. In my experience, the effectiveness with which utilities translate new capabilities (such as those from the so-called "smart grid") into an improved customer experience varies widely. Some customers will identify good service as an informed and empowered telephone agent, while others will cite strong self-service

[29] Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, and Delmarva Power & Light Company (the Joint Application). August 19, 2014. Page 3.

options. But regardless of how individual customers define good customer service, the performance variability exhibited by utilities make customer satisfaction an important metric to measure. Just a few examples of how utilities are using new capabilities to enhance customer satisfaction include:

- Weekly, e-mailed exception reports that alert a customer when predetermined monthly bill targets are likely to be exceeded based on month-to-date usage;
- Smart phone applications that allow customers to monitor the status of an outage affecting their homes or businesses;
- Usage data access that allows commercial and industrial customers the ability to manage peak demand (and reduce peak demand charges) in real time;
- (Secure, private) analysis of detailed customer usage data for the purpose of targeting energy efficiency and demand-response program offers;
- Analyzing detailed meter data by asset (transformer, lateral, circuit, etc.) to better understand reliability performance and proactively identify potential reliability issues before they arise.

Carbon Reduction and Environmental Stewardship. The General Assembly has already passed legislation indicating that clean energy is in the public interest, including the aforementioned legislation to promote renewable energy, energy efficiency, and distributed energy resources (much of which is clean, such as PV Solar).

Distributed Energy Resources. The General Assembly has already determined that distributed energy resources are to be encouraged in the public interest, citing relief of a strained Maryland transmission system and a potential cure for the dearth of in-state generation facilities.[30]

Customer Control. As the Energy Future Coalition observed in its report to the Governor's task force, "…customers will, over time, seek to avail themselves of the latest "smart" equipment to optimize and minimize their use of electricity, and will make appropriate judgments on using those characteristics to achieve greater savings and convenience."[31] The merged entity's performance should be judged in part on the degree to which its decisions and actions empower consumers to take control of their electric service, and enabling the use of 3rd parties to deliver unregulated services.

Innovation. Innovation certainly applies to a utility's own organization, as innovative approaches will be required if performance in the public interest as described in this testimony is to be optimized. In addition, there will be instances in which a utility's innovation capability will be insufficient to support the public interest, or below the level that might be available from that exhibited by a competitive market. Ideally, a utility's innovation performance should be judged not only in its own right, but to the extent the technologies chosen and services provided by a distribution utility enable other

[30] Maryland General Assembly, Department of Legislative Services. "Senate Bill 595, 2007 Session". Fiscal and Policy note, Page 2.

[31] Energy Future Coalition. "Utility 2.0: Piloting the Future for Maryland's Electric Utilities and their Customers". March 15, 2013. Page 10.

companies and industries to innovate and deliver services in the public interest. Care should be taken to ensure services best delivered by a competitive market are not reserved exclusively for the merged entity to deliver.

Safety. Electricity can maim and kill. Employee and public safety is important, and must be considered while pursuing the other objectives. For example, without a safety performance metric, actions taken in pursuit of cost minimization or distributed energy resource objectives could adversely impact employee and public safety.

Q. IS OTHER INFORMATION AVAILABLE TO CONFIRM THAT THESE ARE THE TYPES OF METRICS WHICH SHOULD BE INCLUDED IN A PERORMANCE-BASED COMPENSATION MODEL DEVELOPED IN THE PUBLIC INTEREST?

A. Experience with utility compensation models incorporating significantly-sized, performance-based components is limited. However in a presentation at a symposium that was part of the aforementioned NYSDPS distribution utility reform docket, the Advanced Energy Economy (AEE) described an independently-developed, performance-based distribution utility compensation framework[32] highly consistent with the list above. The AEE's list includes:

- Advancement of clean energy goals;

[32] Frantzis, Lisa. "Creating a 21st Century Electricity System." Advanced Energy Economy. Presentation at the Symposium on Reforming the Energy Vision, May 22, 2014. Slide 11.

- Customer engagement;
- Operational Efficiency;
- Operating Safe, Reliable, and Resilient Systems;
- Innovation.

The RIIO utility compensation model being implemented in the U.K. also offers a highly consistent list of metrics:

- Customer Satisfaction
- Reliability and availability
- Safety
- Connection terms (universal access to services)
- Environmental impact
- Social obligations[33]

Q. DO YOU HAVE SUGGESTIONS AS TO DESIRABLE CHARACTERISTICS OF A PERFORMANCE-BASED DISTRIBUION UTILITY COMPENSATION MODEL?

A. Yes. My experience in the distribution utility industry, combined with best-demonstrated performance measurement practices in other industries, suggest a number of desirable characteristics and considerations for a performance-based compensation model that would align the interests of the merged entity with the public interest in Maryland. I will

[33] Ofgem. "RIIO: A new way to regulate energy networks. Final Decision. October, 2010. Page 21.

describe each to assist the MPSC in its deliberations related to the Coalition for Utility Reform's petition in this case.

- The size of the performance component of the compensation model must be appropriate.
- The performance component of the compensation model should feature symmetrical risks and rewards.
- Performance metrics should reflect broadly-held public interests.
- Performance metrics should incorporate measureable objectives, with pre-established target values and timeframes.
- Performance metrics should relate to levers within the merged utility's span of control.
- A performance-based compensation model should eliminate utility bias towards proprietary, capital-intensive solutions
- A performance-based compensation model should create value for all customers, including low-income customers.

The size of the performance component of the compensation model must be appropriate.
The compensation model must achieve a delicate balance, incorporating a performance-based component large enough to impact management decisions but not so large as to discourage utility investment in Maryland. To manage the risk of lenders purchasing the merged entity's debt, the performance component should not be so large that a worst-case

performance scenario results in a return on equity that is less than the interest rate on any new debt the merged entity needs to issue to make investments in Maryland's grid.

The Coalition for Utility Reform believes 50% of a utility's compensation should be performance based. I concur, but not simply because 50% is a convenient figure. Utility debt interest rates are based on credit ratings such as those established by companies like Moody's. The most common (78%) Moody's credit rating for U.S. investor-owned utilities is Baa;[34] between January 1, 2012, and December 1, 2014, the yield on corporate bonds with a Baa rating has averaged between 4.4 and 5.6%[35] (effectively, 5% over the time period). According to SNL Financial, the average authorized return on equity for U.S. investor-owned utilities has ranged from 10.20% (2011) to 10.07% (2012) over a similar time period.[36] Therefore, if a performance-based compensation component is to be large enough to encourage strong performance (for example, the utility earns the target rate of return -- about 10% currently -- for meeting all its performance metrics), but not so large that it inhibits the utility's ability to borrow for grid investment (anything below the rate it must pay on new debt – about 5% currently – for missing all its performance metrics), a 50% performance component is appropriately sized (5% divided by 10%).

[34] Moody's Investors Service. "US Regulated Utilities: Regulatory Support, Low Natural Gas Prices Maintains Stability". Industry Outlook. February 6, 2013. Page 12.

[35] Federal Reserve Bank of St. Louis. "Moody's Seasoned Baa Corporate Bond Yield". H.15, Selected Interest Rates, January 1, 2012 through December 1, 2014. Accessed via internet on December 2, 2014 at http://research.stlouisfed.org/fred2/series/DBAA/.

[36] Moody's Investors Service. "US Regulated Utilities: Regulatory Support, Low Natural Gas Prices Maintains Stability". Industry Outlook. February 6, 2013. Page 3.

The performance component of the compensation model should feature symmetrical risks and rewards. It seems equitable that a utility subject to performance-based penalties for poor performance should also be offered opportunities for rewards for excellent performance. Rewards encourage utilities to take the prudent risks sometimes required in pursuit of exceptional performance. If the lower limit for worst case performance is the rate the merged entity must pay on new debt, perhaps traditional methods used to determine appropriate rates of return on equity could be used to establish a target rate of return awarded when all performance metric objectives are met. The difference between the lower limit and the target rate of return could be added to the target rate to represent an upper limit on the merged entity's rate of return in the event all performance metrics are exceeded. In a simplified example:

	Earned by Utility When	**Rate based on recent experience**
Lower ROE Limit	No performance objectives met	5% (interest rate on new debt)
Target ROE	All performance objectives met	10% (as determined using traditional regulatory practices)
Upper ROE Limit	All performance objectives exceeded	15% (symmetrical reward)

Performance metrics should reflect broadly-held public interests. Organizations, like people, can only focus on a limited number of priorities simultaneously. Accordingly, a performance-based compensation model should consist of a limited number of metrics reflecting broadly held public interests. The eight metrics recommended by the Coalition for Utility Reform described above are appropriate and consistent with public interest as defined by the Maryland General Assembly.

Performance metrics should incorporate measurable objectives, with pre-established target values and timeframes. Though this recommendation is self-explanatory, it is important. A sound example is "Achieve average annual distribution voltage of 114 or less by 2018 with no material increase in power quality complaints." In addition, like the metrics to include in a performance-based compensation model, the objectives, target values, and timeframes used to evaluate performance on each metric are best determined through a stakeholder engagement process.

Performance metrics should relate to levers within the merged utility's span of control. Some well-meaning regulators have established performance objectives for public interests outside a utility's ability to control. For example, the California Public Utilities Commission ordered IOUs in that state to report the magnitude of total load served by grid-connected distributed generation, implying that utilities could control the outcome. Though interconnection standards and application processing do influence such a measure, the benefit-cost ratio of distributed generation technologies and the price of grid electricity to which it is compared are much greater drivers of distributed generation adoption. As these determinants are beyond a distribution utility's control, a better metric might be the level of distributed generation capacity, measured as a percent of total capacity, a utility commits to reliably accommodate.

A performance-based compensation model should eliminate utility bias towards proprietary, capital-intensive solutions. As described above in my testimony on cost minimization, today's compensation model skews utility decision-making in favor of proprietary capital investment. This bias can result in higher costs and/or sub-optimal performance and discourage outsourcing and/or open market solutions. Some utility compensation models used in Europe have effectively neutralized this bias, making such models worthy of MPSC consideration.

A performance-based compensation model should create value for all customers, including low-income customers. Low-income customers can be difficult to engage in the pursuit of public interests such as increased energy efficiency and distributed energy resources, as these efforts often require capital and involve circumstances (multifamily and rental housing) that inhibit participation. As low income customers have disproportionate needs, and present largely untapped opportunities for energy efficiency and distributed energy resources, it makes sense to incorporate concerted efforts on their behalves as part of performance-based compensation model and metric development.

Q. IN CONCLUSION, DO YOU HAVE ANY SUMMARY REMARKS?

A. Yes. Performance-based compensation represents the MPSC's best opportunity to align the interests of the merged entity's shareholders with the public interest. Performance-based compensation can be thought of as a means to an end: a utility motivated to perform in the interest of the public it serves, rather than a utility that is discouraged from performing in the public interest by proprietary business interests and today's compensation model.

As my testimony makes clear, the current compensation model – one that rewards input (investment) rather than outputs (performance) – discourages distribution utilities from performing in the public interest. This is particularly true in this case, in which the merged entity would own significant generating assets in the region whose value is jeopardized by the public interest as defined by the General Assembly (increased renewable generation, energy efficiency, and distributed energy resources). The joint merger application already anticipates performance-based compensation for reliability measures;[37] it makes sense to expand the concept to other public interests.

The Maryland Public Service Commission has demonstrated a capability to lead important regulatory policy development in the past, and I hope it can continue its track record in these merger proceedings.

[37] Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, and Delmarva Power & Light Company (the Joint Application). August 19, 2014. Page 4.

EXHIBIT PJA-1

Materials Related to Paul Alvarez, Witness for the Coalition for Utility Reform

On November 19, the Joint Applicants sent Data Request 1 (hereafter "DR-1") to the Coalition for Utility Reform (hereafter "Coalition"). On December 1, Ryan Spiegel, acting as counsel for the Coalition for Utility Reform, objected to DR-1, while agreeing to provide certain information in response to JA-I-1, JA-I-2, and JA-I-4 contained therein. As stated in the objection, the Coalition agreed to provide the testimony itself in response to JA-I-2, which is provided above. Below, find the information requested in JA-I-1 and JA-I-4 that the Coalition agreed to provide, related to the Coalition's witness, Mr. Paul J. Alvarez.

Re: JA-I-1.
Curriculum Vitae of Mr. Paul J. Alvarez:

Paul J. Alvarez MM, NPDP

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Professional Experiences

2012-Present **President, Wired Group**

As the leader of this distribution utility consulting firm:

- Business development and marketing
- Business strategy and product development
- Team leadership and personnel development
- Project management

Also:

- Adjunct professor, Global Energy Management Program, University of Colorado
- Adjunct professor, Institute for Public Utilities, Michigan State University

2007-2011 **Principal and Utility Practice Leader, MetaVu, Inc.**

Increased revenues and profits for this boutique consulting firm by establishing and leading the Utility and Smart Grid Practices:

- Smart grid deployment evaluation project management
- Smart grid thought leadership (speaking, trade pub articles, trade group participation)
- Utility/smart grid team recruiting, development, and resource management
- Utility/smart grid business development, practice development, and marketing

Results:

- Closed and led delivery of smart grid evaluation projects for Duke Energy, Xcel Energy
- Conducted RPS compliance performance benchmark/workshop of 10 leading IOUs

- Grew utility practice from zero to $2 million in revenues in 3 years
- Awarded New Product Development Professional designation by the PDMA.

2005-2007 **Area Vice President. Option Care, Buffalo Grove, Illinois (acquired by Walgreens)**
Increased revenues and profits in the Southwest Area for this home healthcare company:
- P&L responsibility for 8 offices with $48 million in annual revenue and 175 employees
- Sales, sales management, and customer relations (physicians, hospitals, insurers)
- Operations management (pharmacy, nursing, distribution, billing, etc.)
- JV and Acquisition prospecting, due diligence, negotiation, and implementation

Results:
- Increased quarterly revenues 11% first year (22% growth in higher margined services)
- Increased quarterly profits 89% in first year
- Turned over underperforming General and Operations managers and sales people
- Maintained high levels of customer service and increased employee engagement
- Reduced bad debt rate 2% and maximized billed $ per patient

2001-2004 **Product Development Manager; Product Developer. Xcel Energy, Denver, CO.**
Increased revenues and helped maintain customer satisfaction by developing new products and services for this utility with 500,000 commercial customers and 2.5 million consumers:
- Development process and schedule management
- Unregulated business strategy
- Cross-functional operations development and implementation for new products

Results:
- Developed and managed several new energy efficiency, demand response, and renewable energy products for commercial and residential markets, including InfoWise, Savers' Switch, Interruptible Service Option Credit, FixedBill, and WindSource.
- Implemented website enhancements including new content and self-service options
- Increased revenues $9 million annually from new commercial & consumer products
- Promoted to Product Development Manager; staff of 7; $1.5 million annual budget.

1998-2001 **Vice President, West Area; Director, West Area. Patient Infosystems, Rochester, NY.**
Improved corporate profitability for this healthcare consumer support and software outsourcer with annual revenues of $10 million:
- Sales and sales management; channel management
- Product Development and Launch

Results:
- Developed software designed for internal operations into a successful, licensed ASP software application and associated product and service line
- Launched and managed the new software offering, including positioning, sales training and support, collateral development, promotions and pricing/licensing
- Implemented distribution channel program and negotiated key alliances with high profile clients such as PCS Health Systems and Rx America
- Generated annual revenue increases of $2.5 million
- Promoted from sales to sales management.

1994-1998 **Finance Director; Market Development Manager. Searle Pharmaceuticals, Skokie, IL.**

Increased market share for this pharmaceutical manufacturer (now Pfizer) with $1 billion in annual revenues. Also led the finance and marketing functions for a JV with Health Decisions, Inc. in Golden, CO, a healthcare consumer support and software provider:

- Target market strategy, positioning, branding, advertising, business development
- Product management, including value-added service development, implementation
- Financial analysis, reporting, and control implementation
- Operational process assessment and improvement

Results (Searle):

- Negotiated exclusive distribution rights, debt, and equity investments in various service and software suppliers for private labeled value added services
- Implemented value added services for various product lines, including cardiovascular, GI, pain/inflammation, and other markets
- Increased product share from 3.5% to 5% ($8 M revenue growth) in target market

Results (Health Decisions JV)

- Developed and Launched internal operations software into a successful, licensed WAN application with $500,000 in year 1 revenues
- Successfully shifted corporate market position, perception for new delivery model
- Sales efforts resulted in $1 million in annual revenues to high-profile clients including Microsoft, Great West/One Health Plan, and Ceridian.
- Led service delivery modifications, reducing operating costs $1 million annually

1992-1994 **Marketing Director. Option Care, Buffalo Grove, IL.**

Improved corporate and franchisee profitability while minimizing federal antitrust risk:

- Target Market strategy, positioning, branding, and advertising
- Product and Market Management
- Customer Service and Experience Management

Results:

- Negotiated innovative agreements with franchise network that fostered competition yet presented single set of rates to national customers
- Established and managed a customer service call center and contact application to improve contract profitability tracking, contract administration, and direct marketing
- Launched target market identity and position through sales collateral, communication planning and execution, promotions, and events
- Improved share from 5% to 7% in two years ($11.5 M revenue growth)
- Simultaneously improved target market profitability from 15% to 30%.

1987-1992 **District Mgr; Area Finance Mgr; Sr Financial Analyst. Caremark, Lincolnshire, IL.**

Improved financial performance in a series of financial, sales support, and sales roles for subsidiary of Baxter International with $600 Million in annual sales

1986-1987	Accounting Projects Manager. Addison/Wesley Publishing, Chicago, IL. Corporate budgeting/forecasting and accounting automation projects Economic modeling to evaluate operations options and acquisition candidates.
1984-1986	Financial Analyst; Contract Analyst. Motorola Communication, Schaumburg, IL. Arranged financing for equipment purchases; A/R ledger maintenance Promoted to Contract Analyst for cellular telephone and service business.

Education

Master of Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Accounting, Finance, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Marketing and Finance.

Re: JA-I-4

In two occasions, Mr. Alvarez was a member of a team whose evaluation report was used in a proceeding. In both occasions, Mr. Alvarez's personal direct testimony was not used.

1. Colorado PUC 11A-1001E: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE SMARTGRIDCITY COST RECOVERY

2. Ohio PUC 10-2326-GE-RDR: IN THE MATTER OF THE APPLICATION OF DUKE ENERGY OHIO, INC. TO ADJUST RIDER DR-IM AND RIDER AU FOR 2010 SMART GRID COSTS AND MID-DEPLOYMENT REVIEW

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CERTIFICATE OF SERVICE

I hereby certify that on this 8th day of December, 2014, a copy of the foregoing Direct Testimony of Paul J. Alvarez on behalf of the Coalition for Utility Reform was served electronically and mailed first-class, postage prepaid, on all parties on the Service List in Case 9361:

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Roger A. Berliner, Esq.
Coalition for Utility Reform

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 6
Page 1 of 3

Please provide copies of the following documents listed in Appendix A: Curriculum Vitae of Paul Alvarez attached to Mr. Alvarez's testimony:

(a) Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

(b) Best Practices in Grid Modernization Capability Optimization: Visioning, Strategic Planning, and New Capability Portfolio Management. Top-5 US utility; client confidential. 2014.

(c) Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

(d) Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

(e) Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

(f) A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

(g) Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

(h) The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

(i) NARUC Committee on Energy Resources and the Environment. How big data can lead to better decisions for utilities, customers, and regulators. Washington DC. February 15, 2016.

(j) National Conference of Regulatory Attorneys 2014 Annual Meeting. Smart Grid Hype & Reality. Columbus, Ohio. June 16, 2014.

QUESTION No. 6

(k) NASUCA 2013 Annual Conference. A Review and Synthesis of Research on Smart Grid Benefits and Costs. Orlando. November 18, 2013.

(l) IEEE Power and Energy Society, ISGT 2013. Distribution Performance Measures that Drive Customer Benefits. Washington DC. February 26, 2013.

(m) Canadian Electric Institute 2013 Annual Distribution Conference. The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities. Keynote. Toronto, Canada. January 23, 2013.

(n) Great Lakes Smart Grid Symposium. What Smart Grid Deployment Evaluations are Telling Us. Chicago. September 26, 2012.

(o) Mid-Atlantic Distributed Resource Initiative. Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities. Philadelphia. April 20, 2012.

(p) DistribuTECH 2012. Lessons Learned: Utility and Regulator Perspectives. Panel Moderator. January 25, 2012.

(q) DistribuTECH 2012. Optimizing the Value of Smart Grid Investments. Half-day course. January 23, 2012.

(r) NARUC Subcommittee on Electricity. Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators. St. Louis. November 13, 2011.

RESPONSE:

Most of these materials can be downloaded directly via links presented on the Wired Group website, either on page "Reference Work" (http://www.wiredgroup.net/reference-work.html) or on page "About Us" (http://www.wiredgroup.net/about-us.html). Exceptions are described below and/or provided in attachments.

b. As noted in Mr. Alvarez's Appendix A, the identity of this client is confidential. Mr. Alvarez is not allowed to provide this non-public information and therefore it cannot be provided in this proceeding.

i. See attached file "Wired Group NARUC Winter 2016.pdf"

QUESTION No. 6
Page 3 of 3

j. See attached file "National Conf of Regulatory Attorneys Smart Grid.pdf"

k. See attached file "Benefit-Cost Webcast 9-27-2013.pdf"

l. See attached file "Alvarez PES ISGT 2013.pdf"

m. See attached file "WIRED_GROUP_CEA.pdf"

n. See attached file "WIRED_GROUP_GREAT_LAKES.pdf"

p. See attached file "FINAL DistribTECH 2012 Lessons Learned – Utility and Regulator Perspectives.pdf"

q. See attached file "UU210 – Evaluating Smart Grid Performance Workshop Notes.pdf"

r. See attached file "MetaVu NARUC Presentation.pdf"

Distribution Performance Measures that Drive Customer Benefits

Paul Alvarez, President
Wired Group
palvarez@wiredgroup.net
303-997-0317, x801
February 26, 2013

Preview

- What Do Customers Want from a Distributor?
- How Can Smart Grid Capabilities Contribute?
  - Info on Comprehensive, Independent Evaluations
  - Economic Benefits
  - Reliability Benefits
- What Else Do Customers Want?
- Metrics in Use Today: CA, IL, MD, OH
- The Future of Performance Measurement
- Challenges and Next Steps

Customer Wants

BETTER ECONOMICS

My Costs
Offer/Facilitate TOU/CPP/PTR Rates
Reduce Voltage/Improve VAr

System Costs
Capacity (Generation)
Distribution O&M

BETTER RELIABILITY

My Reliability

System Reliability

MEET ANCILLARY NEEDS

Convenience   Confidence   Environmental Impact   Information   Accommodate DG

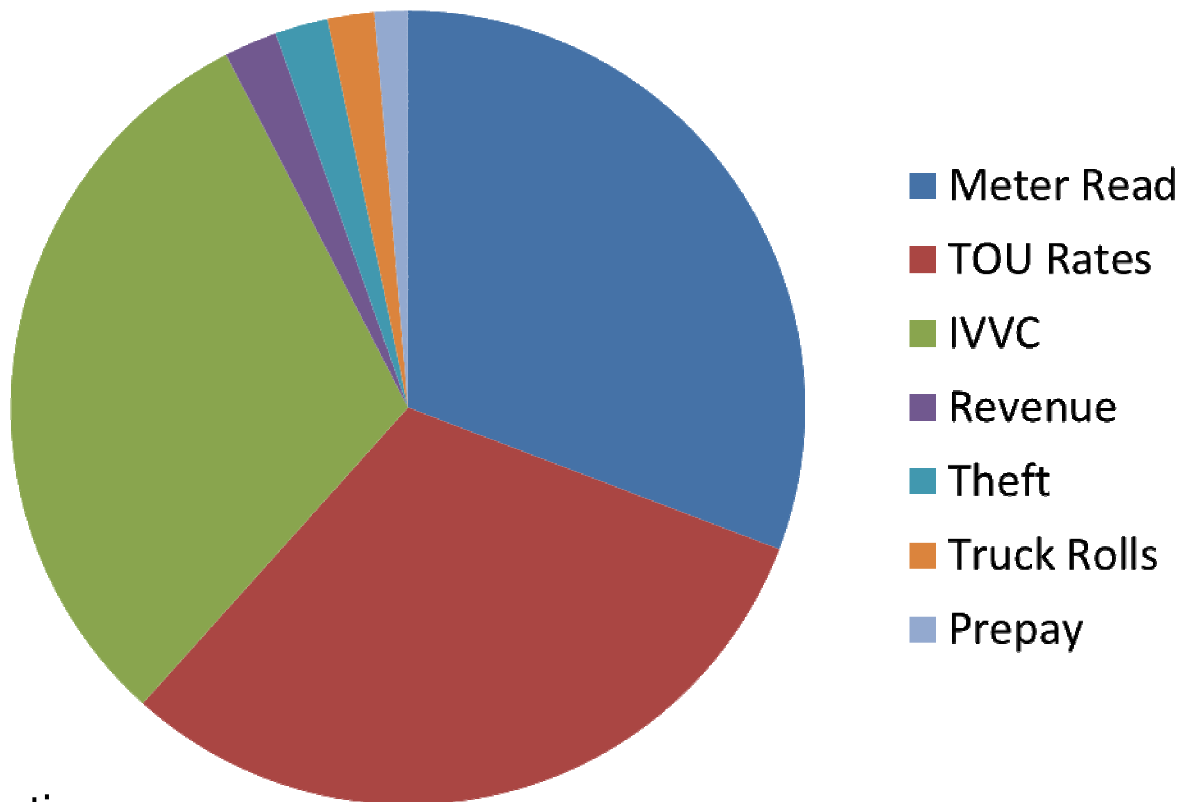
Power & Energy Society®

How Can Smart Grid Contribute?

Comprehensive, Independent Evaluations (2)

- Cost/Benefit Analyses of Smart Grid Capabilities (6)
- Duke Energy (Ohio PUC); SmartGridCity (Xcel Energy)
- Quantified Actual *and Potential* Value; Examined Why
- Pre- and Post-Deployment Queries
  - Data (Pi historian; OMS; IVR; WOMS; MDMS; Accounting; etc.)
  - People (Control Center, Reliability Eng, Cap Planning, IT, Call Center, Linemen, Substation Maintenance, Meter Readers, etc.)
- Guided by Leading Reference Sources
  - EPRI, EDF, Smart Grid Maturity Model, PUC Orders, Utilities, etc.

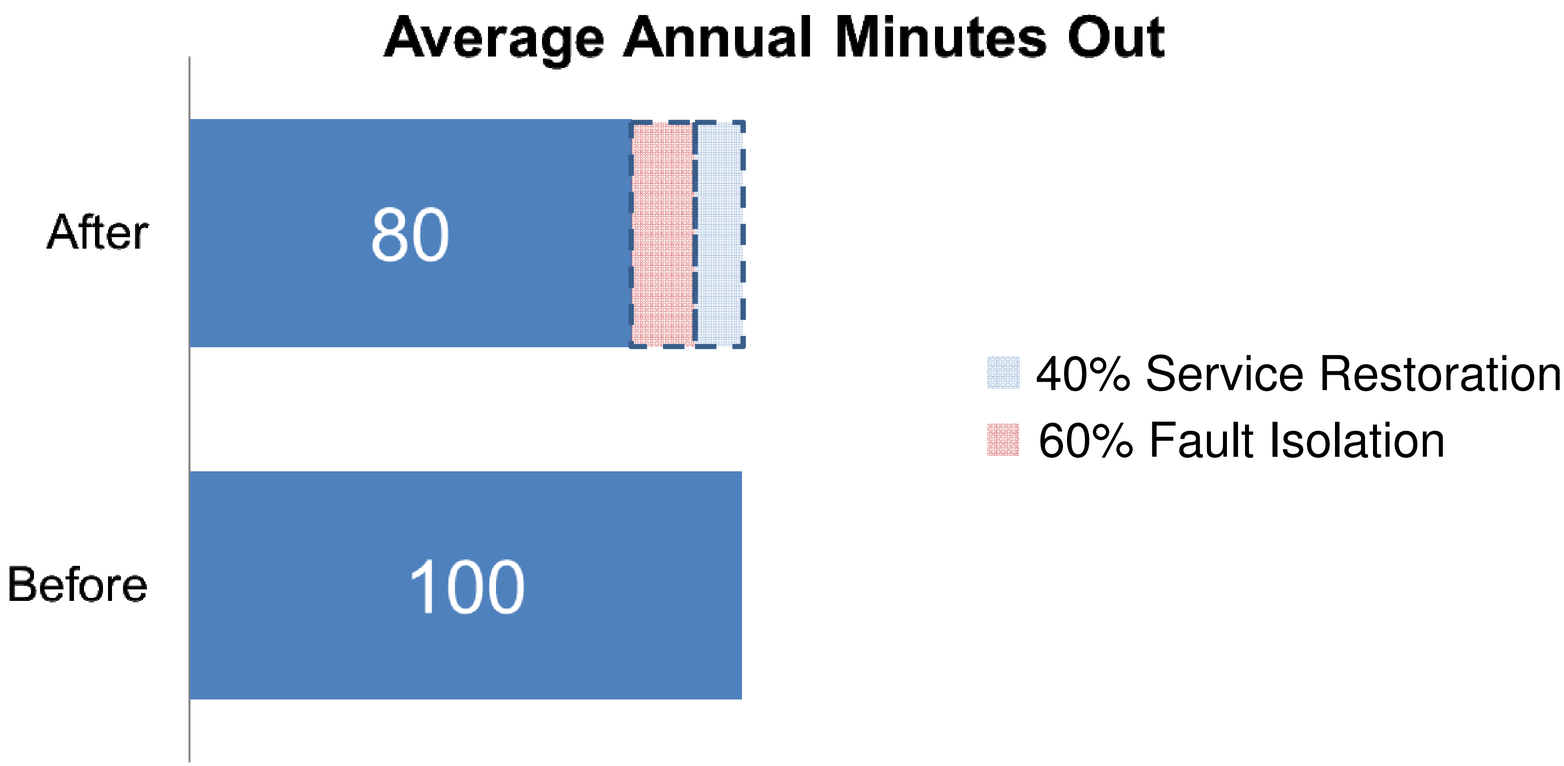
Economic Benefit Potential



<u>Assumptions</u>

Meter Reading: $12 per meter per year prior to deployment
TOU Rates: 20% participation; 0.5 kW/participant; value = $120/kW yr.
IVVC: Operational 24 x 7 x 365; 10¢/kWh residential; 5¢/kWh C&I

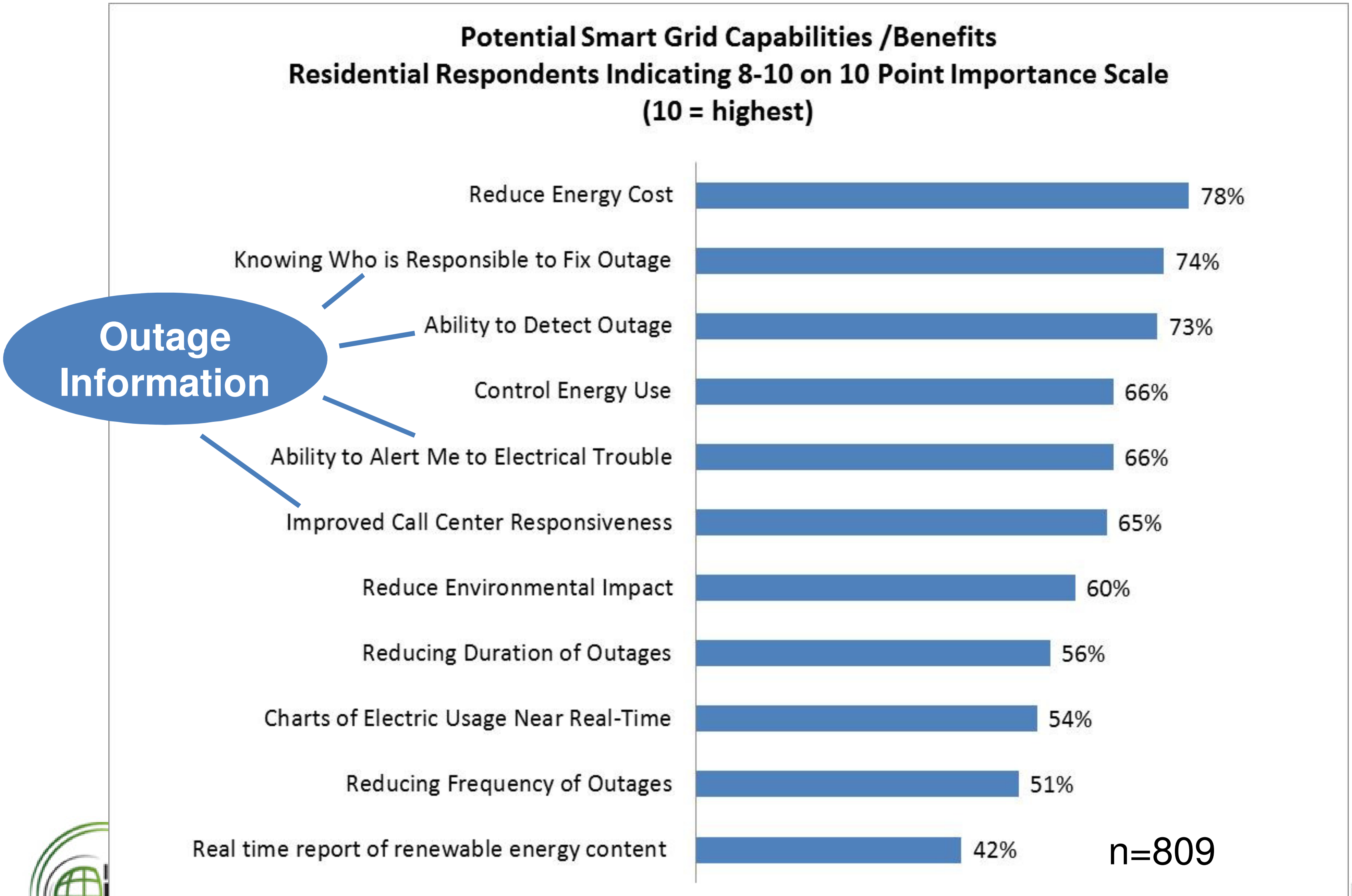
Actual Reliability Benefits



Notes

- In both evaluations, utilities highly reliable (99.98%) prior to deployment
- No severe storms occurred during test periods

Ancillary Needs



Metric Counts by Type

State	Reliability Metrics	TOU/DR Participation (%) and/or Impact (MW or $)	Unaccounted for Energy	Meter/HAN Failures and Complaints	Truck Rolls Avoided via Meter "Pinging"	Customer Engagement	Cybersecurity	Theft Detection and Billing	Others*	Total
CA	4	3		4		2	In development		7	21
IL	4		1					1	3	9
MD		10		2	4	5				21
OH	4	Ed. Plan	5	2	3		Annual Plan	1	13	30
	12	14	6	8	7	7	2	2	23	81

Only MD, OH, OK have tied cost recovery to economic benefits

Performance Measurement: The Future

- Performance Reporting Increasingly Common
  - Benefits Not Reported = Benefit Not Generated
  - Low Benefits = Cost Recovery and Customer Sat Risk
- Metrics Will Be Used To Drive Utility Behavior

Customer Concern	Sample Metric
Distribution O&M Cost	Meter Reading Cost/Customer/Yr
Generation Capacity Cost	MW delivered per DR event day
kWh Usage	Ave. System Voltage/VAr
My Reliability	Large Storm Restoration?
Ancillary Needs	Environmental Defense Fund, others

Measurement Challenges, Next Steps

1. Traditional ratemaking contradicts performance*
2. Lack of Focus on “the Critical Few” (add economics)
3. Lack of Standardization
4. Concern that measures will impact compensation
5. State regulators lack resources, authorization
6. Consumer advocates focused on low income

* In 35 states and for 100% of Municipal and Co-Operative utilities

Thank You!

Paul Alvarez, President, Wired Group
palvarez@wiredgroup.net
303-997-0317, x-801

Please contact me with comments, questions, and input!

Smart Grid Services:

- *Benefit Quantification/Effectiveness Evaluation*
- *Visioning: Roadmap/Design/Business Case Development*
- *Implementation: Project and Change Management*
- *Optimization: Customer Rate, Program, Services Designs*

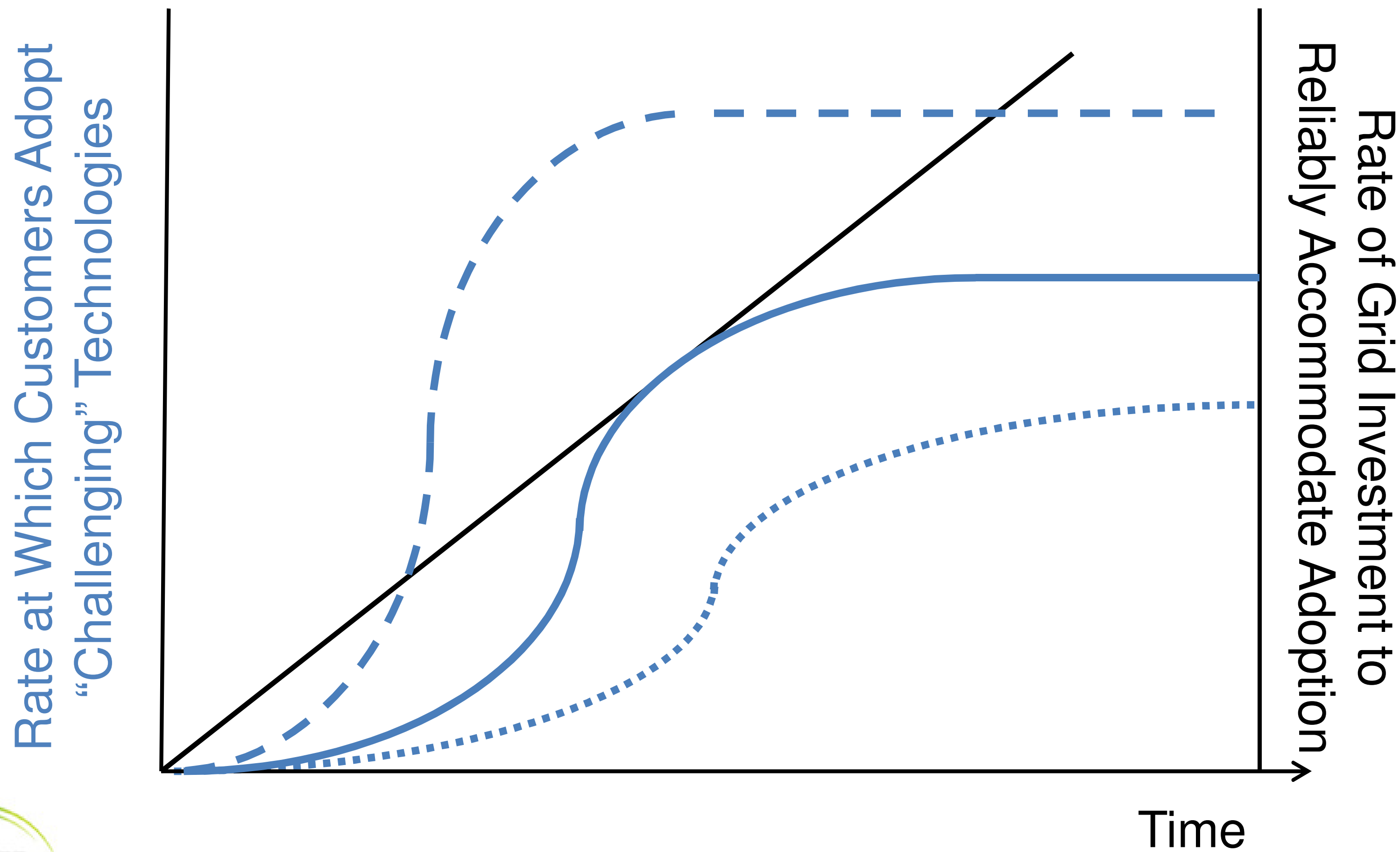
To download evaluation reports/reference sources visit www.wiredgroup.net/Reference_Work_Resources.html

EEI Members: Please join Smart Grid Value Group! See/contact me for more information.

Join Linked In Group: Smart Grid Benefit Measurement & Maximization

Potential Reliability Benefits

(What is the Value of a Reliability Insurance Policy?)



Smart Grid Economic and Environmental Benefits

A Review and Synthesis of Research on Smart Grid Benefits and Costs

SmartGrid consumer collaborative
listen, educate, collaborate

Message from the SGCC

SmartGrid consumer collaborative
listen, educate, collaborate

- Suggestion: Tie research to SGCC mission and vision.
  - Best Practices?
  - Customer Engagement?
  - Etc.

Acknowledgements

- Suggestions:
  - Describe why this research was commissioned?
  - Issue disclaimer?
  - List members?

SmartGrid consumer collaborative
listen, educate, collaborate

We are learning from Smart Grid deployments

- How Smart Grid investments benefit customers
- The size of the benefits from various capabilities
  - Economic
  - Environmental
  - Reliability
  - Customer Choice
- How much the Smart Grid costs
- Benefit drivers

SmartGrid consumer collaborative
listen, educate, collaborate

Research approach

1. Define Smart Grid capabilities
2. Identify and review available research on each
3. Evaluate and prioritize available research
   A. Controlled Studies/Surveys
   B. Informed Analyses
   C. Consider the Source
4. Prioritize for this review; clarify for report users

Executive Summary of Findings

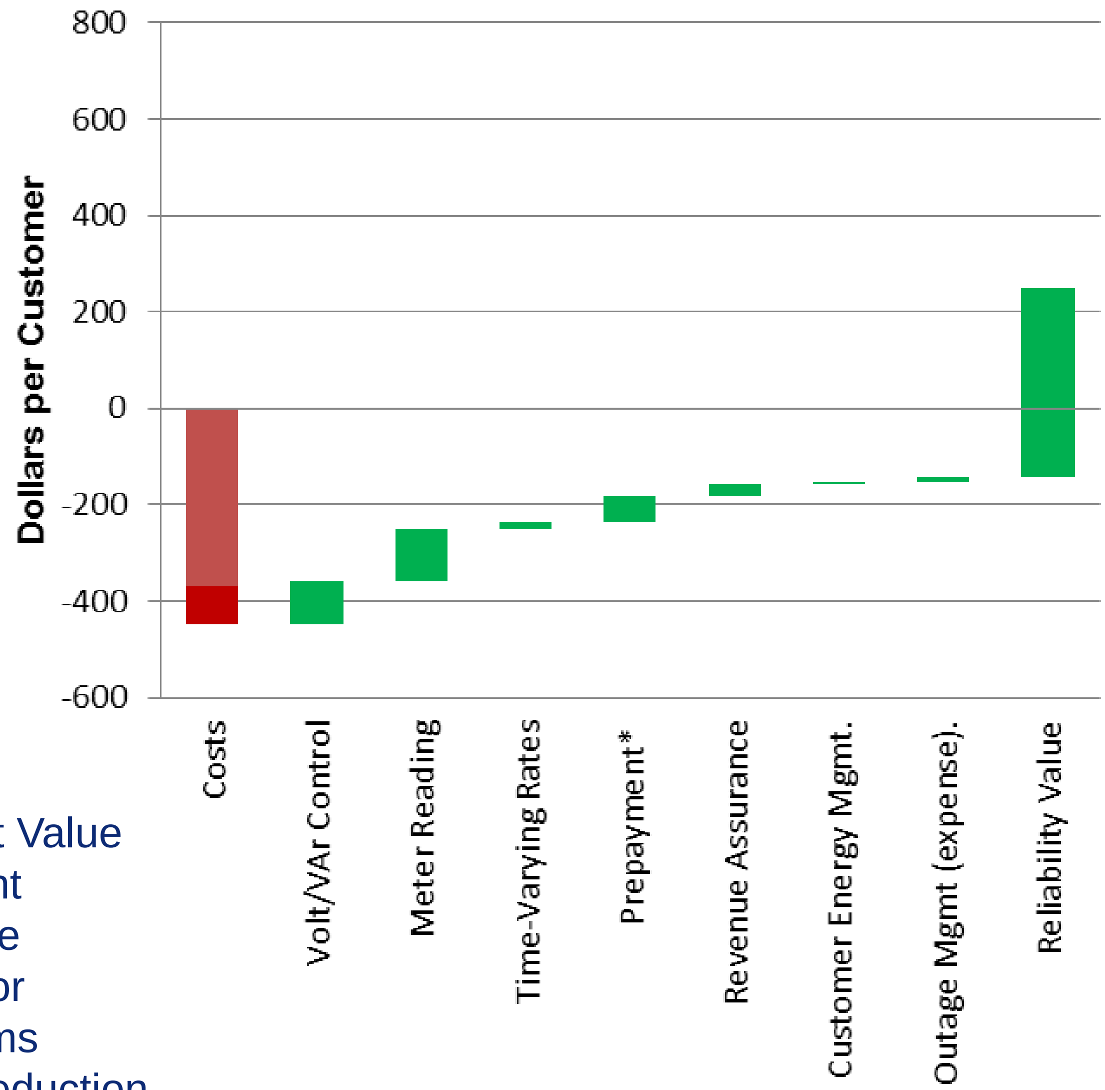
SmartGrid consumer collaborative
listen, educate, collaborate

– Direct and indirect economic benefits in excess of costs are likely (1.5 to 1) w/conservative assumptions

– Extensive environmental benefits are also available but can be difficult to quantify

– Economic and environmental benefits can be higher (2.6 to 1); variances explained by 3 primary drivers
  - Utility operating characteristics pre- and post-deployment
  - Customer-participation levels in Smart Grid programs
  - Speed of operating cost reductions and recognition

Reference Case Cost-Benefit by Capability



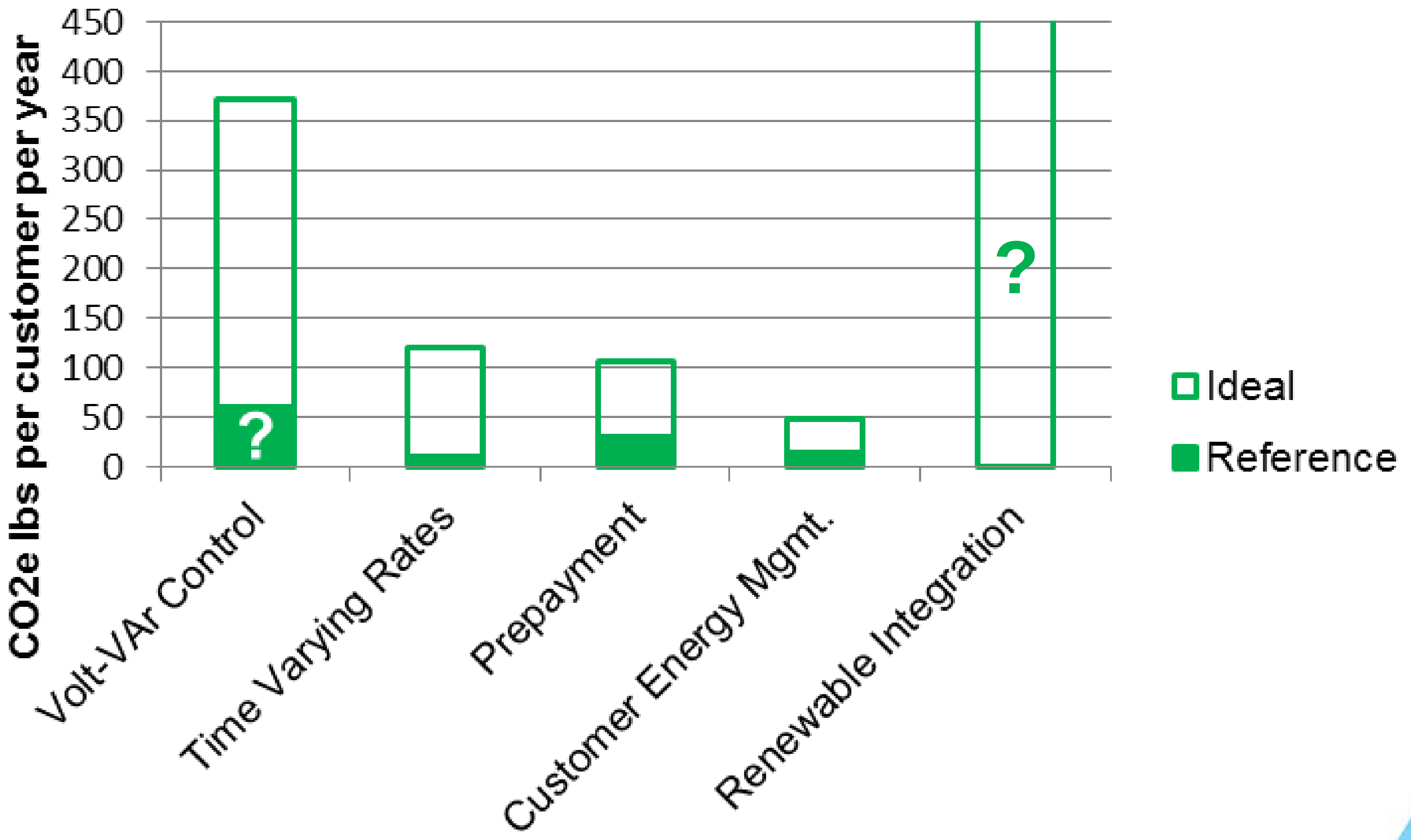
13-year Net Present Value

- 3 year deployment
- 10 year project life
- 3-year ramp-up for customer programs
- Immediate cost reduction

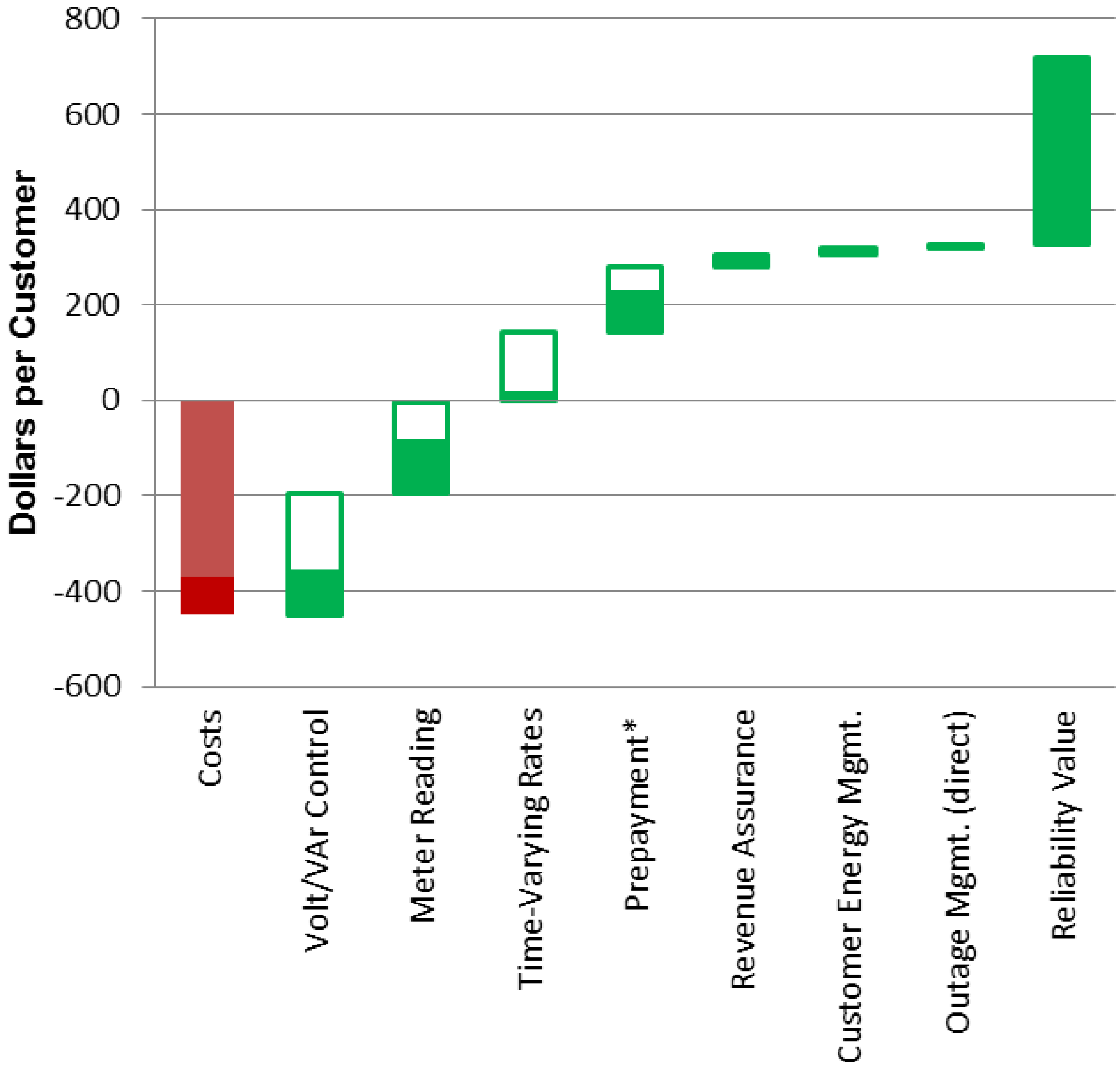
* Includes remote disconnect/reconnect benefits

SmartGrid consumer collaborative
listen, educate, collaborate

Environmental Benefits



Ideal Case Cost-Benefit by Capability



13-year Net Present Value

- 3 year deployment
- 10 year project life
- 3-year ramp-up for customer programs
- Immediate cost reduction

* Includes remote disconnect and reconnect benefits

1. A systems approach is needed to maximize benefits
   1. Utility Operations
   2. Customer Engagement
   3. Regulatory/Governance
2. Stakeholders must collaborate to define the grid they want
   1. Capabilities
   2. Flexibility
   3. Cost

Smart Grid Lessons Learned

Utility and Regulator Perspectives

Duke Energy

Xcel Energy
RESPONSIBLE BY NATURE™

EMPOWERING OKLAHOMA
Oklahoma Corporation Commission
ENERGY • TRANSPORTATION • UTILITIES

PUBLIC UTILITIES COMMISSION
EUREKA
STATE OF CALIFORNIA

Mr. Mark Wyatt | Mr. Gene Smith | Hon. Dana Murphy | Ms. Liza Malashenko

metavû
Creating a Return on Environment℠

Paul Alvarez, Moderator

Panel Discussion, January 25, 2012

Rationale For Panel

- MetaVu Evaluations: comprehensive, independent
  - SmartGridCity™ for Xcel Energy
  - Largest Midwest deployment for PUC of Ohio
- Perspectives: Costs, Benefits, Customer, Org/Ops
- Methods:
  - Pre- and post-deployment operational data
  - Business cases, regulatory orders, relevant research
  - Emerging measurement frameworks
  - Quantitative and qualitative consumer research

Top Three Value Drivers

Situational Characteristics

- Energy Cost
- Capacity Value
- System Load
- Operating Norms
- Distribution Standards

Regulatory Choices

- Restructured?
- Decoupled?
- Investment Incentives?
- Performance Incentives?
- Restrictive Rules?

Utility Choices

- Design
- Implementation
- Optimization

Smart Grid Investments Are Different!

Traditional Investments in G, T, & D (Value is Black and White)

Needed + Fairly Procured + Commissioned = Customer Value Assured

Smart Grid Investments (Value is Highly Dependent on Choices)

Investment Optimization + Change Mgmt. + Customer Program Development = Customer Value Assured

Utility Choices Influenced by Regulation

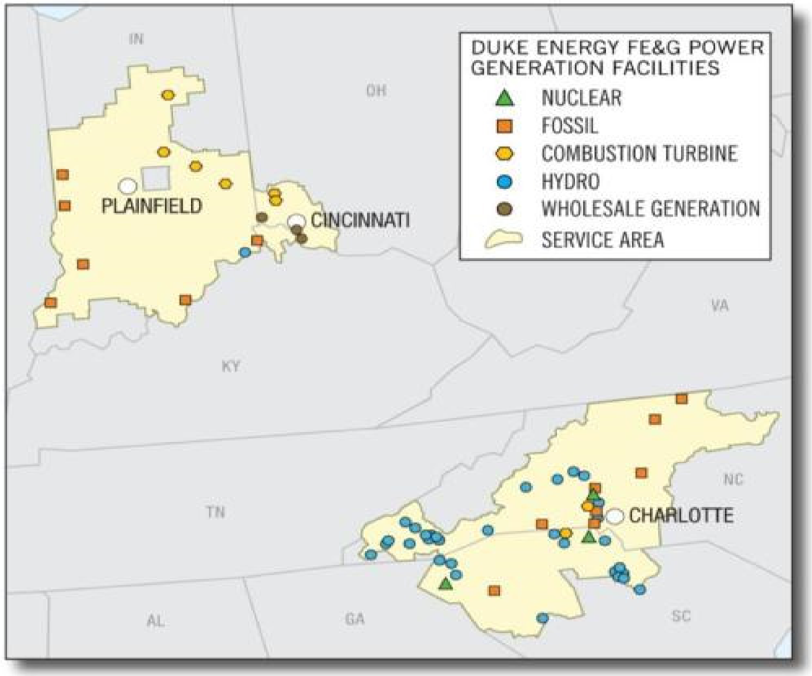
Investment Optimization (Design)	Change Management (Implementation)	Customer Program Development (Optimization)
Communications	Organizational Structure	Data Access
Volt/VAr Control	Operating Processes	TOU Pricing
Sectionalization	Systems Integration	Outage Information
Remote Disconnect	Organizational Capabilities	DSM Designs

Duke Energy Smart Grid

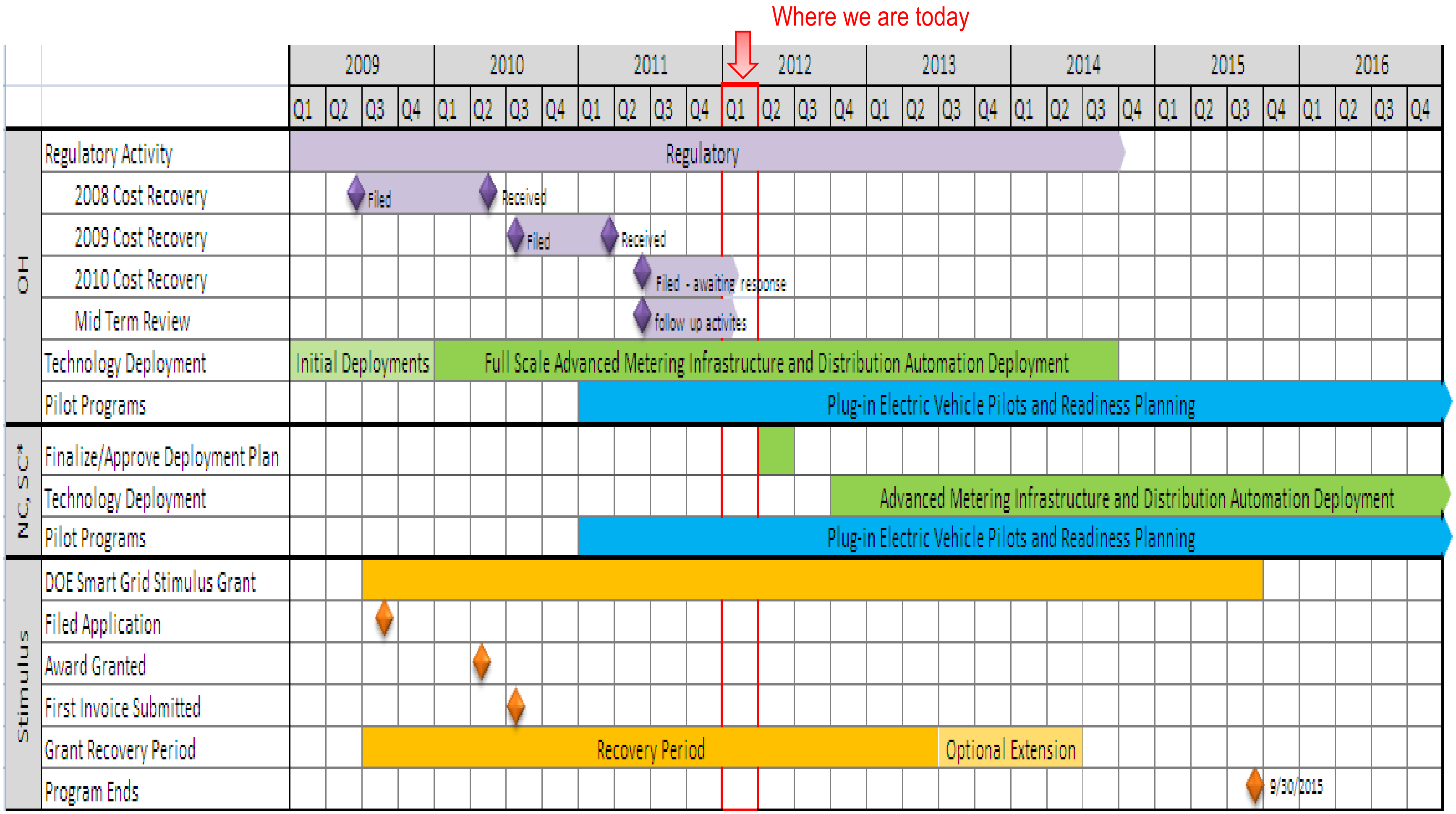
Mark Wyatt, Vice President, Smart Grid and Energy Systems
January 2012

Facts About Duke Energy

- 150+ years of service
- Fortune 500
- Over 18,000 employees
- $57+ billion in assets
- 5 states: North Carolina, South Carolina, Indiana, Ohio and Kentucky
- 50,000 square miles of service area
- 27,000 MW of regulated generating capacity
- 4.0 million retail electric customers
- 500,000 retail gas customers



Smart Grid Program Timeline



* Pending Regulatory Approval

◆ Indicates a key milestone/ date

Program to Date Summary

Advanced Metering Infrastructure

COMM NODE VS. PLAN

Installed	Plan	Progress
72,892	72,274	100.9%

ELECTRIC METER VS. PLAN

Installed	Plan	Progress
325,923	310,230	105.1%

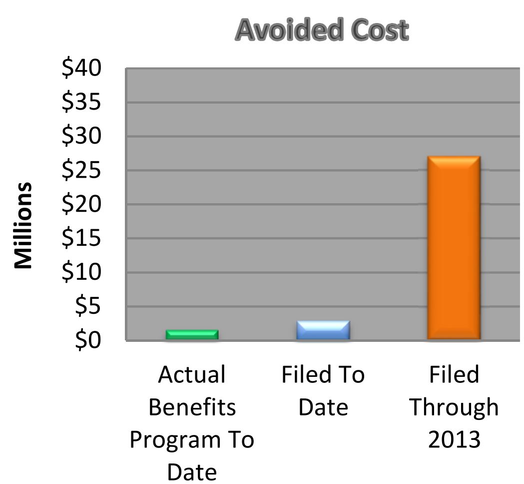
GAS MODULE VS. PLAN

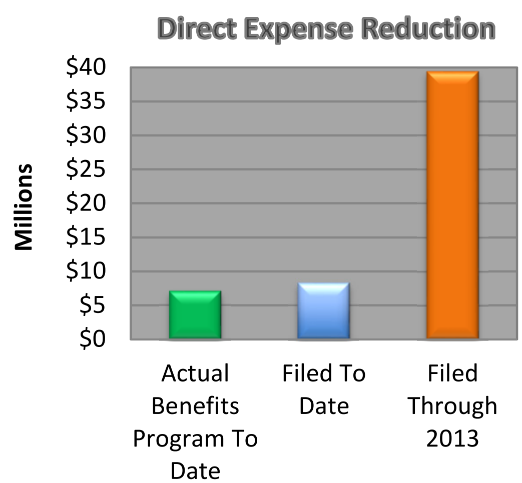
Installed	Plan	Progress
229,704	217,279	105.7%

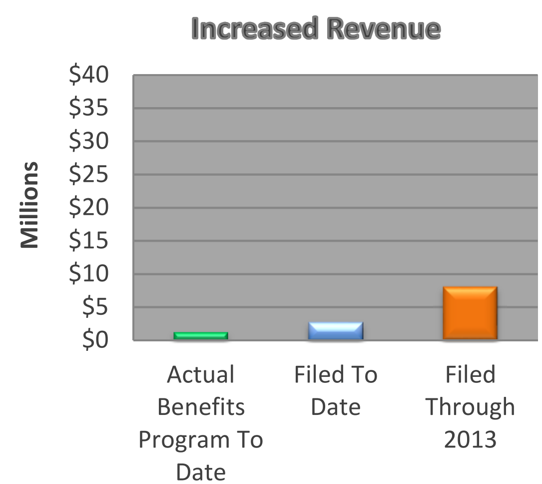
Distribution Automation

Substation Comm	32
Circuit Breakers	49
Relays	224
Sectionalization	273
Line Sensors	200
Capacitors	536
Self healing	17

Ohio Benefits Being Realized as of 12/31/11



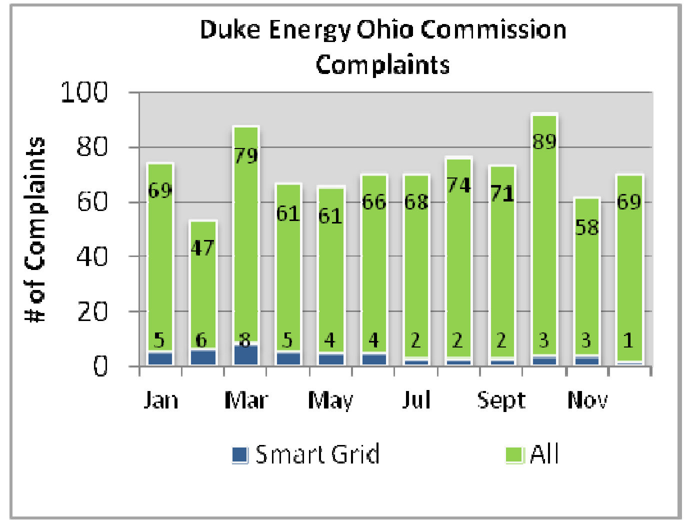




Customer Engagement Model

Duke Energy engages customers throughout the meter deployment lifecycle.

- Educating customers on grid modernization and its associated benefits.
- Engaging customers early in the deployment lifecycle.
- Ensuring customers are aware of what we will be doing and when we will be doing it.
- Proactively managing and addressing individual events to prevent negative publicity. To date, events are at a minimum.



Observations and Learnings

- Extensive transparency and regulatory engagement and dialogue are required.
- Repeatable and scalable cross-functional processes , staffing models and vendor contracts are necessary for large scale change.
- Enable a plug and play smart grid infrastructure to accommodate evolving smart grid technologies and standards.
- Customer engagement is critical.

SmartGridCity™
Understanding Value

Lessons Learned – Utility and Regulator Perspectives

Gene Smith - Program Manager,

Transmission and Distribution Technology Projects

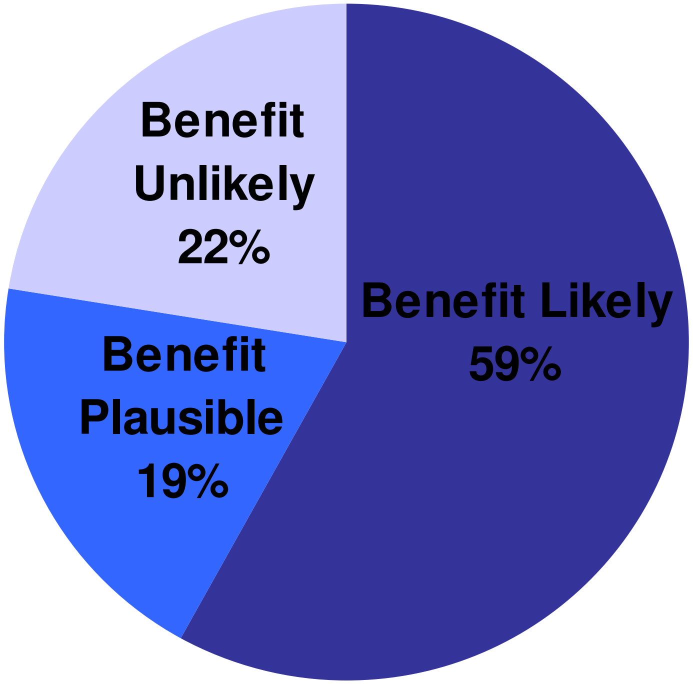
January 25, 2012

Xcel Energy®

Xcel Energy®

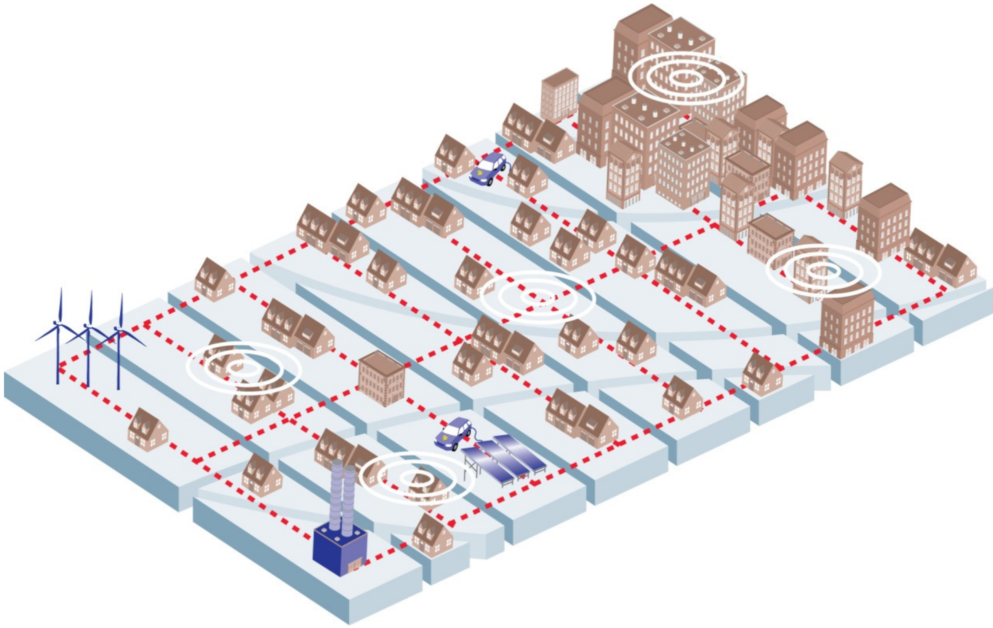
Project Objectives

- **Create an ongoing testing platform for technology and customer interaction**
- **Build skills and experience**
- **Evaluate Value Propositions**
  - More than 60 original hypotheses were evaluated
- **Determine internal and external benefits**



Where we are today

- Field Infrastructure / IT Systems Complete



SmartGridCity™ Partners

Internal Benefits - Customer Perspective

- Evaluated systems to optimize future investments and avoid rate increases
- Increased electric reliability and reduced customer minutes out (CMO)
- Provided experience operating a modern grid system
- Spurred successful spin-off upgrades and other modernization efforts that benefit the entire service territory

Customer Value

- Enables customers to better understand energy and usage through interval data presentation
- Meter pinging allows for reduction of investigation-related delays
  - Faster outage restoration, reduced service calls
- Ability to detect outages without requiring a customer notification
- Customer research identified communication, education, and energy usage information preferences tailored to perceived value

Lessons Learned – Internal and External

- Significant systems integration generates larger challenges, but yields a more holistic assessment of potential applications
- Trailblazing new technologies requires invention not just implementation
- Better understanding of vendor contributions

Lessons Learned – Regulatory Interactions

- Proactive communication positions the utility as the subject matter expert instilling confidence in smart grid initiatives
- Large, experimental initiatives require transparent dialogue with regulators which increases trust in utility
- Incentives needed for innovation and creativity

Thank You

Smart Grid Lessons Learned:

Utility and Regulator Perspectives

Presented by

Oklahoma Corporation Commission Chair Dana Murphy

January 25, 2012

Oklahoma Corporation Commission

Oklahoma Regulated Utility Project Basics

OKLAHOMA GAS AND ELECTRIC COMPANY

- Order Approved July 1, 2010, in Public Utility Docket 201000029
- $357.4 million budget with $130 million covered by stimulus funds
- 484,000 meters installed to date
- Completed installations by December 31, 2012
- Recovery through a tariff rider
- Required a minimum of $2.3 million be dedicated to consumer education
- Required that website access be made available at no additional charge as well as free monthly energy reports for Low income and Senior Citizen ratepayers
- Guaranteed minimum O&M savings of $22,201,687 as part of the Commissions approval. Reduces recovery through the rider.
- Projected generation savings of $155 million and fuel savings of $68 million

PUBLIC SERVICE COMPANY OF OKLAHOMA

- 14,000 meter pilot project in Owasso Oklahoma
- Funded through low interest loans as part of the Federal Stimulus Package
- In-home networking will be a major focal point

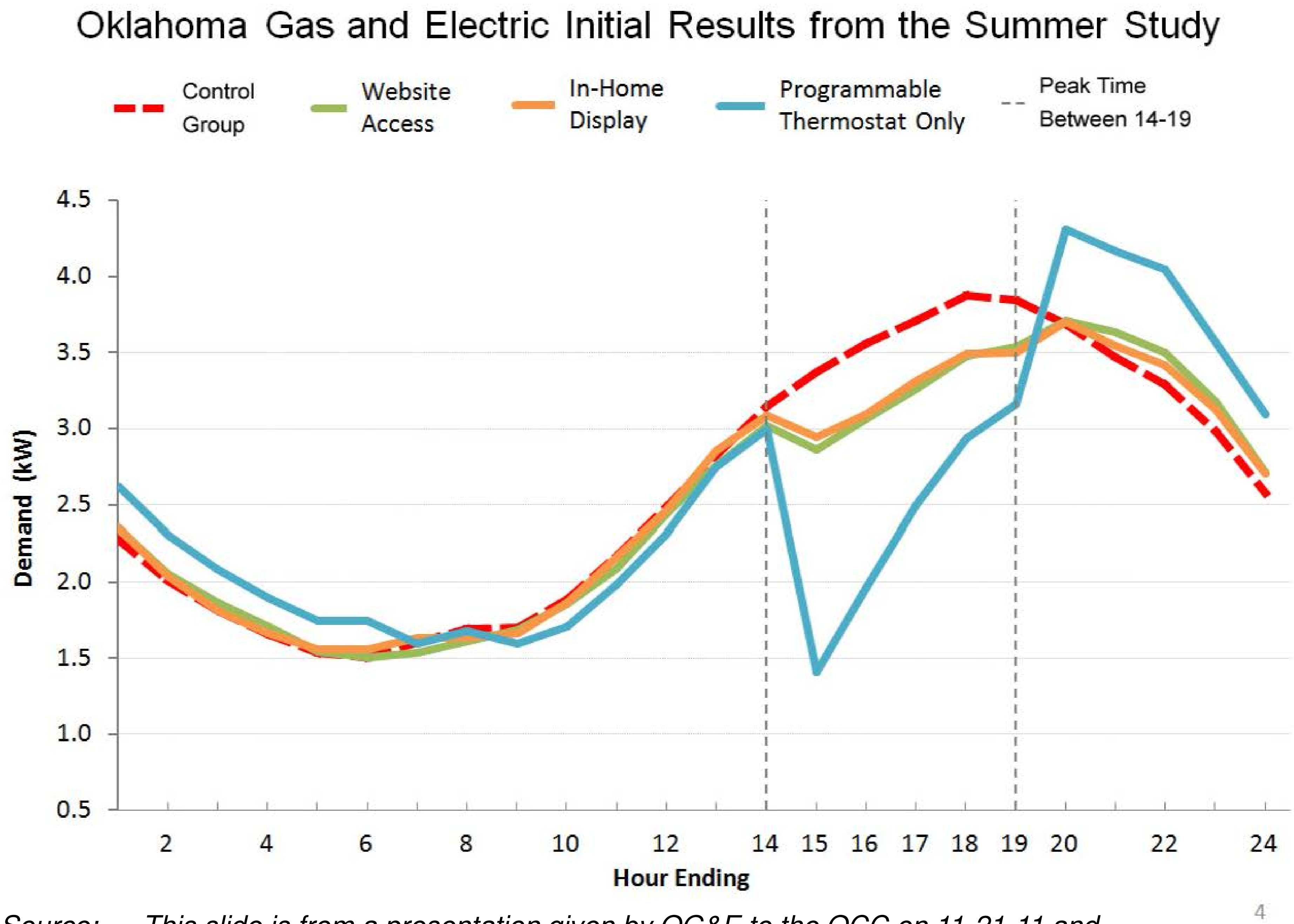
Direct Customer Benefits

<u>OKLAHOMA GAS AND ELECTRIC COMPANY</u>

- Customer interactive Website
  - Near real-time usage and cost tracking
  - Comparison to like users and Energy Savings tips
- Voluntary Peak Pricing Tariffs and Programmable Thermostat Pilot Program
- In-Home Device Pilot Program
- Faster Service Restoration through pinpoint outage identification
- OG&E guaranteed O&M savings of $22 million required by Order
  - Reduced 185,000 truck rolls as of November 2011
  - 127,000 remote connect/disconnects as of November 2011
- Has reduced electricity theft with 841 instances identified
- Lower accident/injury rates for utility workers and fewer property claims

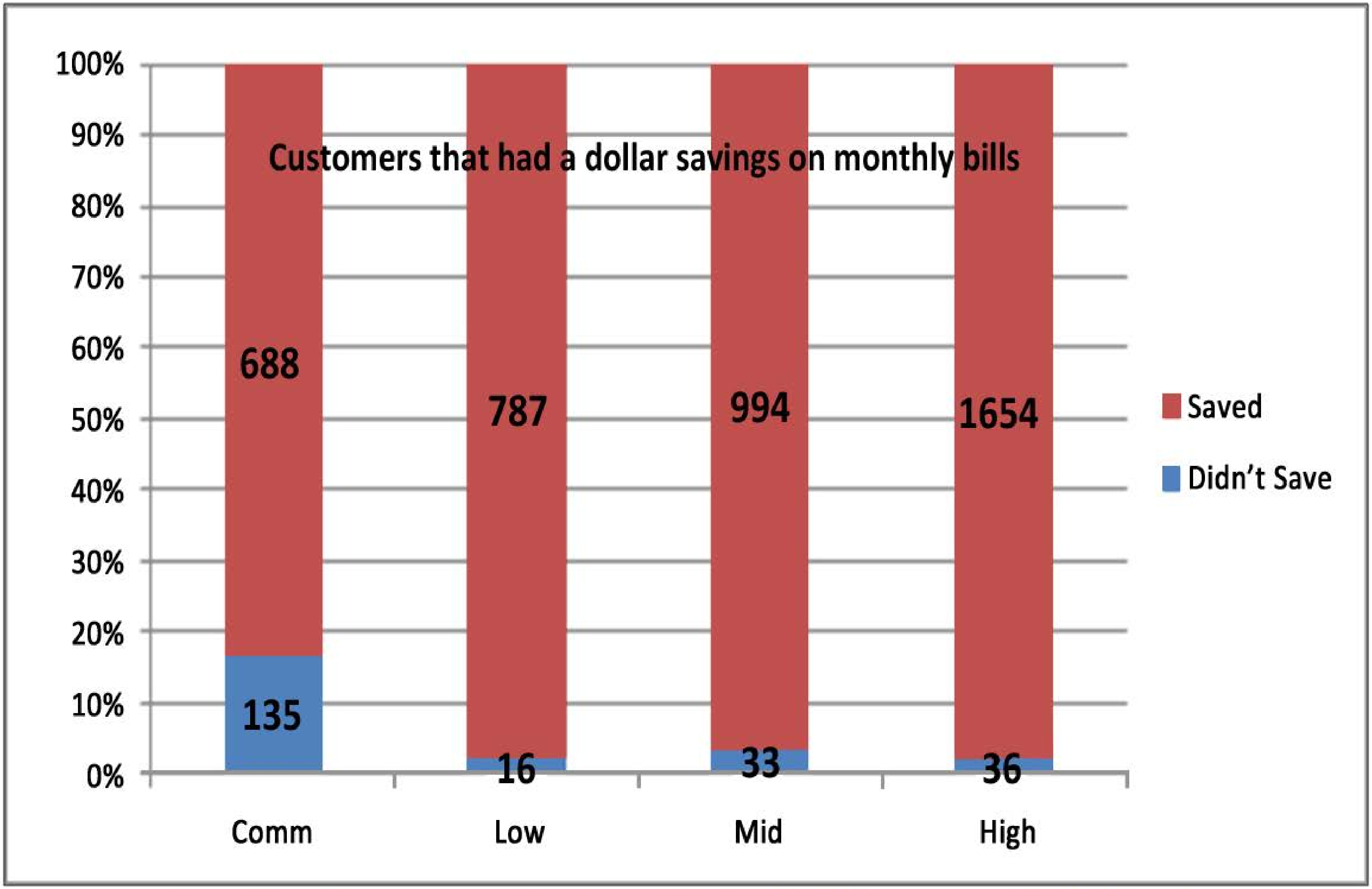
<u>PUBLIC SERVICE COMPANY OF OKLAHOMA</u>

- Customer interactive Website similar to OG&E's
- Voluntary Peak Pricing Tariffs
- Voluntary Direct Load Control Programmable Thermostat Pilot Program
- In-Home Device Pilot Program
- Wi-fi enabled Home Networking with Zigbee based appliance communication



Source: This slide is from a presentation given by OG&E to the OCC on 11-21-11 and is available in its entirety at www.occeweb.com.

OGE Volunteer Ratepayers' 2011 Savings from the Study



Source: This slide is from a presentation given by OG&E to the OCC on 11-21-11 and is available in its entirety at www.occeweb.com.

DistribuTECH

Smart Grid Lessons Learned

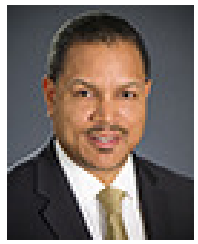
Liza Malashenko

California Public Utilities Commission

January 25, 2012

California Public Utilities Commission (CPUC)

President Michael R. Peevey



Commr. Timothy A. Simon

Commr. Michael Florio

Commr. Catherine Sandoval

Commr. Mark Ferron

- Headquartered in San Francisco
- Regulates privately owned telecommunications, electric, natural gas, water, railroad, rail transit and passenger transportation companies such as moving companies, limousines and charter buses.
- Responsible for ensuring that customers have safe, reliable utility service at reasonable rates, protecting against fraud, and promoting the health of California's investor-owner utilities (IOUs).
- Five Commissioners are appointed by the Governor and confirmed by the California Senate.
- Governor selects one of the five Commissioners to serve as the CPUC president.
- Commissioners make all CPUC policy decisions, meeting usually twice a month to discuss and vote on issues.

The Smart Grid (SG) Timeline of Decisions

AMI Projects Approved:
2006 – PG&E
2007 – SDG&E
2008 – SCE

December 22, 2008
CPUC R.08-12-009
Rulemaking to modernize the electric Grid

September 19, 2010
CA AB 1476 requires privacy rules

September 29, 2010
AB 2514 is enacted for storage and Electric Vehicles

July 14, 2011
R.09-08-009
CPUC Rules on Electric Vehicles

Q1/Q2 July 2012
CPUC Decision to adopt Smart Grid metrics/goals

October 2012
CA IOUs file SG Annual Report with CPUC

2013
Smart Meter Opt Out cost allocation decision

May 8, 2003
Energy Action Plan I

October, 2005
Energy Action Plan II

February, 2008
Energy Action Plan Update

October 11, 2009
CA SB 17 requires filing of Smart Grid Deployment Plans

June 24, 2010
D.10-06-047
CPUC decision on Smart Grid Deployment Plan Requirements

July 1, 2011
CA IOUs file Smart Grid Deployment Plans

July 28, 2011
D.11-07-056
CPUC adopts SG privacy & security rules

Q1/Q2 2012
Phase 1 Smart Meter Opt Out decision

July, 2012
CPUC Decision on Smart Grid Deployment Plans

October, 2013
Energy Storage decision

Summary of Major Smart Grid Initiatives

Smart Meter Deployment

- SDG&E: over 95% complete. Working on difficult cases. Total 1.1 million electric and 0.9 million gas meters.
- PG&E: ~95% complete. Deployment to finish by Q3 2012. Total over 5 million electric and 4 million gas meters.
- Edison: ~70% complete. Majority of deployment to finish by end of 2012. Total over 4 million electric meters.
- All IOUs will have an Opt-Out program by end Q2 2012.

American Recovery and Reinvestment Act (ARRA) Projects

- Federal funding of $153 million received for five projects - over 50 green jobs created.
- SDG&E: Grid communication System project.
- Edison: Irvine Smart Grid Demonstration and Tehachapi Wind Energy Storage project.
- PG&E Synchrophasor project and Compressed Air Energy Storage project.

Customer Data Access

- All three California IOUs are working with United States Chief Technology Officer, Aneesh Chopra, to implement a "Green Button" for customer data access.
- All three California IOUs have files Home Area Network (HAN) plans to outline steps towards mass activation of HAN capabilities and 3rd party participation.
- There are several HAN and Demand Response pilots currently underway.

Other Smart Grid Initiatives

- CPUC required all three IOUs to create Smart Grid Deployment Plans, which detail grid modernization efforts, including investments of $6 billion to $8 billion dollars over the next 10 years.
- SDG&E: Outage Management, Distribution Automation, supporting customer solar etc.
- Edison: Distribution Automation, Distribution VoltVAR devices, Customer empowerment.
- PG&E: Has files a Smart Grid Pilot application, consisting of distribution automation, fault detection, customer segmentation and other capabilities. Currently under review.

Smart Grid Deployment Challenges

- Awareness – Smart Grid continues to be a specialized topic among policy makers.
- Number of Smart Grid initiatives – impact on many CPUC polices and proceedings.
- Cost and rate pressure – Smart Grid requires significant investments in foundational infrastructure (e.g. communication network).
- Coordination – sharing experiences across utilities in a quickly evolving space.
- Cyber-security – new issue for regulators.
- Market and 3rd party enablement – key for realization of Smart Grid.
- Adoption of standards and standard maturity – coordination challenges and resource constraints.
- Misleading communication – Smart Grid is often being marketed as the "house of the future“, not upgrading utility infrastructure.

Lessons Learned – Importance of Customer Focus

- A combination of grass-roots community outreach combined with mass-media is often effective.
- Utilities must provide clear messages that appropriately target their customer class and adequately explain the tools *becoming* available to them.
- The CPUC and the utilities must educate their CSRs to in turn educate and empower customers who call with a complaint or inquiry.
- Utilities and the CPUC must utilize customer feedback as a teaching and learning opportunity (i.e., using complaints as case studies to make adjustments rather than simply keeping a record of complaints).
- When issues arise, utilities must make adjustments necessary to meet customer needs; appropriately and immediately react to customer complaints.
- The transition to a smarter grid needs customer acceptance and all three utilities must be nimble, responsive, and proactive to customer needs.

Current CPUC Priorities for 2012

- Smart Grid Deployment Plans – provide direction by July 2012.
- Smart Grid goals and metrics – track progress of Smart Grid.
- Privacy rules – enforcement and potential expansion.
- Cyber-security – develop requirements and collaborate with the national cyber-security initiatives.
- Market enablement – 'demarcation point' for utility ownership of assets within a customer home.
- Distributed energy resource interconnection – update the rules.
- Energy storage – cost effectiveness methodologies.
- Electrical Vehicles – communication of sub-meter data.
- Smart Meter Opt-Out – enact for all California utilities and begin Phase 2 to consider cost-allocation.

Thank you!

"Smart Grid is the foundation for the transformation of the electric industry from a passive and reactive system to one that it more reliable, efficient, and cost-effective for consumers. By using more advanced technology, a Smart Grid will empower consumers to manage their electricity use and save money, help utilities reliably deliver power, and increase our use of renewable resources."

CPUC President, Michael R. Peevey

For further information related to Smart Grid, please contact Elizaveta Malashenko:
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Linked In Group: "Smart Grid Benefit Measurement and Maximization"

metavû

Creating a Return on Environment℠

Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for IOUs and Regulators

Presentation to the Staff Subcommittee on Electricity

MetaVu, Inc.
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Denver, CO USA 80205
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NARUC Annual Conference, November 13, 2011

Maximizing Smart Grid Customer Benefits

OUTLINE

- MetaVu and 2 smart grid deployment evaluations
- Top 2 benefits of greatest interest to customers
- Measuring customer benefits
  - Top 3 economic capabilities
  - Top 3 emerging standards
- IOU and Regulator roles
- Suggested actions for IOUs, Regulators

TAKEAWAYS

- A benefit not communicated to customers = no benefit
- Assume a capability not measured will not deliver customer benefits
- Specific and significant utility actions are required to maximize customer benefits

About MetaVu
Creating a Return on Environment[sm]

What we do

- **Innovate products, services and business models** employing sustainability as a strategy for value creation.
- **Build organizational capabilities** to integrate social and environmental performance throughout the value chain
- **Measure performance** with evaluation and assurance products / services

Utility Practice

- Renewable Energy Strategy
- Consumer Portfolio, Program, and Promotional Development
  - DSM
  - TOU Pricing & Prepayment
- Smart Grid Deployment Evaluation

VERDANTIX *2010 "Smart Innovator Award – Top Sustainability Consultant"*

Representative MetaVu Clients

Smart Grid Deployment Evaluations

Comprehensive, Independent Assessments

Ohio Public Utilities Commission Staff

- **800,000 premises, electric and gas**
- **Full AMI and DA, entire service area**
- **Scope of Assessment**
  - Estimated economic benefits: Fuel, Capital, Expenses, Revenue Capture
  - Meter accuracy and RF emissions
  - Cyber security guideline conformity
  - Systems/operations integration level
- **Public version of report released June 30 on PUCO website**

Xcel Energy SmartGridCity™

- **46,000 premises, half with AMI**
- **Full DA on selected feeders**
- **Scope of Assessment (by Capability)**
  - Actual economic benefits: Fuel, Capital, Expenses, Revenue Capture
  - Actual non-economic benefits: reliability, environmental, safety
  - Projected roll-out costs based on actual
  - Relative value of capabilities from customers' perspective (market research)
  - Organizational and operational change management in event of roll-out
- **Public release imminent**

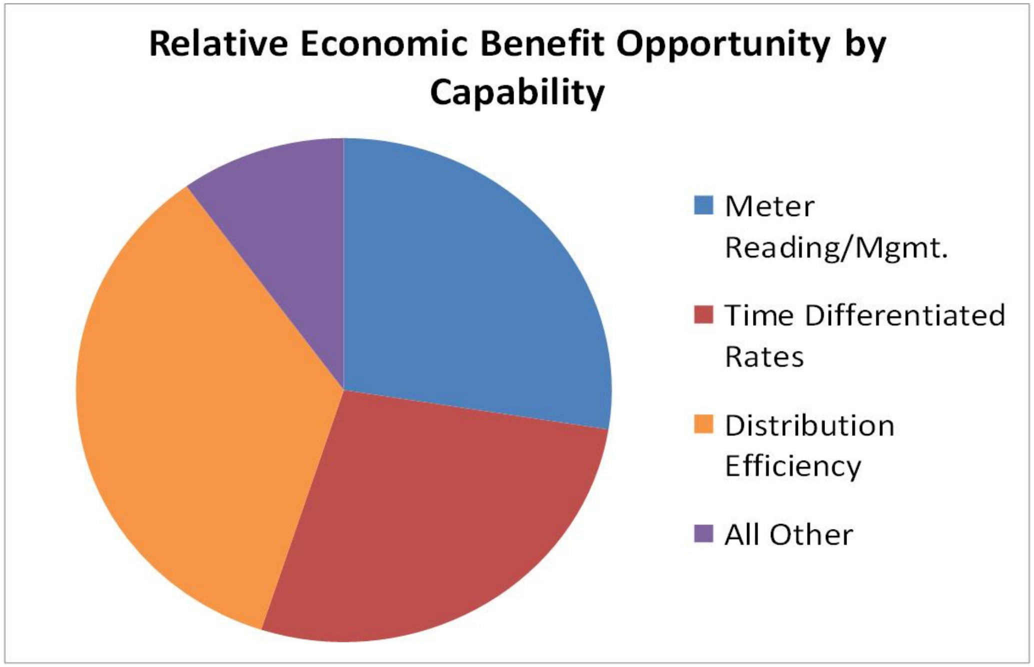
What Benefits Are of Interest to Customers?

Top 2 Customer Benefits; Top 3 Economic Capabilities

Smart Grid Benefits Important to Utility Customers*

Least:	Environmental Benefits (51%)
2nd Least:	Reliability Benefits (54%)
2nd Most:	Improved Outage Services (73%)
Most:	Reduced Cost (78%)

Customers will not perceive benefits unless they are communicated!



Benefits cannot be assured unless they are measured!

*800 CO Residential Customers; % ranking benefit as important (8,9, or 10 on 0-10 scale)

Measuring Customer Benefits

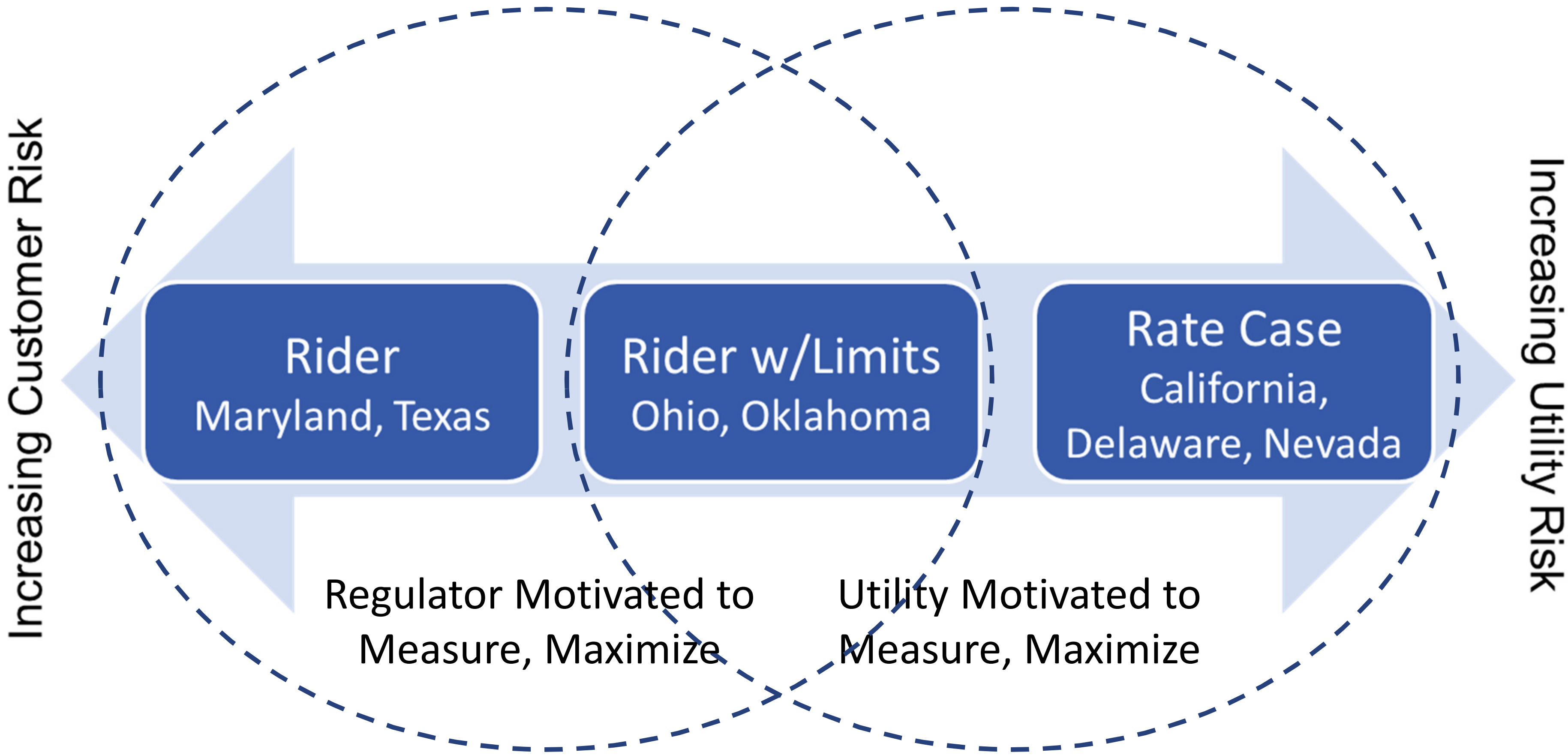
Top 3 Emerging Standards

Guideline/Resource	Developer	Best Use
Measuring the Costs and Benefits of the Smart Grid	EPRI (1020342)	Quantifying the costs and benefits of various capabilities
Smart Grid Maturity Model	U.S. DOE and Carnegie Mellon University	Assessing the ability of a utility organization to maximize the value of smart grid investments (Leading Indicators)
Evaluation Framework for Smart Grid Deployment Plans	Environmental Defense Fund	Outcome reporting metrics (Lagging Indicators)

How would a customer know if an IOU's smart grid was worth the investment?

Who Should Lead Benefit Measurement?

It Depends on the Cost Recovery Model



How Can an IOU Maximize Benefits?

Formal Change Management and Ongoing Efforts Strongly Suggested

Change Management Framework

Organizational Structure	Process and Governance
Systems and Tools	Capabilities and Resources

Specific and significant organizational and operational utility actions are required if customer benefits are to be maximized

- DSM program portfolios, features, and promotions should be modified to take advantage of new capabilities
- Some utility function budgets should decrease while others should increase
- Field Services will need to gain computer hardware and software skills
- Distribution Engineering will need to gain communications network skills
- Organizational realignments may be needed to reflect changing responsibilities
- Business Systems will transition from distribution operations support to peer
- Systems will need to be integrated to take advantage of newly available data
- Plan investments according to the 80/20 rule

How Can a Regulator Maximize Benefits?

Examples Indicated

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Prudent Investment

Benefit Maximization

Performance Measures
- Reliability
- Distribution Efficiency

Decoupling
- Distribution Efficiency

Cost Recovery Limits
- O&M Savings
- Revenue Capture

Performance-Based Rates
- Time Differentiated Rate Participation, Impact

Rule Changes
- Remove Barriers to New Services
- Data Privacy and Availability

Thank You!

1. If a benefit is not communicated to customers, there is no customer benefit
2. Assume that a capability not measured will deliver no customer benefit
3. Specific and significant utility actions are required to maximize customer benefits

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Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment

Wired Group

National Conference of Regulatory Attorneys

Columbus, Ohio, June 16, 2014

Paul Alvarez, President, Wired Group

palvarez@wiredgroup.net

Our Smart Grid Thesis

- A smarter grid can indeed deliver customer benefits in excess of costs and help prepare for future challenges
- Utilities are sub-optimizing benefits by a significant margin
  - Utility organizational and operational changes are significant
  - Customer engagement is extremely difficult
  - Regulatory and governance structures inhibit benefits
    - 70% of benefits stem from capabilities that reduce sales volumes*
    - Rate case timing impacts rate recognition of O&M/revenue benefits
    - IOUs are rewarded for process (investment), not outcomes (performance)
- Significant regulatory changes are needed in the near term
- Dramatic regulatory changes are advised in the long term

* Ideal case scenario

Smart Grid Systems and Capabilities

Smart Meters

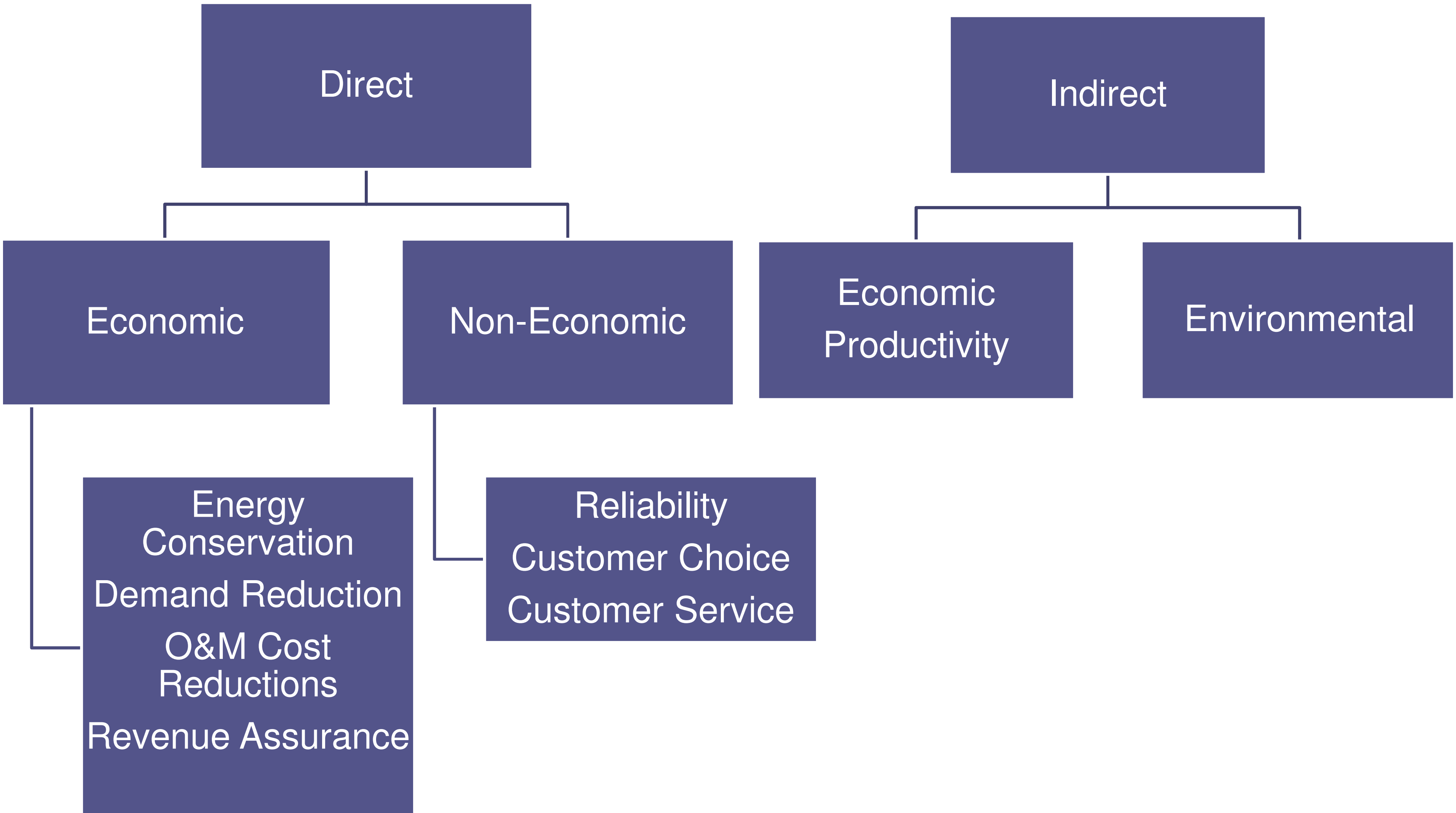
- Auto Meter Reading
- Time-Varying Rates
- Prepayment
- Revenue Assurance
- Outage Management

Distribution Automation

- Fault Location
- Fault Isolation
- Integrated Volt-VAr Control
- Customer-Sited Generation Management

Communications Networks

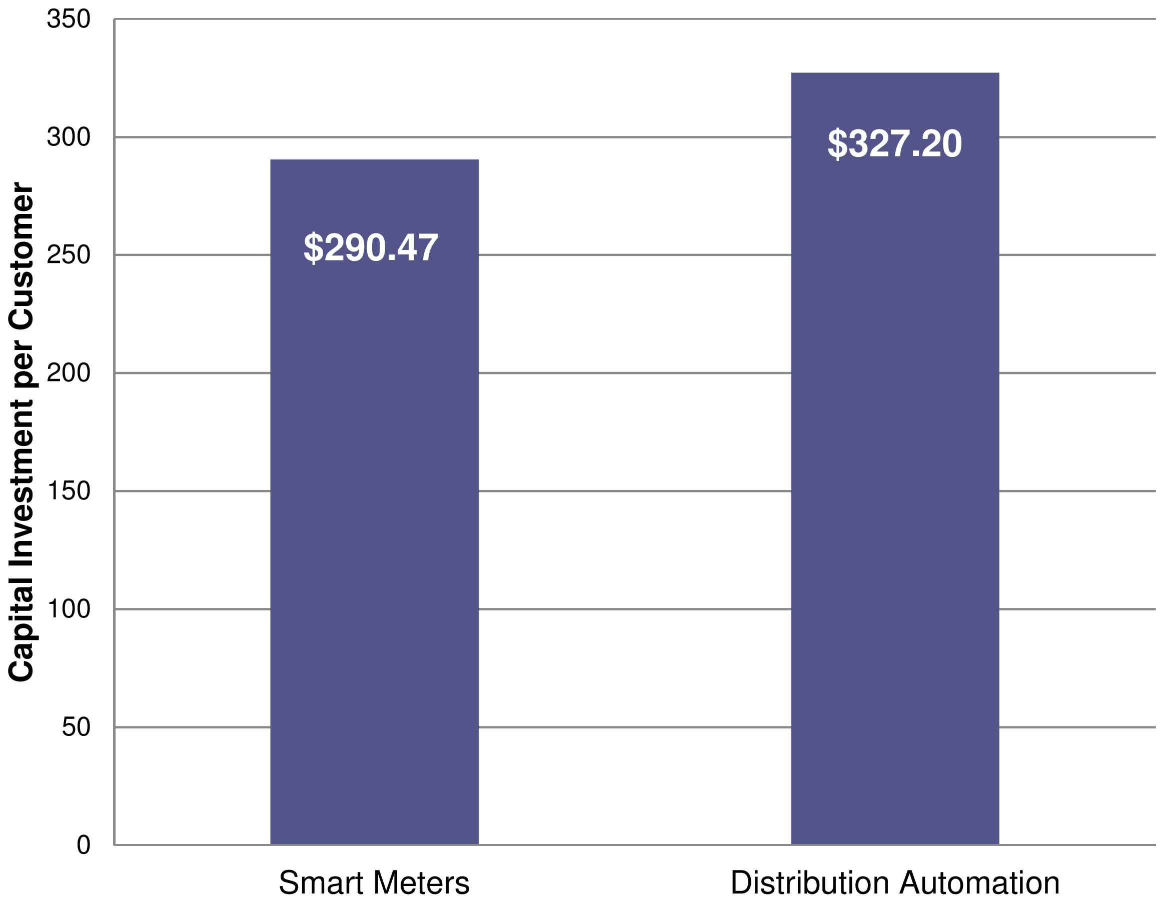
Potential Smart Grid Benefits



Smart Grid Value Proposition Matrix

Systems	Capabilities	Benefits								
		Direct							Indirect	
		Economic (in $)								
		Energy Conservation	Demand Reduction	Operations & Maintenance Cost Reduction	Revenue Assurance	Improved Reliability (in percent)	Increased Customer Choice	Enhanced Customer Service	Economic Productivity	Environmental (in lbs. CO2e)
Smart Meters	Meter Reading									
	Time-Varying Rates									
	Prepayment									
	Revenue Assurance									
	Outage Mgmt.									
Distribution Automation	Fault Location									
	Fault Isolation									
	IVVC									
	Customer-Sited Gen									

System Capital Costs per Customer



Source: SGIG Application Data

1. Identified projects as AMI, DA, or Both
2. Noted customers covered
3. Removed the "Both" projects
4. Divided costs by customers covered

$7.25 per month over 10 years at 10% ROR, 6% interest rate, 50/50 D to E ratio

Cost-Benefit Scenarios and Assumptions

Typical Case

- Typical of where most utilities are today
- Sub-optimal utility operating characteristics pre- or post-deployment
- Low customer participation

Ideal Case

- Designed to represent what utilities could reasonably be expected to achieve
- Optimal pre- and post-deployment operating characteristics
- Moderate customer participation

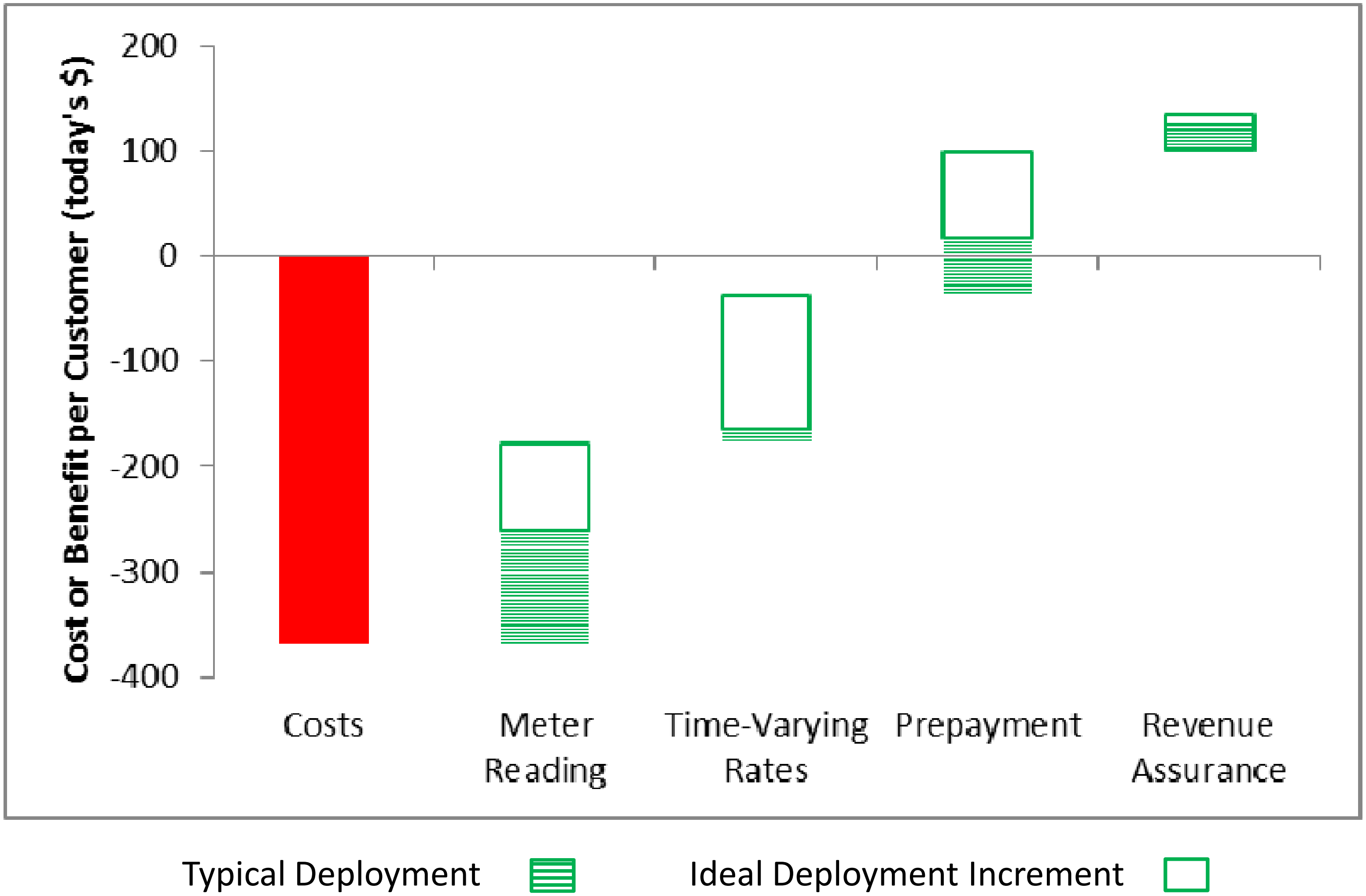
Average Costs: From DOE SGIG proposals but includes Present Value of 10 years' worth of operating costs @ 4% of capital/year

Energy and Capacity values: U.S. averages

$ Benefits per year: Allocated across all customers (not just participants)

Reliability Benefits: Not translated into $ nor incorporated in $ benefits

Smart Meter Benefit-Cost/Customer, 10 years

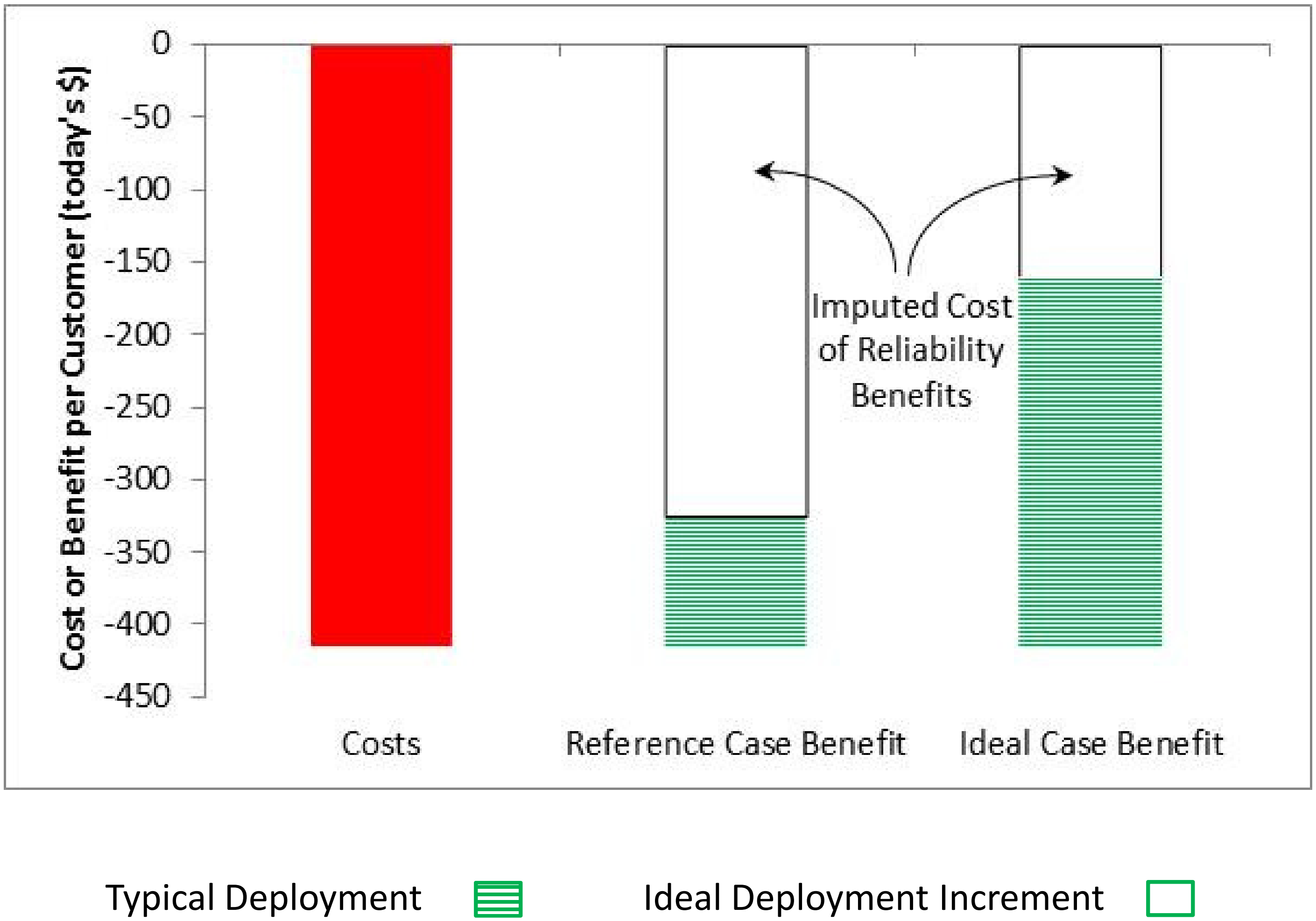


Smart Meter Ideal Case Details

Systems and Costs (Present Value) per Customer	Capabilities and Annual Benefits per Customer, per Year (Ideal Case)	Benefits									
		Direct								Indirect	
		Economic (in $)									
		Energy Conservation	Demand Reduction	Operations & Maintenance Cost Reduction	Revenue Assurance	**ECONOMIC TOTALS**	Improved Reliability (in percent)	Increased Customer Choice	Enhanced Customer Service	Economic Productivity	Environmental (in lbs. CO2e)
Smart Meters $369	Meter Reading			23.92		**23.92**			YES		
	Time-Varying Rates	6.15	13.83			**19.99**		YES			110
	Prepayment	4.23		15.00		**19.23**		YES	YES		76
	Revenue Assurance				4.44	**4.44**					
	Outage Mgmt.						4.5%		YES	Some	
	TOTALS	**10.39**	**13.83**	**38.92**	**4.44**	**67.58**	**4.5%**	**YES**	**YES**	**Some**	**186**

Observations: 1) Customer engagement is required for a favorable benefit-cost ratio
2) Customer engagement capabilities involve significant sales volume reductions

Distribution Automation Benefit-Cost/Customer

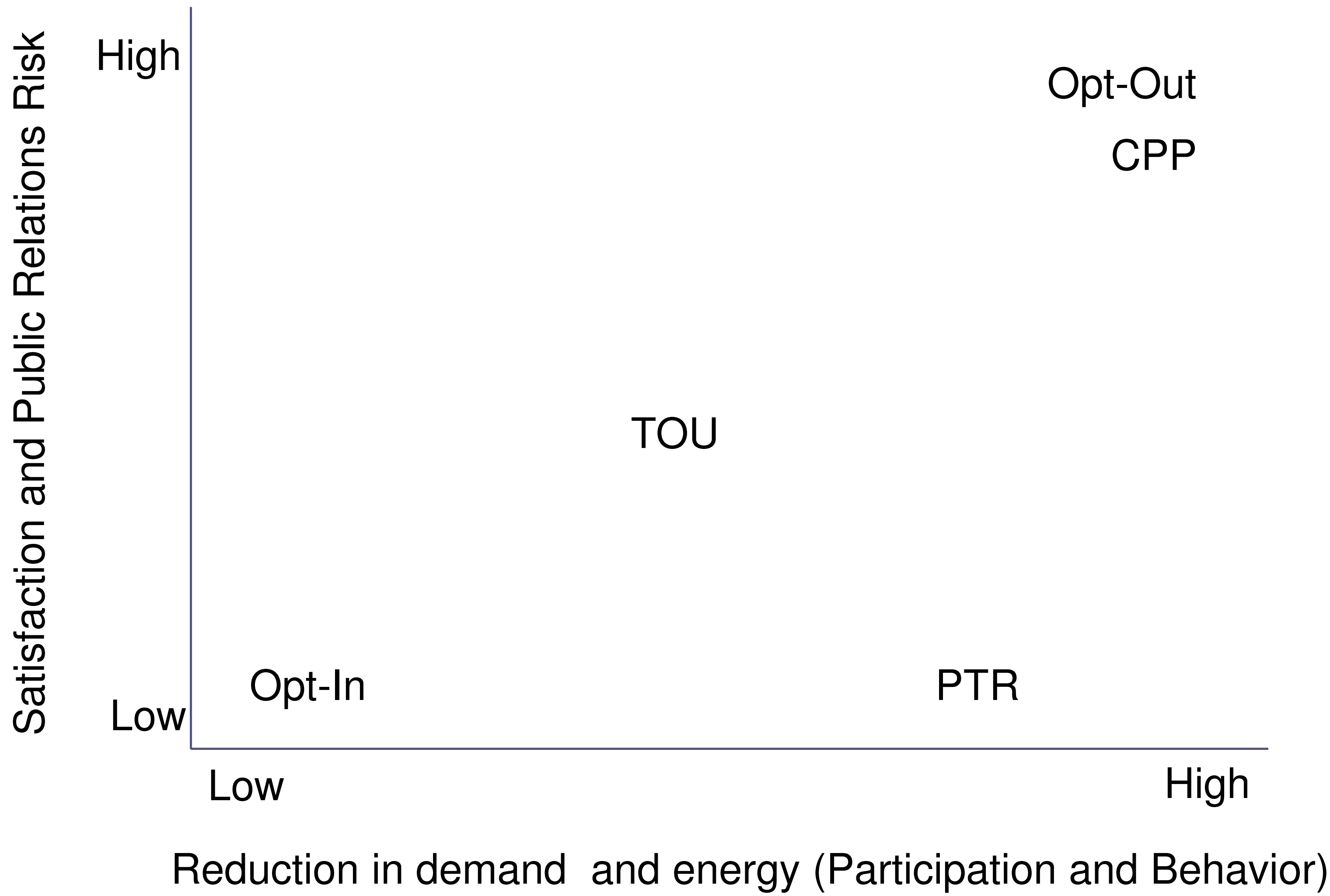


Distribution Automation Ideal Case Details

Systems and Costs (Present Value) per Customer	Capabilities and Annual Benefits per Customer, per Year (Reference Case)	Benefits									
		Direct								Indirect	
		Economic (in $)									
		Energy Conservation	Demand Reduction	Operations & Maintenance Cost Reduction	Revenue Assurance	**ECONOMIC TOTALS**	Improved Reliability (in percent)	Increased Customer Choice	Enhanced Customer Service	Economic Productivity	Environmental (in lbs. CO2e)
Distribution Automation $80	Fault Location						4.8%			Some	
	Fault Isolation						22.9%			High	
	IVVC	20.77	11.24			**32.01**	YES			Some	372
	Customer-Sited Gen		YES			**YES**	YES	YES			YES
	TOTALS	**20.77**	**11.24**			**32.01**	**27.7%**	**YES**		**HIgh**	**372**

Observations: Energy conservation benefits from using IVVC continuously are almost double the benefits from using it during peak periods

Time-Varying Rate Types, Introduction Methods



Utility Organization and Operating Systems

Competencies

- Project Management
- Change Management
  - Organizations & budgets
  - Processes & systems
  - People
- Innovation

Business Functions

- Distribution Control Centers
- Distribution Engineering
- Field Service Centers
- Information Technology
- Customer Care Centers
- Marketing

RIIO Utility 8-year Plan Components

- Overall goals and associated performance targets
  - Safety; Reliability; Environmental; Customer Service; Customer Satisfaction; Social Obligations
- Revenue requirements
- Capital vs. expense spending
- Energy efficiency performance metrics and targets
- Incentive proposals for each performance target
- Overall Innovation incentive proposal and cost to consumers if awarded (a utility plan competition)

Is the Thesis Proven?

- A smarter grid can indeed deliver customer benefits in excess of costs and help prepare for future challenges
- Utilities are sub-optimizing benefits by a significant margin
  - Utility organizational and operational changes are significant
  - Customer engagement is extremely difficult
  - Regulatory and governance structures inhibit benefits
    - 70% of benefits stem from capabilities that reduce sales volumes*
    - Rate case timing impacts rate recognition of O&M/revenue benefits
    - IOUs are rewarded for process (investment), not outcomes (performance)
- Significant regulatory changes are needed in the near term
- Dramatic regulatory changes are advised in the long term

* Ideal case scenario

Thank You!

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Please call with comments, questions, and input!

Domains: Smart Grid, Demand Response, and Renewable Energy
Services: Visioning, Planning, Execution, Evaluation
Clients: Utilities, Regulators, Governing Boards, Suppliers, Associations

To download evaluation reports in the public domain visit
www.wiredgroup.net/Reference_Work_Resources.html

"Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment"
available on Wired Group website & Amazon.com

Appendix: Distribution Performance

Wired Group

A Tale of Two Utilities

	FP&L	SDG&E
Dist. Rate/kWh	$0.044	$0.051
These Utilities are Peers!		
kW/Customer	4.8	3.9
Customers/Mile	64	62
Dist. Revenue/Customer/Yr.	$973	$598
Distribution Assets/Customer	$1,516	$2,013

Evaluating Smart Grid Performance

Optimizing the Value of Smart Grid Investments

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Creating a Return on Environment℠

Paul Alvarez and Kalin Fuller, Instructors

Utility University® Course 210 -- Monday, January 23rd, 2012

Introductions and Orientation

- Intros: Name, Organization, Role, Course Goal
- Orientation
  - MetaVu Qualifications
    - Smart Grid City Deployment Evaluation for Xcel Energy
    - Largest Midwest Deployment Evaluation for PUC of Ohio
  - Course Preview
  - Smart Grid Landscape

MetaVu Deployment Evaluations

Measurement Guidelines
- EPRI
- SGMM
- EDF

Business Cases, Regulation
- BG&E
- OG&E
- PG&E
- SCE
- SDG&E

Quantified Economic Benefits
- Distribution Efficiency
- Revenue Capture
- O&M Savings
- Capital Deferral

Quantified Other Benefits
- Reliability
- Cust. Svc.
- Safety

Investigated Costs
- Capital
- O&M
- Initial
- Ongoing

Tested Meters
- Smart
- Legacy
- RF Emissions

Reviewed Secondary Research
- TOU Rates
- Theft
- Prepayment
- Equipment life

Consumer Research
- Qualitative
- Quantitative
- Capabilities
- Benefits
- TOU Rates

Course Preview

Time	Item
8:00-8:30	Context and Preview
8:30-9:00	Top 3 Customer Expectations from Smart Grid
9:00-9:30	Capabilities Required to Deliver on Expectations
9:30-10:00	Measuring Capability Performance
10:00-10:15	Break
10:15-10:45	Anticipating Challenges to Maximum Performance
10:45-11:30	Overcoming Challenges to Maximum Performance
11:30-12:00	Top 3 Sources & Drivers of Economic Value; Wrap up

Smart Grid Landscape

- We are at the very beginning of the journey

- Customers: What did we get for all that money?
- Regulators: Measurement and Verification!
- Utilities: We do what we are incented to do
- Smart Grid investments fundamentally different

Smart Grid Investments Are Different!

Traditional Investments in G, T, & D (Value is Black and White)

Needed + Fairly Procured + Commissioned = Customer Value Assured

Smart Grid Investments (Value is Highly Dependent on Choices)

Investment Optimization + Change Mgmt. + Customer Program Development = Customer Value Assured

Utility Choices Determine Customer Value

Investment Optimization
- Communications
- Volt/VAr Control
- Sectionalization
- Remote Disconnect

Change Management
- Organizational Structure
- Operating Processes
- Systems Integration
- Organizational Capabilities

Customer Program Development
- Data Access
- TOU Pricing
- Outage Information
- DSM Designs

Prioritizing Modernization Investments

Break Out #1: Top 3 Customer Expectations

- Break into 3 groups
- Brainstorm all potential customer expectations; select top 3
- Present top 3 to the group
- MetaVu observations
- Finalize top 3 expectations as a group

Prioritizing Modernization Investments

Break Out #1: Top 3 Customer Expectations

Notes:

Reliability -3

Integration of New Technologies

Dynamic Pricing Programs

Economic Benefits -2

Consumer Engagement

Environmental

Less “Big Brother”

Customer programs

Selecting Capabilities and Approaches

Break Out #2: Capabilities to meet Expectations

- Brainstorm smart grid capabilities required to meet assigned expectation
- Select 3-4 with greatest potential contribution
- Present to group
- MetaVu observations

Selecting Capabilities and Approaches

Break Out #2: Capabilities to meet Expectations

Expectation 1: Customer Program Capabilities:	**Expectation 2: Reliability Capabilities**	**Expectation 3: Economic Benefit Capabilities**
1. Awareness/Education – Consumption Info. Assisted by Regulators.	1. Monitoring – Track Assets	1. Home Area Network/ Smart Devices, TOU Pricing
2. Tracking and Communicating Consumption Data	2. Remotely control infrastructure and load e.g. DA	2. Automated Meter Reading/Disconnect
3. Energy Management Tools and Services	3. Volt/VAR Management	3. Microgrid Generation
4.	4. Data for Dist. Capacity Planning	4 Volt/VAR Management;

Measuring Capability Performance

Break Out #3: Performance Metrics

- Develop metrics for each of the capabilities identified in last exercise
- Present to group
- MetaVu observations

Measuring Capability Performance

Break Out #3: Performance Metrics

Expectation 1: Customer Programs

Capabilities:	**Performance Metrics:**
1. Awareness/Education – Consumption Info. Assisted by regulators.	1. Customer sign up numbers, number of inquires or webpage hits,
2. Tracking and Communicating Consumption Data	2. Reductions in high bill complaints in call center; results of satisfaction surveys
3. Energy Management Tools and Services	3. Track usage of the tools by customers; measure impact on usage; Track adoption of TOU rates.

Measuring Capability Performance

Break Out #3: Performance Metrics

Expectation 2: Reliability

Capabilities:	**Performance Metrics:**
1. Monitoring – Track Assets	1. Time to restoration, time to outage notification, accuracy of diagnosis
2. Remotely control infrastructure and load e.g. DA	2. Cost to restore, reduction of average number of customers impacted,
3. Volt/VAR Management	3. Reduction of energy losses; Voltage complaints per 1,000 customers per year
4. Data for Dist. Capacity Planning	4. Users of data per day, frequency of non-weather related outages

Measuring Capability Performance

Break Out #3: Performance Metrics

Expectation 3: Economic Benefits

Capabilities:	**Performance Metrics**
1. Home Area Network/ Smart Devices, TOU Pricing	1. Billing comparisons (time of year, flat rate, neighborhood comparison)
2. Automated Meter Reading/Disconnect	2. Operation Costs (Minimizing Truck Rolls, Customer Service)
3. Microgrid Generation	3
4 Volt/VAR Management;	4. Reduction of Distribution Loss (capture more revenue, sell excess energy/reduce generation)

Anticipating Challenges

Break Out #4: What must a utility change?

- Anticipate challenges to excelling on the metric for each capability identified in Break Out 2
- Briefly describe challenges
- Present to group
- MetaVu observations

Anticipating Challenges

Break Out #4: Performance Metric Inhibitors

Expectation 1: Customer Programs

Capabilities:	**Performance Metric Inhibitors:**
1. Awareness/Education – Consumption Info. Assisted by PUCs.	1. Medium of training, resources available for training, customer message concise and simple, improved marketing capabilities
2. Tracking and Communicating Consumption Data	2. Infrastructure to track and communicate is not in place, regulatory constraints on customer data, cost of communication and tracking
3. Energy Management Tools and Services	3. Consumer willingness to share, what flexibility means (how many programs/tools), resources available to support tools and services

Anticipating Challenges

Break Out #4: Performance Metric Inhibitors

Expectation 2: Reliability

Capabilities:	**Performance Metric Inhibitors**
1. Monitoring – Track Assets	1. IT System Upgrades needed, employee skill sets, process transformations, regulatory hurdles,
2. Remotely control infrastructure and load e.g. DA	2. Major Capital Investment/Costs, sometimes no initial benefits – benefits will accure in future,
3. Volt/VAR Management	3. Time to deploy, interruptions of service to install
4. Data for Dist. Capacity Planning	4. IT systems to support data mining and distribution, process transformation

Anticipating Challenges

Break Out #4: Performance Metric Inhibitors

Expectation 3: Economic

Capabilities:	**Performance Metric Inhibitors:**
1. Home Area Network/ Smart Devices, TOU Pricing	1. Highlighting relevant data, Communicating clearly to customers how they can use data
2. Automated Meter Reading/Disconnect	2. Regulatory requirements, process and lack of agility, high cost of deployment, Proving ROI
3. Volt/VAR Management	3. Trust in system, resistance to change, Proving ROI, skill sets, who owns what? Costs required 3 to 1 compared to savings. Regulatory disincentives (to reduce sales) in most jurisdictions

Overcoming Challenges

Exercise #5: How should a utility change?

- Pick a few critical ‘Anticipated Challenges’ from previous exercise
- Apply Quattro℠ change management framework to develop sample optimization plans

Organization Structure	Operating Processes & Governance	Systems and Integration	Organizational Capabilities

Quattro℠ Change Mgmt. Framework

Organization Structure

Departments Responsible

Departments Impacted

Realignments?

Operating Process & Governance

Processes Impacted

Policy & Process Redesigns

Regulatory & Incentive Changes

Systems & Integration

Systems Integration

Data availability

Decision support tools

Organization Capabilities

Skill Sets

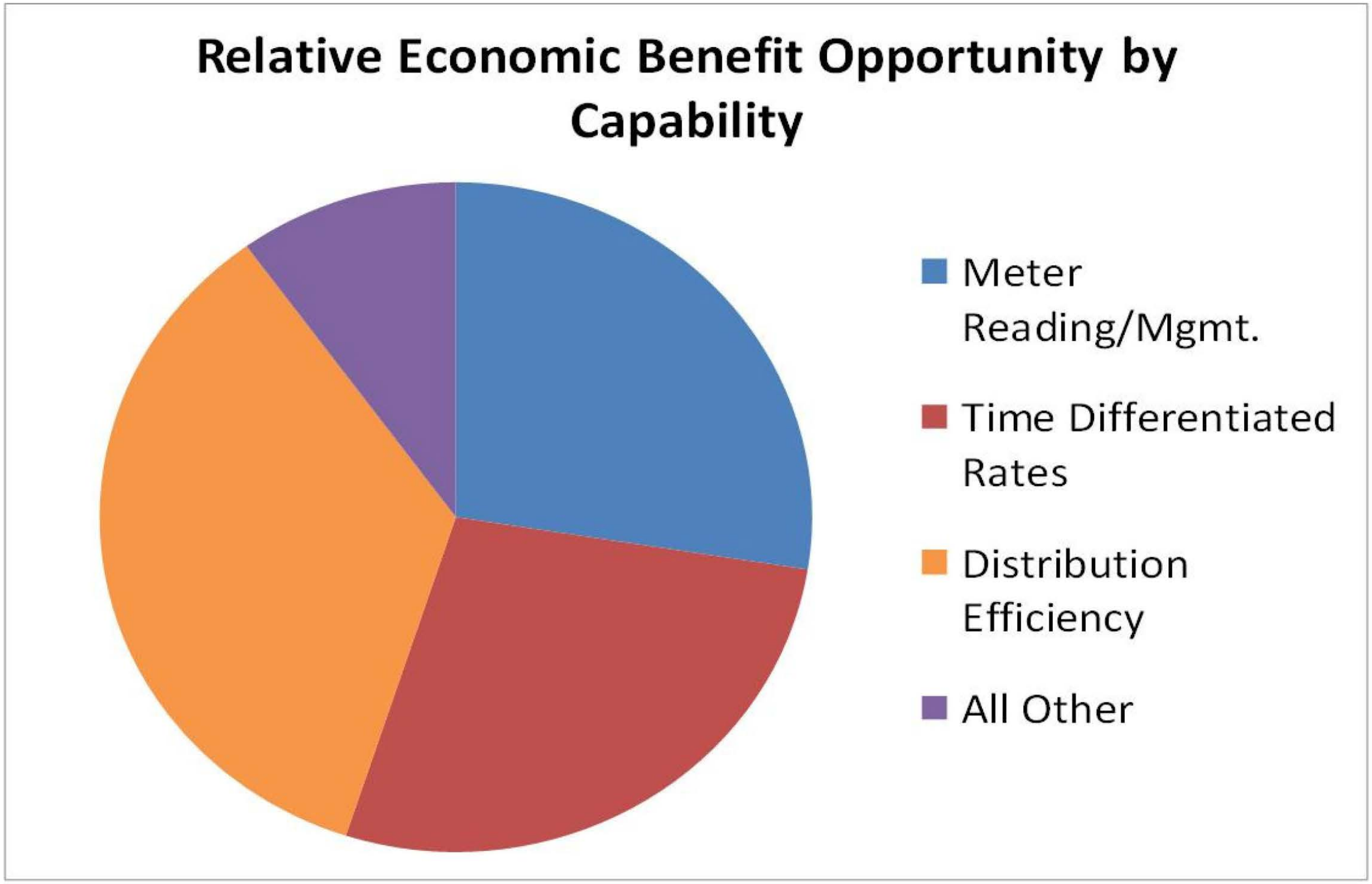
Resources/Budgets

Training

Overcoming Challenges

Sample Performance Metric Inhibitor	Organization Structure	Operating Processes and Governance	Systems and Integration	Organization Capabilities
1. Customer Clearly communicating to customer	Billing center, and other businesses must be altered	Redefining new process and roles and responsibilities, creating consistent customer messages,	Create new infrastructure for parties that need it, who owns the infrastructure, who manages it?	Retraining of employees, new skill sets, transitions of skills with the incorporation of new skills
2. Economic -Trust in Technology	No longer IT vs. OT, now convergence of IT and OT Board-level champion	Make it performance based (incentived adoption) Planning Roadmaps, e.g. Scenario roadmaps, dispute resolution	Understanding legacy of electrical controls and future IT infrastructure (SCADA vs. IT controls), Standards Development,	Understanding maturity model of organization and develop org roadmap,
3. Reliability IT Systems	Areas of responsibilty, Op centers new roles/responsibilities, restructure of organization (merging IT & OT)	Mulitple departments engaged and data exchange between groups, process changes around data exchanges,	Data BUS, new IT systems	Skill set development

Top 3 Sources of Economic Value



Top 3 Drivers of Economic Value

Situational Characteristics

- Energy Cost
- Capacity Value
- System Load
- Meter Reading
- Distribution Standards

Regulatory Choices

- Restructured?
- Decoupled?
- Investment Incentives?
- Performance Incentives?
- Restrictive Rules?

Utility Choices

- Design
- Implementation
- Optimization

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Linked In Group: "Smart Grid Benefit Measurement and Maximization"

Using Data to Increase the Value Utilities Deliver to Customers

Wired Group

NARUC Energy Resources and Environment Committee

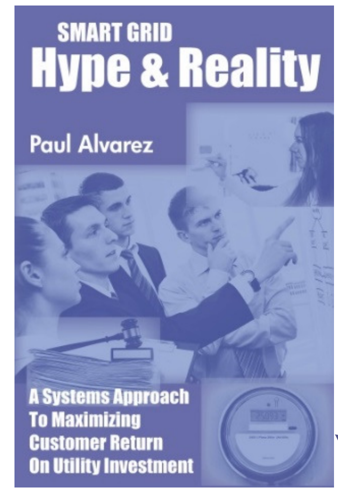
Winter Meeting February 15, 2016

Paul Alvarez, President, Wired Group

palvarez@wiredgroup.net

Wired Group Introduction

- **Clients: advocates, regulators, associations, utility suppliers**
- **Expertise: electric distribution grids/utilities/businesses**
  - DSM program development, marketing, evaluation
  - RPS compliance/PV Solar incentive program design
  - New rate development, offer design, and marketing
  - Distribution utility performance and compensation
  - Modern Grid: distribution, metering, communications



- **Distinctive Competence: evaluations of smart grid deployments**
  - Boulder Colorado for Xcel Energy
  - Duke Energy Cincinnati for Ohio PUC

Free to NARUC members; e-mail mailing address to palvarez@wiredgroup.net

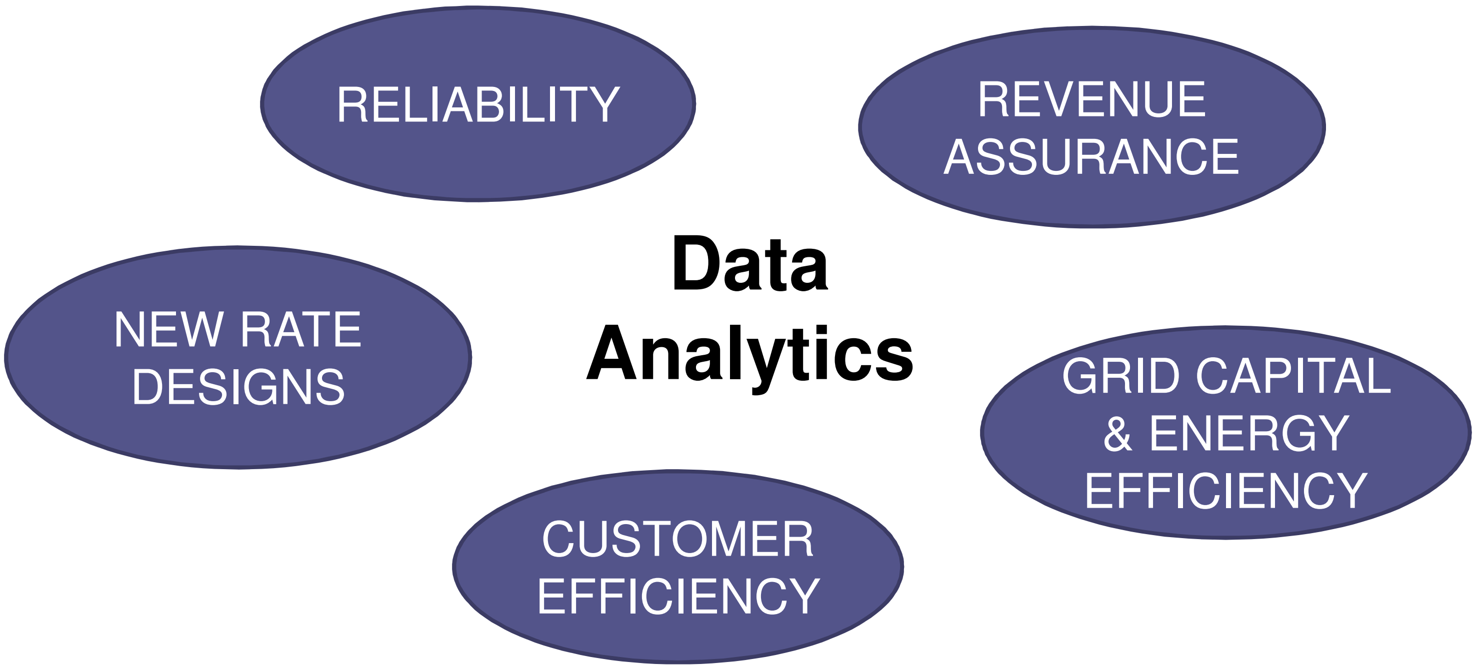
Preview

1. How utilities can use data to increase customer value from grid modernization investments

   Q: To what degree do ratemaking mechanics discourage IOUs from maximizing smart grid value for customers?

2. How Regulators and Staff can use publicly-available data to encourage greater value through performance benchmarking

Data Analytics Are Critical to Improving the Customer Benefit-Cost Ratio . . .

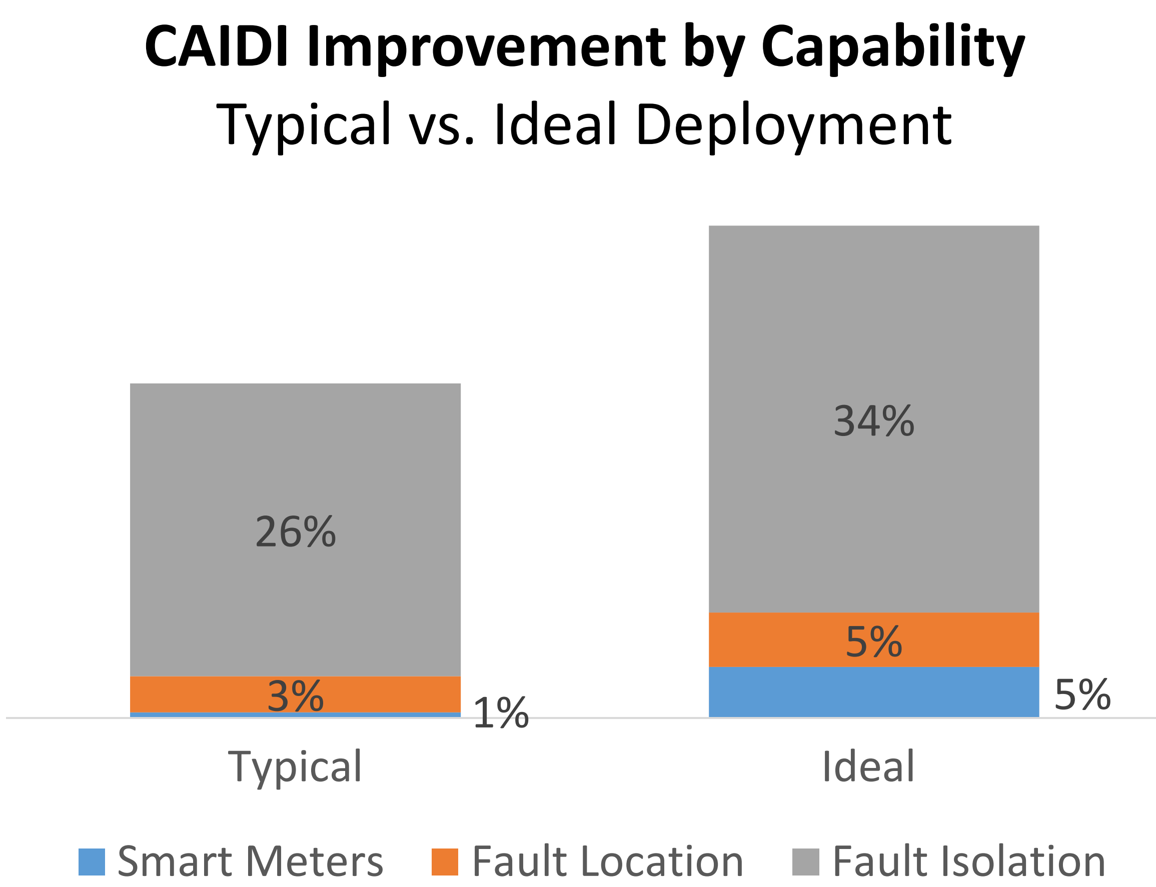


. . . But We Must Eliminate IOU $ Penalties for Doing So!

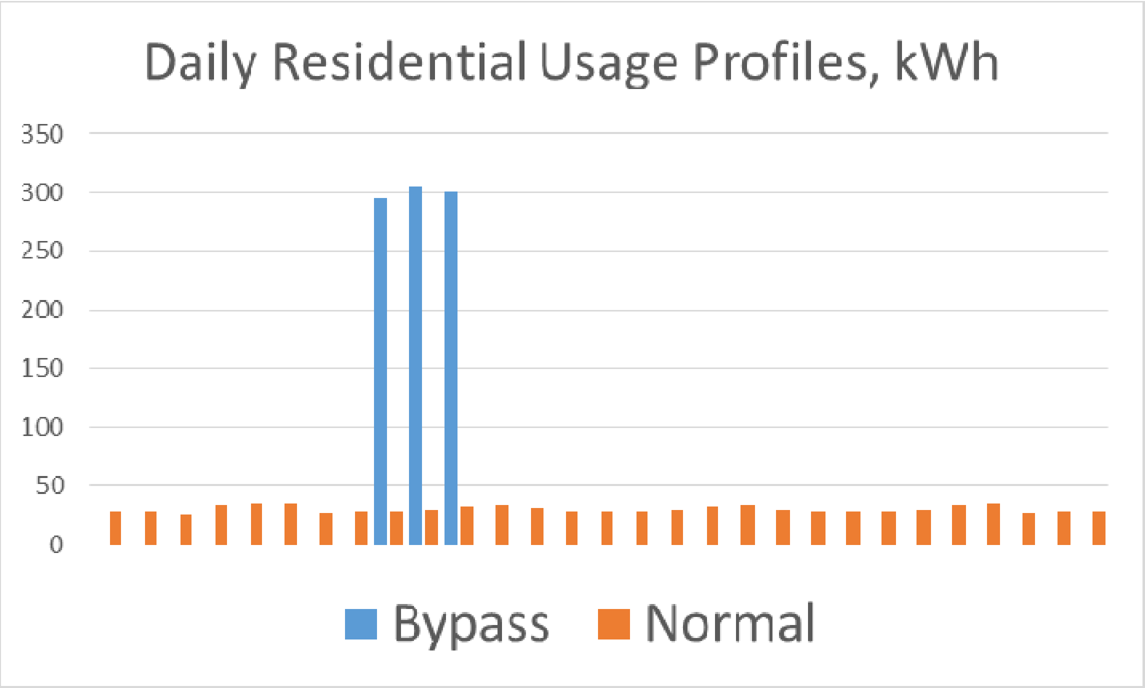
Reliability – Outage Restoration

Observations on smart meter data and reliability

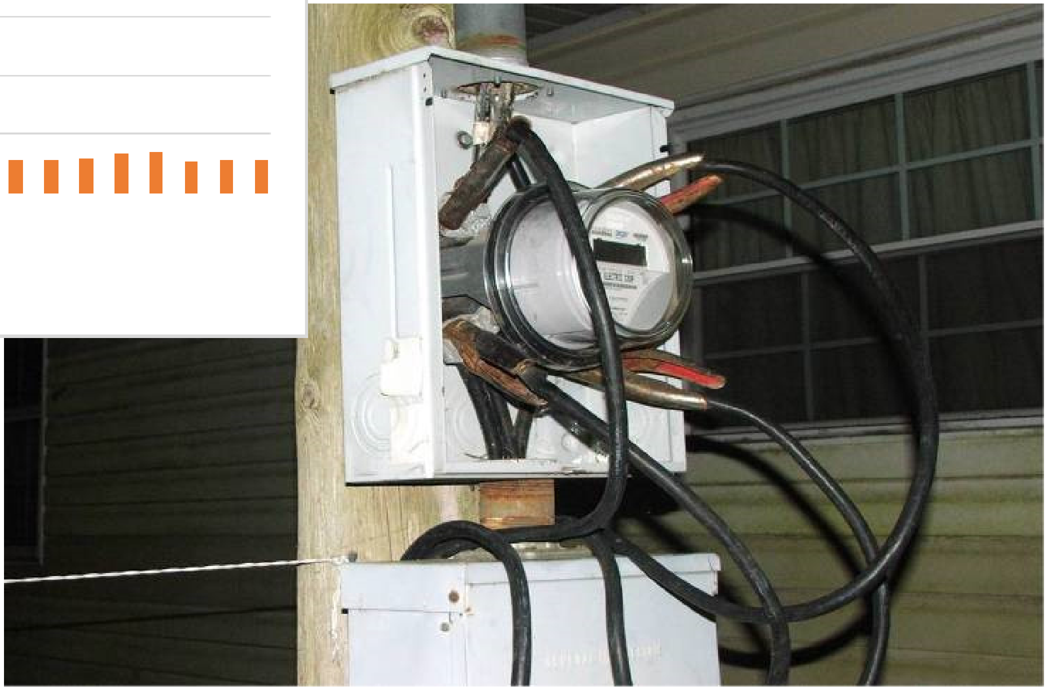
- "Last gasp"/OMS integration: not critical to CAIDI improvement
- Voltage data exception reporting: has some merit, but incidence typically low
- MASS METER PING to identify "nested outages": best CAIDI improvement from meter data.



Revenue Assurance – Meter Bypass Theft



Enhancements to Validation, Editing, and Estimation (VEE) routines are needed to detect theft via bypass in meter data.



Grid Capital and Energy Efficiency: Advanced Distribution Management Systems

Capability	Reliability	Energy Efficiency	Capital Efficiency
Fault Location/Isolation/Svc. Restoration (FLISR)	●		
Device Condition Monitoring (outage prevention)	◔		
Conservation Voltage Reduction & Volt-VAr Optimization		●	◑
Distributed Energy Resource Management System	◔		
Distribution Optimization Modeling – Phase Balance		◑	
Distribution Optimization Modeling – Load Balance			◑

● ◕ ◑ ◔ ○

High Value → No Value

Customer Efficiency: DSM Programs

Data Analytics

REDUCED DSM PARTICIPANT ACQUISITION COSTS

Target Marketing

NEW PROGRAM OPPORTUNITIES

Southern California Edison's "Budget Assistant"

IMPROVED MEASURMENT & VERIFICATION

Energy Efficiency
Demand Response

New Rate Designs (3-Part, TVR, etc.)

DESIGN

- More effectively reduce peak
- More accurately revenue neutral

Data Analytics

INTRODUCE
(Default/Opt-Out)

- Which customers will be big losers?
- Special outreach?
- Smoother transition

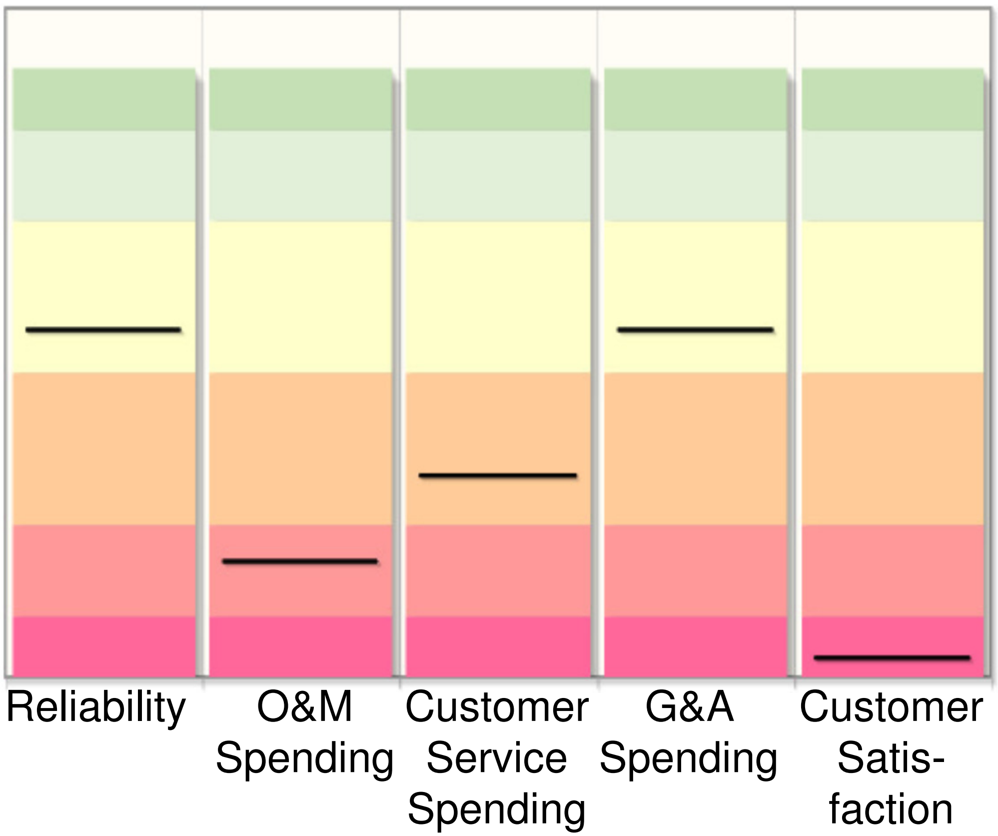
ADMINISTER

The *Utility Evaluator™*

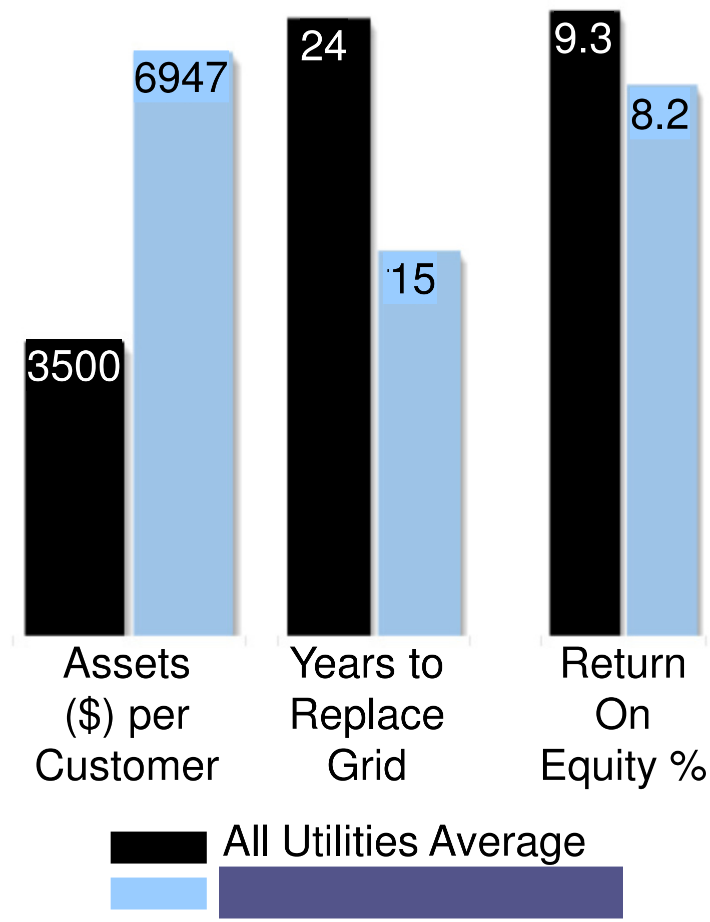
- Internet-based software application
- Aggregates public data into actionable information
  - Financial data from FERC Form 1
  - Operational data from EIA Form 861
  - Customer Satisfaction from JD Powers & Associates
  - Regulatory filings, SEC filings, ACEEE, others
- Benchmarks key performance indicators & trends (reliability, costs, satisfaction, ROE, DSM, etc.)
- Enables peer grouping by utility characteristics (load, customer, business, regulatory, demographic)

2014 Performance Dashboard for: [redacted]

Quantile Performance vs. All Utilities

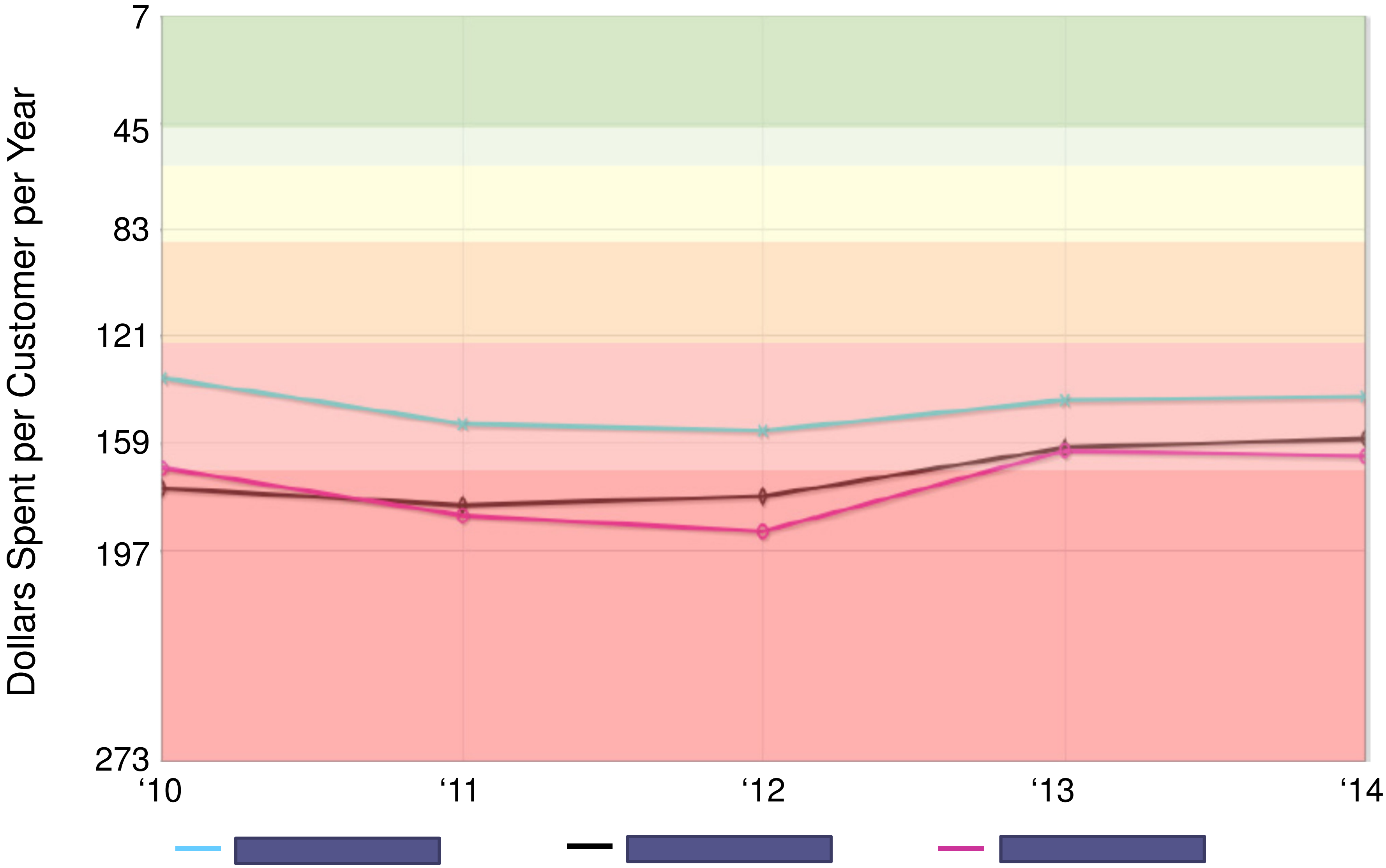


Performance vs. All Utilities Average

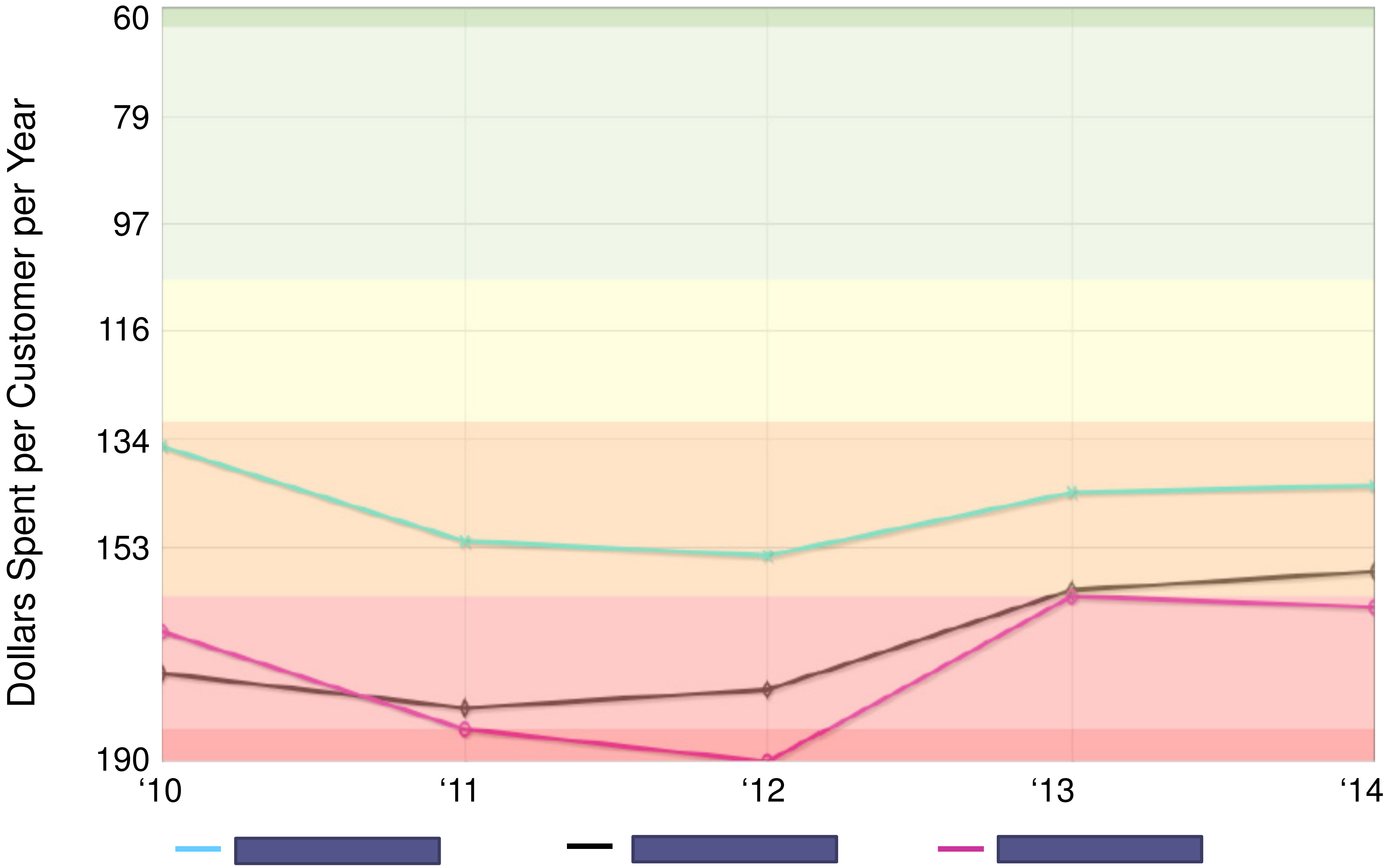


Key Performance Indicator: Billing & Customer Service Spend per Customer

Peer Group: All Utilities



Key Performance Indicator: Billing & Customer Service Spend per Customer
Peer Group: Customer Count > 1,400,000 AND AMI > 75%



Thank You!

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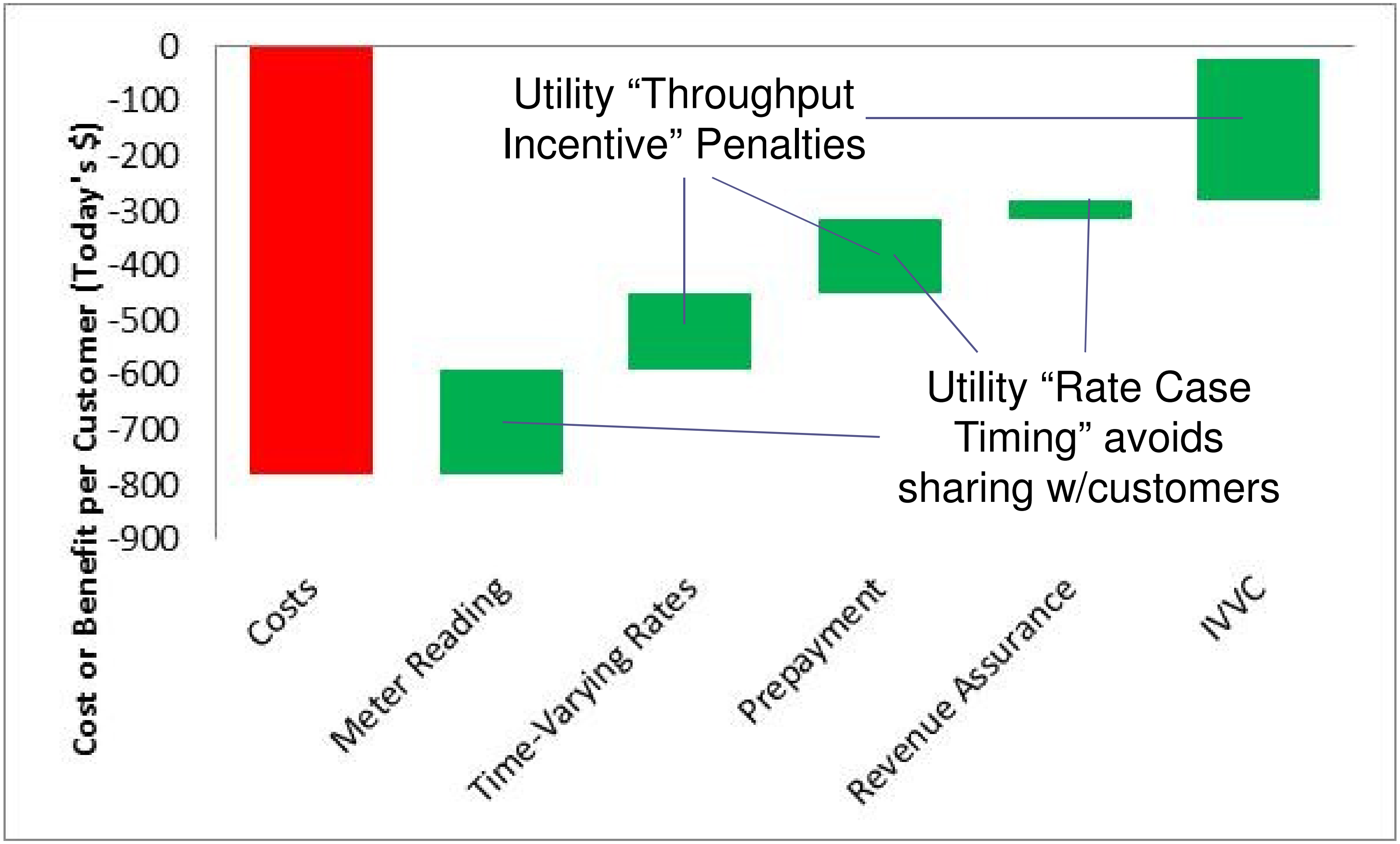
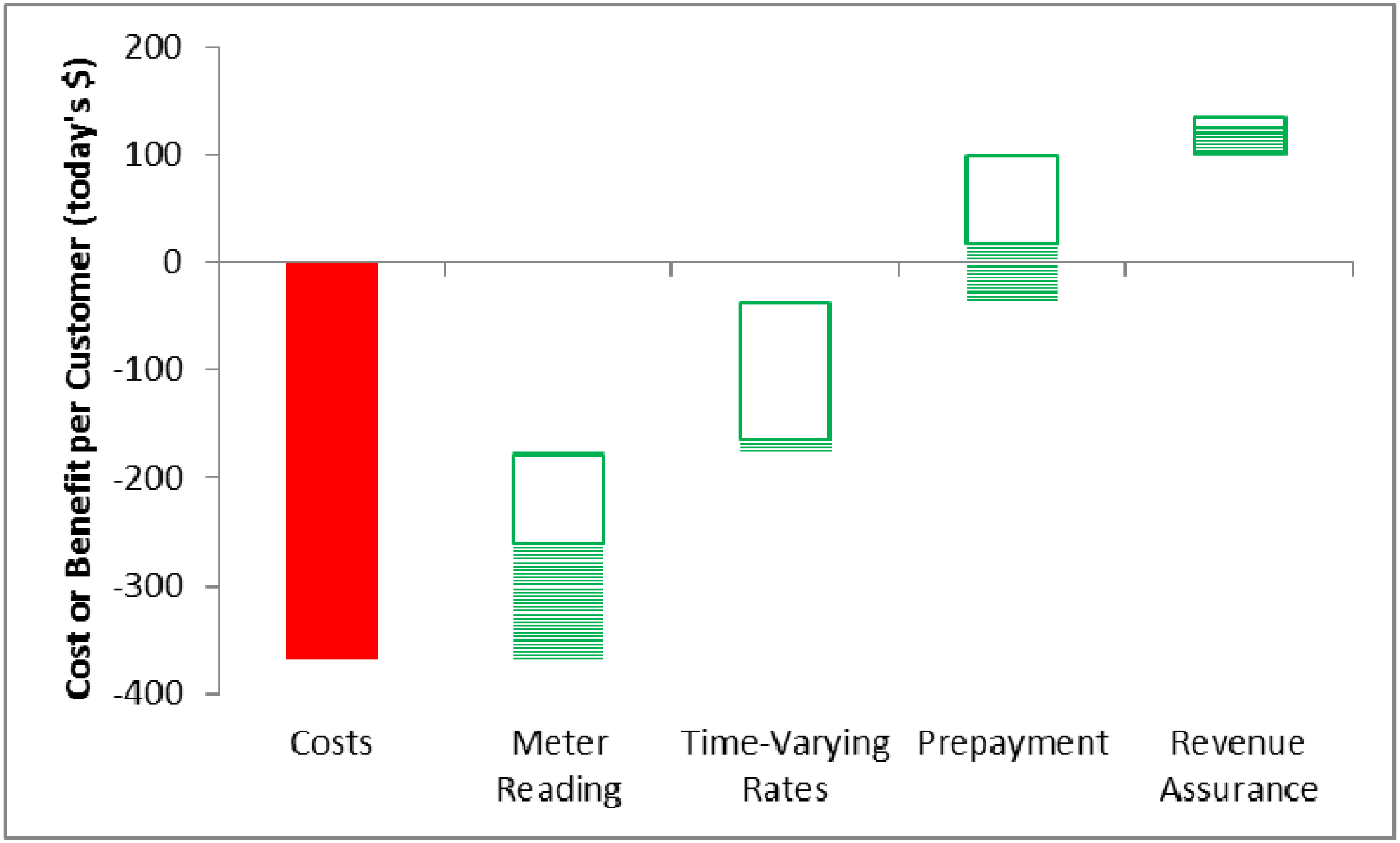
Copies of **Smart Grid Hype & Reality** *are being made available to NARUC members at no charge; simply e-mail Paul Alvarez with preferred mailing address and number of copies desired. A limited number of free trial subscriptions to the Utility Evaluator™ are also available for a limited time.*

AMI & DA $ Benefit-Cost/Customer, Ideal Case



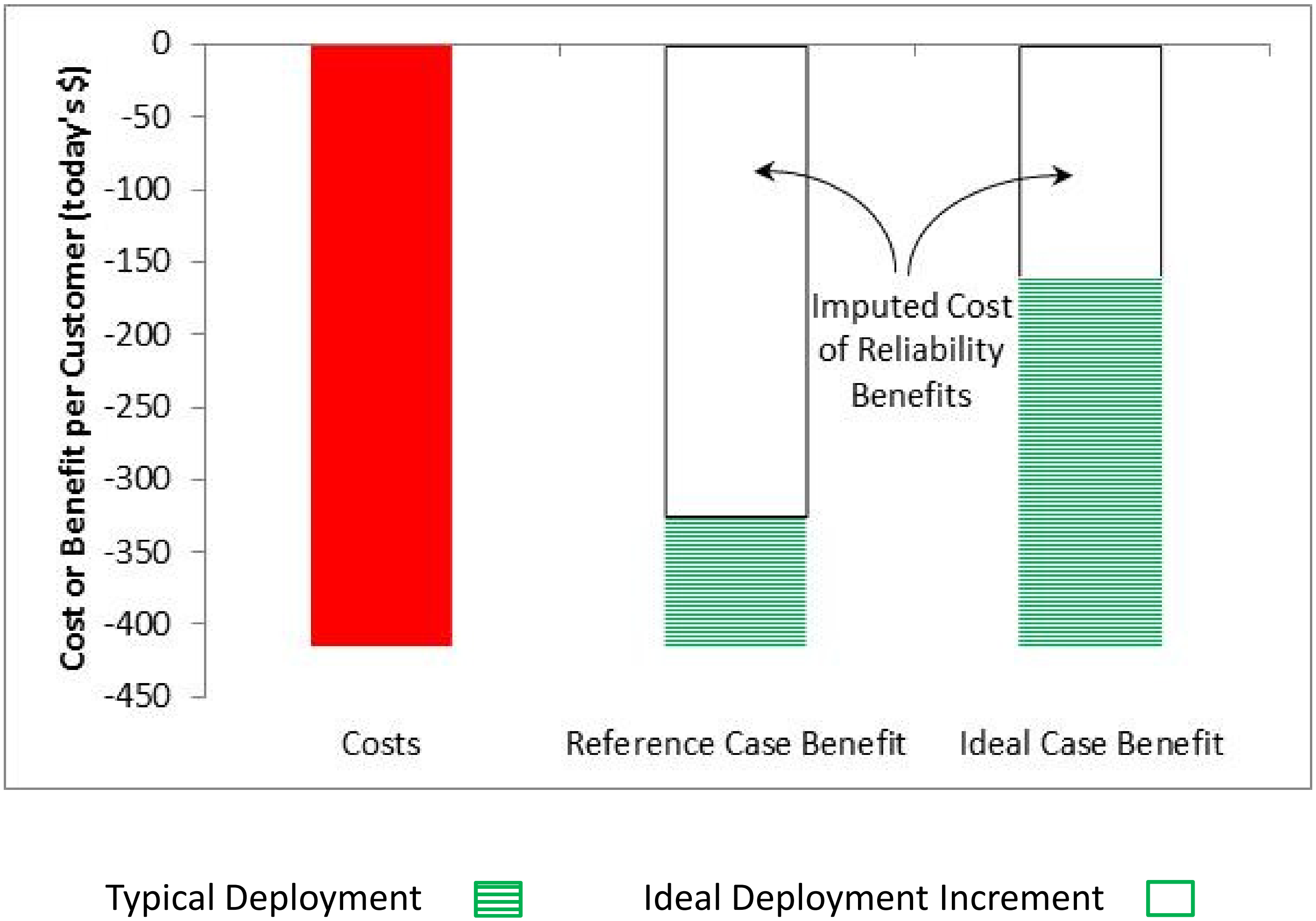
Smart Meter Benefit-Cost/Customer, 10 years



Typical Deployment

Ideal Deployment Increment

Distribution Automation Benefit-Cost/Customer



The Story So Far: Costs, Benefits, Risks, Best Practices, Missed Opportunities

Wired Group

Large US Deployment Evaluation Finding Summary

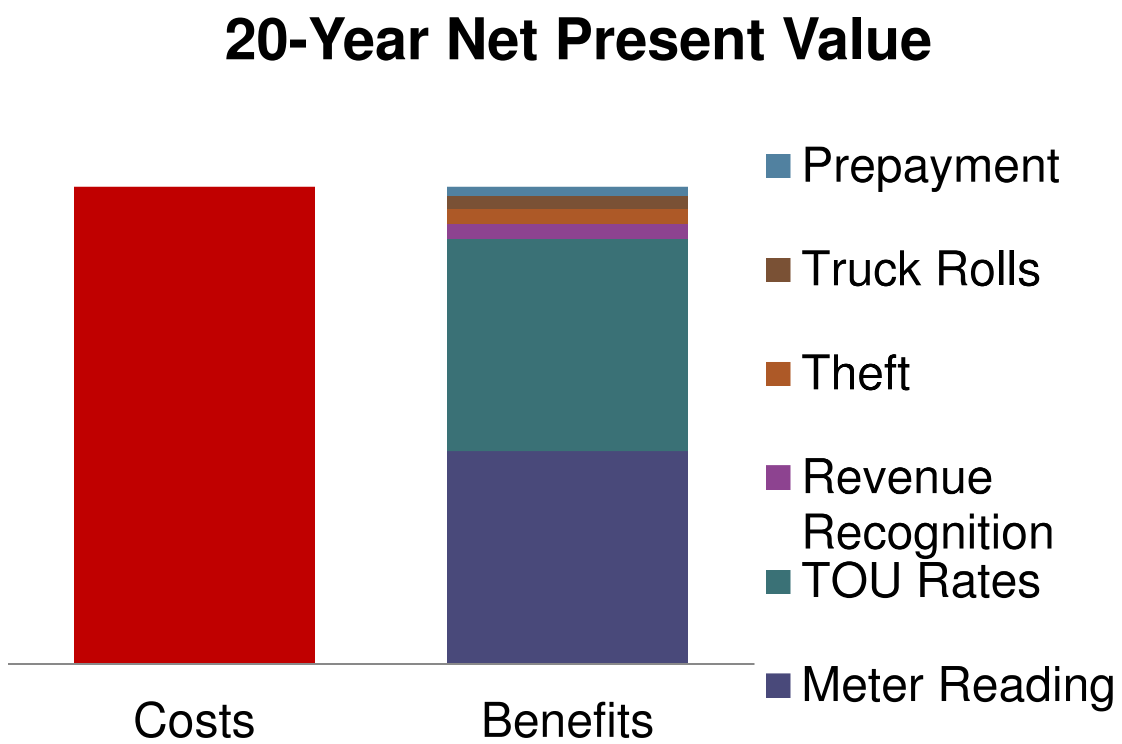
Canadian Electric Association Distribution and Customer Meeting

January 23rd Dinner Comments

Paul Alvarez, President, Wired Group

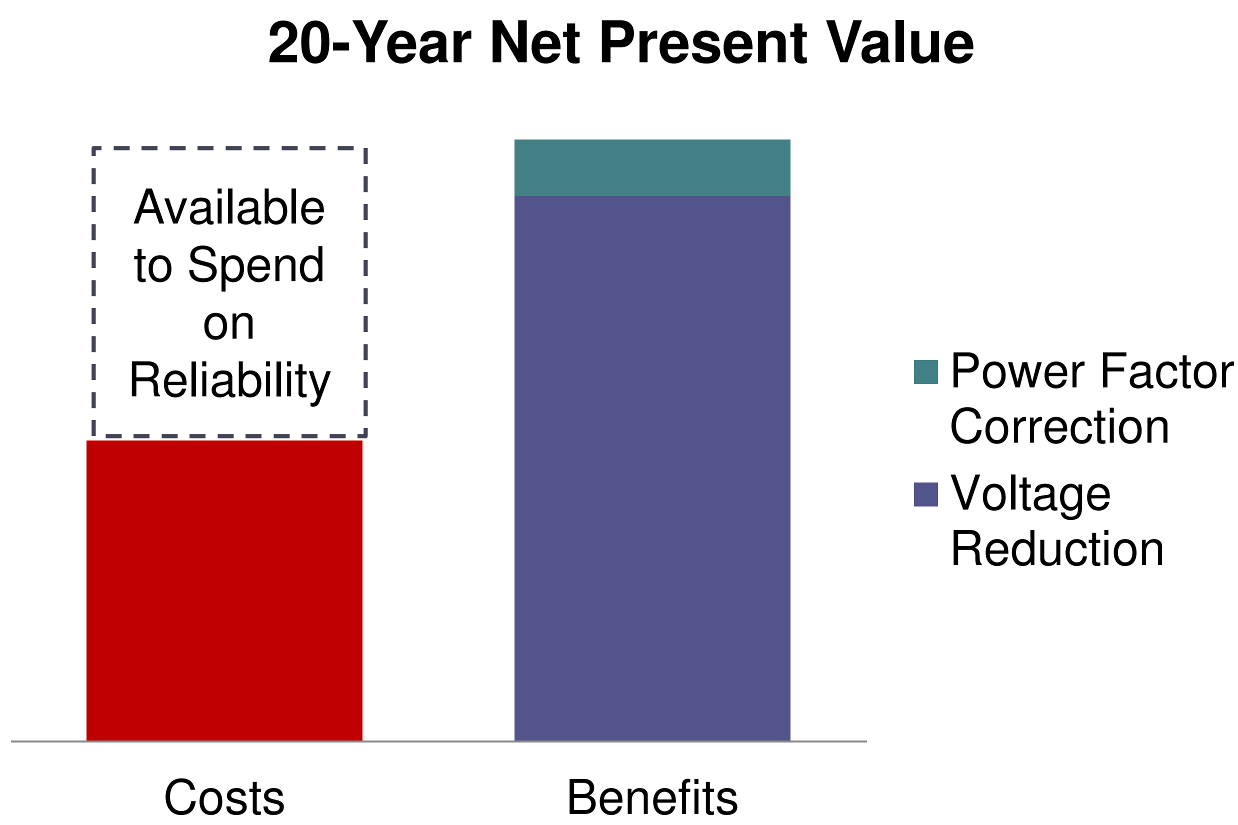
www.wiredgroup.net

Bill Cost/Benefit Potential #1: AMI

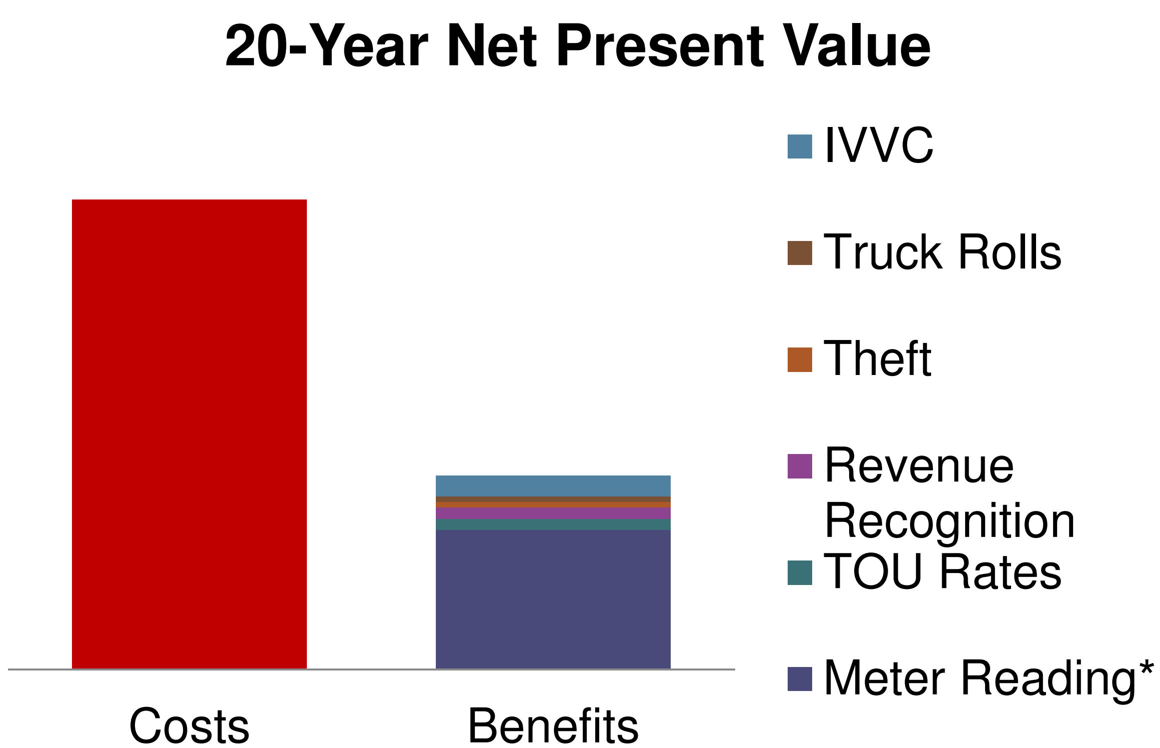


<u>Assumptions</u>
TOU Rates: 20% participation; 0.5 kW/participant; value = $120/kW yr.
Meter Reading: performed manually prior to deployment

Bill Cost/Benefit Potential #2: IVVC/Grid Efficiency



Actual Bill Costs/Benefits

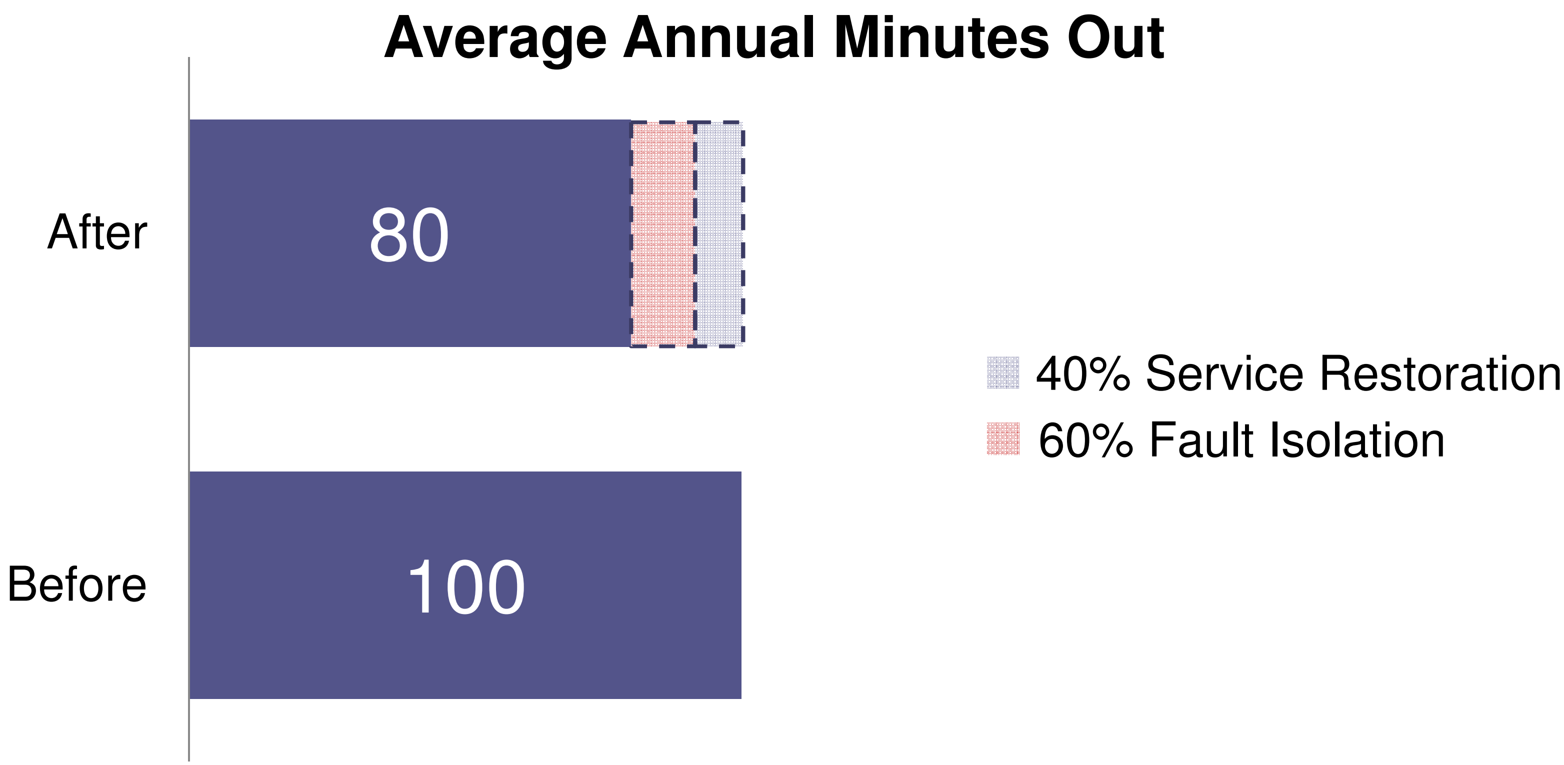


*Assumes Meter Reading Was Performed Manually Prior to Deployment

Why the Difference between Potential, Actual?

- Sales Reductions between Rate Cases = Penalty
  - TOU; IVVC; Prepayment
- Change Management Is Both Critical and Difficult
  - Organizational Capabilities and Structures
  - Operating Processes and Governance
  - Systems and Tools
  - Customer Services
- Risk: Rewards for Avoiding, not for Taking

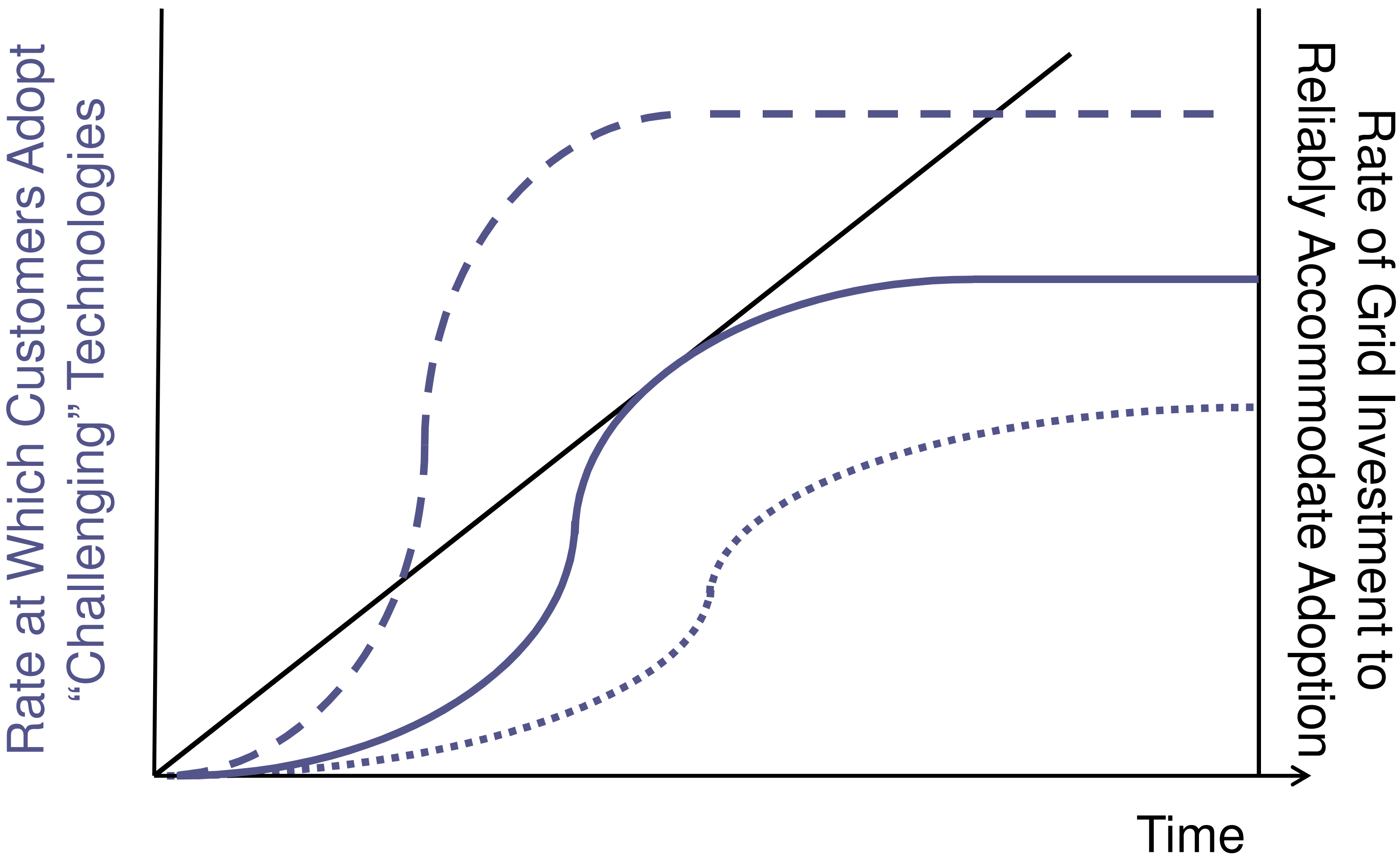
Actual Reliability Benefits (Pre vs. Post)



Notes
- In both evaluations, utilities highly reliable (99.98%) prior to deployment
- No severe storms occurred during test periods

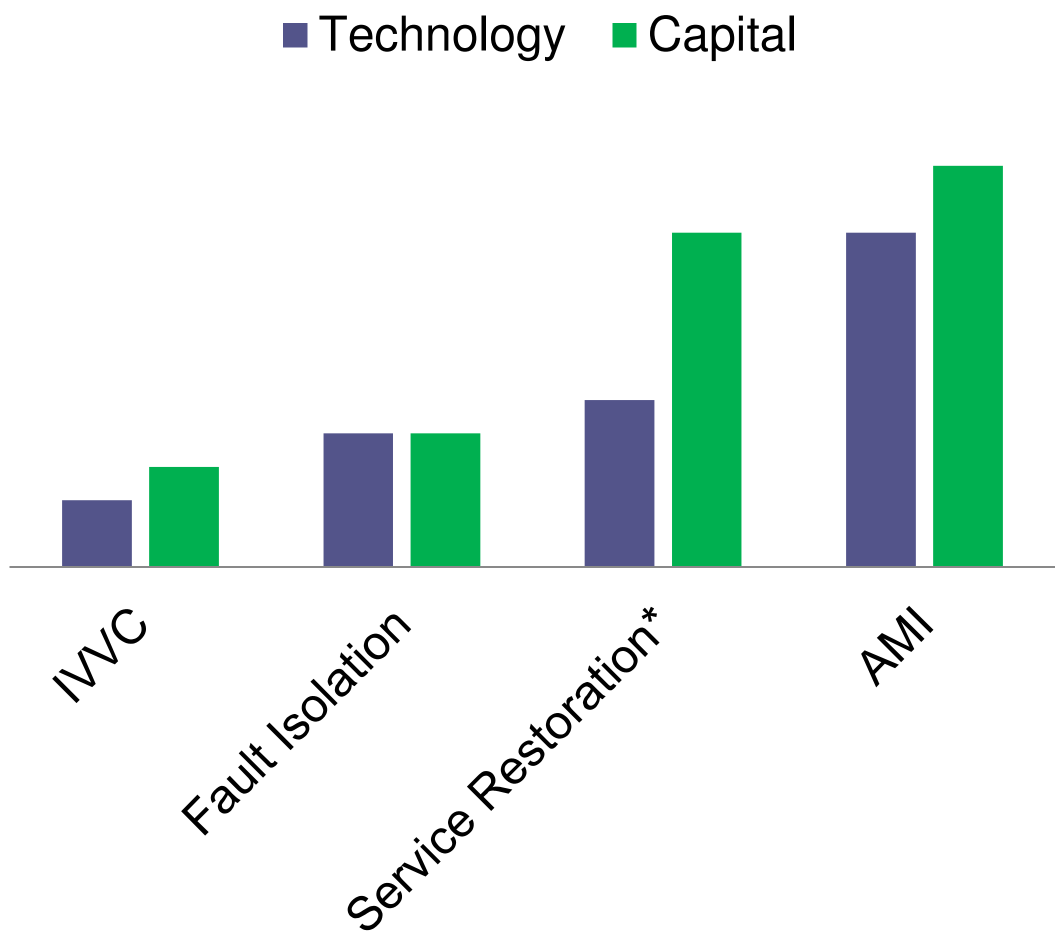
Potential Reliability Benefits (Future)

(What is the Value of a Reliability Insurance Policy?)



Risk Grows as Investment Nears Customer

- Technology Risk
  - Obsolescence
  - Cybersecurity
  - Failure Rates
- Capital at Risk



*Assumes meters not used as sensors, increasing the need for line sensors and costs

Thank You!

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Please call with comments, questions, and input!

Smart Grid Services:

- *Vision/Roadmap/Business Case Development*
- *Implementation Project Management*
- *Benefit Quantification/Effectiveness Evaluation*
- *Change Management/Capability Optimization*
- *Customer Rate and Service Enhancement Designs*

To download evaluation reports/reference sources visit www.wiredgroup.net/Reference_Work_Resources.html

Customer Benefits: What Smart Grid Deployment Evaluations are Telling Us

Wired Group

Findings, Lessons, and Metrics

Great Lakes Smart Grid Symposium

September 26, 2012

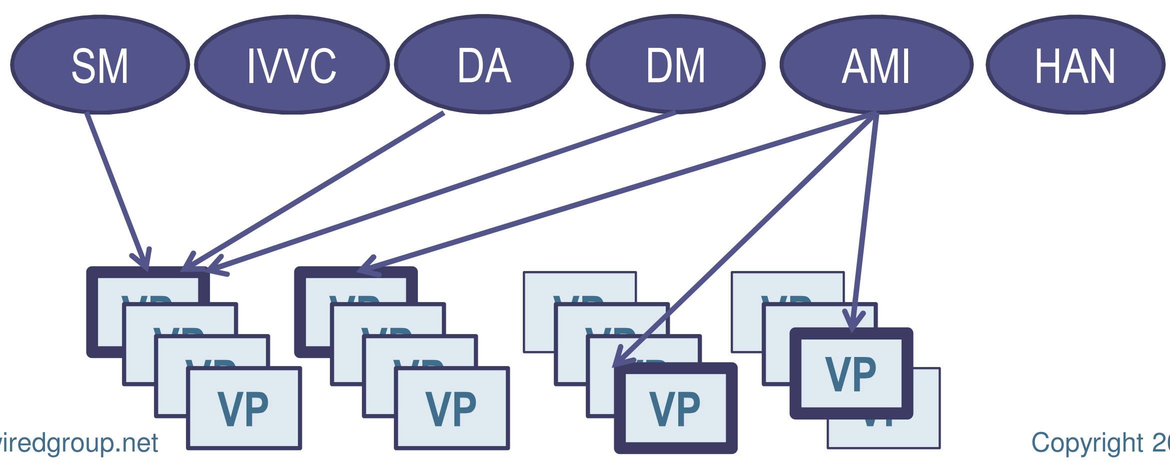
Preview

- Evaluations, Methodologies, Reference Sources
  - Xcel Energy's SmartGridCity™
  - Duke Energy's Ohio deployment
- Benefits/Drivers: Economic, Reliability, Customer Services
- Costs/Risks by Smart Grid Capability
- Lessons:
  - Smart grid investments are different than any other a utility makes
  - Change Management is critical to value creation
  - Performance-based regulation may be indicated
- Performance Metrics

Benefit Quantification

How much benefit did you/could you get?

- Economic Benefits, Reliability Benefits, Costs
- Establish Value Propositions (hypotheses)
- Gather data
  - Examine existing research
  - Interviews (internal/external SMEs, suppliers, etc.)
  - Pre-/post-deployment operational data queries; meter tests
- Translate data to $ (Fuel/O&M/Capital/Rev) or Cust. Minutes Out
- Associate Hypotheses to Systems, Costs



EPRI ELECTRIC POWER RESEARCH INSTITUTE

*Strong resource: EPRI's "Methodological Approach to Measuring Cost and Benefits of Smart Grid Demonstration Projects"

Effectiveness Review

What could you do to increase benefits (or reduce risks)?

- Customer Service*, Operational^, IT Risk~, Intangibles
- Establish Value Propositions (Hypothesis)
- Gather Data
  - Market Research (Qualitative, Quantitative)
  - Interviews/Process Documentation pre- and post-deployment
  - Data Utilization/Systems Integration reviews
- Identify gaps from emerging best practices
- Provide options for consideration

*Strong Resource: The Environmental Defense Fund's "Evaluation Framework for Smart Grid Deployment Plans"

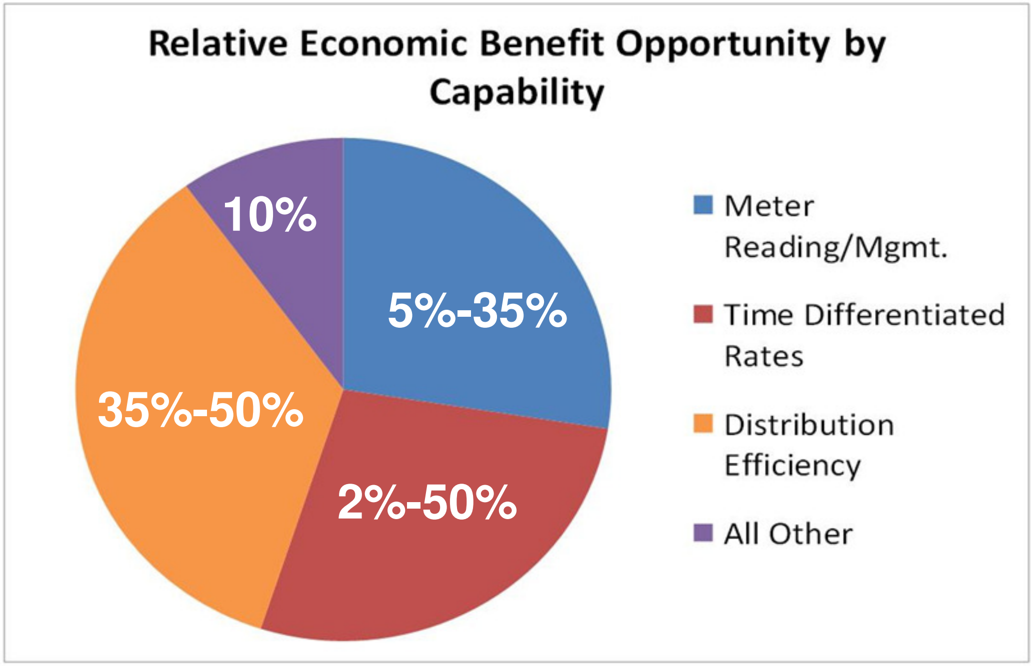
^Strong Resource: "The Smart Grid Maturity Model" from the US DOE and Carnegie Mellon University

~Strong Resource: NIST's "Guidelines for Smart Grid Cyber Security"

Findings: Economic Benefits (Value Drivers)

"All Other"
- Distribution capital avoided
- Revenue collected

Distribution Efficiency (IVVC):
- Circuit Load
- Circuit Voltage
- Circuit Power Factor



Meter Reading:
- Manual reads prior to deployment?
- Insufficient on its own for strong business case

80-90% of Economic Benefit Potential Comes from Just 3 Sources!

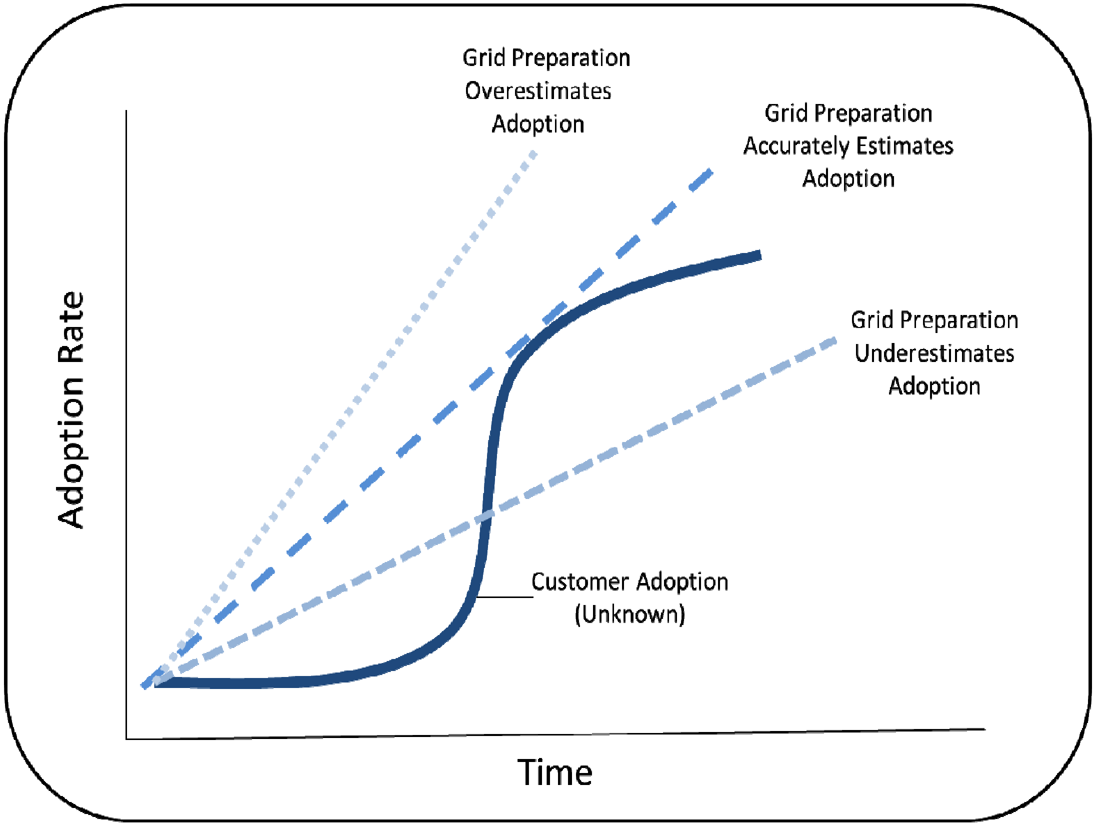
While benefits are significant in the aggregate, they may be difficult for an individual customer to perceive

TOU Rates/Demand Response:
- Participation Rate
- Degree of behavior change; free riders
- Recruiting & retention costs
- Benefit split between participants and non-participants

Findings: Reliability Benefits (Value Drivers)

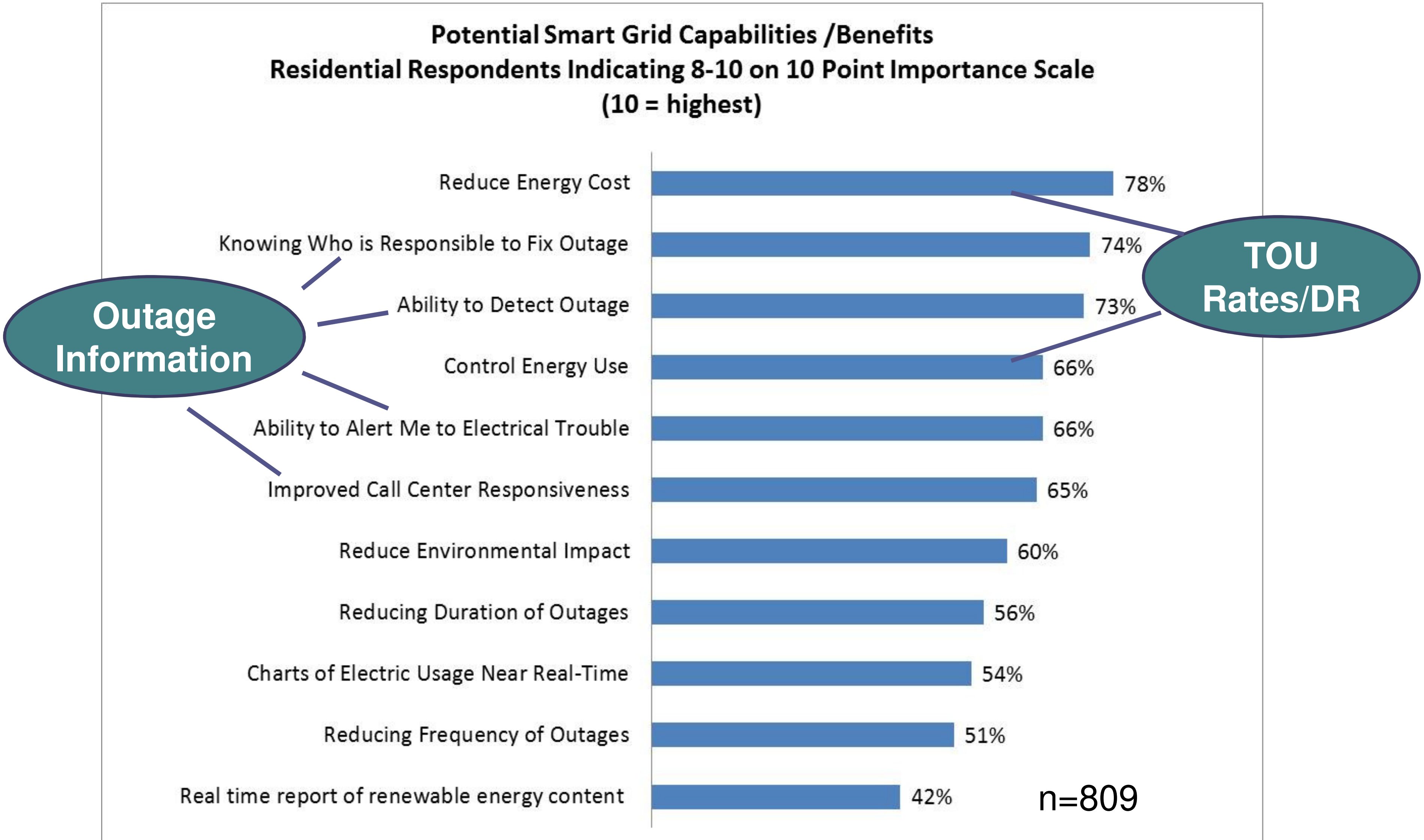
- "CMO" reduced ~ 20% (60% from DA, 40% from DM)
- Drivers: baseline performance; sensor granularity; data polling frequency
- At 99.98% reliability, 20% = 20 minutes annually(!)
- Greater DA/DM value is more likely in the future (EVs, PV Solar)

How Prepared Should the Grid Be?



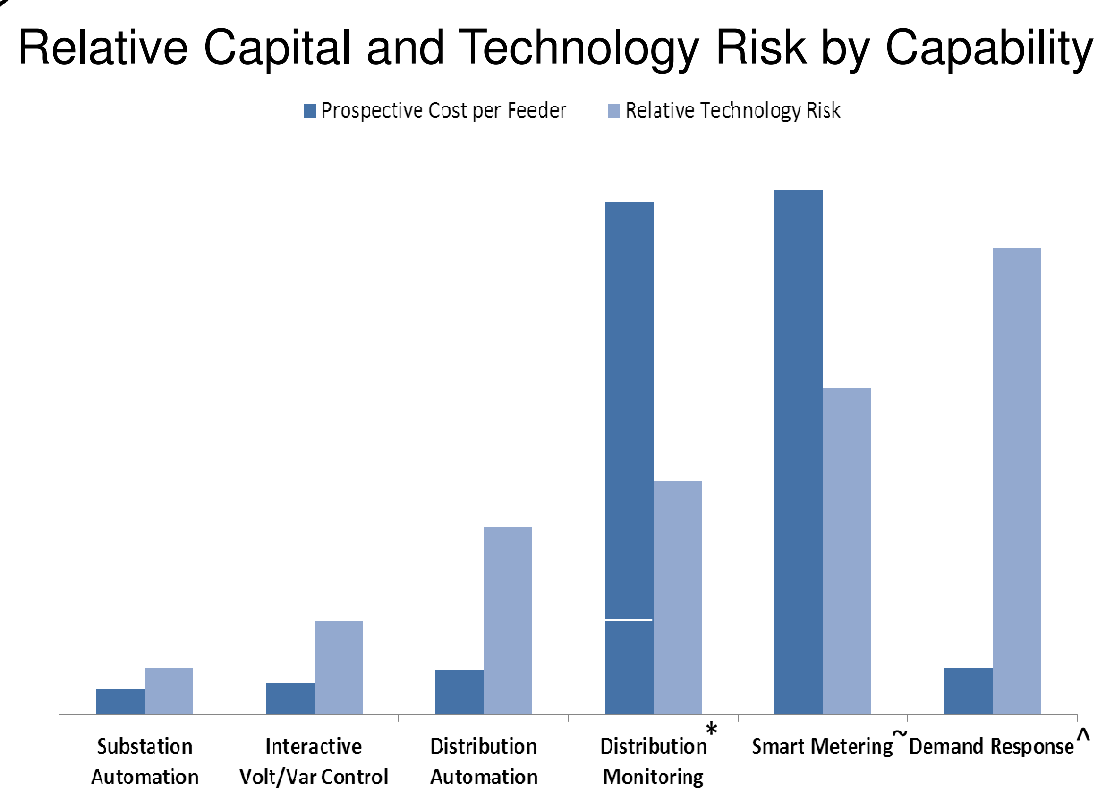
Findings seem to indicate that reliability benefits will be noteworthy but insufficiently large to be recognized by most customers

Findings: Customer Services (Quantitative)



Findings: Costs (Drivers)

- AMI:
  - Features
  - Communications
- All Other:
  - Extent of Deployment
  - Employ 20/80 Rule!



See notes for this chart in the Appendix

Findings seem to indicate that the initial capital and <u>ongoing O&M costs</u> of smart grid capabilities are consistently being under-estimated in available utility business cases

Lesson: Smart Grid Investments Are Different!

Traditional Investments in G, T, & D (Value is Black and White)

Needed + Fairly Procured + Commissioned = Customer Value Assured

Smart Grid Investments (Value Creation Is Performance Based)

Bang for the Buck (Strategy/Design) + Change Mgmt. (Implementation) + Customer Programs (Optimization) = Customer Value Assured

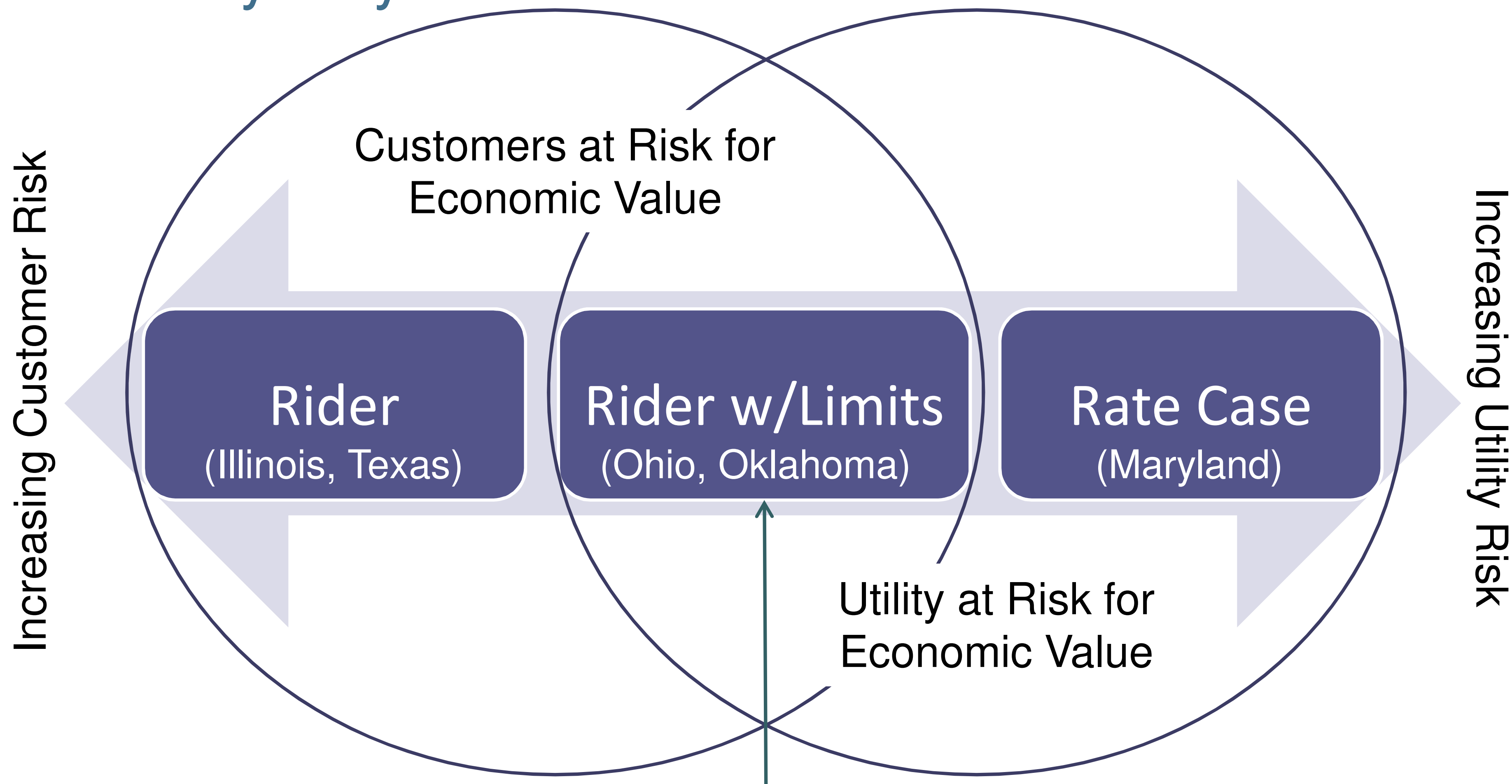
Investment does not make a grid smart – a utility's designs and capability usage determine benefits and value!

Lesson: Change Management Is Critical

Organizational Resources & Capabilities	• Budget Reallocations • Personnel capabilities and skill sets
Operational Processes & Governance	• New Capabilities = New Processes • New Processes = New Incentives
Systems & Tools	• Systems Integration • Data Availability & Convenience
Customer Programs & Services	• Time-Of-Use Rates, Data Access • Outage Information

Failure to conduct formal change management is directly correlated with failure to maximize the value of new capabilities

Lesson: Performance-Based Cost Recovery May Be Indicated



Smart grid investments can present a 'Win-Win' for shareholders and customers if ROI opportunities for strong performance are offered along with associated risks.

Performance Metrics

- Critical Characteristics
  - Reasonable in Number
  - Focused on the “Critical Few” Benefits (80/20 Rule)
  - Use for Performance-Based Cost Recovery?
- Primary Types: Deployment and Ongoing

<u>Deployment Metrics</u>

- By Category
  - Infrastructure (IT, Comm’s)
  - Specific Capability
- Capital Spend Percent/Total
- Completion Percent/Total

<u>Ongoing Metrics</u>

- Economic Benefits
  - Meter Reading Costs
  - TOU/DR Participation/Impact
  - Ave. Voltage/VAr
- Reliability Benefits
- Customer Services Benefits

Ongoing Metrics Today

State	Reliability Metrics	Old Meter Operations System Capital Avoided	TOU/DR Participation (%) and/or Impact (MW or $)	Unaccounted for Energy	Meter/HAN Failures and Complaints	Truck Rolls Avoided via Meter "Pinging"	Percent of Bills Estimated	Cybersecurity	Theft Detection and Billing	Others*	Total
CA	4		3		4			In development		9	20
IL	4			1			1		1	2	9
MD		3	3		4	1	7		2	16	36
OH	4	4	Education Plan	5	2	3		Annual Plan	1	9	28

Thank You!

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Please call with comments, questions, and input!

Smart Grid Services:

- *Benefit Quantification/Effectiveness Evaluation*
- *Visioning/Design/Business Case*
- *Implementation/Project and Change Management*
- *Optimization/Customer Rate, Program, Services Designs*
- *Expert Testimony*
- *Utility Supplier Market Strategy/Tactics*

To download evaluation reports/reference sources visit www.wiredgroup.net/Reference_Work_Resources.html

EEI Members: Please attend Smart Grid Value Working Group call TOMORROW at 12:30 CT. See me for details.

Notes to Costs Shown on Slide 9

° Amounts indicated do not include fixed infrastructure capital costs.

* Distribution Monitoring capital cost estimate assumes transformer-based sensing; the portion above the break indicates capabilities and costs that might be duplicated with the installation of smart meters with certain sensing capabilities. (Note that the use of meters as sensing devices is contingent upon readily- and cost effectively-available data, which is in turn based on communications infrastructure design choices.)

~Smart Metering capital cost estimates include communications-enabled meter and premise-variable communications costs per premise.

^Demand Response capital cost estimates assume that customers purchase home energy management equipment; amounts indicated consist of equipment rebates likely paid by utility.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 7
Page 1 of 1

Please provide copies of any and all documents, analysis, summaries, white papers, work papers, spreadsheets (electronic versions with cells intact), including drafts thereof, as well as any underlying supporting materials created by Mr. Alvarez as part of his evaluation of the Company's CPCN for a Metering Upgrade or used in the creation of Mr. Alvarez's testimony.

RESPONSE:

Mr. Alvarez has no work papers. Objection. The question assumes facts not in evidence, is overbroad and unduly burdensome and is thus an intent to harass, is vague, confusing, non-sensical and requires speculation.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 8
Page 1 of 1

Please provide copies of any and all documents not created by Mr. Alvarez, including but not limited to, analysis, summaries, cases, reports, evaluations, etc., that Mr. Alvarez relied upon, referred to, or used in the development of his testimony.

RESPONSE:

Objection. The question is vague, confusing, overbroad, unduly burdensome and thus is intended to harass, assumes facts not in evidence, and seeks information irrelevant to the instant proceeding. Without waiving said objections, to the extent discoverable, and in the spirit of discovery, Mr. Alvarez developed his perspectives on smart meter deployments over the course of over 15 years in the electric utility industry, including 7 years focused almost exclusively on the outcomes of grid modernization investments. He relied on these perspectives in evaluating the Company's smart meter CPCN.

Many of the analyses, summaries, cases, reports, evaluations, studies, and other sources that helped him develop his perspectives on smart meter deployments over the years can be found in the bibliography to his 2014 book, "Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment". The bibliography is attached as file "Smart Grid Hype & Reality Bibliography.pdf".

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WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 9
Page 1 of 1

Referring generally to Mr. Alvarez's direct testimony at page 2, during his time at Xcel Energy, please state whether Mr. Alvarez was a witness in any electric base rate proceedings.

(a) If the response is affirmative, please identify all such rate case proceedings and Mr. Alvarez's role and area of involvement.

(b) If the response is affirmative, please state whether Mr. Alvarez submitted testimony or was cross-examined.

    (1) If the response is affirmative, please provide copies of such testimony and transcript of cross examination.

RESPONSE:

Objection. The question seeks information already asked and answered in both DEK DR 3 and DEK DR 5. As such, it is duplicative and overly burdensome and must be seen as an intent to harass. Without waiving said objection, to the extent discoverable, in the spirit of discovery, and as already set forth is responses to DEK DR 3, Mr. Alvarez states that he was never a witness in any electric base rate proceedings during his time at Xcel Energy.

a. Not applicable.

b. Not applicable.

    1. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 10
Page 1 of 1

Refer to page 3 of Mr. Alvarez's testimony where he explains that he started Wired Group in 2012, please identify by name, title, and area of responsibility, any Wired Group personnel who assisted Mr. Alvarez in his review of the Company's filing in this proceeding.

(a) For the person(s) identified in response to the above, please describe the nature of the work performed by each person with respect to the Company's Meter Upgrade proceeding.
(b) For the person(s) identified in response to the above, please provide copies of any summaries, analysis, research, memorandum, work papers, or documents of any kind, that were created by such person(s) with respect to this proceeding.

RESPONSE:

None.

a. Not applicable.

b. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 11
Page 1 of 1

Referring to Alvarez testimony at 3, please provide the curriculum and syllabus for the courses Mr. Alvarez taught at University of Colorado's Global Energy Management Program and Michigan State University's Institute for Public Utilities.

RESPONSE:

See attached file "GEMM_6630_syllabus_Jan_2014 final USE THIS ONE.pdf" for the syllabus of the course I teach at the University of Colorado's Global Energy Management Program.

A syllabus is not available for the 4-hour course Mr. Alvarez occasionally teaches at Michigan State University's Institute for Public Utilities. However, the Institute publishes the following description in promotional materials for its Advanced Regulatory Studies Program, which Mr. Alvarez believes accurately describes course content: "**Evaluating demand-management and smart-grid programs** [Alvarez] Energy demand and efficiency. California Standard Practice Manual (SPM). Overview of critical tests. Dissecting a DSM program application. Overview of smart grid capabilities and benefits (real and actual). Applying the SPM to smart grid programs. Value drivers and limiters. Distribution system performance benchmarking."

GEMM 6630
Commercialization and Management/Leadership of Renewable Energies

Instructor: Paul Alvarez
Phone 720-308-2407
E-mail paul.alvarez@ucdenver.edu

Course Objective

This course builds upon the technologies reviewed in GEMM6300 by teaching students about the unique leadership challenges faced when developing renewable generation projects, managing the sale or acquisition of renewable energy on a large or small scale, or owning a (renewable) energy services business. New learnings will be acquired through on-line discussions with a particular emphasis on using renewable energy business cases to enable students to acquire a global senior executive perspective. The focus is on the knowledge, skills and abilities required by an executive to effectively execute business decisions related to renewable energy and technologies. The course will highlight the regulatory, technical, economic, and market issues that are unique to renewable energy. The course has four over-arching learning goals:

1. **Renewable Energy Leadership.** To understand how to use renewable energy to accomplish organizational objectives.
2. **Business Case Development.** To acquire the skills required to make informed decisions about renewable generation investment, renewable energy procurement, and (renewable) energy service business operations.
3. **Renewable Energy Strategic Decision Making.** To create winning renewable energy business strategies and confidently implement them in complex business situations often requiring cross-functional trade-offs.
4. **Enterprise Risk Management.** To gain practical experience in the successful management of renewable energy risks: project, technology development and commercialization

Since renewable technologies typically generate electricity, the course will focus extensively on electric generation, transmission, and distribution industries. As these industries have a history of monopoly market power and associated regulation, and as renewable generation industries' very existence relies on regulation, the course will focus heavily on electric regulation, policy, and markets. An understanding of these is critical to the understanding of renewable energy commercialization and management.

Course Content

This course employs economic fundamentals to help students understand renewable energy leadership and the inter-relationship with the electricity industries. In short, students will learn how to analyze, evaluate, and make sound business decisions related to renewable energy from information and data supplied to them by engineers, utilities, financial analysts, tax accountants, customers, and others. Topics to be covered include:

1. Electricity technology operations, economics, and characteristics
    a. Generation (coal, gas, nuclear, wind, solar)
    b. Transmission
    c. Distribution (including smart grids)
    d. Storage
2. Electric utility types
    a. Investor-Owned
    b. Municipally- and Co-operatively Owned
    c. Federally- and State-Owned
3. Electricity markets
    a. "Restructured" (Deregulated)
        i. Energy Markets
        ii. Capacity Markets
    b. Traditionally Regulated (Vertically Integrated utilities)
4. Electricity industry regulation (US)
    a. Federal
        i. Federal Energy Regulatory Commission
            1. Generation
            2. Transmission
        ii. Environmental Protection Agency
        iii. Tax Policies favoring Renewable Energy
        iv. Federal Trade Commission/Interstate Commerce Clause

    b. State
        i. Renewable Portfolio Standards
        ii. Greenhouse Gas Initiatives
            1. RGGI (northeast US states)
            2. Assembly Bill 32 (California & others, potentially Canadian)
    c. International
        i. Global warming and the electric generation industry
        ii. UN Intergovernmental Panel on Climate Change
        iii. Kyoto Protocol

5. Electricity: The Customer Perspective
    a. Commercial customers
        i. Operating Costs
        ii. Market Perceptions and Opportunities
    b. Residential customers
6. Electricity alternatives
    a. Energy Efficiency
    b. Demand Response
7. Energy storage technologies and economics
8. Anthropogenic Climate Disruption (multiple perspectives)
9. Electric distribution and the Smart Grid
10. Due Process for Electric Utilities

Assignments

Graded case assignments will be given approximately every other week to reinforce learnings and provide students specific feedback. They will consist of developing or analyzing business cases, generally using Microsoft Excel™, to accomplish each of the 4 course learning goals described above. Several study questions will accompany each Case Assignment and will generally require both quantitative and qualitative analysis. Each Case assignment will be completed by teams of four or five.

Case Assignments will be awarded a grade for the team as well as by individual assessments of team members' performance by the other team member(s). The grade for the team will be based on both quantitative and qualitative perspectives as follows:

Case Assignment 1: 16 points, all qualitative
Case Assignments 2-4: 10 points quantitative, 6 points qualitative
Final Case Assignment: 16 points, all qualitative

The quality of quantitative and qualitative work will be evaluated as described below.

Quantitative Analysis Score
The Quantitative Analysis Score will be based on an excel spreadsheet to be developed by each team to help answer the quantitative study questions (cases 2-4). The instructor will provide inputs and assumptions to be used in the development of the spreadsheet. Quantitative Analyses will be graded on five characteristics.

a. Logic: do the analyses quantify the components necessary to answer quantitative study questions? Spreadsheets must show the team's thought processes.

b. Presentation: are the analyses clearly laid out and easy to understand? Assume your analyses will be reviewed by a time-crunched exec with attention deficit disorder.
c. Accuracy: do the spreadsheets calculate accurately in support of the thought processes provided by the team?
d. Modeling Capability: do the spreadsheets utilize an 'inputs' or 'assumptions' capability that enable a user to change an input or assumption and readily ascertain changes to the outcome/study question response?
e. Scenario Development: do the analyses consist of meta-examination of the inputs and outputs, for example, a range of outputs or best/worst/most likely case from the limited information available upon which to base a decision?

Qualitative Analysis Score
The Qualitative Analysis Score will be based on a presentation (MS PowerPoint or similar) provided by each team. The Presentation will summarize the team's work (to be accompanied by supporting quantitative analysis in appropriate assignments). The Presentation will help time-crunched managers with ADD for which you work to understand the team's approach, thought processes, and recommendations. The Presentation will also address all of the qualitative study questions accompanying the case assignment. Qualitative study questions will generally address those aspects of renewable energy decisions that are difficult to quantify but should nonetheless be considered as part of a decision process. Qualitative Analyses will be graded on four characteristics:

a. Creativity: has the team identified and thought through all of the issues likely to bear on the assignment?
b. Support: has the team adequately supported rationale for its responses to the assignment?
c. Clarity: is the Presentation easy to follow and boiled down to top issues and recommendations?
d. Confidence: does the team's output provide the time-crunched exec with confidence that the team's work will meet assigned objectives?

Students are to be familiar with all required readings and resources prior to arrival for Day 1 in Denver. ("Familiarity" is not anticipated to require 8 hours of work; 2 to 3 hours should sufficiently prepare students for week 1 discussions.) In-class participation is 6% of the total grade. You should, therefore, plan to spend time on the readings and resources prior to your arrival in Denver.

'At a Glance' Assignments and Due Dates

Week	Pre	Den	Wk 2	Wk 3	Wk 4	Wk 5	Wk 6	Wk 7	Wk 8	Wk 9	Wk 10	Final Due
Begins:	**1/3**	**1/10**	**1/20**	**1/27**	**2/3**	**2/10**	**2/17**	**2/24**	**3/3**	**3/10**	**3/17**	**3/21**
Book/Prep												
Live Class												
Online Discuss												
Team Case 1												
Team Case 2												
Team Case 3												
Team Case 4												
Final Case												

Pre Denver Work

- Read: Electric Power Industry in Non-technical Language. Warkentin, Denise. PennWell Books. 2006. Chapters 1, 4, 5, 6, and 8 (Text purchased by students).
- Read: Electricity Regulation in the U.S. – A Guide (Provided electronically in Canvas; also available from The Regulatory Assistance Project, Montpelier, VT).
- Complete Week 1 Discussion 1: Why you elected to take this course?
- Complete Week 1 Discussion 2: Ask at least one question prompted by the readings for discussion during First Four Days in Denver. More questions better.
- Familiarize yourself with all the other readings and resources.

Online Discussion/In-class participation

1. Learners are expected to review, analyze and discuss the readings and lectures.
2. Learners are expected to make comments on what interests you or how your interests are related to the topics.
3. Learners should make concise, informed comments. Quality is more important than quantity, and rants are frowned upon. Postings are usually just one or two screens (6-24 lines) and they are always created in the message box NOT attachments.
4. On-line discussion counts for 9% of your total grade. On-line discussion grading will be as follows:
    - 1.00 point will be earned for valuable contributions to class conversations, defined as comments which add value and expand overall understanding.
    - 0.75 point will be awarded for relevant comments but ones that have not advanced the collective understanding as much as was possible.

- 0.50 points will be earned for participating but adding little or nothing in new thought or ideas.
- Zero points if you did not participate.

Grading

The final grade in GEMM 6630 will be based on the following components:

- Class Participation, Week 1: 6 points
- Case Assignments (5 at 17 points each)
    - Team Grades at 16 points per case (80 points)
    - Peer Evaluations by team members at 1 point per team case (5 points)
- Online Discussions at 1 point per week: 9 points

Final letter grades are assigned as follows:

A	≥930
A-	≥890
B+	≥860
B	≥830
B-	≥790
C	≥750
C-	≥700
F/I	<700

UC DENVER GRADING POLICY:
According to The Business School policy, the average grade for this course should range between 3.0 and 3.5.

According to university policies, anyone who earns a C- must take the course again and earn a higher grade. All university polices and guidelines will be adhered to, see the UC Denver site for more: http://administration.ucdenver.edu/admin/policies/

Course Schedule
First Four Days in Denver

Day/Topics	Details

Friday, January 10: Introduction to the course; Introduction to the global electric utility industry	• Instructor Introduction
	• Syllabus Review
	• Discuss students questions from Week 1 Discussion 2.
	• Utility Operations (global)
	    o System Loads, characteristics, and drivers
	    o Generation planning and economics
	    o Transmission Systems and Operations
	    o Electric Distribution Systems
	• Utility Economics and Ratemaking (global)
	• Restructured/Deregulated Markets vs. Vertically Integrated Markets
	• Utility types, regulations, incentives, motivations, and more (global/US)

Saturday, January 11: Federal and State Policies and Regulation related to Renewable Energy	▪ U.S. federal electricity market policy
	▪ U.S. federal Interstate transmission policy
	▪ Renewable energy tax incentives
	    o Corporate Production Tax Credit
	    o Corporate Investment Tax Credit
	    o Residential Renewable Energy Tax Credit
	    o 5 year MACRS Depreciation
	• Environmental Protection Agency
	• Interstate Commerce Clause
	• State policies and regulation related to renewable energy, including Renewable Energy Standards
	    o Utility scale vs. customer scale
	    o Specifications: solar vs. wind vs. others
	    o Utility Rebate Programs
	▪ Geographic and commodity variation in ‘grid cost parity’
	▪ State and local corporate and residential tax breaks
	▪ State- and locally-sanctioned residential renewable generation financing

Sunday, January 12: The Corporate Perspective on Renewable Generation; The impact of GHG Legislation	• The Corporate Perspective on Renewable Generation
	    o Operating costs of purchased electricity
	    o Economic characteristics of owned renewable generation.
	    o Corporate electricity costs
	    o Investor-related corporate sustainability initiatives
	    o Consumer demand for ‘green’ products
	    o B2B Considerations
	• Renewable Energy Credits
	• Greenhouse Gas Legislation and Potential Impacts
	    o Kyoto Protocol status and future
	    o US: Regional Greenhouse Gas Initiative
	    o US: California’s AB32

Monday, January 13: Guest speakers from the trenches; Applying Basic Financial Analysis Concepts in Support of Renewable Energy Decisions	NOTE: Guest speaker timing will depend on availability. Guest speakers are also likely to be scheduled on Friday, with corresponding schedule adjustments made as required to accommodate the most appropriate experts. Don't miss any days in Denver! • A utility scale generation project developer/owner (Tentative: Michael Rucker, CEO, Juwi Wind) • A corporate energy/facility/operations manager considering renewable energy supply options (Drew Torbin, VP Renewable Development, ProLogis) • The owner of a (renewable) energy service/installation business (Amanda Bybee, co-owner, Namaste Solar) • A manager of an investor-owned utility (Tentative: Kent Scholl, Manager, Renewable Generation, Xcel Energy). Team Case 1 assigned. Teams will be formed. We will go over the case as a group to determine an approach, including guidance and tips. We will also cover the basic principles of/how to conduct financial analyses.

Online

Dates/Topics	Activities and Assignments
Week 2, January 20-26. • Evaluating renewable generation options as a corporate energy, facility, or operations manager	• Read Corporate Energy Manager Perspective materials • Case Assignment 1 due by Jan 27. • Participate in Week 2 Online Discussions.
Week 3, January 27-February 2 • Electric energy and capacity commodity markets • Team Case 2 guidance and tips.	• Case 2 Assigned. • Read Capacity and Forward Market materials • Participate in Week 3 Online Discussions
Week 4, February 3-9 • Energy Efficiency and Demand Response	• Case Assignment 2 due by Feb. 10. • Participate in Week 4 Online Discussions
Week 5, February 10-16 • Understanding the economics of PV Solar • Team Case 3 guidance and tips	• Case 3 assigned. • Participate in Week 5 Online Discussions
Week 6, February 17-23 • Utility Renewable Energy Procurement • Large Central Renewable Generation Deelopers	• Case 3 due by February 24. • Read Utility renewable energy procurement materials • Participate in Week 6 Online Discussions

Week 7, February 24-March 2 • Anthropogenic Climate Disruption: Science or Fiction? • Team Case 4 guidance and tips	• Case 4 assigned. • Participate in Week 7 Online Discussions
Week 8, March 3-9 • Energy Storage	• Team Case 4 due by March 10. • Participate in Week 8 Online Discussions
Week 9, March 10-16 • Electricity Distribution and the Smart Grid • Final Case guidance and tips	• Final Case assigned • Participate in Week 9 Online Discussions
Week 10, March 17-21 • Due Process for regulated utilities	• Final Case due March 21 • Participate in Week 10 Online Discussions

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel

QUESTION No. 12
Page 1 of 1

Refer to Mr. Alvarez's testimony at page 3, lines 3-10 and footnote 2, Please describe and explain Mr. Alvarez's specific involvement in the creation of MetaVu's Duke Energy Ohio Smart Grid Audit and Assessment Report for the Public Utilities Commission of Ohio mentioned in his testimony.

RESPONSE:

Mr. Alvarez led the MetaVu team that conducted an Audit and Assessment of the Duke Energy Ohio smart grid deployment on behalf of the Ohio PUC staff as ordered in 08-920-EL-SSO. As team lead Mr. Alvarez was ultimately responsible for all audit and assessment findings, as well as to complete the project and associated report within the budgeted costs by the targeted completion date. Mr. Alvarez and two MetaVu employees worked almost full-time on the audit and assessment from January through June, 2011. Mr. Alvarez also managed two subcontractors, Okiok Data (cybersecurity, data privacy, and interoperability) and Alliance Calibration (legacy and smart meter bench testing), hired to complete some aspects of the project. The report is provided as an attachment in response to Question 5(g), above.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 13
Page 1 of 1

Refer to Page 3 of Mr. Alvarez's testimony that "Wired Group clients include utilities". Please provide a list of those utilities for the last 4 years and summarize the nature of such engagements.

RESPONSE:

Objection. The request seeks information which is confidential. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, the Wired Group completed two projects for a major investor-owned utility, one in late 2013 and one in early 2014. These projects, and the name of the utility are confidential, and thus Mr. Alvarez cannot summarize them here.

In June 2014, coincident with publication of Mr. Alvarez's book *Smart Grid Hype & Reality*, the Wired Group began to focus on markets underserved by other smart grid consultants, namely consumer and environmental advocates. As a result, the Wired Group has had no other utility clients.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections.

QUESTION No. 14
Page 1 of 1

See Alvarez testimony at Page 4-5:
(a) Is it Mr. Alvarez's opinion that the determination of "the rate impact of stranded cost recovery" is required for CPCN approval?
(b) If the response is in the affirmative, please explain or provide the basis upon which Mr. Alvarez is making such a claim.
(c) If the response is in the affirmative, please state whether Mr. Alvarez is aware of the Commission ever finding that the rate impact of stranded cost recovery must be known at the time of CPCN evaluation and prior to approval, and provide support for that position.

RESPONSE:

a. Objection. The question seeks a legal opinion, but Mr. Alvarez has never held himself out as an attorney. To that extent, the question is unduly burdensome, is intended to cause delay, is intended to harass and to mislead the Commission. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, Mr. Alvarez states that nothing in this question causes him to change his recommendation that customers' interests are best served when the recovery of stranded cost is defined and incorporated into a smart meter cost-benefit analysis.
b. Not applicable.
c. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel

QUESTION No. 15
Page 1 of 1

Referring to page 5, line 1 of Mr. Alvarez's testimony, Does Mr. Alvarez agree that the rate impact of the Company's early retirement of its existing meter infrastructure (est. $9.6 million) is dependent upon both the balance of the regulatory asset and the amortization period ordered by the Commission?

(a) If Mr. Alvarez does not agree, please explain why.

RESPONSE:

Yes, but Mr. Alvarez notes those are just two of the factors which determine the rate impact of early retirements associated with the Company's CPCN. In addition, Mr. Alvarez notes that several other variables determine stranded cost recovery rate impact, including the allowed rate of return, taxes on profits, interest expense, and disposal costs. By considering the CPCN in conjunction with a rate case, the Commission can determine all of these factors, bringing certainty to CPCN rate impact calculations and reducing customer rate risk related to the CPCN.

a. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 16
Page 1 of 1

Referring to page 5, line 2 of Mr. Alvarez's testimony, does Mr. Alvarez agree that the Company is not seeking to increase its rates to customers as part of this CPCN proposal?

(a) If Mr. Alvarez does not agree, please identify and explain where in the Company's application that Mr. Alvarez believes the Company is seeking to increase customer rates in this proceeding.

RESPONSE:

Yes, Mr. Alvarez understands that the Company is not seeking to increase its rates to customers as part of this CPCN. However, Mr. Alvarez also understands that the Company will request cost recovery, including a rate of return on investments, at some point in the future if the CPCN is approved. Thus Mr. Alvarez believes the CPCN will increase customer rates eventually. Mr. Alvarez also notes the Company will in the future likely seek recovery of stranded costs, including a return on investment, thereby compounding the rate increases likely to result if the CPCN is approved.

a. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objection

QUESTION No. 17
Page 1 of 1

Referring to page 5, line 2 of Mr. Alvarez's testimony, does Mr. Alvarez believe that if the Commission approves the Company's CPCN application in this proceeding that the Commission is ceding its authority to evaluate the prudency of the Company's Meter Upgrade investment in a future rate case?

(a) If the response is in the affirmative, please explain Mr. Alvarez's belief.

RESPONSE:

To the extent that the question seeks a legal opinion, the Attorney General objects, as Mr. Alvarez has never held himself out as an attorney. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, Mr. Alvarez states, based on his layman's understanding: No.

a. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel

QUESTION No. 18
Page 1 of 1

Referring to page 5, line 2 of Mr. Alvarez's testimony, does Mr. Alvarez agree that if the Company's Meter Upgrade CPCN is approved in this proceeding, the costs to deploy the Meter Upgrade will be funded by the Company and its shareholders until such time as the Company seeks base rate recovery in the future?

(a) If Mr. Alvarez does not agree, please explain fully.

RESPONSE:

Yes. Mr. Alvarez agrees that the cost to deploy the Meter Upgrade will be funded by the Company and its shareholders until such time as the Company seeks base rate recovery in the future. However, Mr. Alvarez notes the Company will seek base rate recovery for such spending in the future, along with an authorized rate of return, taxes on profits, and interest expense. Mr. Alvarez also expects the Company to request cost recovery (and similar carrying costs) for assets stranded by the CPCN. As a result of these expectations, Mr. Alvarez believes the fact that the Company will fund the Meter Upgrade until the next rate case to be inconsequential.

a. Not applicable

WITNESS/RESPONDENT RESPONSIBLE:
Counsel as to Objections.

QUESTION No. 19
Page 1 of 1

Referring to page 5, line 3, is Mr. Alvarez familiar with the rate making concept of cost causation?

(a) If the response is in the affirmative, please explain Mr. Alvarez's understanding of the rate making principle of cost causation.

RESPONSE:

Objection. The question is vague, overbroad, confusing, requires speculation, assumes facts not in evidence, is intended to harass and divert attention from the scope of Mr. Alvarez's testimony, and is not reasonably calculated to lead to the discovery of admissible evidence. Mr. Alvarez's testimony does not discuss the concept of cost causation.

a. Same objections. DEK is just as capable of performing research on this subject as is the Attorney General.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 20
Page 1 of 1

Referring to page 5, line 3, does Mr. Alvarez agree that the rate making concept of cost causation should be followed with respect to rates enabled by smart meters?

(a) If the response is in the negative, please explain why Mr. Alvarez does not agree.

RESPONSE:

See response to question no. 19. Objection. The question is vague, overbroad, confusing, requires speculation, assumes facts not in evidence, is intended to harass and divert attention from the scope of Mr. Alvarez's testimony, and is not reasonably calculated to lead to the discovery of admissible evidence. Mr. Alvarez's testimony does not discuss the concept of cost causation. Without waiving this objection, to the extent discoverable and in the spirit of discovery, Mr. Alvarez states: Yes, however, Mr. Alvarez distinguishes between cost causation (costs should be recovered from the rate class causing costs to be incurred) and rate design (the various mechanisms by which costs are recovered from a rate class, with associated variations in both the split of risks between shareholders and customers and the incentives such rate designs create for the Company).

a. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 21
Page 1 of 1

Referring to page 5, line 3, regarding Mr. Alvarez's statement that "design of new rates made possible by smart meters can be determined in advance," does Mr. Alvarez agree that "new rates made possible by smart meters" cannot actually go into effect until the smart meters and supporting infrastructure described in the Company's Meter Upgrade are actually deployed?

(a) If Mr. Alvarez does not agree, please explain how Mr. Alvarez believes that a new rate made possible by smart meters can somehow go into effect before the meter and supporting infrastructure is actually deployed?

RESPONSE:

Yes, Mr. Alvarez agrees that new rates made possible by smart meters cannot actually go into effect until actual deployment. However, Mr. Alvarez also understands that rate designs, and avoided cost assumptions impact the benefits that customers can secure from a meter upgrade. As such, rate designs become part and parcel of a cost-benefit analysis, and therefore should be considered as part of a CPCN request specific to a meter upgrade.

a. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 22
Page 1 of 1

Does Mr. Alvarez agree that if the Commission approves the Company's Meter Upgrade in the current CPCN proceeding, and the Company files its next base rate case after the Meter Upgrade deployment commences, that the Company could still propose new customer rates that are made possible by the Meter Upgrade?

(a) If Mr. Alvarez does not agree, please explain why Mr. Alvarez believes that the Company could not propose new customer rates that are made possible by the Meter Upgrade?

RESPONSE:

Mr. Alvarez agrees, subject to his response in question no. 21, above.

a. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 23
Page 1 of 1

Please identify any Commission rule, Commission precedent, or Kentucky law that requires the Company's CPCN for a Meter Upgrade to only be evaluated in a base rate case.

RESPONSE:

Objection. The question seeks a legal opinion, but Mr. Alvarez has never held himself out as an attorney. To that extent, the question is unduly burdensome, is intended to cause delay, is intended to harass and to mislead the Commission. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, Mr. Alvarez states that while he is not aware of any such legal requirement, this does not change his recommendation that customers' interests are best served when a smart meter application is considered in the context of a base rate case, because a) the rate impact of stranded cost recovery can be determined in advance; b) the shifting of several types of risk from shareholders to ratepayers is reduced; c) the design of new rates made possible by smart meters can be determined in advance and implemented upon deployment; and d) data required to properly evaluate the Company's cost-benefit analysis is more readily available.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 24
Page 1 of 1

Please identify any Commission rule, Commission precedent, or Kentucky law that requires "the design of new rates made possible by smart meters" be determined in advance of such smart meter deployment?

RESPONSE:

Objection. The question seeks a legal opinion, but Mr. Alvarez has never held himself out as an attorney. To that extent, the question is unduly burdensome, is intended to cause delay, is intended to harass and to mislead the Commission. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, Mr. Alvarez states that while he is not aware of any such legal requirement, this does not change my recommendation that customers' interests are best served when the design of new rates made possible by smart meters are determined in advance. Customers stand to benefit by advance rate determination because: a) rates detrimental to customers can be avoided; b) the benefits of time-varying rates can be estimated and incorporated into a smart meter cost-benefit analysis; and c) some existing rates, such as reconnection fees, can be adjusted as appropriate.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 25
Page 1 of 1

Referring to page 6, footnote 3 of Mr. Alvarez's testimony, please explain which state legislatures he is referring to in his statement that the collective track records on such matters to be very poor from a customer standpoint?

(a) Please explain, citing specific examples, of poor smart meter or grid modernization legislation, and why Mr. Alvarez believes them to be poor.

RESPONSE:

In Mr. Alvarez's experience and in his opinion, grid modernization legislation in Illinois, Indiana, and Pennsylvania have resulted in poor customer cost-benefit ratios or are likely to result in poor customer cost-benefit ratios in the future. In these states, well-meaning legislators unfamiliar with the fundamentals of monopoly utility regulation or the mechanics of cost-based monopoly ratemaking make utility-related decisions without the benefit of regulatory staff experience. In these states Mr. Alvarez believes grid modernization legislation limits the ability of regulators to ensure the most cost-effective utility investments, and short-changes regulatory processes developed over decades to ensure stakeholders have a say in the capabilities and costs they believe to be necessary, just, and reasonable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 26
Page 1 of 2

Referring to page 6, line 11 of Mr. Alvarez's testimony where he states the Company's application is notable for the large size of the asset write-offs relative to meter deployment costs:

(a) On what basis does Mr. Alvarez believe the Company's application is notable?

(b) Please explain what Mr. Alvarez believes is a typical asset write-off to meter deployment cost percentage or ratio?

(c) Provide all comparisons of meter asset write-offs relative to smart meter deployments that Mr. Alvarez has made to support his conclusion that makes the Company's filing notable.

(d) Does Mr. Alvarez agree that if the Commission approves the Company's proposal for the creation of the regulatory asset related to the retired meter cost, currently estimated at approximately $9.62 million (ref. Peggy Laub Testimony at pg. 6), that once included in rates, that balance will be amortized over a period of years?

(1) If Mr. Alvarez does not agree, please explain.

(e) Does Mr. Alvarez agree that the $9.6 million estimated cost of early retirement of the existing metering system is a nominal value versus a net present value?

(1) If Mr. Alvarez does not agree, please explain why.

RESPONSE:

a. Mr. Alvarez believes the Company's application is notable for the high level of stranded costs relative to CPCN costs. As stated in his testimony (p. 7, lines 15-19), the assets stranded by the Company's proposed CPCN amount to 20% of projected smart meter cost, and given that significant percentage, the company's cost-benefit analysis should have taken that figure into consideration Furthermore, as the Company's request to recover these stranded costs are likely to include profits, taxes on profits, interest expense, and disposal costs, the total rate impact to customers is likely to be much larger than $9.62 million.

QUESTION No. 26
Page 2 of 2

b. Mr. Alvarez believes a typical ratio of stranded asset costs to smart meter costs to be 10%.

c. The table below provides a few examples of the size of stranded costs relative to the size of smart meter deployment costs.

IOU/State	Case Number	Stranded Asset $	Smart Meter Capital $	Stranded as a %
ComEd, IL	12-0298	$55 million	$925 million	5.9%
OG&E, OK	2010-00029	$32 million	$366 million	8.7%
National Grid, MA	15-120	$39 million	$294 million	13.3%
PECO, PA	M-2009-2123944	$42 million	$290 million	14.5%

d. Yes.

1. Not applicable.

e. Yes. Nominal dollars do not reflect the impact of inflation, whereas present value takes into account the idea that a dollar saved or spent in the future is worth less than a dollar saved or spent today.

1. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 27
Page 1 of 1

Referring to Mr. Alvarez's testimony at page 9, lines 5-9, does Mr. Alvarez agree that Duke Energy Kentucky did not request carrying costs as part of its request for regulatory asset related to early retirement of its existing metering system.

(a) If the response is in the negative, please cite to where in the Company's application it made a request for inclusion of carrying costs.

RESPONSE:

Yes. But it is Mr. Alvarez's understanding that the Company is not precluded from making such a request in the future, and it is likely the Company will make such a request in the future. Given this scenario that the Company is likely to make such a request in the future, and that request is likely to result in customer rate increases if approved, then it only makes sense to make such determinations and incorporate them as part of CPCN consideration. Such an approach would help the Commission make the most informed CPCN decision possible.

a. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 28
Page 1 of 1

Referring to Mr. Alvarez's testimony on page 9, lines 11 through 18 where he discusses the Duke Energy Indiana Cause No. 44720 proceeding and cites to testimony of Duke Energy Indiana witness Brian P. Davey:

(a) Please state whether or not either Mr. Alvarez or the Wired Group, participated in Duke Energy Indiana's Cause No. 44720 in any way.

(1) If the response is in the affirmative, please explain and describe in detail the participation of Mr. Alvarez and/or the Wired Group in Duke Energy Indiana's Cause No. 44720, including on whose behalf was such participation and the level of such participation.

(i) Please provide copies of any and all summaries, documents, work papers, and analysis prepared by either Mr. Alvarez or the Wired Group as part of such participation.

(2) If the response is in the negative, please explain how Mr. Alvarez became aware of the Duke Energy Indiana Cause No. 44720.

RESPONSE:

a. Neither Mr. Alvarez nor any employee of the Wired Group participated in IURC Cause No. 44720 in any way on behalf of any party.

1. Not applicable.

i. Not applicable.

2. As an extremely large ($2 billion) investment proposal, Duke Energy Indiana's grid modernization application received extensive attention by industry trade press and was reported by many electronic media outlets. As a student of grid modernization and a specialist in the field, Mr. Alvarez takes note of such proceedings as he becomes aware of them, and follows them as they develop. In addition, the Company references the application in its response to AG-DR-01-067 in the present case.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 29
Page 1 of 1

Please see Mr. Alvarez's testimony on Page 10, which reads: "The Commission possesses no predefined mechanism to hold a CPCN holder accountable for cost overruns".

(a) Does Mr. Alvarez agree that the Commission could disallow inclusion of imprudent cost overruns in utility rate base at the time of a rate case?

(1) If Mr. Alvarez does not agree, please explain why he believes the Commission cannot do so.

RESPONSE:

a. Yes.

1. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections

QUESTION No. 30
Page 1 of 1

Referring to Mr. Alvarez's testimony on page 11, lines 2 through 12. Does Mr. Alvarez agree that if the Company's Meter Upgrade CPCN was proposed in a rate case that used a historical test period, that no costs or benefits related to Meter Upgrade deployment would be reflected in base rates during that case because the investment had not yet occurred?

(a) If Mr. Alvarez does not agree, please explain how the Commission could include costs yet to be incurred, in base rates when a historic test period is used?

(b) Please cite to any relative precedent, law, or regulation that would support Mr. Alvarez's position that future costs can be included in a Kentucky base rate case preceding that uses a historic test period.

RESPONSE:

Objection. The question seeks a legal opinion, but Mr. Alvarez has never held himself out as an attorney. To that extent, the question is unduly burdensome, is intended to cause delay, is intended to harass and to mislead the Commission. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, Mr. Alvarez states that: (a) he is not a revenue requirements expert; and (b) under Kentucky law, he is not familiar with the specific types of costs that can and cannot be included in a base rate proceeding utilizing an historic test period.

a. Not applicable

b. Same objection.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel as to Objections.

QUESTION No. 31
Page 1 of 1

Referring to Mr. Alvarez's testimony on page 11, lines 2 through 12. Does Mr. Alvarez agree that if the Company's Meter Upgrade CPCN was proposed in a rate case that used a forecasted test period, that only the costs and benefits that occur during that future test period could be includable in the utility's base rates as part of that case?

(a) If Mr. Alvarez does not agree, please explain Mr. Alvarez's belief that the Commission could allow base rate recovery of future costs or benefits projected to be incurred outside of the forecasted test period?

(b) Please cite to any relative precedent, law, or regulation that would support Mr. Alvarez's position that such costs could be recoverable in rates.

(c) Does Mr. Alvarez agree that if the Company's CPCN Application were included as part of a base rate case that included a forecasted test period, that forecasted costs of meter deployment and cost savings would be used as the basis for inclusion in rates and not actual costs?

(1) If Mr. Alvarez does not agree, please explain.

RESPONSE:

Objection. The question seeks a legal opinion, but Mr. Alvarez has never held himself out as an attorney. To that extent, the question is unduly burdensome, is intended to cause delay, is intended to harass and to mislead the Commission. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, Mr. Alvarez states that: (a) he is not a revenue requirements expert; and (b) under Kentucky law, he is not familiar with the specific types of costs that can and cannot be included in a base rate proceeding utilizing a forecasted test period.

a. Not applicable.

b. Same Objection. Additionally, Mr. Alvarez knows of no Kentucky precedent, law, or regulation that would or might preclude the Company from requesting a capital tracker or other mechanism that would allow costs incurred outside the forecasted test period to be recovered from customers.

c. Same objection.

1. Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 32
Page 1 of 1

Referring to Mr. Alvarez's testimony page 13, lines 6-12 and foot note 9, where he quotes an excerpt from Duke Energy Indiana's June 29, 2016 press release, does Mr. Alvarez agree that Attachment 1 to this data request is a true, accurate, and complete copy of the press release cited in his testimony?

(a) if the response is negative, please provide a copy of the press release Mr. Alvarez is referring to.

RESPONSE:

The June 29, 2016 press release Mr. Alvarez quoted can be found on Duke Energy's website at https://news.duke-energy.com/releases/indiana-state-utility-regulators-approve-duke-energy-s-plan-to-modernize-its-statewide-energy-grid

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 33
Page 1 of 1

Referring to page 14 of Mr. Alvarez's direct testimony discussing time-varying rates and demand rates, does Mr. Alvarez agree that Duke Energy Kentucky is not seeking to introduce any such rates in this preceding?

(a) If Mr. Alvarez does not agree, please cite to where in the Company's application it is proposing to implement such rates.

(b) Does Mr. Alvarez agree that if the Commission approves the Company's Meter Upgrade CPCN application in the current proceeding and outside of a rate case, that the Company would still be able to design optional time of use rates in the future?

(1) If Mr. Alvarez does not agree, please explain.

(c) Does Mr. Alvarez agree that if the Commission considers and approves the Company's Meter Upgrade CPCN in the current preceding (i.e. not part of a base rate case) that the Commission would still be able to review and evaluate optional time of use rates in a future rate case?

(1) If Mr. Alvarez does not agree, please explain.

RESPONSE:

Yes.

a. Not applicable.

b. Yes.

1. Not applicable

c. Yes.

1. Not applicable

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez

QUESTION No. 34
Page 1 of 1

Referring to page 17, lines 20-22, discussing reconnection fees, does Mr. Alvarez agree that Duke Energy Kentucky's reconnection costs will not decrease due to the Metering Upgrade technologies until the Metering Upgrade is actually deployed and automatic reconnection is enabled?

(a) If Mr. Alvarez does not agree, please explain how Mr. Alvarez believes the Company's reconnection costs will be reduced prior to the Meter Upgrade deployment and enabling of automatic reconnection?

(b) Has Mr. Alvarez conducted any studies to determine whether the Company's current reconnection fee is accurately reflecting the Company's current costs for reconnection?

(1) If the response is in the affirmative, please provide such studies.

RESPONSE:

Yes, and Mr. Alvarez believes that issues such as reconnection fees, automatic reconnection and associated tariff modifications are best addressed in the context of a base rate case.

a. Not applicable

b. No.

1. Not applicable

WITNESS/RESPONDENT RESPONSIBLE:
Alvarez / Counsel

QUESTION No. 35
Page 1 of 1

Referring to page 18, line 9 through 10 of his testimony, please provide all studies, analysis, case studies, comparisons, regulatory proceedings, and instances upon which Mr. Alvarez bases his statement that "In my experience, smart meter cost-benefit analysis are more likely than not to underestimate costs and overestimate benefits."

(a) For the response(s) indicated above, please identify which such studies, analysis, comparisons, etc., were performed by Mr. Alvarez.

RESPONSE:

Mr. Alvarez knows of only 3 objective evaluations of smart meter deployments. The results of those evaluations are presented in the table below and form the basis for his statement. The evaluations led by Paul Alvarez are provided in response to Question 5. The evaluation completed by the California Office of Ratepayer Advocacy is attached as file "CA ORA SCE CBA.pdf".

Evaluator (a)	**Smart Meter Deployment**	**Actual Costs vs. Projected Costs**	**Actual Benefits vs. Projected Benefits**
MetaVu (evaluation led by Paul Alvarez)	Xcel Energy SmartGridCity	Higher	Benefits not projected
MetaVu (evaluation led by Paul Alvarez)	Duke Energy Ohio	Actual Costs not examined	Lower
California Office of Ratepayer Advocacy	Southern California Edison	Higher	Lower

DRA

DIVISION OF RATEPAYER ADVOCATES

Case Study of Smart Meter System Deployment

Recommendations for Ensuring Ratepayer Benefits

March 2012

About DRA

The Division of Ratepayer Advocates (DRA) is an independent consumer advocacy division within the California Public Utilities Commission (CPUC) that represents the customers of California's investor-owned utilities. DRA's statutory mission is to obtain the lowest possible rates for utility service consistent with safe and reliable service levels. In fulfilling this goal, DRA also advocates for customer and environmental protections.

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Case Study of Smart Meter System Deployment

Recommendations for Ensuring Ratepayer Benefits

by

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March 2012

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Executive Summary

This case study is an examination of Southern California Edison's (SCE) "SmartConnect" Advanced Metering Infrastructure (AMI), or smart meter program, to date. The report presents key findings stemming from the Division of Ratepayer Advocate's (DRA) review of cost requests thus far. DRA supported the use of AMI to the extent that it can provide net benefits to customers as projected when approval was granted by the California Public Utilities Commission (CPUC). DRA intends for this report to alert the CPUC to the challenges of tracking AMI costs and benefits and recommends regulatory actions be taken, if necessary, to ensure AMI systems statewide provide a net benefit to customers.

DRA reviewed SCE requests for SmartConnect-related cost recovery in multiple CPUC proceedings and compared them to the costs and benefits estimated in SCE's approved SmartConnect business case, which forecasted costs for its AMI program. DRA also evaluated progress toward the CPUC-adopted estimate of $9 million in lifetime net benefits for SCE customers, which should result in a net reduction in customer bills as a result of smart meter deployment.[1] This version of the report contains confidential data which is blacked out in tables and text.

SmartConnect was approximately 40% deployed during the discovery phase of this study,[2] and only three years of a 24 year program had been completed. Therefore, this report does

[1] The $9 million figure is the result of a present value revenue requirement (PVRR) analysis. SCE also estimated $295 million in societal benefits reflecting reduced energy theft and increased meter accuracy, which parties accepted as reasonable but agreed not to include in the business case (i.e., for purposes of determining cost-effectiveness).

[2] As of January 31, 2012, deployment was approximately 78% complete.

not attempt to offer a conclusion as to the final net cost or net benefit of SCE's program. Further, this report is not intended to propose disallowances of approved SmartConnect costs. However, data thus far does reveal trends and potential hurdles to achieving an overall net benefit for customers. Based on the analysis in the case study, DRA offers recommendations to regulators, policymakers, and utilities on ways to overcome those hurdles.

Key Findings presented in Section V of this report include:

- According to SCE's AMI business case, the total cost to customers will be greater than $5 billion, rather than the $1.6 billion cost explicitly approved by the CPUC, which only included nominal deployment costs;
- Many forecasted benefits have been delayed or reduced, which erases the projected margin of net benefits as calculated in SCE's business case;
- SmartConnect-related costs not anticipated in SCE's original business case have already been approved by the CPUC in other proceedings, beyond the over $5 billion cost referenced above. In many cases, these costs were approved without a showing of incremental benefits, and DRA anticipates that more will be requested;
- SmartConnect features such as remote disconnect and SmartConnect-enabled time-varying rates have a high potential for adverse impacts for low-income and other "at-risk" customers; and
- Ascertaining SmartConnect net benefits is hampered by a complicated cost recovery process.

The report concludes with specific recommendations to assist the CPUC with ongoing review of AMI-related proposals by the utilities.

A detailed discussion of the recommendations is in Section VI. They include:

1. Track AMI benefits and cost impacts throughout the life of the investment;
2. Require that any request for AMI-related incremental cost recovery includes a showing of increased cost-effectiveness;
3. Ensure that realization of customer benefits are synchronized with recovery of costs;
4. Condition approval of Demand-side Management expenditures on corresponding adjustments to supply-side procurement needs;
5. Create an environment that fosters the development of new benefits from the sunk cost of AMI; and
6. Ensure the needs of low-income and other “at-risk” customers are considered in program development and implementation.

Introduction and Overview

Advanced Metering Infrastructure (AMI) - also known as "smart meters" - is a metering and information technology (IT) system. "Smart meters"[3] are the main, but by no means the only, component of an AMI system. AMI is intended to provide benefits to customers and service providers by automating meter reading, optimizing utility resources, and reducing electricity demand via customer response to more detailed energy usage information.

This report provides the results of an extensive analysis of Southern California Edison's (SCE) AMI system, which is known as "SmartConnect."[4] SCE's AMI deployment was selected for analysis with the intention that lessons learned might apply to the other California utilities deploying AMI. SCE's system was selected initially for this analysis because:

- It was perceived as a "simple case" with only electric smart meters;
- SCE benefited from lessons learned by being the last of the three largest California electric utilities to deploy an electric AMI system;
- SCE's AMI deployment was not complicated by a meter upgrade proceeding, as was Pacific Gas and Electric Company's (PG&E) AMI deployment; and
- SCE has a pending General Rate Case (GRC), in which it is requesting recovery of AMI-related costs.

[3] "Smart meter" has become a generic term for AMI.

[4] SmartConnect™ is the trademarked term for SCE's smart metering system. For ease of reading, we do not include the superscript "TM" in this report.

It is also important to note that, so far, SCE's requests for AMI-related funding have been lower than such requests made by PG&E and San Diego Gas & Electric Company (SDG&E).

The objectives of this report are to:

1. Determine how the actual cost-effectiveness of SCE's SmartConnect system compares to the forecasted costs and benefits of the original business case; and
2. Alert regulators to the risks and complications involved in actually realizing the benefits of AMI systems, especially now that the three large investor owned utilities (IOUs) have begun requesting AMI-related funding beyond that requested and approved in their original business cases.

This report does not provide a definitive answer to the simple question "Does SCE's SmartConnect Program provide a net benefit to customers?" Nor can it since deployment is not yet complete, and the original cost/benefit analysis extends through 2032. Instead, this report provides specific examples of how SmartConnect-related costs are being requested and/or how benefits are being realized in SCE regulatory filings, including Energy Resource Recovery Account (ERRA)[5] applications, Phases 1 and 2 of GRCs,[6] Demand Response (DR) applications, Smart Grid proceedings, and the Long Term Procurement Planning (LTPP)

[5] ERRA is discussed in Section III as well as Appendix 3.

[6] For California IOUs, general rate cases (GRCs) are filed generally every three years and are typically divided into two different proceedings, or "phases." In Phase 1, the CPUC determines the revenue requirement that utilities will be authorized to recover through rates. In Phase 2, the CPUC determines how to allocate the total revenue requirement among the different customer classes, as well as rate design for specific customer classes. Separately, in the intervening years between GRCs, the utilities may file applications to propose new or modified tariffs – this interim process is referred to as the Rate Design Window (RDW).

proceeding. Cost recovery requests in these proceedings were compared to the original SmartConnect forecasts. DRA provides findings regarding AMI cost-effectiveness and recommendations aimed at realizing the projected customer benefits through reduced rates.

The exercise of performing a comprehensive analysis of AMI cost-effectiveness resulted in many lessons learned and highlights areas for further consideration by the CPUC, and other relevant regulatory bodies, to actualize the potential of AMI. DRA intends this report to aid CPUC decision-makers in ensuring cost-effective AMI systems, as well as CPUC staff who will address AMI-related funding requests in future proceedings over the next two decades and beyond.

A glossary, including acronyms and key AMI terminology, is provided in Appendix 1.

II. Background on AMI and SCE's SmartConnect

In California, the CPUC established requirements for AMI systems in response to the electricity crisis of 2000-2001, which was a period of highly volatile wholesale electricity prices and rotating outages resulting from partial deregulation of the electricity market and unchecked market manipulation. The CPUC issued a Ruling ordering California's large IOUs (Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company) to file preliminary AMI deployment analyses, followed by applications containing AMI deployment strategies.[7] Thus, the IOUs began to file applications for deployment of AMI beginning in 2005. PG&E and SDG&E both filed their applications in March 2005.[8]

SCE was the last electric IOU to file an AMI application.[9] At the time that PG&E and SDG&E submitted their applications, SCE's business case analysis, including multiple scenarios, showed that AMI deployment was not a cost-effective endeavor. Two of its scenario analyses showed a positive Present Value Revenue Requirement (PVRR),[10] largely due to the added Demand Response from large customers[11] that already had interval meters.[12] SCE stated that

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[7] "Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure," R.02-06-001, July 21, 2004, pp. 2 and 4 (mimeo). *See* Attachment A and Appendix A.

[8] "Application of San Diego Gas & Electric (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design," A.05-03-015; "Application of Pacific Gas and Electric Company for Recovery of Pre-Deployment Costs of the Advanced Metering Infrastructure (AMI) Project," A.05-03-016.

[9] SCE filed "Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism," A.07-07-026 on July 31, 2007. Southern California Gas Company filed its AMI application, A.08-09-023 in September 2008.

[10] PVRR is a single calculated value that sums the time-discounted cost/benefit cash flows of SmartConnect (in terms of revenue requirements) for each year of the program.

[11] Large customers are defined as having maximum demand >200 kW.

"the technology envisioned by the Ruling is unproven and not commercially available at this time."[13]

Between 2005 and 2007, SCE requested funds to study and test AMI technology, and the CPUC approved $57.2 million for this purpose. Based on its preliminary findings, SCE filed an application in July 2007 (referred to in this report as the "SmartConnect Application") seeking authorization to spend $1.634 billion to deploy a specific AMI system it called SmartConnect. SCE initially estimated that this investment would result in $109 million in net benefits (PVRR) over the estimated 20-year project life. This estimate increased to $116 million in net benefits (PVRR) through a set of errata testimony and workpapers, submitted in December 2007. SCE's business case continued to evolve through several iterations. SCE and DRA eventually reached a Settlement Agreement, which they petitioned the CPUC to adopt.[14] In late 2008, the CPUC adopted the SCE – DRA Settlement Agreement in Decision (D.)08-09-039 (referred to in this report as the "SmartConnect Decision"), by which the parties estimated a final quantifiable net benefit of $9.2 million (PVRR). The settlement also included $295 million (PVRR) in "societal" costs and benefits, though these societal costs and benefits were not

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[12] Following the California electricity crisis, the state legislature took immediate action to enable large customers (i.e., customers with maximum demand of >200 kW) to reduce peak load by authorizing $35 million from the State General Fund to the California Energy Commission (CEC) for meters that could measure energy usage in time intervals of one hour or less. Interval meters can store data for a defined time interval and contain electronic components enabling them to be read remotely by the utility and then to communicate the collected energy usage data to a utility's billing system. They are often considered a precursor to AMI, but include fewer capabilities. *See* CEC Report to the Legislature on Assembly Bill 29X, *Real Time Metering Program* (June 2002), pp. 1 and 3 (mimeo). *See* http://www.energy.ca.gov/reports/2002-06-27_400-02-004F.PDF, accessed April 6, 2011.

[13] "Southern California Edison Company's (U 338-E) Revised Preliminary Analysis of Advanced Metering Infrastructure Business Case," R.02-06-001, January 12, 2005, p. 17 (mimeo).

[14] In addition to its motion for adoption of the Settlement Agreement, SCE filed jointly with the Utility Reform Network (TURN) a motion for adoption of stipulations, which are contained within the Settlement Agreement.

included in SCE's final business case for determining cost-effectiveness.[15] In the SmartConnect Decision, the CPUC authorized SCE to spend up to $1.634 billion (nominal) in AMI deployment costs, over a deployment period extending through 2012.[16]

The SmartConnect Decision explicitly authorized a deployment period budget of $1.634 billion and, by finding the SmartConnect program cost-effective over its entire lifecycle, implicitly adopted forecasted post-deployment costs of $1.582 billion and lifetime benefits of $7.4 billion (nominal).[17]

One complexity of analyzing AMI business cases comes from the fact that, on a nominal basis, costs are highly "front loaded" and benefits are "back loaded." In other words, the majority of the estimated costs will be incurred early in the program (i.e., during deployment), while greater benefits were estimated to occur during the later years of the business case. This is shown in the following table.

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[15] The adopted settlement included $352 million (PVRR) in societal benefits associated with reduced energy theft detection and increased meter accuracy, as well as $57 million (PVRR) in societal costs associated with higher energy usage.

[16] Contingency costs of approximately $130.1 million were implicitly adopted and are included in the final authorized amount of $1.63 billion. The settlement generally shielded SCE shareholders from potential cost overruns by enabling SCE to record $100 million more than the authorized amount before the program is subject to an after-the-fact reasonableness review. Ten percent (10%) of this additional amount would be borne by shareholders.

[17] D.08-09-039, Findings of Fact 2, 4, 6, 9, and 10.

Table 1: Nominal Costs and Benefits of SmartConnect Program

($ millions)

	Deployment 2007-2012	Post-Deployment 2013 - 2032	Total
Benefits	$437.6	$6,999.7	$7,437.3
Costs	$1,633.5[18]	$1,582.1	$3,215.6
Net Benefits	-$1,195.9	$5,417.6	$4,221.7

The table shows $4.2 *billion* in net benefits based on a comparison of nominal dollars. In contrast, as stated above, SmartConnect was adopted based on an estimate of $9.2 *million* in net benefits on a PVRR basis owing to the time-discounted value of money.[19] In SCE's PVRR analysis, all costs and benefits were converted to "revenue requirements" and discounted to 2007 as the present value year.

SCE began mass deployment of SmartConnect in September 2009 and, according to a recent SCE quarterly Technical Advisory Panel (TAP) report, it had completed approximately 78% of projected installations as of January 31, 2012. SCE reports that all expenditures recorded to

[18] Note that the deployment cost adopted in the SCE business case is $47.4 million greater than the $1.634 billion authorized for cost recovery by D.08-09-039. The difference includes $45.2 million of pre-deployment costs and $2.2 million of Phase III power procurement costs, which the settling parties used to calculate the final net benefit of the project but were not authorized for recovery in D.08-09-039.

[19] It is important to note that SCE used a discount rate of 10%, which was significantly higher than SDG&E's and PG&E's discount rates of 8.23% and 7.6%, respectively (see D.07-04-043, p.25 (mimeo) and D.06-07-027, p.49 (mimeo)). The effect of SCE's higher discount rate was to reduce the net benefit of SmartConnect in present value terms. Regardless of the discount rate used, the benefits forecasted in the SCE business case still must be reflected as rate reductions, or decreased rate increases, in order to ensure AMI is cost-effective overall.

the Edison SmartConnect Balancing Account (ESCBA)[20] are within budget, and it anticipates completing mass deployment by the end of 2012 with $105 million of the authorized $130.1 million contingency funding remaining as of January 31, 2012.[21] However, it should be noted that incremental funding requests are being made that are not recorded to the ESCBA, as discussed further below.

Appendix 2 contains a more detailed background.

[20] A balancing account is an account established by a utility to record, for recovery through rates, certain authorized amounts and to ensure that the revenue collected is neither less than nor more than those amounts.

[21] All data from the TAP quarterly report.

III. Overview of SmartConnect Cost Recovery Process and Realization of Benefits

Utility expenditures for programs, equipment, plant, and expenses are authorized in CPUC decisions, but authorization does not directly result in rates increasing or decreasing. Additional mechanisms are used to ensure the utility collects these authorized costs through customer bills. The SmartConnect Decision explicitly provides for recovery of deployment costs and a limited portion of the estimated benefits. Post-deployment program costs and a vast majority of program benefits will impact rates through a wide range of routine CPUC cost recovery processes. Ultimately, customer rates are directly changed through a CPUC-approved utility *advice letter*, which modifies *rate tariff sheets*. The following is a brief summary of how SmartConnect deployment will impact customer rates (additional details are provided in Appendix 3).

SCE cost recovery for AMI deployment costs from 2008 through 2012 can be summarized as follows:[22]

- The forecasted SmartConnect deployment revenue requirement is added to customer rates *before* expenses are incurred;
- SmartConnect costs and some benefits are recorded in the ESCBA as they are incurred or realized; and
- Rates are subsequently adjusted for any differences between forecasted and actual revenue requirements.

[22] Recovery of AMI pre-deployment costs of $12 million are not addressed here.

In practice, this is a complicated process that involves multiple balancing accounts and a detailed understanding of the multifaceted Energy Resources Recovery Account (ERRA) proceedings, where balances in these accounts are reviewed. Going forward, the process described above will be modified in two ways. First, beginning in August 2011, SCE's SmartConnect costs will not be recovered through the ERRA proceedings, but rather through an advice letter filing.[23] DRA requested this change because review of advice letter filings will allow greater scrutiny of SmartConnect costs that are eclipsed by the larger fuel and power procurement costs reviewed in the ERRA proceedings.[24] Second, in SCE's pending 2012 GRC application (A.10-11-015), SCE requests authority to keep ESCBA open, with certain limitations, through 2014.[25]

ESCBA was approved to permit recovery of the $1.634 billion of deployment period costs, and $151.5 million in deployment period benefits, as discussed in Finding 1 in Section V below. The only deployment period benefits that are captured in the ESCBA are those associated with meter reading labor cost reductions. Thus, the following costs and benefits are not recovered through ESCBA and must be recovered through alternative means:

1. Additional deployment period benefits, including all capital benefits;
2. "Avoided cost" benefits due to Demand Response programs;

[23] "Decision Approving a Consolidated Revenue Requirement Increase of $403.8 Million, But a Rate Level Increase of $183.4 Million," D.11-04-006 in A.10-08-001, April 14, 2011, p. 10 (mimeo), Finding of Fact 9. *Also see* discussion at p. 7.

[24] Ibid.

[25] "Application of Southern California Edison Company (U 338-E) for Authority to, Among Other Things, Increase its Authorized Revenues for Electric Service in 2012, and to Reflect That Increase in Rates," A.10-11-015, 2012 General Rate Case – Customer Service Volume 1 – Policy, November 23, 2010, p. 30 (mimeo).

3. All post-deployment period costs and benefits; and
4. Costs and benefits that are, or will be, incremental to the SmartConnect Decision.

In addition to the general summary of these cost recovery mechanisms in Appendix 3, Section V discusses how these costs and benefits are actually being realized to date.

The benefits defined in the SmartConnect business case should be realized as a rate reduction, or reduced rate increase, which applies to all customers. In addition, individual customers can realize benefits through reduced electricity bills if they use feedback from their SmartConnect meter to reduce their consumption, or to shift their usage to times when it is less expensive when they are on a time-varying rate tariff. The $295 million of societal benefits included in the SmartConnect Settlement relate to increased meter accuracy and reduced theft, but neither the settlement nor the SmartConnect Decision specify how these benefits could be realized.

IV. DRA Analysis Methodology

DRA's review of the SmartConnect program included four major analytical steps:

1. Review and summarize pertinent sections of SCE's AMI business case submitted in Application (A.)07-07-026 ("SmartConnect Application");[26]
2. Analyze SCE's recorded AMI costs and benefits and pending AMI-related cost recovery requests;
3. Compare steps 1 and 2 above; and
4. Investigate and explain the cause of any deviations found in step 3 above.

Although SCE updated the SmartConnect business case and workpapers through several iterations of testimony, SCE never updated its workpapers to reflect the final settlement adopted by the SmartConnect Decision.[27] In order to review and summarize SCE's adopted AMI business case, DRA developed its own workpaper which quantifies the final set of costs and benefits adopted in the SmartConnect Decision through the following:

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[26] SCE's AMI business case for SmartConnect is a detailed analysis of whether the proposed program will provide net benefits, on a present value basis. *See* "Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism," A.05-03-026, March 30, 2005; "Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Pre-Deployment Activities and Cost Recovery Mechanism," A.06-12-026, December 21, 2006; and "Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism," A.07-07-026, July 31, 2007. *Also see* http://www.sce.com/CustomerService/smartconnect/industry-resource-center/regulatory-filings.htm, accessed June 28, 2011.

[27] In at least one data request response, SCE stated that it did not update its workpapers to reflect the final settlement adopted by the SmartConnect Decision. *See* SCE response to DRA data request (DRASmtCnt-SCE-KAR-002 question 2), received April 29, 2011.

- Adjusting for the terms of the Settlement Agreement; [28]
- Combining and reformatting SCE's original workpapers into a single spreadsheet which shows the nominal value of each cost and benefit for each year, (2007 – 2032);
- Categorizing costs and benefits as capital or Operations & Maintenance (O&M); and
- Categorizing costs and benefits as either operational or demand response related.

The resulting workpaper was cross-checked against the Settlement Agreement and original workpapers to ensure it was accurate within $0.05 million.[29] The final DRA workpaper allows for easy review, sorting, and charting of summary data, or annual data for any year, for each cost and benefit. Table 2 provides a summary of DRA's workpaper.

Table 2: SmartConnect Costs and Benefits

($ millions, nominal)[30]

		Deployment Costs	Post-Deployment Costs	Deployment Benefit	Post-Deployment Benefit
Operations					
	Capital	$ 1,187.9	$ 410.2	$ 86.5	$ 341.6
	O&M	$ 258.3	$ 823.1	$ 170.7	$ 3,704.4
	Total	$ 1,446.2	$ 1,233.3	$ 257.1	$ 4,046.0
Demand Response					
	Capital	$ 38.8	$ 16.3	$ 70.3	$ 161.8
	O&M	$ 148.5	$ 332.6	$ 110.2	$ 2,792.0
	Total	$ 187.3	$ 348.8	$ 180.5	$ 2,953.8
Total (Operations & Demand Response)					
	Capital	$ 1,226.7	$ 426.4	$ 156.8	$ 503.4
	O&M	$ 406.8	$ 1,155.7	$ 280.8	$ 6,496.3
	Total	**$ 1,633.5**	**$ 1,582.1**	**$ 437.6**	**$ 6,999.7**
Total		$ 3,215.6		$ 7,437.3	

[28] D.08-09-039, Appendix A.

[29] Figures in the adopted settlement were rounded to the nearest $0.1 million.

[30] This is based on DRA workpapers that estimate the adopted costs and benefits of the SmartConnect decision; original data is from SCE's workpapers in the SmartConnect Application.

Analysis of the recorded and requested costs required extensive discovery with SCE. While SCE was cooperative and timely in providing responses, discovery and analysis was complicated by the fact that the cost categories in the AMI business case were not perfectly aligned with those used in subsequent proceedings. Note that DRA's analysis is based on nominal values for each year of the business case, since there was insufficient time or resources to operate SCE's revenue requirement model.[31] Small, but noteworthy, errors may be encountered where costs and benefits calculated in different years are compared.

Comparing actual SCE cost requests with the SmartConnect business case requires clear definitions of the following terms:

- Deployment costs/benefits;
- Post-deployment costs/benefits;
- Incremental costs/benefits;
- Capital costs/benefits;
- O&M costs/benefits;
- Operational costs/benefits; and
- Demand Response-related costs/benefits.

Each of these terms is defined in Appendix 1.

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[31] In its workpapers, SCE provided annual itemized cost data in nominal terms and separately provided a "revenue requirement model" by which (nominal) cost categories could be translated into revenue requirements. While it is more accurate to analyze revenue requirements, as these are the real costs to ratepayers, DRA did not have sufficient information to be able to calculate revenue requirements for each individual cost/benefit item.

V. Findings

1. Without Effective Regulatory Oversight of AMI Costs and Benefits, it is Unlikely that Projected SmartConnect Benefits will be Fully Realized.

It is challenging to monitor AMI-related costs, as discussed further below. It is even more challenging, however, to ensure estimated benefits are realized, since in most cases benefits are actually a *reduction in costs*, compared to a scenario without SmartConnect. Tracking benefits requires analysts to be knowledgeable of the more than 130 different costs and 50 projected benefits; this knowledge needs to be maintained and applied through 2032, unless SmartConnect is replaced before this time.

As noted previously, the SmartConnect Decision established a recovery mechanism for only a limited set of deployment benefits. Specifically, $151.5 million in operational O&M benefits[32] during the deployment period, which amounts to less than 2% of the total benefits estimated in the business case, were expected to be recovered through the Edison SmartConnect Balancing Account (ESCBA).[33] However, due to delays in program deployment, it appears that the actual benefit realized via this mechanism will be closer to $100 million.[34] The

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[32] This amount is different from the amount recorded in Table 2. The discrepancy is due to pensions, post-retirement benefits other than pensions, and results sharing that are not recorded in ESCBA.

[33] D.08-09-039, Appendix A, p. 10. These benefits are operational (as opposed to DR) O&M benefits during the deployment period, net of pensions, benefits, and profit sharing.

[34] D.08-09-039 assumed the benefit of $151.5 million would be recovered over 106 million "meter months" and adopted a recovery rate of $1.42 per meter for each month the meter was installed (a meter month). The term "meter months" refers to the total number of months each meter is deployed in the deployment period. This value was estimated by SCE and was

remaining amount of nearly $50 million, and all other estimated SmartConnect benefits, can only be realized through cost reductions in other proceedings. DRA's analysis indicates that achieving cost reductions is hampered by poorly defined cost recovery mechanisms, lumping SmartConnect costs within the ERRA proceeding, overlapping funding requests from AMI-related proceedings, and the lack of accounting for the contribution of demand reduction programs (Energy Efficiency and Demand Response) in assessing the need for new utility power procurement. Some examples are discussed below.

Deployment Period Capital Benefits are Not Fully Reflected in Rate Reductions

First, SmartConnect benefits other than the limited deployment benefits above should be realized as a reduction, or at least a reduced increase, in cost requests in GRCs, ERRA proceedings, specific Demand-side Management (DSM) programs, and the CPUC energy and capacity procurement processes. However, this is not happening to the full extent forecasted by SCE. For example, recovery of $86.5 million in deployment period operational capital benefits was not well defined in the SmartConnect Decision.[35] The largest category within those operational capital benefits was related to the avoided cost of electromechanical meters,

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intended to capture all of the operational O&M benefits resulting from SmartConnect monthly during the deployment period, as meters are activated. In response to a DRA data request, SCE provided an updated estimate that the number of meter months at the end of 2012 will be 72.0 million. Using this revised estimate and the adopted recovery rate of $1.42 per meter month results in a total benefit in rates of $102.2 million, rather than $151.5 million. *See* SCE response dated May 26, 2011 to DRA data request DRA-SCE 270-tcr, question 4b, in the 2012 GRC, A.10-11-015.

[35] Capital benefits totaled $86.5 million, but the SmartConnect Decision only addresses realization of capital benefits during 2009-2011, accounting for just $15 million of the capital benefits. Realization of capital benefits after 2011 was not addressed at all. *See* "Decision Adopting Settlement on Southern California Edison Company Advanced Metering Infrastructure Deployment," D.08-09-039, in A.07-07-026, September 18, 2008, p. 12 of Appendix A (mimeo) and p. C-3 of Attachment C to Appendix A (mimeo). *Also see* SCE Testimony in A.07-07-026 dated July 31, 2007, SCE-5, pp.8-9.

estimated at $46.5 million in the SmartConnect business case for the deployment period. DRA was able to determine that those benefits for 2009-2011 were to be reflected in rates through annual advice letter filings, pursuant to SCE's Post-Test Year Ratemaking Mechanism.[36] In ERRA testimony, SCE described the avoided cost of legacy electromechanical meters for 2010, whereby SCE credited $1.6 million for the "2010 capital-related revenue requirement benefit to the BRRBA."[37] Further, in its 2012 GRC testimony, SCE states that "meter capital benefits will recognize reductions in meter capital expenditures of $1.6 million in 2010 and $5.1 million in 2011. Consistent with this approach, $8.5 million in meter capital benefits will be included in the GRC capital meter forecast in 2012."[38] The ERRA testimony does not note any benefits from 2009, and the GRC testimony and supporting workpapers do not describe how the benefits for 2011 were determined, or how they have been, or will be, realized as rate reductions. Additionally, the amounts noted in ERRA and GRC testimony are lower than the amount estimated in the SmartConnect business case. Recovery of 2012 capital benefits was not discussed in the SmartConnect Decision, but this should logically occur in the 2012 GRC. SCE's 2012 GRC testimony indicates that they are claiming a meter benefit of $8.5 million for

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[36] In the ERRA forecast proceeding, the credit and debit entries in the Authorized Distribution Base Revenue Requirement (ADBRR) are evaluated. Prior to the 2012 GRC any cost reductions associated with avoiding the purchase of legacy meters would have been booked as a credit to the ADBRR, the resulting balance of which is reflected in Post-Test Year Ratemaking advice letter filings and flows through the ERRA forecast proceeding. DRA did not find evidence of that being done. *See* SCE Testimony in A.07-07-026 dated July 31, 2007, SCE-5, pp.8-9. SCE footnote 16 on page 8 of this testimony further states "SCE currently expects that all of the Phase III costs and benefits, as adopted in a decision in this proceeding, will be incorporated into its 2012 GRC forecast; and therefore a separate ADBRR reduction for 2012 Phase III capital benefits may not be necessary."

[37] *See* SCE testimony in A.11-04-001, Chapters IX-XVI, Review of Operations 2010, public version, p. 135. The purpose of the Base Revenue Requirement Balancing Account (BRRBA) is to record: 1) the difference between SCE's authorized distribution and generation base revenue requirements and recorded revenues from authorized distribution and generation rates; and 2) record other authorized and recorded costs authorized by the Commission.

[38] *See* SCE testimony in A.10-011-015 dated November 2010, SCE-4, volume 4, p.11.

2012, but in the same table, SCE indicates that the total routine metering capital cost is $20.5 million, leaving $12 million of potential benefits unaccounted for.[39] After a detailed analysis, the full extent to which rates have been reduced for deployment period benefits is not apparent. However, to the extent deployment period capital benefits are reflected in rates, those benefits appear to be much lower than forecasted in the SmartConnect business case. This analysis highlights the challenges in accurately tracking benefits as rate reductions through multiple proceedings.

Meter Reading Benefits are Not Fully Actualized

A second example of cost reductions not being achieved relates to the realization of post-deployment benefits in GRC applications and is illustrated using the single largest estimated benefit class, reduced meter reading costs.[40] SCE's TY 2012 GRC requests metering costs and cost reductions (benefits) in the discussion of Federal Energy Regulatory Commission (FERC) account 902.[41] SCE states that "[FERC] account 902 captures *all* expenses related to reading of customer meters,"[42] and that "approximately 98 percent of field meter reading" will be automated due to SmartConnect.[43] SCE provides an analysis of metering costs that indicates a cost of $12.0 million in 2013, comprised of 2009 recorded costs of $44.3 million reduced by $32.3 million for "SmartConnect" benefits.[44] The 2013 estimated meter reading

[39] *See* SCE Testimony in A.10-11-015, SCE-04, volume 4, p.11.

[40] Nearly $1.5 billion in meter reading benefits were forecast for the post-deployment period, 2013 through 2032.

[41] Electric public utilities & licensees, natural gas pipeline companies, oil pipeline companies, and centralized service companies within FERC jurisdiction are required to maintain their books and records in accordance with the CPUC's Uniform System of Accounts (USofA). The USofA provides basic account descriptions, instructions, and accounting definitions.

[42] A.10-11-015, SCE-4, Volume 2, p.125 (mimeo). Emphasis added.

[43] A.10-11-015, SCE-4, Volume 2, p.1 (mimeo).

[44] A.10-11-015, SCE-4, Volume 2, Figure IV-10, p.130 (mimeo).

costs for full SmartConnect deployment are therefore 27.7% of the recorded pre-deployment meter reading costs. However, the SmartConnect business case estimated a benefit of $62.1 million in 2013 for meter reading costs associated with FERC account 902, which is nearly double the $32.3 million benefit suggested in the TY 2012 GRC.[45] Thus, it appears that the requested SmartConnect benefit, which reduces metering costs by only 72.3%, is too small, and the residual 2013 metering costs of $12.3 million is excessive. Stated another way, SCE has requested over $12 million annually for direct labor and non-labor meter reading expenses for 2013 in the TY 2012 GRC.[46] SCE has not documented why it needs over 27% of the pre-SmartConnect meter reading expenses, even after 98% of this function has been automated, and the post-SmartConnect expenses have been shifted to other FERC accounts.[47]

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[45] This comparison is complicated by the fact that estimated SmartConnect benefits are based on a labor rate which includes benefits, while the GRC benefits mentioned above does not. However, in the TY 2012 GRC, SCE only provided analysis of 2013, and hence a discussion of post-deployment benefits, in Customer Service Organization testimony (exhibit SCE-4). Exhibit SCE-6, which covers employee benefits, does not discuss 2013 cost or benefits, and therefore the forecasted benefit of reduced employee benefits was not requested in this GRC

[46] A decision in SCE's 2012 GRC is currently pending as of October 31, 2011. The CPUC *may* order SCE to update its 2013 attrition filing to include updated meter reading costs, which may be higher or lower than the estimates included in the current application. However, that is unlikely unless a party specifically raises the issue. At the time this paper was drafted, DRA was not aware of any recommendations that SCE be required to update meter reading costs in its 2013 attrition filing. This example demonstrates the need for explicitly tracking costs and benefits of AMI, as ensuring the expected benefits of one specific technology can easily be lost in the enormity of a GRC.

[47] For example, SmartConnect operations center costs are requested in FERC account 902.3. *See* A.10-11-015, SCE-4, Volume 2, p.131 (mimeo).

Avoided Capacity Benefits May Not be Achieved

Another example of cost reductions not being achieved relates to benefits attributed to the Peak Time Rebates (PTR)[48], Critical Peak Pricing (CPP)[49], and Time-of-Use (TOU)[50] rates enabled by SmartConnect deployment. The following table shows that the estimated benefits from these three programs are due to avoided energy and capacity purchases and that they total over $900 million in the post-deployment period.[51]

Table 3: Adopted Post-Deployment (2013-2032) Benefits Related to Demand Response

($ in millions)*[52]

Category	PCT	PTR	TOU	CPP	IHD	All/shared	Total
Avoided energy & capacity purchases	1,071.2	559.5	176.7	173.5			1,980.8
Conservation effect					811.1		933.2
TDBU Deferred Capital	105.6					39.6	145.2
Measurement & evaluation						12.4	12.4
Program benefit	1,176.8	559.5	176.7	173.5	811.1	52.0	2,949.6

*Errors due to rounding

From a customer perspective, "avoided capacity" means rates that reflect the avoidance or deferral of new power procurement resulting from successful demand-side resources, such as energy efficiency (EE), Demand Response (DR), distributed generation (DG), and time-varying rate programs. However, new power procurement is actually avoided/deferred if, and only if,

48 Peak Time Rebates (PTR) are rebates that can be offered to customers who lower their energy usage on peak event days.

49 Critical Peak Pricing (CPP) is a time-varying rate whereby electricity prices rise significantly on certain days, established one day prior to the calling of high-demand days

50 Time-of-Use (TOU) is a time-varying rate whereby pre-established rates vary based on the time at which electricity is used.

51 Deployment period benefits for PTR, TOU, and CPP add $46.4, $12.7, and $12.8 million respectively to these figures.

52 IHD refers to in-home displays. TBDU refers to Transmission and Distribution Unit.

utilities include the forecasted demand-side resources (i.e., MW savings) into their procurement plans. In its current Long Term Procurement Plan (LTPP) proposal, SCE argues that 653 MW of "AMI-enabled DR" included in the CPUC's Standardized Planning Assumptions should not be included in its forecast of available DR resources. SCE stated this capacity reduction would not be achieved "because of the considerable uncertainties that surround AMI-enabled DR at this time." SCE's Preferred Analysis excludes capacity from AMI-enabled DR programs, such as the Programmable Communicating Thermostat (PCT), Residential TOU, medium commercial and industrial (C&I) CPP, and medium C&I TOU programs, because "it is not necessary to use very aggressive DR assumptions in establishing SCE's maximum procurement limits."[53] This last sentence is in striking contrast to previous SCE statements that the assumptions used to estimate DR benefits in the Smart Connect business case were "reasonable" and "conservative."[54]

If the CPUC accepts SCE's preferred DR forecast, then the benefits associated with avoided capacity purchases, as adopted in the SmartConnect business case, will not be realized and will further reduce the cost-effectiveness of SCE's SmartConnect investment. Over the ten year period covered by SCE's LTPP proposal, this would amount to approximately $490 million, or 68%, in reduced benefits.[55]

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[53] "Rebuttal Testimony of Southern California Edison Company to Intervenor Testimony on AB 57 Bundled Procurement Plan," R.10-05-006, Exhibit SCE-10, pp. 28-29 (mimeo).

[54] See for instance SCE-4 (errata) at p. B-14, lines 4-8 regarding load impact estimates from CPP and TOU for C&I customers. *Also see* SCE-8 (rebuttal) pp. 2-10 regarding all Demand Response estimates.

[55] This estimate is based on the avoided cost assumptions used in A.07-07-026.

2. In Order to Realize the Full Lifecycle Benefits of the Adopted Business Case, the Full Cost of SmartConnect will be More than Double the $1.6 Billion Approved for Deployment Costs.

Though not made clear in the SmartConnect Decision, the SmartConnect business case implicitly included post-deployment costs of $1.582 billion[56] in addition to the explicitly approved deployment costs of $1.634 billion. SCE's deployment costs received much attention in the SmartConnect Decision, but additional attention will need to be paid to the post-deployment cost requests as the deployment period comes to a close. As discussed in greater detail in Finding 4, it is practically impossible to track most post-deployment costs given the cost recovery processes adopted for SCE.

The CPUC should carefully scrutinize the classification of costs as capital versus Operations and Maintenance (O&M). A major impact on program cost is the rate of return SCE earns for SmartConnect costs classified as capital expenditures, which leads to revenue requirements and rate increases much larger than the nominal value of those costs or expenses. As shown in Table 2 above, capital costs account for approximately 75% of deployment costs and 37% of post-deployment costs, or $1.65 billion total capital costs. Given that the majority of SmartConnect costs are capital costs, it is not surprising that prior to the SmartConnect Settlement, SCE estimated a total revenue requirement of more than $5 billion (nominal) over

[56] Implicitly approved costs include such things as ongoing demand response costs, telecommunications costs necessary to maintain and update the smart meter communications system, meter costs for new customers or replacements due to failures, and support systems such as data management systems, bill verification, and quality assurance checks.

the life of the project.[57] Classification of costs as capital or expense is governed by generally accepted accounting principles (GAAP) and federal accounting standards.

Other likely costs beyond the SmartConnect business case include incremental costs that were largely unforeseen at the time of the AMI proceedings. Some incremental AMI-related costs have already been requested, as discussed further in Finding 3, while others have not yet been requested but are anticipated by DRA, based on CPUC decisions in various proceedings. For example, a small percentage of customers throughout California requested to forgo smart meter installation and retain their current electromechanical meters, and the CPUC recently adopted an AMI "opt-out" option for PG&E customers.[58] If SCE decides, or is ordered, to provide an alternative metering system in parallel with SmartConnect, incremental costs will be incurred and some may be charged to customers at-large.[59]

Incremental AMI-related costs could also be incurred in a multitude of programs that the CPUC oversees in support of California's energy policy goals. While such incremental AMI-related costs may be anticipated, and not necessarily objectionable, all of the incremental AMI-related

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[57] SCE-3 (errata), Table V-18 / p. 52 (mimeo). This table does not reflect the deployment and post-deployment costs in the Settlement Agreement, which were approximately $50 million higher on a nominal basis than in the errata workpapers.

[58] *See* "Decision Modifying Pacific Gas and Electric Company's SmartMeter Program to Include an Opt-Out Option," D.12-02-014, February 1, 2012, in A.11-03-014. *Also see* "Application of Pacific Gas and Electric Company for Approval of Modifications to its SmartMeter™ Program and Increased Revenue Requirements to Recover the Costs of the Modifications," A.11-03-014; "Application of Utility Consumers' Action Network for Modification of Decision 07-04-043 so as to Not Force Residential Customers to Use Smart Meters," A.11-03-015; and "Application of the County of Santa Barbara, the Consumers Power Alliance, et al for Modification of D.08-09-039 and a Commission Order Requiring Southern California Edison Company (U338E) to File an Application for Approval of a Smart Meter Opt-Out Plan," A.11-07-020.

[59] The incremental costs could be funded by ratepayers generally, customers who opt out, or SCE shareholders, at the discretion of the CPUC.

costs in each program area discussed below should have incremental benefits associated with them. These benefits should be compared to the benefits forecasted in the AMI business cases to ensure the same benefits are not "recycled" or otherwise erroneously used to justify new cost requests.

Smart Grid

A large component of the currently envisioned Smart Grid involves using smart meters to monitor conditions in the distribution system and to help customers control their energy usage and bills through AMI-enabled in-home devices. The CPUC recently directed the three large IOUs to make AMI data available to customers online, provide third party access to AMI data with customer authorization, and develop Home Area Network (HAN)[60] implementation plans with an initial phased rollout of 5,000 HAN devices.[61] Each of these mandates is AMI-enabled and will have incremental costs attached, though the costs are not known at this time.

Additionally, in July 2011 the three large IOUs filed Smart Grid deployment plans in conformance with CPUC directives, which called for such plans to include a vision statement for a Smart Grid, planned components of a Smart Grid, and estimated costs and benefits of those components. Once deployment plans are adopted, they may be used as just one part of the justification for future funding requests. As AMI-enabled programs and technologies are

[60] HAN is a communication network within the home of a residential electricity customer that allows transfer of information between electronic devices, including, but not limited to, in-home displays, computers, smart appliances, energy management devices, direct load control devices, distributed energy resources, and smart meters. HANs can be wired or wireless.

[61] "Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company," D.11-07-056 in R.12-08-009, July 28, 2011, pp. 164-166 (mimeo), Ordering Paragraphs 5, 6, and 11.

such a prominent part of Smart Grid, their inclusion in deployment plans may indicate future funding requests that are incremental to the IOUs' adopted AMI business cases.[62]

Alternative Fueled Vehicles

Alternative-Fuel Vehicles (AFVs), specifically Plug-in Electric Vehicles (PEVs), offer many potential benefits beyond decreasing oil dependence, such as offering load management via energy storage capabilities. Many of these added benefits require communication from the vehicle to the electric grid, as well as from the grid to the vehicle, which can leverage previously deployed smart meters. In Rulemaking (R.)09-08-009, the CPUC is currently considering the impacts AFVs may have on the state's electric infrastructure and what actions the CPUC should take.[63] In a 2011 decision, the CPUC made clear that while it did "not conclude that the meter is needed for anything other than measuring electricity usage at this time," it did "confirm the utilities' obligation to ensure that PEV meters are AMI- and HAN-enabled."[64] As discussed in Finding 3 below, SCE has already requested funding for PEV metering expenses, which are incremental to the SmartConnect business case.

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[62] *See* D.10-06-047.

[63] "Order Instituting Rulemaking to Consider Alternative-Fueled Vehicle Tariffs, Infrastructure and Policies to Support California's Greenhouse Gas Emissions Reductions Goals," R.09-08-009, August 24, 2009, p. 2 (mimeo).

[64] "Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code §740.2," D.11-07-029 in R.09-08-009, July 14, 2011, p. 34 (mimeo).

Energy Efficiency/Integrated Demand-side Management

The SmartConnect business case included both demand (kW) and energy (kWh) reduction benefits, the latter through in-home displays (IHDs) that would interface with the meter in order to show customers their energy use in real time. Energy Efficiency (EE) and Demand Response (DR) are natural complements to each other; indeed many of the IOUs' EE programs achieve both energy (kWh) and demand (kW) savings. Acknowledging this overlap, the CPUC approved funding for Integrated Demand-side Management (IDSM) activities through both EE (D.09-09-047) and DR (D.09-08-027), though it has stated that "future authority and funding for IDSM activities [will] be considered in future energy efficiency proceedings, starting with the energy efficiency applications for 2013-2015."[65] Given this consolidation of IDSM funding requests, it is entirely possible for the utilities to request recovery of both AMI post-deployment costs as well as costs that are incremental to their AMI business cases through their EE applications. Particular costs from the SmartConnect business case that SCE could eventually consolidate into an EE portfolio application include IHD rebates – especially if the CPUC denies SCE's request to extend the Edison SmartConnect Balancing Account (ESCBA) through 2014 – along with web presentment tools such as the Residential Tier Alert, which the CPUC disapproved for SCE's 2009-2011 DR portfolio on the basis that it was more focused on energy conservation rather than demand response.[66] Going forward, there is significant potential to use the HAN technology to communicate with smart meters for EE- and energy conservation-specific activities.

[65] R.07-01-041, Administrative Law Judge's Ruling Providing Guidance for the 2012-2014 Demand Response Applications, August 27, 2010.

[66] SCE subsequently funded Tier Alert costs through the ESCBA.

Distributed Generation

Distributed Generation is generally understood to mean generation with capacity up to 20 MW and interconnected to the distribution system primarily to serve local load. The CPUC administers a variety of Distributed Generation (DG) programs, including the California Solar Initiative (CSI)[67] and the Self-Generation Incentive Program (SGIP).[68] Smart meters will provide more granular energy usage data that can be used to evaluate program performance for these and other Demand-side Management programs and will allow Net Energy Metering (NEM)[69] on a Time-of-Use (TOU) basis. The voltage measurement capabilities of SmartConnect meters could also help evaluate the impact of DG on distribution system performance, particularly as the level of DG penetration increases.[70]

3. SCE has Begun to Request Incremental AMI-related Costs, before Deployment has been Completed.

In Finding 2 above, potential incremental costs are discussed. This finding addresses actual requests SCE has made to date. AMI-related costs fall into one of three categories:

1. Approved deployment costs;

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67 CSI provides incentives to customers who install solar energy systems

68 SGIP provides incentives to support existing, new, and emerging distributed energy resources, including wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems.

69 NEM is a program available to CSI and SGIP customers whereby they can “sell” their excess generation to their utility at the utility’s applicable retail rate

70 DRA has commented multiple times in DG proceedings that the ratepayer investment in AMI systems should be leveraged to support DG programs and systems, but to date DRA is not aware that SCE or any California utility has requested funds for this purpose.

2. Post-deployment costs quantified in the AMI business case; or
3. Incremental costs related to AMI, either unanticipated in the original business case, or necessary in addition to costs previously approved, to achieve the anticipated benefits.

From a regulatory standpoint, the full cost of an AMI program should include *all three* categories. However, it can be difficult to classify costs if baseline conditions are not known. For example, SCE's business case defines deployment costs primarily based on when they are incurred, rather than for a specific list of deliverables, making it difficult to determine if a post-deployment cost requested in the GRC application should have instead been recovered through ESCBA.[71] In DR applications and the Test Year (TY) 2012 GRC, SCE began to request incremental AMI-enabled costs, even before SmartConnect was 50% deployed. Some incremental AMI-enabled costs can be necessary, but only if we can reasonably expect such costs to produce incremental benefits which improve the overall cost-effectiveness of the SmartConnect program.

In SCE's 2009-2011 DR portfolio (A.08-06-001), D.09-08-027 approved incremental costs of $1.3 million for two pilot projects related to the programmable communicating thermostat (PCT) program approved by the SmartConnect decision, but which SCE had yet to implement to the extent anticipated in their AMI business case. As indicated, the $1.3 million is incremental, which means that it is in addition to adopted costs anticipated for the PCT program. D.09-08-027 also included certain other costs (mainly pilot projects, measurement

[71] SCE's testimony in its SmartConnect Application describes the elements of the SmartConnect system and the functionality it will provide, but the description is spread over multiple exhibits and does not account for changes in the authorized program. DRA reviewed SCE's testimony and the settlement to develop its own list of what should be delivered as part of SmartConnect deployment.

and evaluation, and outreach and education) which are related to SmartConnect to varying degrees. These cost requests were not supported with quantification of incremental benefits, and there is no evidence to date that they will produce incremental benefits.

In the TY 2012 GRC, SCE specifically requested SmartConnect incremental costs for the Customer Service Business Unit in 2013.[72] This includes multiple incremental cost increases, including $1.079 million for nine new employees to test and inspect meters, and cost decreases, such as $1.222 million in reduced marketing costs. These and other associated costs and benefits net to a total cost increase of $1.45 million.[73] This request for an increase in SmartConnect costs was not accompanied with a description of incremental benefits that would be provided. Also, SCE requests the addition of 21 new staff positions to support PEV meter testing,[74] which should include testing compatibility with deployed SmartConnect meters and HAN devices. The SmartConnect business case did not include costs or benefits associated with PEVs, so some of the costs for these new positions are an example of incremental AMI-enabled costs.

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[72] SmartConnect incremental costs for 2013 were only provided for CSBU, not for any other business units or organizations in the TY 2012 GRC.

[73] A.10-11-015, exhibit SCE-4, volume 1, Table V-3, p. 26.

[74] A.10-11-015, exhibit SCE-4, volume 2, Table III-5, p. 19.

In its 2012-2014 DR application SCE is requesting $33.4 million for 2012-2014 funding of critical peak pricing (CPP) (<200 kW) [75] and peak-time rebate (PTR) / Save Power Day – approximately $12.6 million more than estimated in the business case. [76] The DR application also includes estimated benefits different than those adopted in the SmartConnect decision: 102 MW more for CPP and 40 MW less for PTR. Those changes represent a 16.9% decrease in cost-effectiveness on a dollars-per-megawatt basis. [77]

While these incremental cost requests are small compared to the adopted SmartConnect deployment costs, they illustrate how the original estimates of cost-effectiveness can be degraded if such cost requests are not accompanied by even larger incremental benefits. It should also be noted that, to date, SCE's requests appear to be lower than both PG&E and SDG&E.[78] One challenge revealed by this analysis is that it can be very difficult to determine how to classify CPUC-approved costs as deployment, post-deployment, or incremental and thus determine how costs should be recovered. Accurate descriptions of baseline conditions

[75] "Southern California Edison Company 2012-2014 Demand Response Program Portfolio," A.11-03-003, Exhibit SCE-1, Vol. 2, pp. 45-49 (mimeo). Although SCE's proposal for CPP in the DR application also includes agricultural and pumping customers, the proportion of these customers to the total is 0.2 percent, so we assume the marginal cost to include these customers is negligible.

[76] Confirmed per SCE's response to a data request (A.11-03-003, DRA-SCE-002), received April 27, 2011.

[77] Rebuttal Workpapers_MW_Calculations, Event Day MW, CPP MW Reduction in 2014 (cell M189); and SCE response to DRA data request (A.11-03-003, DRA-SCE-002, Q. 13). In its data request, DRA did not request C&I-specific load reduction estimates for 2012 and 2013.

[78] For example, PG&E has requested AMI-related funding in A.05-12-002 (2007 GRC, approximately $263 million), A.08-06-003 (2009-11 Demand Response, approximately $54 million), A.09-02-022 (2009 RDW, approximately $123 million), A.09-12-020 (2011 GRC Phase 1, approx. $310 million) and A.10-03-014 (2011 GRC Ph. 2, approximately $52 million), A.09-08-018 (SmartAC, approx. $38 million), and A.10-02-028 (2010 Rate Design Window, approximately $29 million). SDG&E has requested $118 million incremental funding in A.10-07-009 (Dynamic Pricing Application) and over $11 million in A.10-12-005 (2012 GRC Ph. 1). These examples may not include all AMI-related funding requests, as DRA has not performed a comprehensive analysis of PG&E's or SDG&E's post-AMI decision applications.

at the utility and a detailed list of what will be delivered through AMI project funding are required to make such determinations. Recommendations related to this aspect are made in Section VI.

4. The Current Process for Cost Recovery Poses Difficulties in Comparing Actual SmartConnect Revenue Requirement Impacts with SCE's Original Cost Estimates.

AMI affects many facets of utility operations and demand-side programs, which creates challenges in tracking the costs and cost reductions attributable to SmartConnect. As noted in Section III, cost recovery has only been clearly established for deployment period costs (O&M and capital) and a limited set of deployment benefits (O&M). The remaining costs and benefits, roughly half of the nominal costs and a vast majority of forecasted benefits, must be realized through a variety of proceedings including GRCs, Rate Design Window (RDW)[79] proceedings, and potentially through the proceedings discussed in the previous finding. SmartConnect is being deployed in parallel with many other programs designed to reduce energy consumption or modernize the electrical grid. Attribution of costs and benefits to a specific program such as SmartConnect is increasingly difficult as the CPUC moves toward Integrated Demand-side Management (IDSM) and building a Smart Grid.

[79] According to the CPUC's Rate Case Plan, utilities may file proposals to change their rate designs once per year in years between General Rate Cases (GRCs), typically in the 4th calendar quarter. Such proceedings are called Rate Design Window proceedings.

Comparing the deployment costs and benefits in the Edison SmartConnect Balancing Account (ESCBA) with forecasted values is relatively straightforward, but tracking the revenue requirements impacts currently requires delving into a series of arcane elements of the ERRA proceedings. SCE discusses SmartConnect costs in this large and multifaceted proceeding at a very high level. SCE does not, for instance, report on the specific recorded SmartConnect expenses as they correspond with the cost/benefit items in the adopted business case. Only a comprehensive audit of the ESCBA activity would address concerns regarding whether: (1) the recorded costs are consistent with the estimates adopted in the business case, and (2) SCE is recording costs correctly as capital vs. O&M. Such an audit will likely not occur unless the CPUC explicitly orders one.[80]

Outside of ESCBA, SCE has requested cost recovery for different components of the SmartConnect DR programs through different applications. Several types of AMI-related costs - namely for Information Technology (IT), marketing and outreach, and measurement and evaluation - appeared in both SCE's Demand Response (DR) 2012-2014 application as well as its 2012 GRC Phase 1 application. While they may not be duplicative, the fact that this situation arises means that, even after carefully scrutinizing the utility's testimony and in many cases performing extensive discovery, analysts are required to assure that there are no duplicative cost requests. Moreover, most of the costs that did trace back directly to the business case were significantly different from the adopted estimates. In many cases, though not all, this was due to changes in key aspects of the adopted programs. For instance, the

[80] The adopted settlement in PG&E's 2011 GRC Phase 1 included an independent audit, the cost of which "shall be recoverable through the SmartMeter balancing accounts." D.11-05-018 Attachment 1, pp. 1-10 (mimeo). The purpose of the audit was to determine whether costs that should have been recorded in PG&E's smart meter balancing accounts were instead recorded in other accounts.

adopted Peak Time Rebate (PTR) program included an illustrative rebate of \$0.66 per kWh reduction. However, the CPUC did not actually adopt rebate levels until SCE's 2009 GRC Phase 2 proceeding. Through D.09-08-028, the CPUC adopted PTR rebate levels of \$0.75 and \$1.50 for customers with enabling technologies. Such program changes will likely continue over the life of SmartConnect. Analysts should assess such proposed changes carefully to balance achieving the greatest net benefit from AMI-enabled DR programs with minimizing bill impacts and volatility.

Further compounding the complexity in tracking post-deployment costs is the fact that SCE's 2012 GRC application overlaps the authorized operation of the ESCBA in 2012. While SCE prepared a separate Test Year (TY) forecast for the business unit most impacted by SmartConnect to explicitly reflect this overlap, it is nevertheless difficult, if not impossible, to determine from SCE's testimony whether or not it is requesting costs that are duplicative of approved SmartConnect funding in its TY 2012 forecast. For example, a side-by-side exhibit comparing SmartConnect costs forecast to occur in 2012 with all AMI-related costs included in the TY 2012 forecast would have helped the CPUC confirm SCE's statement that it is not requesting double recovery in its 2012 GRC. Moreover, SCE proposed to extend the ESCBA beyond 2012 in order to recover costs for specific deployment activities, and if this proposal is adopted by the CPUC, the period of potential overlap will be extended.

5. Implementation Delays Reduce Net Program Benefits.

It should be clear from the foregoing discussion that recovery of costs is independent of realization of benefits, even where both occur in the same proceeding. On a present value basis, benefits in the future have less value than those today. Therefore, even if all benefits are eventually realized, any delay can still reduce the value of those benefits. SCE's adopted business case was based on meter deployment ramping up in January 2009. However, mass deployment did not begin in earnest until mid-September 2009, primarily due to delays in the availability of products that met SCE's functionality specifications. This delay has various impacts and implications for the ultimate cost- effectiveness of SmartConnect.

The delay in deployment had an asymmetrical impact on the benefits relative to the costs incurred and reflected in rates. SCE's advice letter request to update rates to reflect SmartConnect costs was deemed effective as of March 1, 2009.[81] Separately, SCE's authorized cost recovery proposal provided that SCE would record operational O&M benefits, on a per meter basis, eight months after meters were recorded in rate base (and thus earning a rate of return) to reflect a time lag between purchase and installation. Had deployment begun in January 2009, customers would have begun receiving a benefit via the ESCBA in August 2009. Instead, as a result of the delay, SCE did not begin recording operational O&M benefits to the ESCBA until April 2010. Thus, while SCE began charging customers for SmartConnect costs on March 1, 2009, customers did not start receiving any benefit from SmartConnect until over a year later.

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[81] SCE Advice Letter 2320-E.

As discussed in Finding 1, the change in schedule not only caused delayed accrual of benefits, but it may decrease operational O&M benefits overall. Unless the CPUC orders SCE to continue recording deployment period operational O&M benefits beyond 2012 or SCE otherwise captures those benefits as post-deployment rate reductions, the benefits not yet recorded at the end of 2012 may be lost.[82]

Delayed meter installation also had a ripple effect in terms of both operational capital and all Demand Response benefits being realized, since nearly all benefits can only start accruing after meters are installed (for many benefits, the meter also had to be "program-ready," i.e., installed, tested, communicating, and customer being billed based on interval usage data). For instance, metering capital benefits - which were related to the avoided cost of electromechanical meters, deferred projects, and computers - should be reflected in SCE's annual post-Test Year revenue requirement advice letter filing. Based on DRA's review of these advice letters, capital benefits appear not to have begun accruing as of the end of 2010. According to the business case, DRA estimates that this amount should have amounted to more than $35 million by the end of 2010. Meanwhile SCE has, over the same period, booked over $345 million in meter-related capital expenditures – approximately 75% of the amount estimated in its adopted business case – to the ESCBA. Similarly, for Demand Response (DR) benefits, SCE reported zero participation in all of its DR programs, whereas the adopted business case assumed more than 386,000 customers would be enrolled in one or more of the

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[82] PG&E's 2011 GRC Phase 1 settlement provided for PG&E's SmartMeter Benefits Realization Mechanism to be continued through the 2011 GRC cycle, with certain adjustments. *See* D.11-05-018 Attachment 1, section 3.5.2(c). SCE states in its 2012 GRC that SmartConnect operational benefits of $58 million are included in its 2013 forecast, but this is specific to the post-deployment period and does not remedy the reduced benefits due to the delay in deployment.

DR programs at the end of 2010. DRA estimates that, for the same time period, SCE has recorded between $15.5 and $41.6 million of DR-specific costs.

Even accounting for delayed deployment, it appears that DR benefits for Peak Time Rebate (PTR), Critical Peak Pricing (CPP), and Time-of-Use (TOU) are lower than estimated: as of July 31, 2011, SCE's reported participation rate for PTR is lower than the mid-2010 participation rate estimated in the business case by approximately 63%; for TOU the reported rate is less than 1% of the corresponding estimate in the business case;[83] still no customers have enrolled in CPP. This indicates a possible compounding effect of delayed deployment translating into *reduced* benefits, given that many SmartConnect benefits are cumulative in nature (i.e., the current year's level of benefits build upon the previous year's). The cumulative nature of these benefits also has cost-effectiveness implications with respect to the actual life of SmartConnect (as opposed to the business case life of 20 years): if the technology becomes obsolete or some other problem forces SCE to replace SmartConnect meters earlier than planned, a significant amount of benefits (estimated to occur in the final years of the business case) will also be lost.

Finally, delays were not limited to the availability of the meters: the Programmable Communicating Thermostat (PCT) and In-Home Display (IHD) programs have both been significantly delayed because the communications protocol, Smart Energy Profile (SEP) 2.0 on

[83] The adopted settlement included illustrative PTR, TOU, and CPP rate designs, but these rates were not formally approved until SCE's 2009 GRC Phase 2, in D.09-08-028. While previous decision D.08-09-039 adopted an illustrative default TOU rate for medium C&I customers, SCE subsequently settled in its 2009 GRC Phase 2 to offer an opt-in TOU rate for this class of customers. DRA was not a party to the Medium and Large Power Rate Group Rate Design Settlement Agreement. In its testimony DRA stated its preference for an opt-in TOU, but supported a default TOU with the ability to opt out and one year of bill protection.

which these devices are supposed to operate, has yet to be ratified by the ZigBee Alliance.[84] The benefits associated with these two programs constituted over 53% of total DR benefits during deployment. As with unforeseen costs, it is clear that unforeseen obstacles to achieving the benefits of SmartConnect also have a major impact on its cost-effectiveness.

6. Many Projected AMI Benefits Have a High Potential for Adverse Impacts for "At-Risk" Customers.

Two general types of features of the SmartConnect program could have adverse impacts on certain types of customers: use of the remote service connect/disconnect switch (RSS) and AMI-enabled time-varying rates. In the business case, both features promised significant net benefits for customers overall. Yet realization of these benefits may occur at the expense of low-income and other "at-risk" customers, such as customers who are ill, elderly, or unemployed.

Most SmartConnect meters are equipped with RSS, which enables service to be remotely disconnected and reconnected, thereby eliminating the need for a "house call" from an SCE field service representative.[85] This category of benefits of the RSS result in an estimated operational O&M benefit of over $1.310 billion during the SmartConnect program life due to

[84] The ZigBee Alliance is an association of companies working together to enable reliable, cost-effective, low-power, wirelessly networked, monitoring, and control products based on an open global standard.

[85] RSS is included for meters serving a load less than 200 amps, which includes most residential and some small business customers.

reductions in field service staff levels and other expenses to support field service visits.[86] This is the second largest of all benefits in the SmartConnect business case, after benefits associated with reduced meter reading costs. An additional category of benefits are those associated with using the RSS to more efficiently disconnect customers with unpaid bills, which total approximately $85 million.[87] As a result of these RSS benefits, SCE has proposed reducing connection costs for residential customers: from $26 to $15 for same-day service establishment and from $28 to $17 for same day reconnection.[88]

While supporting reduced connection and disconnection costs, consumer advocates are concerned that more efficient disconnection will pave the way for simply *more* disconnections, particularly for ill, elderly, and unemployed customers. SCE implemented more lenient collection policies for vulnerable customers in 2010,[89] and has stated that it plans to continue the current collection policies through 2014.[90] Of the three large IOUs, SCE's disconnection rates are the highest, even with the current lenient practices, for all residential customers including low-income customers.[91] Currently, two CPUC rulemakings are examining the

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[86] For benefits B10.01 and a portion of B10.06, B29.02 and B30.01. This includes $65 million for deployment and $1.250 billion for post-deployment benefits.

[87] For benefits B23.01, B23.02, and B23.03. This total includes both deployment and post-deployment benefits.

[88] SCE Testimony in 2012 GRC, A.10-11-015, SCE- 4, Volume 1, p. 21 (mimeo).

[89] The CPUC's February 2010 Interim Order D.10-02-005 and July 2010 Disconnection decision D.10-07-048 required SCE to waive credit deposit requirements as a condition for service reconnection and to permit customers to spread unpaid amounts due over a minimum three month period. This decision extended the CPUC's February 2010 rules to waive credit deposits and extend longer terms for repayment of bills.

[90] SCE Testimony in 2012 GRC, A.10-11-015, SCE- 4, Volume 1, p. 11 (mimeo).

[91] Division of Ratepayer Advocates Report, *Status of Energy Utility Service Disconnection in California*, November 2009 and March 2011. *Also see* DRA Opening Comments of May 20, 2011 in Rulemaking 10-02-005.

impact of SCE's credit and collection practices on low-income customers.[92] In these proceedings, DRA has recommended that SCE limit disconnections of low-income customers to 6% or fewer annually.[93] DRA also recommended that SCE develop and offer Arrearage Management Programs in order to motivate improved bill payment behavior by forgiving past debt in exchange for timely payments.

A similar situation results from implementation of time-varying rate tariffs which are made possible by AMI-enabled interval usage data. The ability to provide price feedback to customers was a fundamental basis for the CPUC mandate for universal AMI deployment. SCE estimated savings from avoided energy and capacity due to implementation of time-varying rate tariffs would lead to benefits of nearly $1 billion over the project life.[94] As described in more detail in Finding 5 above, the magnitude of the estimated benefits are changing over time, but what has not changed is that the benefits are predicated on the assumption that customers will reduce energy demand during times of peak system demand. However, some customers may be unable to react to the price signals and will face significantly increased energy costs as a result. DRA has described this issue extensively in

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[92] The proceedings are R.10-02-005 on residential disconnection practices and A.11-05-017, SCE's application for renewal of its CARE rate discount and free energy efficiency retrofit.

[93] "Opening Comments of the Division of Ratepayer Advocates on the Administrative Law Judge's Ruling Providing Opportunity for Comments on Phase II Issues," May 20, 2011, in R.10-02-005, p. 4 (mimeo) and "Protest of the Division of Ratepayer Advocates," June 20, 2011, in A.11-05-017, p. 21 (mimeo).

[94] DRA estimates the benefit to be $980 million. SCE workpapers in A.07-07-026 clearly indicate that expected demand response benefits total over $3 billion. DRA subtracted the Programmable Communicating Thermostat (PCT) program and energy conservation from this total to obtain a value for PTR, CPP, and TOU benefits.

many proceedings and remains supportive of carefully crafted rate programs.[95] The design and implementation of dynamic rates programs must include provisions to protect "at-risk" customers; otherwise, the costs of SmartConnect to these customers in particular will be especially high.

Together, these two classes of fundamental AMI benefits (RSS and time-varying rates) represent over 30% of the estimated benefits of SmartConnect, and failure to realize even a small portion of these benefits will result in a program which is not cost-effective. The delicate balance between realizing of AMI-enabled systemwide benefits, while protecting low-income and "at-risk" customers, will be an ongoing challenge for regulators.

[95] DRA White Paper, *Time-Variant Pricing for California's Small Electric Consumers*, May 2011, p. 8 (mimeo). *Also see* "Testimony on San Diego Gas and Electric's Dynamic Pricing Application," A.10-07-009, pp. 1-8 to 1-10, 2-3 to 2-4, 2-9 (mimeo); and "Petition for Modification of the Division of Ratepayer Advocates, the California Small Business Association and the California Small Business Roundtable of Decision 10-02-032," pp. 4-6 (mimeo).

VI. Recommendations

Based on DRA's analysis and findings, we offer the following recommendations aimed at ensuring cost-effective AMI systems that will benefit customers.

1. Track AMI Benefits and Cost Impacts throughout the Life of the Investment.

The CPUC committed customers to investing over $5 billion in SCE's SmartConnect system alone, and it is incumbent upon the CPUC and IOUs to track costs and benefits to determine whether a net benefit is achieved. Regulators and policy makers should commit to ensuring that forecasted AMI system net benefits are ultimately realized. It is unlikely that regulatory staff involved with an AMI application will be available to review AMI-related cost requests across the full range of AMI-related proceedings, and over the full life of the AMI project. It is therefore necessary to ensure that utilities and regulators establish a formal method to track AMI costs and benefits. The CPUC should require utilities to establish a tracking mechanism to compare the original business cases to various AMI-related funding requests[96] made through applications, advice letters and other cost recovery mechanisms. The Commission also should require the utilities to provide status updates about the cost-effectiveness of their AMI investments. One vehicle for doing so might be the Smart Grid Deployment Plans required by P.U. Code § 8367. Additionally, DRA recommends that the following be included in any future large-scale long-term deployments utilizing a new technology, especially as Smart Grid technologies are adopted:

[96] This includes post-deployment costs and benefits identified in the utility's business case as well as incremental costs and benefits associated with technologies and programs that build on the original business case.

- Definition of costs and benefit categories consistent with the FERC accounting categories used in GRCs;
- Full documentation of the baseline state and capabilities of all systems (e.g., IT systems) and processes (e.g., billing and meter reading) impacted by the new technology;
- A list of specific deliverables which will be provided within the adopted deployment costs. This should be used as a baseline for subsequent requests for post-deployment or incremental technology-enabled costs;
- A single spreadsheet with the projected costs and benefits over the life of project, as adopted;[97] and
- Clear definition of the cost recovery process for all types of costs and benefits (e.g. post-deployment capital benefits due to DR).

2. Require that any Request for AMI-related Incremental Cost Recovery Includes a Showing of Increased Cost-Effectiveness.

In a recent proceeding, the CPUC ordered "[i]n future general rate cases, Pacific Gas and Electric Company shall not add a new type of cost to the revenue requirement without estimating and including in the revenue requirement the cost savings to be achieved by the

[97] The spreadsheet should express costs and benefits in the same terms as the AMI business cases, i.e., annual nominal dollar amounts for each cost / benefit item, broken out by O&M and capital. Additionally, applications should include the revenue requirements associated with these costs and benefits.

new type of cost or an explanation of the reasons there will be no cost savings."[98] Such an order should be issued in each proceeding where incremental AMI-related costs could be requested.

3. Ensure that Realization of Customer Benefits are Synchronized with Recovery of Costs.

PVRR analyses indicating net benefits can easily become outdated and invalid if benefit streams are delayed relative to cost streams. AMI and AMI-related programs should be designed to begin realizing benefits once mass deployment begins and regulators should ensure that both the magnitude and timing of forecasted benefits are reasonable. For example, support systems such as communication networks, back office IT systems, and marketing programs should be planned before mass deployment begins, so they can be launched concurrently with mass deployment. This recommendation applies both to the pending deployment of SoCalGas's AMI system and all AMI-enabled programs for which the utilities will seek cost recovery in the future. Ideally, cost recovery should be tied to benefit realization.

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[98] PG&E 2011 GRC Phase 1 decision D.11-05-018, Ordering Paragraph 37, p.97 (mimeo). This is separate from the requirement in P.U. Code §451 that "[a]ll charges demanded or received by any public utility . . . for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable."

4. Condition Approval of Demand-side Management (DSM) Expenditures on Corresponding Adjustment to Supply-side Procurement Needs.

A major forecasted AMI benefit is the new capacity avoided by AMI-enabled Demand Response (DR) programs, but in times of over capacity, there is no new capacity to avoid. Rulings in both the DR policy (R.07-01-041)[99] and the LTPP (R.10-05-005) proceedings reflect the CPUC's intention that avoided cost realization is supposed to be a "full-circle" process (i.e., utilities' expenditures in demand-side programs will reduce their supply-side costs). DRA observes, however, that in California the utilities have been allowed to financially benefit from self-reported megawatt and megawatt-hour savings on the one hand (e.g., through the Energy Efficiency Risk/Reward Incentive Mechanism)[100] but still argue for new procurement on the other (e.g., PG&E's Oakley application).[101] If the impacts of AMI, DSM programs, and time-varying rates are not going to result in reduced procurement costs, regulators should not saddle customers with the redundant cost of these programs.

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[99] "Scoping Memo and Ruling," R.10-05-006, Dec. 3, 2010, Attachment 1 ("Standardized Planning Assumptions (Part 1) for System Resource Plans"), pp. 10-11 (mimeo).

[100] D.12-01-019 approved an additional $68 million for a total of $211 in incentive awards to the IOUs over the 2006-2008 period. *See* "Decision Regarding the Risk/Reward Incentive Mechanism Earnings True-Up for 2006-2008," in R.09-01-019, December 16, 2010, p. 2 (mimeo).

[101] *See* A.09-09-021.

5. Create an Environment that Fosters the Development of New Benefits from the Sunk Cost in AMI.

Based on DRA's review of SmartConnect, it is likely that the net benefits promised in SCE's adopted program will not be fully realized, even if the recommendations above are implemented. An alternative way of making AMI cost-effective is to find new benefits which can be extracted with minimal incremental cost. Many such benefits related to increasing penetration of PEVs and DG[102] are anticipated through Smart Grid implementation, as well as full implementation of voltage monitoring and outage management.[103] Use of smart meters as a measurement and evaluation tool for Demand-Side Management (DSM) programs also has potential for incremental benefits. However, as mentioned in Recommendation 2 above, proposals requesting incremental AMI-related costs should be rejected unless they provide compelling evidence that they will provide incremental net benefits. Regulators must at the same time ensure that benefits promised in the AMI business case are not subsequently reused to justify other investments.

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[102] DRA notes that increased penetration of DG does not actually provide a benefit as long as there is excess capacity. As noted in the previous recommendation, energy savings on the demand side should be reflected in reduced procurement of excess capacity. So far, this does not appear to be happening.

[103] Improved outage management was considered a benefit of SmartConnect, and SCE was allowed to recover costs associated with integration of AMI data with the outage management system. However, SCE has already requested $7.3 million in incremental funding in its 2012 GRC to upgrade its outage management system to further leverage AMI and repair defects. SCE also anticipates a more expansive upgrade in 2015-2020. *See* "Application of Southern California Edison Company (U-338-E) for Approval of its Smart Grid Deployment Plan," A.11-07-001, pp. 88-89 (mimeo).

6. Ensure the Needs of Low-Income and Other "At-Risk" Customers are Considered in Program Development and Implementation.

The use of a remote service switch (RSS) and implementation of time-varying rate tariffs provides nearly a third of the benefits expected from the SmartConnect program, but both can adversely impact certain types of customers. As discussed in Finding 6 above, DRA has made specific recommendations to protect "at-risk" customers in California. In addition, DRA has recommended more moderate introductory rates than are in the business case. Both of these recommendations reduce AMI benefits relative to those claimed in the business case, signaling a dynamic tension with other recommendations in this paper. This tension cannot be removed, but can be mitigated through a careful balance between the need for net benefits generally, with the protection for those in need. For certain classes of customers such as low-income customers and other "at-risk" customer groups, special efforts should be undertaken to ensure that such customers understand rate and bill impacts, and such customers should be encouraged to sign up if, and only if, they will benefit.

VII. Conclusion

The CPUC required California's large IOUs to file AMI applications and required a demonstration that AMI systems *could* produce net customer benefits. Initially, SCE found that AMI was not cost-effective for its customers, but AMI technological improvements in 2005 and 2006 led to the SmartConnect Application in 2007, which forecasted a very slim margin of lifetime net benefits on a present value basis. The CPUC authorized SmartConnect deployment costs of $1.634 billion, and SCE customers in aggregate have so far experienced a revenue requirement increase in excess of $193.1 million to cover these costs.[104] This is a real cost increase, one which will certainly rise as more meters are purchased and deployed, and as SCE begins to incur post-deployment costs. DRA's review of SCE's SmartConnect business case and analysis of the program to date revealed a number of findings.

First, total SmartConnect costs paid by customers will actually be more than $5 billion (nominally), accounting for post-deployment costs and the financing costs incurred over the 20 year life of the SmartConnect system. This total cost will be even greater if the cost of future AMI-enabled investments and programs are included. While SCE's incremental cost requests have thus far been relatively conservative, it is important to note that PG&E and SDG&E have so far requested much higher amounts in incremental AMI funding: PG&E has requested and received approval for funding in excess of $500 million, and SDG&E has received funding approval for over $93 million.

[104] $98.4 million in 2009 (AL 2320-E) and $94.7 million in 2010 (AL 2446-E); AL 2577-E authorizes a SmartConnect revenue requirement of $203.5 million ($205.8 million with franchise fees and uncollectibles) in 2011.

Second, it appears probable that the SmartConnect benefits forecasted by SCE will not be fully realized, and as a result, SCE customers will not experience the eventual rate *reductions* forecasted in the adopted business case. The CPUC only explicitly provided a cost recovery mechanism for $151.5 million in deployment benefits, and delayed implementation will result in only two-thirds of this amount being collected as planned. The remaining 98+% of benefits, estimated to be $7.437 billion, can only be realized through a plethora of cost reductions in multiple proceedings. While this finding is based on a limited analysis early in a 24 year program, the delays and reduction in forecasted benefits are sufficient to erase the razor-slim margin of net benefits adopted by the CPUC. Note that this finding relates to the 50 specific benefits defined by SCE in 2006 and does not include new and incremental SmartConnect related net benefits that may yet be provided.

Third, the cost/benefit analysis in the SmartConnect business case, and this report, generally relates to SCE customers as a whole, and the impacts on individual customers can vary substantially. For example, customers can use their smart meter to reduce electricity usage and reduce their bills, even taking into account the rate increase for SmartConnect costs. In contrast, other individuals will be subjected to adverse impacts due to remote disconnection and higher rates during hot summer days. Evaluation of any AMI program needs to consider individual impacts and protect “at-risk” customers.

Finally, in performing this analysis, DRA found many impediments to tracking cost-effectiveness during SmartConnect program implementation. This is in spite of SCE having a generally well defined business case and being responsive to DRA’s discovery requests. Knowledgeable and diligent regulators will be hard pressed to limit actual lifecycle costs to the forecast estimates. It will be even more difficult to ensure the promised benefits are realized by customers as a net reduction in their rates, since regulators must actively look for cost reductions that may not be clearly identified by the utility. DRA offers recommendations intended to aid the ongoing evaluation of AMI programs by enabling transparent and ongoing tracking of cost-effectiveness.

The overall point of this report is not to fault SCE for performance to date or to propose retroactive ratemaking, but rather to highlight the many challenges to be overcome if AMI-related customer benefits are to be realized. Utilities have a clear financial motivation to quickly and fully recover all authorized expenditures through rate increases, but not such clear motivation to ensure that anticipated benefits are realized through rate decreases. Given this fundamental asymmetry, the CPUC has the responsibility of ensuring the investment in AMI ultimately yields a net benefit to customers. California IOUs have been authorized to expend over $5.3 billion to *deploy* AMI systems,[105] and it is too late to keep these expenses out of rates. However, billions more will be requested for *post-deployment* and incremental costs. The ultimate value or financial burden of AMI will be determined by the CPUC's actions regarding each and every one of these requests.

[105] This figure includes the $1.0507 billion approved for SoCalGas's (gas-only) AMI system (D.10-04-027). The Commission approved $572 million for SDG&E (D.07-04-043); up to $1.6 billion (D.06-07-027), plus $466.8 million (D.09-03-026 – upgrade) for PG&E's gas and electric AMI deployments.

APPENDIX 1: Glossary

AMI	Advanced Metering Infrastructure. AMI is also commonly referred to as "smart meters," although AMI encompasses meters and other equipment, software, and processes necessary to make the meters fully functional. SCE's SmartConnect is a specific example of an AMI system.
Capital Expenditure	An expenditure that is treated as an accounting asset and depreciated over time. They also are placed in rate base, and customers pay a rate of return on these expenditures. Capital expenditures include all long-term assets, which are expected to be "used and useful" over an extended period of time; for instance IT hardware and software physical plant, and related equipment, etc. In other words, a capital expenditure is a capital investment (i.e., part of rate base), upon which the utility is allowed to earn a profit (commonly referred to as rate of return). The capital investment shows on the utility's balance sheet.
CEC	California Energy Commission
CPP	Critical Peak Pricing. A time-varying rate in which customers are notified, typically on a day-ahead basis, that their rates will increase during a specified "event" (usually four to six hours during the late afternoon). CPP events are typically called in anticipation of abnormally high demand or other system constraints.
CPUC	California Public Utilities Commission
CSBU	Customer Services Business Unit. The organization at SCE which includes meter reading, field service, and billing, which is most affected by the SmartConnect program.

Demand Response (DR)	Gives individual electric customers the ability to reduce or adjust their electricity usage in a given time period, or shift that usage to another time period, in response to a price signal, a financial incentive, or an emergency signal. Programs designed to reduce energy demand during peak usage periods, which drives procurement of new capacity. This includes time-varying rates/tariffs, programs designed to generate load control and price-responsive demand response, and in certain cases energy conservation. Generally used in reference to DR programs adopted by the CPUC.
Deployment Costs/ Benefits	Costs/benefits which have been approved by regulators and for which a cost-recovery mechanism has been established. For SmartConnect, this originally referred to costs/benefits incurred during the time period beginning September 18, 2008 through December 31, 2012[106]. It also describes the costs/benefits required to be provided by the functionality, features, and programs proposed in SCE's application (adopted in D.08-09-039).
DRA	Division of Ratepayer Advocates
DR-specific Costs/ Benefits	As opposed to operational costs/benefits (see below), DR-specific costs are those that are not necessary for AMI deployment, *except* to implement and administer DR programs. DR benefits are benefits that could only occur as a result of these programs.
ERRA	Energy Resources Recovery Account
ESCBA	Edison SmartConnect Balancing Account. Also referred to as the SmartConnectBA by SCE.
GRC	General Rate Case

[106] SCE has proposed modifying the pervious definition of SmartConnect deployment costs to extend beyond December 31, 2012. See SCE testimony in the TY 2012 GRC, Exhibit SCE-4, volume 1, page 30.

HAN	Home Area Network
IHD	In-Home Display
IOU	Investor owned utility
Incremental AMI-enabled Costs/ Benefits	Requests for new AMI enabled programs, operational costs, or capital investments which promise benefits beyond those quantified in the original business case. “Incremental” refers to those costs and benefits that were either excluded or underestimated in the original business case for various reasons (e.g., unforeseen costs).
Meter Month	A term used to amortize deployment period benefits into rates. For each new meter, it is the number of months the meter has been in service, as counted starting 8 months after the meter was purchased. For example, 10 meters installed May 1, 2009 would generate 120 meter months as of December 31, 2010.
Operational Costs/ Benefits	In terms of the AMI business cases, operational costs are all the costs necessary to implement and administer AMI deployment. Operational benefits are all the benefits resulting from such costs. In R.02-06-001, the CPUC directed the electric IOUs to analyze AMI deployment scenarios that included operational costs/benefits only, and scenarios that included both operational and DR-specific costs/benefits.
Operations & Maintenance (O&M) Expense	An accounting expense that shows on the utility’s income statement (i.e., annual profit and loss statement). O&M expenses are not included in rate base. O&M expenses include, for example, purchased power and fuel; customer accounts, services, and marketing expenses; and administrative and general expenses.
PCT	Programmable Communicating Thermostat

Post-Deployment Costs/ Benefits	Costs/benefits, other than deployment costs, in the adopted cost-benefit analysis and which have corresponding benefits in the AMI business case. For SCE, those costs/benefits incurred during the time period beginning January 1, 2013.[107]
PTR	Peak Time Rebate. Demand Response (DR) program in which customers are notified, typically on a day-ahead basis, that they may receive rebates for reducing their electricity usage during a specified "event" (usually four to six hours during the late afternoon). PTR events are typically called in anticipation of abnormally high demand or other system constraints.
PVRR	Present Value Revenue Requirement
RSS	Remote Service Switch (connect/disconnect). A feature of SmartConnect meters installed on services less than 200 amps which allows the utility to end, and restart electrical service remotely, without sending a service technician.
SCE	Southern California SCE
SmartConnect	Southern California SCE's brand name for their AMI system.
SPP	Statewide Pricing Pilot
TOU	Time-of-Use. A time-varying rate in which prices vary depending on the season and time of day. TOU prices are typically higher during "peak" and "semi-peak" hours, when demand is expected to be higher, as opposed to "off-peak" hours. In contrast to CPP, TOU does not include significantly higher prices that can be applied to rates on a day-ahead basis.

[107] Ibid.