I&M Exhibit: _____

Cause No. 45576

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

CURTIS H. BECH

Content

DIRECT TESTIMONY OF CURTIS H. BECH
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction

Q1. Please state your name and business address.

My name is Curtis H. Bech and I am based in the Accenture PLC (Accenture) Pittsburgh office. My business address is 210 6th Avenue 8th Floor, Pittsburgh, PA 15222.

Q2. By whom are you employed and what is your position?

I am employed by Accenture. Accenture is a leading global professional services company, providing a broad range of services in strategy and consulting, interactive, technology and operations, with digital capabilities across all these services. I am a Senior Manager in the Utilities Strategy and Consulting group.

Q3. What are your principal areas of responsibility with Accenture?

As a Senior Manager, I am responsible for leading client engagements, cultivating business relationships, building new market offerings, and training consulting teams to serve our utility clients.

More specifically, the focus of my work has been on developing investment strategies and performing a wide range of financial analyses for utility clients across the United States and North America.

Q4. Would you please describe your educational and professional background?

I have a BSE in Structural Engineering and Architecture from Princeton University and an MBA from the Fuqua School of Business at Duke University. I have almost 20 years of experience at Accenture, Alcoa / Arconic, and as an entrepreneur.

At Accenture, I have a wide range of experience serving North American utility companies which includes developing growth strategies for regulated and unregulated businesses and performing financial analysis for capital programs that include Smart Grid technologies.

At Alcoa / Arconic, I held multiple roles including strategic analysis and program management (for a range of operational analyses and growth initiatives), corporate venture capital (including Industry X.0 technology scouting and negotiating startup partnerships), and corporate finance (corporate capital planning and audit).

As an entrepreneur for an early stage technology company, I had the opportunity to run day-to-day operations and support fundraising as Chief Financial and Operations Officer. A common thread across all these roles is a focus on performing financial planning and analysis to support decision making related to new investments in people, processes, and technologies.

Q5. Have you previously testified before the Indiana Utility Regulatory Commission (Commission or IURC) or other regulatory agencies?

No.

II. Purpose of Testimony

Q6. What is the purpose of your testimony in this proceeding?

The purpose of my testimony is to explain and present the Cost Benefit Analysis (CBA) for the Indiana Michigan Power Company (I&M or Company) Advanced Metering Infrastructure (AMI) Plan for Indiana. This report was prepared by Accenture on behalf of the Company. My testimony will focus on the following:

- Accenture's engagement with the Company
- The CBA principles
- Data gathering and analysis
- Financial model used to prepare the CBA
- AMI costs overview
- AMI benefits overview
- CBA results and conclusions

Q7. Are you sponsoring any attachments in this proceeding?

Yes. I am sponsoring Attachment CHB-1. This attachment is titled "Cost and Benefit Analysis of Indiana Michigan Power Company Advanced Metering Infrastructure Plan for Indiana".

Q8. Did you submit any workpapers?

Yes. I am sponsoring Workpaper CHB-1. This work paper is titled "Advanced Metering Infrastructure Cost and Benefit Analysis Financial Model for Indiana" and contains confidential Company information.

Q9. Were these attachment and work papers prepared or assembled by you or under your supervision?

Yes.

Q10. Please summarize your testimony.

A cost benefit analysis is a systematic approach to calculating and comparing the benefits and costs of a course of action in a given situation. Accenture mobilized the CBA effort, engaged with a cross-functional Company team, calculated AMI program costs and benefits, and developed a business case that leveraged both Company data and Accenture expertise.

The CBA captures benefits that are generally included in AMI business cases and because AMI is widely considered to be an enabling technology, reasonably quantifies how AMI can improve and drive incremental customer benefits in related programs like demand side management (DSM) and conservation voltage reduction (CVR).

Based on the results of the analysis, the expected cumulative benefits are distributed across multiple value streams that are associated with the AMI technology. This diversity of benefits is reflective of a comprehensive strategy by the Company to ensure that new AMI capabilities are leveraged across a wide range of program areas to drive incremental customer benefits.

The deployment alternatives assessed by Accenture depict a reasonable range of options available with respect to the Company's deployment of AMI. The Moderate AMI deployment plan (which is the scenario the Company proposes to use) balances deployment pace with other considerations, such as program risk management and launch of programs enabled by AMI, such as demand side management and new rate structures.

The CBA shows the benefits exceed the costs and the proposed capital investment is forecasted to reduce costs and ultimately customer bills over the 20-year forecast period compared to what costs would be otherwise. After considering the CBA results, it is Accenture's conclusion that the Moderate scenario the Company proposes to implement is reasonable, financially justified, and valuable for both the Company and its customers.

III. Accenture's Engagement with the Company

Q11. Please explain Accenture's scope of responsibilities with respect to this CBA.

As discussed by Company witness Thomas, Accenture was engaged by the Company to conduct a cost benefit analysis for the Company's AMI plan in Indiana. More specifically, Accenture mobilized the CBA effort, engaged with a cross-functional Company team, calculated AMI program costs and benefits, and developed a business case that leveraged both Company data and Accenture expertise.

Q12. What are Accenture's qualifications and experience in performing cost benefit analysis in the utility industry?

Accenture has significant experience performing business case analyses across the utility value chain. These engagements have included investment analyses and program implementation support for Information Technology (IT), generation technologies, and advanced transmission and distribution technologies that include AMI.

Specific to AMI, Accenture has been engaged by multiple North American utilities over recent years to analyze costs and benefits for proposed deployments most notably for National Grid US Niagara Mohawk Power Corporation, Louisville Gas and Electric, and First Energy Jersey Central Power and Light. It is from these experiences that Accenture has developed financial modeling tools and industry insights that were leveraged during this CBA effort.

Q13. When did Accenture prepare the CBA?

Accenture performed this CBA over a 4-month period starting in August 2020 and ending in early November 2020.

Q14. Are the results and conclusions reached in this CBA based on Accenture's independent review of the assumptions and Accenture's financial modeling?

Yes. Accenture has independently reviewed the benefit and cost calculations developed as part of this CBA and believes they are based on fair assumptions that are in line with industry research and AMI business case observations from peer utilities. In addition, together with Company leaders and cross-functional experts, Accenture has also reviewed the CBA in the context of current Company operations, financial, and strategic plans.

As a result, Accenture believes that the results and conclusions presented in this report can be reasonably acted upon by the Company for the benefit of its customers and stakeholders in Indiana.

IV. Cost Benefit Analysis Introduction

Q15. Can you please describe the purpose of CBA?

A cost benefit analysis is a systematic approach to calculating and comparing the benefits and costs of a course of action in a given situation. This type of analysis is commonly used in a wide range of business applications to determine if the cost of a proposed investment is justified by the benefit value that will be realized by the Company and its stakeholders.

Q16. Please describe the principles that Accenture used in the development of the CBA in this case.

On page 10, of Attachment CHB-1, the principles of this CBA are described as follows:

- Costs that are required to enable program benefits are included in the analysis;
- Costs are based on best available data and information including those provided by vendors, past Company experience, insights from other American Electric Power (AEP) operating companies, and Accenture experience and research (where applicable);
- Benefits are only those enabled by program costs and can be reasonably and transparently quantified. This includes future monetary impacts in areas where new functionality and benefits are enabled due to AMI capabilities; and
- Costs and benefits are assessed from the customer perspective. In other words, the financial analysis is focused on estimating the impact on total customer bills over a set forecast window.

Q17. Are these principles consistent with similar CBA studies that Accenture reviewed in the utility industry?

Yes. As part of this engagement and where appropriate, Accenture applied key learnings from its previous CBA experience at other utility clients and from literature review of CBAs from peer utilities.

These insights were used in three primary ways. First, they were used to ensure a comprehensive scope for the CBA such that a wide range of impact areas were considered and quantified. Second, key assumptions from this research were vetted with the Company and, where appropriate, used in specific cost and benefit calculations. Finally, peer benchmarks were used to test if the CBA results were reasonable when compared to other industry analyses.

Q18. In preparing the CBA in this case, what AMI investment deployment alternatives did Accenture consider?

As presented on page 8 of Attachment CHB-1, Accenture evaluated the following three deployment alternatives provided by the Company for its AMI program in Indiana:

- Accelerated AMI deployment scenario: 27-month deployment period where AMI meters and communications equipment deployment is completed by mid-2023;
- Moderate AMI deployment scenario: 45-month deployment period where AMI meters and communications equipment deployment is completed by the end of 2024; and
- End of Life (EOL) AMI deployment scenario: AMR meters are upgraded to AMI at the end of their 15-year expected average service life such that AMI is deployed over a 15-year period (where full deployment is completed by early 2035).

Q19. Why are these three investment alternatives a reasonable basis for this CBA?

The deployment alternatives defined by the Company depict a reasonable range of options available with respect to the Company's deployment of AMI. More specifically, the accelerated plan is the fastest or most aggressive scenario as it assumes that meters are replaced as soon as practical.

On the other hand, the end of life plan is the slowest or most drawn out scenario as it assumes that meters are replaced by (and upgraded to) AMI at the end of the expected average service life of existing AMR assets. In the middle is the Moderate AMI deployment plan which is the option that Accenture and the Company believes balances deployment pace with other considerations such as program risk management and launch of programs enabled by AMI such as dDSM and new rate structures (e.g., time variable rates).

The rationale for the Moderate case is further discussed later in this testimony in the section titled “CBA RESULTS AND CONCLUSIONS”. In addition, Company witnesses Isaacson and Walter will provide more detailed information on key assumptions, AMI execution plans, and Company plans for key program areas such as CVR and DSM.

V. Data Gathering and Analysis

Q20. Please describe Accenture’s process in the data gathering and analysis phase of the CBA project.

During the initial phases of the engagement, Accenture and the Company established a core project team that included individuals from different departments throughout the Company. The team was broken down into the following functional areas:

- Meter reading and operations
- Distribution operations and engineering
- Telecommunications
- Information technology and cybersecurity
- Regulatory
- Customer and external relations

Then, through interviews and collaborative working sessions over the course of this three-month effort, Accenture gathered information required to conduct this CBA.

Q21. Did Accenture collect any sources of information outside of the Company for use in the CBA?

Yes. In addition to the information provided by the Company, Accenture compiled and analyzed a number of AMI cost benefit analyses from the Company's peer utilities, as well as other utilities outside of Indiana and Michigan. Accenture also conducted research on AMI related topics in various industry reports, periodicals and websites. The specific sources used in this analysis are cited throughout Attachment CHB-1.

VI. Financial Model

Q22. Please describe the financial model that Accenture utilized in this CBA.

The financial model utilized in this case is a Microsoft Excel workbook. These analysis tools were developed by Accenture through multiple CBA efforts at regulated utilities across the United States. As described in Section 1 of Attachment CHB-1, this financial model quantifies a full inventory of program cost and benefits, brings them together into 20-year financial forecasts, and evaluates these forecasts using three (3) cost benefit measures:

- Net Present Value (NPV) – which represents the difference between cost recovery for the return of and return on new capital investments and lower expenses that are passed through to customers;
- Total Resource Cost (TRC) – which evaluates the AMI program benefits in relation to the costs of the AMI meter deployment; and
- Societal Cost Test (SCT) – which builds upon the TRC test by including two societal benefits that are typically included in AMI business cases, namely customer value from improved system reliability and reduced emissions.

Accenture selected these cost benefit measures based on a review of peer AMI CBA filings. Sources for these filing documents are provided in Attachment

CHB-1. From this review, we observe that a wide range of financial metrics and benefit-to-cost ratios have been used by peer utilities to evaluate cost effectiveness of Smart Grid programs like AMI.

For example, Vectren Indiana (now CenterPoint) presented 20-year forecasts for costs and benefits from which one can derive a nominal benefit-to-cost ratio. In the case of Duke Indiana, the presented CBA figures focus on NPV from which one can derive a ratio of discounted program benefits to costs.

In the case of Ameren Illinois, benefits and costs are separated into capital and operations and maintenance (O&M) expenses such that the regulated rate of return, other financing costs, and incremental taxes can be calculated and included on the cost side of the equation when forecasting a customer bill impact from the AMI program.

In the case of the CBA performed here on behalf of the Company, Accenture recommended a similar approach as Ameren Illinois in order to forecast the impact of program costs and benefits on the average customer bill. As mentioned above, costs were separated between capital costs and O&M expenses.

For capital costs, program net capital costs were put through a simple rate base calculation in order to forecast the actual customer bill impact. For O&M expenses, reduced expenses were included as simple pass through savings from the customer perspective. Then, bringing together net capital costs and net O&M expenses, the resulting positive NPV represents a reduction in the cost to serve and overall customer bills.

Q23. How did Accenture determine that a 20-year forecast period was appropriate for this CBA?

Accenture reviewed a number of recent CBA's for AMI investments and found that a 20-year forecast period is commonly used for this type of financial analysis. Peer utilities that used a 20-year forecast period include Vectren Indiana (now CenterPoint), Duke Indiana, and Ameren Illinois.

VII. AMI Costs Overview

Q24. Please summarize the costs that Accenture included in the CBA.

As described in more detail in Section 3 in Attachment CHB-1, Accenture assessed costs associated with the deployment of the AMI program, and split the costs between capital costs and O&M expenses.

The costs have been broken down in the CBA report by the following categories:

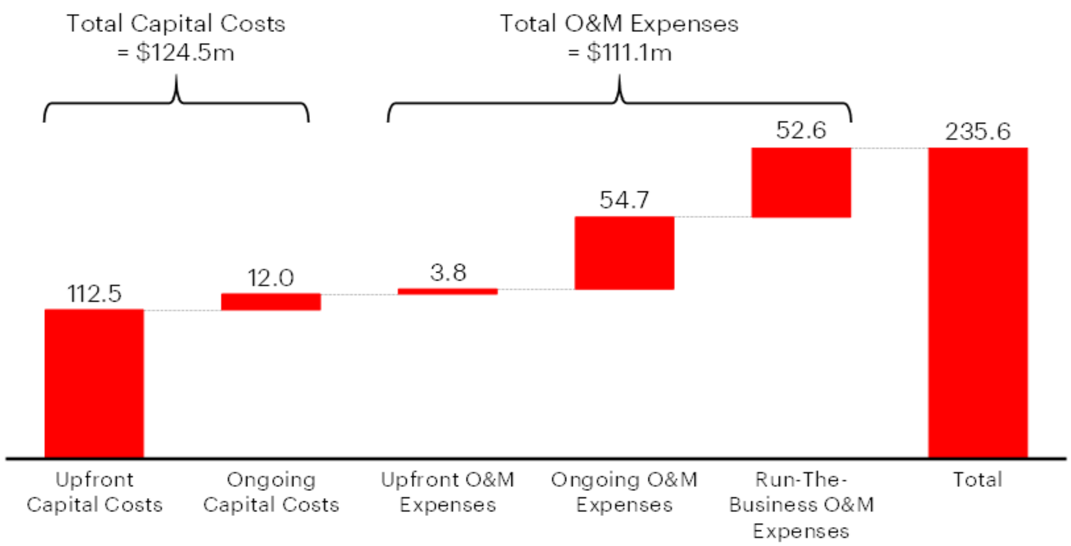
- Upfront Capital Costs – These are the total capital costs expected to be incurred during the proposed AMI deployment period. They include meter, communications infrastructure, IT, and program management costs.
- Ongoing Capital Costs – These are ongoing capital costs that begin upon completion of the upfront AMI deployment. They include AMI meter growth and failure capital costs expected to be incurred through the 20-year business case period.
- Upfront O&M Expenses – These are the total O&M expenses expected to be incurred during the proposed AMI deployment period. They include the O&M portion of meter and communications infrastructure costs as designated by the Company.
- Ongoing O&M Expenses – These are ongoing O&M expenses that begin once upfront AMI deployment activities are completed and extend throughout the 20-year business case period. These costs include routine meter maintenance, annual IT fees, and ongoing support of AMI analytics and data warehousing.

- Run the Business O&M Expenses – These are ongoing O&M expenses associated with new AMI capabilities such as meter data analysis and enhanced revenue protection processes. These incremental man-hours are required to enable specific benefits claimed in this CBA.

Q25. Can you please summarize the results of the analysis on the cost of the AMI program?

Yes. As you can see below from Figure 5 of Attachment CHB-1, the 20-year cumulative costs (including both capital costs and O&M expenses) for the Indiana jurisdictional AMI program total $235.6M.

Figure 5: 20-Year Cumulative Cost by Category ($, millions)



The largest cost elements are upfront capital costs ($112.5M) which include meter replacement costs, meter communications upfront costs, IT upgrade costs, and program management costs. A breakdown of these costs is provided in Section 3.1 of Attachment CHB-1.

Other significant cost elements are associated with ongoing O&M expenses ($54.7M) and run the business O&M expenses ($52.6M). In the ongoing O&M expense category are support costs for new metering and communications equipment, IT related expenses, and customer portal vendor expenses.

In the run-the-business O&M expense category are DSM program administration costs and costs associated with data warehousing, AMI-related advanced analytics, and customer engagement.

A breakdown of these expenses is provided in Section 3.5 of Attachment CHB-1. In addition, Company witnesses Isaacson and Walter will provide more detailed information on the assumptions and Company plans associated with these cost elements.

Q26. Based on Accenture's experience and review of industry benchmarks does Accenture consider the costs included in this CBA to be reasonable?

Yes. From Accenture's industry research and previous experience, the cost estimates included in this analysis are reasonable from two perspectives.

First, all common cost elements generally included in AMI business cases have been accounted for. This can mean that they have been included in this analysis based on estimates from Company data or Accenture experience. It can also mean that they were analyzed and then not included in the analysis due to Company-specific context.

For example, because many of the AEP operating companies have already implemented AMI, many of the IT systems (e.g., Meter Data Management) have already been upgraded thereby eliminating the need for upfront large-scale system upgrade projects or program management planning activities.

Second, the magnitude of included costs in each category – when compared to peer AMI business cases – fall within expected benchmark ranges. For example, the Company estimated a blended AMI equipment and installation cost of approximately $200 per meter. When compared to estimates from select peer utility AMI filings, this is in the middle of the observed range.

In addition, included upfront IT costs of $16 per meter are at the low end of an observed peer cost range. As mentioned earlier, based on a review of IT-related cost elements and input from Company functional experts, Accenture considers this to be expected and reasonable.

VIII. AMI Benefits Overview

Q27. Please summarize the benefits that Accenture included in the CBA.

The benefits included in this CBA are described in detail in Section 4 in Attachment CHB-1. The benefit areas include those that are utility-driven cost reductions, impacts that are a result of customer behavior changes, and select societal benefits. Accordingly, the specific benefit areas in the CBA report are broken down into the following categories:

- Avoided O&M Expenses – accounts for avoided O&M expenses related to eliminated manual meter reads and disconnect/reconnect trips, as well as efficiencies within outage management and billing estimation.
- Revenue Protection Benefits – accounts for revenue protection benefits including reduced bad debt, tamper and theft, and consumption on inactive meters (CIM).
- Enhanced Conservation Voltage Reduction – accounts for incremental benefits associated with the integration of AMI meter voltage readings into existing and planned CVR deployments during the 20 – year business case period.
- Customer Benefits – accounts for quantified customer benefits (energy savings and peak load reductions), including DSM and rates, enhanced customer engagement tools, and Flex Pay program.
- Avoided Capital Cost – accounts for avoided costs associated with maintaining existing AMR system – including meters and IT system upgrades – that would otherwise be required if AMI program were not implemented.

- Societal Benefits – accounts for two societal benefits associated with AMI deployment, including customer value from improved system reliability and reduced emissions.

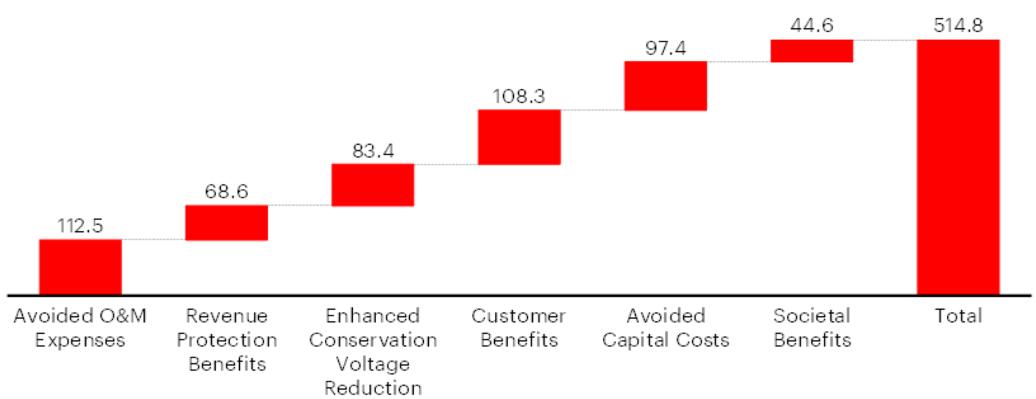
Q28. Based on Accenture's experience and review of CBA's prepared for other utilities, does the CBA properly represent the benefits associated with the AMI program?

Yes. Based on Accenture's experience and other studies that have been reviewed, this CBA captures benefits that are generally included in AMI business cases. Furthermore, since AMI is widely considered to be an enabling technology, Accenture and the Company expended a significant effort to explore and quantify how AMI can improve and drive incremental customer benefits in related programs like DSM and CVR.

Q29. Can you please summarize the results of the analysis on the benefits of the AMI program?

Yes. As you can see below from Figure 11 of Attachment CHB-1, the 20-year cumulative benefits for the AMI program total \$514.8M, including societal benefits. Excluding societal benefits, the total benefits are calculated to be \$470.2M.

Figure 11: 20-Year Cumulative Benefit by Category ($, millions)



Based on the results of the analysis, the expected cumulative benefits are distributed across multiple value streams that are associated with the AMI technology. This diversity of benefits is reflective of a comprehensive strategy by the Company to ensure that new AMI capabilities are leveraged across a wide range of program areas to drive incremental customer benefits.

Q30. Can you please explain further what is included in the Avoided O&M Expenses category?

Yes. As a result of a full AMI deployment, the Company expects to see reductions in expenses related to avoided trips for disconnects and reconnects due to remote metering, reduced outage restoration costs, and a reduction in costs associated with meter reading.

A description of each of these categories along with assumptions and the calculation methodology is included in Section 4.1 of Attachment CHB-1. Company witness Isaacson will provide more detail with respect to the Company's plans to achieve the operational benefits associated with the AMI technology.

Q31. What is included in the Customer Benefits category?

This is the second largest benefit category. These benefits are realized when customers participate in new Company programs that are enabled by AMI and as a result, change their electric consumption behavior.

There are three specific DSM programs that are included in this category: Direct Load Control, Customer Engagement Demand Response, and Critical Peak Pricing.

In addition to these DSM programs, this category also includes enhanced customer engagement tools (through vendors like Oracle OPower and Uplight First Fuel), a proposed Flex Pay program, and increased participation in existing electric vehicles time of use (TOU) rates.

In each of these programs, Accenture used proposed program design and other information provided by the Company, as well as independent data sources, to develop customer participation and impact forecasts. The assumptions, select industry research, and calculation methodologies used for each program are provided on Section 4.4 of Attachment CHB-1.

Q32. What is included in the Avoided Capital Costs benefit category?

This benefit category captures the avoided costs associated with continuing to operate the legacy AMR system in the event that the Company metering system is not upgraded to AMI. There are two benefit areas in this category:

- The majority of AMR equipment was installed in 2012 or earlier. For AMR equipment, the Company assumes a fifteen-year expected average service life. As a result, it is assumed that all meters and supporting infrastructure will need to be replaced or upgraded within the 20-year forecast period of this CBA. Further calculation details for this avoided cost benefit are discussed on Section 4.5 of Attachment CHB-1.
- The Company currently installs a secondary interval meter for customers with distributed generation (DG) / photovoltaic (PV) generation assets. As part of this CBA and based on industry research, it is assumed that once AMI is implemented, this secondary meter will no longer be required for residential-scale DG/PV assets. Further details on assumption and calculation methodology for this avoided cost benefit are discussed on Section 4.5 of Attachment CHB-1.

Q33. What benefits associated with Enhanced Conservation Voltage Reduction are captured in this CBA?

This benefit area accounts for the incremental benefits associated with the integration of AMI meter voltage readings into existing and planned CVR deployments across the Company’s service territory during the 20-year business case period. The AMI technology will provide meter voltage readings at many more points along a distribution circuit and once integrated into CVR operating schemes, it is expected to enable incremental voltage level reductions.

Based on information provided to Accenture, the Company operates its existing CVR schemes with a target average voltage reduction of 3%. Once AMI voltage readings are integrated into CVR schemes, the Company expects that it will be able to reduce average voltage by another 1% (to a 4% average voltage reduction level). This assumption is based on Company evaluation, measurement, and verification (EM&V) results and experience from other AEP operating companies. In addition, based on select industry research, Accenture believes this assumption to be reasonable.

Overall, the CVR benefit included in this CBA assumes that the Company will invest additional capital to expand its CVR system and reach the performance targets mentioned above. The resulting benefit is then a combination of incremental energy savings and peak demand reductions that result from this incremental voltage reduction. Assumptions and calculation methodologies are discussed in detail on Section 4.3 of Attachment CHB-1.

Company witness Walter provides a further explanation of the Company's plans for CVR in his testimony.

Q34. What are the components of the Revenue Protection Benefits included in this CBA?

The revenue protection benefits category is comprised of the AMI related benefits associated with reducing bad debt, tamper and theft, and CIM. Based on Accenture's research of AMI business cases across multiple utilities each of these areas are commonly identified as benefits the AMI technology can provide.

Bad debt is positively impacted by the AMI technology by supporting revised collection processes (including billing, call center, revenue management, and metering) and leveraging more remote disconnect AMI functionality. As a result of these enhancements, the Company will be able to respond to past due accounts in a more timely manner and reduce overall bad debt expense.

The Company will also be able to leverage AMI to improve meter tampering and energy theft detection efforts. As part of a broader category called unaccounted for energy (UFE), tamper and theft is considered to be a significant industry issue and has been estimated to be as high as 2% of revenue by the Energy Information Administration (EIA).

As indicated by most peer utility AMI CBA filings, AMI technology is expected to provide foundational capabilities for addressing this issue. When coupled with analytics software and increased analysis and field service efforts, detecting anomalous patterns of energy usage can be done in a more real-time, comprehensive, and effective manner.

Last, the AMI technology will provide the Company with the ability to access consumption data in near real-time and leverage remote disconnect capabilities to reduce or eliminate CIM.

Each of the areas above are discussed in more detail, with calculation methodologies, in Section 4.2 of Attachment CHB-1.

Q35. Can you please explain the Societal Benefits that Accenture included in this CBA?

Yes. Based on Accenture research and review of multiple utility business cases, it is commonly recognized that the AMI technology provides an opportunity for improved system reliability and that this has an impact on economic losses customers experience due to planned and unplanned outages.

In this CBA, Accenture chose to use the Interruption Cost Estimate (ICE) calculator – a publicly available tool created by the U.S. Department of Energy – to quantify the customer value of improved service reliability due to AMI.

Accenture also utilized other industry sources to estimate what a reasonable improvement in System Average Interruption Duration Index (SAIDI) might be as a result of an AMI deployment. Based on Accenture's research, this CBA assumes that AMI will improve SAIDI in the Company's Indiana service territory by 2%.

In addition to customer value from improved service reliability, the AMI technology will also provide the Company with an opportunity to reduce overall carbon emissions. The first reduction lever comes from the reduction in fleet miles to read meters, address meter-related issues, and reconnect service.

Second, AMI meters can be used to create customer level voltage profiles to manage system voltage levels and improve CVR savings, which also lowers carbon emissions. Third, the Company's programs that provide customers the opportunity to reduce energy usage during peak periods and lower their overall energy use results in lower carbon emissions.

The societal benefits are discussed in more detail in Section 4.6 of Attachment CHB-1, including calculation methodologies and key assumptions.

Q36. Are there any other AMI benefits that Accenture has not quantified in this CBA?

Yes. While this CBA includes a wide range of quantified benefits, it is expected that the value of AMI as an enabling and transformational capability will be even more significant. Based on Company experience and industry research, Accenture provides examples of qualitative benefits in Section 4.7 of Attachment CHB-1.

The examples include improvements in employee safety, emergency response, customer communication and engagement, call center efficiency, distribution planning and operations, and improved customer capabilities.

IX. CBA Results and Conclusions

Q37. Based on Accenture's financial modeling, what are the results of the CBA?

As reflected in Figure 22 of Attachment CHB-1, the NPV for the moderate scenario (not including societal benefits) is a positive $62.2M. The NPV including societal benefits is $83.2M. Using the TRC ratio, the score not including societal benefits is 1.60 (1.81 with societal benefits).

Overall, these results mean that the benefits exceed the costs and that this proposed capital investment is forecast to reduce costs and ultimately customer bills over the 20-year forecast period compared to what they would be otherwise.

Q38. How does the moderate option compare to the other modeled deployment schedules?

Accenture calculated NPV's for each of the three scenarios provided by the Company. These NPV's (without societal benefits) are as follows:

- Accelerated AMI deployment scenario: NPV = $62.8M
- Moderate AMI deployment scenario: NPV = $62.2M
- End of Life (EOL) AMI deployment scenario: NPV = $52.2M

Q39. Based on the results of the CBA what conclusion has Accenture reached with regard to the Company's proposed AMI implementation?

After considering the CBA results, it is Accenture's conclusion that the Moderate scenario is reasonable, financially justified, and valuable for both the Company and its customers.

When comparing the Moderate scenario versus the EOL scenario, the following three factors make the Moderate scenario more compelling:

- A planned and continuous deployment plan allows the Company to complete the AMI meter replacements in a more cost-effective manner than replacing meters as they reach the end of their expected average service life, therefore resulting in a lower capital cost.
- Capital investments, such as communication networking, IT system enhancements, and customer program fixed costs are required in order to obtain the benefits of the AMI technology. These investments are required at the time the AMI meter replacements start. Under the Moderate scenario, many benefits ramp up faster in proportion to the number of meters deployed. A longer deployment schedule delays the utility's and the customer's ability to recognize many of the program benefits thereby reducing the overall NPV.
- The Moderate scenario offers the opportunity for the Company to engage in a planned wide scale customer engagement and marketing campaign that will increase participation levels in programs such as DSM, electric vehicle time of use rates, and customer engagement tools. The increased participation and earlier adoption of these benefits increases the financial results of the Moderate plan versus the EOL scenario.

When comparing the Moderate scenario versus the Accelerated scenario, the following two factors make the Moderate scenario more compelling:

1) It will provide additional time to plan and standup required program management capabilities. This will result in a more methodical approach to replacing meters in the field such that the Company is able to better capture and apply lessons learned throughout the deployment.

2) When evaluating the Company's current plans for programs enhanced by AMI, their strategies and schedules are often dictated by something other than the timing of AMI meter deployments. For example, in the case of CVR, the ramp up of potential benefits is a function of the rate at which

capital can be deployed to upgrade substations and circuits to support CVR functionality.

In the case of potential DSM offerings, the ramp up is a function of regulatory approvals and customer adoption of new programs and rates. As a result, the Moderate scenario deployment schedule appears to be better aligned with current plans and forecasts for many of these programs enhanced by AMI and included in this CBA.

In conclusion, the successful execution of the AMI program, as laid forth in this testimony, attachment, and workpaper, will allow the Company to join its peer utilities in modernizing the grid and improving the customer experience for all its Indiana stakeholders.

Q40. Does this conclude your pre-filed verified direct testimony?

Yes.

VERIFICATION

I, Curtis H. Bech, Senior Manager at Accenture PLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

June 24, 2021

Date: ____________________ ________________________________

Curtis H. Bech

COST AND BENEFIT ANALYSIS OF INDIANA MICHIGAN POWER COMPANY ADVANCED METERING INFRASTRUCTURE PLAN FOR INDIANA

PREPARED FOR

Indiana Michigan Power Company

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Table of Figures

1. Executive Summary

This document provides a detailed assessment of Indiana Michigan Power Company's (the Company) plan to deploy Advanced Metering Infrastructure (AMI) technology in its service territory within the state of Indiana. The Company has engaged Accenture to conduct this financial analysis. The analysis builds upon previous AMI plans presented by the Company as part of their 2019 base rate case and elaborates on how AMI will create value for the Company's customers and stakeholders.

This effort:

- Leveraged existing AMI infrastructure cost estimates informed by vendor data and experience from other American Electric Power (AEP) sister utilities;
- Supplemented them with holistic program costs to build out a complete 20-year view of expected costs to be incurred by implementing AMI;
- Included a detailed assessment of expected program benefits based on the Company's data and observations from AMI business cases from across the industry; and
- Assessed impact of identified costs and benefits across three deployment scenarios, provided by the Company, to determine which was most reasonable.

This report discusses the analysis and conclusions.

AMI Context

AMI refers to systems that measure, collect, and analyze energy usage from meters through a communications network. The infrastructure behind AMI includes meter and communications hardware, the communications network, customer information systems (CIS), and meter data management systems (MDMS).

Advancements in grid technology offer an opportunity to improve the delivery of electricity for both the utility and its customers. At its core, AMI serves as a foundational piece of equipment to further enable grid modernization activities – functional upgrades include the ability to remotely read electricity consumption, remotely reconnect and disconnect customers, detect potential instances of meter tampering, increase visibility and understanding of service interruption and momentary outages incidents, and improve efficiency through functions such as Conservation Voltage Reduction (CVR).

AMI provides more granular consumption data (e.g., at 15-minute intervals) versus the status quo Automated Meter Reading (AMR) system where meters are most often read only once per month. This increased transparency around consumption can empower customers to take greater control of their energy usage by enabling high usage alerts, demand side management (DSM) programs, and other cost saving opportunities.

These potential benefits are due largely in part to the proliferation and expedition of data from the meter to the utility and customer. Figure 1 outlines the key benefit areas quantified in this cost benefit analysis (CBA). As will be discussed throughout this document, this analysis considers those benefit areas that are commonly observed in industry literature and are reasonably supported by company data and future operational plans.

Figure 1: Key Benefit Areas

Avoided O&M Costs	• Eliminated Meter Readers • Avoided Trips Related to Reconnects Due to Remote Metering • Avoided Trips Related to Disconnects Due to Remote Metering • Avoided Trips Related to Disconnect Notices • Reduced Meter Investigations (OK on arrival) • Reduced Billing Estimation & Exception Handling • Reduced Outage Restoration Costs • Avoided Load Research Program Costs
Revenue Protection	• Reduced Bad Debt Expense • Reduced Tamper and Theft • Eliminate Consumption on Inactive Meters (CIM)
Distribution Automation	• Enhanced Conservation Voltage Reduction (CVR)
Demand Response, Rates & Customer Engagement Tools	• Enable Demand Side Management (DSM) Programs • Peak Reduction Due to Electric Vehicle (EV) Time-of-Use (TOU) rates • Enhanced Residential Customer Engagement Tools • Enhanced Commercial and Industrial (C&I) Customer Engagement Tools • Prepay Program Benefits
Avoided Capital Costs	• Avoided AMR Meter Replacements • Avoided AMR IT Support Costs • Avoided Secondary Meter for Residential-scale Distributed Generation (DG) • Avoided AMR Meter Replacements – Meter Growth • Delayed Distribution Capital Cost Due to Peak Reductions
Societal Benefits	• Improved Customer Productivity (Value of Lost Load - VOLL) • Carbon Dioxide (CO2) Emissions Reductions

Outside of the benefit items listed in Figure 1, additional benefit areas have been considered qualitatively and are discussed further in Section 4.7. These include improvements to:

- Employee safety
- Emergency response
- Customer communications
- Call center efficiency
- Day-to-day distribution planning and operations
- Customer engagement
- Move-in/move-out processes for customers
- Other Processes and back-office activities
- Customer products and services

AMI in Indiana and Michigan

As the utility industry continues to increase overall adoption of AMI, as seen in the historical AMI deployments in Figure 2, it is reasonable and appropriate to recognize that AMR technology is being supplanted by AMI. The Company intends to maintain its service and facilities in an operating state of efficiency corresponding to the progress of the industry.

Figure 2: Advanced Metering Count by Technology Type, United States[1]

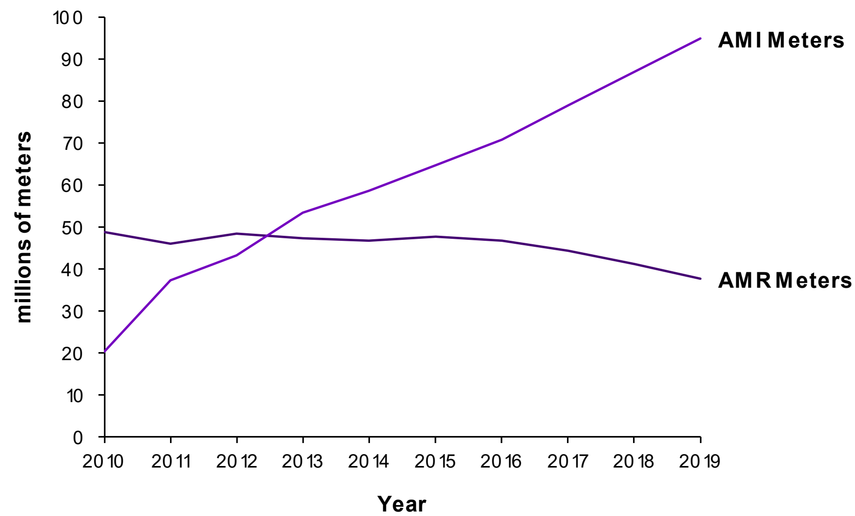


Figure 3: Company Service Territory

A view of the Company's service territory can be seen in **Error! Reference source not found.**. The Company currently has approximately 470,000 electric customers in its Indiana service territory and 130,000 electric customers in Michigan.

Most of the major utilities in Indiana and Michigan have begun or completed smart meter deployments. For example, in Indiana, Vectren, Indianapolis Power & Light, and Duke Energy have deployed AMI. In Michigan, both DTE Energy and Consumers Energy have deployed AMI.

Near universal smart meter programs in Indiana and Michigan corroborate the Company's view that it is appropriate to transition to AMI technology and to deploy it in a planned manner for the benefit of the Company's customers.

The Company is well positioned to successfully deploy an AMI program. AEP sister companies, including AEP Texas, Public Service Company of Oklahoma (PSO), and AEP Ohio, have deployed AMI meters and have provided the Company with valuable insights regarding deployment and benefit realization. In 2010, the Company had its own experience with AMI

[1] Energy Information Administration. 2010-2019. *EIA-861, Annuual Electric Industry Reports*.

deployment in the form of a pilot program with 10,000 smart meters being installed in the South Bend service area. The pilot resulted in a 73% reduction in field visits for customer requests, 50% increase in theft detection and reduced billing estimation levels from 3.8% of customers to 0.4%. During the pilot, the Company also identified the need to develop a comprehensive customer communication strategy that promotes the benefits of the AMI technology and encourages customer engagement with the products, services, and technology platforms that utilize AMI data. The Company plans to build upon these learnings and successes by bringing AMI technology to the entirety of its customers. [2]

Deployment Options and Recommendation

As part of the financial analysis, Accenture was provided guidance on deployment scenarios by the Company. Each deployment scenario starts in Q2 2021 by standing up key Program Management Office (PMO) functions, launching customer engagement programs, executing information technology (IT) upgrades, and installing new equipment as follows:

1. Accelerated AMI deployment scenario: 27-month deployment period where AMI meters and communications equipment deployment is completed by mid-2023;
2. Moderate AMI deployment scenario: 45-month deployment period where AMI meters and communications equipment deployment is completed by end of 2024; and
3. End of Life (EOL) AMI deployment scenario: AMR meters are upgraded to AMI at the end of their 15-year expected average service life such that AMI is deployed over a 15-year period (where full deployment is completed by early 2035).

Cost Benefit Analysis

The following CBA methodology is consistent with previous Accenture studies and standard industry practices and, where appropriate, leverages learnings from select peer utility AMI business case filings.

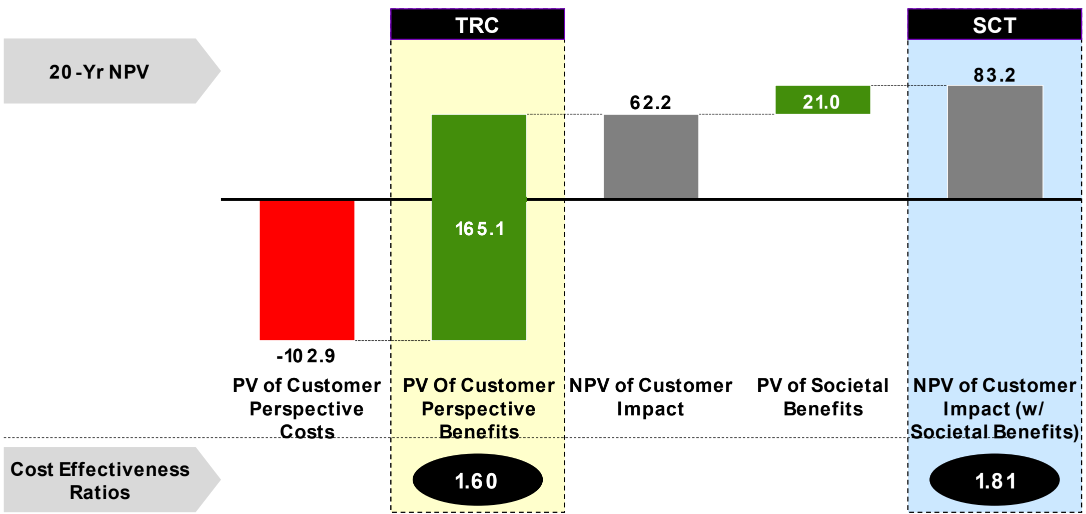
A common AMI CBA analysis tool is Net Present Value (NPV). In the case of this financial CBA, NPV represents the difference between cost recovery for the return of and return on new capital investments and lower expenses that are passed through to customers. Overall, the results of this AMI evaluation show a positive NPV, where the NPV of benefits exceeds the NPV of costs over the life of the forecast AMI investment. This means that the Company's proposed program is expected to result in a lower cost to serve from the customer perspective versus the AMR status quo baseline condition.

In addition to NPV, two benefit-to-cost ratios were also analyzed. First, a Total Resource Cost (TRC) metric was employed to evaluate the AMI program benefits in relation to the costs of

[2] Indiana Michigan Power Company. 2011. *Indiana Michigan Power Company Smart Meter Pilot Program Process and Impact Evaluation Report.*

the AMI meter deployment (CBA costs). For the TRC test, benefits were limited to those that are a result of direct decision making and action by either the utility or the customer. Second, to augment the scope of the TRC test, a broader look included common societal benefits that are related to electric service. Accordingly, a Societal Cost Test (SCT) builds upon the TRC by adding customer benefits from improved reliability and the societal value of emissions savings.

Figure 4: NPV of Customer Benefits ($, millions)



The financial results found in Figure 4 and the analysis described in this report demonstrates that the Company's AMI deployment plan represented by the Moderate scenario is reasonable and financially justified. In addition, it is foundational for improving future quality and reliability of electric service and enables incremental customer benefits stemming from two other Company strategic priorities. First, the Company's CVR program will be enhanced through the integration of AMI meter voltage readings into existing and planned CVR schemes. Second, AMI will augment the Company's current portfolio of DSM offerings that can influence system peak loads and overall system utilization. In short, capabilities enabled by AMI are integral to the Company's mission to provide customers with safe, reliable and efficient electricity services where customers have access to, are more informed from, and can engage further with data and information about their individual consumption patterns and their cost of electricity.

2. Advanced Metering Infrastructure (AMI) Business Case Approach Overview

On behalf of the Company, Accenture conducted a comprehensive review and analysis of the Company's AMI program costs and benefits. Accenture is a management consulting firm who, as part of multiple engagements over the previous decades, has been involved in AMI financial analysis and testimony support across multiple jurisdictions in the United States. From this experience, Accenture was engaged by the Company to create and drive the financial analysis, provide guidance on approach and insights from previous peer utility AMI business cases, and support the Company as it assessed and incorporated the analysis findings into its future program plans. As such, Accenture finds that the methodology used in this business case analysis is consistent with previous Accenture studies and standard industry practices.

Principles of the CBA are as follows:

- Costs that are required to enable program benefits are included in the analysis;
- Costs are based on the best available data and information including those provided by vendors, past Company experience, insights from other AEP operating companies, and Accenture experience and research (where applicable);
- Benefits are only those enabled by program costs and can be reasonably and transparently quantified. This includes future monetary impacts in areas where new functionality and benefits are enabled due to AMI capabilities; and
- Costs and benefits are assessed from the customer perspective.

In developing AMI meter and communications infrastructure costs, Accenture leveraged previous Company AMI experience and engagements with key infrastructure vendors as well as estimates based on previous industry research and experience. For IT system upgrades, ongoing maintenance, licensing fees and relevant administrative costs, Accenture leveraged past AEP experiences with AMI deployments at sister companies.

Overall, past AEP AMI deployments largely enhance the Company's business case by offering the following advantages:

- Better estimates of program costs and benefits based on experience from other AEP company deployments;
- Access to AMI-ready IT systems that would otherwise require capital to stand-up;
- AEP has made investments to upgrade infrastructure, in preparation for AMI, throughout many of its service territories. The Company can leverage the insights gained during this experience; and
- Ability to coordinate across multiple AEP operating companies in order to get purchasing economies of scale from key vendors.

Quantified benefits fall into one of three categories: 1) utility-specific actions that do not require the customer to make changes; 2) customer incentives and tools that facilitate customer electricity consumption behavior changes; and 3) indirect societal benefits.

Utility-specific actions represent actions that will be executed by the utility and do not rely upon the engagement or performance of other stakeholders. These benefits include Avoided

O&M Costs, Revenue Protection, Distribution Automation (i.e., CVR), and Avoided Capital Costs. Customer incentives and tools rely upon customer engagement for benefit realization and include Demand Response offerings and Rates & Customer Engagement Tools. The indirect societal benefits are realized by the customer and community and are summarized in the Societal Benefits category.

Overall, many of these benefit areas are direct cost reduction actions taken by the Company while other benefits are actions taken by the Company or the customer to reduce overall energy consumption or system peak loads. For the latter, incremental energy and demand savings result in lower or avoided generation costs. This is monetized using forward looking forecasts for PJM energy and capacity prices provided by the Company.

As previously mentioned, this AMI CBA analysis focuses on the NPV from the customer perspective, a TRC, and a SCT. The TRC assesses the impact on the customer bill of only those costs and benefits that result from direct actions / decisions made by the utility or the customer. The SCT builds upon the TRC by including common indirect benefits to society. While the societal benefits could be analyzed based on a number of different perspectives, Accenture chose to include two factors assumed to have societal benefit: customer productivity gains due to reliability improvements and emissions reductions.

3. AMI Program Cost Overview

The Company assessed costs associated with the deployment of an AMI program, split between capital and operations and maintenance (O&M) costs. In line with industry research and various AMI business cases observed from other investor owned utilities, the Company has chosen to use a 20-year analysis period.

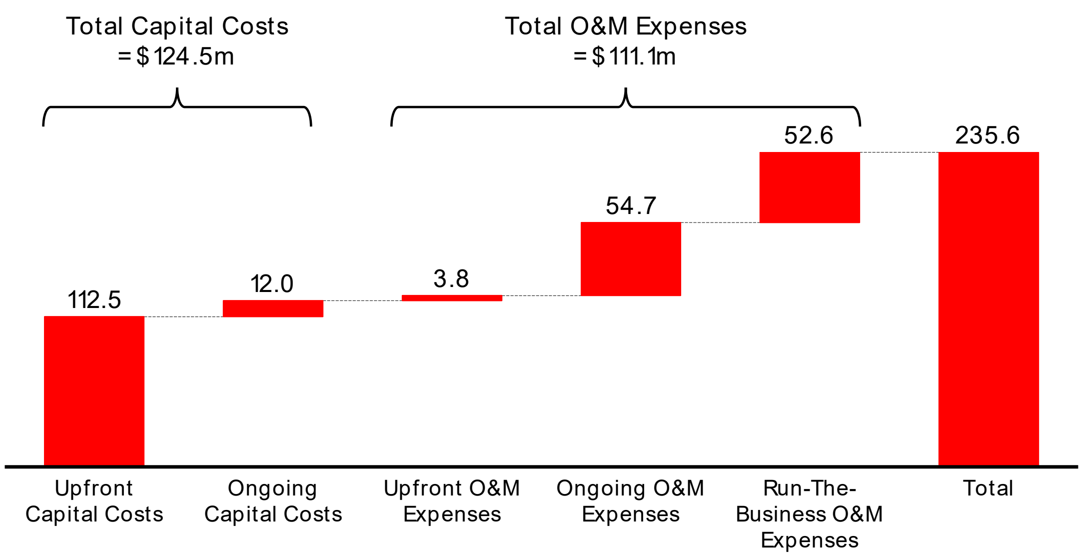
No incremental cyber security costs were included in the CBA. Due to previous AMI deployments at other AEP peer utilities, the Company has determined that cyber capabilities at the time of this analysis are sufficient to support AMI throughout the 20-year business case period. Overall, the Company will leverage broader AEP experience and systems to ensure a comprehensive cyber protection program is in place that will satisfy requirements and stakeholder considerations as well as ensure the security of customers' smart meters and associated usage data.

To ensure customers are involved and aware of the proposed AMI deployment, the Company is developing a proactive engagement plan that encourages customer involvement and welcomes discourse during and after the proposed deployment period. Business planning around customer and stakeholder engagement has been formed largely through learnings from past Company meter deployments, as well as through other AEP operating companies and their respective experiences with AMI deployments.

Accenture leveraged existing Company estimates for customer engagement to inform cost estimates captured in the business case. Accenture also looked to prior engagements and available industry research to vet initial customer and stakeholder engagement cost estimates. While more detailed program planning will be undertaken at the time of implementation, the Company's initial cost estimates are reasonable for purposes of this analysis. Cost components considered in this business case include:

- Management and General Program Oversight – leadership engagement, external relations, etc.
- Engagement – customer Inquiries, outreach & education, etc.
- Marketing – social media, billboards, digital campaigns, targeted outreach, etc.

Figure 5: 20-Year Cumulative Cost by Category ($, millions)



3.1. Upfront Capital Costs

This cost category represents the total upfront capital costs associated with AMI deployment including meter, communications infrastructure, IT and program management costs.

Figure 6: 20-Year Cumulative Upfront Capital Costs Breakout ($, millions)

Upfront Capital Costs	Total
Meter Replacement Cost	84.8
Meter Communications Upfront Cost	7.7
IT Upgrade Capital Cost	8.8

Program Management Cost	11.3
TOTAL	**112.5**

3.1.1. Meter Replacement Cost

AMI meter replacement capital cost represents the cost of the physical meters that allow for two-way communication and measure interval energy consumption. These meters include internal switches that allow for remote reconnect and disconnect of electric service and processing capabilities that enable remote firmware upgrades, pinged support, consumption recording, etc. These meters also include algorithms that recognize operational abnormalities, making it possible to detect theft and recognize measurement inaccuracies that lead to improper billing.

3.1.2. Meter Communications Upfront Cost

Specific upfront meter communications cost components include access points and relays. Access points exist on the edge of the wide-area-network, collect data from smart meters and consolidate it for retrieval by back-office administrators. Meter relays monitor load, allow for power correction, and enable remote control of smart meters.

3.1.3. IT Upgrade Capital Cost

IT costs associated with AMI deployment include upgrading the following systems and capabilities:

- Analytics capability: to process AMI data to identify trends, deliver insights and ultimately drive value for the utility and its customers, the Company must further build out current analytics capabilities. Specific costs include total upfront development, annual Software as a Service (SaaS) fees as well as configuration, testing and costs for various configurations with the CIS.
- CIS: exchange of AMI data between distribution systems allows for the transfer of files between entities and enables real-time data integration. Costs include upfront software costs, middleware costs, and integration services to tie data flows.
- Head End System (HES): the HES serves as the communication and control system that integrates communications infrastructure with back office systems. Costs include configuration & testing of Itron's UtilityIQ (UIQ).
- MDMS: the MDMS provides long term data storage and processing of usage and event data. Costs include enhancements to manage additional meters and new meter programs.
- Outage Management System (OMS): IT costs include costs for MOPS (outage event processing), and any associated enhancements.
- Work Management System (WMS): Upfront IT costs include the costs to enhance the DWM suite of apps.
- Home Energy Management: Upfront IT costs include the Company's portion of the Oracle Opower platform deployment. These costs cover the Opower license for years 1-5, Oracle professional services and internal IT costs.

- Data Warehousing: The Data Warehouse (sometimes referred to as the Data Lake) functions as a data repository hosting internal and external utility data. Access to data allows employees to perform analyses, create 360 customer views and make data accessible to customers and anyone customers choose to share their data with.

3.1.4. Program Management Cost

Cost components associated with AMI program management activities include:

- Governance: Overall program oversight, such as ensuring cross-functional collaboration, managing delivery metrics, and ensuring appropriate sponsorship / ongoing executive engagement.
- Quality Management: The application and ongoing management of standard Company processes that will guide the quality of program delivery activities.
- Scheduling and Staffing: The allocation of appropriate resources – both internal staff and external contractors – to ensure timely delivery considering program timelines.
- Issue and Risk Management: The application of standard Company risk identification and management capabilities – typically employed for large cross-cutting capital programs – to ensure appropriate and timely identification, reporting, prioritization, escalation, and mitigation / resolution of program risks and issues.
- Financial/Benefits Realization and Regulatory Management: Deployment of financial planning, analysis, and reporting capabilities to: (1) guide benefits measurement and realization; and (2) support program regulatory reporting and compliance requirements set forth by the Indiana Utility Regulatory Commission (IURC).
- Procurement, Sourcing, and Vendor/Contract Management: Single point of contact to: (1) coordinate engagement with supporting procurement functions; (2) ensure compliance with legal requirements and corporate policies; and (3) perform contractual, administrative and communication functions related to in scope vendors and commercial contracts.
- Employee communications: Support planning and execution of communications activities, including those with internal audiences and external stakeholders, to ensure common messages, executive sponsorship and appropriate stakeholder involvement.

3.2. Ongoing Capital Costs

This cost category represents the total ongoing meter growth and failure capital costs for the duration of the 20-year business case period.

Figure 7: 20-Year Cumulative Ongoing Capital Costs Breakout ($, millions)

Ongoing Capital Costs	Total
Meter Growth Capital Cost	2.2

Meter Failure Capital Cost	9.7
TOTAL	**12.0**

3.2.1. Meter Growth Ongoing Capital Cost

Following deployment, additional meters will be required for new customers requesting electric service from the Company. This CBA accounts for additional customers by forecasting system growth rates to determine incremental costs throughout the 20-year business case period. The total cost represents the costs incurred to deploy meters to the forecasted number of new customers that enter the Company's service territory during the 20-year business case.

3.2.2. Meter Failure Ongoing Capital Cost

This cost element considers industry observed rates of smart meter failures. Similar to cost item 3.1.21, this element forecasts historically observed failure rates to capture additional costs throughout the 20-year period. While vendor warranty will cover meters for a period, the Company will be responsible for replacement costs once this period ends and accounts for these costs here. The total cost represents the cost incurred to replace the expected number of failed meters over the course of the 20-year business case period. This calculation uses industry data and AEP sister company observations by including an annual AMI meter failure rate of 0.45%.

3.3. Upfront O&M Expenses

This cost category represents the total upfront O&M expenses associated with AMI deployment throughout the 20-year business case period including meter and communications infrastructure costs.

Figure 8: 20-Year Cumulative Upfront O&M Expenses Breakout ($, millions)

Upfront O&M Costs	Total
Program Management Upfront O&M	0.4
Direct Load Control (DLC) Equipment O&M	3.4
TOTAL	**3.8**

3.3.1. Program Management Upfront O&M

This cost element accounts for the planning and execution of the Company's stakeholder engagement plan. Cost components that make up the plan include physical mailers, town hall meetings, hiring and training customer service representatives, and efforts to identify key stakeholder groups. Considering the large scope of stakeholders requiring engagement, the effort will require detailed and comprehensive planning to properly schedule events, contact stakeholders, create content, and further refine cost estimates put forth here.

3.3.2. Direct Load Control (DLC) Program Equipment O&M

This cost line item accounts for the upfront O&M expenses for devices associated with the Company's DLC program. These are utility owned devices that will connect through the AMI communications network. For participating customers, the Company is able to measure and control certain point loads (e.g., residential AC units and electric water heaters) in exchange for incentive payments.

3.4. Ongoing O&M Expenses

This cost category accounts for the total ongoing O&M expenses for the duration of the 20-year business case period. These estimates are largely comprised of routine meter maintenance, annual fees for the HES and MDMS, as well as ongoing O&M expenses to support AMI analytics capabilities and data warehousing requirements.

Figure 9: 20-Year Cumulative Ongoing O&M Expenses Breakout ($, millions)

Ongoing O&M Expenses	Total
Meters & Communications Ongoing O&M	20.2
IT-Related Ongoing O&M	24.0
Customer Portal Vendor O&M	10.5
TOTAL	**54.7**

3.4.1. Meters and Communications Ongoing O&M

The Company anticipates various ongoing costs to operate, manage, and maintain smart meters and communications infrastructure. Costs in this category include both Company and vendor costs. They are expected to ramp up to 100% realization in proportion to the deployment rate of AMI meters.

3.4.2. IT-Related Ongoing O&M

Realizing the capabilities offered by AMI will require additional enhancements to existing infrastructure to integrate the new metering technology and accommodate more frequent interval data. Following AMI deployment, this new and enhanced IT infrastructure will require ongoing maintenance; this cost element accounts for IT-related costs that fall into operations & maintenance for the duration of the 20-year business case period.

3.4.3. Customer Portal Vendor O&M

The Company selected Oracle's Opower solution as its residential customer platform and Uplight's First Fuel product for its C&I customer platform. For both solutions, the Company has developed 20-year cost forecasts for software fees, program administration cost, and evaluation, measurement, & verification (EM&V) costs based on Company experience as well as vendor discussions and quotations.

3.5. Run the Business (RTB) Costs

Following AMI deployment, the Company is expected to incur various incremental, ongoing costs associated with the proliferation of data and capabilities that AMI allows. The RTB Cost category captures the additional full-time equivalent (FTE) required to serve the Company's customers and execute an AMI program in order to realize the benefits identified in this document; these labor efforts involve areas including meter data services, account maintenance, revenue assurance and IT support.

Figure 10: 20-Year Cumulative Run the Business Costs Breakout ($, millions)

Run the Business Costs	Total
AMI Field Technician RTB	3.3
AMI Functional Analyst RTB	5.7
AMI Revenue Protection RTB	3.3
Demand Side Management (DSM) Program Administration RTB O&M	34.2
Customer Portal Admin RTB O&M	3.7
AMI CVR Operations Analyst RTB O&M	2.4
TOTAL	**52.6**

3.5.1. AMI Field Technician RTB

This cost element accounts for the incremental labor that is required for timely data processing due to additional meter data validation, estimation and editing (VEE) to support the meter to cash process following AMI deployment. Previous experience with smart meter deployments and industry data indicate that incremental labor is needed to support timely data processing. This extra cost is captured as the AMI meter data services RTB cost.

3.5.2. AMI Functional Analyst RTB

This cost element covers incremental labor required for data processing due to an anticipated uptick in customer outreach regarding bill validity following the AMI deployment. AEP's previous experience with AMI deployments and industry research indicate that incremental labor will be required to support timely data processing. This extra cost is captured as the AMI account maintenance RTB cost.

3.5.3. AMI Revenue Protection RTB

This cost element includes the additional resources needed to enhance back office and field service theft monitoring, investigations and prevention. While AMI infrastructure can provide the alerts for potential theft, the Company is expected to incur incremental costs associated with addressing theft related data; these resources are captured as the AMI revenue assurance RTB cost.

3.5.4. Demand Side Management Program Administration RTB O&M

This cost element covers annual administrative costs to manage and maintain the Company's proposed direct load control (DLC) programs, Customer Engagement Demand Response program, and its Critical Peak Pricing (CPP) program. Administrative costs are dependent upon customer enrollment rates and are incurred annually during the 20-year business case period. It is expected that DSM administrative costs will increase as program enrollment increases.

Accenture looked to both Consolidated Edison and Commonwealth Edison to inform cost estimates contained in the CBA; while Commonwealth Edison's program encompasses Peak Time Savings (PTS) / Peak Time Rebate (PTR), Consolidated Edison's program plans include TOU Rates. Both have been considered in estimating how costs might scale in conjunction with program participation.

These cost estimates captured in this business case serve as directional planning figures produced from existing literature and Company feedback. Accenture acknowledges that this cost item will require additional planning to further refine estimates.

3.5.5. Customer Portal Admin RTB O&M

This cost element covers administrative costs to manage and maintain the Company's customer engagement platforms (Oracle Opower for residential customers and Uplight First Fuel for commercial and industrial customers). Annual cost estimates are based on Company estimates for program administration and EM&V costs.

3.5.6. AMI Conservation Voltage Reduction (CVR) Operations Analyst RTB O&M

This cost element captures the expected incremental RTB costs associated with support activities to supporting the analysis and operation of incremental CVR systems. Identified costs reflect incremental costs resulting from the expansion of the current CVR program through AMI meter voltage reading integration.

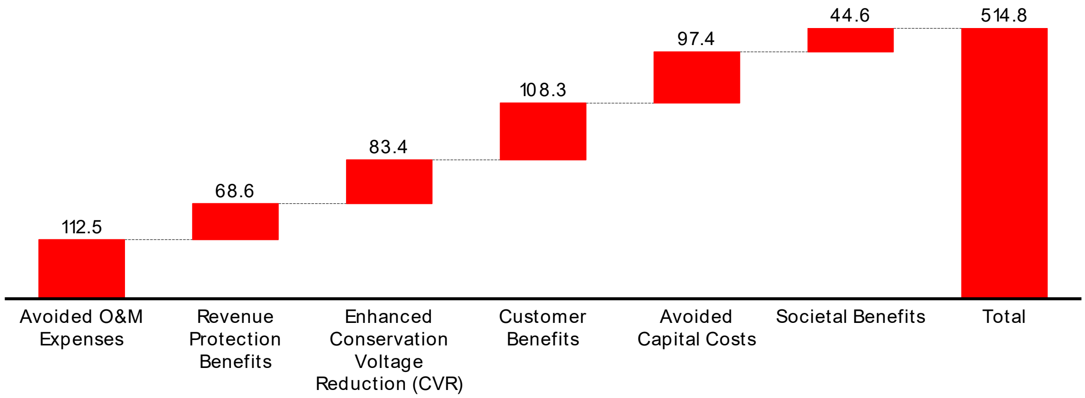
4. AMI Program Benefits

Accenture identified and quantified a select list of expected benefit areas that are reasonably enabled by the proposed AMI program. To do this, Accenture brought together:

- Company data, strategic plans, and perspectives; and
- Insights from public research and the review of peer utility AMI business cases (e.g., Vectren, Duke Energy, Consumers Energy, DTE Energy, Ameren Illinois, National Grid and Con Edison).

Benefit areas are broken down into three overarching categories: benefits to the utility (cost reductions), benefits to the customer, and societal benefits. These areas are included in the business case to provide an estimate of the overall value of the Company's AMI program.

Figure 11: 20-Year Cumulative Benefit by Category ($, millions)



4.1. Avoided O&M Expenses

This benefit category accounts for avoided O&M expenses associated with AMI deployment including eliminated manual meter reads and disconnect / reconnect trips, as well as efficiencies within outage management and billing estimation.

Figure 12: 20-Year Cumulative Avoided O&M Expenses Breakdown ($, millions)

Avoided O&M Expenses	Total
Eliminated Meter Readers	19.8
Avoided Trips Related to Reconnects Due to Remote Metering	22.1
Avoided Trips Related to Disconnects Due to Remote Metering	21.1
Avoided Trips Related to Disconnect Notices	17.4
Reduced Meter Investigations (OK on Arrival)	3.4
Reduced Billing Estimation & Exception Handling	3.9
Reduced Outage Restoration Costs	21.8
Avoided Load Research Program Costs	3.1
TOTAL	**112.5**

4.1.1. Eliminated Meter Readers

Background and Description

Current operations require that the Company use a fleet of radio equipped service vans to collect consumption data on a monthly basis. By replacing AMR meters with AMI-enabled technology, Accenture expects that the Company will eliminate the costs associated with AMR meter reading activity. These avoided costs include internal and contracted labor, fleet and relevant supplies and tools.

AMI's remote metering capabilities will allow the Company to perform meter reading tasks from the operations center, avoiding physical trips to the meter.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to reducing meter reading activity is as follows:
  - Forecast current meter reading costs
    - Annual meter reading expense is forecasted out 20 years using a 2.8% labor growth rate
    - Meter Reading Fleet, Materials & Overhead, and Outside service expenses are forecasted out 20 years using a 3% non-labor growth rate
  - Determine impact of AMI
    - Expenses are summed and reduced by 100% to calculate the annual benefit from eliminating traditional meter reading activities

Benefit Realization Schedule

Benefit is realized beginning in 2022 and is in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.1.2. Avoided Trips Related to Reconnects Due to Remote Metering

Background and Description

The AMR meters that the Company currently has deployed to customers within its service territory require on-premise field visits to reconnect service. AMI provides the ability to connect electric service remotely and in near real-time, resulting in reduced labor and vehicle costs currently required to reconnect customers. This capability avoids visits to the meter for manual meter reconnects and provides the customer with quicker service. Accenture expects that eliminating the need for in-person reconnects will allow the Company to eliminate the costs for the internal field workers or contracted workers who perform reconnect services and associated transportation costs (vehicles and fuel).

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to reducing trips related to reconnects is as follows:
  - Forecast and quantify the value of avoided reconnect trips
    - The number of Reconnect trip types (Regular Business Hours, Workday / Saturday Overtime, and Sunday/Holiday Overtime) are forecasted out 20 years using the Annual Meter Growth rate (0.1%).
    - The forecasted number of trips are multiplied through by the % reduction to reconnects for non-payment (RNP) due to AMI (90%)
    - This provides the total number of RNP trips avoided each year
      - Next, the annual cost per RNP trip type (Regular Business Hours - $41.5 / trip, Workday / Saturday Overtime - $51.6 / trip, and Sunday/Holiday Overtime - $135.6 / trip) are forecasted out 20 years by the labor growth rate, 2.8%[3]
    - Multiply the number of RNP trips avoided each year by the respective cost per RNP trip type
  - Determine the value of avoided RNP trips
    - Summing the avoided costs per RNP trip type, results in the quantified benefit of avoided RNP trips

Benefit Realization Schedule

Benefit is realized beginning in 2022 and is in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.1.3. Avoided Trips Related to Disconnects due to Remote Metering

Background and Description

Current technology requires the Company to visit each customer to disconnect service. Disconnect trips are conducted for customers who have fallen behind on bill payments and must have their service discontinued. AMI provides the ability to disconnect electric service remotely and in near real-time, resulting in reduced labor and vehicle costs for avoided meter visits. This capability will allow the Company to avoid visits to the meter for manual meter disconnects. Eliminating the need for in-person disconnects will allow the Company to eliminate the cost associated with internal and contracted field workers who perform disconnect services. This includes associated transportation costs (vehicles and fuel).

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to reducing avoided trips related to disconnects is as follows:
  - Forecast and quantify the value of avoided disconnect trips

[3] Indiana Regulatory Commission Cause No. 45235, Direct Testimony of Kurt. C. Cooper, Figure WP-KCC-1, p. 1, May 14, 2019.

- The number of Disconnect trip types (Regular Business Hours, Workday / Saturday Overtime, and Sunday/Holiday Overtime) are forecasted out 20 years using the Annual Meter Growth rate (0.1%).
- The forecasted number of trips are multiplied through by the % reduction to DNPs due to AMI (90%)
- This results in the number of disconnects for non-payment (DNP) trips avoided each year
  - Next, the annual cost per DNP trip type (Regular Business Hours - $41.5 / trip, Workday / Saturday Overtime - $51.6 / trip, and Sunday/Holiday Overtime - $135.6 / trip) are forecasted out 20 years by the labor growth rate, 2.8%
    - Multiply the number of DNP trips avoided each year by the respective cost per DNP trip type
- Determine the value of avoided trips
  - Summing the avoided costs per DNP trip type results inthe quantified benefit of avoiding DNP trips

Benefit Realization Schedule
Benefit realization begins in 2023 upon regulatory approval of remote disconnect. Realization is also a function of the percentage of meters converted to AMI each year.

4.1.4. Avoided Trips Related to Disconnect Notices

Background and Description
Current practices require that the Company visit each customer in order to disconnect service for non-payment. Occasionally, the Company's employees are unable to execute the disconnect for unforeseen circumstances; in these events, the Company must leave the customer's premise and come back at a later time to perform the disconnect. Customers are currently charged for Disconnect Notice Trips; these trips could be avoided following an AMI deployment, where the Company would no longer be required to physically visit the meter to perform the disconnect.

While in-person disconnects are currently mandated by the IURC[4], advancements in metering technology allow utilities to avoid these trips by implementing more digital alternatives. While AMI would allow the Company to realize this benefit upon meter deployment, this benefit area is largely reliant on regulatory approval.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to avoided trips for disconnect notices is as follows:

[4] With the exception of Duke Indiana, who was recently granted a waiver from 170 IAC 4-1-16 for their Prepaid Advantage pilot program. Indiana Regulatory Commission Cause No. 45193, Order of the Commission, p. 18, September 11, 2019.

- Forecast and quantify the value of avoided trips for disconnect notices
  - The number of trips to leave disconnect notices are forecasted out 20 years using the Annual Meter Growth rate (0.1%).
  - The forecasted number of trips for disconnect notices are multiplied through by the % reduction to due to AMI (90%)
  - This results in the number of trips for disconnect notices avoided each year
- Forecast labor costs
  - Forecast the cost per trip 20 years by multilpying the repsective cost per trip by the labor growth rate, 2.8%
- Value the avoided trips
  - Multiply the number of avoided trips for disconnect notices each year by the respective cost per trip to forecast the benefit of avoiding trips for disconnect notices due to AMI

Benefit Realization Schedule

Benefit realization begins in 2023 upon regulatory approval. Realization is also a function of the percentage of meters converted to AMI each year.

4.1.5. Reduced Meter Investigations (OK on Arrival)

Background and Description

'Ok on Arrival' events occur when the Company dispatches crews to address an alleged outage event and determine that the meter is in fact "live". These trips are inherently inefficient as the Company is using resources to resolve non-existent outages and issues.

Real time power and outage data from AMI allow customer call center staff to detect outage conditions remotely before sending field representatives to conduct manual meter investigations, thus reducing labor & vehicle costs for unnecessary power loss investigations. The Company's back-office staff can alert field service representatives that customer reported problems or power losses have been resolved before they are dispatched to the customer's property.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to reducing meter investigations is as follows:
  - Calculate the FTE reduction:
    - # of 'Ok on Arrival' trips ("Trip Charge") are forecasted out 20 years using the meter growth rate (0.1%)
    - # of 'Ok on Arrival' trips are multiplied by the % reduction due to AMI, 100%, to calculate the # of avoided trips each year
    - The # of avoided 'Ok on Arrival' trips each year is divided by the amount of working days per year, 250, to calculate the amount of trips avoided each day

    - The amount of trips avoided each day is divided by the amount of trips conducted per employee per day to calculate the respective reduction to FTEs performing investigations
  - Calculate and forecast the cost components:
    - The Field Service Representative annual salary is forecasted out 20 years using a labor growth rate of 2.8%
    - The Field Service Representative annual salary is multiplied by a fringe factor of 135%
    - Annual cost of vehicle ownership is forecasted at 3% non-labor growth rate and added to the FTE cost
  - Determine the benefit value
    - Multiply the annual FTE reduction by the respective FTE cost to forecast the benefit of reducing meter investigations

Benefit Realization Schedule

Benefit is realized beginning in 2022 and is in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.1.6. Reduced Billing Estimation & Exception Handling

Background and Description

From review of peer business cases, the Company expects that AMI metering when compared to the AMR status quo will lead to more accurate meter reads, more frequent reads, and more timely corrections of meter read and/or billing errors. With current business processes, 3.5 FTEs are required to estimate bills for instances when an accurate meter read is not achieved for the billing cycle. The improved meter reading accuracy of AMI technology will enhance processes around bill estimation and exception handling, providing an opportunity for further efficiency, particularly for back office resources.

With AMI, Accenture expects the Company will be able to reduce cost by leveraging increased volume and quality of meter read data and associated billing determinants on the meter data management (MDM) platform. Example impacts on system billing activities may include:

- Reduced time spent on system billing exceptions (often as a result of missing or incorrect meter read data) due to improved data integrity;
- Eliminated use of estimated meter reads that are often inaccurate; and
- Reduced quantity of rebilling activities due to higher quality and accuracy levels for original bills.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to reducing billing exception activity is as follows:

- Determine the FTE Cost
  - The salary for FTE's dedicated to performing billing exceptions is forecasted out 20 years using a 2.8% labor growth rate
  - The salary for FTE's dedicated to performing billing exceptions is multiplied by a fringe factor of 135%
  - This annual cost is multiplied by the number of FTEs to determine the annual cost of performing billing exceptions
- Determine the impact of AMI
  - The cost of performing billing exceptions each year is multiplied by an AMI efficiency factor of 56% to value the impact of AMI
- Allocate to each state
  - The total benefit figure is distributed to each state using meter ratios of 78% and 22%, for Indiana and Michigan respectively

Benefit Realization Schedule
Benefit is realized beginning in 2022 and is in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.1.7. Reduced Outage Restoration Costs

Background and Description
Granular outage data enabled by AMI can be used to enhance outage & work management systems. AMI can provide automated outage notifications to the Company's back office staff, allowing crews to be dispatched to outage locations more efficiently, while also assisting in the identification of nested outages. AMI technology allows for remote outage verification and enhances current operations heavily reliant on customer notifications; improvements to major and non-major storm restoration efforts are assumed to be 15% and 10%, respectively, given peer business case observations and observations from other AEP operating companies.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to enhancing outage restoration capabilities is as follows:
  - Determine the annual cost of storms
    - Add the Major Storm and Non-Major Storm budgets to calculate the annual cost of storms
    - Forecast out the annual cost of major storms by a 3% escalation factor for the 20 year business case period
  - Quantify the impact of AMI
    - Multiply the forecasted cost of major and non-major storms by AMI improvement factors of 15% and 10%, respectively, to value the impact of AMI to outage

restoration functions. This improvement is informed by a combination of peer research and experiences at AEP sister companies.

Benefit Realization Schedule
Benefit is realized beginning in 2022 and is in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.1.8. Avoided Load Research Program Costs

Background and Description
The Company currently uses Interval Data Recorders (IDR) to assess and manage system load to conduct studies, perform load forecasting and mitigate any system-wide issues. Load research is necessary to maintain system safety and operations however, infrastructure is often costly including IDRs, communications infrastructure and field maintenance services. AMI provides timely and accurate load profile information, thereby eliminating the need for the deployment and servicing of IDRs and avoiding load research capital and maintenance costs.

Calculation Methodology
- The calculation for quantifying the benefits of AMI related to avoiding Load Research Program Costs is as follows:
  - Forecast IDR failures
    - Multiply the number of IDRs each year by the estimated IDR failure rate
  - Calculate the avoided costs associated with replacing IDR as they fail
    - Sum the forecasted IDR equipment cost with the forecasted cost of installation each year to calculate the cost to replace an IDR
    - Multiply the cost to replace an IDR through to the forecasted number of IDR failures each year to calculate the avoided annual costs of replacing IDRs
  - Calculate the avoided cost of Cellular service for IDRs
    - Multiply the total number of IDRs by the annual cell service cost to calculate the total annual cost of of cellular service for IDRs

Benefit Realization Schedule
Benefit is realized beginning in 2022 and is in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.2. Revenue Protection Benefits

This benefit category accounts for revenue protection benefits associated with AMI deployment including reduced bad debt, reduced tamper and theft and eliminated unauthorized use.

Figure 13: 20-Year Cumulative Revenue Protection Benefits Breakdown ($, millions)

Revenue Benefits	Total
Reduced Bad Debt Expense	17.0
Reduced Tamper and Theft	47.8
Eliminated Consumption on Inactive Meters (CIM)	3.8
TOTAL	**68.6**

4.2.1. Reduced Bad Debt Expense

Background and Description

Bad debt expense is the cost incurred by the Company when customers are unable or unwilling to pay their bills. To remediate these situations, the Company must visit the customer premise to disconnect service. There is currently lag time between when existing collections processes determine an account is eligible for disconnect and when the actual field trip to disconnect of service is scheduled and executed.

For 2021, the Company forecasts bad debt expense to be $5.7 million across its Indiana and Michigan service territories. The Company's fellow AEP operating company, PSO, observed actual debt expense reduction of 17% following AMI deployment. The Company's current credit policy is similar to PSO and as a result, the Company expects to experience a similar bad debt expense reduction as a result of AMI.

Bad debt management is an essential function that controls cost and helps customers use energy wisely. By revising collections processes (including billing, call center, revenue management, and metering) and leveraging remote disconnect AMI functionality (to reduce the overall amount of fieldwork), the Company will be able to disconnect outstanding DNP accounts in a timelier manner.

Calculation Methodology

- The calculation for this AMI benefit is as follows:
  - Create long-term bad debt expense forecast using 2021 estimate and nominal cost inflation rate
  - Allocate Company-wide bad debt expense forecast to each state using meter ratios of 78% and 22% for Indiana and Michigan respectively
  - Multiply bad debt expense forecast by the % improvement due to AMI to determine the annual benefit of reducing bad debt expense

Benefit Realization Schedule

Benefit realization begins in 2023 upon regulatory approval. Realization is also a function of the percentage of meters converted to AMI each year.

4.2.2. Reduced Tamper and Theft

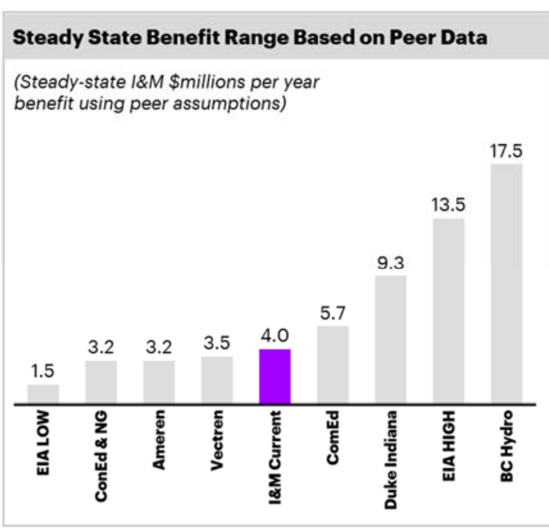
Benefit Background

Non-technical losses include energy theft through tampering or bypassing a meter. By providing real time meter data and system diagnostic tools (e.g., tamper alarms), AMI systems enable improvement to meter tampering and energy theft detection efforts. When coupled with analytics software (like Itron Optimizer), detecting anomalous patterns of energy usage can be done more quickly and at a lower cost (reduced level of back office effort and avoided investigative / diagnostic truck rolls).

With better diagnostics, monitoring capabilities, and corrective actions, utilities have been shown to reduce overall volumes of unbilled energy and the resulting socialized system costs that customers absorb through fuel adjustment clauses. In addition, depending on the nature of each case of theft, the Company assumes that some amount of baseline unbilled tamper and theft energy will be converted to legal consumption.

The Company's revenue protection group focuses on detecting and eliminating tamper and theft. In 2019, the Company identified and eliminated 2,809 MWh (or 0.01% of total system consumption) of theft across its system. Of this identified theft, the Company was able to bill and collect payments on roughly 2,503 MWh, or just under 90% of overall theft. While the rate of collection against identified theft is high, the additional amount of theft occurring on the Company's system is likely magnitudes higher than what is currently being identified given industry research.

Figure 14: Industry Averages for Reduced Unaccounted for Energy (UFE)



Observations from Peer Filings	
EIA	• 0.5-2% of US electric revenue stolen each year
Vectren	• UFE is 212 kWh per customer per year • Assumed 50% of UFE recovered w/ AMI • Assumed 25% of bills can be forwarded for legal sales
Con Edison	• Estimated utilities have 1-3% loss of annual revenue due to theft / tampering • Assumed 0.25% of annual electric revenue will be recovered
National Grid	• EPRI estimates companies experience 0.5-3.5% revenue loss due to tamper and theft • Assumed theft recovery of 0.25% of annual electric revenue
Ameren Illinois	• Est. savings of 0.5%-1% of revenue / meter • Estimated 50% of theft eliminated w/ AMI
ComEd	• UFE is 134.2 kWh per customer per year • Assumed 50% of UFE recovered w/ AMI
Duke Indiana	• 2015 TDSIC estimated $267.5m of savings from reduced UFE ($16 / customer / year)
BC Hydro	• UFE is 472 kWh / customer / year • 67% of UFE recovered w/ AMI

Figure 14 summarizes industry observations for the annual benefit from reduced energy theft due to AMI. From these industry observations, annual revenue losses due to tamper and theft have been estimated to be anywhere between 0.5%-3.5% of total revenue. Given this range, this analysis conservatively estimates that 0.5% of overall consumption is currently lost to energy theft and that AMI –with advanced analytical tools and increased revenue protection efforts – can lead to the identification and elimination of 50% of total leakage due to tamper and theft.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to reducing tamper and theft is as follows:
  - Determine the incremental amount of theft occurring on the Company's system
    - Multiply the % loss due to energy theft by the annual consumption forecast
    - Subtract the current amount of observed theft on the system to calculate the unobserved energy theft
  - Calculate the amount of theft to be impacted by AMI
    - Multiply the amount of unobserved theft by the % reduction to theft to determine the amount of energy theft impacted by AMI
  - Calculate shift and elimination of energy theft
    - Sales conversion:
      - Multiply the amount of energy theft impacted by AMI by the % of theft expected to be converted to sales
      - Multiply by the average retail rate to determine the annual benefit of converting energy theft to sales
    - Elimination of consumption:
      - Multiply the amount of energy theft impacted by AMI by the % of theft expected to be eliminated
      - Multiply by the avoided cost of generation (energy) to determine the annual benefit of eliminating consumption prevoiusly stolen
  - Sum benefit values from converting theft to sales and elimination of consumption previously stolen to calculate the annual benefit of reducing theft through AMI

Benefit Realization Schedule

Benefit realization begins in 2023 and takes 3 years to ramp up to 100%. Realization is also a function of the percentage of meters converted to AMI each year.

4.2.3. Eliminated Consumption on Inactive Meters (CIM)

Background and Description

The Company experiences Consumption on Inactive Meters (CIM) when usage is observed at a meter that does not have a customer account associated with it. These instances require that the Company investigate and potentially disconnect a meter in order to limit CIM. With the ability to access consumption data in near real-time and remotely disconnect meters, AMI will allow the Company to identify these anomalies much faster and reduce the cost associated with addressing CIM.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to reducing CIM is as follows:
  - Forecast CIM
    - Multiply current levels of CIM by the annual meter growth rate to calculate forecasted levels of CIM
  - Determine the impact of AMI
    - Multiply the forecasted levels of CIM by the % of CIM that is currently unrecoverable (80%)
    - Multiply by the % reduction to CIM due to AMI (100%) to calculate the amount of CIM (MWh) eliminated each year due to AMI
  - Value the benefit
    - Multiply the amount of CIM eliminated each year (MWh) by the avoided cost of generation to determine the annual benefit of eliminating CIM

Benefit Realization Schedule

Benefit is realized in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year

4.3. Enhanced Conservation Voltage Reduction (CVR)

This category accounts for incremental benefits associated with the integration of AMI meter voltage readings into existing (and planned) CVR deployments across the Company service territory during the 20-year business case period. Discussed further in Section 4.3.1, CVR benefits captured in this business case leverage existing Company analyses which Accenture has compared to industry research and findings at AEP sister companies.

Figure 15: 20-Year Cumulative Enhanced Conservation Voltage Reduction (CVR) Breakdown ($, millions)

CVR	Total
Enhanced Conservation Voltage Reduction (CVR)	83.4
TOTAL	**83.4**

Benefit Area Background

CVR allows utilities to better manage voltage levels and optimize the grid through automated voltage control devices installed at substations. Without the use of AMI meters, CVR schemes rely on end-of-line sensors placed near, but not specifically at, the end of the distribution circuit, to more accurately read and confirm actual voltage levels on each distribution circuit. The use of these sensors facilitates the application of lower voltage profiles on those circuits while staying above or at minimum voltage requirements. The application of lower voltage levels results in energy and demand (both peak and non-peak) savings largely through more efficient operation of end-use electricity consuming equipment.

By providing more timely and actual end-of-line meter voltage readings, the integration of AMI meter voltage meter readings into CVR operating schemes enables incremental (i.e. lower) voltage level reductions to be applied as opposed to the non-AMI voltage levels applied from reliance on end-of-line sensors, while still operating within mandated safety parameters. Without AMI, the Company operates its existing CVR schemes with a target average voltage reduction of 3%. Based on industry research and EM&V results and experience from other AEP operating companies, once AMI voltage readings are integrated and considered into CVR schemes, incremental average target voltage reduction by another 1% (from 3% to 4% total voltage reduction) occurs, resulting in incremental energy and demand reductions (i.e. energy and demand savings incremental benefits). It is the value of this *incremental* voltage reduction that is attributed to the AMI business case.

After estimating the lower voltage level that CVR systems can operate at with AMI integrated into CVR schemes, a corresponding CVR Factor estimate is used to determine subsequent energy and demand savings. A CVR Factor explains the expected load reduction at a given voltage reduction level. For example, if the voltage on a circuit is reduced by 1%, and the subsequent load reduction observed is 0.8%, the calculated CVR Factor would be 80%. CVR Factors are influenced by several characteristics, including but not limited to customer and end-use load density, residential vs. commercial end use load mix, and time of year.

The third and final consideration is overall uptime of CVR system. Factors that influence uptime are power outages, distribution and transmission system construction / system upgrades, time to perform measurement and testing activities, and system operator discretion. While the Company has operated its CVR systems with uptime levels at an annual average of 45% in the past, ranging from 25% to 80% across the various CVR operated distribution circuits and largely influenced by the level of distribution system and transmission system construction activity and system reliability need, the Company forecasts the annual average CVR system uptime at a 60% average range for the short-term and improving to 80% in the future. The latter long-term target is informed by operational performance perspectives provided by other AEP peer utilities (e.g., PSO, AEP Ohio).

The Company currently has CVR deployed at 64 substations across circuits and is evaluating plans for a large-scale expansion of CVR at points across its entire distribution network. It is important to note that the AMI benefits forecasted here only correspond to circuits where CVR is cost effective prior to consideration of AMI. This is because both Accenture and the Company found it was appropriate to only include capital costs directly related to the AMI program. In other words, any capital costs and benefits associated with circuits for which CVR becomes cost effective due to enhancements from the aforementioned operating parameters (voltage reduction, CVR factor, and uptime) are considered outside the scope of this analysis. Last, the CVR benefits captured here are contingent on the approval and execution of these CVR expansion plans as well as the effective integration of AMI meter data into CVR software tools and operational schemes.

4.3.1. Enhanced Conservation Voltage Reduction (CVR) Benefits

Background and Description

This benefit captures the incremental energy savings and peak demand reductions achieved by supplementing CVR programs with AMI meters. Increasing visibility into voltage activity on circuits will allow the CVR system to further lower voltage levels, capturing additional savings as a result. The incremental benefits captured in this business case resulting from CVR are informed by data and previous circuit analyses provided by the Company and its third party EM&V vendor; modeling assumptions regarding incremental voltage reduction and improved levels of uptime are consistent with industry research and improvements observed at AEP sister companies at the time of this analysis.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to enhancing CVR is as follows:
  - Determine Incremental Energy Savings from AMI
    - Forecast CVR savings without AMI
      - Multiply annual consumption on circuits with CVR by respective CVR without AMI impact to calculate energy savings without AMI
    - Determine incremental savings attributable to AMI
      - Multiply annual consumption on circuits with CVR by expected CVR impact with AMI to calculate energy savings with AMI
      - Subtract CVR savings without AMI from CVR energy savings with AMI to determine the incremental savings attributable to AMI
      - Multiply the incremental savings reductions by the avoided cost of generation (energy) to calculate the value of incremental energy savings due to CVR
    - Forecast CVR demand savings without AMI
      - Multiply historical station transformer measured peak demand in MW by 1,000 to calculate actual peak demand in KW.
  - Multiply historical station transformer measured peak demand in KW. by the demand CVR factor to calculate demand savings without AMI

- Determine incremental demand savings from AMI
  - Multiply historical historical station transformer measured peak demand in MW by 1,000 to calculate incremental demand savings attributable to AMI (KW)
  - Multiply historical station transfomer measured peak demand in KW by the AMI CVR factor to calculate incremental demand savingsattributable to AMI (KW)
  - Subtract CVR peak demand savings without AMI from CVR peak demand savings with AMI to determine the incremental peak demand savings attributable to AMI
  - Multiply the incremental demand savings by the forecasted avoided cost of generation (capacity) and multiply by days per year (365) to calculate the value of incremental demand savings due to CVR
- Sum the incremental energy savings from AMI with the incremental demand savings from AMI to calculate the incremental value of AMI to existing and forecasted CVR programs

Benefit Realization Schedule

Benefit realization is in proportion to the rollout of AMI meters and dependent on the Company's baseline capital CVR expansion plans.

4.4. Customer Benefits

This benefit category accounts for quantified customer benefits included in this report.

Figure 16: 20-Year Cumulative Customer Benefits Breakdown ($, millions)

Customer Benefits	Total
Enable Demand Side Management (DSM) Programs	66.6
Peak Reduction Due to Electric Vehicle (EV) TOU Rates	5.9
Enhanced Residential Customer Engagement Tools	19.1
Enhanced Commercial and Industrial (C&I) Customer Engagement Tools	9.3
Flex Pay Program Benefits	7.5
TOTAL	**108.3**

4.4.1. Enable Demand Side Management (DSM) Programs

An AMI deployment and the respective meter data will enable the Company to broaden DSM programs and increase their participation.

Upon Company direction, Accenture has included three program types in this analysis: DLC, Customer Engagement Demand Response, and CPP. Analyses that have been conducted for these rate types are largely informed by previous Company experience and select industry research. Prior to any filing, approval or launch of these new DSM offerings, more detailed program design, analysis, and/or pilot activity is likely required.

Based on past experiences, the Company's perspective is that AMI is required to make DLC programs cost effective; as such, the Company has provided forecasts for DLC adoption and potential with AMI. This analysis has been split between the Residential and Commercial and Industrial (C&I) customer segments. The Company provided additional data sourced to the respective vendors for these programs that captures how advanced analytics and personalization of consumption data work to achieve energy savings. Costs considered as part of these programs include that of the actual load control equipment, the energy hub for customers and various administrative costs.

Regarding Customer Engagement Demand Response and CPP programs, Accenture worked with the Company to perform cost-benefit analyses based on Company input and industry research to directionally estimate program potential. [5] [6]

Based on Company guidance, this analysis includes an opt-in program structure for the first 7 years of the 20-year forecast period where participation rate is between 20-30% of total residential customers. Then, the Company has modeled an opt-out program structure beginning in 2028. This timing aligns with the Company's forecasted capacity position as it transitions away from coal starting in 2023 with the expiration of the Rockport Unit 2 lease and then in 2028 with the retirement of Rockport Unit 1. The shift towards an opt-out CPP program increases customer participation to 80% of total residential customers across forecasted Customer Engagement Demand Response and CPP programs. Additional data inputs regarding the expected load reduction resulting from DSM programs are sourced from peer observations and published reports discussed below.

Peak Time Rebates – Peer Observations

The Company's proposed Customer Engagement Demand Response program is similar to peer utility PTR programs. PTR programs incentivize customers to reduce load during peak demand events called by the Company throughout the year in exchange for bill credits. Barriers are low for customers to adopt PTR rates as the number of annual events is small and there is no requirement / mandate for customers to reduce load during utility specified peak events.

Key studies that were reviewed as part of this study were Commonwealth Edison's Peak Time Savings annual reports from 2016 and 2019. A review of these reports showed that:

- Peak events typically last 3-5 hours between 11AM and 7PM CDT on hot summer days;

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[5] Bell, E. et. al. 2019. *Commonwealth Edison Company's Peak Time Savings Program Annual Report For the Year Ending May 31, 2019.* Nexant.

[6] George, S. et. al. 2015. *Cost Effectiveness of Time-Varying Pricing with Advanced Metering Infrastructure in CECONY Territory.* Nexant.

- Participating customers were paid $1 per kWh reduced during peak events;
- Participation rates ramped up between 2016 and 2019 (to 15%+ of residential customer segment by 2019); and
- Participating customers reduced load by an average of 6.12% during peak periods, which reperesents approximately 0.15 kW reduced per home per event period.

In addition to a review of these Commonwealth Edison reports, an additional study by the American Council for an Energy-Efficient Economy (ACEEE) analyzed 50 customer pilot programs and found even higher PTR peak reduction of 17.8%. For the purpose of this study, the Company selected a lower average PTR peak reduction rate of 6% due to the similarity of climate zone, commonality with the PJM ISO capacity markets, and nature of customer engagement deployed by Commonwealth Edison (i.e., summer cooling season opt-in behavior-based deployment).

Time of Use Rates – Peer Observations

TOU structures have been implemented at utilities across the country. An industry study conducted by the Brattle Group found that TOU programs typically lead to peak demand reduction levels that are a function of rate and program design. For the purposes of this study, a key objective was to use industry research to define a 'typical' TOU rate and use that as a proxy for estimating the customer value that might be created if/when the Company were to offer a large scale TOU program to its customers. Key observations from this Brattle Group study were as follows:

- Median peak to off-peak price ratios were 2.7 to 1;
- 75% of TOU rates in this study had two pricing tiers;
- Typical duration of peak hours are 6 hours or less per day; and
- An average TOU defined by these attributes would be expected to result in an average peak load reduction of 5-10%.[7]

In addition, an analysis of 50 TOU programs, conducted by the American Council for an Energy-Efficient Economy (ACEEE), found that TOU rates can yield 7% peak load reductions from participating customers.[8] Together with the Brattle Group study and previous modeling assumptions for its proposed CPP program, the Company has decided to use a 6% peak reduction estimate for customers who opt-in to this program.

Additionally, the Company intends to expand the CPP program by transitioning to opt-out (or default) within the 20-year forecast window. As such, the Company acknowledges that these opt-out customers will likely not be as active in terms of participation and performance (i.e.,

[7] Faruqui, A., et al. 2019. *A Survey of Residential Time-of-Use (TOU) Rates.* The Brattle Group.
[8] Baatz, B. 2017. *Rate Design Matters: The Intersectionof Residential Rate Design and Energy Efficiency*. American Council for an Energy-Efficient Economy.

load reduction). In line with industry observations (e.g., Sacramento Municipal Utility District's Smart Pricing Options pilot[9] and Consolidated Edison's AMI business case[10]), the Company has assumed a 3% peak reduction rate (50% of assumed opt-in rate) following transition to an opt-out program to account for lower engagement levels from customers who receive the CPP rate without specifically opting in.

Further, the same ACEEE study also found that TOU's can yield energy savings in the range of 1-3% depending on rate structure, region, and whether the rate is opt-in or out-out. Based on these findings, the Company has decided upon a conservative estimate of 1% and 0.5% energy savings for opt-in and opt-out CPP scenarios respectively.

Analysis of Customer Rates

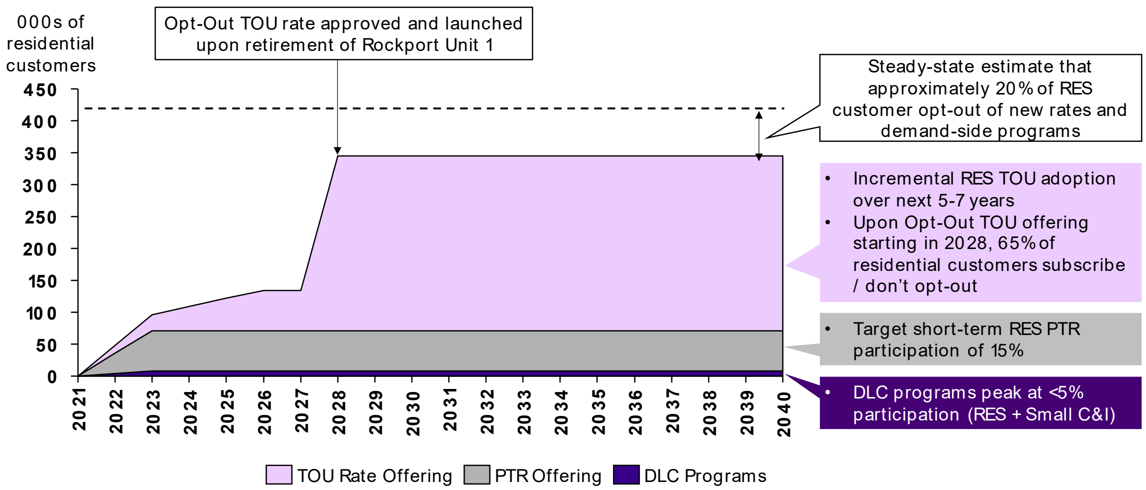
For Customer Engagement Demand Response and CPP programs, Accenture focused its analysis on only residential customer segment because of established literature and research relative to other rate structures. Also, the proposed Customer Engagement Demand Response and CPP Programs are modeled using the TRC test. As part of the TRC, while incentive payments are a cost to the program, they are considered to be a transfer of value between the utility and customer. Because of the offsetting nature in the context of the TRC test, they have been excluded.

The assumptions and forecasts included in this business case are informed by both Company-specific data and relevant pilots and studies observed throughout the industry. At the time of this analysis, Accenture believes that the assumptions and approach used are reasonable to forecast the potential value that DSM programs can provide for the Company's customers. Moving forward, Accenture recommends that the Company perform more detailed rate design, customer segment analysis, and planning prior to program execution.

[9] Potter, S.,et. al. 2014. *SmartPricing Options Final Evaluation.* Sacramento Municipal Utility District.

[10] George, S., et. al. 2015. *Cost Effectiveness of Time-Varying Pricing with Advanced Metering Infrastructure in CECONY Territory.* Nexant.

Figure 17: Modeled Adoption Rates for Demand Side Management Portfolio



Calculation Methodology

DSM calculations were conducted on a portfolio of program offerings across the 20-year business case period. Figure 17 shows the participation rate forecasts by program.

- Calculations for quantifying AMI benefits related to Customer Engagement Demand Response and CPP programs are as follows:
  - Calculate incremental demand savings (for DLC, Customer Engagement Demand Response, and CPP):
    - Multiply Residential peak load forecasts by the forecasted adoption rates (Opt-In or Opt-Out Rates)
    - Multiply by the % peak load reduction to calculate the forecasted demand savings (MW)
    - Multiply by forecasted avoided cost of generation (capacity)
    - Multiply by days per year to calculate the value of incremental demand savings
  - Calculate incremental energy savings (for CPP only):
    - Multiply forecasted residential energy consumption by the forecasted adoption rate (Opt-In or Opt-Out Rates)
    - Multiply by the forecasted consumption reduction rates to calculate the forecasted energy reduction due to CPP programs
    - Multiply the forecasted energy reduction by the forecasted avoided cost of generation (energy) to calculate the annual energy savings value
  - Calculate value of load shifting (for CPP only):
    - Multiply forecasted peak load reduction by estimated peak hours per year
    - Multiply by the average load factor to calculate amount of peak consumption impacted (MWh)

        - Reduce amount of peak consumption impacted by the amount of energy consumption reduced to calculate amount of peak consumption shifted (MWh)
        - Multiply by the forecasted difference in peak vs. off-peak cost of generation (energy) to calculate the forecasted value of shifting load from peak to off-peak
    - Sum the values of incremental demand savings, energy savings, and load shifting to arrive at the total calculated benefits of a demand side management portfolio attributable to AMI

Benefit Realization Schedule

This benefit follows specified adoption and effectiveness rates as outlined in the tables and figures above.

4.4.2. Peak Reduction Due to Electric Vehicle (EV) Time-of-Use (TOU) Rates

Background and Description

Deployment of AMI coupled with marketing efforts to educate customers about AMI technology and encourage customers to enroll in AMI-enabled programs offer an opportunity to share with customers the benefits of electric vehicle (EV) TOU rates and increase program adoption. This assertion is based largely on a 2019 study conducted by the Smart Electric Power Alliance that found 2-3x higher enrollment in EV TOU rates with enhanced customer engagement tools and marketing budget.[11] One specific method discussed in the report involves using AMI to analyze consumption data in an effort to identify potential EVs on the grid and market TOU programs accordingly. This benefit area aims to capture the incremental customers that join EV TOU programs as a result of concerted customer engagement and marketing efforts that are proposed as part of this overall AMI program.

Calculation Methodology

- Calculations for quantifying AMI benefits related to EV TOU programs are as follows:
    - Identify incremental EV TOU participants as a result of the AMI program
        - Multiply the forecasted number of EV owners by the difference in the following adoption rates:
            - % of customers who adopt EV TOU without AMI integrated marketing
            - % of customers who adopt EV TOU with AMI integrated marketing
    - Identify incremental consumption shifted from peak to off-peak
        - Multiply the incremental EV TOU paricipants as a result of the AMI program by the average number of miles driven per EV
        - Divide by the average miles / kWh to calculate the average incremental EV consumption of additional EV TOU program participants

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[11] Smart Electric Power Alliance. 2019. *Residential Electric Vehicle Rates That Work.*

- Multiply by the % of energy consumed during on-peak hours and the resulting shift of consumption to off-peak as a result of the EV TOU program
- Value the peak reduction
  - Divide the amount of consumption shifted from peak to off-peak by the number of peak hours per year to calculate the peak reduction
  - Multiply by the avoided cost of generation (capacity) and days per year to calculate the annual demand savings benefit of moving EV charging from peak to off-peak

Benefit Realization Schedule

Benefit is realized in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.4.3. Enhanced Residential Customer Engagement Tools

Background and Description

Customer engagement portals / tools are common elements of industry AMI programs. Industry research indicates that AMI enables incremental customer energy saving programs and features, including, but not limited to: near real-time energy usage information and alerts, customized billing data and data presentment, and end-use load disaggregation information. Common areas related to AMI-enabled customer portal functionality are listed in Figure 18.

Figure 18: Customer Engagement Portal Programs Enabled by AMI

Program	AMI Enablement	Customer Engagement / Value
Real-Time Energy Use Information	Granular AMI data allows customers to see their usage data broken down into more frequent increments on a daily and sometimes hourly basis	Customers have insight into their energy usage throughout the month / day, giving them the option to participate in more customer programs to reduce energy usage
Prepay Program	AMI allows customers to see how much pre-paid energy they have used through the month	Pre-pay gives customer greater autonomy over their payment schedule and reduces the risk of unknown disconnect
Real-Time High Bill Alerts	The utility can alert customers when their bill will likely be higher than normal based on daily energy usage data provided by AMI	High bill alerts give customers the opportunity to tailor their energy usage and prevent higher than average energy bills
Performance-Based Energy Efficiency / Demand Response Programs	AMI data enables the utility to accurately credit customers for program-related energy savings	Customers can view their program performance in real time
Customized Billing Data	Billing periods can be customized with AMI enabled real-time billing data	Customers will have greater autonomy over how and when they receive billing information
Data Presentment / Data Aggregation	Programs such as Green Button Connect and Green Button Download my Data allow customers to automatically share their usage data with third parties	Customers have greater autonomy over their energy usage data

These programs, when enhanced by AMI, are expected to increase not only the level of customer engagement but the quality of the engagement as well. This functionality can lead to incremental improvement in overall participation in future demand side management programs. As a result, both the full cost and benefit of the proposed customer engagement portal are included in this AMI business case.

Currently, Opower is the customer portal vendor of choice for residential customers. Consistent with industry research, Opower asserts that AMI will enable incremental energy saving through programs such as near real-time energy usage information and alerts, customized billing data, data presentment, and high bill alerts. In the coming years, the Company has decided to prioritize near real-time energy data and home energy report programs, accessible for customers either through a web-based portal or mobile application.

Additionally, based on results from 100 utilities nation-wide, Opower cites incremental energy savings attributed to Home Energy Reports (HERs) of 2.5%.[12]. The American Economics Review conducted a study of over 500,000 households using Opower home energy reports and found energy savings upwards of 3%[13]. On top of home energy report savings, Opower's high bill alert functionality can add an additional 0.3% energy savings according to an American Council for an Energy-Efficient Economy assessment of eight Opower HER programs[14].

Based on these industry observations and Company experiences, this analysis assumes a steady state customer participation rate of 15-20%. In this context, participation is defined as a combination of the following: ability to receive electronic communications, percent of communications which are opened and viewed, and the rate in which positive action is taken in response to recommendations. For estimated energy savings from customers that use the enhanced customer engagement capabilities from the customer engagement portal programs, this analysis assumes that electronic home energy reports (eHERs) and high bill alerts (HBAs) together will result in a 2% energy reduction rate for participating customers, which is in the middle of the identified industry peer and vendor observations range.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to enhancing the customer engagement portal is as follows:
  - Calculate customer portal vendor cost forecasts
    - Multiply the vendor cost ($ / customer) by the total number of the Company's residential customers with an email address on record
  - Calculate customer portal program administration and EM&V costs
    - Multiply the Program Administration and EM&V cost ($ / customer) by the total number of the Company's residential customers with an email address on record

[12] Oracle. 2019. *Opower Behavioral Energy Efficiency.*
[13]American Economic Review. 2014. *The Short-Run and Long-Run Effects of Behavioral Interventions: Experimental Evidence from Energy Conservation.*
[14] American Council for an Energy-Efficient Economy. 2020. *Leveraging Advanced Metering Infrastructure To Save Energy*.

- Sum the previously forecasted vendor, administration, and EM&V costs to calculate total customer portal costs
- Calculate benefits of customer portal
  - Calculate energy savings
    - Multiply total engaged customers annually by the residential consumption per customer to calculate the total consumption eligible for impact through the customer portal program
    - Multiply total consumption eligible for impact by the expected energy reduction through the customer portal program (2%) to calculate the expected energy savings forecast (MWh)
    - Multiply by the average avoided cost of generation (energy) to calculate the estimated energy savings benefit
  - Calculate peak demand savings
    - Multiply forecasted engaged customers annually by the average expected demand savings per customer to calculate the annual demand savings due to customer portal
    - Multiply the annual demand savings (KW) by the avoided cost of generation (capacity) to calculate the benefit of reducing peak demand through the customer portal
  - Sum annual energy savings with annual demand savings to calculate the total annual benefit of the customer portal

Benefit Realization Schedule

Benefit from the customer engagement portal programs are realized in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.4.4. Enhanced Commercial and Industrial (C&I) Customer Engagement Tools

Background and Description

Based on industry research, the Company finds that customer engagement tools for the commercial and industrial segment will provide customers with necessary energy usage insights and lead to incremental energy savings for customers in this segment. According to the Company's chosen customer portal vendor, First Fuel (a.k.a. Uplight), HBAs and other tools can result in energy savings for commercial and industrial customers of up to 3.2%[15]. For this analysis, the Company assumes a conservative 1% average reduction in energy consumption (and associated peak demand savings) for participating C&I customers.

Calculation Methodology

[15] Uplight. 2020. *Uplight's Real-time AMI Digital Alerts Increase Customer Engagement.*

- The calculation for quantifying the benefits of enhanced C&I customer engagement tools is as follows:
  - Forecast the number of customers using First Fuel
    - Multiply the forecasted # of C&I customers by the percentage of C&I customers expected to utilize First Fuel
  - Calculate annual energy savings for customers using First Fuel
    - Multiply the number of customers using First Fuel by the estimated annual energy savings rate
    - Multiple the energy savings amount by the avoided cost of generation (energy)
  - Calculate estimated demand savings for customers using First Fuel
    - Estimate demand savings associated with forecasted energy savings using assumptions for load factor and coincident peaks
    - Multiply the demand savings forecast by avoided cost of generation (capacity)
  - Total the estimated C&I First Fuel Benefit
    - Sum the estimated energy and demand savings

Benefit Realization Schedule

The C&I customer engagement portal benefits are realized in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.4.5. Flex Pay Program Benefits

Background and Description

The Flex Pay program will allow customers to pay in advance for power each month, preventing monthly bills in excess of the amount they can afford. AMI interval data enables these programs by allowing the Company to monitor daily energy usage of program participants and, in turn, disconnect power when customer-chosen monthly usage limits have been reached. AMI-enabled energy usage insights throughout the month allow customers to monitor how much of their prepaid energy has been used; the Company has provided guidance that this often results in customers reducing consumption to stay within the boundaries they've set. This benefit captures the energy savings expected to occur due to customer adoption of the Flex Pay program

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to Flex Pay is as follows:
  - Forecast the number of customers enrolled in the Flex Pay program
    - Multiply the forecasted # of residential customers by the % of residential customers expected to participate in the Flex Pay program

- Calculate the annual energy savings for residential consumption who enroll in the Flex Pay program
    - Multiply the forecasted number of customers enrolled in the Flex Pay program by the annual consumption per customer to calculate the total amount of consumption eligible for reduction
    - Multiply the total amount of consumption eligible for reduction by the expected % energy savings due to the Flex Pay program
- Calculate annual energy savings for customers enrolled in the Flex Pay program
    - Multiply the forecasted energy savings by the avoided cost of generation (energy)

Benefit Realization Schedule

Benefit is realized in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

4.5. Avoided Capital Costs

This benefit category accounts for avoided costs associated with an AMR deployment including AMR meters and supply costs for integrating Distributed Generation (DG).

Figure 19: 20-Year Cumulative Avoided AMR Costs Breakdown ($, millions)

Avoided Capital Costs	Total
Avoided AMR Meter Replacements	53.1
Avoided AMR IT Support Costs	3.9
Avoided Secondary Meter for Residential-scale Distributed Generation (DG)	27.5
Avoided AMR Meter Replacements – Meter Growth	1.5
Delayed Distribution Capital Cost Due to Peak Reductions	11.5
TOTAL	**97.4**

4.5.1. Avoided Automated Meter Reading (AMR) Meter Replacements

Per guidance from the Company, AMR assets are expected to have a 15-year expected average service life. As the Company's AMR assets reach end of expected average service life, meter replacement can be conducted in one of two ways: 1) replace AMR meters as they fail, or 2) pre-emptively replace AMR meters once they reach the end of their expected average service life. In line with Company guidance and select peer research, Accenture finds the latter option to be reasonable. Upgrading AMR meter assets pre-emptively will maintain reliability, avoid higher costs of emergency field work, and protect against technology obsolescence. As such, this benefit captures the avoided costs associated with replacing meters as they reach their expected average service life.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to avoided AMR Meter Replacement is as follows:
  - Forecast Meter Installations
    - Take the historical vintage data for AMR meter installations
    - Add the expected average service life to each AMR meter vintage year to calculate the expected replacement date – this creates a schedule of forecasted meter replacements by year and quantity
  - Determine total cost of meter installations
    - Forecast the cost of AMR meter equipment out 20 years using the non-labor growth rate to determine expected costs of AMR meter equipment
    - Forecast the labor cost of AMR meter installations out 20 years using the labor growth rate to determine expected costs of AMR meter installation
  - Calculate the value of avoiding AMR Meter Installations
    - Multiply the annual number of meter installations by the total cost of meter installations to determine the value of avoided AMR meter replacements

Benefit Realization Schedule

Benefit is realized based on AMR meter vintage data from the Company and assumes proactive replacement upon the end of 15-year expected average service life.

4.5.2. Avoided AMR IT Support Costs

Background and Description

In order to maintain the current AMR metering system, additional ongoing IT support costs and additional hardware certification and functional testing would be required. Replacing AMR meters with AMI will eliminate these IT support costs.

Calculation Methodology

- This benefit is the sum of three avoided cost elements:
  - Avoided vendor costs, including headend annual support fees, associated with upgrading the existing AMR system
  - Avoided software / IT costs, including MDM system upgrades
  - Avoided testing costs for new AMR meters, including hardware certification and functional testing

Benefit Realization Schedule

Benefit is realized based on AMR meter vintage data from the Company and assumes proactive replacement upon the end of 15-year expected average service life.

4.5.3. Avoided Secondary Meter for Residential-scale Distributed Generation (DG)

Benefit Background

Adoption of DG is growing nation-wide as various technologies become more cost effective. Common DG technologies typically include solar photovoltaic (PV), battery storage, combined heat and power, and wind. In line with this observed industry trend, Company-provided forecasts show residential installed capacity for DG / PV growing to more than 43MW in the Company's Indiana service territory by 2035.[16]

For these residential customers who adopt DG / PV, current operations require that the Company visit the customer premise and install a secondary interval meter. Accenture's understanding is that AMI meters satisfy integration and net metering requirements for residential-scale DG assets and eliminate the need for a secondary interval meter. For example, from Consumers Energy's plans for their new Distributed Generation Program, customers installing systems sized at less than or equal to 20kW require only a single meter.[17] As such, this benefit captures the avoided cost of a secondary interval meter for the Company's residential customer segment that would otherwise need to be installed without AMI.

Calculation Methodology

- The calculation for quantifying this benefit is as follows:
  - Forcast DG Adoption and the avoided installation costs
    - Divide the forecasted installed base of Residential DG by the average size of a residential DG system to forecast the cumulative number of residential customers with DG
    - Subtract year to year amounts to identify the incremental amount of customers requiring DG installations each year
    - Multiply the incremental number of customers requiring DG installations each year by the secondary meter equipment and installation costs to calculate the annual benefit
  - Calculate the avoided cost of cellular service
    - Multiply the cumulative amount of DG customers each year by the annual cost of cell service to calculate the annual avoided cost of cell service
  - Sum the avoided installation costs with the avoided cost of cellular service to calculate the annual benefit of avoiding secondary meters for supporting Residential DG

Benefit Realization Schedule

Benefit is realized immediately starting in 2021 as customers adopt DG / PV.

[16] *Distributed Solar Generation Update.* PJM Load Analysis Subcommittee. December 2019.
[17] Consumers Energy Net Metering Tariff. https://www.consumersenergy.com/residential/renewable-energy/net-metering

4.5.4. Avoided AMR Meter Replacements – Meter Growth

Benefit Background

This benefit area acknowledges that customer / meter counts will inherently change over time and that new customers will need new meters installed by the Company regardless of the metering technology selection. The Company forecasts this long-term meter growth rate to be 0.1%. This benefit area represents the avoided costs of deploying new AMR meters to these new customers that would still be required without program.

Calculation Methodology

- The calculation for quantifying the benefits of AMI related to avoided meter growth is as follows:
  - Calculate customer growth
    - Using the total retail customer forecast, subtract year to year customer counts to determine incremental new customers each year
  - Calculate cost to support new customers
    - Sum the cost per AMR meter with the cost per AMR Meter Installation
  - Determine value of avoiding AMR Growth
    - Multiply the incremental new customers each year with the cost to support new customers to determine the value of avoiding AMR meter installations as a result of the AMI program

Benefit Realization Schedule

This benefit tracks to the calculated customer growth forecast and is realized 100% each year.

4.5.5. Delayed Distribution Capital Cost Due to Peak Reductions

Background and Description:

This benefit captures the value of reducing peak load that delays forecasted distribution peak-demand-growth-driven capital costs. By reducing peak demand, capital costs that would otherwise be required to meet increasing system peak loads are delayed, creating financial value. Using the value of specific load growth driven capital improvement projects to derive an estimated average capital cost for an incremental unit of system capacity improvement, an avoided capital cost forecast was created and modeled as an incremental rate base reduction. To affirm the directionality and appropriateness for the incremental benefit value, the Company and Accenture relied upon industry research and an analysis performed by an AEP peer utility.

Specifically, unitary capital cost estimates and average or levelized customer benefits from delayed distribution capital investments were benchmarked against industry observations [18]

[18] Feldman, B., et. al. 2015. *Peak Demand Reduction Strategy.* Navigant Consulting.

[19]. From a review of these sources, average industry estimates range from $20-30 per KW-year. Based on this analysis, these levelized figures are in line with Company estimates of $150-175 per KW average capital costs for new capacity.

Calculation Methodology:

- Estimate annual incremental peak reduction from specific programs included in this AMI business case (e.g., DLC, Customer Engagement Demand Response, CPP, EV TOU, customer engagement tools, etc.)
- Multiply annual incremental peak reduction by the capital cost of new distribution capacity ($/KW)

Benefit Realization Schedule:
This benefit is realized 100% each year as the aggregation of peak reductions throughout the business case already incorporates the deployment schedule.

4.6. Societal Benefits

This benefit category accounts for societal benefits associated with AMI deployment including avoided customer outage costs and carbon dioxide (CO_2) emission reductions.

Figure 20: 20-Year Cumulative Societal Benefits Breakdown ($, millions)

Societal Benefits	Total
Improved Customer Productivity (Value of Lost Load - VOLL)	43.6
Carbon Dioxide (CO_2) Emissions Reductions	1.0
TOTAL	**44.6**

4.6.1. Improved Customer Productivity (Value of Lost Load - VOLL)

Benefit Background

Estimating the impact of improving system reliability relies heavily on the value of lost load (VOLL), a metric that aims to signal the economic losses customers experience due to planned and unplanned outages. In reviewing industry research and numerous studies, Accenture acknowledges that this metric varies drastically throughout service territories and amongst customer segments. As such, this business case uses the Interruption Cost Estimate (ICE) Calculator – a publicly available tool created by the US Department of Energy (DoE) – to quantify the value of improving service reliability due to AMI.

[19] Hledik, R., et. al. 2015. *Valuing Demand Response: International Best Practices, Case Studies, and Applications.* The Brattle Group.

While the ICE Calculator quantifies the impact to customers given a movement in service reliability, Accenture looked to other industry sources to estimate what a reasonable improvement in System Average Interruption Duration Index (SAIDI) might be as a result of an AMI deployment. Looking to data provided by both the Institute of Electrical and Electronic Engineers (IEEE) and Public Service Enterprise Group (PSEG), this analysis assumes that AMI will improve current SAIDI scores in both service territories by 2%.[20]
Accenture and the Company have chosen to exclude medium & large C&I customers from this calculation. This is done to not overstate the economic impact of improving service reliability; this customer segment likely will not experience an improvement of the same magnitude as the Residential & Small C&I customer segments.

AMI Enablement of Outage Duration Reduction
Detecting and pinpointing outage locations can be difficult without automated technology that remotely alerts a utility of power losses. Smart meters provide this functionality by transmitting an alert to the back office that specifies where and when a customer has lost power. Typically, this data is linked with additional outage data to determine the cause of an outage and develop a solution to return power in outage-affected areas. Smart meters provide the missing, specific outage location details necessary to improve Company outage response.[21]

Additionally, smart meters can ping grid operators once power has been restored, indicating when customers and service territories are fully back on the grid. Faster outage resolution leads to fewer productivity losses for residential, commercial, and industrial customers.

In addition to the economic benefit provided by smart meters and considered in this business case, reduction in average outage duration also results in safety benefits for customers. Power outages can result in health and safety concerns for children, the elderly, and customers who rely on power for health-related appliances. Reducing outage duration and increasing safety for customers is an additional benefit provided by smart meters.

Calculation Methodology
To quantify the impacts of improving service reliability for Residential and small Commercial & Industrial customers (defined as those who consume <50,000 kWh / year), Accenture leveraged the ICE Calculator – a tool developed by the US DoE. Operational inputs required for the tool include customer count by segment and expected improvements to the SAIDI and System Average Interruption Frequency Index (SAIFI). The improvements to SAIDI as a result

[20] Page 27. *Direct Testimony of Paul Alvarez, In the Matter of the Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Cloud ("CEF-EC") Program on a Regulated Basis*. BPU Docket No. EO18101115. August 2020.
[21] U.S. Department of Energy. 2012. *Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results.*

of AMI are assumed to be 2%. While improvements to the Momentary Average Interruption Frequency Index (MAIFI) and SAIFI are likely to occur as a result of AMI, less literature exists to support this assumption; as such, reliability improvements have been limited to SAIDI.

Benefit Realization Schedule
Benefit is realized beginning in 2022 and is in proportion to the rollout of AMI meters, based on percentage of meters converted to AMI each year.

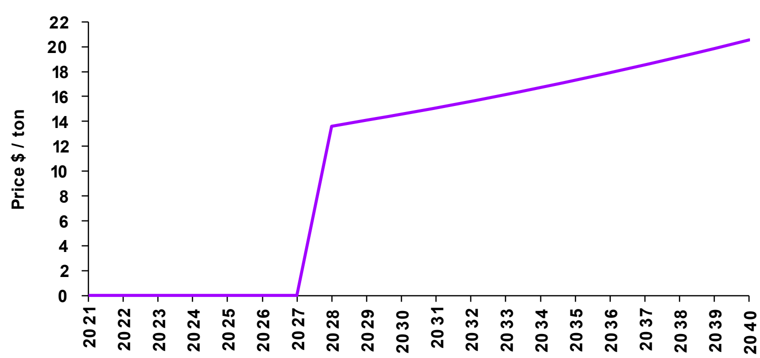
4.6.2. Carbon Dioxide (CO2) Emissions Reductions

Social Cost of Carbon
Carbon emission reduction has become an essential effort across many industries, the electric utilities industry being no exception. According to the Environmental Defense Fund, the social cost of carbon measures the negative economic impacts of environmental harm caused by carbon pollution. The U.S. Environmental Protection Agency (EPA) defines it as, "a measure, in dollars, of the long-term damage done by a ton of carbon dioxide emissions in a given year."

In terms of the economic value of reducing carbon emissions, a current estimate of carbon's social cost is $50 per ton of carbon[22] and according to the EPA, this will increase to $60 per ton by 2040.[23]

However, for the purposes of this analysis, Figure 21 shows the forecasted 2021-2040 CO_2 prices provided by the Company that are used to monetize reduced emissions in this analysis.

Figure 21: Range of CO2 Prices ($/Ton)



To make the social cost of carbon a real economic factor for businesses, carbon taxing has become a popular regulatory measure to encourage businesses and utilities alike to reduce

[22] Environmental Defense Fund. 2019. *The True Cost of Carbon Pollution*.
[23] U.S. Environmental Protection Agency. 2017. *The Social Cost of Carbon.*

their carbon emissions. Thus, beyond social implications, it is in a firm's economic interest to reduce carbon emissions where possible to prevent potential future taxation.

I&M Carbon Emission Reduction Levers

The Company's plan to deploy AMI provides an opportunity to reduce the Company's overall carbon emissions. The first reduction lever comes from the reduction in fleet miles to read meters, augment meter-related issues and reconnect service. The remote reading and reconnect / disconnect capabilities enabled by smart meters will reduce the miles driven to support customer meters and eliminate the associated carbon emissions.

Meter reading for the Company's current AMR meters happens once a month. Deployment of smart meters will prevent the need for monthly meter visits as meter reads will be conducted remotely.

AMI data can be used to create customer-level voltage profiles to manage system voltage levels and improve CVR energy savings, in turn reducing carbon emitted. TOU pricing enabled by smart meters encourages customers to reduce their energy usage during on-peak times, reducing load and overall energy savings. The Company's smart meter program plays a vital role in grid modernization efforts that lead to greater energy savings and therefore carbon emission reductions. AMI is expected to enable additional grid modernization technologies down the line, providing additional social benefit from CO2 emission reduction.

Calculation Methodology

- Carbon emission reductions are calculated specifically for each driver (e.g., benefits that lead to energy savings, reductions in overall fleet miles, etc.). For example, the calculation methodology fo reduced fleet miles is as follows:
  - Divide the miles driven by meter reader personnel (miles) by the fuel economy for AMR reading vehicles (mi/gal)
  - Multiply by the CO2 content for fuel (lbs./gal)
  - Divide by pounds per metric ton (lbs./ton) to calculate the CO2 emissions from annual meter reader miles driven (metric tons)
  - CO2 emissions from annual meter reader miles driven (metric tons) is multiplied by the forecasted price of CO2 ($/metric ton) to find the annual CO2 benefit from reduction of meter reads, ($/year).

Benefit Realization Schedule

Realization of benefits tied to reducing CO2 emissions are tied to their respective benefits (i.e., CO2 reduction of meter reads follows deployment schedule of eliminating meter readers)

4.7. Additional Benefit Areas

Accenture acknowledges that the business case put forth here is not exhaustive in capturing the benefits associated with AMI. Previously discussed benefits largely reflect those commonly seen throughout the industry where existing research and peer experiences exist to help inform estimates. While Accenture acknowledges that additional quantifiable benefits exist, qualitative impacts of AMI are put forth here for consideration as well. Similarly, this list is not exhaustive of all qualitative benefit areas expected to be realized through an AMI deployment. This section contains additional benefit areas to illustrate incremental value derived from AMI that is not quantified in this business case.

4.7.1. Improved Employee Safety

The reduction in total trips for field workers reduces instances in which employees can be hurt or placed in the face of danger. Deployment of AMI will reduce employee-related accidents in the field for metering activities.

4.7.2. Improved Emergency Response

A public safety benefit of AMI is improved communications and management during emergency events including residential or commercial fires. With AMI, emergency responders will have more data at their fingertips and will be able to more easily communicate with the Company to disconnect power in affected areas. Remote disconnect will make it easier and more efficient to manage customer power during emergency events.

4.7.3. Improved Customer Communication

Another public safety benefit of AMI is that increased granularity around outage location data will allow the Company to more quickly and efficiently communicate with customers about where and when outages occur. In addition, with granular customer data and energy profiles, the Company can provide customers with personalized insights, creating a more streamlined and informative customer service experience. Generally, arming customer service representatives with better data will allow for an improved customer experience.

4.7.4. Improved Call Center Efficiency

AMI data makes it possible to build comprehensive customer profiles based on energy usage history, streamlining call center processes. Therefore, fewer call center FTE are needed to complete call center activities. The call center efficiency benefit has not been forecasted quantitatively in this business case as the cost of AMI-related increases in call volume must be considered to understand the true magnitude of the call center benefit.

4.7.5. Improved Day-to-Day Distribution Planning and Operations

AMI data will enable the Company to improve distribution planning efforts including preventative maintenance and asset management. The Company can optimize investment in system infrastructure and conduct more accurate load growth assessments with AMI-enabled interval, voltage and outage data.

4.7.6. Increased Customer Engagement

The AMI program is reasonably expected to allow for greater overall customer engagement. The smart meter customer engagement plan, communications with customers and customer participation in new programs will increase customer interaction with and awareness of the Company's activities across the board.

4.7.7. Easier Move-In/Move-Out Process

While the ability to remotely reconnect customers is quantified as an avoided O&M cost, this benefit area acknowledges that customer satisfaction will improve for reasons outside of reducing cost to serve such as reduced wait times and enhanced ease of reconnect / disconnect scheduling.

4.7.8. Improved Back-Office Processes and Analytics

Customer profiles enabled by AMI data will streamline back office processes allowing for more efficient analysis to improve decision making, manage regulatory compliance and conduct more robust analysis for distribution planning.

4.7.9. New Customer Capabilities

AMI can enable additional customer programs and technologies that are emerging in the marketplace. For example, increased customer touchpoints / communication channels can improve overall customer engagement to:

- Help customers take advantage of smart hardware programs (e.g., appliances, thermostats, etc.); and
- Enable customers (through capabilities like Green Button Download My Data) to engage at their discretion with 3rd party software vendors who offer advanced analytical tools (e.g., machine learning / artificial intelligence (AI) software products) to help further optimize customers' energy usage.

5. Business Case Results – Net Present Value (NPV) and Total Resource Cost (TRC) Test

As previously mentioned, the focus of this financial analysis was on two metrics (NPV and TRC). First, Accenture brought together forecasts for program costs and benefits to understand the overall customer impact. Using the Company provided discount rate, Accenture performed an NPV analysis. Second, Accenture performed a TRC analysis with the following considerations:

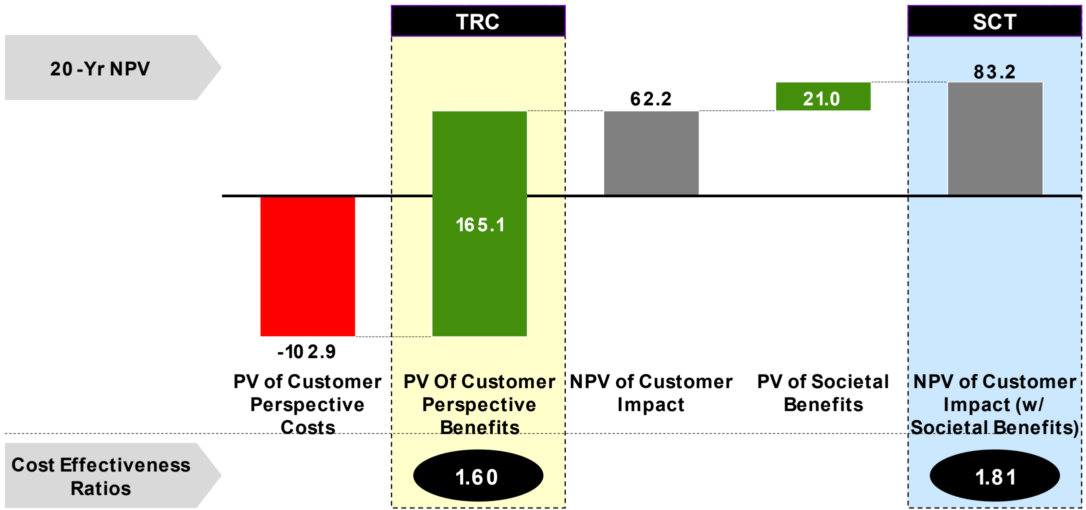
- Accenture notes that TRC is a widely used test in the United States for analyzing cost effectiveness of energy efficiency and other utility programs;
- The objective of this TRC analysis test is to examine efficiency from the viewpoint of an entire service territory;
- It does this by comparing total benefits of avoided power supply costs to the total costs of administering a program and upgrading equipment; and
- When the TRC ratio is greater than 1, this indicates a reduction in the average bill for a customer in the service territory being analyzed. The identified benefits – in the form of reduced O&M expenses and avoided capital costs – outweigh the identified incremental costs associated with the investment.

In addition, based on review of peer AMI business cases in Indiana and Michigan, Accenture has defined the financial forecast period for this analysis to be 20 years.

Per the Company's guidance, the Moderate deployment scenario was defined as follows:

1. Program start date is Q2 2021;
2. Standup program management office (PMO) functions, launch customer engagement programs, and execute information technology (IT) upgrades; and
3. Install meters and communications infrastructure over a 45-month period where deployment is completed by end of 2024

Figure 22: NPV & TRC Test Results



The results of the NPV and TRC analysis associated with the Moderate deployment scenario for the Company's Indiana service territory can be found in Figure 22.

Additionally, as stated earlier, the Company provided guidance on two additional deployment scenarios that were analyzed during this study. Similar to the Moderate scenario, each of these additional deployment scenarios starts in Q2 2021 by standing up key Program Management Office (PMO) functions, launching customer engagement programs and executing information technology (IT) upgrades. Overall, installation of new equipment proceeds as follows for each scenario:

- Accelerated AMI deployment scenario: 27-month deployment period where AMI meters and communications equipment deployment is completed by mid-2023;
- End of Life (EOL) AMI deployment scenario: AMR meters are upgraded to AMI at the end of their 15-year expected average service life such that AMI is deployed over a 15-year period (where full deployment is completed by early 2035).

NPVs calculated for each scenario can be seen in Figure 23 below.

Figure 23: 20-Year NPV by Scenario Breakdown ($, millions)

Scenario	NPV
Accelerated	$62.8m
Moderate	$62.2m
EOL	$52.2m

With respect to the EOL scenario, this analysis shows a lower NPV when evaluating the costs and benefits considered in this analysis. This is largely due to the delay in the realization of identified benefits, the impact to cost by forecast inflation, and higher levels of cost associated with running two metering systems in parallel for the 14 years. Additionally, replacement of AMR meters only at EOL would not permit the Company to achieve efficiencies from synchronizing replacements while also considering meter location while planning meter replacements.

When comparing the Accelerated scenario to the Moderate scenario, the NPV for this scenario is slightly better than the Moderate scenario defined above. That said, this accelerated approach could introduce additional execution risks and risk of cost overruns associated with the breadth of activities that need to get planned, launched, and executed over the coming months. Accenture expects that some of these risks will be mitigated in the Moderate deployment scenario because there will be more time for planning and program launch activities.

6. Conclusion

After considering the results of the AMI business case analysis, it is Accenture's conclusion that the Company's AMI deployment plan as represented by the Moderate AMI deployment scenario is reasonable, financially justified versus the status quo, and valuable for both the service provider (the Company) and its customers. Executing the AMI program plan laid forth in this document will allow I&M to join its fellow peers in modernizing the grid and provide a greater experience for Indiana customers.

7. Appendix

7.1. Financial Details

INDIANA MICHIGAN POWER

Figure 24: NPV and TRC Results for Moderate AMI Deployment Scenario

INDIANA

LT Debt	49.2%
Common Equity	50.8%
Cost of LT Debt	4.3%
Return on Equity	9.7%
Income Tax (federal & state)	25.9%
Pre-tax WACC	7.0%

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Program capital costs	43.9	23.1	22.5	23.3	1.0	1.1	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Avoided capital costs	(15.1)	(5.1)	(4.8)	(2.8)	(3.6)	(3.4)	(28.8)	(3.1)	(1.7)	(1.9)	(2.8)	(2.2)	(3.7)	(2.2)	(2.6)	(2.4)	(2.6)	(2.7)	(3.0)	(3.2)
Net capital expenditures	28.8	18.0	17.7	20.5	(2.6)	(2.3)	(28.1)	(2.5)	(1.1)	(1.2)	(2.1)	(1.6)	(3.0)	(1.5)	(1.9)	(1.7)	(1.8)	(2.0)	(2.2)	(2.4)
Amort for recovery	1.2	3.1	4.2	5.6	6.2	5.5	4.0	3.1	3.0	2.8	2.6	2.4	2.3	2.1	2.0	1.5	0.2	(1.2)	(2.6)	(3.4)
ADIT	(1.7)	(0.3)	(1.0)	(1.3)	(1.1)	(0.7)	0.2	0.8	0.7	0.5	0.5	0.6	0.9	1.2	1.5	1.2	0.7	0.1	(0.2)	(0.4)
Rate Base	25.8	40.4	53.0	66.6	56.7	48.2	16.3	11.5	8.2	4.6	0.4	(3.0)	(7.4)	(9.8)	(12.3)	(14.2)	(15.6)	(16.3)	(16.1)	(15.5)
Net Income	1.3	2.0	2.6	3.3	2.8	2.4	0.8	0.6	0.4	0.2	0.0	(0.1)	(0.4)	(0.5)	(0.6)	(0.7)	(0.8)	(0.8)	(0.8)	(0.8)
Taxes	0.4	0.7	0.9	1.1	1.0	0.8	0.3	0.2	0.1	0.1	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)
EBT	1.7	2.7	3.5	4.4	3.8	3.2	1.1	0.8	0.5	0.3	0.0	(0.2)	(0.5)	(0.7)	(0.8)	(0.9)	(1.0)	(1.1)	(1.1)	(1.0)
Interest	0.5	0.8	1.1	1.4	1.2	1.0	0.3	0.2	0.2	0.1	0.0	(0.1)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
EBIT	2.3	3.5	4.6	5.8	5.0	4.2	1.4	1.0	0.7	0.4	0.0	(0.3)	(0.6)	(0.9)	(1.1)	(1.2)	(1.4)	(1.4)	(1.4)	(1.4)
Depreciation	1.2	3.1	4.2	5.6	6.2	5.5	4.0	3.1	3.0	2.8	2.6	2.4	2.3	2.1	2.0	1.5	0.2	(1.2)	(2.6)	(3.4)
EBITDA	3.5	6.6	8.9	11.4	11.2	9.7	5.4	4.1	3.7	3.2	2.6	2.2	1.6	1.3	1.0	0.2	(1.1)	(2.6)	(4.0)	(4.7)
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New O&M expenses	1.4	4.3	5.2	4.1	4.3	4.4	4.5	6.3	5.7	5.8	5.9	6.0	6.2	6.3	6.4	6.6	6.7	6.9	7.0	7.2
O&M expense savings	-	(1.3)	(3.3)	(4.5)	(5.2)	(5.3)	(5.4)	(5.6)	(5.7)	(5.9)	(6.0)	(6.2)	(6.3)	(6.5)	(6.6)	(6.8)	(7.0)	(7.1)	(7.3)	(7.5)
Energy cost impacts	-	(1.2)	(3.6)	(6.2)	(8.8)	(10.4)	(11.2)	(14.7)	(15.0)	(15.4)	(15.6)	(15.8)	(16.2)	(16.5)	(16.9)	(17.3)	(17.9)	(18.6)	(19.2)	(19.9)
Revenue Requirement	4.9	8.5	7.3	4.7	1.4	(1.6)	(6.7)	(9.9)	(11.4)	(12.3)	(13.0)	(13.7)	(14.7)	(15.4)	(16.1)	(17.3)	(19.3)	(21.5)	(23.5)	(24.9)

NPV OF CUSTOMER IMPACT ($m)	**62.2**

NPV of BENEFITS ($m)	165.1
NPV of COSTS ($m)	102.9
TOTAL RESOURCE COST TEST	**1.60**

Figure 25: CBA Results: Cost Summary for Moderate AMI Deployment Scenario

INDIANA	SUMMARY			20 YEAR FORECASTS																			
Costs ($m)	**20 Yr Total**	**20 Yr NPV**	**15 Yr NPV**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Meter Replacement CAPEX	84.8	72.4	72.4	26.6	19.2	19.2	19.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Meter Comms Upfront CAPEX	7.7	7.2	7.2	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IT Upgrade CAPEX	8.8	7.8	7.8	6.2	0.9	0.2	0.3	0.4	0.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Mgmt Upfront CAPEX	11.3	9.6	9.6	3.4	2.5	2.6	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total Upfront Capital Cost	**112.5**	**96.9**	**96.9**	**43.9**	**22.6**	**22.0**	**22.8**	**0.4**	**0.5**	**0.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Meter Growth CAPEX	2.2	1.1	0.9	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Meter Failure CAPEX	9.7	4.6	3.7	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Sub-Total Ongoing Capital Cost	**12.0**	**5.7**	**4.6**	**0.0**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**
Total Capital Cost	**124.5**	**102.7**	**101.6**	**43.9**	**23.1**	**22.5**	**23.3**	**1.0**	**1.1**	**0.7**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**
Program Mgmt Upfront O&M	0.4	0.4	0.4	0.3	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DLC Program Equipment O&M	3.4	2.9	2.9	0.0	1.7	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total Upfront O&M Expense	**3.8**	**3.2**	**3.2**	**0.3**	**1.7**	**1.7**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Meters Ongoing O&M	19.2	8.9	7.1	0.1	0.3	0.5	0.7	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
Comms Ongoing O&M	1.0	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
IT Ongoing O&M	24.0	12.0	10.0	0.0	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4
Customer Portal Vendor O&M	10.5	5.5	4.7	0.7	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
Sub-Total Ongoing O&M Expense	**54.7**	**26.8**	**22.1**	**0.9**	**1.7**	**2.2**	**2.4**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**	**3.1**	**3.1**	**3.2**	**3.2**	**3.3**	**3.3**
AMI CVR Operations Analyst RTB O&M	2.4	1.1	0.9	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
AMI Revenue Protection RTB O&M	3.3	1.6	1.2	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
AMI Functional Analysts RTB O&M	5.7	2.7	2.1	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
AMI Field Technician RTB O&M	3.3	1.5	1.2	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
DR and TVR Program Mgmt RTB O&M	34.2	15.0	11.3	0.0	0.4	0.7	0.8	0.8	0.9	0.9	2.6	1.9	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.5	2.5	2.6
Customer Portal Admin RTB O&M	3.7	1.8	1.5	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Sub-Total Run-The-Business O&M Expense	**52.6**	**23.7**	**18.3**	**0.2**	**0.8**	**1.3**	**1.6**	**1.7**	**1.8**	**1.8**	**3.5**	**2.8**	**2.9**	**3.0**	**3.1**	**3.2**	**3.3**	**3.4**	**3.5**	**3.6**	**3.7**	**3.8**	**3.9**
Total O&M Expense	**111.1**	**53.8**	**43.6**	**1.4**	**4.3**	**5.2**	**4.1**	**4.3**	**4.4**	**4.5**	**6.3**	**5.7**	**5.8**	**5.9**	**6.0**	**6.2**	**6.3**	**6.4**	**6.6**	**6.7**	**6.9**	**7.0**	**7.2**

Figure 26: CBA Results: Benefit Summary for Moderate AMI Deployment Scenario

INDIANA	SUMMARY			20 YEAR FORECASTS																			
Benefits ($m)	**20 Yr Total**	**20 Yr NPV**	**15 Yr NPV**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Eliminated meter readers	19.8	9.1	7.2	0.0	0.4	0.6	0.8	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.4
Avoided trips related to reconnects due to remote metering	22.1	10.2	8.1	0.0	0.4	0.6	0.9	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5	1.5	1.5
Avoided trips related to disconnects due to remote metering	21.1	9.6	7.5	0.0	0.0	0.6	0.8	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5	1.5
Avoided Trips Related to Disconnect Notices	17.4	8.3	6.8	0.0	0.0	0.6	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Reduced bill estimation / bill exceptions	3.9	1.8	1.4	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Reduced meter investigations (OK on arrival)	3.4	1.6	1.2	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Reduced outage restoration costs	21.8	10.1	7.9	0.0	0.4	0.6	0.9	1.0	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5	1.5	1.5
Avoided Load Research Program Costs	3.1	1.4	1.1	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total - Avoided O&M Expenses	**112.5**	**52.2**	**41.3**	**0.0**	**1.3**	**3.3**	**4.5**	**5.2**	**5.3**	**5.4**	**5.6**	**5.7**	**5.9**	**6.0**	**6.2**	**6.3**	**6.5**	**6.6**	**6.8**	**7.0**	**7.1**	**7.3**	**7.5**
Reduced bad debt expense	17.0	7.9	6.2	0.0	0.0	0.5	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.2
Reduced tamper and theft	47.8	21.3	16.5	0.0	0.0	0.5	1.3	2.2	2.3	2.4	2.7	2.7	2.8	2.8	2.8	2.9	3.0	3.0	3.1	3.2	3.3	3.4	3.4
Eliminate unauthorized Consumption on Inactive Meters (CIM)	3.8	1.7	1.4	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Sub-Total - Revenue Protection	**68.6**	**30.9**	**24.1**	**0.0**	**0.1**	**1.1**	**2.1**	**3.2**	**3.3**	**3.4**	**3.8**	**3.9**	**3.9**	**4.0**	**4.0**	**4.1**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**4.7**	**4.8**
Enhanced VVO	83.4	36.0	27.1	0.0	0.3	0.6	1.3	2.2	3.2	3.7	4.8	5.0	5.3	5.3	5.3	5.4	5.5	5.6	5.7	5.9	6.0	6.2	6.3
Sub-Total - Volt / VAR Optimization	**83.4**	**36.0**	**27.1**	**0.0**	**0.3**	**0.6**	**1.3**	**2.2**	**3.2**	**3.7**	**4.8**	**5.0**	**5.3**	**5.3**	**5.3**	**5.4**	**5.5**	**5.6**	**5.7**	**5.9**	**6.0**	**6.2**	**6.3**
Enable demand response and time variable rates	66.6	29.3	22.4	0.0	0.4	1.1	1.7	2.0	2.4	2.5	3.9	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9
Peak reduction due to EV TOU rates	5.9	2.0	0.8	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.8	1.0	1.3
Enhanced residential customer engagement tools	19.1	8.7	6.8	0.0	0.3	0.4	0.7	0.8	0.8	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4
Enhanced C+I customer engagement tools	9.3	4.0	3.1	0.0	0.0	0.1	0.2	0.3	0.3	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Pre-Pay program benefits	7.5	3.4	2.7	0.0	0.1	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Sub-Total - Rates, Demand Response, and Energy Efficiency	**108.3**	**47.5**	**35.8**	**0.0**	**0.8**	**1.9**	**2.8**	**3.4**	**4.0**	**4.1**	**6.0**	**6.1**	**6.2**	**6.3**	**6.4**	**6.6**	**6.8**	**7.0**	**7.2**	**7.6**	**7.9**	**8.3**	**8.8**
Total - Energy Cost Impact	**260.4**	**114.3**	**86.9**	**0.0**	**1.2**	**3.6**	**6.2**	**8.8**	**10.4**	**11.2**	**14.7**	**15.0**	**15.4**	**15.6**	**15.8**	**16.2**	**16.5**	**16.9**	**17.3**	**17.9**	**18.6**	**19.2**	**19.9**
Avoided AMR meter replacements	53.1	37.8	37.8	14.8	0.7	1.7	0.9	1.4	1.8	27.5	0.1	0.3	0.6	1.0	0.6	1.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Avoided AMR IT support costs	3.9	2.7	2.7	0.0	1.7	0.3	0.0	0.3	0.0	0.3	0.0	0.3	0.0	0.3	0.0	0.3	0.0	0.3	0.0	0.0	0.0	0.0	0.0
Avoided secondary meter for customer DG (RES)	27.5	11.7	8.2	0.3	0.4	0.5	0.7	0.7	0.8	0.8	0.9	1.0	1.1	1.3	1.5	1.7	1.8	2.1	2.1	2.2	2.4	2.5	2.7
Avoided AMR meter replacements - Meter Growth	1.5	0.7	0.6	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Delayed distribution capital cost due to peak reductions	11.5	7.7	7.3	0.0	2.2	2.2	1.1	1.1	0.7	0.1	2.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4
Total - Avoided Capital Costs	**97.4**	**60.6**	**56.5**	**15.1**	**5.1**	**4.8**	**2.8**	**3.6**	**3.4**	**28.8**	**3.1**	**1.7**	**1.9**	**2.8**	**2.2**	**3.7**	**2.2**	**2.6**	**2.4**	**2.6**	**2.7**	**3.0**	**3.2**
Improved customer productivity (Value of Lost Load - VOLL)	43.6	20.7	16.5	0.5	1.0	1.4	1.9	1.9	2.0	2.0	2.1	2.2	2.2	2.3	2.4	2.4	2.5	2.6	2.7	2.7	2.8	2.9	3.0
CO2 emissions reductions	1.0	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total - Societal Benefits	**44.6**	**21.0**	**16.7**	**0.5**	**1.0**	**1.4**	**1.9**	**1.9**	**2.0**	**2.0**	**2.2**	**2.2**	**2.3**	**2.4**	**2.4**	**2.5**	**2.6**	**2.7**	**2.7**	**2.8**	**2.9**	**3.0**	**3.1**