BEFORE THE

ILLIINOIS COMMERCE COMMISSION

COMMONWEALTH EDISON COMPANY	)	
	)	
Petition for Statutory Approval of a Smart Grid	)	No. 12-0298
Advanced Metering Infrastructure Deployment	)	
Plan pursuant to Section 16-108.6 of the Public	)	
Utilities Act	)	

DIRECT TESTIMONY AND EXHIBITS

OF

J. RICHARD HORNBY

ON BEHALF OF

THE PEOPLE OF THE STATE OF ILLINOIS

AG Exhibit 3.0

MAY 11, 2012

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EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND PRESENT POSITION.

A. My name is James Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, Inc., 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the People of the State of Illinois ("the People"), represented by the Office of the Illinois Attorney General ("AG")..

Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including: electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am a consultant specializing in planning and ratemaking in the electric and gas industries. Over the past twenty five years, I have presented expert testimony and provided litigation support on these issues in more than 120 proceedings in over thirty jurisdictions in the United States and Canada. Over this period, my clients have included staff of public utility commissions, state energy offices, consumer advocate offices and marketers.

Prior to joining Synapse in 2006, I was a Principal with CRA International and, prior to that, Tabors Caramanis & Associates. From 1986 to 1998, I worked with the Tellus Institute (formerly Energy Systems Research Group), initially as Manager of the

Natural Gas Program and subsequently as Director of their Energy Group. Prior to 1986, I was Assistant Deputy Minister of Energy for the Province of Nova Scotia.

I have a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology ("MIT") and a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now merged with Dalhousie University. I have attached my resume to this testimony as AG Exhibit 1.1 .

Q. PLEASE SUMMARIZE YOUR EXPERIENCE WITH THE ECONOMICS OF, AND RATEMAKING FOR ADVANCED METER INFRASTRUCTURE ("AMI") PROJECTS SUCH AS THE SMART GRID AMI DEPLOYMENT PLAN THAT COMMONWEALTH EDISON (COMED) HAS FILED IN THIS PROCEEDING.

A. Since 2008 I have submitted testimony regarding proposed AMI and smart grid projects in Arkansas, Maine, Maryland, Pennsylvania and Texas. I have reviewed proposed AMI projects for clients in New Jersey, the District of Columbia and Nevada.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. ComEd filed its Smart Grid AMI Deployment Plan ('AMI Plan") and supporting Direct Testimony on April 23, 2012. The Office of Attorney General retained Synapse to assist in its review of that submission. My testimony addresses the present value of the projected benefits from the AMI Plan minus its projected costs, which I refer to as its net present value ("NPV"), as well as the potential to increase the value of the AMI Plan to customers.

Q. WHAT DATA SOURCES DID YOU RELY UPON TO PREPARE YOUR TESTIMONY AND EXHIBITS?

A. I relied primarily on the Company's AMI Deployment Plan, the Direct Testimony and exhibits of the Company's witnesses as well as the Company's responses to various data requests ("DR"). Certain of those responses are provided in AG Exhibit 1.5. In addition, I relied upon evidence and reports from AMI and Smart Grid proceedings of other utilities in which I have participated or which I have reviewed.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATION REGARDING THE NPV OF THE PROJECTED TOTAL BENEFITS AND COSTS OF THE AMI DEPLOYMENT PLAN.

A. My first conclusion is that there is considerable uncertainty as to whether the AMI Plan is cost beneficial to its customers. According to ComEd's own projections, customers will not receive a cumulative net positive impact from the AMI Plan until 2021, as indicated on line 31 of Table A-4 of Exhibit 6.02. In addition, the AMI Plan is only marginally cost-beneficial when analyzed for a case which reflects currently effective disconnection regulations and the NPV of that case is calculated using a reasonable discount rate and time horizon.

My second conclusion is that the Company's position that the AMI Plan will be cost-beneficial hinges primarily upon the Company's projections of the value of the additional revenues and avoided power costs it expects to achieve by reducing unaccounted for electricity (UFE) use, consumption at inactive meters (CIM) and bad debt. If the actual unit values, i.e. $/kWh, of the additional revenues and avoided power costs the Company achieves by reducing the annual kWh in each of those categories prove to be materially less than the Company has projected, the AMI Plan will not be cost-beneficial.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE POTENTIAL TO INCREASE THE VALUE OF THE AMI PLAN TO CUSTOMERS.

A. The Company has the potential to increase the value of the AMI Plan to customers in at least two ways. First, it could offer a new Time-of-Use ("TOU") rate in addition to its proposed new Peak Time Rebate (PTR). Second it could modify its schedule for deploying its AMI investments to coordinate with its schedule for deploying its distribution automation (DA) investments. This is necessary in order to balance and optimize improvements in reliability with the installation of advanced meters.

Based upon those two conclusions, I recommend that the Commission require the Company to offer a new TOU rate in conjunction with is filing for a new PTR, and also require the Company to submit a modified AMI Plan with a deployment schedule that is coordinated with the Company's schedule for deploying DA investments.

III. PROJECTED BENEFITS AND COSTS OF COMED AMI PLAN

Q. PLEASE SUMMARIZE THE RESULTS OF COMED'S ASSESSMENT OF THE PROJECTED BENEFITS AND COSTS OF ITS AMI PLAN.

A. Mr. Trump presents an overview of the projected benefits and costs of the ComEd AMI Plan in his Direct Testimony. He presents his estimate of the cumulative values of 20 years of those projections in Table 1-2 in ComEd Exhibit 6.02. The Company modified those projections through a correction to AG1.04 distributed to parties on May 10, 2012. My testimony refers to the Company's corrected values.

The three largest sources of projected benefits from the AMI Plan, according to Table 1-2, are:

- reduction in unaccounted for energy (“UFE”) and consumption at inactive meters (“CIM”);
- operational efficiencies and cost reductions; and
- reduction in bad debt expense.

According to that Table, the cumulative value of those projected benefits plus projected avoided capital expenditures is $4.613 billion. In contrast, the cumulative value of the projected costs of the AMI Plan over 20 years is $2.028 billion. Dividing the total benefits by the total costs produces a benefit to cost ratio of 2.3. The Table also indicates that the NPV of benefits less costs over the 20 years is $1.251 billion.

Q. DO THE COMED RESULTS PROVIDE A REASONABLE ESTIMATE OF THE BENEFIT TO COST RATIO OF THE AMI PLAN OR OF ITS NPV?

A. No. My analysis indicates that those ComEd results overstate the benefit to cost ratio of the AMI Plan and of the NPV for three reasons. First, the Base Case for which the Company has calculated these results does not reflect currently effective customer notification requirements. Second, the discount rates the Company used to calculate the benefit to cost ratio and the NPV under its Base Case are too low. Third, the number of years the Company used in its calculation of benefits and costs is too long.

Q. PLEASE EXPLAIN WHY THE BASE CASE THE COMPANY USED IS NOT REASONABLE.

A. Under currently effective regulations, the Company must send an employee to notify, in person, any residential customer about to be disconnected for non-payment. The Base Case for which the Company has calculated its results assumes this regulation will be changed (or that no premise visit or in-person contact is required now) to allow the Company to notify such customers by phone and to disconnect the customer remotely via the disconnect switch capability of the smart meter. Thus, the Base Case results the Company presents in Table 1-2 do not reflect currently effective customer notification requirements. Black and Veatch prepared an estimate of results for a "sensitivity scenario", which it refers to as the "Doorknock Sensitivity" under which the currently effective regulations remain in effect.

Q. ARE THE COMPANY'S RESULTS FOR THE DOORKNOCK SENSITIVITY LESS COST-BENEFICIAL THAN THE BASE CASE?

A. Yes. The NPV of benefits minus costs for the Doorknock Sensitivity is 18**%** less than the corresponding NPV for the Base Case. The benefit to cost ratio is 14% less, at 2.0. AG Exhibit 3.1 presents a comparison of the Company's results for those two cases.

Q. PLEASE EXPLAIN WHY THE DISCOUNT RATES AND TIME PERIODS THE COMPANY USED IN ITS BASE CASE CALCULATIONS ARE A MATTER FOR REVIEW IN THIS PROCEEDING.

A. The discount rates and time periods the Company used to calculate its Base Case results are a matter for discussion and interpretation because they are not defined explicitly in the Illinois Public Utilities Act. That Act requires the Illinois Commerce Commission ("Commission") to make a determination of whether an AMI Plan is, or is not, cost-beneficial.[1] According to the Act, an AMI Plan meets the cost-beneficial standard if: "… the present value of the total benefits of the Smart Grid AMI Deployment Plan exceeds the present value of the total costs of the Smart Grid AMI Deployment Plan." However, the Act does not specify either the discount rate or the number of years to be used to calculate that present value. Section 16-108.5, however, does require a utility seeking formula rate regulation to complete the reliability and smart grid infrastructure

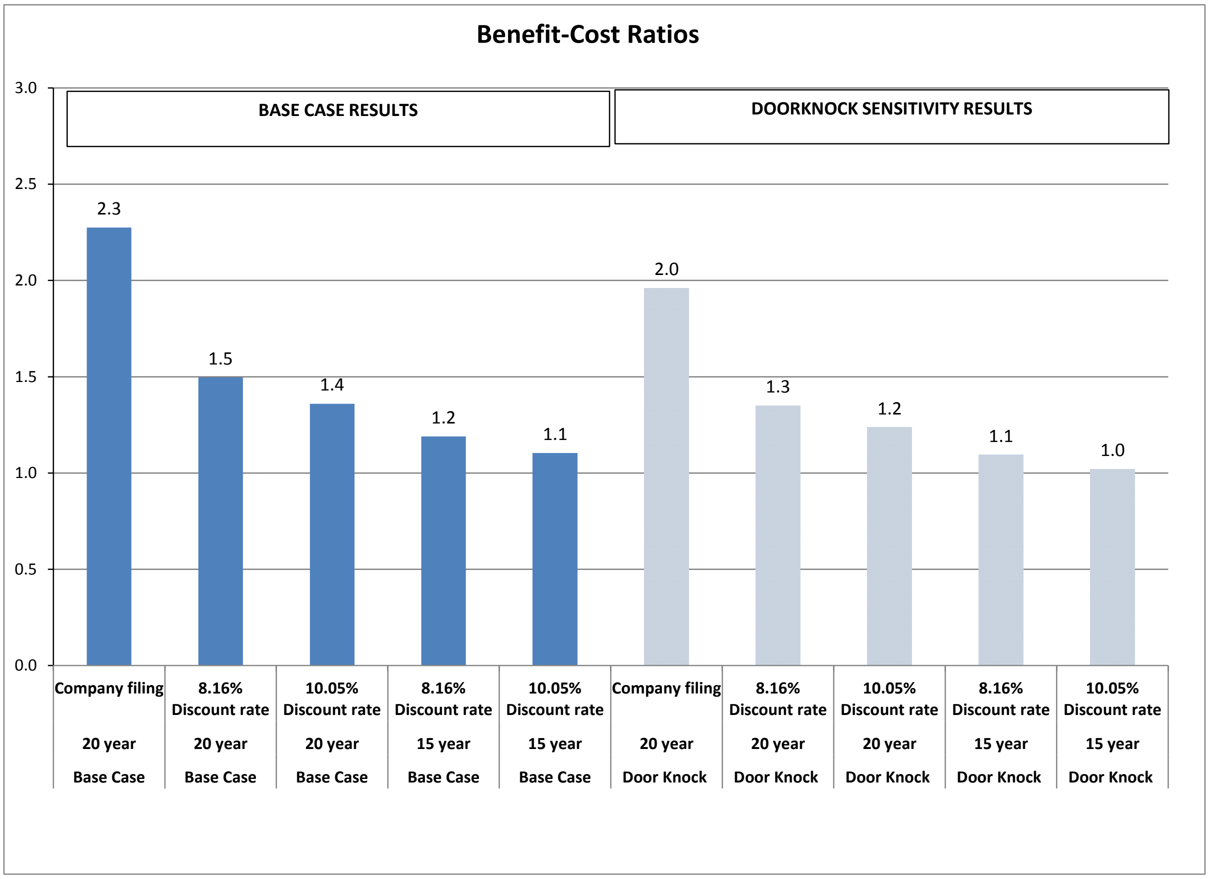
[1] Section 16-108.6 (c) requires the Commission to determine if "…the implementation of the AMI Plan will be cost-beneficial consistent with the principles established through the Illinois Smart Grid Collaborative, giving weight to the results of any Commission-approved pilot designed to examine the benefits and costs of AMI deployment."

investments listed therein within 10 years. I am advised by counsel that how and whether that requirement affects the evaluation of the AMI cost benefit analysis is a matter of legal interpretation.

Q. DO THE DISCOUNT RATE AND TIME HORIZON CHOSEN TO CALCULATE THE NPV OF THE AMI PLAN HAVE A MATERIAL IMPACT ON WHETHER IT IS, OR IS NOT, COST-BENEFICIAL?

A. Yes. The choice of a discount rate and a time horizon has a major impact on whether the AMI Plan under either the Doorknock Sensitivity or the Base Case will be, or not be, cost-beneficial. The impact on the benefit to cost ratio of those cases of a discount rate higher than the Company used and a time horizon shorter than the Company used is presented in Figure 1, the summary bar chart below, which is page 2 of AG Exhibit 3.2.

Figure 1



As indicated in Figure 1, the benefit to cost ratio of the Base Case drops from 2.3 under the Company's discount rate and time horizon assumptions to 1.1 with a 10.05% discount rate and a 15 year time horizon. Similarly the benefit to cost ratio of the Doorknock Sensitivity drops from 2.0 to 1.0 using a 10.05% discount rate and a 15 year time horizon.

Q. HAVE PARTIES TO AMI PLAN PROCEEDINGS OF OTHER UTILITIES DISAGREED OVER THE CHOICE OF A DISCOUNT RATE AND OF A TIME HORIZON?

A. Yes, to varying degrees. The choice of a time horizon has been a matter of debate in several of the AMI Plan proceedings in which I have participated. The choice of a discount rate has been less contentious as the sponsoring utility has typically proposed a discount rate equivalent to its weighted average cost of capital (WACC) and parties have generally accepted that proposal.

Q. PLEASE EXPLAIN WHY ANALYSTS USE A DISCOUNT RATE TO CALCULATE THE PRESENT VALUE OF FUTURE BENEFITS AND COSTS, AND THE IMPORTANCE OF USING A REASONABLE DISCOUNT RATE IN THIS PROCEEDING.

A. Present value can be defined as "…the value on a given date of a payment or series of payments made at other times"[2] Analysts use a discount rate to calculate the present value of future benefits and costs in order to reflect the generally accepted view that a dollar to be received sometime in the future, e.g., ten years from now, is not worth the same as a dollar to be received today. This view is referred to as the time value of money. Even at today's low interest rates, most people would prefer to have a dollar in their pocket today than to be promised a dollar ten years from now.

It is particularly important that the net present value of the AMI Plan be calculated using a reasonable discount rate because ComEd will start recovering the costs of the AMI Plan from customers years before customers see any material benefits from it. As indicated in Figure 6-1 of Exhibit 6.02, ComEd projects that costs will exceed benefits during the first five years of the AMI Plan, through 2016. Of even more importance is ComEd's projection that customers will not receive a cumulative net positive impact from the AMI Plan for ten years, until 2021, as indicated on line 31 of Table A-4 of Exhibit 6.02. The fact that it will be ten years before customers are better off with the AMI Plan than without it, assuming the ComEd projections are accurate, is due to the fact that ComEd expects to recover the majority of the costs of the AMI Plan from customers during the first 10 years while it projects the majority of the benefits will not start flowing to customers until after year five (2017).

[2] Wikipedia, http://en.wikipedia.org/wiki/present_value. 5/11/2012.

It is important that a reasonable discount rate be used to calculate the present value of this stream of future costs and future benefits in order to determine whether the cumulative net benefits that ComEd projects customers will realize from 2021 onward are sufficient to justify approval of the AMI Plan.

Q. PLEASE EXPLAIN WHY THE DISCOUNT RATES COMED HAS USED TO CALCULATE THE PRESENT VALUE OF ITS BENEFITS AND COSTS ARE TOO LOW.

A. ComEd presents two measures of the benefits of its AMI Plan relative to the costs of that plan, a benefit to cost ratio and a NPV of its benefits minus its costs. The Company has used an implicit discount rate of zero to calculate the benefit to cost ratio, because it has calculated that ratio as the undiscounted sum of benefits over 20 years divided by the undiscounted sum of costs over those years. The Company used an explicit discount rate of 3.087% to calculate the NPV of benefits less costs.

The discount rate of zero is clearly too low, as it implies that a dollar at any point in the future, up to 20 years in the future, is worth a dollar today.

The 3.087% is also too low for several reasons. Exhibit 6.02 presents the 3.087% as being a "customer-facing" discount rate that ComEd applied in response to a recommendation from the Illinois State Smart Grid Collaborative (ISSGC).[3] On the contrary, ComEd does not appear to have interpreted the ISSGC recommendation correctly and, in addition, 3.087% is not a reasonable customer discount rate.

Q. WHY DOES IT APPEAR THAT COMED HAS NOT INTERPRETED THE ISSGC RECOMMENDATION CORRECTLY?

[3] Exhibit 6.02 footnote 5 page 1-3

A. The ISSGC recommendation was made in the context of a discussion of preparing up to five different benefit-cost calculations from five different perspectives, i.e., participant, ratepayer impact, program administrator, total resource and societal, and choosing the appropriate discount rate for each. In fact, at page 236 the ISSGC report recommends:

> *The utility should be required to present multiple views, or perspectives, as part of their cost-benefit analysis to be filed with the regulatory commission. The ICC and others should have the benefit of these different perspectives when weighing the merits of smart grid investments.*

The full quote from the ISSGC discussion of testing different discount rates on page 237 of its report, including the last sentence which footnote 5 of Exhibit 6.02 does not include, is as follows:

> *For certain tests, the rate of return on utility investments could be a reasonable choice for a discount rate. However, the use of a different discount rate may be appropriate for other tests because customers may have a different assumed cost of capital. (The discount rates used in the analyses are not intended to affect the rate of return that the Commission may set for future cost recovery on the investment.)* ***Discount rates used in the analyses, and the rationale for their use, should be clearly documented. (Emphasis added.)***

This recommendation is consistent with the discussion of the choice of discount rates for calculating cost-effectiveness on page 4-8 of *Understanding Cost-Effectiveness of Energy Efficiency Programs.*[4] That report presents illustrative discount rates for each of the different cost-benefit tests, i.e., 10% for the participant test, 8.5% as a utility WACC for

[4] National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs*. Energy and Environmental Economics and Regulatory Assistance Project. www.epa.gov.eeactionplan.

the ratepayer impact, program administrator and total resource tests and 5% for the societal test.

Q. WHY IS 3.087 PERCENT NOT A REASONABLE CUSTOMER DISCOUNT RATE?

A. The 3.087% discount rate the Company has used is not a reasonable customer discount rate because it is much too low. As I explain below, a reasonable customer discount rate would be, at a minimum, in the order of 8% to 10%. The 3.087% discount rate the Company has used would be a reasonable societal discount rate if the Company were calculating the benefits and costs from a societal perspective and if it had projected its future benefits and costs in constant (non-inflationary) dollars. However, it is not calculating the benefits and costs from a societal perspective.

Q. WHAT ARE REASONABLE DISCOUNT RATES AND HOW DO THEY AFFECT THE RESULTS FOR THE COMPANY'S BASE CASE AND "DOORKNOCK" SENSITIVITY?

A. It is reasonable to test the results of discount rates from a utility perspective and a residential customer perspective because the utility bases its investment decisions on its ability to earn its weighted average cost of capital and because residential customers will be paying for the majority of the costs of the AMI plan. The appropriate discount rate from ComEd's utility perspective would be approximately 8.16%, the weighted average cost of capital under Section 16-108.5(c)(3), contained in the Proposed order in Docket 11-0721. The appropriate discount rate from a ComEd customer perspective could be as low as 10.05%, the return on equity for ComEd shareholders approved in the Proposed Order in the same docket, or as high as 18%, the effective annual rate ComEd applies to bills that are over-due.

At those discount rates and still using the 20-year timeline assumed by the Company, both the Base Case and the Doorknock Sensitivity are less cost-beneficial than suggested by ComEd. AG Exhibit 3.3presents a comparison of the results for each of those cases at higher discount rates. As indicated in that Exhibit, the benefit to cost ratio of the Base Case drops from 2.3 under the Company's discount rate to 1.5 with an 8.16% and 1.4 with a 10.05% discount rate. Similarly the benefit to cost ratio of the Doorknock Sensitivity drops from 2.0 to 1.3 and 1.2 using 8.16% and 10.05% discount rates respectively.

Q. **PLEASE EXPLAIN WHY THE NUMBER OF YEARS THE COMPANY USED IN ITS BASE CASE CALCULATIONS IS TOO LONG.**

A. The Company has calculated the benefits and costs of its AMI Plan over 20 years. Other utilities have proposed, or been required to use, a 15 year period in several other AMI proceedings in which I have either participated or reviewed. The choice of 15 years reflects the uncertainty associated with these projections, including projected costs, projected benefits and the expected life of the smart meters.

The ISSGC report noted earlier also discusses the appropriate time-frame for a cost-benefit analysis. On page 239 of that report the IGSSC makes the following recommendation:

> *The length of time over which a cost benefit analysis is calculated should reflect the projected useful life of the smart grid investment or system. "Useful life" means the continuous period of time when the components and systems of the investment operate correctly and reliably to perform their designed functions. Absent any persuasive contrary evidence, the depreciable life of the investment for regulatory (non-tax) purposes should match the useful life of the investment.*

> *The utility should document the basis for its determination of the useful life of the investment.* ***The utility should also document the length of time over which reasonable customer benefits can reliably be estimated****. (*Emphasis added***).***

Q. HOW DOES THE COMBINATION OF HIGHER DISCOUNT RATES AND A 15 YEAR TIME HORIZON AFFECT THE RESULTS FOR THE BASE CASE AND THE DOORKNOCK SENSITIVITY?

A. The Doorknock Sensitivity and the Base Case are each much less cost beneficial if their NPV is calculated using a 15 year time horizon and higher discount rates, as indicated on page 1 of Exhibit 3.4. In fact, at a 10.05 % customer discount rate and a 15 year time horizon, the Doorknock Sensitivity and the Base Case are each only marginally cost-beneficial, with benefit to cost ratios of 1.0 and 1.1 respectively.

Q. ARE THE BASE CASE AND THE DOORKNOCK SENSITIVITY COST BENEFICIAL UNDER A 10 YEAR TIME HORIZON?

A. No. Neither the Doorknock Sensitivity nor the Base Case are cost beneficial under a 10 year time horizon regardless of the discount rate that is used. The results of analyzing those two cases over a 10 year time horizon are presented on page 2 of AG Exhibit 3.4.

Q. DO THE MARGINAL RESULTS YOU HAVE PRESENTED SUPPORT THE COMPANY'S POSITION THAT THE AMI PLAN IS COST-BENEFICIAL?

A. No. The Company's estimates of the NPV of its Base Case and Doorknock Sensitivity are based upon numerous projections, some of which may not have been analyzed in detail and all of which are subject to uncertainty.

In terms of uncertainty, one problem is the limited experience with full deployment of AMI by utilities in the United States. While a number of utilities have conducted pilot projects testing AMI and dynamic pricing on a limited basis, it is only in the last few years that several U.S. utilities have received regulatory approval to fully deploy AMI and dynamic pricing tariffs on their systems. Most of those utilities are currently in the process of completing that deployment. For example, in its AMI Plan filing in Arkansas, Oklahoma Gas and Electric assumed its smart meters would have an average life of 15 years but it only had a five year warranty from its smart meter supplier.

The Company projections of its rates, and its electric supply costs, over the next 15 to 20 years are another major source of uncertainty. The Company projects that without AMI, those rates and costs will increase steadily with inflation at 2 percent per year, year after year. ComEd uses those projected rates and unit costs to calculate the value of benefits from reducing UFE and CIM. The Company values these benefits at more than $2.0 billion, i.e., $542 million plus $649 million plus $963 million per Table 1-2 in exhibit 6.02. As a result, those projected benefits are sensitive to the validity of its assumptions regarding increases in its rates and changes in future electricity energy supply prices, which in turn are very sensitive to future natural gas prices. These assumptions are essentially speculative.

Q. PLEASE EXPLAIN WHY IT IS IMPORTANT FOR THE COMMISSION TO CONSIDER THESE MARGINAL RESULTS WHEN DECIDING WHETHER TO ACCEPT OR REJECT THE AMI PLAN.

A. It is important for the Commission to consider these marginal results when deciding whether to accept or reject the AMI Plan because, if approved, the Company will bear very little of the financial risk associated with the AMI Plan. In particular, under Rider DSPP the Company will make the same AMI investment and earn the same return on that investment regardless of the actual monetary value of its reductions in UFE, CIM and Bad Debt.

ComEd maintains that the AMI Plan should be approved because its financial analysis projects the total benefits from the AMI Plan will substantially exceed projected total costs. However, my analysis demonstrates that, even if one accepts all of the Company's projections, the benefit cost ratio of the AMI Plan is only marginally greater than 1. If the actual value of any of these benefits proves to be materially less than the Company's projections, the actual net benefits to customers will be correspondingly less. The possibility that future actual benefits may be lower than the projections in Exhibit 6.02 would be less of a concern if ComEd was proposing to bear that risk or if it was proposing to guarantee customers its projected savings regardless of what the values actually prove to be. However, that is not the case. ComEd is in fact proposing to bear little, if any, of that financial risk associated with the possibility that the future actual benefits from the AMI Plan may prove to be significantly less than those it projected.

IV. POTENTIAL TO INCREASE THE VALUE OF THE AMI PLAN

Q. WHAT STEPS COULD THE COMPANY TAKE TO INCREASE THE VALUE OF THE AMI PLAN?

A. The Company has the potential to increase the value of the AMI Plan in at least two ways. First, it could offer a new Time-of-Use ("TOU") rate in addition to its proposed new Peak Time Rebate (PTR). Second it could modify its schedule for deploying its AMI investments to coordinate with its schedule for deploying its distribution automation (DA) investments in order to balance and optimize both improvements in the reliability of its service and a reduction in the cost of its service due to enhanced ability to identify and locate unexpected outages.

Q. PLEASE EXPLAIN HOW A NEW TOU RATE WOULD DIFFER FROM THE EXISTING RATE OFFERINGS AND FROM THE PTR.

A. Under a TOU rate the Company would establish on-peak and off-peak periods, and the price for electric supply during on-peak periods would be higher than in off-peak periods. (This is essentially the same peak/off-peak pricing concept that phone companies have offered.) In its Customer Applications Program (CAP), ComEd tested a TOU rate with an on-peak period of weekday afternoons from 1 pm to 5 pm and all other hours being off-peak. These peak and off-peak periods would remain stable over time, so customers could become familiar with them and set their major appliances accordingly.

A TOU rate would differ from the existing rate under which the price for supply is the same regardless of when you use electricity. Compared to existing fixed price supply, customers would pay a somewhat higher price for their use during on-peak periods and somewhat lower rates in the off-peak hours. A TOU rate would differ from real-time pricing by not varying every hour, i.e. it would be set for the specific peak and off-peak periods for several months at a time. Finally, a TOU rate would differ from the proposed PTR by being applicable in all 8,760 hours of the year, in set peak and off-peak periods, and it would be a predictable price for both blocks. The PTR only applies about 15 times a year in periods of 6 hours each, for a total of 90 hours per year. The PTR events are "dynamic," hence customers only are alerted to them several hours in advance.

Q. PLEASE EXPLAIN HOW OFFERING A NEW TOU RATE WOULD INCREASE THE VALUE OF THE AMI PLAN TO CUSTOMERS.

A. A new TOU rate would increase the value of the AMI plan to customers who have the flexibility to shift some portion of their use from peak periods to off-peak periods. TOU rates have proven very popular elsewhere. As noted on page 8 of ComEd Exhibit 5.02, Arizona Public Service and Salt River Project, two Arizona utilities, have achieved cumulative participation rates in their residential TOU rates of about 51 percent and 28 percent respectively. Further, customers have the ability to save more money over a year by taking service under a TOU rate than by participating in PTR.

Q. PLEASE EXPLAIN HOW THE COMPANY HAS THE POTENTIAL TO COORDINATE ITS PROPOSED AMI PLAN DEPLOYMENT WITH ITS PROPOSED DISTRIBUTION AUTOMATION DEPLOYMENT.

A. The Company's AMI Plan focuses primarily on reducing the cost of its electricity service. In contrast, in January 2012 ComEd filed an Infrastructure Investment Plan with a distribution automation (DA) component with a primary goal of improving the reliability of its electricity service. ComEd proposes to recover the costs of both sets of investment from ratepayers through performance based formula rates.

ComEd's investments in DA, in and of themselves, will help it reduce the frequency of outages. However, ComEd's investments in AMI will provide specific outage information to its DA, such that their combined impact will enable the Company to make a greater improvement in service reliability. According to its responses to the data requests included as AG Exhibit 3.5, ComEd does not appear to be coordinating the deployment of its investments in AMI with its investments in DA.

Q. PLEASE EXPLAIN HOW COORDINATING AMI PLAN DEPLOYMENT WITH DISTRIBUTION AUTOMATION DEPLOYMENT HAS THE POTENTIAL TO ADD VALUE.

A. ComEd has the potential to provide greater value to customers sooner by coordinating its AMI Plan deployment with its DA deployment. I understand there are numerous constraints and tradeoffs the Company has to consider in setting its schedules for AMI and DA deployment. However, it is important that the Company demonstrate that it is coordinating those deployment schedules in order to balance the need to expedite improvements in service reliability in the operating regions of its system with the worst service reliability while also achieving maximum cost reductions earlier rather than later.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

James Richard Hornby

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA.
Senior Consultant, 2006 to present.

Provides analysis and expert testimony regarding resource planning and ratemaking issues in the electricity and natural gas industries. Resource planning related projects include evaluation of the potential impacts of a renewable and energy efficiency portfolio standard in Kentucky, evaluation of Oklahoma Gas & Electric wind power purchase agreements and associated transmission project and projections of long-term avoided costs of electricity and natural gas. Ratemaking projects include evaluation and testimony regarding proposals for advanced metering infrastructure (AMI or smart grid) and dynamic pricing in several states. Major projects regarding alignment of financial incentives with aggressive pursuit of energy efficiency by electric and gas utilities include testimony on the "save-a-watt" approach proposed by Duke Energy in North Carolina, Indiana and South Carolina.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA.
Principal, 2004-2006, *Senior Consultant,* 1998–2004.
Expert testimony and litigation support in energy contract price arbitration proceedings and various ratemaking proceedings. Productivity improvement project for electric distribution companies in Abu Dhabi. Analyzed market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA.
Vice President and Director of Energy Group, 1997–1998.
Manager of Natural Gas Program, 1986–1997.
Presented expert testimony on rates for unbundled retail services, analyzed the options for purchasing electricity and gas in deregulated markets, prepared testimony and reports on a range of gas industry issues including market structure, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada.
Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986.
Assistant Deputy Minister of Energy 1983–1986.
Director of Energy Resources 1982-1983
Assistant to the Deputy Minister 1981-1982

Nova Scotia Research Foundation, Dartmouth, Canada, *Consultant*, 1978–1981.
Canadian Keyes Fibre, Hantsport, Canada, *Project Engineer*, 1975–1977.
Imperial Group Limited, Bristol, England, *Management Consultant*, 1973–1975.

EDUCATION

M.S., Technology and Policy (Energy), Massachusetts Institute of Technology, 1979.
B.Eng., Industrial Engineering (with Distinction), Dalhousie University, Canada, 1973

TESTIMONY

Jurisdiction	Company	Docket	Date	Issue
Kentucky	Kentucky Power Company	2011-00401	April 2012	Cost-effectiveness of electricity resource options
Nova Scotia	Heritage Gas	NG-HG-R-11	September 2011	Cost allocation and rate design
Arkansas	Oklahoma Gas & Electric	10-109-U	May 2011 and June 2011	advanced metering infrastructure (AMI)
Texas	Texas-New Mexico Power	PUC 38306	April 2011	advanced metering infrastructure (AMI)
Arkansas	Oklahoma Gas & Electric	10-067-U	March 2011	Windspeed transmission line
Pennsylvania	PECO Energy	M-2009-2123944	December 2010 and January 2011	Dynamic Pricing
Arkansas	Oklahoma Gas & Electric	10-073-U	November 2010	Wind power purchase agreement
Indiana	Vectren Energy Delivery of Indiana	Cause No. 43839	July 2010	Sales Reconciliation Adjustment
Alaska	Enstar Natural Gas	U-09-069 and U-09-070	March 2010	Rate Design
Pennsylvania	Allegheny Power	M-2009-2123951	March 2010 and October 2009.	Smart meters / advanced metering infrastructure (AMI)

Jurisdiction	Company	Docket	Date	Issue
Massachusetts	All Massachusetts regulated electric and gas utilities	D.P.U. 09-125 et al.	December 2009	Avoided Energy Supply Costs in New England
Pennsylvania	Metropolitan Edison Company	M-2009-2123950	October 2009.	Smart meters / AMI
Maryland	Potomac Electric Power	No. 9207	October 2009 and July 2011.	Smart meters / AMI
Maryland	Baltimore Gas and Electric	No. 9208	October 2009 and July 2010.	Smart meters / AMI
New Jersey	Jersey Central Power & Light	EO08050326 and EO08080542	July 2009	Demand response programs
Minnesota	CenterPoint Energy	G-008/GR-08-1075	June 2009.	Conservation Enabling Rider
South Carolina	Progress Energy Carolinas	2008-251-E	January 2009.	Compensation for efficiency programs
North Carolina	Progress Energy Carolinas	No. E-2 sub 931	December 2008.	Compensation for efficiency programs
Maine	Central Maine Power	2007 – 215	October 2008.	Smart meters / AMI
North Carolina	Duke Energy Carolinas	E-7 Sub 831	June 2008	Compensation for efficiency programs (save-a-watt)
Indiana	Duke Energy Indiana	No. 43374	May 2008.	Compensation for efficiency programs (save-a-watt)
Pennsylvania	PECO Energy Company	P-2008-2032333	June 2008.	Residential Real Time Pricing pilot

Jurisdiction	Company	Docket	Date	Issue
Arkansas	Entergy Arkansas	06-152-U Phase II A	October 2007	Interim tolling agreement and proposed allocation of Ouachita Power capacity
Washington	Avista Utilities	UE-070804 and UG-070805	September 2007.	Cost allocation, rate design
Arkansas	Entergy Arkansas	06-152-U	January 2007.	Need for load-following capacity
Michigan	Consumers Energy Company	U-14992	December 2006.	Proposed sale of Palisades nuclear plant and associated power purchase
Connecticut	Connecticut Natural Gas Corporation	06-03-04PH01	November 2006.	Gas supply strategy and proposed rate recovery
Michigan	Consumers Energy Company	U-14274-R	October 2006.	Purchases from Midland Cogeneration Venture Limited Partnership
Illinois	WPS Resources and Peoples Energy Corporation	Docket No. 06-0540	October and December 2006.	Service quality metrics and benchmarks
Arizona	Arizona Public Service	E-01345A-05-0816	August 2006 and September 2006.	Hedging strategy and base fuel recovery amount
Ontario	Transalta Energy Corporation versus Bayer Inc.	Private arbitration	January 2006.	Price for steam under a 20-year contract
Nova Scotia	Nova Scotia Power vs Shell	Private arbitration	October 2005.	New natural gas price under a 10-year supply contract

Jurisdiction	Company	Docket	Date	Issue
New York	Consolidated Edison of New York, New York State Electric and Gas	Case 00-M-0504	September and October 2002.	Rates for unbundled supply, distribution, metering and billing services
New Jersey	Public Service Electric and Gas	BPU Docket GM00080564	April 2001.	Proposed transfer of gas contracts to an unregulated affiliate and supply contract associated with that transfer.
Nova Scotia	Sempra	NSUARB-NG-SEMPRA-SEM-00-08	February 2001.	Proposed distribution service tariff rates including market-based rates
New Jersey	Generic proceeding	BPU Docket EX99009676	March 2000.	Design and pricing of unbundled customer account services
United States of America	Bonneville Power Administration	BPA Docket WP-02	November 1999.	Functionalization of communication plant
South Carolina	South Carolina Electric and Gas	99-006-G	October 1999.	Purchased gas costs
New Jersey	Public Service Electric & Gas, South Jersey Gas, New Jersey Natural Gas and Elizabethtown Gas	GO99030122–GO99030125	July and September 1999.	Service unbundling policies and rates
Maine	Northern Utilities Inc.	Docket 97-393	September and December 1998.	Rate redesign and partial unbundling

Jurisdiction	Company	Docket	Date	Issue
Pennsylvania	Peoples Natural Gas	R-00984281; A-12250F0008	May 1998.	Purchased gas costs and proposal to transfer production assets to affiliate
New Jersey	Rockland Electric Company	BPU E09707 0465 OAL PUC-7309-97 BPU E09707 0464 OAL PUC-7310-97	January and March 1998.	Rate unbundling
New Jersey	Jersey Central Power & Light d/b/a GPU Energy.	BPU EO9707 0459 OAL PUC- 7308-97 BPU E09707 0458 OAL PUC-7307-97	November 1997.	Rate unbundling
Pennsylvania	Equitable Gas Company	R-00963858	June and July 1997.	Rate structure proposals
Pennsylvania	Peoples Natural Gas Company	R-00973896 and A-0012250F-0007	May 1997.	Purchased gas costs, proposal to transfer producing assets to CNG Producing Company and proposed Migration Rider
South Carolina	South Carolina Pipeline Corporation	97-009-G	April 1997.	Reasonableness of proposal to acquire additional pipeline capacity
FERC	Transcontinental Gas Pipeline	RP95-197-001; RP97-71-000	March 1997.	Review of proposed rolled-in ratemaking for Leidy Line incremental facilities
Arkansas	Arkla	95-401-U	September 1996.	Gas purchasing and transportation plan
Maine	Northern Utilities Inc. and Granite State Gas	95-480; 95-481	April 1996	Precedent Agreement for LNG Storage Service and PNGTS Transportation Service

Jurisdiction	Company	Docket	Date	Issue
	Transmission			
Rhode Island	ProvGas	2025	November 1995	Settlement Agreement
Pennsylvania	T.W. Phillips Gas and Oil	R-953406	October 1995	Cost allocation, rate design
Illinois	Northern Illinois Gas	95-0219	August1995	Cost allocation, rate design
Pennsylvania	Columbia Gas of Pennsylvania	R-953316	May 1995	Purchased gas costs
Pennsylvania	Peoples Natural Gas	R-943252	May 1995	Cost allocation, rate design
South Carolina	South Carolina Pipeline Corporation.	94-007-G	April 1995	1994 purchased gas costs
Pennsylvania	National Fuel Gas Distribution Corp	R-943207	March 1995	1995 Purchased Gas Adjustment filing
Pennsylvania	UGI Utilities	R-00943063	December 1994	FERC Order 636 transition cost tariff
South Carolina	South Carolina Electric and Gas Co.	94-008-G	October 1994	1994 Purchased Gas Adjustment
Oklahoma	Public Service of Oklahoma	PUD 920 001342	September and November 1994	Gas supply strategy, transportation and agency services and rate mechanism
Pennsylvania	Pennsylvania Gas and Water	R-943078	September 1994	Market Sensitive Sales Service

Jurisdiction	Company	Docket	Date	Issue
Massachusetts	Generic proceeding	D.P.U. 93-141-A	September 1994	Policies on interruptible transportation and capacity release
Hawaii	HELCO	7259	August 1994	DSM programs for competitive energy end-use markets, multi-attribute analysis
Pennsylvania	Pennsylvania Gas and Water	R-00943066	July 1994	1994 Purchased Gas Adjustment
Pennsylvania	Pennsylvania Gas and Water	R-942993; R-942993 C0001-C0004	May 1994	Take-or-Pay Cost Recovery
Pennsylvania	Columbia Gas of Pennsylvania	R-943001	May 1994	Cost allocation, rate design
Pennsylvania	Columbia Gas of Pennsylvania	R-943029	May 1994	1994 Purchased Gas Adjustment; Negotiated Sales Service
Pennsylvania	Peoples Natural Gas	R-932866; R-932915	March 1994	Cost allocation, rate design
Kansas	Generic proceeding	180; 056-U	February 1994	IRP rules for gas utilities
Arizona	Citizens Utility Company Arizona Gas Division	E-1032-93-111	December 1993	Cost allocation, rate design
Hawaii	HECO	7257	December 1993	Residential sector water heating program
Hawaii	GASCO	7261	September 1993	IRP

Jurisdiction	Company	Docket	Date	Issue
Pennsylvania	Pennsylvania Gas and Water	R-932655; R-932655 C001; R-932655 C002	September 1993	Balancing service
Pennsylvania	Pennsylvania Gas and Water	R-932676	July 1993	1993 Purchased Gas Adjustment filing
Rhode Island	Providence Gas Company	2025	April 1993	IRP
Pennsylvania	Equitable	I-900009; C-913669	March 1993	Charges for transportation service and cost allocation methods in general
Arkansas	Arkla Energy Resources, Arkansas Louisiana Gas	92-178-U	August 1992	Gas cost and purchasing practices
Colorado	Generic proceeding	91R-642EG	August 1992	Gas integrated resource planning rule
Pennsylvania	Pennsylvania Gas and Water	R-00922324	July 1992	1992 Purchased Gas Adjustment filing
Pennsylvania	Peoples Natural Gas Company	R-922180	May 1992	Cost allocation, rate design
Michigan	Consumers Power Company	U-10030	April 1992	Gas Cost Recovery Plan, role of demand-side management as a resource in five-year forecast and supply plan
Pennsylvania	T.W. Phillips	R-912140	March 1992	1992 Purchased Gas Adjustment

Jurisdiction	Company	Docket	Date	Issue
FERC	Columbia Gas Transmission and Columbia Gulf Transmission	RP91-161-000 et al RP91-160-000 et al.	February 1992	Cost allocation, rate design
Arkansas	Arkla Energy Resources	91-093-U	February 1992	Base cost of gas
New Hampshire	Energy North Natural Gas	DR90-183	January 1992	Cost allocation, rate design
Arizona	Southwest Gas Corporation	U-1551-89-102 & U-1551-89-103; U-1551-91-069	September 1991	Gas Procurement Practices and Purchased Gas Costs
Maryland	Baltimore Gas and Electric	8339	July 1991	Cost allocation, rate design
Rhode Island	Bristol and Warren Gas	1727	June 1991	Gas procurement
New Mexico	Gas Company of New Mexico	2367	June 1991	Gas transportation policies
Pennsylvania	T.W. Phillips	R-911889	March 1991	Gas supply
Michigan	Michigan Gas Company	U-9752	March 1991	Gas Cost Recovery Plan
Arkansas	Arkla	90-036-U	August and September 1990	Gas supply contracts, including Arkla-Arkoma transactions
Arizona	Southern Union Gas	U-1240-90-051	August 1990	Cost Allocation and Rate Design
Utah	Mountain Fuel Supply	89-057-15	July1990	Cost Allocation and Rate Design

Jurisdiction	**Company**	**Docket**	**Date**	**Issue**
Pennsylvania	Equitable Gas Company	R-901595	June 1990	Cost Allocation and Rate Design
West Virginia	APS	90-196-E-GI ; 90-197-E-GI	May 1990	Coal supply strategy
Pennsylvania	T.W. Phillips Gas and Oil Co.	R-891572	March 1990	Purchased Gas Costs
Colorado	Generic proceeding	89R-702G	January 1990	Policies and rules for gas transportation service
Arizona	Generic proceeding	U-1551-89-102 and U-1551-89-103	October 1989	Regulatory Oversight of Purchased Gas Costs
Rhode Island	Narragansett Electric Company	1938	October 1989	Sales Forecast, Cost Allocation, rate design
Pennsylvania	Pennsylvania Gas and Water	R891293	July 1989	Purchased Gas Costs
Pennsylvania	Columbia Gas of Pennsylvania	R891236	May 1989	Take-or-Pay Cost Recovery
New Jersey	Elizabethtown Gas Company	GR 88081-019	December 1988and February 1989	Take-or-Pay Cost Recovery
Montana	Montana-Dakota Utilities	87.7.33; 88.2.4; 88.5.10; 88.8.23	December1988	Gas Procurement, Transportation Service Gas Adjustment Clause

Jurisdiction	Company	Docket	Date	Issue
New Jersey	South Jersey Gas Company	GR 88081-019 and GR 88080-913-	November 1988 and February 1989	Take-or-Pay Cost Recovery
New Jersey	Public Service Electric and Gas	GR 88070-877	October 1988 and February 1989	Take-or-Pay Cost Recovery
District of Columbia	District of Columbia Natural Gas	Formal Case 874	September 1988	Gas Acquisition, Gas Cost Allocation, take or pay-costs; Regulatory Oversight
Illinois	Generic proceeding	88-0103	July 1988	Take-or-Pay Cost Recovery
West Virginia	Generic proceeding	240-G	June 1988	Gas Transportation Rate Design
Pennsylvania	Pennsylvania Gas & Water	R-880958	June 1988	Purchased Gas Adjustment
Utah	Mountain Fuel Supply	86-057-07	March 1988	Gas Transportation Rate Design
South Carolina	South Carolina Electric and Gas	87-227-G	September 1987	Gas Supply and Rate Design
Arizona		U-1345-87-069	September 1987	Fuel Adjustment Clause

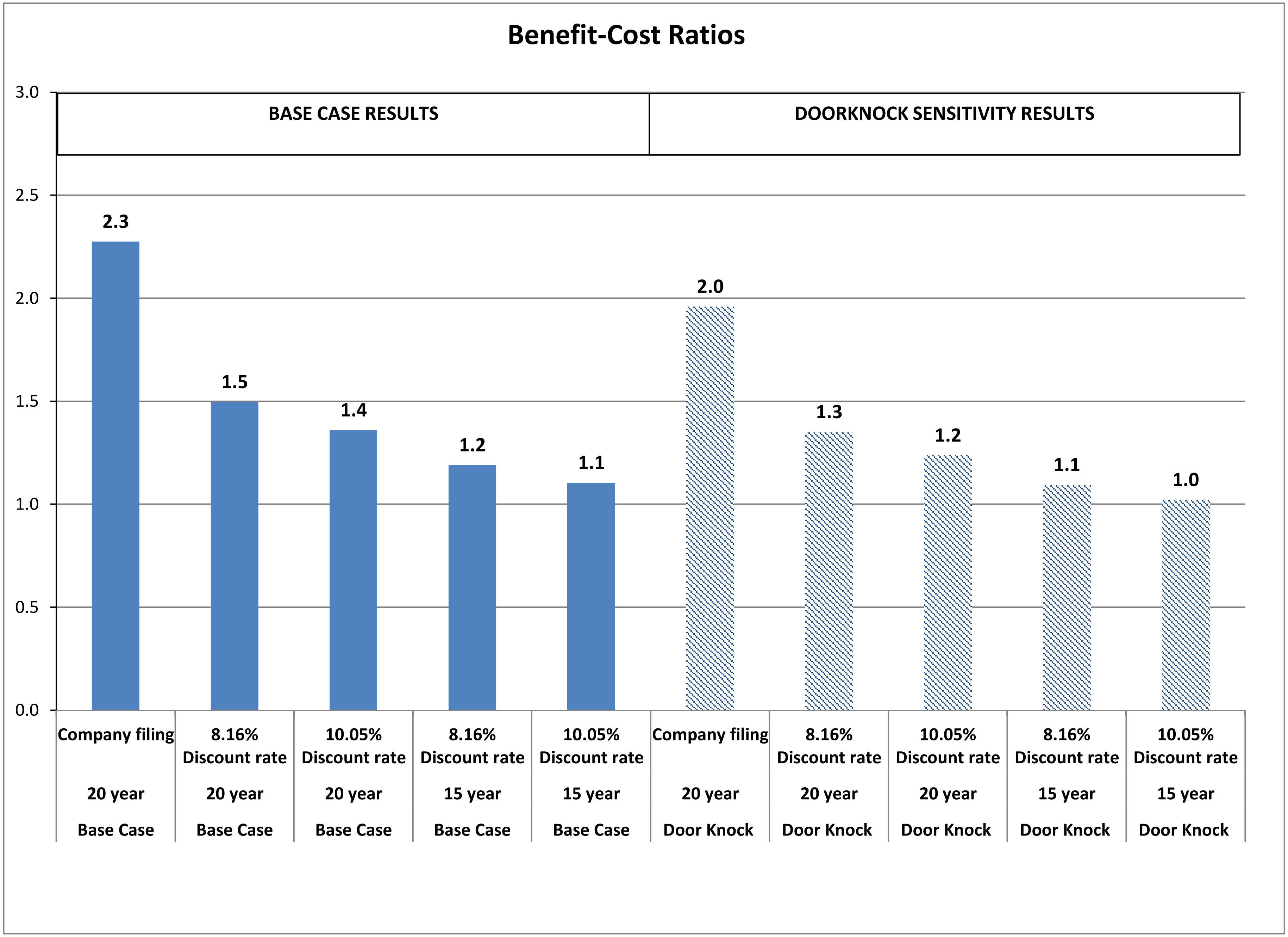
ComEd 10 Year AMI Operational Plan Element - Financial Summary
($ in millions, nominal unless stated otherwise)

Line	Item	Base Case (10-Year Deployment) Cumulative, 20 Years (1)	Doorknock Sensitivity (2)	Dorrknock Sensitivity as % of Base Case
A. COSTS				
1	**Operation and Maintenance (O&M) Expense for AMI System**	$968	$1,281	32%
2	**New Capital Investment for AMI System**	$1,060	$1,074	1%
3 = 1 + 2	**Subtotal**	$2,028	$2,354	16%
B. OPERATIONAL BENEFITS AND DELIVERY SERVICE REVENUES				
4	**Operational Efficiencies and Cost Reductions**	$1,761	$1,761	0%
5	**Avoidance of Capital Expenditures**	$3	$3	0%
6	**Collection of Delivery Service Revenues Due to Reduction in UFE and CIM**	$542	$542	0%
7 = 4 + 5 + 6	**Subtotal**	$2,306	$2,306	0%
C. ADDITIONAL BENEFITS (ENERGY, TRANSMISSION, AND OTHER RIDER COST REDUCTIONS AND				
8	**Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM**	$649	$649	0%
9	**Collection of Energy and Other Revenues Due to Reduction in UFE and CIM**	$963	$963	0%
10	**Reduction in Bad Debt Expenses**	$695	$695	0%
11 = 8 +9+10	**Subtotal**	$2,307	$2,307	0%
D. SUMMARY				
12 = 7 + 11 - 3	**Benefits Less Costs**	$2,585	$2,259	-13%
13 = (7 + 11) / 3	**Benefits to Cost Ratio**	2.3	2.0	-14%
14	**Benefits Less Costs, NPV***	$1,251	$1,031	-18%
15	**Discounted Payback Period (Customer Discount Rate Perspective)**	11 years	12 years	

Sources

1 "Results" tab, AG 1.04 CORRECTED_Attach 1 (Confidential and proprietary).xlsx

2 "Scenario Cumulative" tab, CORRECTED_Attach 1 (Confidential and proprietary).xlsx


Benefit-Cost Ratios
BASE CASE RESULTS
DOORKNOCK SENSITIVITY RESULTS
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.3
1.5
1.4
1.2
1.1
2.0
1.3
1.2
1.1
1.0
Company filing 20 year Base Case
8.16% Discount rate 20 year Base Case
10.05% Discount rate 20 year Base Case
8.16% Discount rate 15 year Base Case
10.05% Discount rate 15 year Base Case
Company filing 20 year Door Knock
8.16% Discount rate 20 year Door Knock
10.05% Discount rate 20 year Door Knock
8.16% Discount rate 15 year Door Knock
10.05% Discount rate 15 year Door Knock

ComEd 10 Year AMI Operational Plan Element - Financial Summary
($ in millions, nominal unless stated otherwise)

		Base Case - 20 Year Time Horizon			
Line	**Item**	**Cumulative, 20 Years (1)**	**NPV at 3.087% (2)**	**NPV at 8.16% (2)**	**NPV at 10.05% (2)**
A. COSTS					
1	**Operation and Maintenance (O&M) Expense for AMI System**	$968	$685	$422	$360
2	**New Capital Investment for AMI System**	$1,060	$900	$710	$655
3 = 1 + 2	**Subtotal**	$2,028	$1,585	$1,131	$1,016
B. OPERATIONAL BENEFITS AND DELIVERY SERVICE REVENUES					
4	**Operational Efficiencies and Cost Reductions**	$1,761	$1,168	$634	$515
5	**Avoidance of Capital Expenditures**	$3	$2	$2	$1
6	**Collection of Delivery Service Revenues Due to Reduction in UFE and CIM**	$542	$364	$201	$165
7 = 4 + 5 + 6	**Subtotal**	$2,306	$1,534	$837	$681
C. ADDITIONAL BENEFITS (ENERGY, TRANSMISSION, AND OTHER RIDER COST REDUCTIONS AND					
8	**Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM**	$649	$435	$241	$197
9	**Collection of Energy and Other Revenues Due to Reduction in UFE and CIM**	$963	$646	$357	$292
10	**Reduction in Bad Debt Expenses**	$695	$466	$258	$211
11 = 8 +9+10	**Subtotal**	$2,307	$1,547	$856	$700
D. SUMMARY					
12 = 7 + 11 - 3	**Benefits Less Costs**	$2,585	$1,495	$562	$365
13 = (7 + 11) / 3	**Benefits to Cost Ratio**	2.3	1.9	1.5	1.4
14	**Benefits Less Costs, NPV***	$1,251	$1,251	$533	$383
15	**Discounted Payback Period (Customer Discount Rate Perspective)**	11 years	11 years	12 years	12 years

		Doorknock Sensitivity - 20 Year Time Horizon			
Line	**Item**	**Cumulative, 20 Years (1)**	**NPV at 3.087% (3)**	**NPV at 8.16% (3)**	**NPV at 10.05% (3)**
A. COSTS					
1	**Operation and Maintenance (O&M) Expense for AMI System**	$1,281	$895	$538	$456
2	**New Capital Investment for AMI System**	$1,074	$910	$716	$661
3 = 1 + 2	**Subtotal**	$2,354	$1,804	$1,254	$1,117
B. OPERATIONAL BENEFITS AND DELIVERY SERVICE REVENUES					
4	**Operational Efficiencies and Cost Reductions**	$1,761	$1,168	$634	$515
5	**Avoidance of Capital Expenditures**	$3	$2	$2	$1
6	**Collection of Delivery Service Revenues Due to Reduction in UFE and CIM**	$542	$364	$201	$165
7 = 4 + 5 + 6	**Subtotal**	$2,306	$1,534	$837	$681
C. ADDITIONAL BENEFITS (ENERGY, TRANSMISSION, AND OTHER RIDER COST REDUCTIONS AND					
8	**Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM**	$649	$435	$241	$197
9	**Collection of Energy and Other Revenues Due to Reduction in UFE and CIM**	$963	$646	$357	$292
10	**Reduction in Bad Debt Expenses**	$695	$466	$258	$211
11 = 8 +9+10	**Subtotal**	$2,307	$1,547	$856	$700
D. SUMMARY					
12 = 7 + 11 - 3	**Benefits Less Costs**	$2,259	$1,276	$439	$264
13 = (7 + 11) / 3	**Benefits to Cost Ratio**	2.0	1.7	1.3	1.2
14	**Benefits Less Costs, NPV***	$1,031	$1,031	$411	$282
15	**Discounted Payback Period (Customer Discount Rate Perspective)**	12 years	12 years	13 years	13 years

Sources

1	AG Ex 3.2
2	"Synapse Table" in SYNAPSE rerun AG 1.04 CORRECTED_Attach 1 (Confidential and proprietary) - Base Case.xlsx
3	"Synapse Table" in SYNAPSE rerun AG 1.04 CORRECTED_Attach 1 (Confidential and proprietary) - Door Knock Sensitivity.xlsx

ComEd 10 Year AMI Operational Plan Element - Financial Summary
($ in millions, nominal unless stated otherwise)

		Base Case - 15 Year Time Horizon			
Line	Item	Cumulative, 15 Years (1)	NPV at 3.087% (2)	NPV at 8.16% (2)	NPV at 10.05% (2)
A. COSTS					
1	Operation and Maintenance (O&M) Expense for AMI System	$652	$502	$345	$304
2	New Capital Investment for AMI System	$1,030	$882	$702	$650
3 = 1 + 2	Subtotal	$1,681	$1,384	$1,047	$954
B. OPERATIONAL BENEFITS AND DELIVERY SERVICE REVENUES					
4	Operational Efficiencies and Cost Reductions	$1,029	$745	$456	$385
5	Avoidance of Capital Expenditures	$2	$2	$1	$1
6	Collection of Delivery Service Revenues Due to Reduction in UFE and CIM	$332	$242	$150	$127
7 = 4 + 5 + 6	Subtotal	$1,364	$989	$608	$513
C. ADDITIONAL BENEFITS (ENERGY, TRANSMISSION, AND OTHER RIDER COST REDUCTIONS AND					
8	Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM	$397	$290	$179	$152
9	Collection of Energy and Other Revenues Due to Reduction in UFE and CIM	$590	$430	$266	$225
10	Reduction in Bad Debt Expenses	$426	$310	$192	$163
11 = 8 +9+10	Subtotal	$1,413	$1,030	$638	$540
D. SUMMARY					
12 = 7 + 11 - 3	Benefits Less Costs	$1,095	$635	$198	$99
13 = (7 + 11) / 3	Benefits to Cost Ratio	1.7	1.5	1.2	1.1
14	Benefits Less Costs, NPV*	$539	$539	$234	$163
15	Discounted Payback Period (Customer Discount Rate Perspective)	11 years	11 years	12 years	12 years

		Doorknock Sensitivity - 15 Year Time Horizon			
Line	Item	Cumulative, 15 Years (1)	NPV at 3.087% (3)	NPV at 8.16% (3)	NPV at 10.05% (3)
A. COSTS					
1	Operation and Maintenance (O&M) Expense for AMI System	$840	$640	$431	$377
2	New Capital Investment for AMI System	$1,039	$889	$708	$655
3 = 1 + 2	Subtotal	$1,879	$1,530	$1,138	$1,032
B. OPERATIONAL BENEFITS AND DELIVERY SERVICE REVENUES					
4	Operational Efficiencies and Cost Reductions	$1,029	$745	$456	$385
5	Avoidance of Capital Expenditures	$2	$2	$1	$1
6	Collection of Delivery Service Revenues Due to Reduction in UFE and CIM	$332	$242	$150	$127
7 = 4 + 5 + 6	Subtotal	$1,364	$989	$608	$513
C. ADDITIONAL BENEFITS (ENERGY, TRANSMISSION, AND OTHER RIDER COST REDUCTIONS AND					
8	Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM	$397	$290	$179	$152
9	Collection of Energy and Other Revenues Due to Reduction in UFE and CIM	$590	$430	$266	$225
10	Reduction in Bad Debt Expenses	$426	$310	$192	$163
11 = 8 +9+10	Subtotal	$1,413	$1,030	$638	$540
D. SUMMARY					
12 = 7 + 11 - 3	Benefits Less Costs	$898	$489	$107	$21
13 = (7 + 11) / 3	Benefits to Cost Ratio	1.5	1.3	1.1	1.0
14	Benefits Less Costs, NPV*	$393	$393	$143	$86
15	Discounted Payback Period (Customer Discount Rate Perspective)	12 years	12 years	13 years	13 years

Sources

1 AG Ex 3.2
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3 "Synapse Table" in SYNAPSE rerun AG 1.04 CORRECTED_Attach 1 (Confidential and proprietary) - Door Knock Sensitivity.xlsx

ComEd 10 Year AMI Operational Plan Element - Financial Summary
($ in millions, nominal unless stated otherwise)

		Base Case - 10 Year Time Horizon			
Line	Item	Cumulative, 10 Years (1)	NPV at 3.087% (2)	NPV at 8.16% (2)	NPV at 10.05% (2)
A. COSTS					
1	Operation and Maintenance (O&M) Expense for AMI System	$386	$323	$248	$227
2	New Capital Investment for AMI System	$1,000	$862	$691	$641
3 = 1 + 2	Subtotal	$1,385	$1,185	$939	$868
B. OPERATIONAL BENEFITS AND DELIVERY SERVICE REVENUES					
4	Operational Efficiencies and Cost Reductions	$442	$351	$245	$215
5	Avoidance of Capital Expenditures	$2	$2	$1	$1
6	Collection of Delivery Service Revenues Due to Reduction in UFE and CIM	$151	$120	$85	$75
7 = 4 + 5 + 6	Subtotal	$595	$473	$331	$291
C. ADDITIONAL BENEFITS (ENERGY, TRANSMISSION, AND OTHER RIDER COST REDUCTIONS AND					
8	Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM	$180	$143	$101	$89
9	Collection of Energy and Other Revenues Due to Reduction in UFE and CIM	$268	$213	$150	$132
10	Reduction in Bad Debt Expenses	$193	$154	$108	$96
11 = 8 +9+10	Subtotal	$641	$510	$359	$317
D. SUMMARY					
12 = 7 + 11 - 3	Benefits Less Costs	-$149	-$202	-$250	-$260
13 = (7 + 11) / 3	Benefits to Cost Ratio	0.9	0.8	0.7	0.7
14	Benefits Less Costs, NPV*	-$6	-$6	-$56	-$68
15	Discounted Payback Period (Customer Discount Rate Perspective)	11 years	11 years	12 years	12 years

		Doorknock Sensitivity - 10 Year Time Horizon			
Line	Item	Cumulative, 10 Years (1)	NPV at 3.087% (3)	NPV at 8.16% (3)	NPV at 10.05% (3)
A. COSTS					
1	Operation and Maintenance (O&M) Expense for AMI System	$473	$393	$298	$271
2	New Capital Investment for AMI System	$1,006	$867	$695	$645
3 = 1 + 2	Subtotal	$1,479	$1,260	$993	$916
B. OPERATIONAL BENEFITS AND DELIVERY SERVICE REVENUES					
4	Operational Efficiencies and Cost Reductions	$442	$351	$245	$215
5	Avoidance of Capital Expenditures	$2	$2	$1	$1
6	Collection of Delivery Service Revenues Due to Reduction in UFE and CIM	$151	$120	$85	$75
7 = 4 + 5 + 6	Subtotal	$595	$473	$331	$291
C. ADDITIONAL BENEFITS (ENERGY, TRANSMISSION, AND OTHER RIDER COST REDUCTIONS AND					
8	Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM	$180	$143	$101	$89
9	Collection of Energy and Other Revenues Due to Reduction in UFE and CIM	$268	$213	$150	$132
10	Reduction in Bad Debt Expenses	$193	$154	$108	$96
11 = 8 +9+10	Subtotal	$641	$510	$359	$317
D. SUMMARY					
12 = 7 + 11 - 3	Benefits Less Costs	-$243	-$277	-$304	-$308
13 = (7 + 11) / 3	Benefits to Cost Ratio	0.8	0.8	0.7	0.7
14	Benefits Less Costs, NPV*	-$81	-$81	-$110	-$116
15	Discounted Payback Period (Customer Discount Rate Perspective)	12 years	12 years	13 years	13 years

Sources

1 AG Ex 3.2
2 "Synapse Table" in SYNAPSE rerun AG 1.04 CORRECTED_Attach 1 (Confidential and proprietary) - Base Case.xlsx
3 "Synapse Table" in SYNAPSE rerun AG 1.04 CORRECTED_Attach 1 (Confidential and proprietary) - Door Knock Sensitivity.xlsx

ICC Docket No. 12-0298

Commonwealth Edison Company's Response to
The People of the State of Illinois ("AG") Data Requests
AG 3.01 – 3.06
Date Received: May 2, 2012
Date Served: May 7, 2012

REQUEST NO. AG 3.04:

Please describe how the Company's planned spending of $148 million for Distribution Automation projects as detailed in *Commonwealth Edison Company's Infrastructure Investment Plan* dated January 6, 2012 is sequenced with the Company's proposed Advanced Meter Infrastructure deployment plan.

RESPONSE:

ComEd objects to this data request, AG 3.04, on the grounds that it is irrelevant, outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of relevant and admissible evidence. Without waiving these objections or any of its General Objections, ComEd states as follows. The planned spending for Distribution Automation ("DA") projects detailed in *Commonwealth Edison Company's Infrastructure Investment Plan* dated January 6, 2012 properly has a sequence independent of ComEd's proposed AMI deployment outlined in ComEd's AMI Plan.

ICC Docket No. 12-0298

**Commonwealth Edison Company's Response to
The People of the State of Illinois ("AG") Data Requests
AG 3.01 – 3.06
Date Received: May 2, 2012
Date Served: May 7, 2012**

REQUEST NO. AG 3.05:

With reference to AG 3.4, please identify any operating centers that will see the deployment smart meters before the completion of scheduled distribution automation projects.

RESPONSE:

ComEd objects to this data request, AG 3.05, on the grounds that it is irrelevant, outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of relevant and admissible evidence. Without waiving these objections or any of its General Objections, ComEd states as follows. Distribution Automation ("DA") deployment described in *Commonwealth Edison Company's Infrastructure Investment Plan* is properly proceeding in multiple operating centers concurrently. Therefore, any operating center with AMI meter deployment occurring prior to 2017 could see the deployment of AMI meters prior to the completion of these DA projects.

See also ComEd's objection and Data Request Response to AG 3.04.

ICC Docket No. 12-0298

**Commonwealth Edison Company's Response to
The People of the State of Illinois ("AG") Data Requests
AG 3.01 – 3.06
Date Received: May 2, 2012
Date Served: May 7, 2012**

REQUEST NO. AG 3.06:

With reference to AG 3.4, please provide a breakdown of distribution automation projects by cost and schedule for each of the nineteen operating centers.

RESPONSE:

ComEd objects to this data request, AG 3.06, on the grounds that it is irrelevant, outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of relevant and admissible evidence. Without waiving these objections or any of its General Objections, ComEd states as follows. Please see ComEd's objection and Data Request Response to AG 3.04 and AG 3.05.