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Dominion Energy®

Petition, Direct Testimony, Exhibits and Schedules of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and condition applicable to electric service

Volume 2 of 3
PUBLIC VERSION

Case No. PUR-2019-00154

Filed: September 30, 2019

Petition of Virginia Electric and Power Company
For approval of a plan for electric distribution grid
Transformation projects pursuant to § 56-585.1 A 6
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WITNESS DIRECT TESTIMONY SUMMARY

Witness: Edward H. Baine

Title: Senior Vice President – Distribution

Summary:

Company Witness Edward H. Baine provides the background and an overview of the Company's proposed plan to transform its electric distribution grid (the "GT Plan" or "Plan"), including the needs driving the Plan and the Company's engagement with customers and stakeholders which drove changes to the Plan. Mr. Baine also addresses the Final Order issued in the 2018 GT Plan proceeding, and explains how the Company addressed issues raised in that order. Finally, Mr. Baine introduces the Company's other witnesses in this proceeding.

As to need, Mr. Baine explains that the Company is proposing the GT Plan to address the current and future needs of the Company's distribution grid in a systematic manner, recognizing and accommodating significant changes in the electric utility industry and changing customer expectations.

Next, Mr. Baine provides an overview of the Commission's findings in the 2018 GT Plan proceeding, and describes the Company's efforts to address the concerns raised by the Commission, its Staff, and other parties to that proceeding.

Mr. Baine next describes the Company's efforts to seek customer feedback and engage stakeholders. Through collaborative conversations with stakeholders, Mr. Baine describes the four common goals for grid transformation that emerged: (i) Optionality; (ii) Sustainability; (iii) Resiliency; and (iv) Affordability.

Mr. Baine next describes the components of the GT Plan, many of which are foundational to a transformed grid: (i) AMI; (ii) CIP; (iii) grid improvements, both grid technologies and grid hardening projects; (iv) telecommunications infrastructure; (v) cyber security; and (vi) the Smart Charging Infrastructure Pilot Program. As Mr. Baine explains, the Company also proposes a customer education plan that touches upon these components.

As Mr. Baine testifies, the GT Plan meets the statutory objectives of the GTSA by facilitating improvements that will make the grid more reliable and resistant while also meeting the increased need for visibility on the grid, which will allow the Company to effectively monitor and operate the evolving and increasingly complex grid infrastructure while incorporating DER, battery storage, EVs, microgrids, and other emerging technologies.

Mr. Baine additionally provides an overview of the costs and benefits of the GT Plan, and provides a list of proposed metrics intended to track the success of the Plan.

Finally, Mr. Baine testifies as to why now is the optimal time for a grid transformation plan.

**DIRECT TESTIMONY
OF
EDWARD H. BAINE
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154**

Q. Please state your name, business address and position of employment.

A. My name is Edward H. Baine and my business address is 600 East Canal Street, Richmond, Virginia 23219. I am Senior Vice President – Distribution for the Power Delivery Group of Dominion Energy, Inc. ("Dominion Energy"). A statement of my background and qualifications is attached as Appendix A.

Q. What are your management responsibilities with respect to Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company")?

A. I am responsible for all facets of Dominion Energy Virginia's regulated electric distribution business that provides electricity to over 2.5 million customer accounts in Virginia, powering the business economy and serving over 5 million residents.

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

A. The purpose of my testimony is to provide background and an overview of the Company's proposed plan to transform its electric distribution grid (the "Grid Transformation Plan," the "GT Plan," or the "Plan"), including the needs driving the Plan and the Company's engagement with customers and stakeholders to refine the Plan. I will also address the Final Order dated January 17, 2019, issued by the State Corporation Commission of Virginia (the "Commission") in Case No. PUR-2018-00100 on the Company's initial filing related to the GT Plan (the "2018 Final Order"), and will explain how the Company has addressed the issues raised by the Commission in that order. Finally, I will introduce the Company's other witnesses in this proceeding.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, EHB, consisting of Schedules 1 and 2, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. Schedule 1 provides an overview of the costs of the GT Plan, and Schedule 2 provides the metrics the Company proposes to track the success of the Plan, along with the Company witnesses who support each metric. The table below provides a description of these schedules:

Schedule	Description
1	Overview of GT Plan Costs
2	Proposed Metrics and Witness Support

I also sponsor certain sections of the Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document.

Q. You mentioned the Plan Document, can you explain the purpose of this document?

A. The Company prepared the Plan Document as an executive summary of the Grid Transformation Plan. The Plan Document guides the reader through the need for grid modernization, the state of the existing distribution system, the development of the GT Plan, an overview of the Plan itself, and the associated customer benefits. The Plan Document also provides an acronym list and glossary that can serve as a quick reference guide for the words and concepts discussed in testimony. It is intended to be a reference document that provides the drivers and solutions that make up the Grid Transformation

Plan, along with the future technologies, plans and programs the Company commits to pursue upon Commission approval of the Plan.

Q. Mr. Baine, how is your testimony organized?

A. My testimony is organized into the following sections:

I. Need for the Grid Transformation Plan

II. Background and Overview of the Grid Transformation Plan

III. The Grid Transformation Plan

IV. Conclusion

I. NEED FOR THE GRID TRANSFORMATION PLAN

Q. Why is the Company proposing the Grid Transformation Plan?

A. The Company is proposing the Grid Transformation Plan to address the current and future needs of the Company's distribution grid in a systematic manner. There is a paradigm shift driven by the needs of our customers, technology, and security that are creating significant changes in our industry.

Q. Please elaborate on the significant changes in the energy industry.

A. Modern society increasingly relies on electronic and connected devices for nearly all functions of daily life, making the electric power grid the critical foundation for practically every aspect of functioning in today's world. Customers are more reliant on electricity than ever before in many ways from education, commerce and health care systems to the banking, communications, and transportation industries. As society has grown more dependent on electricity, so too have the threats to this critical infrastructure, necessitating investments in physical and cyber security that can meet the evolving nature of the threat landscape. In addition, outages caused by severe weather and other events only become more disruptive. While service interruptions have always been an inconvenience, the safe, reliable, and consistent delivery of power has never been more important than it is today and customer expectations for a high level of reliability has intensified.

The demand for electricity generated from renewable energy resources has also increased. In contrast to conventional power sources, renewable energy sources can connect directly to the distribution grid. The distribution grid was originally designed for the one-way flow of electricity—not for the direct connection of generation sources that cause two-way power flow. In the meantime, technology has developed that can provide electric utilities with increased visibility on the current state of their systems, which helps utilities manage two-way power flow and maximize the benefit of distributed energy resources. For example, intelligent grid devices can transmit information to the utility that will allow for visibility and analysis of the real-time status at substations and circuits that support directly connected generation and customer load.

Another significant change is the increased customer demand for information. Many customers want their detailed energy usage information so that they can make informed decisions about their consumption, and they want the flexibility to access that information over different channels of communications. Customers also want more options, such as different rates and choices on when and how to pay their bills. When outages do occur, customers want frequent, up to date information on restoration.

Q. What are the structural limitations of the existing distribution system in light of these significant changes?

A. As noted above, the Company's existing distribution grid was originally designed for one-way delivery of electricity to meet customers' demand—from the substation through the distribution grid to the end-use customer. The existing grid was not designed to effectively integrate the ever-increasing amount of distributed energy resources ("DERs"), such as solar and wind generation, which feed directly into the distribution system. Consequently, the existing grid is fundamentally challenged in adapting to the two-way power flow created by DER. The Company has limited visibility into the distribution grid, and cannot monitor in real-time, or remotely respond to, the effects of these two-way power flows or other voltage stability issues. The existing infrastructure will not support the Company's use of DERs during an outage event.

With Commission approval of Phase IB, the Company will know where the outage occurs, can isolate the outage, and can bring the DERs back online more quickly. With the introduction of DERs on the distribution grid, we cannot think about the grid's performance only in terms of reliability, but must also now take into consideration the impact of the grid's availability (or unavailability) with as much focus as we do with the transmission grid today. Indeed, while the GT Plan is needed to help support the proliferation of DERs on the grid and address any related issues, it also maximizes the benefits for DERs, through reliability, startup power, voltage quality, efficiency and energy transaction. In addition, because DERs rely on the distribution system to deliver the electricity they produce, a resilient distribution system is vital to maximizing the value of DERs.

The majority of the Company's customers are served with automated meter reading ("AMR") meters, which provide after-the-fact total usage once per month. As such, AMR meters do not provide dynamic interval energy usage information to assist customers in making informed and immediate decisions on consumption that can affect the result on their next bill, and that can allow the utility to provide more advanced customer rates. Nor are AMR meters capable of providing the Company with basic information such as outage notifications, leaving the reporting obligation on the customer. Further, the over 20 year-old customer information system on which the Company relies for managing customer accounts is built on antiquated technology that cannot accommodate the incremental volume and complexity of customer interactions, such as billing more complex rate structures, providing rate comparisons, leveraging graphics in bill presentment, or registering multiple contacts with the account for notifications (*e.g.*, business owner, facility manager, and billing administrator).

Q. The Grid Transformation and Security Act of 2018 (the "GTSA") requires that the Company evaluate "[l]ong-term electric distribution grid planning and proposed electric distribution grid transformation projects" as part of its integrated resource planning process. Do you have any comments?

A. The Company has continuously engaged in long-term distribution grid planning since its inception, as any prudent utility must. Company Witness Robert S. Wright, Jr., details the comprehensive analysis that led to the proposed grid improvement solutions proposed herein.

That said, the Company recognizes that its distribution planning must evolve to adapt to the fundamental changes in the energy industry discussed above. To that end, the

Company has attached a white paper as Appendix B to the Plan Document that provides a detailed overview of the Company's current distribution planning process and limitations, the investments needed to evolve the process, and how the Company's integrated distribution planning ("IDP") process will transform over time.

II. BACKGROUND AND OVERVIEW OF THE GRID TRANSFORMATION PLAN

Q. Please provide background related to the Company's Grid Transformation Plan.

A. In 2018, Dominion Energy Virginia developed a 10-year plan to transform its electric distribution grid into a smarter, stronger, and greener grid. The Company developed this plan consistent with the need for such transformation on its grid and the support for transformation efforts by the General Assembly and other stakeholders.

In July 2018, in Case No. PUR-2018-00100, the Company petitioned for approval of the first three years of the Grid Transformation Plan, which was referred to in that filing as "Phase I." Phase I focused on seven components of the overall Grid Transformation Plan: (i) advanced metering infrastructure ("AMI"); (ii) customer information platform ("CIP"); (iii) reliability and resilience; (iv) telecommunications infrastructure; (v) cyber and physical security; (vi) predictive analytics; and (vii) emerging technology.

In January 2019, the Commission issued the 2018 Final Order approving proposed Phase I investments related to cyber and physical security, including supporting telecommunications infrastructure, as reasonable and prudent. The Company will refer to these portions of the GT Plan approved in the 2018 Final Order as "Phase IA" of the GT Plan. Company Witnesses Jonathan S. Bransky and Bradley R. Carroll, Sr., will discuss the approved Phase IA security and telecommunications investments, respectively, including how the Company has differentiated approved and unapproved portions of such investments. The Commission denied the remaining portions of the proposed Phase I, without prejudice to the Company seeking approval of the GT Plan in future petitions and provided additional requirements to incorporate in the next filing through the 2018 Final Order.

Q. Please summarize the findings contained in the 2018 Final Order.

A. The Commission acknowledged on page 15 of the 2018 Final Order that "smart meters and other grid enhancements hold the promise for a true transformation of the grid and for the more efficient consumption of electricity." While the Commission denied the majority of the proposed Phase I investments, it recognized that such expenditures would be reasonable and prudent if "accompanied by a sound and well-crafted plan to fulfill the promise that smart meter technology and grid enhancements offer." The 2018 Final Order provided details on what a sound and well-crafted plan should contain, including "detailed, accurate, and reasonable cost information" (page 9) and "a level of benefits commensurate with the projected costs" (page 14). The 2018 Final Order also indicated that a well-crafted plan should demonstrate the need for the proposed investments, specifically as it relates to reliability and resiliency investments.

Q. What steps did the Company take after it received the 2018 Final Order?

A. Since its issuance, the Company has been working diligently to address the concerns raised by the Commission, its Staff, and other parties to last year's GT Plan proceeding. Among other action items, the Company continued to focus on ensuring that its proposed investments maintained alignment with the statutory objectives of grid transformation—to facilitate integration of distributed energy resources and to enhance physical electric distribution grid reliability and security—as well as the Company's objective to also enhance the customer experience. The Company issued multiple requests for proposals ("RFPs") across programs to strengthen the accuracy and reasonableness of the cost estimates for proposed investments. To refine its cost estimates, the Company also began to prepare the project scopes and designs for the targeted mainfeeder segments on which it proposes grid improvement investments. The Company retained an independent, experienced, third-party partner, West Monroe Partners, to generate a cost-benefit analysis for the GT Plan based on its industry expertise. In addition, the Company solicited customer feedback and convened a series of stakeholder meetings to receive input and feedback on next steps for our Grid Transformation Plan. As a result, the Company has responded to concerns raised on its GT Plan to date from the Commission, its Staff, and stakeholders in a meaningful manner, and has incorporated those results into this filing to the best of its ability.

Q. You mentioned that the Company solicited customer feedback and convened a series of stakeholder meetings. Please elaborate.

A. Dominion Energy Virginia strives to meet its customers' energy needs while providing a seamless customer experience. To that end, the Company frequently seeks feedback from its customers in various forms and forums. The Company has also sought specific feedback to assist in the development of the Grid Transformation Plan. Section V.B of the Plan Document describes this customer engagement.

The Company also convened a series of stakeholder meetings in mid-2019, facilitated by an industry expert, Navigant Consulting, Inc. ("Navigant") that guided the conversation on the stakeholders' vision and objectives for grid transformation. Through collaborative conversations with stakeholders, four common goals for grid transformation emerged: (i) enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access ("Optionality"); (ii) evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles ("Sustainability"); (iii) build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management ("Resiliency"); and (iv) deliver value for customers by optimizing demand and seeking to reduce system and customer costs ("Affordability"). Section V.C of the Plan Document describes how the components of the GT Plan align with these goals.

Q. What is the Company requesting in this proceeding?

A. The Company is requesting approval of the next phase of the Grid Transformation Plan, which the Company will refer to as "Phase IB." Phase IB covers the same period as Phase I in the previous filing—the years 2019, 2020, and 2021. The 2019 costs include activities needed to develop a filing that is consistent with the guidance received from the 2018 Final Order, as well as activities related to the limited installation of smart meters in 2019. The Company then seeks approval of two years of GT Plan investments, those for 2020 and 2021.

Q. What are the components of Phase IB of the GT Plan?

A. Phase IB focuses on six components of the Grid Transformation Plan, many of which are foundational to a transformed grid: (i) AMI; (ii) CIP; (iii) grid improvements; (iv) telecommunications infrastructure; (v) cyber security; and (vi) the Smart Charging Infrastructure Pilot Program. The Company also proposes a customer education plan that touches upon each of these components. Building on the foundational components of the previous filing, the Company developed detailed cost estimates for the investments based on responses to RFPs and renegotiating existing contracts; incorporated feedback from stakeholders and customers; completed project designs and scopes in order to provide more detail regarding the solutions proposed for grid improvements; and completed a cost-benefit analysis that included future programs that will leverage the proposed GT Plan components. The comprehensive GT Plan proposed herein is the result of this work and represents the Company's commitment to execute the proposed components and future programs with Commission approval.

III. THE GRID TRANSFORMATION PLAN

Q. What are the statutory objectives for grid transformation?

A. I am not a lawyer, however, my understanding of the statutory objectives for grid transformation, as provided in the policy direction given by the General Assembly, are to facilitate integration of distributed energy resources and to enhance physical electric distribution grid reliability and security.

Q. How does the proposed Grid Transformation Plan meet these objectives?

A. The Grid Transformation Plan will facilitate integration of DER and will enhance physical electric distribution grid reliability and security by enabling connectivity between intelligent grid devices, control centers, automated control systems, distributed energy resources, electric vehicle ("EV") infrastructure, and supporting technologies. The Plan also includes activities to harden the grid. Together, these improvements will result in a modernized and interconnected distribution grid that is available and allows for proactive management of assets, prevents certain outages on hardened feeders, and enables speedier recovery times when outage events and storms do occur. These improvements will make the grid more reliable and resilient while also meeting the increased need for visibility on the grid, which will allow the Company to effectively monitor and operate the evolving and increasingly complex grid infrastructure while incorporating DER, battery storage, EVs, microgrids, and the Smart Charging Infrastructure Pilot Program.

This increased visibility provided by AMI, intelligent grid devices, and automated systems, when paired with a more resilient grid, in turn will enable the Company to effectively interconnect and operate the grid with DER, ensuring that the intermittent output from these resources does not pose threats to voltage stability and system operations and reliability, while also optimizing the output from these resources with the grid being more available. The investments proposed in the GT Plan will also provide the Company with more options to integrate a wide range of emerging technologies. For example, electric vehicles continue to gain popularity. A transformed grid will allow the Company to intelligently manage the increased demand for electricity needed to charge electric vehicles and incorporate batteries and microgrids in a manner that benefits all customers.

Q. **Beyond the statutory objectives for grid transformation, does the GT Plan meet the goals for grid transformation identified through the stakeholder process?**

A. Yes, it does. For similar reasons as just described, and as further discussed in Section VI.C of the Plan Document, the proposed Grid Transformation Plan investments meet the goals of Optionality, Sustainability, Resiliency, and Affordability.

Q. Please provide an overview of the proposed Phase IB of the GT Plan.

A. Phase IB of the Plan will focus on installing the foundational infrastructure that is required to create a transformed grid. Vitally, the Company plans to fully deploy AMI across its service territory. At the same time, the Company proposes to begin the transition to a new CIP. Together, AMI and the CIP will unlock a host of benefits to the Company and its customers, from operational efficiency to time-varying rates to energy efficiency and targeted demand-side management programs.

In conjunction with AMI and CIP, the Company also has plans to invest in grid improvements, focusing on both grid technologies and grid hardening. For example, the Company proposes to install a self-healing grid, which includes technologies and systems that automate power restoration, reducing both the impact and length of power interruptions. During this process, the Company will also focus on grid resiliency by, for example, hardening mainfeeders and proactively upgrading equipment.

All of these investments require robust telecommunications and security infrastructure, and such accompanying investments are included in Phase IB.

Finally, the Company proposes specific investments related to EVs. Specifically, the Company proposes investments in EV infrastructure targeting different customer segments, including transit bus charging, direct current ("DC") fast charging, workplace charging, multi-family residential charging, and rideshare charging.

Throughout the Grid Transformation Plan, educating customers is of primary importance, including education about the grid transformation process and its benefits, about the associated projects and investments, and about when and how they can fully utilize the new capabilities and benefits of the transformed distribution grid. Section VI.A.7 of the Plan Document describes the Company's plans for customer education across all the Plan components.

Q. What are the costs proposed for Phase IB of the GT Plan?

A. The forecasted total proposed investment estimate associated with Phase IB of the Grid Transformation Plan is shown in Table 1 below in capital investment and operations and maintenance ("O&M") investment.

Table 1. Phase IB Capital & O&M Investments

Nominal $, in Millions	**2019**	**2020**	**2021**	
	Year 1	**Year 2**	**Year 3**	**3-year Total**
Phase IA	$8.5	$17.9	$37.0	$63.3
Capital	$7.3	$17.7	$36.5	$61.4
O&M	$1.2	$0.2	$0.5	$1.9
Phase IB	$39.4	$246.8	$307.3	$593.4
Capital	$26.8	$218.4	$265.4	$510.5
O&M	$12.6	$28.4	$41.9	$83.0

Additional details are provided in my Schedule 1. The Company's other witnesses will support and provide further detail on these costs, and will describe the robust process for how the cost estimates were created.

Q. What are the benefits of the Grid Transformation Plan?

A. The quantitative benefits of the GT Plan can be grouped into two general categories: customer benefits and additional benefits. Quantitative customer benefits include reliability improvements, energy and demand savings, avoided capital, avoided O&M, and reduction of bad debt and energy diversion. The cost-benefit analysis ("CBA") shows the proposed investments are beneficial to customers and represent a positive business case from a financial perspective providing over $3 billion of customer benefits, which represents net benefit to customers of approximately $322.5 million all on a net present value basis. Additional quantitative benefits include reduced greenhouse gas ("GHG") emissions, increased EV ownership savings, and positive economic development impacts. Some of the benefits derive from programs and offerings that the Company intends to implement, including a time-varying rate, a peak time rebate program, a prepay program, and a program related to residential EV use. Including these in the cost-benefit analysis reflects the Company's commitment to these programs and offerings.

Beyond these quantifiable benefits, the GT Plan will provide many qualitative benefits, like avoiding a cyberattack; providing resilient service to critical services and infrastructure like homeland security, large medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pump facilities; and providing customers with accurate and timely information that can impact their choices to use energy.

Q. Based on the costs and benefits of the GT Plan, do you believe that the projects associated with Phase IB, including the estimated costs, should be found reasonable and prudent by the Commission?

A. Yes, I do. As I mentioned earlier, the Company retained West Monroe Partners ("West Monroe") to complete a CBA for the GT Plan. Company Witness Thomas Hulsebosch presents testimony explaining that analysis and presenting the results. As sponsored by Mr. Hulsebosch, the proposed investments are beneficial to customers and represent a positive business case from a financial perspective, even considering only benefits to customers. Indeed, as further described by Mr. Hulsebosch, this benefit estimate may be conservative. Mr. Hulsebosch also shows additional benefits like reduced GHG emissions, savings to EV owners and economic benefits.

Q. Does the Company intend to establish performance metrics to track the success of the GT Plan?

A. Yes. A list of proposed metrics is attached as my Schedule 2. As reflected therein, the specific metrics are sponsored by other Company witnesses by component. The Company will continue to work with Staff to refine the list to determine the ultimate performance metrics to be approved by the Commission that the Company will use to track the GT Plan's success.

Q. How does the Company intend to report on these metrics?

A. The Company proposes to submit an annual report on the progress of the Grid Transformation Plan by April 30 of each year for the prior calendar year, starting in 2021. The Company also plans to continue stakeholder engagement on the GT Plan in the future. The Company intends to work with stakeholders to determine the best structure, process, and cadence of stakeholder meetings going forward.

IV. CONCLUSION

Q. Why is now an optimal time for a grid transformation plan?

A. The time is right for numerous reasons. Our customers are expecting different interactions, services, and offerings from our Company. We need to deliver for our customers. In addition, costs for the relevant technologies have decreased as peer utilities across the country have worked to transform their distribution grids. The Company has talked to our peer utilities and has learned from their experiences. Additionally, the Company has tested certain components of the GT Plan on a smaller scale. The Company used this knowledge to develop the GT Plan, ensuring that its investments will be reasonable and prudent for our customers.

Further, the General Assembly has recognized the importance of investments to transform the electric distribution grid in the Commonwealth with the passage of the GTSA, identifying such qualifying investments as being in the public interest. These investments will be critical to prepare for the significant growth in intermittent renewable generation resources, also signaled by the GTSA, with up to 5,500 MW of new renewable generation in the public interest, 500 MW of which is specifically focused on small-scale DER development. Recent policy direction will continue to fuel the exponential growth the Company has experienced in new DER interconnection, even since the 2018 GT Plan filing. In 2019 alone, the Company has already interconnected more than 1,700 new Net Energy Metering ("NEM") customers, representing over 16 MW of new NEM capacity, nearly a 100% increase over the same period last year. As the proliferation of DERs and two-way power flows continues in the Commonwealth, we must plan accordingly.

Indeed, the Governor's recent issuance of Executive Order 43 ("EO 43")[1] recognizes the beginning of grid transformation and through executive action provides guidelines for expanding access to clean energy that are dependent upon a modern, transformed grid.

[1] Commonwealth of Virginia, *Executive Order Number Forty-Three (2019): Expanding Access to Clean Energy and Growing the Clean Energy Jobs of the Future*, September 16, 2019.

Specifically, EO 43 requires the Commonwealth to develop a plan to produce thirty percent of Virginia's electricity from renewable energy sources by 2030 and by 2050 to obtain one hundred percent of the Commonwealth's electricity needs from carbon-free sources. The Company has declared its support for the bold targets established by EO 43 and recognizes that the GTSA paves the way for achieving them. The Phase IB investments proposed in today's filing are necessary to lay the foundation essential to reaching objectives and timeline established by EO 43.

Additionally, the General Assembly has continued to recognize the need for grid transformation, passing additional legislation through Senate Bill 1769 in the 2019 Session concerning dynamic rate structures that assumed foundational investments in AMI and the CIP. In the end, we believe that the public policy underlying the GTSA is of critical importance to our customers and the Commonwealth overall. The Company's GT Plan will take a strategic approach to deploy these interdependent and coordinated offerings that will result in a smarter, stronger, and greener electric distribution grid. The Plan will benefit our customers, and will address the current and future needs driven from this paradigm shift.

Q. Please introduce the other Company witnesses in this proceeding.

A. The Company is presenting the following additional witnesses:

- Thomas G. Hulsebosch, Senior Managing Director for Energy and Utilities with West Monroe Partners, presents the cost-benefit analysis for the Grid Transformation Plan.

- Nathan J. Frost, Director of New Technology and Energy Conservation, provides details on the Company's plan to deploy AMI across its service territory, the proposed opt-out policy, and the Company's plan for customer education consistent with the 2018 Final Order. Company Witness Frost will also discuss the Smart Charging Infrastructure Pilot Program.

- Thomas J. Arruda, Director of Customer Information Platform, describes the CIP that the Company plans to deploy to transform the customer experience.

- Robert S. Wright, Jr., Director of Distribution Grid Planning and Asset Management, explains the grid improvement investments that the Company proposes for Phase IB of the GT Plan. Company Witness Wright also supports the Company's plans to evolve toward an integrated distribution planning process.

- Bradley R. Carroll, Sr., Director of IT Infrastructure, describes the development and proposed execution of new telecommunications infrastructure enabling the functionality of the other components of the GT Plan for Phase IB. Company Witness Carroll will also differentiate between approved Phase IA and proposed Phase IB telecommunications investments.

- Jonathan S. Bransky, Director of Threat Intelligence, describes the cyber controls that the Company plans to deploy as part of the GT Plan for Phase IB. Company Witness Bransky will also differentiate between approved Phase IA and proposed Phase IB security investments.

- Gregory J. Morgan, General Manager of Regulatory Affairs, addresses the proposed rate treatment of certain GT Plan components and provides a Phase I revenue requirement and estimated rate impact. He also discusses the Company's plan to propose time-varying rates consistent with the process envisioned by recent legislation. Finally, Company Witness Morgan supports the requested tariff approval related to smart meter opt out.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

Appendix A

BACKGROUND AND QUALIFICATIONS
OF
EDWARD H. BAINE

Edward H. Baine is Senior Vice President – Distribution for the Power Delivery Group of Dominion Energy, Inc. ("Dominion Energy"). He is responsible for all facets of Dominion Energy's regulated electric distribution business that provides electricity to about 2.6 million customer accounts in Virginia and northeastern North Carolina.

Mr. Baine joined Dominion Energy in 1995 as an associate engineer and has held numerous engineering, operational, and management positions within the Company. In 2006, he was named Director – Electric Distribution Operations Centers. He was promoted to Vice President – Shared Services, effective July 1, 2009, and was named Vice President – Fossil & Hydro Merchant Operations in January 2012. He was named Vice President – Power Generation System Operations in July 2013 and Senior Vice President – Transmission & Customer Service in June 2015. He assumed his current post in February 2016.

Mr. Baine is a member of the boards of directors of the Dominion Energy Credit Union, Chamber RVA, Venture Richmond, and the Capital Region Collaborative. He is also a member of the Board of Visitors of Virginia Tech. Mr. Baine also serves on the board of the Chesterfield Public Education Foundation. In addition, Mr. Baine serves on the boards of directors of SEE, the Virginia Tech Athletic Fund, MEGA Mentors, and the Valentine Museum, as well as the EEI National Response and AEIC Power Delivery executive committees.

Mr. Baine earned his bachelor's degree in electrical engineering from Virginia Tech and completed the advanced management program at Duke University's Fuqua School of Business. He is a registered professional engineer in Virginia.

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Capital Expenditures Summary (GTP)

(Nominal dollars, in millions)

	2019	2020	2021		
	Yr 1	Yr 2	Yr 3	3-yr Total	10-yr Total
Advanced Metering Infrastructure (AMI)	$14.9	$71.9	$100.3	$187.0	$394.4
Customer Information Platform / Meter Data Management (CIP/MDM)	$7.3	$38.4	$45.2	$90.8	$197.7
Stakeholder Engagement & Customer Education	-	-	-	-	-
Telecommunications	$6.4	$65.2	$66.0	$137.6	$453.2
Grid Technologies	$2.5	$31.9	$21.3	$55.6	$452.0
Grid Hardening	$2.2	$20.9	$61.3	$84.5	$1,233.2
Cyber Security	-	$2.9	$1.9	$4.8	$20.9
Physical Security	$0.9	$3.5	$3.5	$7.9	$50.7
Transportation Electrification *(GTP Programs Only)*	-	$1.5	$2.4	$3.8	$7.3
Total Capital Expenditures:	$34.0	$236.0	$301.9	$571.9	$2,809.5
Total Capital Expenditures (Phase 1B):	$26.8	$218.4	$265.4	$510.5	

Projected Capital Expenditures inclusive of GTP programs only

O&M Expenditures Summary (GTP)

(Nominal dollars, in millions)

	2019 Yr 1	2020 Yr 2	2021 Yr 3	3-yr Total	10-yr Total
Advanced Metering Infrastructure (AMI)	$1.9	$3.0	$4.6	$9.6	$53.9
Customer Information Platform / Meter Data Management (CIP/MDM)	$4.2	$8.7	$10.8	$23.7	$160.3
Stakeholder Engagement & Customer Education	$0.0	$1.4	$1.8	$3.2	$11.1
Telecommunications	$1.2	$2.3	$2.9	$6.3	$74.4
Grid Technologies	-	$1.1	$1.8	$2.9	$45.2
Grid Hardening	$6.0	$6.2	$8.1	$20.3	$36.7
Cyber Security	-	$0.9	$1.4	$2.3	$32.1
Physical Security	$0.0	$0.1	$0.2	$0.3	$5.2
Transportation Electrification *(GTP Programs Only)*	$0.4	$4.9	$10.9	$16.2	$33.5
Total O&M Expenditures:	$13.8	$28.6	$42.4	$84.9	$452.4
Total O&M Expenditures (Phase 1B):	$12.6	$28.4	$41.9	$83.0	

Projected Operating Expenditures inclusive of GTP programs only

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Proposed Metrics and Witness Support

Benefit Category	Company Identified Benefit	Metric[1]	Witness(es)
Improved Customer Experience	Reduce outage events, including self-healing	SAIDI / SAIFI	Wright
		# of outages and minutes avoided	Wright
	Reduce number of customers affected by outages	# of equipment health issues proactively detected by AMI & automated control systems	Frost / Wright
		# and % of outages detected remotely by AMI and automated control systems	Frost / Wright
	Faster restoration time (shorter outage durations)	Customer minutes of interruption	Wright
		Restoration time for major events	Wright
	Improved support for Distributed Energy Resource (DER) integration	# of events where Company DERMS adjusted/changed DER operational modes to maintain distribution grid reliability	Wright
		# of DER interconnection requests received, Small Generator Interconnection Agreements (SGIA) completed, and average time to complete SGIA from receipt of electric inspection	Wright
		Total number of DER customers and interconnected MW capacity	Wright
	Reduced likelihood of successful cyber & physical attacks	# of cyber or physical security events associated with GT Plan that require further investigation or analysis.	Bransky
		# of mandatory cyber and physical security incident reports sent to federal agencies	Bransky
	Modernized customer relationship by delivering better information and value to each customer	Outage Center app	Arruda
		What-if Analysis / Rate Comparison by 2023	
		e-Bill upgrade to include graphical usage information by 2023	
		Notification & Alert Options through preferred channel by 2023	
		Account specific details on charges available to customers within online portal by 2023	
		Bill re-design by 2024	
		Average monthly number of bills requiring manual intervention	
		# of transactions for new capabilities delivered	
	Reduced service order completion times	# of remote service orders executed (turn ON/OFF)	Frost
		% of total service orders executed remotely (turn ON/OFF)	Frost
		# of same-day service orders completed	Frost
	New rate structures	# of customers enrolled in opt-in time-varying rate programs	Morgan
	Expanded set of self-service options and digital communication channels	List of digital communication channels introduced	Arruda
	Smart Charging Infrastructure Pilot Program	# of rebates by customer type and $ deployed	Frost
	Customer Education	# of direct communications	Frost
		# of digital impressions	Frost
		# of public meetings and events	Frost
Reduced Components of Cost of Service	Field labor savings (incl. reduced truck rolls, # of personnel)	# Ton/Toffs/CNPs	Frost
		# reduced Found Ons	Wright
		Restoration OT Hrs	Wright
	Reduced storm damage restoration costs	Storm related tree trimming expenses	Wright
		# of truck rolls	Wright
	Better management of energy diversion	Annual energy diversion recovery ($)	Frost
		Annual energy diversion expenses ($)	Frost
		# of identified energy diversion customers / incidents	Frost
	Improved billing & meter read rate accuracy	# of escalated bill-related customer complaints	Arruda
		# of monthly bills estimated	Frost

[1] *Metrics will be reported once available, to the extent enabling infrastructure / technology is deployed and twelve months of data is obtained*

part 6

19950002

Hulsebosch

<u>WITNESS DIRECT TESTIMONY SUMMARY</u>

<u>Witness</u>: Thomas G. Hulsebosch

<u>Title</u>: Senior Managing Director with West Monroe Partners, LLC

<u>Summary</u>:

Thomas G. Hulsebosch with West Monroe Partners, LLC ("West Monroe") testifies on behalf of the Company regarding the cost-benefits analysis ("CBA") for the Grid Transformation Plan.

Mr. Hulsebosch first describes the general process and structure of the CBA and summarizes the results of the CBA. He testifies that the benefits of the GT Plan exceed the costs and demonstrate a positive benefit/cost ratio. The CBA thus represents a positive business case from a financial perspective, providing over $3 billion of customer benefits, which represents net benefit to customers of approximately $322.5 million all on a net present value basis.

Next, he outlines the methodology used by West Monroe for valuation of the projected costs and benefits for GT Plan. For costs, West Monroe coordinated with the Company to capture and input capital and O&M costs associated with delivering the GT Plan, including internal and external labor, equipment, software, hardware, and services. West Monroe benchmarked the cost inputs based on industry experience and perspective from similar efforts. For benefits, the nature and value of the customer benefits from the GT Plan have been provided by the Company witnesses who support the individual GT Plan components. Customer benefits are categorized as (1) Total Avoided / Deferred Capital, (2) Total O&M Savings, (3) Total Energy / Demand Benefit, (4) Total Improved Reliability Benefit, and (5) Total Reduction of Bad Debt and Energy Diversion. Additional benefits for GHG reduction, EV ownership savings, and economic impact are separately included in the CBA as "additional benefits."

Finally, Mr. Hulsebosch provides relevant industry perspective and context regarding the GT Plan. He addresses obsolescence concerns of Grid Transformation-related technologies and investments generally, and specifically regarding AMI technology. He notes that the status of AMI Deployment across the United States and the Company's past experience with solid-state meters that have communications devices also provides evidence and support that this technology is not at risk of near-term obsolescence. He provides a white paper with additional details in this area.

DIRECT TESTIMONY
OF
THOMAS G. HULSEBOSCH
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, position of employment and business address

A. My name is Tom Hulsebosch, and I am employed by West Monroe Partners, LLC ("West Monroe") as a Senior Managing Director for the Energy and Utilities practice. My business address is 5910 North Central Expressway, Suite 950, Dallas, Texas 95206.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") with respect to its plan to transform its electric distribution grid (the "Grid Transformation Plan," the "GT Plan," or the "Plan").

Q. Please describe your area of responsibility as it relates to this proceeding.

A. I am a member of the West Monroe Executive team and a member of the board of directors. I help utilities to develop their strategies and projects for grid modernization to optimize costs and benefits based on their unique operating conditions. My team and I work with utilities across the United States and Europe on grid modernization cost benefit analyses, and I have personally worked on more than 20 utility modernization analyses over the past ten years. These efforts have resulted in the refined approach used to quantify the benefits to society, customers, and operations for the Company's Grid Transformation Plan. Additionally, my team and I have supported the implementation and execution of grid modernization programs similar to the GT Plan, to realize the anticipated benefits. This end-to-end experience has informed our approach to cost-benefit analysis and enabled our team to continuously improve accuracy. A statement of my background and qualifications is attached in Appendix A.

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

A. West Monroe has worked with the Company to complete a comprehensive cost-benefits analysis ("CBA") for the Grid Transformation Plan. The purpose of my testimony is to describe the general process and structure of the CBA, as well as the cost and benefit inputs and other information provide to West Monroe by the Company, and to support and explain certain customer and societal benefits that I calculated that are associated with the GT Plan. I will also summarize the results of the CBA and provide relevant industry perspective and context regarding the GT Plan.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, TGH, consisting of Schedules 1 through 5, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules:

Schedule	Description
1	GT Plan Costs
2	Quantitative Customer Benefits of the Grid Transformation Plan
3	Additional Benefits of the Grid Transformation Plan
4	GT Plan Deployment Timeline Summary
5	AMI Obsolescence White Paper

I also sponsor certain sections of Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. CBA Results and Process Summary

II. Quantified Customer Benefits

III. Additional GT Plan Benefits

IV. Obsolescence Considerations

I. CBA RESULTS AND PROCESS SUMMARY

Q. Before you discuss the process for developing the CBA, what are the results of the CBA for the planned GT Plan investments?

A. Figure 1 below illustrates the projected benefits, costs, net present value ("NPV"), and benefit/cost ratio of the GT Plan. Additional benefits related to greenhouse gas ("GHG") emission reductions, electric vehicle ("EV") ownership savings, and overall economic investment impacts are also displayed in this figure as "Additional."

Figure 1

Cost/Benefit Summary (Revenue Requirement Basis)

(in Millions)

BENEFITS & COSTS	PV[1]
BENEFITS *(Asset Life)*:	
Customer	**$3,026.1**
Avoided/Deferred Capital	$375.6
O&M Savings	$265.9
Energy & Demand Savings	$237.5
Improved Reliability	$2,028.1
Reduction of Bad Debt & Energy Diversion	$118.9
COSTS *(Revenue Requirement)* :	**$2,703.6**
Total Net Benefit (Cost):	**$322.5**
Total Benefit/Cost Ratio:	**1.1**

[1]Present Value (NPV) calculated using Weighted Average Cost of Capital (WACC) of 7.62%

	PV[1]
Additional Benefits	**$85.3**
Reduced GHG	$4.1
EV Ownership Savings[2]	$81.2
Economic Impact[3]	$2,829.0
Total + Additional Net Benefit (Cost):	**$407.8**
Total + Additional Benefit/Cost Ratio:	**1.2**

[2]Adjusted to apply 7.2% benefits correlation factor to reduction

[3] Economic Benefits are neither included in the Total + Additional Net Benefit nor in the Total + Additional Benefit/Cost Ratio

Jobs Creation[4]	
Indirect Jobs	17,228
Direct Jobs	4,540

[4]Jobs creation is calculated using a multiplier applied to Millions of $ in Capital Spend (PV)

As can be seen in Figure 1, the benefits of the GT Plan exceed the costs and demonstrate a positive benefit/cost ratio. The CBA thus represents a positive business case from a financial perspective, providing over $3 billion of customer benefits, which represents net benefit to customers of approximately $322.5 million all on a net present value basis. The additional benefits are presented because they are quantifiable, legitimate and reflect benefits to society and individual participants through reduced GHG emissions, savings to EV owners and general economic benefits from the investments made in the GT Plan. The additional benefits have been aggregated and shown separately because they can be considered incremental to the "total" benefits and because they are not tied to benefits that directly impact customers through reduced costs.

Q. What methodology did West Monroe employ in completing the CBA?

A. West Monroe leveraged an established methodology for valuation of the projected costs and benefits for large grid transformation projects. For costs, West Monroe coordinated with the Company to capture and input capital and operations and maintenance ("O&M") costs associated with delivering the GT Plan, including internal and external labor, equipment, software, hardware, and services. For each cost component, the Company provided cost data inputs, unit costs, assumptions, and other information. In the pre-filed direct testimony of the Company witnesses who support individual GT Plan components, they provide the process they underwent to develop the costs whether that be through existing contracts that underwent competitive procurement or new requests for proposals that have led to or will lead to new competitively bid contracts. The individual Company witnesses, therefore, support the reasonableness of the costs of the individual components of the GT Plan. West Monroe, however, benchmarked the cost inputs based on industry experience and perspective from similar efforts. The benchmarking process helped balance scope and investment to match anticipated benefits based on the experience of other utilities. The cost information served as one input to the CBA, which also considers projected annual costs and ongoing operational impacts, and applies inflation and other escalation factors, as appropriate.

As for the benefits calculations provided by the Company, the nature and value of the customer benefits from the GT Plan have been provided by the Company witnesses who support the individual GT Plan components. My Schedule 2 provides a summary of the categories of benefits included in the CBA as well as the sponsoring witness for that benefit calculation. At a summary-level, the customer benefits are categorized as (1) Total Avoided / Deferred Capital, (2) Total O&M Savings, (3) Total Energy / Demand Benefit, (4) Total Improved Reliability Benefit, and (5) Total Reduction of Bad Debt and Energy Diversion.

Again, additional benefits for GHG reduction, EV ownership savings, and economic impact are separately included as "additional" benefits, and I explain how those additional benefits were calculated in more detail later in my testimony. My Schedule 3 provides the calculation for these categories.

Q. Over what period of time are the benefits projected to be delivered to customers?

A. Benefit realization for customers will begin as soon as the GT Plan deployments start and will continue to be delivered in the years and decades that follow. The CBA accounts for deployment dates and the expected useable life of the individual asset being deployed. In other words, once an asset is deployed, the benefit stream tied to it is projected to be realized only from that starting point and during the expected life. My Schedule 4 provides a Deployment Timeline Summary for the GT components.

Q. Please further describe the role that West Monroe played in the calculation of these benefits within the CBA?

A. For each scope area, West Monroe facilitated internal working group workshops with the

Company to identify the specific inputs and data points that would be needed to project the calculation of benefits. In some cases, the benefit values were provided directly to West Monroe and input into the analysis without modification. In other cases, information was provided and additional work was undertaken using established tools, relevant industry knowledge and experience, benchmarking, and other analysis to complete the projection of benefit and incorporate it into the CBA. It should be noted that the overall benefit projections assume that all elements of the GT Plan will be approved.

Q. Has this methodology used for the CBA been leveraged for similar utility investments in other jurisdictions?

A. Yes. The West Monroe CBA has been leveraged by many utilities over the last 10+ years. This includes as a key component of Department of Energy ("DOE") Grant Applications that were selected for award, utility modernization approvals for municipalities across the U.S., formal grid modernization hearings in Massachusetts, Ohio, and California, and multiple internal prudency and benefit cost reviews by utilities across the country.

Q. The costs in Figure 1 are presented on a revenue requirement basis. Please explain.

A. To develop a more comprehensive view of the planned investments, GT Plan costs were provided to Company Witness Gregory J. Morgan in order to calculate costs of a revenue requirement basis. Company Witness Morgan provided the revenue requirement calculations for the GT Plan investments that became inputs into the CBA. Please note, there are differences between the CBA revenue requirement and the revenue requirement presented by Company Witness Morgan, as discussed in his testimony.

Q. Please provide a summary of the investments that are included in the CBA.

A. Detailed cost information for the GT Plan as pertinent to the CBA is provided in my Schedule 1.

West Monroe received detailed cost information by component and sub-component. Please note the CBA includes certain costs and benefits associated with Programs for which the Company is not seeking approval in this proceeding but have benefits that are enabled by GT Plan investments. These include time-varying rates, peak time rebate, prepay, and the Single-Family Residential charging program (Managed Charging) component of the Electric Vehicle program. Accordingly, my Schedules 1-3 include the comprehensive view of all associated costs and benefits; Company Witness Edward H. Baine provides a cost schedule (his Schedule 1) that is specific to what the Company is seeking approval of in this proceeding.

II. QUANTIFIED CUSTOMER BENEFITS

<u>(1) Total Avoided / Deferred Capital</u>

Q. Please explain how the benefits associated with total avoided / deferred capital as presented in the CBA were derived.

A. West Monroe worked with the Company to identify the previously planned investments that would be avoided or deferred as a result of investments within the GT Plan scope. This analysis was based on Company operating history and previously existing plans if the GT Plan were not to move forward. The Company provided details for a wide range of investment types that would be avoided or deferred, including equipment, IT mainframe costs, distribution infrastructure, and others. As noted in Figure 1, the total benefits associated with avoided / deferred capital are approximately $376 million (NPV) over the asset life of the proposed investments.

<u>(2) Total O&M Savings</u>

Q. Please explain how the benefits associated with total O&M savings as presented in the CBA were derived.

A. West Monroe worked with the Company to identify areas of O&M spend that would be eliminated as a result of investments within the GT Plan scope. This analysis was based on Company operating history and existing budgets if the GT Plan were not to move forward. The Company provided these O&M savings details for areas such as AMR meter reading and meter serving costs, AMR and meter servicing vehicle costs, and other avoided truck rolls and operational improvements. As noted in Figure 1, the total benefits associated with O&M savings are approximately $266 million (NPV) over the asset life of the proposed investments.

<u>(3) Total Energy / Demand Benefit</u>

Q. Please explain how the benefits associated with total energy / demand benefit as presented in the CBA were derived.

A. Several of the GT Plan investments will result in the reduction of energy and demand across the Dominion Energy Virginia distribution system, including managed charging of transportation electrification, advanced rates, such as time-varying rates and peak time rebates ("PTR"), prepay, and voltage optimization. For the transportation electrification component of this benefit, West Monroe worked closely with the Company to determine the impact of the scope areas defined under GT Plan, projected behavior and adoption levels of customers in Virginia based on research and data provided by a third-party consultant to the Company, and the cost of energy to determine the system impact of leveraging managed electric vehicle charging versus the current unmanaged approach to electric vehicle charging, including the impact on peak demand system capacity savings.

The estimated population of EVs in the Company's service territory feeds the savings achieved through forecasting the impact of intelligent / managed EV charging for energy and demand relative to unmanaged EV charging. West Monroe collaborated with the Company to perform analysis comparing the system and energy impacts of EV proliferation with and without the Company taking action to improve efficiency and costs with intelligent and managed charging. The differences in those two scenarios (managed vs. unmanaged) is the benefit delivered via intelligent / managed charging programs by the Company. Managed EV charging is modeled to begin in 2020. The quantified energy and demand savings are then multiplied by electricity and capacity price forecasts, respectively.

For the time-varying rates component of this benefit, the demand savings projections were calculated based on a gradual escalation, linked to the full implementation of AMI for time-varying rate and program penetration and participation levels discussed by Company Witness Morgan modeled to begin in 2020 for the experimental portion, and 2025 for the expanded offering. The costs for energy and demand are then multiplied by the quantified energy and demand reductions from the time-varying rates to calculate demand savings.

Similarly, there are energy and demand savings associated with the proposed residential PTR program based on program penetration and anticipated customer behavior. For this opt-in program, the Company would be offering a rebate to customers based on their reduced usage during PTR events that are called during periods of peak energy usage. The demand and energy reductions associated with this program are anticipated to begin in 2026 following deployment of AMI and assume an initial adoption rate of 2%, growing to a peak of 11% by year 2034. The assumed participation level in the program is 50%, and the CBA assumes 10 events to be called per year (5 in the winter and 5 in the summer).

As noted in the testimony of Company Witness Nathan J. Frost, the Company plans to deploy a prepay program that will allow customers to more closely manage their energy consumption by establishing self-imposed limits on energy consumption by prepaying their electric utility bill. Published studies of prepay programs have shown energy and demand reductions for customers that use this program. The energy and demand savings of prepay, which are calculated based on an assumed escalation of adoption following the full implementation of AMI, eventually peaking at 5% of eligible customers. The projected benefit modeled to begin in 2026 of 10% reduction of energy usage, and 0.5% reduction in demand are based on steady-state assumptions, conservatively estimated from similar prepay program results from across the country. The resulting reduction in energy and demand due to prepay are multiplied by the costs of energy and demand for each year to calculate demand savings. The resulting benefit projection can be found in my Schedule 2.

As described by Company Witness Robert S. Wright, voltage optimization investments will also drive energy and demand savings. The projected savings in this area were provided by the Company and incorporated into the CBA, modeled to begin in 2022.

Q. Does the Company expect to realize energy and demand benefits related to the availability of interval energy usage data for customers via AMI and the customer information platform ("CIP"), including expanded digital customer channels?

A. Yes, benefits have been captured in this area. As noted in the direct testimony of Company Witnesses Nathan J. Frost and Thomas J. Arruda, the Company plans to deploy AMI and a modernized CIP that includes enablement of advanced channels of communication with customers. Among the information that will be accessible to customers via the CIP is the presentation of the interval energy usage data that is made available via AMI. The CIP also enables additional alerting and notification options. Research has shown that customers with AMI meters and enhanced customer portals reduce their energy consumption. The benefit calculation incorporates the percentage of customers that are expected to actively engage with and leverage the additional information, as well as the percentage of energy usage that will decline as a result of that engagement and change in behavior. Within the CBA, it is projected that 5.8% of customers will be actively engaged and adjusting their behavior, and that the impact of that will be a 1.1% reduction in energy usage in the steady state, following AMI and CIP deployment.

Q. What is the overall benefit projection for energy / demand savings associated with the GT Plan?

A. As noted in Figure 1, the total benefits associated with energy / demand benefit are approximately $238 million (NPV) over the asset life of the proposed investments.

Q. Focusing on the EV-related benefits that you discussed, what work was done to project additional EV ownership savings associated with Transportation Electrification?

A. As discussed by Company Witness Frost, the Company proposes to provide incentives to manage charging and deploy EV charging stations in furtherance of future intelligent and managed charging program in response to the expected levels of EV adoption. A study performed by Navigant Consulting, Inc. provided to the Company and West Monroe focused on Virginia and the Company's service territory and anticipates the steady increase in the penetration of EVs over the next 20 years and beyond. As a result of the Company's investments in infrastructure and programs, EV owners will be better positioned to save money on their transportation costs by shifting from gas to electric as the source of power. Additionally, electricity is a more environmentally friendly source of fuel as compared to gasoline.

The calculation of benefits in this area is done by comparing the cost of electricity needed to power the projected EVs to the cost of gasoline for an equivalent number of miles driven. The detail used for this calculation includes the number of EVs projected, the projected number of EV miles driven, the total dollars that would have been spent on gasoline for the same number of miles driven, the cost of electricity for the EV miles driven (7,800 miles annually based on industry benchmarking), the energy savings from the conversion to EVs, and the portion of those savings that are reasonably attributable to the Company's programs and investments as part of GT Plan.

Q. What was the calculation method for the difference in customer spend on gas-powered vehicles versus electric vehicles?

A. The average miles per gallon forecast provided by the Environmental Protection Agency ("EPA") was multiplied by the forecasted cost of gasoline to calculate the customer spend on gas-powered vehicles. Consumer costs for EV miles driven was then calculated by taking the number of EV miles driven and the forecasted miles per kilowatt-hour ("kWh") and multiplying by the forecasted cost of electricity. The benefit is then calculated by subtracting the costs of EV "fuel" (*i.e.*, electricity) from the costs for gas-powered vehicles for the same number of miles.

Q. Can the Company be reasonably credited with driving all of the projected proliferation of EVs in the Company's service territory, and therefore all of the projected EV Ownership Savings benefits?

A. No, and the CBA has not captured (or taken credit for) the full value of benefits associated with EV ownership. There are customers that have and will continue to purchase EVs irrespective of any planned investments or programs in the GT Plan. However, by installing additional charging stations and offering programs such as managed charging, the growth of EVs will be accelerated by limiting the customer concern associated with a lack of charging infrastructure (*i.e.*, "range anxiety") and positioning them to save money. The Institute for Physics published a paper in July of 2017, titled "The Role of Demand-Side Incentives and Charging Infrastructure on Plug-In EV adoption: Analysis of US States,"[1] which forecasted the relationship of public charging accessibility to increased adoption of EVs. The research demonstrated the

[1] https://iopscience.iop.org/article/10.1088/1748-9326/aad0f8.

impacts of the public charging stations funded by the American Recovery and Reinvestment Act deployed between 2011 and 2014 of roughly $40 million. The study showed that the EV penetration rate can be increased between 2.3% to 9.75%, based on the type of vehicle and whether enough public charging stations are available to address "range anxiety." In cases where there was deemed to be sufficient public charging stations deployed, the average improvement in EV sales was 7.2%. There are additional studies and research papers that suggest a higher correlation between infrastructure investment program availability, and greater EV sales.

All that said, the portion of EV energy savings and the corresponding GHG reductions associated with EV use was derived by taking the total EV energy and EV GHG savings and multiplying it by 7.2%.[2] The total benefits calculated for EV Ownership Savings and GHG savings related to EV ownership are displayed on lines 46 and 9, respectively of my Schedule 3.

<u>**(4) Total Improved Reliability Benefit**</u>

Q. Please explain how the benefits associated with total improved reliability benefit as presented in the CBA were derived.

A. There are several sources of the reliability improvements in the GT Plan described by Company Witness Wright, including Self-healing Grid, Outage Management System improvements with AMI, Enterprise Asset Management System, Proactive Component Upgrades, and Grid Hardening. For each of these areas, the Company provided specific reliability improvement projections based on the detailed scopes of work and engineering

[2] This conservative adjustment was applied to only these components of the EV benefits captured within the model. The other EV Benefits captured are not applicable to this factor.

exercises that were completed in the form of reduced customer interruptions ("CI") and customer minutes of interruption ("CMI") based upon the specific project and the number of customers directly impacted. Since the analysis focused on specific equipment in the system, the exact number and type of customers that would see a direct benefit of each specific project was captured.

West Monroe then input this Company-specific information into the United States Department of Energy Interruption Cost Estimate ("ICE") Model, version March 2018, to calculate the value of the improved reliability benefits to customers in dollar form. The resulting calculation captured the aggregate benefits from each type of reliability improvement by year in the CBA and were included in the CBA based on the timing of planned GT Plan investments and the asset life of the related assets that drive the benefit.

As noted in Figure 1, the total benefits associated with improved reliability benefit are estimated to be approximately $2.0 billion (NPV) over the asset life of the proposed investments.

Q. Is the DOE ICE model a reasonable method for quantifying reliability benefits?

A. Yes. Lawrence Berkeley National Laboratory created the model for the DOE as a means to identify the value of service reliability for electricity customers in the United States. The DOE ICE model quantifies the economic benefit from improvements in system average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI") to key customer segments for utilities based on their size and region in a consistent and transparent fashion. The DOE ICE model is accepted in the industry as a dependable source for reliability benefit valuation and has gone through several iterations since being introduced about a decade ago, including the latest update in March 2018.

The ICE model creates state specific estimates of electric system reliability improvements for each of the 50 states in the US, including the Commonwealth of Virginia. The ICE model leverages 34 Cost Interruption Studies from 10 different utilities that were executed between 1989 and 2012. Notably, 3 of these 10 utilities were from the southeast. The model has taken the information from these studies to estimate the value of reliability to different types and sizes of commercial and industrial customers, as well as for residential customers. The model uses the state input information to determine the appropriate mix of these different types and sizes of commercial and industrial customers based on an analysis of the business Standard Industrial Classification codes. The 2018 version of the DOE ICE model has been updated to improve the accuracy of the reliability calculations by also taking into consideration the state gross domestic product ("GDP"). The researchers have found that that the higher the state GDP the more important electric reliability is to the customers, especially for the businesses. Additional information on the model and the calculation methods used to correlate reliability improvements to customer economic impacts can be found at www.icecalculator.com.

Many utilities have used the DOE ICE model to translate specific customer reliability improvements in the form of SAIDI and SAIFI to customer financial benefits, which are found in technical literature, industry conference presentations, and utility fillings.

It is important to note that as part of the detailed planning and engineering work referenced by Company Witness Wright, the Company completed a detailed analysis that identifies key system components impacted, including the nature and state of the distribution infrastructure, historical reliability performance, and customer impacts. The resulting GT Plan targets those feeders and segments of the grid that will provide the largest opportunity for benefit delivery to as many customers as possible, which is then translated to customer financial benefits through the output of the ICE model.

<u>(5) Total Reduction of Bad Debt and Energy Diversion</u>

Q. Finally, please explain how the benefits associated with total reduction of bad debt and energy diversion as presented in the CBA were derived.

A. West Monroe worked with the Company to identify the current and projected levels of customer bad debt that the Company must write-off, and energy diversion associated with meter tampering. By leveraging the functionality of AMI, specifically use of the remote connect and disconnect switch, and the ability to more accurately identify meter tampering activities or the identification of malfunctioning equipment, utilities across the country have experienced significant reductions in bad debt expense and energy diversion. Projected savings for Dominion Energy Virginia were based on similar programs and technology deployments, and as noted in Figure 1, the total benefits associated with bad debt and energy diversion are approximately $119 million (NPV) over the asset life of the proposed investments.

Q. You have mentioned that a conservative approach was taken to many of the benefits assumptions used to complete the CBA. Why is that?

A. There are several reasons why it is more appropriate and prudent to conservatively estimate benefit components of the CBA. First, many of the planned investments within GT Plan are foundational by nature, and not yet installed. Because of this, and given the unique nature of any company's service territory, it is appropriate to take a measured approach to projecting elements of the analysis that drive certain benefits, particularly those associated with customer behavior and program adoption. For this reason, a blend of industry benchmarking and Company history with customer programs were used to develop certain benefit projections. For instance, there are examples across the country of the adoption in time-varying rates and peak time rebate programs; West Monroe used adoption levels on the low end of industry experience for the projects in the CBA. It is important to note that even with the more conservative benefit assumptions, the overall GT Plan remains cost beneficial due to the wide range of impactful benefits that are delivered via the planned investments.

III. ADDITIONAL GT PLAN BENEFITS

Q. Please explain why certain benefits were not included in the "total" for the CBA NPV calculation, and are instead listed as "additional."

A. While West Monroe and the Company are confident in the value of GT Plan benefits that are not classified as "Customer Benefits," it was deemed appropriate to exclude them from the initial NPV and benefit/cost ratio in order to provide a customer-focused assessment of the planned investments. Again, for reference, the additional benefits include reduction in GHG, EV ownership savings, referenced in my testimony above, and overall economic impact of the planned investments.

Q. What work was done to project GHG reduction benefits associated with GT Plan investments?

A. The projects that reduce the consumption of electricity, as described and quantified earlier in this testimony, also result in lower emissions due to the reduction in electricity generation. Other GTP programs reduce the amount of GHG created from vehicles, which include utility vehicle GHG reduction due to lower truck rolls and the reduction of GHG due to EV adoption. Two separate calculations were made to capture the reduction in greenhouse gas emissions: 1) reduced miles travelled in gasoline/diesel vehicle, and 2) impact due to reduced MWh of electricity generation. The Company provided inputs and data points to West Monroe to then calculate these GHG reductions.

The deployment of AMI meters results in a reduction in fleet requirements, both for AMR meter reading that is eliminated and for a wide range of orders executed by the field services function. Planned investments in Self-healing Grid, Outage Management, and Main Feeder Hardening also have an impact in this area. The resulting reduction in miles driven by utility personnel results in a reduction of GHG emissions.

The GHG impact of reduced MWh electricity generation was calculated for other programs, such as deployment of time-varying rates and programs, and voltage optimization. Lastly, GHG emissions reductions are calculated for Transportation Electrification by comparing the GHG emissions from conventional vehicles to GHG emissions from electricity generation needed to charge EVs.

DOE measurements and data points were leveraged to derive the estimated tons of GHG emissions per megawatt-hour ("MWh") of electricity generated, which was converted to calculate avoided electricity to GHG savings. The total GHG benefit is calculated by taking the amount of reduced GHG emissions and multiplying it by the forecasted value of GHG emissions, also known as the social cost of carbon. The categories and details associated with projected reductions in GHG emissions are captured in my Schedule 3.

Q. What method was used to calculate the economic impact of the GT Plan investments?

A. The Company worked with West Monroe to develop the projected impact of the GT Plan on the economy, including creation of jobs and overall stimulus. As shown in Figure 1, the additional benefit associated with the economic impact of the GT Plan is approximately $2.8 billion (NPV).

Q. Please provide additional detail on the estimate for total economic impact associated with the Company's proposed GT Plan projects?

A. The Bureau of Economic Analysis ("BEA") Regional Input-Output Modeling System II ("RIMS II") approach was used to estimate the economic impact based on a capital multiplier that is specific to the region. The economic impact calculation is based on regional economy-wide impacts of the BEA RIMS II approach. The BEA is a United States government organization that is responsible for the creation of official economic statistics, which provide a comprehensive and up-to-date picture of the United States economy and are used to aid businesses, policy makers, and households. The local and state impact of the GT Plan on direct and indirect job growth will have a positive impact on the overall state economy in Virginia. The overall economic impact, like the indirect jobs impact, benefits the overall United States economy in addition to the Commonwealth of Virginia. As noted above, these economic benefits have been calculated and are not included in the "total" CBA, but are noted as "additional" benefits for Commission consideration.

Q. **Regarding economic impact, how many new jobs are estimated to be created as a result of the proposed GT Plan investments and how was that estimate derived?**

A. For the purposes of this analysis and testimony, a job is defined as a resource working full time for one year. Direct jobs are those that result from people working on a GT Plan project, and indirect jobs are those that result from increased economic activity as a result of the planned investments (*i.e.*, suppliers, other service providers, etc.).

Over a 20-year period, the BEA RIMS II Model projects that approximately 4,500 direct and 17,000 indirect jobs will be created as a result of the proposed GT Plan investments. Direct jobs are expected to be high-paying, technology-oriented positions that will enable economic growth and stability, while providing rewarding and developmental opportunities to a growing workforce. Indirect jobs, such those associated with restaurants, hotels, and construction are based on a capital multiplier that is specific to the region.

Q. **Are there further benefits that are not easily quantified in terms of economic value?**

A. Yes, there are. One prime example is the significant improvement to the customer experience that will be delivered by the GT Plan. The increased level of customer choice, engagement, and satisfaction of customers that will result from these investments, particularly those in the areas of CIP and AMI are difficult to assign a value to, but the Company is confident that they are real and in alignment with what customers are demanding. The GT Plan will also improve the overall operating condition of the distribution grid resulting in improvements to safety of both customers and employees. This is also difficult to specifically quantify, but the Company is confident that this critical area will be positively impacted by the GT Plan. Another area of benefit that is not specifically captured is the reliability improvements associated with targeted corridor improvements. The specific and targeted activities planned for selected corridors to pro-actively address areas where excess vegetative growth can cause system delays, outages, and other operational issues will drive improvements to reliability, but the specific values were not able to be isolated and projected to a level of certainty, and are therefore not included in the CBA. Although the Company has not attempted to quantify these benefits in this case to remain conservative, they further demonstrate that the business case is positive and that the planned investments are prudent.

Q. Are there specific projected benefits associated with the planned investments in Advanced Analytics?

A. The Company has not allocated specific benefits to the deployment of Advanced Analytics as this investment enabled the quantified benefits already allocated to other areas of the GT Plan. As noted throughout Company testimony, and specifically with Company Witness Wright's areas of focus, the planned investments in Advanced Analytics have a wide range of impacts and will drive value across the organization. The benefits planned to be delivered in other areas would not be realized without the Advanced Analytics investments. Data coming from AMI and other intelligent grid devices and control systems will be leveraged by the Advanced Analytics platform and organization in the development of specific use cases and reporting that will drive efficiencies and improvements in operations. Actionable output from the Advanced Analytics organization will also prevent the erosion of benefits over time by identifying data trends, required process changes, and prioritized activities to ensure that systems and equipment are performing at their anticipated levels, and that benefits delivery continues at the projected levels, or at enhanced levels.

IV. OBSOLESCENCE CONSIDERATIONS

Q. Based on your industry experience, what concerns should utilities have regarding the potential for premature obsolescence of Grid Transformation-related technologies and investments?

A. Public utilities should always carefully weigh and consider investments, especially large-scale capital expenditures, using a number of lenses, including consideration of possible obsolescence of technology. It is important to maintain flexibility and forward-compatibility as key criteria for the selection of software, hardware, and other field devices associated with the continued modernization of the grid.

Dominion Energy Virginia has demonstrated that these are priorities, via their plans to leverage cloud-based solutions for software and leveraging an iterative planning and implementation process for field devices and other technologies that rely on the ongoing assessment of new and emerging capabilities that deliver the desired functionality and targeted customer benefits. West Monroe has seen, first-hand, the value that the Company places on forward compatibility of the planned investments during vendor evaluation and the planning process and believes that the investments within the GT Plan will deliver long-lasting and sustainable benefits consistent with the CBA.

Q. Specifically, what is West Monroe's perspective on the potential premature obsolescence of the Company's proposed AMI technology?

A. There are several reasons why this concern has been addressed, including specific technology features and capabilities of the AMI solution that has been selected. The main feature of AMI technology that addresses this concern is the ability to leverage the communication network to update the meter and firmware (the software programmed into each meter) remotely, also known as "over the air" programing, allowing the Company to stay current on updates that deliver improvements and enhancements to the AMI system and the smart meters. This technology capability of "over the air" programing prolongs the useful life of the entire solution, from meters through the communication devices and network technology, positioning the Company to operate a long-term, flexible, and dependable AMI solution. Additionally, there is feedback and analysis on this specific topic by multiple third parties and industry researchers that has conclusively addressed this concern.

The status of AMI Deployment across the United States and the Company's past experience with solid-state meters that have communications devices also provides evidence and support that this technology is not at risk of near-term obsolescence. This information and more can be referenced in a white paper authored by West Monroe, attached as my Schedule 5, which outlines our perspective on this topic.

Q. Please summarize your testimony.

A. West Monroe worked closely with the Company to identify the required inputs, assumptions, data points, and deployment timelines associated with the GT Plan that would enable accurate projection of the associated and comprehensive costs and benefits. This information was input into the established CBA methodology for analysis.

The CBA demonstrates that the GT Plan investments are cost beneficial. The planned investments deliver significant benefit to all customers across a wide range of areas, while also driving reductions in greenhouse gas emissions, increase in new jobs and economic growth in the Commonwealth, and savings to EV owners.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS
OF
THOMAS G. HULSEBOSCH

Tom Hulsebosch is a member of the Executive Leadership team and serves on the Board of Directors of West Monroe Partners. West Monroe is a management and technology consulting firm with over 1300 employees in 10 offices across the United States. Tom leads the firm's Energy & Utilities practice as well as the Dallas Office.

Tom is a 30-year veteran of the utility, ISP, and wireless telecommunication industries, with extensive experience creating and delivering solutions for utilities, enterprises, cities, and service providers. Over the past twelve years, Tom has been driving innovative smart grid, smart community, and sustainability programs for utilities and cities along with other key industry stake holders such universities, National Laboratories, and the US Department of Energy.

Tom has a Bachelor of Science in Electrical Engineering from Marquette University in Milwaukee and a Master of Science in Electrical Engineering from the Illinois Institute of Technology in Chicago. Tom also holds seven US Patents. In 2015, Tom was recognized as one of the Top 25 Consultants in the US for his work in Energy by Consulting Magazine.

Tom has performed the role of smart-utility architect for several utilities going through the transformation that is associated with major business process, technology, and business model changes. This includes creating smart-utility strategy, selecting the best technology, identifying the new business model, quantifying the benefits, creating the business case, optimizing the deployment plan, selecting vendors, integrating systems, and providing deployment support. In addition, Tom has guided the technology procurement process for many types of utility telecommunication solutions, smart-grid applications, and smart metering equipment for a variety of water, gas, and electric utilities.

Tom joined West Monroe Partners in 2008 from Strategy 2 Solution, LLC, a consulting firm that he founded. He led Strategy 2 Solution's consulting practice, which focused on developing executable and sustainable wireless network solutions for municipalities, utilities, corporations, and service providers, as well as creating product strategies and sales distribution solutions for equipment vendors. Prior to starting Strategy 2 Solution, Tom was the vice president of municipal network sales for EarthLink Municipal Networks. Tom also spent nearly 20 years with Motorola performing a variety of sales, strategy, marketing, product management, and engineering roles.

Capital Expenditures Summary (Total)

(Nominal dollars, in millions)

	2019	2020	2021		
	Yr 1	Yr 2	Yr 3	3-yr Total	10-yr Total
Advanced Metering Infrastructure (AMI)	$14.9	$71.9	$100.3	$187.0	$394.4
Customer Information Platform / Meter Data Management (CIP/MDM)	$7.3	$38.4	$45.2	$90.8	$197.7
Time-Varying Rates	-	$0.5	-	$0.5	$0.5
Peak-Time Rebate	-	-	-	-	$0.1
Prepay	-	-	-	-	$21.6
Stakeholder Engagement & Customer Education	-	-	-	-	-
Telecommunications	$6.4	$65.2	$66.0	$137.6	$453.2
Grid Technologies	$2.5	$31.9	$21.3	$55.6	$452.0
Grid Hardening	$2.2	$20.9	$61.3	$84.5	$1,233.2
Cyber Security	-	$2.9	$1.9	$4.8	$20.9
Physical Security	$0.9	$3.5	$3.5	$7.9	$50.7
Transportation Electrification *(All Programs)*	-	$1.5	$2.4	$3.8	$7.3
Total Capital Expenditures:	$34.0	$236.5	$301.9	$572.4	$2,831.7
Total Capital Expenditures (Phase 1B):	$26.8	$218.9	$265.4	$511.0	

Projected Capital Expenditures inclusive of GTP and non-GTP programs

O&M Expenditures Summary (Total)

(Nominal dollars, in millions)

	2019	2020	2021		
	Yr 1	Yr 2	Yr 3	3-yr Total	10-yr Total
Advanced Metering Infrastructure (AMI)	$1.9	$3.0	$4.6	$9.6	$53.9
Customer Information Platform / Meter Data Management (CIP/MDM)	$4.2	$8.7	$10.8	$23.7	$160.3
Time-Varying Rates	-	$0.7	$0.7	$1.4	$8.6
Peak-Time Rebate	-	-	-	-	$7.7
Prepay	-	-	-	-	$1.6
Stakeholder Engagement & Customer Education	$0.0	$1.4	$1.8	$3.2	$11.1
Telecommunications	$1.2	$2.3	$2.9	$6.3	$74.4
Grid Technologies	-	$1.1	$1.8	$2.9	$45.2
Grid Hardening	$6.0	$6.2	$8.1	$20.3	$36.7
Cyber Security	-	$0.9	$1.4	$2.3	$32.1
Physical Security	$0.0	$0.1	$0.2	$0.3	$5.2
Transportation Electrification *(All Programs)*	$0.4	$5.3	$11.4	$17.1	$42.9
Total O&M Expenditures:	$13.8	$29.7	$43.6	$87.1	$479.6
Total O&M Expenditures (Phase 1B):	$12.6	$29.5	$43.1	$85.2	

Projected Operating Expenditures inclusive of GTP and non-GTP programs

20005602

Company Exhibit No. __
Witness: TGH
Schedule 2
Page 1 of 3

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Customer Benefits						
2	Total Avoided/Deferred Capital		$ 657,720	$ 8,283,975	$ 10,235,580	$ 375,638,589	Line 10
3	Total O&M Savings		$ -	$ 2,081,834	$ 5,843,195	$ 265,914,344	Line 100
4	Total Energy/Demand Benefit		$ -	$ 80,292	$ 166,512	$ 237,538,720	Line 200
5	Total Improved Reliability Benefit		$ -	$ -	$ 13,357,319	$ 2,028,116,192	Line 239
6	Total Reduction of Bad Debt & Energy Diversion		$ 1,230,830	$ 2,250,491	$ 4,999,690	$ 118,887,075	Line 276
7	Total Customer Benefits		$ 1,888,550	$ 12,696,592	$ 34,602,296	$ 3,026,094,921	Sum Lines 2-6
8							
9							
10	Avoided/Deferred Capital Benefit Detail		$ 657,720	$ 8,283,975	$ 10,235,580	$ 375,638,589	Sum Lines 12-95
11							
12	Avoided AMR/Walk-Up Equipment Upgrade/Replacement (AMI)	Nate Frost	$ 72,720	$ 1,012,909	$ 74,249	$ 2,986,205	Sum Lines 13-18
19							
20	Avoided AMR Meter Replacement (AMI)	Nate Frost	$ 585,000	$ 2,288,025	$ 4,786,211	$ 66,712,729	Line 21*Line 22
23							
24	Avoided CBMS Mainframe Capital Maintenance (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 2,604,928	Sum Lines 25-27
28							
29	Avoided Capital Run Rate (CIP)	Thomas Arruda	$ -	$ 4,528,149	$ 4,671,806	$ 35,920,194	Sum Lines 30-32
33							
34	Avoided T&D Upgrade Investment (Time-Varying Rates)	Greg Morgan	$ -	$ 55,070	$ 110,242	$ 7,066,693	Line 35*Line 36
37							
38	Avoided T&D Upgrade Investment (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 15,983,255	Line 39*Line 40
41							
42	Avoided T&D Upgrade Investment (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 99,602	Line 43*Line 44
45							
46	Reduction in Future Capital from Carrier Cellular costs (Telecom)	Bradley Carroll	$ -	$ 20,467	$ 20,915	$ 330,664	Line 47*Line 48
49							
50	Avoided T&D Upgrade Investment (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 11,914,382	Line 51*Line 52
53							
54	Avoided Mainfeeder Maintenance - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 4,641	$ 2,512,143	*Dominion Projection*
55							
56	Avoided Mainfeeder Outage Truck Roll - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ 1,095	$ 3,249	$ 639,961	Line 57*Line 58*Line 59
60							
61	Avoided Mainfeeder Storm Outage Truck roll - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ 127	$ 266	$ 59,030	Line 62*Line 63*Line 64
65							
66	Avoided Mainfeeder Storm Pole Replacements - Capital (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 11,546	$ 2,252,516	*Dominion Projection*
67							
68	Avoided Outage Truck Rolls - Capital Maintenance (Targeted Corridor Improvement)	Robert Wright	$ -	$ 95,559	$ 98,590	$ 333,062	Line 69*Line 70*Line 71
72							
73	Avoided Service Transformer Overload Failure - Capital Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 5,871	$ 248,822	Line 74*Line 75*Line 76
77							
78	Avoided Poor Health Transformer Replacement (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 171,027,338	Line 79*Line 80
81							
82	Avoided Poor Health Transformer Outage - Capital Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 4,442	Line 83*Line 84*Line 85
86							
87	APM - Deferred Capital Spend (EAMS)	Robert Wright	$ -	$ -	$ -	$ 2,902,263	Line 88*Line 89
90							
91	Centralized Inventory - Avoided Capital Spend (EAMS)	Robert Wright	$ -	$ -	$ -	$ 818,920	Line 92*Line 93
94							
95	Avoided T&D Upgrade Investment (Transportation Electrification)	Nate Frost	$ -	$ 282,576	$ 447,992	$ 51,221,438	Line 96*Line 97
98							
99							
100	O&M Savings Benefit Detail		$ -	$ 2,081,834	$ 5,843,195	$ 265,914,344	Sum Lines 102-191
101							
102	Reduction in AMR Meter Reading Expense (AMI)	Nate Frost	$ -	$ 244,102	$ 2,165,817	$ 102,376,399	Sum Lines 103, 104
105							
106	Reduction in Meter Servicing Expense (AMI)	Nate Frost	$ -	$ 112,147	$ 995,221	$ 47,111,666	Sum Lines 107, 108
109							
110	Reduction in 'Found On' Operations Expense (AMI)	Nate Frost	$ -	$ 30,615	$ 269,528	$ 11,986,036	(Line 112 - Line 113)*Line 111
114							
115	Reduction in Meter Re-Reads (AMI)	Nate Frost	$ -	$ 3,472	$ 6,410	$ 177,494	Line 116*Line 117*Line 118
119							
120	Billing Process Improvement Benefits (AMI)	Nate Frost	$ -	$ 57,312	$ 105,800	$ 2,929,771	*Dominion Projection*
121							
122	Reduction in Customer Calls (AMI)	Nate Frost	$ -	$ 243,597	$ 449,689	$ 12,452,652	Line 123*Line 124*Line 125*Line 126
127							
128	Billing Process Improvement Benefits (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 813,175	*Dominion Projection*

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
129							
130	Avoided CBMS Mainframe Maintenance Expense (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 25,943,557	Sum Lines 131-133
134							
135	CSR Savings (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 319,961	Line 136*Line 137*Line 138*Line 139*Line 140
141							
142	Reduction in O&M from Leased MPLS costs (Telecom)	Bradley Carroll	$ -	$ 90,922	$ 334,137	$ 26,847,841	Line 143*Line 144
145							
146	Reduction in Future O&M from Carrier Cellular costs (Telecom)	Bradley Carroll	$ -	$ 720	$ 1,440	$ 99,503	Line 147*Line 148
149							
150	Total Avoided Capital and O&M costs for New Leased LTE (Telecom)	Bradley Carroll	$ -	$ 13,151	$ 78,905	$ 2,414,386	Line 151*Line 152
153							
154	Avoided Mainfeeder Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 1,703	$ 851,301	*Dominion Projection*
155							
156	Avoided Mainfeeder Outage Truck Rolls (Mainfeeder Hardening)	Robert Wright	$ -	$ 14,542	$ 43,163	$ 8,502,336	Line 157*Line 158*Line 159
160							
161	Avoided Mainfeeder Storm Outage Truck Rolls (Mainfeeder Hardening)	Robert Wright	$ -	$ 1,689	$ 3,540	$ 8,502,336	Line 162*Line 163*Line 164
165							
166	Avoided Corridor Improvement Outage Truck Rolls (Targeted Corridor Improvement)	Robert Wright	$ -	$ 1,269,567	$ 1,309,845	$ 4,424,966	Line 167*Line 168*Line 169
170							
171	Avoided Transformer Overload Failure Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 78,000	$ 3,305,783	Line 172*Line 173*Line 174
175							
176	THA - Avoided Transformer Outage Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 59,018	Line 177*Line 178*Line 179
180							
181	APM - Labor Savings (EAMS)	Robert Wright	$ -	$ -	$ -	$ 2,068,227	Line 182*Line 183*Line 184
185							
186	APM - Recovery of Warranty Leakage (EAMS)	Robert Wright	$ -	$ -	$ -	$ 127,420	Line 187*Line 188*Line 189
190							
191	EWP - Labor Savings (EAMS)	Robert Wright	$ -	$ -	$ -	$ 4,600,518	Sum Lines 192-197
198							
199							
200	Energy & Demand Savings Benefit Detail		$ -	$ 80,292	$ 166,512	$ 237,538,720	Sum Lines 202-220
201							
202	Energy Reduction (AMI)	Nate Frost	$ -	$ -	$ -	$ 3,560,644	*Dominion Projection*
203							
204	Avoided Energy Cost (Time-Varying Rates)	Greg Morgan	$ -	$ 5,808	$ 16,796	$ 3,942,435	Sum Lines 205, 206
207							
208	Avoided Demand Cost (Time-Varying Rates)	Greg Morgan	$ -	$ 7,478	$ 29,533	$ 12,729,008	Line 209*Line 210
211							
212	Avoided Energy Cost (Opt-In) (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 274,507	Sum Lines 213-216
217							
218	Avoided Demand Cost (Opt-In) (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 46,284,013	Sum Lines 219, 220
221							
222	Avoided Energy Cost (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 10,611,700	Line 223*Line 224
225							
226	Avoided Demand Cost (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 3,299,081	Line 227*Line 228
229							
230	Energy Reduction (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 103,021,325	*Dominion Projection*
231							
232	Demand Reduction (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 33,754,882	*Dominion Projection*
233							
234	Energy Savings from Managed Charging (Transportation Electrification)	Nate Frost	$ -	$ 28,636	$ 40,148	$ 3,481,746	*Dominion Projection*
235							
236	Capacity Savings from Managed Charging (Transportation Electrification)	Nate Frost	$ -	$ 38,370	$ 80,035	$ 16,579,380	*Dominion Projection*
237							
238							
239	Improved Reliability Benefit Detail		$ -	$ -	$ 13,357,319	$ 2,028,116,192	Sum Lines 241-273
240							
241	Annual Residential Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 228,307	$ 37,090,003	*Dominion Projection*
242							
243	Annual Small C&I Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 2,117,363	$ 300,478,213	*Dominion Projection*
244							
245	Annual Large C&I Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 329,248	$ 141,732,742	*Dominion Projection*
246							
247	Service Transformer - Reliability Benefit (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 6,456,778	$ 192,715,536	Sum Lines 248-250
251							
252	THA Transformer - Reliability Benefit (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 161,059,243	Sum Lines 253-255
256							
257	Residential Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 1,765,647	*Dominion Projection*

Company Exhibit No. __
Witness: TGH
Schedule 2
Page 3 of 3

095002

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
258							
259	Small C&I Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 11,645,321	*Dominion Projection*
260							
261	Large C&I Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 126,524,322	*Dominion Projection*
262							
263	Residential Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 404,068	$ 62,505,348	*Dominion Projection*
264							
265	Small C&I Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 3,274,784	$ 552,300,281	*Dominion Projection*
266							
267	Large C&I Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 546,770	$ 266,750,062	*Dominion Projection*
268							
269	Residential Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 1,831,271	*Dominion Projection*
270							
271	Small C&I Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 12,116,410	*Dominion Projection*
272							
273	Large C&I Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 159,601,793	*Dominion Projection*
274							
275							
276	Bad Debt & Energy Diversion Reduction Benefit Detail		$ 1,230,830	$ 2,250,491	$ 4,999,690	$ 118,887,075	Sum Lines 278-291
277							
278	Bad Debt Reduction (AMI)	Nate Frost	$ -	$ 119,112	$ 1,471,532	$ 58,142,907	Sum Lines 279, 280
281							
282	Theft/Energy Diversion Recovery (AMI)	Nate Frost	$ 1,092,326	$ 1,973,214	$ 3,238,671	$ 52,163,086	Line 283*Line 284
285							
286	Meter Accuracy Improvement (AMI)	Nate Frost	$ 138,504	$ 158,165	$ 289,487	$ 8,220,363	Line 287*Line 288*Line 289
290							
291	Reduction of Uncollectable (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 360,718	(Line 293/Line 292)*Line 294*Line 295
296							

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	**Additional Benefits**						
2	Total Reduced Greenhouse Gas Emissions Benefit		$ 23,821	$ 30,252	$ 40,468	$ 4,051,014	Line 7
3	Total Customer Pocketbook Savings		$ 112,812	$ 1,631,694	$ 2,081,824	$ 81,222,166	Line 44
4	Total Additional Benefits		$ 136,633	$ 1,661,945	$ 2,122,292	$ 85,273,180	Sum Lines 2-3
5							
6							
7	Reduced Greenhouse Gas Emissions Benefit Detail		$ 23,821	$ 30,252	$ 40,468	$ 4,051,014	Sum Lines 9-40
8							
9	Reduced GHG Benefits (Adjusted as Effect of Lift) (Transportation Electrification)	Nate Frost/Tom Hulsebosch	$ 23,549	$ 29,663	$ 38,441	$ 1,324,247	Line 10*Line 11
12							
13	Reduced GHG Benefits (AMI)	Nate Frost/Tom Hulsebosch	$ -	$ 143	$ 1,225	$ 40,169	Line 14*Sum Lines 15-18
19							
20	Reduced GHG Benefits (Time-Varying Rates)	Greg Morgan/Tom Hulsebosch	$ -	$ 174	$ 530	$ 143,437	Line 21*Line 22
23							
24	Reduced GHG Benefits (PTR)	Greg Morgan/Tom Hulsebosch	$ -	$ -	$ -	$ 1,309	Line 25*Line 26
27							
28	Reduced GHG Benefits (Prepay)	Greg Morgan/Tom Hulsebosch	$ -	$ -	$ -	$ 171,812	Line 29*Line 30
31							
32	Reduced GHG Benefits (Self-Healing Grid)	Robert Wright/Tom Hulsebosch	$ 272	$ 272	$ 272	$ 3,638	Line 33*Line 34
35							
36	Reduced GHG Benefits (OMS)	Robert Wright/Tom Hulsebosch	$ -	$ -	$ -	$ 1,370	Line 37*Line 38
39							
40	Reduced GHG Benefits (Voltage Optimization)	Robert Wright/Tom Hulsebosch	$ -	$ -	$ -	$ 2,365,031	Line 41*Line 42
43							
44	EV Ownership Savings		$ 112,812	$ 1,631,694	$ 2,081,824	$ 81,222,166	Line 46
45							
46	EV Ownership Savings (Transportation Electrification)	Nate Frost/Tom Hulsebosch	$ 112,812	$ 1,631,694	$ 2,081,824	$ 81,222,166	Sum Lines 47-49
50							

Deployment Timeline Summary

Key

COMPONENT	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Grid Modernization										
Advanced Metering Infrastructure (AMI)	■	■	■	■	■	■				
Customer Information Platform / Meter Data Management (CIP/MDM)	■	■	■	■	■	■				
Time-Varying Rates		■								
Peak-Time Rebate								■		
Prepay							■	■		
Stakeholder Engagement & Customer Education	■	■	■	■	■	■	■	■	■	■
Telecommunications	■	■	■	■	■	■	■	■	■	■
Self-Healing Grid	■	■	■	■	■	■	■	■	■	■
Hosting Capacity	■									
Distributed Energy Resources Management System (DERMS)				■	■	■	■	■	■	
Advanced Analytics		■	■	■	■	■	■	■	■	■
Voltage Optimization	■	■	■	■	■	■	■			
Locks Campus Microgrid		■								
Enterprise Asset Management System (EAMS)		■	■	■						
Outage Management System (OMS)					■	■	■			
Mainfeeder Hardening	■	■	■	■	■	■	■	■	■	■
Targeted Corridor Improvement	■	■	■	■	■	■	■			
Proactive Component Upgrades		■	■	■	■	■	■	■	■	■
Voltage Island Mitigation		■	■	■	■	■	■	■	■	■
Cyber Security	■	■	■	■	■	■	■	■	■	■
Physical Security	■	■	■	■	■	■	■	■	■	■
Transportation Electrification		■	■	■	■	■		■		

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AMI OBSOLESCENCE PERSPECTIVE

By: Danny Freeman, July 2019

As technology continues to evolve and Utilities are increasingly inclined to modernize their operations, it is important to understand the impact of today's technology decisions. Utility executives and regulators must continue to challenge their decision-making processes by understanding the risk of selecting the wrong technologies and/or those that will soon become obsolete. This mindset must also be balanced by the damage that can be done by not investing in needed, value-adding technologies that drive innovation and benefit realization for fear of what may be coming in the future that might be better.

While this balance of risk and reward can be complex and very difficult in some areas of emerging and cutting-edge technologies, one conclusion can be safely drawn by utility executives, regulators, and distribution grid operators alike: Advanced Metering Infrastructure (AMI) or "smart meters" are here to stay.

Though technically AMI and smart meter technology has been in place for many years, there are several factors that clearly demonstrate that premature obsolescence of this technology is not a concern, nor will it be in the near-term. These include:

- The state of AMI technology and deployment today
- Vendor technology trends, investment decisions, and market developments
- Feedback from third parties and industry re-searchers

With over 60% of the electric meters in the United States now being smart meters, and several new and planned projects for large smart meter deployment in various stages, the industry has established AMI as the preferred and standard metering technology.

Importantly, it is also clear that vendors and solution providers are doubling-down on their investments in AMI-centric products and offerings and continue to support these solutions for new and past deployments. In fact, most meter manufacturers have eliminated or significantly de-emphasized the large-scale production of the old, analog meter types that require walk-up and drive-by reads because of the limited demand and relevance of them in todays modernized electric utility environment. The industry has moved forward, and the main, foundational vehicle for that modernized future is AMI technology.

Detractors or skeptics of this conclusion and the long-term viability of AMI may point to Automated Meter Reading (AMR) technology as a reference point for a similar metering solution that was touted as the "next big thing" for utilities. It is true that AMR technology represented a significant change and upgrade in metering and operational capabilities. However it is important to recognize that while the AMR solution was impactful, value-adding, and cost-beneficial when compared to traditional metering ("walk-up" meters requiring individual manual reads), there were several factors indicating that the AMR technology was to become replaced in the near-term.

Researchers and meter manufacturers had already begun development and conceptualization of testing of AMI solutions as early as the 1980s. As cellular and other two-way technologies became more prevalent through the 1990's and 2000's, meter manufacturers and utility technology providers began investing in research and development of how broad deployment of two-way communicating networks could be applied to metering, and the value it would unlock across multiple benefit streams. This was happening while AMR solutions were being actively deployed. This is not to say that the decision to invest in and deploy AMR technology during this timeframe was poor or misguided. On the contrary, those investments have proven to deliver operational benefits and cost reductions that have placed a downward pressure on customer rates. In many cases, utilities that invested in AMR did so with "eyes wide open", knowing that a potentially superior solution was under development and would very likely be fully tested, viable, and widely deployed once the next metering decision cycle was upon them.

Another telling sign that AMR technology had the potential to be more of an interim operational solution is that it was not fundamentally transformational by nature. While the value of AMR is clear and the benefits (largely meter reading cost reductions) have exceeded the costs to deploy, it did not fundamentally change how a utility operated the grid nor how they interacted with customers. AMR metering still required manual reading, it was simply done more efficiently via a drive-by van rather than a meter reader walking up to each home. While this was a benefit, other operational improvements were not addressed by this technology, including the costs associated with manually cutting and restoring power and gathering and assessing meter and system health information for trouble shooting and other operational work order types. AMR meters did not improve a utility's ability to effectively identify or respond to power outages, nor did they assist in the identification of meter tampering and theft that led to safety concerns and additional costs socialized to all customers.

The technology did not enable two-way communication, and thus did not further enable broad deployment of customer programs, rates, or dynamic options that rely on metering when compared to what traditional meters could provide. The further enablement of distributed energy resources integration is also not enhanced with AMR. These factors and others also led to the fact that while AMR meters did represent a sizable component of the meter population in the United States, they were not adopted at the levels we see AMI adoption today and anywhere near what is projected moving forward. Nearly all major utilities operating on AMR technology have already transitioned to AMI or are in the process of doing so.

AMI technology, on the other hand, truly does change the game for utilities and their customers. From an operational perspective, by leveraging remote, two-way communication, AMI further reduced and essentially eliminated meter reading costs, while also enabling remote execution of work orders, most notably remote connect and disconnect which is a significant cost for utilities. Other work order types are also significantly reduced or eliminated due to the ability to remotely interrogate and assess operational conditions without the need to send a utility employee to that location.

Outage management capabilities of AMI are also significant and have been proven across the country. The ability to integrate AMI with Outage Management Systems enables utilities to significantly improve their outage response efforts while driving an improved customer experience through proactive outage identification (customers no longer need to call in to report outages) and restoration, and the delivery of updates to customers on the estimated restoration time and related information.

The customer experience is also dramatically improved during non-outage conditions as a result of AMI. By capturing interval energy usage data and enabling two-way capabilities such as pricing signals and demand response functionality, customers with AMI meters are empowered to take direct control of their usage, and participate in programs, rates, and communication channels that were not possible before. Real-time, two-way communication of interval usage data and other data points, when combined with advanced analytics solutions also allow utilities to identify a wide range of operating conditions, such as meter tampering and theft. This positions the utility to take swift action for resolution, significantly reducing related safety concerns and socialized costs to customers.

In summary, AMR technology made sense at the time, but its fundamental characteristics and other market activities demonstrated that it was likely a bridge to a more advanced solution rather than the new standard. That solution is AMI.

From strictly a meter perspective, the asset performance to date has been quite strong. Manufacturers commit to a useful life of 15 years with an estimated 95% of meters expected to be fully functional and in service after that period. Importantly, AMI meters are also fully programmable to ensure compatibility both backwards and forwards, as communications technology continues to adapt and change in the future. This means that as enhancements are made to other components of the technology landscape, remote programming and updating of meters can be done "over the air", thereby avoiding costly field visits and eliminating the need for meter replacement that would have been required with the prior generation of hardware. This includes important updates related to security controls and configurations.

From a telecommunication backhaul perspective, leading AMI vendors have committed to operating the LTE (4g mobile communications standard) network for the foreseeable future and are committed to aligning with new and evolving standards and requirements, while collaboratively developing specific and actionable plans for technology upgrades. These technology components prolong the useful life in ways that were simply not possible before, positioning utilities to operate a long-term, flexible, and dependable solution.

A wide range of research and analysis has been performed by industry third parties and other organizations to look into the risk of obsolescence for AMI technology. The consensus of these organizations, including the Electric Power Research Institute ("EPRI")[1], the National Institute of Standards and Technologies ("NIST")[2], and the North American Electrical Manufacturers Association ("NEMA") is that while the continued evolution of technology is difficult to predict, the risk of obsolescence of AMI is very low and can be effectively managed by specific processes, practices, and partnership with vendors and solution providers that are already in place.

EPRI has clearly laid out their guidelines for how utilities can ensure that their system is future-proofed, such as closely monitoring and measuring the performance of the network to ensure remote upgrades and updates and able to be executed. Additionally, they recommend that a reserve of system memory and performance capability be set aside for future changes and updates. EPRI also notes that the AMI software architecture should also be flexible enough to support multiple communications protocols to not limit its use with a particular technology, and to allow for additional types and quantities of data to be transported to and correctly interpreted with the system. Lastly, they note that AMI systems are secure and agile without needing to rely on frequent and broad hardware implementations, while still meeting the requirements and performance expectations. NEMA has communicated a set of requirements for smart meter upgradeability that inform how utilities can ensure that their solution is flexible and 'future-proofed' to align with ongoing innovation and improvement throughout the AMI value chain.

While the future of AMI as the standard appears certain, it is important that utilities keep close tabs on market trends and vendor activities. If the last decade of transformation in the utility landscape has taught us anything, it is that technology is changing very quickly and can be quite disruptive and impactful. That being said, at this point, unlike the position of AMR technology, there is an absence of any known or proven deployment of a new metering method or technology beyond AMI of any consequence. The transformative nature of the benefits of AMI, both qualitative and quantitative are simply too compelling to ignore. The technology is here to stay, and its foundational role in the context of broader grid modernization should not be ignored in lieu of an as yet identified, deployed, or validated future metering technology.

REFERENCES

1. https://www.epri.com/#/pages/product/3002006738/?lang=en-US
2. https://www.nist.gov/programs-projects/advanced-metering-smart-distribution-grids

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part 7

Frost

Witness Direct Testimony Summary

Witness: Nathan J. Frost

Title: Director – New Technology and Energy Conservation

Summary:

Company Witness Nathan J. Frost details the Company's plan for full deployment of smart meters and the associated infrastructure (together "AMI") as part of its proposal to transform its electric distribution grid (the "GT Plan"). Mr. Frost also addresses the elements detailed in the Final Order issued in the 2018 GT Plan proceeding ("2018 Final Order"), and discusses the proposed deployment of AMI, the proposed opt-out policy, and the Company's plan for customer education consistent with the 2018 Final Order, as well as the Company's initiatives related to electric transportation.

In terms of AMI, Mr. Frost testifies that the Company is proposing to fully deploy smart meters AMI across its Virginia service territory. Through AMI, the Company can remotely read smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. As Mr. Frost testifies, nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, and reduced energy consumption; and additional benefits in reduced greenhouse gases.

Mr. Frost also discusses the proposed opt-out policy. As Mr. Frost explains, while Dominion Energy Virginia fully supports AMI and the benefits it provides, the Company understands that some customers may prefer not to have a smart meter and plans to accommodate those customers where practical, if deemed necessary by the Commission. Under the Company's proposed opt-out policy, residential customers taking basic service on Rate Schedule 1 with accounts in good standing will be eligible to opt out of smart meter installation upon request. As Mr. Frost testifies, the Company proposes to impose a one-time initial fee of $84.53 and an ongoing monthly fee of $29.20. These fees are intended to be revenue neutral.

In terms of electric transportation, Mr. Frost describes the proposed Smart Charging Infrastructure Pilot Program, under which the Company would offer rebates for incentives for infrastructure necessary for managed charging, also referred to as "smart" charging. In addition, the Pilot Program includes Company-owned charging at strategic locations. The information gained from the proposed Pilot Program will provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid.

Mr. Frost additionally testifies as to the Company's education plan. The overarching goal for the plan is to educate customers, to raise awareness and understanding of the benefits of the GT Plan investments, and to encourage participation in future programs and offerings to fully maximize the benefits of the GT Plan. The plan specifically addresses education for full deployment of AMI and the Smart Charging Infrastructure Pilot Program, consistent with the 2018 Final Order.

DIRECT TESTIMONY
OF
NATHAN J. FROST
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, business address, and position of employment.

A. My name is Nathan J. Frost and my business address is 600 East Canal Street, Richmond, Virginia 23219. I am Director of New Technology and Energy Conservation for Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"). A statement of my background and qualifications is included as Appendix A.

Q. Please describe your area of responsibility with the Company.

A. I am responsible for delivering advanced metering and demand side management solutions for Dominion Energy Virginia. I am also responsible for integrating new technologies and developing renewable energy and energy conservation programs within the Company's regulated service territory.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to detail the Company's plan for full deployment of smart meters and the associated infrastructure (together "AMI") as part of its proposal to transform its electric distribution grid (the "Grid Transformation Plan," "GT Plan," or "Plan"). I will specifically address the elements detailed by the State Corporation Commission of Virginia (the "Commission") in its Final Order dated January 17, 2019, in Case No. PUR-2018-00100 (the "2018 Final Order"), and I will discuss the proposed deployment of AMI, including detailed cost estimates for the investments proposed during 2019, 2020, and 2021 ("Phase IB"); the proposed opt-out policy; and the Company's plan for customer education consistent with the 2018 Final Order.

I will also discuss the Company's initiatives related to electric transportation, including the Smart Charging Infrastructure Pilot Program that the Company proposes as part of the GT Plan, as well as customer education proposals.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, NJF, consisting of Schedules 1 through 10, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules:

Schedule	Description
1	Cost Schedule
2	Sample Smart Meter Post Card
3	Sample Smart Meter Door Hanger
4	Current Opt-Out Customer Information Package
5	Proposed Opt-Out Policy
6	Opt-Out Fee Breakdown
7	Proposed Update to Terms and Conditions
8	Opt-Out Fee Comparison
9	Navigant Forecast for Electric Vehicles
10	Department of Energy EVI-Pro Lite Tool Results

Additionally, I sponsor Filing Schedule Frost, Attachments A through C, which provide summaries of executed contracts and request for proposals ("RFP") from which detailed pricing estimates were prepared. The table below provides a description of these filing schedules:

Filing Schedule Frost	Description
Extraordinarily Sensitive Attachment A	RFP Summary for Meter Purchases
Extraordinarily Sensitive Attachment B	RFP Summary for Meter Exchange Vendors
Extraordinarily Sensitive Attachment C	RFP Summary for Workplace Charging

Other supporting documents include:

- AMI Master Service Agreement

This document is not included with my filing schedules due to its voluminous nature; however, the Company will make this document available electronically.

I also sponsor certain sections of the Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document. Finally, I sponsor the metrics categories as identified in Company Witness Edward H. Baine's Schedule 2.

Q. **Did you provide information to West Monroe Partners, LLC ("West Monroe") for use in the cost-benefit analysis ("CBA")?**

A. Yes, I provided costs and additional inputs for AMI, electric transportation initiatives, and customer education to West Monroe for use in the CBA. I also support the benefits reflected in Company Witness Thomas G. Hulsebosch's Schedule 2, as identified therein.

The specific costs I support in Phase IB are:

Nominal $, in Millions	**2019**	**2020**	**2021**	
	Year 1	**Year 2**	**Year 3**	**3-year Total**
Phase IB	$17.2	$83.1	$120.4	$220.8
Capital	$14.9	$73.3	$102.7	$190.8
O&M	$2.4	$9.8	$17.8	$29.9

My Schedule 1 provides detailed cost information for the GT Plan components that I sponsor.

Q. Mr. Frost, how is your testimony organized?

A. My direct testimony is organized as follows:

I. SMART METER DEPLOYMENT

Q. Please provide a brief overview of the Company's plan to deploy AMI as part of the Grid Transformation Plan.

A. Dominion Energy Virginia proposes to fully deploy AMI across its service territory. Through this technology, the Company can remotely read data gathered by smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. The full deployment of AMI is a foundational component of the Grid Transformation Plan, effectively enabling all other Plan components. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, in reduced energy consumption; and additional benefits in reduced greenhouse gases.

Q. Does the full deployment of AMI meet the definition of an electric distribution grid transformation project under Va. Code § 56-576?

A. Yes, the definition of "electric distribution grid transformation project" in Va. Code § 56-576 specifically includes "advanced metering infrastructure."

Q. You mentioned that you will address elements related to AMI required by the 2018 Final Order. What are those elements?

A. In the 2018 Final Order, the Commission denied the Company's proposal to fully deploy AMI, but did so without prejudice to the Company seeking approval of the deployment in future petitions in compliance with requirements set forth in the 2018 Final Order. The Commission specified the elements related to AMI deployment that the Company should include if it chooses to pursue the deployment on pages 10-11 of the 2018 Final Order:

> If Dominion [Energy Virginia] chooses to proceed with a proposal for full deployment of AMI, its next proposal should be supported by a detailed and comprehensive plan for evaluation that addresses, at a minimum, the following elements:
>
> a. Detailed cost estimates for all AMI-related spending.
>
> b. Any plan for time-varying rates; and whether any such offering would be the default tariff for a customer with an installed smart meter.
>
> c. Any customer "opt-out" provision, both as to smart meter installation and time-varying rates, under all tariff scenarios for those consumers who so choose and to protect particularly vulnerable customers, such as those with medical conditions that reduce their ability to manage energy usage; and any fees proposed by the Company to be charged to customers who choose to opt-out both as to time-varying rates and smart meter installation.

d. Analysis of how any plan promotes demand response, energy efficiency, and conservation.

e. A transition plan including adequate customer education.

The full deployment of AMI is foundational to the Grid Transformation Plan and many other Company initiatives. My testimony will address each of these elements, as well as other relevant information to prove that the full deployment of AMI is reasonable and prudent.

Q. On page 12 of the June 27, 2019 Final Order in Case No. PUR-2018-00065 ("2018 IRP Final Order"), the Commission ordered the Company in future integrated resources plans ("IRPs") to "systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects. For identified grid transformation projects, the Company shall include: (a) a detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) detailed cost estimates of each proposed investment; (c) the benefits associated with each proposed investment; and (d) alternatives considered for each proposed investment." (Internal footnotes omitted.) Although this is not an IRP proceeding, does your testimony address these requirements as they relate to AMI?

A. Yes, I will discuss each of these items. I will also discuss the proposed deployment plan for AMI, the proposed opt-out policy, and the Company's plan for customer education consistent with the 2018 Final Order.

A. Existing System, Need, and Proposed Deployment Plan

Q. What is the current make-up of the meter population across Dominion Energy Virginia's service territory?

A. Dominion Energy Virginia serves approximately 2.54 million customer accounts in Virginia. As of July 1, 2019, approximately 78% of Virginia customer meters were automated meter reading ("AMR") meters, approximately 17% were smart meters, and approximately 5% were manually read meters. Section III.D of the Plan Document provides details on these meters and how they function.

Q. What is the need driving the full deployment of AMI?

A. The full deployment of AMI is needed to enable the functionality of a transformed grid and to meet the needs and changing expectations of our customers. The Company's existing AMR meters have served the Company and its customers well but have functional limitations. The existing AMR meters:

- Cannot provide interval energy usage data or demand readings, without which the Company cannot effectively provide detailed usage information to its customers nor offer more advanced rate options like time-varying rates;
- Cannot capture operational conditions in real time or on demand, such as outage information and meter tampering;
- Cannot provide real-time premises level voltage, which is critical to integrating distributed energy resources ("DERs") and enabling advanced analytics;
- Cannot be remotely controlled or operated, meaning that the Company must send a field representative for common requests.

Q. What is AMI and how does it function?

A. The term AMI, or "advanced metering infrastructure," refers to the over-arching metering system, which includes smart meters, a field area network, and a back office system called the AMI head-end system.

Smart meters are electric meters that digitally gather energy usage data in specified increments (*i.e.*, interval data) and other related information. Examples of the information captured by smart meters include energy usage, demand, voltage, and meter temperature, as well as other real-time information regarding the operational status, self-diagnostics, power quality, and condition of the electric grid at the customer premises—enabling the meter to function as an end-of-line sensor at the customer premises.

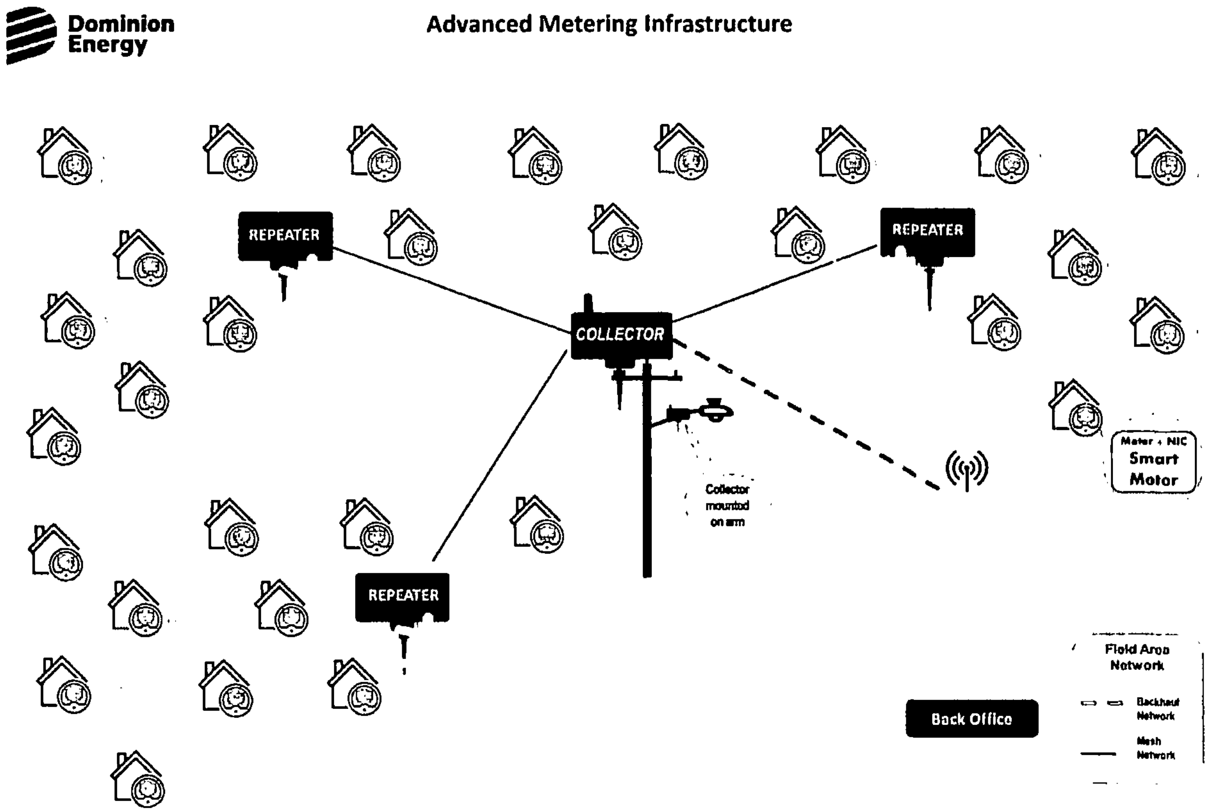
Smart meters are equipped with a network interface card ("NIC") and communicate with each other, creating what is referred to as a mesh network. The higher the density of smart meters, the stronger the mesh network.

A system of field telecommunications devices—comprised of devices called repeaters and collectors—gathers meter data from the mesh network and transmits the data gathered back to the utility through a backhaul network. Together, the mesh and backhaul networks are called the field area network.

A head-end system receives and processes the data and serves as an operating platform for the back office team responsible for operating and maintaining AMI. The head-end system also provides information from smart meters to other Company operating and analytical systems such as the meter data management system, the customer information system, and the outage management system, including valuable, real-time information regarding the operational status and condition of the electric grid at the customer premises.

Figure 1 provides a visual representation of the components of AMI and how they depend on each other to function.

Figure 1: Advanced Metering Infrastructure



Q. Does the Company have experience with AMI?

A. Yes. In 2008, the Company began to deploy AMI technology in a targeted fashion based on specific operational and customer needs. The Company did this at a measured pace over the course of several years during which time we refined our expectations of supplier and technology capabilities and developed operational experience through real-world application. Following a competitive bidding process, the Company continued to deploy smart meters in larger quantities and densities in diverse geographical areas of our service territory in order to validate deployment and operational strategies. The Company used the knowledge gained from this limited deployment of AMI to develop its strategy for full deployment across the service territory.

Q. How does the Company propose to deploy AMI throughout the service territory?

A. The Company expects to complete deployment of AMI over a six-year period beginning in 2019. During this time, the remaining approximately 2.1 million smart meters and 3,100 network devices will be deployed in a structured manner across the Virginia service territory office-by-office, with deployment occurring in multiple offices at the same time.

Within each office, the first step is to establish the field area network by deploying network devices (*i.e.*, repeaters and collectors). Next, the deployment of smart meters occurs, which fills in the mesh network, resulting in a robust, secure, and reliable network for two-way communication. As smart meters are deployed, their levels of communication and performance in the context of the growing AMI footprint are monitored and measured against established criteria. After the installation of smart meters in a given office is complete, a period of network optimization will take place where communication levels are measured, and additional network devices may be deployed to further bolster communications.

Table 1 details the projected plan for full deployment of AMI as measured by the number of smart meters installed in a given office.

Table 1: Smart Meter Deployment Plan

Region	Office	2019	2020	2021	2022	2023	2024	Total
Central	Richmond	40,000	124,000	2,000				166,000
Northwest	Orange	11,000						11,000
Eastern	Williamsburg		51,000					51,000
Eastern	Norfolk		58,000	43,000	1,000			102,000
Eastern	Peninsula		103,000	74,000	2,000			179,000
Central	Petersburg		40,000	62,000	3,000			105,000
Eastern	VA Beach			188,000	11,000	3,000		202,000
Central	East Richmond			80,000	19,000	2,000		101,000
Eastern	Chuckatuck			64,000	65,000	2,000		131,000
Northwest	Woodbridge			40,000	55,000			95,000
Northwest	Warrenton				33,000			33,000
Central	Midlothian				118,000	29,000	1,000	148,000
Northwest	Leesburg				81,000	1,000		82,000
Central	Fredericksburg				79,000	32,000		111,000
Eastern	Chesapeake				75,000	2,000		77,000
Northwest	Fairfax				15,000	107,000	1,000	123,000
Central	Southside					19,000		19,000
Northwest	Blue Ridge					61,000		61,000
Central	Farmville					25,000		25,000
Central	Altavista					14,000		14,000
Northwest	Rockbridge					15,000		15,000
Central	South Boston					20,000		20,000
Northwest	Springfield					40,000	97,000	137,000
Central	Northern Neck						24,000	24,000
Northwest	Alleghany						14,000	14,000
Central	Gloucester						44,000	44,000
Northwest	Shenandoah						20,000	20,000
	TOTALS	51,000	376,000	553,000	557,000	372,000	201,000	2,110,000

For simplicity, the totals represent rounded figures. A very small sub-set of meter replacements may require special equipment and handling that may cause actual completions to fall outside of the years indicated above.

Q. What was the rationale used to determine this deployment plan?

A. The major determining factors for the full deployment plan were metering operations efficiency, deployment efficiency, and geographic diversity. Looking first at operations, the Company analyzed which areas in its service territory require the highest number of truck rolls for basic meter-related service order types. Such requests can be performed remotely once AMI is deployed, and fewer truck rolls will lead to lower cost of service components and reduced greenhouse gas emissions. The Company prioritized field offices based on this analysis; offices that would experience the largest reduction of truck rolls, like Norfolk, Peninsula, and Petersburg, were pulled forward in the deployment plan.

The Company also considered deployment efficiencies in developing its plan. Deploying an entire office and then neighboring offices improves efficiencies for deployment resources and allows support resources to train in one area on the new technology before starting up a team in another area. Additionally, as mentioned previously, smart meters communicate with each other to form the mesh network. Without a strong mesh network, smart meters cannot communicate with the backhaul network. And without the mesh and backhaul network, no two-way communications between the Company and the customers' smart meter exist to enable meter reading and remote functionality or any of the other benefits associated with smart meters. For these reasons, the Company has and proposes to continue to deploy AMI office-by-office, which will ensure operational efficiency and cost effectiveness.

Finally, the Company also incorporated geographic considerations into the deployment plan, ensuring that each of its three regions has deployment activity by 2021, but giving early preference to Central and Eastern regions based on the focus of previous deployments in Northwest region and the truck roll reduction potential in these areas.

Q. Table 1 shows a number of smart meters being deployed in 2019. Why is that?

A. The Company had ordered approximately 60,000 smart meters prior to the 2018 Final Order to further the deployment of the existing 435,000 meters in the field, to keep vendors engaged, and to maintain experience with the most recent technological developments in the industry. We believe that these installations were in the best interest of our customers and are optimistic that the Commission will see the value of the investment.

Q. Will any operating systems be retired or replaced as a result of full AMI deployment?

A. The Company plans to use the AMI head-end system currently in place for the full deployment of AMI. This system has proven to meet the functional and technical specifications of Dominion Energy Virginia, and will scale to support expanded capacity in alignment with the planned rollout of smart meters. The Company will upgrade the system as needed as the deployment of smart meters progresses and as the Company enables additional AMI capabilities. Additionally, the Company plans to retire the AMR head-end and associated systems.

B. <u>Cost Estimates</u>

Q. What are the projected investment levels for AMI deployment during Phase IB of the Grid Transformation Plan?

A. Table 2 shows the Company's anticipated capital and operations and maintenance ("O&M") investments for the deployment of AMI during Phase IB. Table 2 is an excerpt from my Schedule 1. As described by Company Witness Gregory J. Morgan, the Company has committed to the investments related to AMI in Phase IB being recovered through its existing rates for generation and distribution services ("base rates").

Table 2: Phase IB Estimated AMI Capital and O&M Investment (in millions)

2019		2020		2021		Total 3 Years*	
Capital	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
$14.9	$1.9	$71.9	$3.0	$100.3	$4.6	$187.0	$9.6

* Three year totals may not add due to rounding.

Q. What is the Company's total projected investment for AMI deployment?

A. As shown in Schedule 1, the Company anticipates an estimated $394.4 million in capital investment and $53.9 million in O&M investment for the full deployment of AMI over the 10-year GT Plan period.

Q. How did the Company develop these estimates?

A. The Company developed these cost estimates based on competitively negotiated contract pricing for various project components, along with current system information on quantity, type, and location of meters, engineered solutions for AMI field network design by deployment area, current and future internal labor rates, contracts for cellular backhaul network communications, and call center operations historical and projected costs. Our previous experience deploying AMI informed the cost estimates.

Q. Please discuss the competitively negotiated contracts you mentioned.

A. In 2011, the Company conducted a competitive bidding process for the overall AMI systems vendor, including the back office system (*i.e.*, the head-end system), network devices (*i.e.*, repeaters and collectors), network device installation, and smart meter purchases. This process resulted in the selection of Itron Networked Solutions, Inc.

("INSI"), formerly known as Silver Springs Network or SSN. In 2018, the Company went through a process with INSI to transition our AMI head-end system to the cloud, resulting in a new 10-year contract with updated pricing based on our current full deployment plans. The Master Service Agreement ("MSA") and all associated addendums, including the 2018 Statement of Work associated with conversion to the cloud, which are voluminous in nature, will be made available electronically. In addition to an updated contract, transitioning to the cloud provided the Company with cost savings associated with our network and data center infrastructure, which would have otherwise needed upgrading in order to support the full deployment of AMI. Additionally, an enhanced level of support from INSI is available now that the system is hosted in their cloud environment, providing further labor savings to the Company.

In 2019, the Company decided to separate smart meter purchasing efforts from the MSA. The Company conducted an RFP for smart meter purchasing, as described in Filing Schedule Frost, Attachment A. Based on the results of the RFP, the Company decided to use multiple meter suppliers in order to reduce the risk associated with single source supply, to ensure access to new features as they become available, and to maintain competitiveness in pricing. The Company expects to sign contracts with multiple suppliers in the coming months.

Throughout our initial deployment of AMI, the meter exchange vendor has been procured through a competitive bidding process. In 2019, the Company conducted another RFP for meter exchange contractors in order to ensure we have the best partner and most competitive pricing for full deployment. The 2019 RFP is described in Filing Schedule Frost, Attachment B. The Company expects to sign a contract with the chosen supplier in the coming months.

Q. Have these projected costs been incorporated into the CBA presented by the Company in this proceeding?

A. Yes, I have provided my Schedule 1 to Company Witness Thomas G. Hulsebosch from West Monroe, who has included them in the CBA.

C. Benefits of AMI

Q. What are the benefits of full AMI deployment?

A. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. Nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Quantitative benefits from full deployment of AMI include (i) O&M savings; (ii) avoided capital; and (iii) other benefits in the form of reduced bad debt expense, reduced energy diversion, and improved meter reading accuracy. Additional benefits also result from AMI, including reduced greenhouse gas emissions and economic development.

The full deployment of AMI, combined with the proposed customer information platform ("CIP"), also enables broad deployment of time-varying rates and enhances demand-side management ("DSM") programs, leading to energy and demand savings. Together with West Monroe, the Company has quantified these benefits and included them in the CBA to show the value of full deployment of AMI to customers.

In addition to the quantifiable benefits directly related to AMI, smart meters function as end-of-line sensors, generating essential real-time, premises-level data points. Combining these capabilities of AMI with the grid improvement investments discussed by Company Witness Robert S. Wright, Jr., will provide new and valuable insights, correlations, and trends that will, among other things, detect distribution equipment issues proactively and support circuit automation, dynamic circuit reconfiguration, and distribution asset and device monitoring.

In addition to the benefits quantified and shown in the CBA, many qualitative benefits result from the full deployment of AMI, including improved customer experience, reduced hazard exposure for employees, enhanced load forecasting, and enhanced cost of service studies. Other qualitative customer engagement benefits rely on the combination of AMI and CIP.

The benefits of full AMI deployment are perhaps best understood by looking at the functional capabilities of AMI.

Q. What are the foundational capabilities of AMI?

A. Foundational capabilities of AMI include: (i) remote meter reading; (ii) remote connect / disconnect; (iii) "found ons"; (iv) meter alerts; and (v) detailed energy usage data (*i.e.*, interval data). The Company has enabled these capabilities and has seen the resulting benefits in the limited population of AMI already deployed in its service territory. The benefits of these capabilities will grow with the expanded deployment of AMI across our service territory.

Q. Please explain the remote meter reading capability of AMI and describe the associated benefits.

A. With AMI, the Company can remotely read smart meters. As of June 30, 2019, we have completed over 78 million daily reads this calendar year. Our success rate is 99.84% for remote daily reads for this time period, meaning we get a daily read for every smart meter 99.84% of the time. AMI remote reading capability has out-performed non-AMI based reading methods. For example, for the month of May 2019, the read rates for AMR and manually read meters were 99.2% and 96.2%, respectively, meaning we get monthly reads for all AMR meters 99.2% of the time and for manually read meters 96.2% of the time.

Remote meter reading leads to O&M savings because the Company will no longer have expense associated with the people and the vehicles needed to retrieve and process readings from non-AMI meters, or re-readings when the data was missed on the first attempt. In addition, remote meter reading will lead to billing process improvements, driving out inaccuracies and process exception handling. The remote meter reading capability also leads to avoided capital; specifically, the Company will avoid the additional capital associated with AMR-related equipment and systems.

Remote meter reading also provides qualitative benefits in the form of reduced estimated bills and leads to an improved customer experience. Remote meter reading also means that fewer trucks are on the road, resulting in lower fuel usage and greenhouse gas emissions and less hazard exposure for our employees.

Q. Please explain the remote connect / disconnect capability and describe the associated benefits.

A. AMI allows the Company to remotely connect and disconnect electric service from most customer premises, reducing the need for meter servicing personnel to visit customer premises. With the existing population of smart meters on our system, the Company has avoided over 82,000 truck rolls to complete these types of service orders so far this year, equating to approximately 19.3% of all service orders of this type across our system. Once AMI is fully deployed, the Company anticipates that approximately 75,000 service orders of this nature will be completed remotely each month.

Remote connect / disconnect leads to O&M savings because the Company will no longer have expense associated with the people and the vehicles needed to complete these orders for non-AMI meters. This AMI capability also reduces bad debt expense. By reducing the number of calendar days between a disconnect order and its execution, the balance of past due charges and associated fees is more manageable for customers to resolve. As of June 30, 2019, year-to-date, the average customer bad debt amount for AMI customers was $378 versus $686 for non-AMI customers.

Similar to remote meter reading, remote connect / disconnect provides qualitative benefits in the form of an improved customer experience, particularly associated with move in / move out activities, reduced greenhouse gas emissions, and reduced hazard exposure for Company representatives.

Q. Please explain the "found on" capability of AMI and describe the associated benefits.

A. The Company uses AMI during storm restoration to identify premises that have had power restored but that the system still shows as an outage, which the Company refers to as "found ons." Operators can "ping" smart meters from the back office to determine if power is on and, if so, can close the outage work orders proactively.

The "found on" capability enabled by AMI leads to O&M savings because the Company will no longer have the expense associated with sending trucks to locations where power has already been restored. Data from the existing AMI footprint shows that the number of "found ons" during outage events is reduced by 80% with AMI. In addition to eliminating unnecessary truck rolls, this capability allows crews to focus on locations that actually require line work for service restoration, leading to faster overall restoration for all affected customers.

Q. Please explain the meter alerts available with AMI and describe the associated benefits.

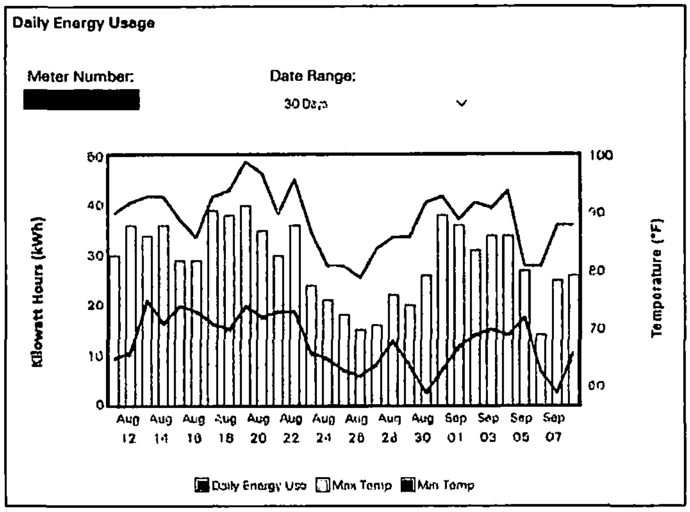
A. AMI meters generate alerts that are communicated to the head-end system, enabling back office personnel to monitor the status of power at the customer premises and generate orders for field investigation when necessary. For example, these alerts can show usage irregularities indicating unauthorized tampering with the Company's metering equipment ("energy diversion"), high internal meter temperature indicating a potential problem with Company or customer equipment, and voltage anomalies indicating operational issues.

Meter alerts lead to O&M savings in the form of reduced energy diversion. In addition to O&M savings, meter temperature alerts from smart meters have generated field visits to investigate operating conditions prior to equipment failure, which has avoided outages and potential damage to equipment and property.

Q. AMI collects and transmits detailed energy usage data (*i.e.*, at a 30-minute interval level). What benefits flow from this data?

A. Having detailed energy usage data unlocks many benefits for the Company and its customers. For customers, this data shows usage patterns, which help them to better understand their bill and to identify ways to reduce usage. For example, the Company has developed a daily graph of usage and weather-related data, which is available to those customers with AMI meters. An example is shown in Figure 2.

Figure 2: Daily Graph of Usage and Weather Data



Additionally, the Company has developed a pilot high usage alert program for its existing AMI customers where enrolled customers receive text or email alerts in near-real time when their energy usage for the day exceeds a kilowatt-hour threshold set by the customer. In the future, with the proposed CIP, the Company can offer high bill alerts, which translate usage data to estimated dollars, and prepay, which is discussed in more detail later in my testimony.

Detailed energy usage data is particularly helpful for net metering customers to understand the details of the energy received and exported at their homes, and how that translates to their net charge each month.

Combined with the proposed CIP, this data will enable the Company to broadly offer time-varying rates and will enhance DSM initiatives, which can lead to significant bill savings and reduced system costs. I will discuss both time-varying rates and DSM initiatives later in my testimony.

In addition to the benefits that detailed energy usage data provides for customers, this data also enables a host of benefits to the Company's operations, including enhancing the Company's load forecasts used in the Company's planning processes. In addition, this data enhances cost of service studies by informing the assignment of revenue and the allocation of costs.

Q. You have discussed the foundational capabilities of AMI from which the Company has already seen the benefits. What other capabilities of AMI does the Company plan to enable or enhance in the future?

A. In the future, the Company plans to enable or enhance: (i) remote transition to net metering; and (ii) enhanced voltage data collection.

Q. Please explain the remote transition to net metering capability and describe the associated benefits.

A. Today, when a customer requests to net meter, the Company must visit the premises and exchange the existing meter once the customer has installed his or her solar system and passed inspection. This is true even in the case where the new net metering customer already has a smart meter. The Company plans to implement programming to enable remote over-the-air transitioning of the existing smart meter to a net meter upon customer completion of the net metering application process.

Remote transition to net metering will lead to O&M savings in the form of reduced expense associated with the people and the vehicles needed to complete these orders. This capability will also improve the customer experience, reduce greenhouse gas emissions, reduce hazard exposure for our employees, and ultimately facilitate the integration of DERs.

Q. Please explain the enhanced voltage data collection capability of AMI and describe the associated benefits.

A. The Company plans to upgrade its AMI head-end system to include a software module associated with voltage data collection and analysis. Enhanced voltage data collection from AMI combined with the system investments discussed by Company Witness Robert S. Wright, Jr., will enable the Company to model the behavior of DERs and perform other analytics, and will enhance feeder voltage optimization. Company Witness Wright describes these benefits.

Q. As you mentioned, and as the Commission noted in the 2018 Final Order, the full deployment of AMI enables the Company to broadly offer time-varying rates. Does the Company plan to offer time-varying rates after full deployment of AMI?

A. Yes, we do. The Company is in the process of developing time-varying rates that will leverage AMI both during and after deployment. Company Witness Morgan describes the Company's plans related to time-varying rates. He also addresses the direction provided in the 2018 Final Order related to opt-in and opt-out options for such rates.

Q. Does full AMI deployment enable a prepay program?

A. Yes. Full AMI deployment combined with the new CIP will enable the Company to develop a prepay program. Prepay is a program that allows customers to make an up-front payment of their energy bill that will then be reduced over time based on their ongoing usage. Customers will receive alerts as their balance is depleted, and can take action accordingly. In other words, prepay allows customers to manage their energy usage within their budget. In the industry, prepay programs have also been shown to result in energy savings.

Q. You also mentioned that AMI will enhance the Company's DSM initiatives. Please discuss.

A. The Company intends to leverage AMI to enhance DSM initiatives in its service territory. To that end, in March 2019, the Company issued an RFP for DSM programs that included a request for information about the degree to which AMI could enhance program operations. The responses generally state that broad deployment of AMI would provide information that could be used to more effectively target the most appropriate customers for specific programs and would provide better recommendations for energy savings within any program that involves a behavioral or educational component. In addition, broad deployment of AMI would provide information that could be used to enhance the evaluation of program effectiveness and would enable, in conjunction with a new CIP, implementation of a future peak-time rebate ("PTR") program.

Q. Please explain how a PTR program would work.

A. PTR is a customer program designed to target and reduce the Company's coincident peak period. The Company would call a certain number of PTR events per year, each lasting for a certain number of hours. For example, the Company could call ten four-hour events per year to cover projected coincident peak periods. Once called, enrolled customers would receive a notification of the opportunity to reduce usage, and would earn a rebate if they reduce usage during the PTR event. Customers would not be penalized if they do not reduce usage during the event.

Q. Aside from enabling DSM programs that leverage AMI, does full AMI deployment provide other benefits to the Company's DSM initiatives?

A. Yes, AMI also provides a significant benefit to the evaluation, measurement, and verification ("EM&V") requirements of DSM programs and further supports DSM operations. For EM&V, AMI provides detailed energy usage data from each customer endpoint where smart meters are deployed. Operationally, for customers enrolled in current peak-shaving programs, AMI can provide data indicating load curtailed at the metering points of participating customers in near-real time.

In sum, the Company fully plans to leverage the full deployment of AMI to promote demand response, energy efficiency, and conservation.

D. Alternatives Considered

Q. What alternatives to the proposed deployment of AMI did the Company consider?

A. The Company considered not expediting AMI deployment, as proposed here, but continuing a slow rollout as we have done for the last several years. Given the aging state of our non-AMI meters and systems today and the amount of investment that would be needed to maintain their viability, as well as the lack of support the legacy meters and systems provide for many grid transformation initiatives, the Company felt that this was no longer a viable deployment approach. A slower rollout of AMI delays benefits and may eliminate the benefit of some avoided capital expense altogether.

Q. Did the Company consider alternative AMI systems?

A. Yes. In 2008, the Company piloted the Elster AMI system. At that time, Elster was an industry leader in AMI systems for large utilities. Elster's AMI technology was proprietary, meaning only its smart meters could be used with its network and back office system. The Company evaluated the Elster system for applications involving commercial and industrial complex meters, rugged and expansive terrain (*e.g.*, mountain, valley, rural), and dense populations (*e.g.*, urban).

The period of 2008 to 2010 saw rapid changes in AMI technology, with many new vendors entering the market. In 2010, the Company issued a request for information ("RFI") to collect information on additional AMI systems available in the market. This research resulted in the Company issuing a competitive RFP in 2011 to select new AMI systems and smart meter vendors.

During this process, the Company focused on potential vendors' relevant experience, competitive pricing, and overall capabilities. From a systems and technology perspective, technical selection criteria focused on security, network reliability, and technical performance; scalability potential; and technical and functional requirements. The Company also had a preference to select an AMI partner that would allow for diversity in smart meter suppliers, and wanted to ensure that the selected technology would not become obsolete in the medium and long term. From this RFP, the Company selected its AMI systems vendor, INSI (formerly Silver Springs Networks).

Q. Does the Company have any concerns related to the potential premature obsolescence with the selected AMI technology?

A. No. The Company is not concerned with premature obsolescence of the chosen AMI technology based on the status of AMI deployment across the United States; the research published by third parties and industry experts; and the technology features and capabilities, including specific feedback and assurances from the vendors. Company Witness Hulsebosch provides further details regarding AMI technology from an industry perspective.

E. Customer Education

Q. The 2018 Final Order required information on a transition plan to AMI, including adequate customer education. How does the Company plan to educate customers in connection with the full deployment of AMI?

A. Fully deploying AMI across the service territory provides the Company with the unique opportunity to interact directly with 2.1 million customers over the next six years. To ensure that the customer experience associated with the meter exchange is a positive one, the smart meter deployment team will be executing an outreach and education strategy, to include targeted communications to each customer prior to and during the installation phase of the new smart meter. These types of communications will be delivered through several channels, including direct mail, door hangers, social media, web, mobile, and public presentations. Customer communications will alert customers of the upcoming meter exchange, direct customers to the website for frequently asked questions, and provide options for setting an appointment for property access if needed. Examples of direct mail and door hangers can be found in my Schedules 2 and 3.

Additional post-deployment communications and outreach will also serve as a mechanism to educate and inform customers on benefits of their smart meter. Post-deployment outreach will include educating customers on tools already available to smart meter customers, and to new tools and applications as they become available. For more information on post-deployment customer education, please refer to Section VI.A.7 of the Plan Document.

Q. Is customer education related to the GT Plan necessary beyond the full deployment of AMI?

A. Yes. Because the Grid Transformation Plan is comprehensive and offers such a wide variety of benefits to all customer types, customer education appropriately extends to multiple GT Plan elements beyond smart meters. Accordingly, the Company will focus on educating customers about the entire grid transformation process, associated projects and investments, and about when and how they can fully utilize the new capabilities of the transformed distribution grid. This GT Plan-related customer education plan supplements the Company's overall efforts to educate its customers from topics ranging from available rate schedules to general energy education.

The Company's customer education plan for the GT Plan, which I sponsor, is attached to the Plan Document as Appendix F. The overarching goals for this plan are to educate customers, to raise awareness and understanding of the benefits of the Grid Transformation Plan investments, and to encourage participation in future programs and offerings to fully maximize the benefits of GT Plan. This will be accomplished by the Company's commitment to deliver concise, consistent, easy-to-understand content via multiple external communications channels, including but not limited to, website content, social media, digital and direct mail, bill inserts and newsletters, presentations and public events, video and display signage, media coverage through local and regional news outlets and interactions with the customer service organization.

F. <u>Opt-Out Policy</u>

Q. The 2018 Final Order required information on any opt-out policy related to smart meter installation. What is the Company's position related to customers opting out of the smart meter deployment?

A. The Company fully supports AMI and the benefits it provides, and believes all customers should have a smart meter. Accordingly, the Company has developed a comprehensive customer education plan. Nevertheless, the Company understands that some customers may prefer not to have a smart meter and we plan to accommodate those customers where practical if deemed necessary by the Commission.

Q. Please describe the process involved when a customer opts out of smart meter deployment.

A. When a customer opts out of smart meter installation, the Company must expend additional resources both initially and on an ongoing basis. Up front, the Company must create an opt-out version of the meter—a smart meter with the communications device removed. The Company must then install that meter. There are also administrative expenses associated with a customer's initial decision to opt out of smart meter installation, such as program administration and reporting, customer communications and account management, work order generation and scheduling, inventory management and shipping. On a monthly basis, the Company must send a meter reader to manually read the non-communicating meter.

Q. What is the Company's current opt-out practice for smart meters?

A. Currently residential customers on Rate Schedule 1 with accounts in good standing are allowed to opt out of smart meter installation upon request and at no expense. These customers receive an information packet explaining the benefits of AMI that they would forego by opting out. The customer is required to complete and return forms confirming their acknowledgement that opting out at no expense is an interim solution until the Company has an opt-out program approved by the Commission. See my Schedule 4 for details on the information packet provided when a customer requests to opt out of smart meter installation.

Q. How many customers have opted out of smart meter installation during the initial deployment of AMI?

A. As of June 30, 2019, a total of 694 customers, or 0.16% of our current smart meter population, have chosen to opt out of having a smart meter. However, opt out to date has occurred at no cost to the customer, so the Company expects the percentage of smart meter opt-out customers to decline once fees are imposed.

Q. Please describe the opt-out policy that the Company is proposing going forward.

A. Under the Company's proposed opt-out policy, residential customers taking basic service on Rate Schedule 1 with accounts in good standing will be eligible to opt out of smart meter installation upon request. The Company proposes to impose a one-time initial fee of $84.53 and an ongoing monthly fee of $29.20. These fees are intended to be revenue neutral, meaning that the Company intends to only recover the incremental costs of a customer opting out of smart meter installation. My Schedule 5 provides a draft of the proposed policy, including fees. My Schedule 6 provides a detailed breakdown of estimated up front and ongoing costs associated with customers opting out of smart meter installation. My Schedule 7 provides the proposed update to the Company's Terms and Conditions in clean and redline formats for which the Company seeks approval to implement these proposed fees. Finally, my Schedule 8 provides charts comparing the proposed fees with those imposed by other utilities for smart meter opt out.

Q. Why is the opt-out policy limited to certain residential customers?

A. Customers receiving electric service on any time-varying or demand rate and customers who generate electricity are ineligible to opt out of smart meter installation because detailed energy usage data is required to bill these customers. Allowing these types of customers to opt out of smart meter installation would require maintenance of legacy systems or significant enhancements to existing systems, which the Company has determined to be cost prohibitive.

Additionally, for customers who generate electricity, allowing these customers to opt out of smart meter installation would preclude the Company from monitoring voltage and other characteristics of electrical service at that endpoint—eliminating the end-of-line sensor benefit of smart meters.

Q. What will happen to existing opt-out customers?

A. Once approved, the Company proposes to send all current interim opt-out customers a letter informing them of the opt-out policy and associated fees. These customers will have the option to opt in to AMI at no charge, or they will be transitioned to the approved opt-out program where ongoing fees will be applied to their account from a specified date going forward. The one-time initial fee will not be billed to these interim opt-out customers because the costs have already been recovered through base rates.

II. ELECTRIC VEHICLES

Q. Mr. Frost, what is the status of the electric vehicle ("EV") market today?

A. EVs are continuing to gain market share, largely due to advancements in battery technology, additional EV model availability, declining costs, and benefits provided to customers and the environment. According to a recent Edison Electric Institute Report,[1] the number of EVs on the road in the United States is projected to reach 18.7 million in 2030, which is up from approximately 1 million EVs on the road at the end of 2018. This projection is about 7% of the 259 million cars and light trucks expected to be on U.S. roads in 2030.

In Virginia, as of December 31, 2018, there were approximately 16,500 electric vehicles registered, which is 63% growth since December 31, 2017. Of the 16,500 EVs in Virginia, approximately 11,110 were registered in the Company's service territory. The Company worked with Navigant Consulting, Inc. ("Navigant") to forecast EV adoption in the Company's service territory. Navigant's forecast shows that adoption is expected to increase in the years to come, with about 169,000 EVs projected to be in the Company's Virginia service territory in 2030. See my Schedule 9 for the full adoption forecast.

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[1] See *http*://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20EV%20Forecast%20 Report_Nov2018.pdf.

Q. Please provide an overview of the Company's overall strategy to meet this growing demand for electric transportation.

A. The Company has worked diligently with its customers, stakeholders, and peers, as well as internal and external experts, to develop a comprehensive electric transportation strategy. The strategy includes internal initiatives focused on the Company's own activities and external initiatives designed to ensure grid reliability and to be a trusted resource for customers as they transition to electric transportation. Internally, the electric transportation strategy includes offering workplace charging to employees and incorporating more EVs into the Company's fleet. Externally, the strategy includes developing rate structures and DSM programs that support off-peak EV charging, supporting the development of smart charging infrastructure, and educating customers on electric transportation.

Q. What portion of this overall electric transportation strategy is the Company seeking approval of in this proceeding?

A. As part of the GT Plan, the Company is seeking approval of incentives for customers to adopt smart charging infrastructure. The Company is also proposing to own charging infrastructure at certain strategic locations. We will refer to these initiatives as the "Smart Charging Infrastructure Pilot Program."

Q. Before discussing the Smart Charging Infrastructure Pilot Program, please provide some additional details on other aspects of the Company's electric transportation strategy. What are some examples of the internal EV-related initiatives?

A. The Company believes that the electrification of transportation provides a number of benefits, and plans to lead by example. The Company has worked collaboratively with its corporate parent, Dominion Energy, Inc. ("Dominion Energy"), to enable many of its internal EV-related initiatives. For example, in May 2019, the Company began operating an all-electric shuttle between its Richmond-based offices. The Company will continue to add additional electric vehicles to its fleet with a goal of having 25% of its light duty fleet converted to electric or plug-in hybrid electric by 2025. As another example, Dominion Energy is installing workplace charging stations at a number of offices. These initiatives support electric transportation options for employees and will help the Company gain installation and operating experience—experience that it can use to help its customers who have similar initiatives.

Q. You also mentioned external initiatives to develop rate structures and DSM programs that support smart EV use. Please elaborate.

A. The Company is developing new, time varying rate structures to allow customers, including EV drivers, to better manage their energy usage. Company Witness Morgan addresses the status of those efforts and the Company's plan to file an experimental, voluntary time varying rate.

The Company is also evaluating DSM programs designed to encourage efficient charging of electric vehicles and shifting of electric vehicle charging load to off-peak periods. The Company solicited market input for EV-related DSM program designs in its most recent DSM RFP. The Company is currently evaluating the results from the DSM RFP in advance of its next DSM filing.

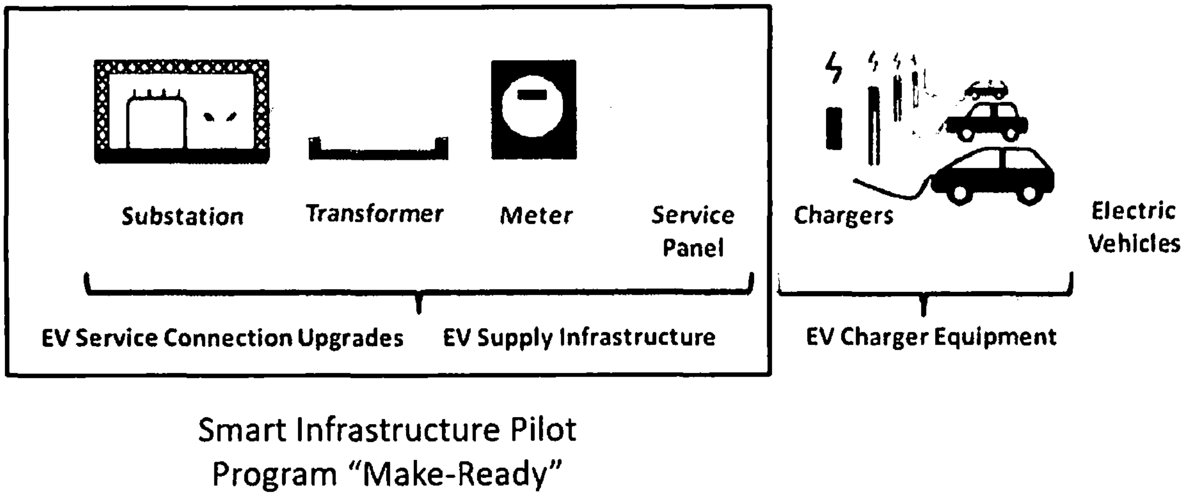
Q. Are there any other external initiatives aside from the Smart Charging Infrastructure Pilot Program that you would like to highlight?

A. Yes, the Company recently launched three other EV-related initiatives that I would like to mention. First, earlier this year, the Company launched an innovative online electric vehicle educational tool at www.dominionenergy.com/EV, which consists of a savings calculator, information on carbon reduction, a charger finder, and more. The Company launched this website to respond to customer questions and to further efforts in gaining customers' trust in the Company as an expert for electric transportation. Second, on August 29, 2019, the Company announced an innovative electric school bus initiative to replace diesel school buses with electric school buses, and then leverage the batteries using vehicle-to-grid technology. Third, the Company is evaluating a potential project to study battery storage paired with direct current fast charging infrastructure, which should provide feedback on the capabilities of the technology.

Q. Turning to the Smart Charging Infrastructure Pilot Program, please explain the proposed program.

A. The proposed Smart Charging Infrastructure Pilot Program aims to provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional investments, pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid. The Pilot Program will consist of (i) rebates for the infrastructure and upgrades, if necessary, at EV charging sites, often referred to as the "make-ready," and (ii) rebates for the smart charging equipment that enables managed charging. Figure 3 provides a diagram of these two components of EV infrastructure.

Figure 3: EV Infrastructure Diagram



Source: Edison Foundation, Plug-in Electric Vehicle Sales Forecast Through 2030 and the Charging Infrastructure Required, Figure 7

The Pilot Program will also include Company-owned charging infrastructure at strategic locations.

Q. **Does Smart Charging Infrastructure Pilot Program meet the definition of an electric distribution grid transformation project under Va. Code § 56-576?**

A. Yes, the Pilot Program includes investment in "electrical facilities and infrastructure necessary to support electric vehicle charging systems."

Q. **Are there other policies that support the Company's strategy, including the Smart Charging Infrastructure Pilot Program?**

A. Yes. The Virginia Energy Plan encourages the shift to alternative fuel transportation including electric vehicles. The Virginia Energy Plan also mentions the benefits of managed charging. The Company's Smart Charging Infrastructure Pilot Program also supports the Commonwealth's participation in the Transportation Climate Initiative by encouraging low-to-no emission vehicles in furtherance of reducing pollution from the transportation sector.

Q. As you did in the AMI section above, can you please address the Commission's four requirements the 2018 IRP Final Order as they relate to the Smart Charging Infrastructure Pilot Program?

A. Yes, I will discuss each of these items in turn. I will also discuss the proposed deployment plan developed based on the identified need, as well as the Company's plan for customer education related to the Pilot Program.

A. <u>Existing System, Need, and Proposed Deployment Plan</u>

Q. Please explain how EVs are typically charged.

A. Charging an EV requires plugging in to a charger that is connected to the electric grid. There are three major categories of chargers that are distinguishable by the amount of power the charger can provide, which results in different speeds of charging. Level 1 refers to use of a standard 120-volt ("V") outlet, which charges three to five miles of range per hour. Level 1 charging is ideal for overnight charging for EV owners that travel about 30 miles or fewer per day. Level 2 chargers require a higher voltage at 240V, which charges 10 to 20 miles of range per hour. Level 2 charging is ideal for workplaces, multi-family dwellings, and locations with the potential for more electric vehicles than chargers. Finally, Level 3—also known as direct current fast charging ("DC Fast Charge" or "DCFC")—can charge an EV battery to approximately 80% of capacity in 20 to 30 minutes. DCFC requires three-phase electric service and significant capacity. It is ideal for public locations to support travel over long distances.

Q. What is the current status of charging infrastructure in Virginia?

A. As of August 15, 2019, there were approximately 595 Level 2 and DCFC charging stations in Virginia available for public use according to the Alternative Fuels Data Center. The Company has worked with charging station companies including Tesla Motors, Electrify America, and EVgo Services to interconnect the majority of the charging stations installed in Virginia, including several sites with connected load of over one megawatt.

While the number of charging stations may seem significant, not all of these stations are available to all EV drivers. For example, many of the DCFC stations are Tesla Superchargers, which are limited to Tesla drivers. Others are installed at dealerships and are only available during business hours. There are also concerns about redundancy; many charging stations sites only have one station, meaning if the station is in use or out of service, an EV driver must wait or attempt to find another charging site. Lastly, most of the non-Tesla DCFC stations have a charging capacity of only 50 kilowatts ("kW"), which is faster than Level 2 charging, but still can require more than one hour to charge an EV battery to 80%. Newer DCFC technology is often 100 kW or higher, which can charge an EV battery much faster than 50 kW technology.

Q. Will this charging infrastructure support the projected level of adoption of EVs in the Commonwealth?

A. No. Industry sources attempt to project the level of charging infrastructure needed to support specific levels of adoption. To support 169,000 EVs forecasted to be in Virginia in 2030, the Department of Energy's EVI-Pro Lite tool[2] estimates the following infrastructure is needed:

- 3,778 workplace charging Level 2 plugs;
- 2,614 public Level 2 charging plugs; and
- 414 public DCFC charging plugs.

My Schedule 10, page 1 of 2, shows the results from the Department of Energy's EVI-Pro Lite tool.

Q. What are the drivers of the Smart Charging Infrastructure Pilot Program?

A. Though the level of adoption varies by source, industry experts agree that EV adoption will continue to increase, and with that adoption comes increased demand for electricity. The Company recognizes the opportunity to manage this increased demand to minimize impacts on the distribution grid and increase overall grid utilization.

Q. What is managed charging and why is it important?

A. Managed charging—also called intelligent or smart charging—allows a utility or third-party to remotely control vehicle charging by turning it up, down, or off to better correspond to the needs of the grid, much like traditional demand response programs. Managed charging is important because without awareness of the additional load resulting from EV charging and the ability to manage it, the Company loses the opportunity to reduce the impacts on the distribution grid.

As shown in Schedule 9, approximately 169,000 EVs are forecasted in the Company's Virginia service territory, requiring 558 gigawatt-hours ("GWh") of electricity annually

[2] *See* https://afdc.energy.gov/evi-pro-lite.

with a demand of 187 megawatts ("MW"). Prudently integrating and managing EV charging load on the grid is foundational to the Company's EV strategy, and vital to the Company's larger grid transformation objectives. The Company is not alone in this goal. According to the Smart Electric Power Alliance, as of May 2019, there were 38 utility-run managed charging pilots or programs for residential customers, multi-family customers, workplaces, fleets, public charging, and transit.

Q. How many rebates does the Company propose to offer through the Smart Charging Infrastructure Pilot Program, and to whom?

A. The Pilot Program will offer rebates to multi-family sites, workplace sites, public DCFC sites, and to transit agencies installing infrastructure for electric buses. The table below provides a summary of the segments, incentive amounts, and number of incentives.

Table 3: Phase IB Rebates

Segment	Rebate Amount	Number of Charging Stations During Phase IB
Multi-family	• Up to \$4,071 for each dual port Level 2 networked charging station • Up to \$11,140 for make-ready for each station	Up to 25 charging stations
Workplace	• Up to \$2,714 for each dual port Level 2 networked charging station, • Up to \$11,140 for make-ready for each stations	Up to 400 charging stations

Segment	Rebate Amount	Number of Charging Stations During Phase IB
DCFC	• Up to $36,720 for each dual port networked DCFC charging station • Up to $73,500 for make-ready for each station	Up to 30 charging stations; each customer must install at least two charging stations per site that can charge all EV types; each customer is limited to four rebates
Transit	• Up to $53,451 for each networked DCFC charging station • Up to $73,500 for make-ready for each station	Up to 60 charging stations; each customer is limited to a maximum of six rebates

To be eligible for a rebate, the site host must agree to provide charging data to the Company. The data includes, but is not limited to, time and duration of charging sessions, energy consumed, and peak demand during the charging sessions. The site host is responsible for the procurement, installation, and ownership of the EV charging station(s). The rebate amounts for the make-ready are designed to offset the cost of the electrical infrastructure and upgrades needed to install the smart charging infrastructure. The rebate amounts for the charging stations are designed to help offset the incremental cost of installing a smart charging station instead of a charging station without the ability to collect charging data and participate in managed charging.

Q. **You stated that the Company will also own charging infrastructure at strategic locations as part of the Smart Charging Infrastructure Pilot Program. Please explain.**

A. Yes. The Company is proposing to own up to four charging stations during Phase IB as part of its ongoing strategy to support electrification in the rideshare market segment. The rideshare segment refers to car services that allow a rider to use a smartphone app to arrange a ride in a privately owned or leased vehicle for a fee. Including the rideshare market segment in the Smart Charging Infrastructure Pilot Program is important for several reasons. The number of vehicle miles traveled in the rideshare market is growing exponentially. Similar to other segments mentioned above, the Company does not have the data necessary to understand charging behavior and impacts to the distribution system resulting from rideshare EV drivers and seeks to obtain this data through the Smart Charging Infrastructure Pilot Program. The Company is proposing to own four charging stations sited to strategically enable additional electric vehicles to participate in rideshare platforms, and to study the charging behavior and impacts to the distribution system resulting from rideshare EV drivers concentrated in a certain area. The Company will install and own the charging stations; procurement will be through an RFP process. The Company is engaged in ongoing discussions with the rideshare industry to identify location(s) for this initiative. Locations will be in the Company's Virginia service territory. If approved, the Company will solicit site hosts in the strategically sited areas, ensuring the stations are accessible to both rideshare drivers and the public. Site hosts at the identified locations will be responsible for electricity bills, and any fees collected from drivers for the use of the charging stations will be provided to the site hosts. The Company will not retain any fees collected from drivers for the use of the charging stations.

Q. How did the Company determine what segments to target?

A. The Company determined what segments to target based on its prior experience and identified areas for growth.

In 2011, the Company launched its Electric Vehicle Pricing Plans Pilot Program to learn about its residential customers' EV charging behaviors and to study the impacts of EV charging on the grid; the Commission approved that Pricing Pilot Program in Case No. PUE-2011-00014. By the conclusion of the Pricing Pilot Program in 2018, the Company had developed a general understanding of current residential charging behavior and potential impacts to the distribution system. Accordingly, the Company is not proposing to further pilot a program for residential single-family customers. Instead, the Company is evaluating managed charging programs for single-family residential customers as part of its future DSM filings.

Since the conclusion of the Pricing Pilot Program, the EV market in Virginia has continued to grow and charging technologies and behaviors have continued to evolve. Interest in EVs has expanded from largely single-family residential customers to customers in many other segments with different charging behaviors. The Company seeks to lay the groundwork to offer pilot programs for several of these segments as part of this proceeding.

Industry experts agree that the majority of EV charging happens at home. Many multi-family residential customers, such as those in apartment complexes or condominiums, are not able to install EV charging at their residence. Instead, EV charging infrastructure would need to be installed in common areas. These customers were not part of the Pricing Pilot Program; thus, the Company seeks to incent smart charging infrastructure at multi-family locations to understand charging behavior and impacts to the distribution system as adoption increases in this segment.

The second most common location for EV charging is at work. Workplace charging allows EV drivers to increase their electric driving range each day, reduces range anxiety, and provides charging options for drivers who do not have access to home charging. The Company is not aware of widespread proliferation of workplace charging stations installed in Virginia and seeks to incent smart charging infrastructure to gather the data necessary to understand workplace charging behaviors and the impacts to the distribution system for this segment.

As stated earlier in my testimony, the Company has worked with charging station companies including Tesla Motors, Electrify America, and EVgo Services to interconnect the majority of DCFC stations installed in Virginia. These charging stations are not individually metered, so the Company seeks to incent smart charging infrastructure to obtain the data necessary to understand charging behavior and impacts to the distribution system resulting from charging at DCFC stations.

Q. Please continue.

A. In addition to charging infrastructure for passenger EVs, the Smart Charging Infrastructure Pilot Program includes incentives for smart charging infrastructure for transit agencies and universities who are electrifying their bus fleets. Similar to passenger EVs, electric transit buses are cheaper to fuel and maintain than traditional diesel buses. Electric buses provide significant environmental benefits over diesel buses in the form of reduced greenhouse gas emissions and reduced transportation noise. There has also been an influx of grant funding for electric transit buses, including in Virginia. For these reasons, the Company believes electric transit bus adoption will increase significantly over the next few years. Indeed, over the last 12 months, the Company has received seven inquiries from transit agencies and universities with bus fleets regarding electric buses. The DCFC infrastructure for transit buses can range from 60 kW to 500 kW per charger. The Company does not have the data necessary to understand charging behavior and impacts to the distribution system resulting from charging electric transit buses, and seeks to obtain this data through the Smart Charging Infrastructure Pilot Program.

The Company chose to include the rideshare segment to understand charging behavior and impacts to the distribution system resulting from vehicles that have high daily vehicle miles traveled in a concentrated area. The Company also believes that including both the transit and rideshare segments in its Smart Charging Infrastructure Pilot Program will lead to more equitable future pilots, programs, or rate designs to support EV adoption while minimizing the impact of EV charging on the distribution grid.

In summary, the Company believes collecting the data necessary to understand the charging behaviors of the segments above and the potential impacts to the distribution grid will benefit all customers because it will position the Company to design programs and rate designs to encourage managed charging.

Q. Does the Company's EV strategy include options for vulnerable customers, such as low income, elderly, and disabled individuals?

A. Yes. Electrifying transit buses will extend the benefits of electric transportation to customers that may not be physically able to drive a vehicle of their own, or that may not be financially able to purchase a vehicle. The Company's incentives for multi-family communities can provide charging infrastructure for customers in affordable housing. Additionally, the Company is committed to supporting electric rideshare vehicles; many such rides start or end in low income areas, with a Richmond Times Dispatch article reporting that 58% of local Lyft rides start or end in low-income areas.[3] Encouraging EVs in the rideshare segment will help ensure the benefits of electric transportation, such as air quality improvement, are seen in low income areas, which are often areas that are impacted with disproportionally higher emissions.

Q. Why is the Company referring to this initiative as a Pilot Program?

A. The Company is referring to this initiative as a Pilot Program because it will incent installation of the required infrastructure and collect the baseline data required to be able to design managed charging programs and other customer offerings that will support EV adoption while minimizing EV charging impacts to the distribution grid.

Q. What is the deployment schedule for the Smart Charging Infrastructure Pilot Program?

A. During the fourth quarter of 2019, the Company will issue an RFP for turn-key implementation services for the Pilot Program, including enrollment, communications, rebate processing, and evaluation. The Company will also issue an RFP for the Company-owned charging infrastructure in 2019.

If approved, the Company intends to implement the Smart Charging Infrastructure Pilot Program within 60 days of approval. The Company plans collect and evaluate data obtained as part of the Smart Charging Infrastructure Pilot Program during 2020 and 2021. In late 2021, the Company anticipates requesting approval of managed charging

[3] *See* https://www.richmond.com/opinion/their-opinion/cabell-rosanelli-column-continue-richmond-s-transportation-evolution/article_57d01f4b-d097-512a-8936-aab3f5c64c39.html. *See also* https://www.forbes.com/sites/korihale/2019/04/02/lyfts-minority-drivers-level-up-in-26-billion-ipo/#23c684882983 (reporting that 44% of Lyft rides start or end in low income areas).

pilots, programs, or rate designs. Importantly, without the data collected as part of the Smart Charging Infrastructure Pilot Program during 2020 and 2021, the Company would not be able to design customer offerings specific to the charging behavior of its customers.

B. Cost Estimates

Q. What is the Company's projected investment for the Smart Charging Infrastructure Pilot Program during Phase IB?

A. Table 4 shows the Company's anticipated capital and O&M investments for the deployment of AMI during Phase IB. Table 4 is an excerpt from my Schedule 1.

Table 4: Phase IB Estimated Smart Charging Infrastructure Pilot Program Capital and O&M Investment (in millions)

2019		2020		2021		Total 3 Years	
Capital	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
$0	$0.4	$1.5	$5.3	$2.4	$11.4	$3.9	$17.1

Q. What is the Company's total projected investment for the Smart Charging Infrastructure Pilot Program?

A. As shown in Schedule 1, the Company anticipates an estimated $7.3 million in capital investment and $42.9 million in O&M investment over the 10-year GT Plan period.

Q. How did the Company develop these estimates and ensure they are reasonable?

A. The Company began with the EV adoption forecast for its Virginia service territory developed by Navigant, attached as my Schedule 9. Next, the Company used the Department of Energy's EVI-Pro Lite tool to estimate the charging infrastructure required to support the number of EVs in the forecast in 2030, as shown in my Schedule 10. Assuming an equal number of required charging stations will be installed per year between 2020 and 2030, the Company calculated the number of charging stations that is estimated to be installed in 2020 and 2021. This served as the basis for the number of rebates proposed in the Smart Charging Infrastructure Pilot Program. The Company believes the number of rebates is reasonable for a two-year pilot program because the number of rebates is based on the infrastructure that will likely be installed during Phase IB.

The Company gathered cost information from various sources to determine the incremental cost of the smart charging stations and the costs for construction and installation. Dominion Energy Services, Inc., issued an RFP for workplace charging stations in March 2019. The Company also solicited pricing from bidders for other types of charging stations, including DCFC stations. Filing Schedule Frost, Attachment C provides a summary of the RFP. The Company used the responses to the RFP as indicative pricing and this pricing served as the basis for the rebate amounts for the charging stations. The Company requested input from several charging station companies regarding installation costs and used this input, coupled with its experience interconnecting charging stations, as indicative pricing for make-ready. The rebate quantities and incentive amounts for the transit segment are based on input from transit agencies, transit bus manufacturers, and the Virginia Statewide Contract for electric transit buses, which was established by the Virginia Department of General Services earlier this year.[4] The costs associated with owning infrastructure were developed based on discussions with charging station equipment manufacturers.

The Company used its experience implementing other pilot programs, such as the Electric Vehicle Pricing Pilot Program, to estimate its administrative activities and costs.

C. <u>Benefits of Smart Charging Infrastructure Pilot Program</u>

Q. What are the benefits of the Smart Charging Infrastructure Pilot Program?

A. The benefits of the Smart Charging Infrastructure Pilot Program are both quantitative and qualitative, including energy and demand savings; fuel and maintenance savings for EV drivers; and reduced greenhouse gas emissions. As I noted above, Company Witness Hulsebosch supports the benefits of the Pilot Program.

D. <u>Alternatives Considered</u>

Q. What alternatives to the Smart Charging Infrastructure Pilot Program did the Company consider?

A. The Company considered a "do nothing" alternative. As shown in my Schedule 9, the approximately 169,000 forecasted in the Company's Virginia service territory in 2030 will require 558 GWh of electricity annually with a demand of 187 MW. As new EV charging load comes on to the grid, grid upgrades will likely be necessary. However, if new EV charging load comes on to the grid at times of peak demand, it can result in higher costs to absorb that load. If the Company were to "do nothing" in terms of managing new EV charging load, it could result in higher costs for the Company and its

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[4] *See* https://logi.epro.cgipdc.com/External/rdPage.aspx?rdReport=Public.Reports.Report9008_Data&lnk From=New.

customers, such as the need for additional distribution upgrades or the need for more fast ramping peaker plants.

In order to fully and prudently support EV adoption, the Company believes that investments in managed EV charging are needed today—in the earlier years of EV adoption to allow the Company the necessary time to implement supporting technologies and infrastructure, and to adapt workforce skills to support them. This includes deploying and learning how to validate methods and processes for managed charging in a diversity of customer scenarios. As a result, we believe it is necessary to lay the groundwork for managed charging today to enable expanded EV adoption in a way that sustains grid reliability and safety.

Q. Did the Company consider any other alternatives?

A. The Company developed the Pilot Program based on the forecasted approximately 169,000 EVs in the Company's service territory in 2030, but also evaluated the low and high forecast scenarios provided by Navigant.

The low scenario provided by Navigant would have a smaller impact on the Company's distribution system; however, the risk of doing nothing still remains. If the Company assumes the low scenario and actual adoption of EVs is higher, and if non-networked, uncontrollable charging stations without the ability to provide data or participate in managed charging are installed, the Company will not have awareness of the resulting EV charging load or the ability to manage it. The Company believes it would be unlikely for customers to remove their non-networked, uncontrollable charging stations shortly after installing them to install networked controllable charging stations to take advantage of managed charging programs. The Company determined the high scenario was not an appropriate assumption for a pilot program as proposed in Phase IB.

E. Customer Education

Q. Please explain the education and communications that will accompany the Smart Charging Infrastructure Pilot Program.

A. The education and communications that will accompany the Smart Charging Infrastructure Pilot Program consist of communications to solicit customer enrollment and ongoing communications with participants. Customer enrollment solicitation will include web content, social media, and other outreach. Ongoing communications with participants will include continued education on managed charging, surveys to obtain customer feedback, and customer service associated with participation in the Pilot Program. For additional discussion on customer education, see Section VI.A.7 of the Plan Document.

III. CONCLUSION

Q. Mr. Frost, please summarize your testimony.

A. My testimony covered two components of the Company's Grid Transformation Plan, the full deployment of AMI and the Smart Charging Infrastructure Pilot Program.

Starting first with the Smart Charging Infrastructure Pilot Program, the Company proposes to offer rebates to incent the infrastructure necessary for managed charging, also referred to as "smart" charging. In addition, the Pilot Program includes Company-owned charging at strategic locations. The information gained from the proposed Pilot Program will provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid.

Turning to AMI, the Company proposes to fully deploy smart meters AMI across its Virginia service territory. Through AMI, the Company can remotely read smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. Nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, and reduced energy consumption; and additional benefits in reduced greenhouse gases.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS OF NATHAN J. FROST

Nathan J. Frost graduated from James Madison University with a Bachelor of Business Administration in Finance. He joined Dominion Energy in 2005 and has held numerous positions in the areas of Enterprise Risk Management, Producer Services, Investor Relations, and Power Delivery. Mr. Frost was most recently Manager – New Technology and Renewable Programs for Dominion Energy Virginia, and assumed his current position as Director – New Technology and Energy Conservation for Dominion Energy Virginia in January 2019. In this position, Mr. Frost is responsible for delivering demand side management and advanced metering solutions for the Company. In addition, he is responsible for developing renewable energy programs and integrating new technologies such as solar distributed generation and electric vehicles with Dominion Energy Virginia's regulated service territory.

Mr. Frost has previously submitted testimony before the State Corporation Commission of Virginia.

Company Exhibit No. ___
Witness: NJF
Schedule 1
Page 1 of 3

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of AMI Capital Costs**					
2						
3	Meter Deployment Labor Costs	$ 4,817,192	$ 14,746,306	$ 20,868,194	$ 40,431,692	$ 93,908,198
4	Meter & Meter Hardware Costs	$ 7,648,555	$ 50,682,244	$ 70,583,342	$ 128,914,140	$ 261,133,576
5	Network Materials & Installation Costs	$ 826,398	$ 1,446,515	$ 2,953,638	$ 5,226,551	$ 11,370,152
6	Licensing & Communications	$ 262,448	$ 1,690,168	$ 2,432,637	$ 4,385,254	$ 9,451,670
7	Capability Development/Enhancement	$ 1,299,671	$ 3,292,951	$ 3,445,551	$ 8,038,173	$ 18,567,744
8						
9	Total AMI Capital Costs	$ 14,854,264	$ 71,858,184	$ 100,283,362	$ 186,995,810	$ 394,431,340
10						
11						
12	**Summary of AMI O&M Costs**					
13						
14	Internal Labor, Vehicle, & Travel	$ 609,608	$ 968,088	$ 900,958	$ 2,478,654	$ 5,292,594
15	Hardware/Software Maintenance, Communications, & Call Center	$ 1,313,783	$ 2,056,922	$ 3,721,143	$ 7,091,848	$ 48,603,942
16						
17	Total AMI O&M Costs	$ 1,923,391	$ 3,025,011	$ 4,622,101	$ 9,570,502	$ 53,896,535
18						

Key Inputs	
Depreciable life	11.4yrs
3yr Total AMI Meter Deployment Count (2019-2021)	985,639
6yr Total AMI Meter Deployment Count (2019-2024)	2,116,548

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Summary of Stakeholder Engagement & Customer Education Capital Costs					
2						
3						
4	Total Stakeholder Engagement & Customer Education Capital Costs	$ -	$ -	$ -	$ -	$ -
5						
6						
7	Summary of Stakeholder Engagement & Customer Education O&M Costs					
8						
9	Collateral & Events	$ 40,000	$ 1,335,500	$ 1,558,860	$ 2,934,360	$ 9,433,106
10	Internal Dominion Labor	$ -	$ 100,000	$ 200,000	$ 300,000	$ 1,700,000
11						
12	Total Stakeholder Engagement & Customer Education O&M Costs	$ 40,000	$ 1,435,500	$ 1,758,860	$ 3,234,360	$ 11,133,106
13						

Company Exhibit No. ___
Witness: NJF
Schedule 1
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Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Transportation Electrification Capital Costs**					
2						
3	Rideshare Charging Station Make Ready and Equipment ($)	$ -	$ 699,700	$ -	$ 699,700	$ 2,798,800
4	Transit Bus Charging Station Make ready ($)	$ -	$ 420,000	$ 1,680,000	$ 2,100,000	$ 2,100,000
5	Public DC Fast Charge Station Make Ready ($)	$ -	$ 350,000	$ 700,000	$ 1,050,000	$ 2,450,000
6						
7	Total Transportation Electrification Capital Costs	$ -	$ 1,469,700	$ 2,380,000	$ 3,849,700	$ 7,348,800
8						
9						
10	**Summary of Transportation Electrification O&M Costs**					
11						
12	**Program Management ($)**	$ 393,500	$ 1,167,842	$ 1,329,881	$ 2,891,223	$ 17,163,695
13	**Single-Family Residential Program Costs**					
14	Single-Family Residential Charger - Equipment Rebate Expense ($)	$ -	$ 116,375	$ 148,375	$ 264,750	$ 1,329,375
15	Single-Family Residential Charging Program O&M Expense ($)	$ -	$ 102,792	$ 162,504	$ 265,296	$ 6,527,793
16	**Multi-Family Residential Program Costs**					
17	Multi-Family Residential Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 152,110	$ 228,165	$ 380,275	$ 1,521,100
18	**C&I Program Costs**					
19	Workplace Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 1,939,560	$ 3,602,040	$ 5,541,600	$ 5,541,600
20	**Public Transit Program Costs**					
21	Transit Bus Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 1,103,406	$ 4,413,624	$ 5,517,030	$ 5,517,030
22	**Public DC Fast Charging Program Costs**					
23	Public DC Fast Charge Station - Make-Ready Rebate Expense ($)	$ -	$ 752,200	$ 1,504,400	$ 2,256,600	$ 5,265,400
24						
25	Total Transportation Electrification O&M Costs	$ 393,500	$ 5,334,285	$ 11,388,989	$ 17,116,774	$ 42,865,994
26						

Key Inputs	
Asset Life	11 yrs
Single-Family Residential Chargers (cumulative in Year 10)	44,268
Steady State Multi-Family Charging Stations	100
Steady State Workplace Charging Stations	400
Steady State Transit Bus Charging Stations	60
Steady-State DC Fast Charging Stations	70
Steady-State Rideshare Charging Stations	16

Company Exhibit No. __
Witness: NJF
Schedule 2
Page 1 of 2

Just like our linemen, our new Smart Meters will work hard for you.

By upgrading to new, advanced metering technologies, we're investing in our infrastructure and in our customers.

Dominion Energy

002777-1_SmartMeter_PostCard_10.5x4.375.indd 1

12/7/18 9:26 AM

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Smart Meters: our newest metering technology for managing energy.

You're due for an upgrade. Soon, Dominion will be exchanging existing meters in your area for new Smart Meters. Why? To continue providing you with better service–like more reliable delivery of energy, better power-outage detection, faster problem resolution and remote meter reading. Smart meters also allow you to view your daily energy usage and participate in pricing plans which help you manage energy and costs.

The meter upgrade will require only a momentary power interruption; no need for you to make an appointment or be present during the exchange.

For more information, including how to view your daily energy usage, please visit DominionEnergy.com/smartmeter

The meter upgrade will occur at:

Dominion Energy®

P.O. Box 26666
Richmond, VA 23261

190950003

Dominion Energy

DOES NOT
PRINT-DIE
INDICATOR

By upgrading to new, advanced metering technologies, we're investing in our infrastructure and in our customers.

Date ______________________________

☐ **A utility service representative upgraded the electric meter today.** If you have any questions or concerns related to the meter exchange, please call:

866-566-6436 | 8 AM to 5 PM, Monday to Friday

☐ A utility service representative stopped by today to upgrade the electric meter. However, **the meter could not be exchanged due to:**

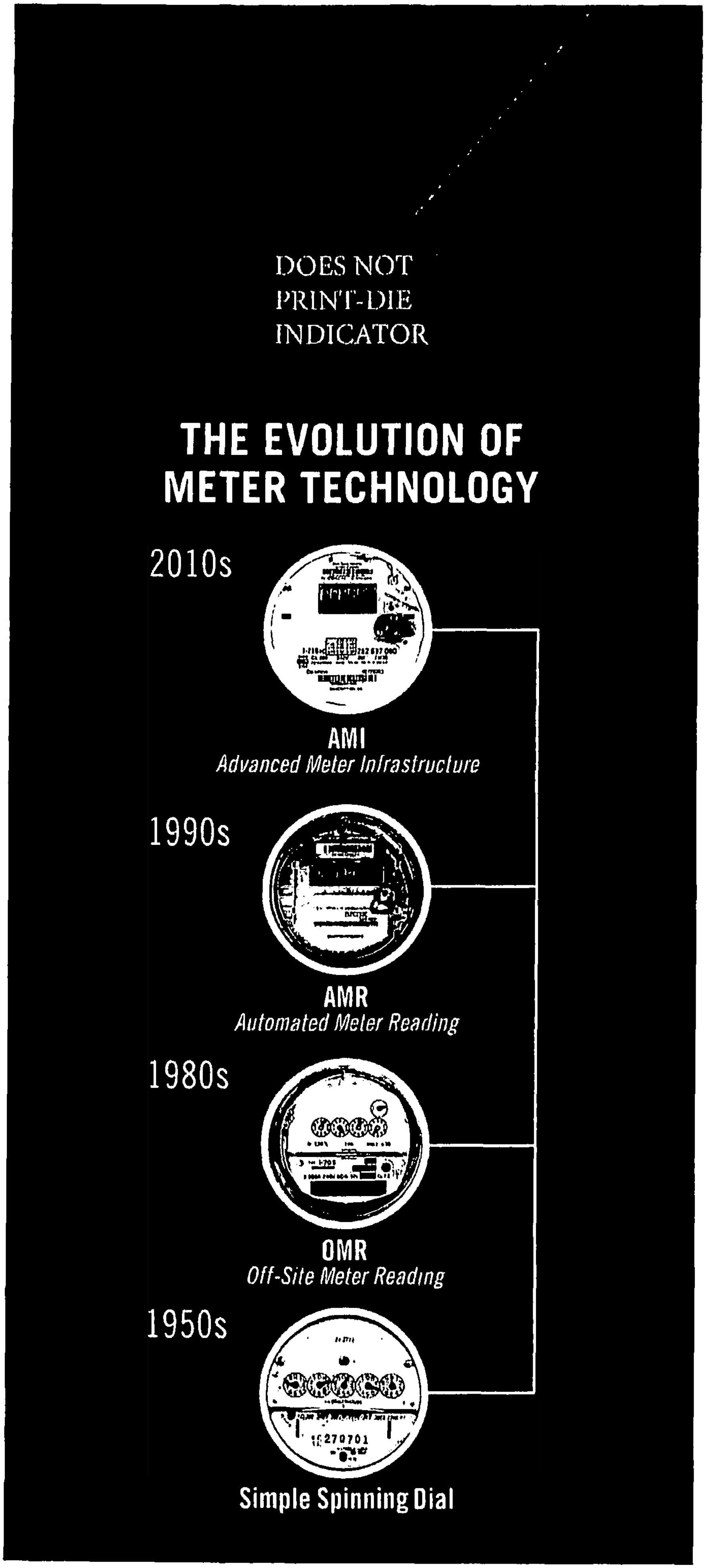
____

____

To discuss the issue and reschedule the meter upgrade, please call:

844-562-9472 | 8 AM to 5 PM, Monday to Friday

DominionEnergy.com/smartmeter


DOES NOT
PRINT-DIE
INDICATOR
THE EVOLUTION OF
METER TECHNOLOGY
2010s
AMI
Advanced Meter Infrastructure
1990s
AMR
Automated Meter Reading
1980s
OMR
Off-Site Meter Reading
1950s
Simple Spinning Dial

<Premise Address>

<Account Number>

<Mailing Address>

<Date>

Dear Valued Customer,

Dominion Energy is committed to providing safe and reliable energy to our customers by investing in our infrastructure. As part of this commitment, we are currently upgrading to smart meters in your area.

This letter is in response to your inquiry for more information about the **Interim Non-Communicating Meter Option (Residential "Opt-Out")**. If you decide to opt-out, the meter at your location will be replaced with non-communicating equipment. The non-communicating meter does not have any data storage features or two way communication functions enabled. As a result, it will be necessary for a meter reader to obtain a visual meter reading monthly.

Smart meters allow innovative features to:

- give you more control over how you use energy by providing you with information about energy usage;
- notify Dominion Energy when your power is out and back on for efficient restoration; and
- offer flexible, alternative pricing structures based on usage data.

Please find a summary comparing smart meters (communicating) to the opt-out program meters (non-communicating).

Comparison of Meter Features

	Standard Smart Meters (Communicating)	Opt-Out Program Meters (Non-Communicating)
Remote Outage Detection	**Yes**	**No**
Remote Service Connection	**Yes**	**No**
Customer Pricing Plan Options	**Yes**	**No**

Currently, Dominion Energy does not charge any special installation or usage fees to customers who choose the Interim Non-Communicating Meter Option; however, since manual monthly meter readings are required for these non-communicating meters, Dominion Energy may propose recovering expenses in the future. Such fees are subject to approval by the State Corporation Commission of Virginia (SCC) and, if approved, Dominion Energy will inform all participants of the Interim Non-Communicating Meter Option.

Hopefully, you will agree upgrading to a smart meter offers many benefits and is the best option for you. Should you wish to opt-out, please review the enclosed Interim Non-Communicating Meter Option requirements and **sign and return the Enrollment Form** as soon as possible.

A meter exchange will be necessary regardless of which meter you choose. Service will be momentarily interrupted during the meter exchange. Customers do not need to be present for the meter exchange, provided adequate access to the meter is available. Please visit our website at DominionEnergy.com/smartmeter or call 1-866-566-6436 for additional information.

Sincerely,

Smart Meter Team
Dominion Energy

Enclosures:
Interim Non-Communicating Meter Option Requirements
Enrollment Form

By receiving electric service from Dominion Energy, customers are subject to the Company's Terms and Conditions for the Provision of Electric Services. Pursuant to Section V of the Terms and Conditions, Dominion Energy owns the meter currently installed at your residence/business and has the right to have unobstructed, safe, and convenient access including but not limited to repair, replace, or exchange the meter. Additionally, as stated in Section XV, Dominion Energy has the right to access customer premises at all reasonable times for the purpose of reading meters, removing its property, and for other proper purposes such as the meter exchange. For an electronic version of Dominion Energy's Terms and Conditions please visit our website, DominionEnergy.com/terms.

Interim Non-Communicating Meter Option
REQUIREMENTS

The following requirements apply to the Interim Non-Communicating Meter (Residential Opt-Out) Option. The Non-Communicating meters are Advanced Metering Infrastructure ("AMI") or Smart Meters with both the two-way communications and data storage features disabled; the only recording features retained are the minimum needed for monthly billing. Because the Non-Communicating Meters' remote communication abilities have been disabled, a Dominion Energy ("Company") representative will manually read the meter.

To participate in this Option, please review these requirements and then sign and return the enclosed enrollment form.

Eligibility Requirements Guidelines and Restrictions

- These Option specific requirements are in addition to the Company's *Terms and Conditions for the Provision of Electric Service* ("Terms and Conditions") currently on file with the State Corporation Commission of Virginia ("Commission"), under which customers receive their Electric Service.

- An Interim Non-Communicating Meter Option Participant (the "Participant") must be a residential customer and can only request the Interim Non-Communicating Meter Option for accounts which they have authority to make account level changes. The Participant must submit an individual enrollment form for each account which enrollment is requested.

- The Participant must already have an AMI meter, or currently scheduled for an AMI meter upgrade.

- Participant must currently receive Electric Service from the Company in accordance with residential Rate Schedule 1 or transfer to Rate Schedule 1 prior to enrolling in the Interim Non-Communicating Meter Option. Non-Communicating Meters are not applicable for customers receiving Electric Service on dynamic-pricing (e.g., Rate Schedule DP-R) or any residential time-of-use rate schedule (e.g., Rate Schedule 1P, 1S, or 1T). In addition, Non-Communicating Meters are not applicable to situations in which the customer generates electricity or additional metering data is required for billing (e.g., Net Metering and Bidirectional Metering, Rate Schedule SP – Solar Purchase (Experimental)).

- The Participant is responsible for providing and maintaining access to the Company for purposes of meter installation, maintenance, and reading, in accordance with Section XV of the Company's Terms and Conditions. The Company has the right of access to the Participant's premises at all reasonable times and must have safe access to the meter.

The Company reserves the right to discontinue this Interim Non-Communicating Meter Option, if such access is not provided and maintained by the Participant.

- The Company has the right to modify these requirements from time to time at its discretion. The most recent version of the requirements is available on the Company's website at DominionEnergy.com/smartmeter.

- The Company plans to propose a charge for the Non-Communicating Meter Option, which will be subject to approval by the Commission. Upon Commission approval, the Company will inform customers who are currently participating in the Interim Non-Communicating Meter Option and will require such customers to enroll in the Commission approved Non-Communicating Meter Option, subject to any Commission approved fee, in order to continue using a Non-Communicating Meter. At that time, the Company will begin assessing any Commission approved fee for customers participating in the Non-Communicating Meter Option.

- Smart Meters help the Company operate its electric distribution infrastructure more efficiently by reducing the amount of excess voltage generated. As a result, customers and the Company may experience savings. By participating in the Non-Communicating Meter Option, the Participant acknowledges that the Company's ability to identify voltage-related concerns, notwithstanding the requirements set forth in Section VII of its Terms and Conditions, may be delayed or compromised.

- Upon receipt and approval of the completed enrollment form, the Company will schedule a meter exchange to coincide with the AMI deployment schedule. In cases where an AMI meter is already installed, the exchange to the Non-Communicating Meter will be completed within three weeks. Service will be momentarily interrupted during the meter exchange process. Customers do not have to be home for the meter exchange as long as adequate access to the existing meter is available.

- Accounts must be in good standing without any pending, recently completed, or active credit activity scheduled on the account.

- Participants may contact the Company to withdraw from the Interim Non-Communicating Meter Option at 1-866-566-6436 between 8:00 a.m. and 5:00 p.m. (Eastern Time) Monday through Friday.

Interim Non-Communicating Meter Option
ENROLLMENT FORM

Customers electing to enroll in the Interim Non-Communicating Meter (Residential Opt-Out) Option are required to complete this enrollment form and return it in the enclosed envelope or by email to ReceivedOpt-OutEnrollmentForms@DominionEnergy.com. Once Dominion Energy has received this signed and completed form, the enrollment will be processed and scheduled in accordance with the Interim Non-Communication Meter Requirements.

Customer Name and Address:

<XXXXX>
<XXXXX>
<XXXXX>

Account Number:

<XXXXXXXXXX>

By signing below, I hereby certify that I have the authority to make account level changes on the account listed above, and that I have fully read and agree to be bound by the requirements of the Interim Non-Communicating Meter Option. The latest requirements can be found at DominionEnergy.com/smartmeter.

PRINTED NAME:

____

SIGNATURE: DATE:

______________________________ ______________

Smart Meter Opt-Out Policy (DRAFT)

Dominion Energy is committed to providing safe and reliable energy to our customers by investing in our infrastructure. As part of this commitment, we are currently upgrading to smart meters.

Smart meters enable innovative features to:

- provide the customer with detailed information about their energy usage;
- offer flexible, alternative pricing structures based on detailed energy usage data; and
- notify the Company when a customer's power is out and back on, improving restoration efficiency.

Clearly upgrading to a smart meter offers many benefits and is the best option for the vast majority of customers. However, for customers who prefer not to have a smart meter, Dominion Energy does offer an opt-out program, with some limitations.

Opt-out limitations:

- Customers must take electric service from Dominion Energy under residential rate Schedule 1. Customers receiving electric service on any time-of-use or demand rate and customers who generate electricity are ineligible due to additional data required for billing and/or operating purposes.
- Accounts must be in good standing without any pending or recently completed (within the last 12 months) adverse credit activity with Dominion Energy.
- As per the Company's *Terms and Conditions for the Provision of Electric Service* as approved by the State Corporation Commission of Virginia, meters must be readily accessible to the Company, as walk-up meter reading will be required on a monthly basis.
- Customers must sign and return the Smart Meter Opt-Out Program enrollment form.
- Customers must allow the Company to exchange the current meter for a non-communicating digital meter. Legacy meters will be exchanged for non-communicating digital meters, as legacy meter reading and meter data processing systems are being retired.

Fees for Smart Meter Opt-Out Program

Due to the fact that additional efforts must be expended to administer the opt-out program, create an opt-out version of the meter, and read the non-communicating meter via walk-up procedures in perpetuity, the following fees will apply to customers who choose to opt out of smart meter implementation based on 2019 cost data:

- One-time initial fee: $84.53
- Ongoing monthly fee: $29.20

Opt-Out fees are subject to SCC approval and subject to revision.

Opt-Out Enrollment, Meter Exchange and On-going Meter Reading Cost Projections

Initial exchange/installation of non-communicating meter

Tasks	Time Spent per opt-out customer	Hourly Rate	Total	Note
Program administration and reporting, customer communications, work order generation/scheduling	0.75	$45.75	$34.31	(1)
Meter order processing, inventory management, shipping	0.5	$42.78	$21.39	(2)
Meter exchange	0.5	$58.55	$29.27	(3)
Credit based upon current costs being recovered in rates			**($0.45)**	
Total			$84.53	

Notes:
(1) Average/combination of Metering Solutions Ops Analyst and Lead Field Metering Analyst; pay grade mid-point, loaded rate
(2) Loaded Hourly Rate of a Shop Meterman
(3) Loaded hourly Meter Servicer + Vehicle rate; Time spent is calculated based on average numer of service order completions in a day in 2019

Monthly Fee

Department	Time Spent	Hourly Rate	Total	Note
Meter read	0.5	$58.55	$29.27	(4)
Credit based upon current costs being recovered in rates			**($0.07)**	
Total			$29.20	

(4) Loaded hourly Meter Servicer + Vehicle rate; Time spent is calculated based on projected average numer of service order completions in a day post-AMI deployment

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES

A. When meters are installed by the Company to measure the Electric Service used by the Company's Customers, all charges for Electric Service used, except certain minimum charges, shall be calculated from the readings of such meters. All meters used to determine billing will be owned and operated by the Company. The Company may for its own purposes use meters that are read remotely.

B. Normally, Electric Service will be furnished and metered through one Delivery Point and will be billed separately on the applicable Rate Schedule selected by the Customer. However, the Company reserves the right where for the Company's own purposes because of the amount or characteristics of electricity required, to install two or more sets of metering apparatus, to combine the readings of meters so installed for billing purposes, and to bill these combined readings on the applicable Rate Schedule selected by the Customer.

C. When one or more transformers are installed at one Delivery Point by the Company for the Company's convenience to provide Electric Service to a single Customer at one nominal voltage, the Company reserves the right, where for the Company's own purposes because of the amount or characteristics of electricity required, to meter the electricity on the Company's side of the transformer or transformers, but the Customer will then be allowed a discount of 2% in the Company's charges that are priced per kilowatt-hour.

D. Meters in service may be tested by the Company, the Commission or any other lawfully constituted authority having jurisdiction. When, as a result of such a test, a meter is found to be no more than 2% fast or slow, no adjustment will be made in the Customer's bills. If the meter is found to be more than 2% fast or slow because of incorrect calibration, the Company will rebill the Customer for the correct amount as calculated for a period equal to the lesser of:

1. One-half of the time elapsed since the most recent test of the metering apparatus.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

The percentage registration of a meter will be calculated by the "weighted average" of light load and full load, which is calculated by giving a value of 1 to the light load and a value of 4 to the full load.

E. Whenever it is found that unmetered Electric Service is being used as a result of tampering, the Customer will pay to the Company an amount estimated by the Company to be sufficient to cover the Electric Service used but not recorded by the meter and for which the Customer has not previously paid.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

F. Whenever it is found that, for reasons other than incorrect calibration or tampering, the Company has not properly billed the Customer, the Company will rebill the Customer in accordance with the terms of this paragraph. In the event the true amount of Electric Service used by the Customer cannot be determined, an estimate will be made of the Electric Service used during the period in question. Such estimate will be based on all known pertinent facts and will be used in calculating the corrected bill. The period of rebilling under this paragraph will be the lesser of the following:

Undercharges

1. The period during which improper billing occurred.

2. 150 days for Customers having a maximum demand below 50 kW during the past year.

3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

Overcharges

The period of rebilling for overcharges under this paragraph will be for the period during which the improper billing occurred not to exceed 36 months, unless the Customer can provide original bills beyond the 36-month period to support any additional refund amount.

G. If, during the term of agreement for furnishing Electric Service to a Customer, the Customer is unable to operate the Customer's facilities, in whole or in part, because of accident, act of God, fire, or strike of the Customer's employees occurring at the location where Electric Service is supplied, the charge for Electric Service used during the period reasonably necessary to correct any such conditions will be reasonably adjusted in accordance with all pertinent facts and conditions.

H. As provided for in the tables below, Interval Meters and Contact Closures shall be available to all of the Company's Customers upon Customer request and in accordance with Rule 20 VAC 5-312-120 of the Commission's "Rules Governing Retail Access to Competitive Energy Services."

The specified charges for each option shall apply as follows:

1. The applicable Installation Charge listed below shall be increased by the Tax Effect Recovery Factor, pursuant to Rider D - Tax Effect Recovery, and shall be paid by the Customer prior to the installation.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

2. In addition, the Customer shall pay an on-going Monthly O & M Charge that is equal to the applicable Installation Charge multiplied by the charge found in Section IV.E.4. (b) of the Terms and Conditions. Such payment will continue until the Interval Metering Service Option is discontinued in accordance with item 3., below.

3. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Interval Metering Service Option, b) the Customer discontinues Electric Service at the location of the Interval Metering Service Option, or c) the Customer elects to receive metering service from a competitive meter provider, when such service is available.

4. Company will acknowledge receipt of Customer's request for Interval Metering Service Options in writing within five business days after receiving such request. Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once Customer has completed the applicable prerequisites, Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charges and One-time Removal Charges for the Interval Metering Service Options are as follows:

Interval Metering Service Options Installation and Removal Charges for Interval Meters		
Type	**Installation Charge**	**Removal Charge**
Single-phase, 240 Volt, class 200	$271.50	$62.38
Single-phase, 240 Volt, 3 wire, class 320	$216.48	$62.38
Single-phase, 240 Volt, 3 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 200 and 320, or class 10 and 20	$233.79	$143.75

(Continued)

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

Installation and Removal Charges for Contact Closures (for kW Data Only)		
Type	**Installation Charge**	**Removal Charge**
One Circuit (Assumes Recorder Under Glass), or Single Service (Assumes Demand Meter Installation)	$203.77	$108.49
Additional Circuits at Same Site (Assumes Recorder Under Glass)	$122.40	$27.12

If Customer requests a special metering functionality (i.e., an Interval Metering Service Option configuration that is different from the types stated above, and that is determined by the Company to be within its capability to provide), the Company will acknowledge receipt of Customer's request for the special metering functionality in writing within five business days after receiving such request. The Company's response shall indicate that within 30 days the Company will provide the Customer with the applicable Installation Charge (calculated by the Company on the basis of net incremental cost), Removal Charge, Monthly O & M Charge, the process, and the Customer's prerequisites, which must be completed before the Company can commence and complete the installation of the special metering functionality. Once Customer has completed the applicable prerequisites, Company shall provide the special metering functionality within 45 calendar days, or as promptly as working conditions permit.

The Company will own interval metering service devices used for measuring and billing the Customer for its consumption of demand and energy. The Company is responsible for the installation and removal of all meters.

I. Former Schedule SG Customers, who elect to keep the standby generator meter while purchasing Electricity Supply Service from a Competitive Service Provider, shall continue to pay the Company the $89.69 monthly charge, as described in Schedule SG, Paragraph II.A., and any related facilities charges, if applicable.

(Continued)

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

J. As provided for in the table below, Non-communicating Meters shall be available to Customers served under Residential Service – Schedule 1 upon Customer request. If a Customer chooses to opt-out of the smart meter installation, the Customer may request to have a Non-communicating Meter installed.

The specified charges for this option shall apply as follows:

1. The Customer shall pay an on-going Monthly Charge to read the Customer's Non-communicating Meter. Such payment shall continue until the Non-communicating Metering Service Option is discontinued in accordance with item 2, below.

2. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Non-communicating Metering Service Option, or b) the Customer discontinues Electric Service at the location of the Non-communicating Metering Service Option.

3. The Company will acknowledge receipt of Customer's request for the Non-communicating Metering Service Option in writing within five business days after receiving such request. The Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once the Customer has completed the applicable prerequisites, the Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charge, One-time Removal Charge, and On-going Monthly Charge for the Non-communicating Metering Service Option are as follows:

Non-communicating Metering Service Option(s) **Installation, Removal, and On-going Charges for Non-communicating Meters**			
Type	**Installation Charge**	**Removal Charge**	**On-going Monthly Charge**
Single-phase, 240 Volt, class 200	$84.53	$29.20	$29.20

The Company will own Non-communicating Meters used for measuring and billing the Customer for its consumption of energy. The Company is responsible for the installation and removal of all meters.

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES

A. When meters are installed by the Company to measure the Electric Service used by the Company's Customers, all charges for Electric Service used, except certain minimum charges, shall be calculated from the readings of such meters. All meters used to determine billing will be owned and operated by the Company. The Company may for its own purposes use meters that are read remotely.

B. Normally, Electric Service will be furnished and metered through one Delivery Point and will be billed separately on the applicable Rate Schedule selected by the Customer. However, the Company reserves the right where for the Company's own purposes because of the amount or characteristics of electricity required, to install two or more sets of metering apparatus, to combine the readings of meters so installed for billing purposes, and to bill these combined readings on the applicable Rate Schedule selected by the Customer.

C. When one or more transformers are installed at one Delivery Point by the Company for the Company's convenience to provide Electric Service to a single Customer at one nominal voltage, the Company reserves the right, where for the Company's own purposes because of the amount or characteristics of electricity required, to meter the electricity on the Company's side of the transformer or transformers, but the Customer will then be allowed a discount of 2% in the Company's charges that are priced per kilowatt-hour.

D. Meters in service may be tested by the Company, the Commission or any other lawfully constituted authority having jurisdiction. When, as a result of such a test, a meter is found to be no more than 2% fast or slow, no adjustment will be made in the Customer's bills. If the meter is found to be more than 2% fast or slow because of incorrect calibration, the Company will rebill the Customer for the correct amount as calculated for a period equal to the lesser of:

1. One-half of the time elapsed since the most recent test of the metering apparatus.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

The percentage registration of a meter will be calculated by the "weighted average" of light load and full load, which is calculated by giving a value of 1 to the light load and a value of 4 to the full load.

E. Whenever it is found that unmetered Electric Service is being used as a result of tampering, the Customer will pay to the Company an amount estimated by the Company to be sufficient to cover the Electric Service used but not recorded by the meter and for which the Customer has not previously paid.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

F. Whenever it is found that, for reasons other than incorrect calibration or tampering, the Company has not properly billed the Customer, the Company will rebill the Customer in accordance with the terms of this paragraph. In the event the true amount of Electric Service used by the Customer cannot be determined, an estimate will be made of the Electric Service used during the period in question. Such estimate will be based on all known pertinent facts and will be used in calculating the corrected bill. The period of rebilling under this paragraph will be the lesser of the following:

Undercharges

1. The period during which improper billing occurred.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

Overcharges

The period of rebilling for overcharges under this paragraph will be for the period during which the improper billing occurred not to exceed 36 months, unless the Customer can provide original bills beyond the 36-month period to support any additional refund amount.

G. If, during the term of agreement for furnishing Electric Service to a Customer, the Customer is unable to operate the Customer's facilities, in whole or in part, because of accident, act of God, fire, or strike of the Customer's employees occurring at the location where Electric Service is supplied, the charge for Electric Service used during the period reasonably necessary to correct any such conditions will be reasonably adjusted in accordance with all pertinent facts and conditions.

H. As provided for in the tables below, Interval Meters and Contact Closures shall be available to all of the Company's Customers upon Customer request and in accordance with Rule 20 VAC 5-312-120 of the Commission's "Rules Governing Retail Access to Competitive Energy Services."

The specified charges for each option shall apply as follows:

1. The applicable Installation Charge listed below shall be increased by the Tax Effect Recovery Factor, pursuant to Rider D - Tax Effect Recovery, and shall be paid by the Customer prior to the installation.

(Continued)

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

2. In addition, the Customer shall pay an on-going Monthly O & M Charge that is equal to the applicable Installation Charge multiplied by the charge found in Section IV.E.4. (b) of the Terms and Conditions. Such payment will continue until the Interval Metering Service Option is discontinued in accordance with item 3., below.

3. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Interval Metering Service Option, b) the Customer discontinues Electric Service at the location of the Interval Metering Service Option, or c) the Customer elects to receive metering service from a competitive meter provider, when such service is available.

4. Company will acknowledge receipt of Customer's request for Interval Metering Service Options in writing within five business days after receiving such request. Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once Customer has completed the applicable prerequisites, Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charges and One-time Removal Charges for the Interval Metering Service Options are as follows:

Interval Metering Service Options Installation and Removal Charges for Interval Meters		
Type	**Installation Charge**	**Removal Charge**
Single-phase, 240 Volt, class 200	$271.50	$62.38
Single-phase, 240 Volt, 3 wire, class 320	$216.48	$62.38
Single-phase, 240 Volt, 3 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 200 and 320, or class 10 and 20	$233.79	$143.75

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

Installation and Removal Charges for Contact Closures (for kW Data Only)		
Type	**Installation Charge**	**Removal Charge**
One Circuit (Assumes Recorder Under Glass), or Single Service (Assumes Demand Meter Installation)	$203.77	$108.49
Additional Circuits at Same Site (Assumes Recorder Under Glass)	$122.40	$27.12

If Customer requests a special metering functionality (i.e., an Interval Metering Service Option configuration that is different from the types stated above, and that is determined by the Company to be within its capability to provide), the Company will acknowledge receipt of Customer's request for the special metering functionality in writing within five business days after receiving such request. The Company's response shall indicate that within 30 days the Company will provide the Customer with the applicable Installation Charge (calculated by the Company on the basis of net incremental cost), Removal Charge, Monthly O & M Charge, the process, and the Customer's prerequisites, which must be completed before the Company can commence and complete the installation of the special metering functionality. Once Customer has completed the applicable prerequisites, Company shall provide the special metering functionality within 45 calendar days, or as promptly as working conditions permit.

The Company will own interval metering service devices used for measuring and billing the Customer for its consumption of demand and energy. The Company is responsible for the installation and removal of all meters.

I. Former Schedule SG Customers, who elect to keep the standby generator meter while purchasing Electricity Supply Service from a Competitive Service Provider, shall continue to pay the Company the $89.69 monthly charge, as described in Schedule SG, Paragraph II.A., and any related facilities charges, if applicable.

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

J. As provided for in the table below, Non-communicating Meters shall be available to Customers served under Residential Service – Schedule 1 upon Customer request. If Customer chooses to opt-out of the smart meter installation, the Customer may request to have a Non-communicating Meter installed.

The specified charges for this option shall apply as follows:

1. The Customer shall pay an on-going Monthly Charge to read the Customer's Non-communicating Meter. Such payment shall continue until the Non-communicating Metering Service Option is discontinued in accordance with item 2, below.

2. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Non-communicating Metering Service Option, or b) the Customer discontinues Electric Service at the location of the Non-communicating Metering Service Option.

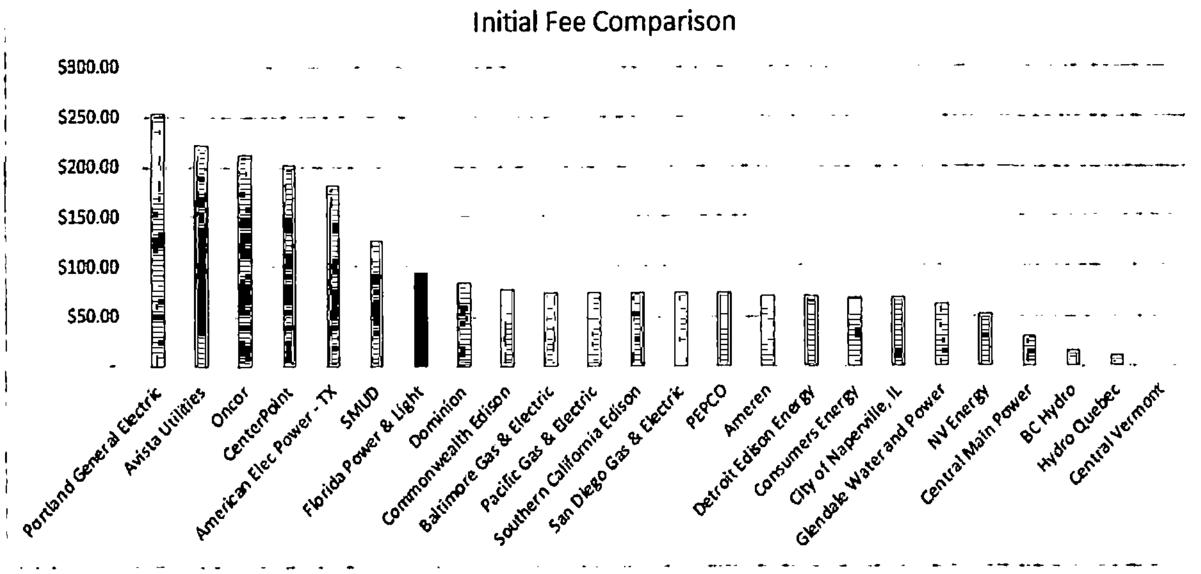
3. The Company will acknowledge receipt of Customer's request for Non-communicating Metering Service Option in writing within five business days after receiving such request. The Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once the Customer has completed the applicable prerequisites, the Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

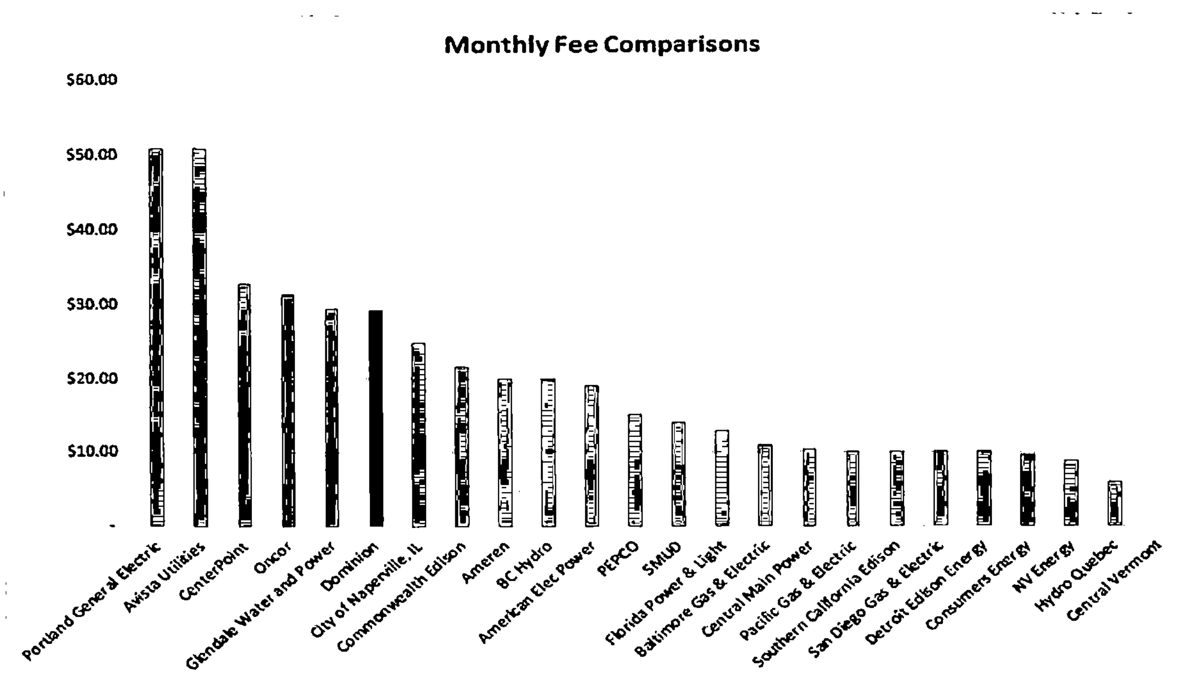
The applicable Installation Charge, One-time Removal Charge, and On-going Monthly Charge for the Non-communicating Metering Service Option are as follows:

Non-communicating Metering Service Option(s) **Installation, Removal, and On-going Charges for Non-communicating Meters**			
Type	**Installation Charge**	**Removal Charge**	**On-going Monthly Charge**
Single-phase, 240 Volt, class 200	$84.53	$29.20	$29.20

The Company will own Non-communicating Meters used for measuring and billing the Customer for its consumption of energy. The Company is responsible for the installation and removal of all meters.

OPT-OUT FEE COMPARISON





Electric Vehicle Adoption Forecast

Counts (Cumulative)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	25,698	33,855	43,416	54,190	66,678	80,456	95,812	112,423	130,201	149,079	169,159
Navigant Low	18,754	22,296	26,837	32,329	39,147	47,078	56,368	66,860	78,473	91,159	105,010
Navigant High	29,906	41,781	55,409	70,528	87,754	106,564	127,296	149,607	173,280	198,144	224,332
MWh (Annual)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	88,499	116,589	148,806	184,755	226,103	271,322	321,431	375,245	432,661	493,590	558,432
Navigant Low	62,948	74,579	89,166	106,659	128,303	153,304	182,547	215,417	251,666	291,182	334,297
Navigant High	101,749	141,758	186,792	236,401	292,627	353,615	420,719	492,606	568,621	648,250	732,000
MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	32	42	53	66	80	95	111	129	148	167	187
Navigant Low	23	27	32	38	45	53	63	74	86	98	112
Navigant High	37	51	67	84	102	123	145	168	192	217	243

Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite

This tool provides a simple way to estimate how much electric vehicle charging you might need at a city- and state-level.

State | Vehicles | Results

Start Over

Your Results

In Virginia, to support 169,159 plug-in electric vehicles you would need:

3,778 Workplace Level 2 Charging Plugs

2,614 Public Level 2 Charging Plugs
There are currently 1,093 plugs with an average of 2.0 plugs per charging station per the Department of Energy's Alternative Fuels Data Center Station Locator.

414 Public DC Fast Charging Plugs
There are currently 308 plugs with an average of 3.6 plugs per charging station per the Department of Energy's Alternative Fuels Data Center Station Locator.

Where Do I Start?

Planners may want to prioritize installation of fast charging infrastructure above Level 2 charging.

Build DC Fast First: Establishing fast charging networks that enable long-distance travel, serve as charging safety nets, and provide charging for drivers without home charging is critical to support all-electric vehicles that have no other alternative for quickly extending their driving range.

Build Level 2 Second: EVI-Pro typically simulates the majority of Level 2 charging demand coming from plug-in hybrid electric vehicles, which have the ability to use gasoline as necessary for quickly extending driving range.

Change Assumptions

Plug-in Electric Vehicles (as of 2016): 7,300

Light Duty Vehicles (as of 2016): 7,331,000

Number of vehicles to support: 169,159

Vehicle Mix

Plug-in Hybrids 20-mile electric range	15 %
Plug-in Hybrids 50-mile electric range	35 %
All-Electric Vehicles 100-mile electric range	15 %
All-Electric Vehicles 250-mile electric range	35 %
Total	100%

How much support do you want to provide for plug-in hybrid electric vehicles (PHEVs)?

- ○ **Full Support** — *Most PHEV drivers wouldn't need to use gasoline on a typical day.*
- ◉ **Partial Support** — *Calculate using half of full support assumption.*
- ○ **Do not count PHEVs in charging demand estimates.**

Percent of drivers with access to home charging: 100 %

See all assumptions.

EV Adoption Forecast, Year 2030: 169,159

		New Charging Infrastructure Needed by 2030	
		Workplace Level 2 Ports	Public DC Fast Charging Ports
Row 1	Charging infrastructure needed to support forecasted adoption (Source: EVI-Pro Lite Tool):	3,778	414
Row 2	Less known existing charging infrastructure (Source: Alternative Fuels Data Center):	N/A	86
Row 3	New infrastructure needed by 2030 (Row 1 less Row 2):	3,778	328
Row 4	New infrastructure needed each year (Row 3 divided by 10 years):	378	33

		New Charging Infrastructure Needed during Phase 1B (2020-2021)	
Row 5	Two years of infrastructure - ports (Row 4 multiplied by 2)	756	66
Row 6	Two years of infrastructure - dual port charging stations (Row 5 divided by 2)	378	32.80

Existing Public Infrastructure (ports):	
Public DC Fast Charging	308
Public DC Fast Charging (No Restrictions)	86
Public Level 2	1,093
Public Level 2 (No Restrictions)	248
(No Restrictions) = No access requirements; available 24/7	

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Part 8

19950004

Arruda

Witness Direct Testimony Summary

Witness: Thomas J. Arruda

Title: Director – Customer Information Platform

Summary:

Company Witness Thomas J. Arruda supports the customer information platform ("CIP") that the Company plans to deploy as part of the Grid Transformation Plan. CIP is a combination of technologies and applications that together deliver comprehensive customer information and streamlined transactions, as well as multi-channeled engagement between Dominion Energy Virginia and its customers.

Mr. Arruda first addresses the need for a modernized CIP. He describes the limitations of the current customer information system and the patchwork of applications required to serve customers. He also explains why the existing customer information system, which was deployed about 23 years ago, cannot adapt to the unprecedented pace of technology changes or meet the evolving needs of the Company's customers. He also discusses detailed cost estimates and the timeline for implementation.

Mr. Arruda next explains how the CIP will enhance the customer experience by modernizing the relationship, providing better information, and delivering value to customers. More specifically, the CIP will enable the Company to use multiple communication channels and offer customers expanded self-service options and new rate structures. As described by Mr. Arruda, customers will be able to utilize various notification, billing and pay options, and be able to take advantage of new rate structures, rate comparison tools, and monitor usage. With the new capabilities and customer functionality, customers will be in a better position to save time and money.

DIRECT TESTIMONY
OF
THOMAS J. ARRUDA
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, business address, and position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company").

A. My name is Thomas J. Arruda and my business address is 600 East Canal Street, Richmond, Virginia 23219. I am Director, Customer Information Platform at Dominion Energy Virginia. A statement of my background and qualifications is attached as Appendix A.

Q. Please describe your area of responsibility with the Company.

A. I am responsible for the development and implementation of the customer information platform ("CIP") as described in this proceeding.

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

A. The purpose of my testimony is to describe the customer information platform ("CIP") that the Company plans to deploy as part of its proposal to transform its electric distribution grid (the "Grid Transformation Plan," "GT Plan," or "Plan"). I will specifically address the elements required by the State Corporation Commission of Virginia (the "Commission") in its Final Order dated January 17, 2019, in Case No. PUR-2018-00100 (the "2018 Final Order") related to the proposed CIP, including the need for the CIP, detailed cost estimates, timeline, and vendor selection. Additionally, I will address the customer capabilities and benefits the CIP will enable and the

Company's commitments to enhancing the customer experience by modernizing the relationship, providing better information, and delivering value to customers.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, TJA, consisting of Schedules 1 through 5, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules:

Schedule	Description
1	Cost Schedule
2	Screenshot Comparison of Legacy System and Modern CIS
3	Industry Assessment of CIS Replacement
4	Alignment of CIP Goals with Customer Feedback
5	Use of Bid Manager to Reduce Project Risk

Additionally, I sponsor Filing Schedule Arruda, Attachments A through C, which provide executed contracts and request for proposals ("RFP") summaries from which detailed pricing estimates were prepared. The table below provides a description of these filing schedules:

Filing Schedules Arruda	Description
Extraordinarily Sensitive Attachment A	Contract with Bid Manager, TMG Consulting
Attachment B	RFP Summary for System Integrator
Attachment C	RFP Summary for Meter Data Management System

I also sponsor certain sections of the Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document. Finally, I sponsor the metrics categories as identified in Company Witness Edward H. Baine's Schedule 2.

Q. Did you provide information to West Monroe Partners, LLC ("West Monroe") for use in the cost-benefit analysis ("CBA")?

A. Yes, I provided costs and additional inputs for the CIP to West Monroe for use in the CBA. I also support the benefits reflected in Thomas G. Hulsebosch's Schedule 2, as identified therein.

The specific costs I support in Phase IB are:

Nominal $, in Millions	**2019**	**2020**	**2021**	
	Year 1	**Year 2**	**Year 3**	**3-year Total**
Phase IB	**$11.5**	**$47.0**	**$56.0**	**$114.5**
Capital	$7.3	$38.4	$45.2	**$90.8**
O&M	$4.2	$8.7	$10.8	**$23.7**

My Schedule 1 provides detailed cost information for the GT Plan components that I sponsor.

Q. Mr. Arruda, how is your testimony organized?

A. My direct testimony is organized as follows:

I. Definition and Context for CIP Deployment

II. Need, Cost, Benefits, Alternatives

Q. Before you begin, does the development of the CIP meet the definition of an electric distribution grid transformation project under § 56-576 of the Code of Virginia ("Va. Code")?

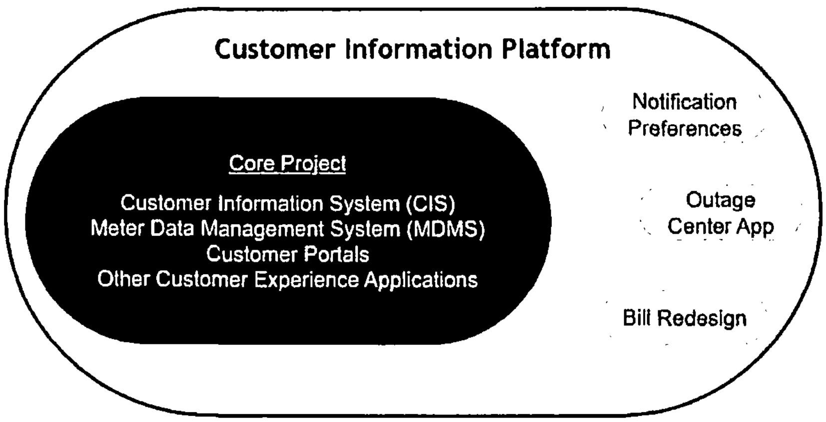
A. Yes. The definition of electric distribution grid transformation project in Va. Code § 56-576 includes "new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information."

I. <u>Definition and Context for CIP Deployment</u>

Q. What do you mean when you use the term "customer information platform" or "CIP"?

A. The Customer Information Platform, or CIP, is a combination of technologies, applications and projects at the core of the customer experience. The CIP consists of the Core Project, which replaces twelve (12) existing applications, and three projects focused on providing additional customer functionality. All four components are integral to the customer experience. Figure 1 illustrates the components of the CIP.

Figure 1: Customer Information Platform (CIP)



The foundation of the Core Project is the replacement of the Customer Information System ("CIS"), which is referred to as CBMS (Customer Business Management System) at Dominion Energy Virginia. The replacement of CIS accounts for the largest part of the CIP project. The CIS is the primary system supporting processes such as metering, billing, credit, service orders, and revenue reporting. In addition to the CIS, the Core Project includes replacing customer-facing applications, including web and mobile interfaces noted on Figure 1 as "Customer Portals" and "Other Customer Experience Applications."

The Core Project will integrate with other critical operational systems that either currently exist or that the Company plans to upgrade as part of the GT Plan. The CIP will replace twelve (12) current systems that support different aspects of the customer experience, listed in Table 1. Many of the applications listed in Table 1 are applications that have been developed to provide additional functionality not readily available in the CIS when installed. The majority of the applications listed in Table 1 provide functionality that is built within the CIP, eliminating the need for separate applications.

Table 1: Applications Being Replaced with the CIP

Application	Brief Description	Customer or Employee Facing	In Service Date
Customer Information System - CBMS (Customer Business Management System)	Core system delivering business functions such as customer service, account management, credit and collections, service orders, meter inventory, usage, billing, service address management, portfolio management, rates and financial based activities	Employee	1996
Manage Account	Customer web self-service platform for residential & small commercial customers	Customer	2003

Application	Brief Description	Customer or Employee Facing	In Service Date
Key Customer	Self-service system for large customers that are assigned an account representative; used by the customer and the account representative. Has many similarities to Manage Account	Customer	2006
Property Manager Portal	Web self-service tool for property management companies to manage landlord agreements and turn on/turn off service for their properties	Customer	2013
AWA (Agency Web Access)	Web self-service application for charities & third-party agencies (e.g., Salvation Army) to make energy assistance payments on behalf of customers	Customer	2006
MDMS (Meter Data Management System)	System that processes and stores interval data used for billing; calculates billable consumption for interval meter data	Employee	2009
Gateway	Web-based front end to CBMS and other systems used in contact center; primary tool for customer service representatives to interact with customers.	Employee	2013
Knowledge	Allows for systematically capturing, describing, organizing, and sharing information including alerts, work processes, and policies across customer service	Employee	2016
E-Gain	Imports and sorts emails and work tickets creating queue; includes auto replies and templates for responses	Employee	2010
LanBill	Allows back office personnel to manually edit and print bills flagged for special handling; used to process large complex bills that are not fully automated in CBMS	Employee	1996
Bill Image	Renders an image of the bill on demand in Manage Account and Gateway	Employee	2003
Agiloft	Record keeping system used to track elevated customer issues and inquiries.	Employee	2011

In addition to the Core Project, the CIP includes projects to provide additional customer functionality including Notification Preferences, Outage Center App, and a bill redesign project as described later in my testimony.

Q. Please describe the Company's existing CIS.

A. The Company deployed the existing CIS (*i.e.*, CBMS) about 23 years ago. The existing CIS is built on a mainframe platform using the programming language COBOL. Users use what is referred to as a "green screen" to view information. The system lacks a logical workflow, requiring users to memorize a series of four letter commands to navigate through screens. The system is not Windows based; nor is it compatible with using a mouse or cursor for simple navigation. A comparison of an initial screen with customer information using the legacy system and a more modern CIS system is provided as my Schedule 2.

When it was implemented, CBMS was designed to address Y2K data concerns. It reflected early 1990s requirements, which entailed less complex rate structures; no riders; 30%[1] fewer customers; and customer communications conducted only on telephone landlines.

[1] *See* https://www.eia.gov/electricity/data/eia861/ for year 1996.

II. Need, Costs, Benefits, Alternatives

Q. In the June 27, 2019 Final Order in Case No. PUR-2018-00065, the Commission ordered the Company in future integrated resource plans ("IRPs") to "systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects. For identified grid transformation projects, the Company shall include: (a) a detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) detailed cost estimates of each proposed investment; (c) the benefits associated with each proposed investment; and (d) alternatives considered for each proposed investment." Although this is not an IRP proceeding, can you address these requirements as they relate to the CIP?

A. Yes, I will address them in order. The detailed description of the existing distribution system is included in Section III of the Plan Document. I address the need for the CIP, costs, benefits, and alternatives. To understand better the costs of the proposed investments, I also discuss the planning for implementation.

<u>Need</u>

Q. Can the existing CIS meet the needs of the Company and its customers?

A. No. The existing CIS cannot adapt to the unprecedented pace of technology changes or meet the evolving needs of our customers. More comprehensive and cost-effective applications are now available. These applications are designed for the "digital age" to serve as the fully functional and centralized repository for customer interactions.

Since 1996, the regulatory landscape, customer expectations, and technology have significantly changed. The teams supporting, managing, and operating the near end-of-life CIS have worked diligently to leverage the technology and derive as much value as possible through a series of enhancements, customizations, and adaptations over the course of two decades. This had led to accumulated costs of approximately $140 million. This approach has largely worked to meet the needs of Dominion Energy Virginia's customers, but the existing CIS is ill equipped to meet the growing and changing demands of a truly modern era.

For example, the existing CIS is unable to effectively and efficiently offer an expanded set of rate structures and customer-centric programs like time-varying rates. Some time-varying rates currently offered by the Company require manual intervention and system work arounds that are inefficient and susceptible to human error. The impact to customers is illustrated in Table 4. As a result, the Company is not able to cost-effectively scale these manual processes with the existing CIS to be prepared for a greater number of customers to take advantage of time-varying rates.

In addition to being ill-equipped to handle customer needs, the existing CIS architecture, which is based on a mainframe using COBOL programming language, cannot accommodate the incremental volume and complexity of customer interactions that a modern digital distribution grid requires. The vendor of the existing CIS no longer supports the system. Similarly, service providers do not routinely hire or train COBOL programmers. The limited services that are available come at an increasingly higher cost. The implementation of the CIP eliminates the current patchwork of applications and standardizes the maintenance of the new system by moving to a vendor-supported application.

Q. What are the needs and drivers for delivering a modernized CIP?

A. Similar to electric utilities across the country, Dominion Energy Virginia seeks to implement several foundational changes to the way it conducts business specifically related to how its customers receive and compensate the Company for service. These changes fall under the category of "customer experience." Fundamentally, customers are seeking more streamlined and convenient interactions with their utility providers that mimic the experiences they have with other retailers and service providers—a foundational shift from traditional customer service experiences provided by utilities. In addition, in an industry assessment by TMG Consulting included here as my Schedule 3, over 50% of utilities will be replacing systems at the core of the customer experience within the next four (4) years, and several major utilities have either completed or are in the process of completing similar projects.

The CIP enables the Company to enhance the customer experience by modernizing the relationship, providing better information, and delivering value to customers. I will speak to each of these foundational goals.

Q. Describe how the CIP will modernize the relationship.

A. The current CIS—CBMS—is built to handle customer communications prevalent in the 1990s. In the ensuing 30 years, customers have shifted to expect digital communications that are customized to their preferences. For instance, over 1.1 million customers are enrolled in the Company's e-Bill program, a bill delivered in an email format, and 23% of those customers receive text notices about their e-Bill. Customers are also shifting to expect use of multiple communication channels depending on the subject. For instance, customers may want outage or high usage alerts through text or smart phone app notifications, while information about new rate programs could be delivered via email.

While not every customer is interested in leveraging new technology, Dominion Energy Virginia recognizes that traditional communication approaches no longer meet the needs of all customers.

To better serve its customers, the Company is also modernizing how applications and systems are managed. The Company has shifted to flexible and vendor-supported systems, which extends the service life of investments and allows the Company to adapt to changing customer needs, industry shifts, and technology advancements with greater speed and less incremental costs. By shifting to vendor-supported applications, updates to the applications are done by the vendor, which allows the Company to address customer needs better and more efficiently as technology changes and advances.

Q. Describe how the CIP will provide better information.

A. As consumers, we are all aware that in a digital age, more and more data is available. Consumers do not want to be inundated with data; rather they expect service providers to translate data into actionable and usable personalized information. The CIP provides the ability to process and organize data, enabling the Company to offer customers better information. For example, customers will be able to access the "What-if" analysis, which will provide customers the option to compare available rates and make assumptions on changing usage. This tool will provide better information and the ability to explore potential options to save money.

Q. Describe how the CIP will deliver value.

A. Customer motivations, interests, and levels of engagement are not homogenous, and the Company recognizes that the needs of each customer require flexibility and adaptability in the systems, processes, and tools used to shape a diverse and personalized customer experience—delivering value to each customer.

Some customers are implementing energy conservation measures or signing up for time-varying rates in efforts to reduce their bill. Some customers are purchasing electric vehicles in efforts to support their sustainability goals. Some customers are setting up auto-payment options for automation and convenience. Flexible and adaptable systems enable the Company to expand offerings and personalize options. An example includes offering customers options for payment due dates. These personalized options allow customers to tailor their experience to address what is important to them.

Q. How do you know that your customers' needs are changing?

A. Representatives from the Company engage with customers every day—from meeting them in the field, to speaking with them on the phone, reading letters, employees speaking with neighbors, surveys, and many other exchanges. The Company gains insight and gathers feedback about customers' needs in each of these engagements; some are qualitative and others we can evaluate quantitatively.

Q. Has the Company incorporated customer and stakeholder feedback in the development of the CIP?

A. Yes. In fact, the feedback from stakeholders along with other customer feedback provides the bases for the customer experience goals of the CIP discussed above:

modernize the customer relationship, provide better information, and deliver value. Section V.B of the Plan Document provides an overview of relevant customer engagement, while Section V.C. provides an overview of stakeholder engagement. My Schedule 4 highlights the feedback that led to the customer experience goals.

<u>**Planning for Implementation**</u>

Q. The 2018 Final Order criticized the proposed CIP because of the "preliminary draft timeline." What steps has the Company taken to begin planning for implementation of the CIP?

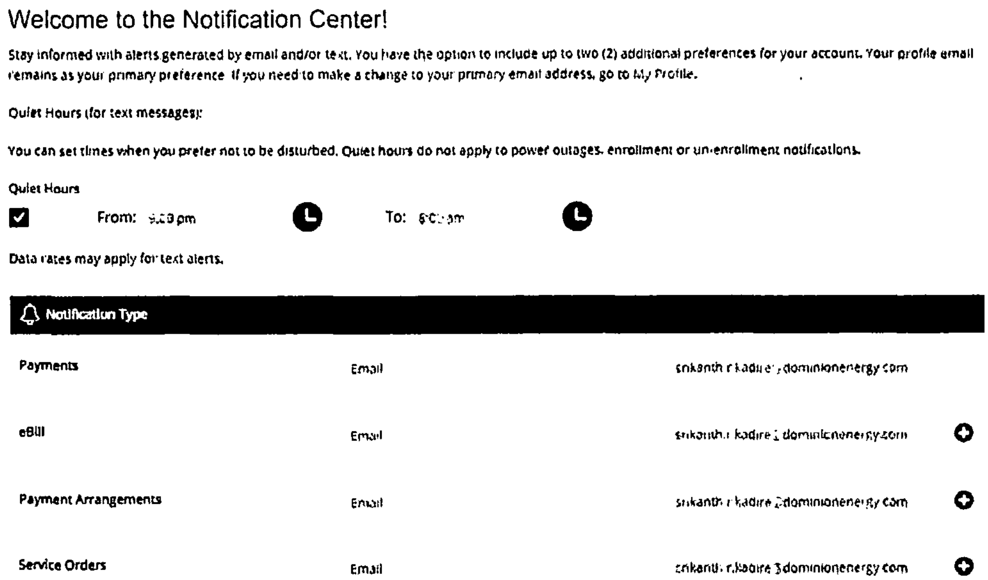
A. Efforts to date can be categorized into three areas: 1) organization alignment to support the project, 2) initial applications and customer facing initiatives, and 3) Core Project bid management.

1) *Organizational alignment.* In March 2019, the Company identified dedicated resources, including me, to lead the CIP effort. This effort included establishing project governance and starting the Core Project bid management activities described below.

2) *Initial applications and customer facing initiatives.* The Company is delivering customer functionality through early releases of technology within the CIP.

The Company will launch the Notification Preferences this year, formerly referred to as Preference Center. From a technology standpoint, this is the first phase of transitioning Manage Accounts to the future CIP platform. The Notification Preferences allow customers to choose the communication channels through which they prefer to engage with Dominion Energy Virginia. This initial phase will enable customers to add contacts to existing channels—email and/or text—for existing offerings such as e-Bill notifications and payment confirmations, where available. The new functionality on Manage Accounts is shown in Figure 2.

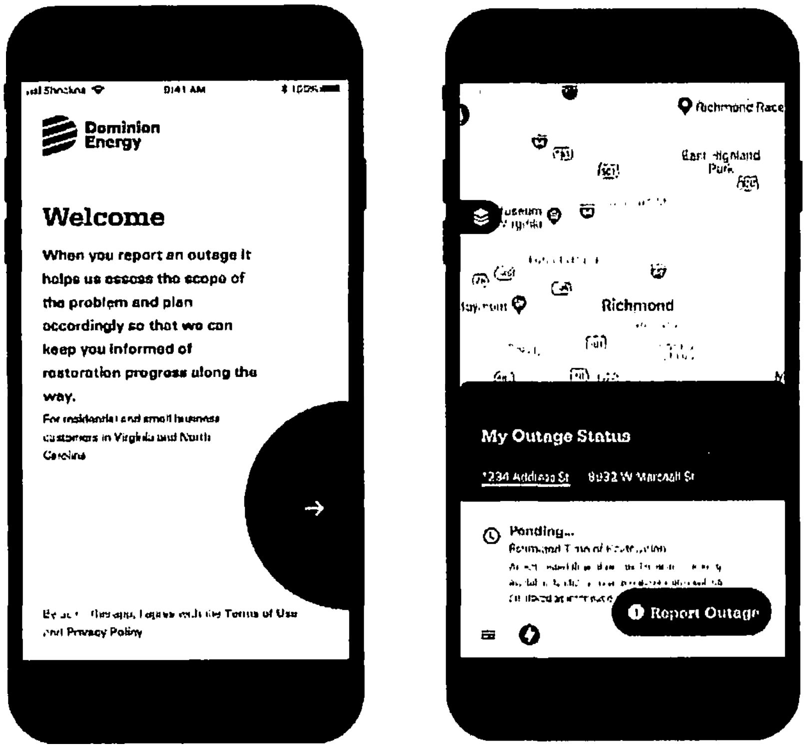
Figure 2: Notification Preferences on Manage Accounts



Future releases of the Notification Preferences will expand on the functions offered and will introduce additional communication channels. The Notification Preferences simplify the ability to offer these communication options as new offerings are developed.

In addition, the Company will launch the Outage Center app for outage communications this year. The app will provide customers the ability to report and check outages on a native app. The app will have similar login functionality and will be consistent with outage mapping information provided on the Company website. The app will also offer new functionality that will provide customers with information on nearby business locations with power, push notifications that will provide the customer with timely restoration updates, and helpful tips on how to cope with a power outage. This is the first step in offering mobile app functionality including push notifications, which is an integral component of the Core Project. Figure 3 shows the Outage Center app screen prototypes.

Figure 3: Outage Center App Screen Prototypes



3) *Core Project bid management.* Replacing highly integrated systems, like a CIS, are recognized in the industry as complex projects that require methodical planning to control scope and costs. To clearly define the project and reduce risk, the Company partnered with a Bid Manager. The Company issued an RFP for bid management services, and selected TMG Consulting ("TMG"). A summary of how partnering with TMG reduces project risk is provided as my Schedule 5. The contract with TMG is provided as Filing Schedule Arruda, Attachment A.

As Bid Manager, TMG's role is to provide expertise and assist the Company in developing business requirements for the Core Project, evaluating resource plans, developing risk and mitigation schedules, and managing the competitive bidding process to select the System Integrator and other key business partners.

The selection of the System Integrator is the critical component to the Core Project, as the System Integrator will develop a plan for the Core Project that represents over 85% of the capital project costs, including System Integrator labor costs and requirements for Company resources, facility needs, and hardware and software needs.

The System Integrator is responsible for leading the Company through design of the new system, configuration of the new system to meet the design, integration of other applications and systems to the new system, testing of the new system to ensure that it meets all requirements, and conversion of required data from the existing system.

The bid management process was initiated in January 2019. A detailed schedule is provided as a part of the RFP Summary in Filing Schedule Arruda, Attachment B. A summary of the milestones for the process is listed in Table 2.

Table 2: Summary of CIS Bid Management Milestones

Milestone	Complete or Date to Complete
Business and Technical Capability Requirement Workshops	Complete
Complete Requirements & Specification	Complete
Issue RFP	Complete
Receive Proposals	Complete
Solution Shortlist Proposals Identified	Complete
Conduct Reference Checks	Complete
Refinement Workshops	Complete
Receive Best and Final Offer	Complete
Contract Negotiations	In Progress
Finalize System Integrator and MDMS Contracts	October 2019

To develop the requirements and specifications for the Core Project, the Company began by reviewing over 4,500 potential business requirements. Through detailed workshops, the Company identified over 3,300 requirements specific to the needs of Dominion Energy Virginia to include in the scope of the RFP sent to potential system integrators. These requirements are described in Filing Schedule Arruda, Attachment B.

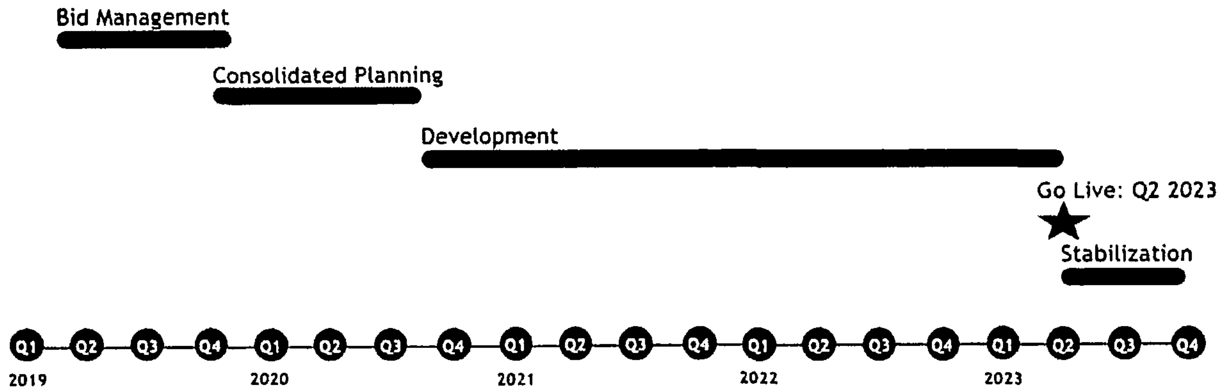
Through the planning process, the Company further defined the scope of the Core Project to include the replacement of the applications listed in Table 1. In addition to replacing these applications, integration of over 70 additional applications and systems were identified within the RFP scope, each requiring configuration. Examples of these applications include outage management system, inventory management system, payment vendor systems, and the interactive voice phone system.

Potential system integrators provided initial responses to the RFP, including project plans and cost estimates. In reviewing responses from the initial proposals, the Company revised the project plan, and budgets, to reflect the information provided by potential system integrators. These revisions are further described below. Currently, the Company is still in the negotiation process. The Company anticipates that a final contract with the System Integrator will be completed in October 2019. The contract will include conditions for execution including regulatory approval. The Company will refine its cost estimates for the CIP provided herein upon completion of final negotiations.

Q. What is the proposed implementation timeline for the CIP?

A. As part of the Core Project bid management process, the potential System Integrators assessed the requirements and provided proposed schedules for implementing the project. A timeline for the Core Project is shown in Figure 4.

Figure 4: Core Project Timeline



The planned delivery dates for the CIP components are as follows:

- Notification Preferences – 2019
- Outage Center app – 2019
- Core Project – 2023
- Bill Redesign – 2024

Q. **What has changed since the 2018 GT Plan filing with respect to the CIP?**

A. Since last year, the Company has further developed and refined the planning for CIP. Several changes are reflected in this application, including aligning with customer feedback, adjusting the scope to include the MDMS, and updating resource requirements.

1) *Alignment with customer feedback.* As discussed previously in my testimony, the Company developed the CIP customer experience goals based on collectively assessing feedback from customer participation in existing self-service offerings, as well as formal feedback the Company initiated this year including the stakeholder process and surveys.

2) *MDMS.* In the 2018 GT Plan filing, the MDMS was evaluated as a part of the

advanced metering infrastructure ("AMI") initiative, and the project plan included replacement of the system starting in 2023. With additional planning and an assessment of the CIP, the Company has updated the plan to include the MDMS as part of the Core Project. The MDMS will be replaced at the same time as the CIS, with an implementation date in the second quarter of 2023.

3) *Refinement of resource needs*. Through the Core Project bid management process, the Company refined project resource needs. As a part of the project planning, the System Integrator estimated resource needs based on the identified requirements. The Company anticipates that over 400 people will be associated with implementing the project during peak periods. This includes resources from the Company and business partners working through the design, implementation and testing of the new Core Project applications. The Company will have a dedicated team working on the project and anticipates that others will support the project for shorter periods, supporting specific work streams. The dedicated team will be responsible for functions such as billing, bill print, meter reading, service orders, customer experience, user experience, training enablement, communications, organizational change management, data conversion, and technical integrations.

A major component of the project will include the development of training and resources for individuals that use the applications for their roles within Dominion Energy Virginia. The Company anticipates training over 2,000 individuals. The training will range in complexity and length depending on role. The training for customer service representatives will be the longest training, occurring over several months. While customer service representatives are in training on the new Core Project applications, the

Company will work with a third party to have additional resources trained to provide customer service support on the legacy system. These additional resources are often referred to as "surge staffing." The addition of surge staffing enables the Company to conduct normal business and sustain quality customer service throughout the project.

Costs

Q. What is the Company's projected investment for CIP?

A. Detailed costs related to the CIP are provided in my Schedule 1. Total costs include the Core Project as well as implementing the Notification Preferences and Outage Center app in 2019, as well as a bill redesign project after the Core Project.

As described by Company Witness Gregory J. Morgan, the Company has committed to the investments related to CIP in Phase IB being recovered through its existing rates for generation and distribution services ("base rates").

Q. How did the Company develop the cost estimates?

A. The Company developed these cost estimates based on responses to competitively bid RFPs for various project components and services, including the MDMS and System Integration services for the new CIS and MDMS. As previously noted, the Company first issued an RFP for Bid Management Services, and selected TMG to control scope and costs. TMG then assisted the Company in conducting the RFP process for specific project components and required installation and configuration services for the various systems and applications. Information gathered through the bid management process provided estimates of internal resources, hardware, software and facilities. After bidders submitted their proposals, the Company revised the project plan, budgets and timelines to reflect the information provided by the bidders. The Company assembled an in-house team to conduct evaluations of each proposal. The Company evaluated both price and non-price factors. Based on the results of the RFPs, the Company selected the vendors and service providers.

Q. How did the Company ensure that the expenditures you have identified for the full deployment of CIP are reasonable?

A. The bid management process provided competitive cost estimates for a system integrator, internal resources, hardware, software, and facilities. As a part of the planning, the Company reviewed industry information to ensure alignment with scope and timelines of similar projects. An assessment of utility CIS replacements is attached as my Schedule 3. This assessment supplemented the costs obtained through the bid management process.

A summary of the RFP for System Integration services for the new CIS and MDMS is included as Filing Schedule Arruda, Attachment B. A summary of the RFP for the MDMS is included as Filing Schedule Arruda, Attachment C.

<u>Benefits</u>

Q. What are the primary benefits of implementing the CIP?

A. With the CIP, there are both qualitative and quantitative benefits. Qualitatively, the Company will modernize the customer relationship, provide better information, and deliver value to each customer. For example, customers will be able to utilize various notification, billing and pay options, and be able to take advantage of new rate structures, rate comparison tools, and monitor usage. With the new capabilities and customer functionality, customers will be in a better position to save time and money. An overview of customer functionality compared to their capabilities today is provided in Table 3.

Table 3: Change in Customer Capabilities

Topic	Current Capability	CIP Capability (Date Available)
What if Analysis/ Rate Comparisons	Bill comparisons for standard residential rate customers not available; once customer contacts customer service representatives, customers are provided rate schedules	On demand rate comparison tool based on customer's historical information (2023)
e-Bill	E-bill email sent to customer	E-bill to include graphical information and customization for customer class (2023)
Bill Redesign	Bill mailed to customers includes list of billable usage determinants, usage history, and list of bill detail.	Include graphical information and customization for customer class (2024+)
View/ Pay Bill	Eight different modes of payment available. Bill viewable through Manage Account or from mailed paper view.	Online payment options (e.g. PayPal, Venmo) (2021) Bill viewable through mobile native app (2023)
Outage Communications	Outage map and updates available online; report an outage through phone or online; regional information available as texts	Outage map, nearby information, and push notifications available in native mobile app (2019)
Notification & Alert Options	Alerts include high usage (kwh) alerts (pilot for AMI customers), payments, e-bill and payment arrangements to email or phone number associated with the account for customers with smart meters	Expand to include push notification options (2023) Alerts available to additional emails, texts or phone numbers Expand alerts to include high bill alerts ($) (2023)
Bill Calculation Transparency	PDF of paper bill provided online; Charges described online; Generic Schedule 1 calculator available online https://www.dominionenergy.com/home-and-small-business/billing-options/understanding-your-bill	Account specific details on charges available online to customers within the portal (2023)
FAQs/ Information	FAQs and information available on dominionenergy.com, Manage Accounts, and through calling a Customer Service Representative	Provide information through chat (2022) and digital assistant (2024+)

Q. Do the capabilities in Table 3 require additional GT Plan investments?

A. Yes. Some of the capabilities described in Table 3 rely on AMI. Capabilities focused on providing the customer better information and value rely on both investments for customers to fully benefit. Capabilities that are more robust with both investments include "what-if" analysis, usage and energy information, and alerts.

For example, the Core Project includes high bill alerts,[2] which also depends on AMI technology. An unexpected increase in a customer's bill can occur at a customer's premises for a wide range of reasons, including changes in weather patterns or malfunctioning heating, ventilation, and air conditioning ("HVAC") systems, or high usage. Currently, when these unexpected increases in energy consumption occur, the customer would likely not be aware that an issue exists until they receive an abnormally high monthly energy bill. In fact, customers who are enrolled in budget billing or automated bank draft may not notice a significantly higher bill for several months. After implementation of the GT Plan, customers can opt to receive a high bill alert, providing information within the billing period, making them more aware of abnormally high usage. These alerts would allow the customer to react quickly to avoid costly energy bills and possibly to take prompt action to safely resolve any issue in their home. High bill alerts rely on customer engagement through the CIP, but also information gathered daily from smart meters.

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[2] This differs from the high usage alerts currently available only to customers with smart meters. In particular, the high usage alerts only provide information regarding actual energy consumption and not the actual costs associated with the higher usage.

Q. How does the CIP support new rate structures?

A. When combined with data collected from smart meters, the CIP provides the technology and applications required to efficiently offer new rate structures or effectively expand current rate structures. From a billing perspective, the new CIP provides an adaptable application for billing modern rates. With the CIP, building, testing, and changing rates will be a quicker process. The CIP is more adaptable to modern rate structures, which will lead to less manual intervention in the billing process.

In addition to the operational efficiencies, the CIP enables more modern customer engagement including education, program management, and customer communication, including self-service options for rate enrollments, rate comparisons, and ongoing education.

The CIP enables the Company to provide customers better information empowering them to make better decisions about their usage and bills. Better information comes in different forms—providing communication channels for education; providing "what-if" analyses for changing rates and behavior; and providing notifications on account and/or rate anomalies for customers to be empowered to continue to manage their costs. "What-if" analyses, for example, will provide customers the option to compare available rates and make assumptions on changing usage. This tool will fully empower customers to understand the impact of changing rates and behavior. These analyses will be available online and will utilize the customers own interval data, providing convenient and personalized information.

As Company Witness Morgan describes, the Company is committed to bringing time-varying rates before the Commission later this fall. While the functionality of the Core Project will not be available in time to support the experimental rate, online enrollment, on-going education, and an analysis comparing a customer's bill under their current rate and the new time-varying rate will be provided in the interim. Additional details on the customer engagement will be provided this fall when the Company makes its filing with the Commission.

Table 4 is a summary of how customer engagement with time-varying rates will evolve with the experimental rate, and future rates offered once the CIS is in place and AMI is deployed.

Table 4. Customer Engagement with current time varying rates, experimental rate and future rate offerings

Current Process (Rates 1S & 1T)	New Experimental Time Varying Rate (projected for 2020 start)	Future Time Varying Rate (2024+)
Education & Enrollment		
Customer calls Customer Service to inquire	Digital education; Limited to AMI meters	Digital education; increase in customer eligibility (increase in AMI)
Company mails customer rate schedules	Static on-line comparison information	Full "what-if" analysis identifies eligible rates and recommendations
Customers calls to enroll in rate	Rate and Notification Enrollment on Manage Accounts	Full "what-if" analysis for customers to personalize and select best rate
Company mails rate enrollment package	Customer provided welcome package	Rate and Notification Enrollment on Manage Accounts
Customer mails back package		
Back Office Processing		
Company exchanges meter	No meter exchange required (AMI)	No meter exchange required (AMI)
Manual rate schedule change at bill cycle	Manual rate schedule change at bill cycle	Automated rate schedule change
Rate managed in existing CIS	Rate, bill, and exceptions managed in CIS/ MDMS	Automated notification processing
Exceptions managed within CIS & MDMS		Rate, bill, and exceptions managed in CIP; reduced exceptions handling due to configurability
Ongoing Education		
Not applicable	Program notifications sent for ongoing education	Program notifications- automated customer notifications
Process Time		
2-3 months	< 30 days	< 30 days

Q. Will the proposed investments in the CIP improve the customer experience as it relates to understanding the bill?

A. Yes, the CIP will provide the necessary functionality and information to enable an easier to understand bill, such as using graphics for personalized electricity usage and bill history. Due to the complexity involved, the bill redesign will occur in two stages: e-Bill then paper bill. The e-Bill redesign in the online portal will occur first as part of the Core Project. Today approximately 1.1 million or 43% of customers engage digitally with e-Bill, with increasingly more customers choosing to do so. In addition to using graphics for personalized electricity usage and bill history, the redesigned online portal will also include the option to view additional detail on the components of the bill and how the bill is calculated.

To provide better information to customers that do not or cannot leverage information available online, the paper bill redesign will be implemented once the CIS is in place.

Q. Will contact center representatives still be available for customers to contact?

A. Yes. The Company recognizes that some customers value engaging with Dominion Energy Virginia by calling the contact center. In, fact, the proposed CIP will enhance the contact center representatives' ability to assist customers. Today, contact center representatives likely need to access several systems and offline tracking tools to respond to a customer's question. In addition, the contact center representative has no insight into customer requests. For example, today the information available to a representative to assist most customers contacting the contact center about a high bill is limited. Often the information available to a representative is limited to the customer's monthly billing meter read. The representative will discuss with customers their usage patterns, weather, and suggest generic anomalies to look for within the home to assess potential causes of the customer's high bill. With the new CIP, the representative will have more information on the customers' interactions with the Company, more user-friendly ways to view customers' usage making it easier to explain usage patterns, and more granular information within the bill period. All of these benefits will enable representatives to have more meaningful interactions with the customer. The proposed CIP will enable a seamless and integrated set of digital tools and dashboards that the contact center representative can use to quickly and accurately access all details of the customer's account. Equipped with improved tools, the contact center representative will be able to resolve customer inquiries faster and more efficiently and provide a better and more personalized customer experience.

Q. Will the CIP be compatible with the Green Button Standard?

A. Yes. Green Button is a means of providing detailed customer energy usage information available for download in a simple, common, and standardized format. Green Button essentially creates a standard data file and data format that is consistent across all Green Button platforms and providers.[3] Customers can then upload their own data to a third-party application if they choose. The Company's existing online Manage Accounts provides residential AMI customers the ability to securely download their own energy data in .csv format and Green Button Download My Data ("DMD") format.

The CIP will be Green Button compatible and will continue to offer the DMD functionality to customers.

[3] *See* http://greenbuttondata.org/.

In addition, the CIP enables customer access to usage data and will make viewing, accessing and understanding their usage information more user friendly. The Company will continue to assess the industry and adapt the development of the CIP as customers' needs change with respect to data access. In addition, as outlined in House Bill 2332, the Company will participate in the data access stakeholder group and incorporate the resulting feedback and findings into future decisions regarding data access.

Q. In addition to all the new capabilities and resulting benefits from the modern CIP, what are the quantitative benefits or cost savings benefits of a modern CIP?

A. The CIP not only enables the Company to provide qualitative benefits by expanding customer capabilities, but it also enables the Company to operate more efficiently. By replacing outdated legacy systems, the Company can provide customer capabilities in a more cost-effective and efficient manner, because the CIP is a more adaptable, flexible, and vendor-supported system.

Operational benefits include a reduction in manual work arounds to support more complex bill types. The new CIP will drive improved automation and processing capabilities that will reduce manual steps associated with the calculation of certain bill types as well as exception processing that takes place as a result of system errors or other issues. Another operational benefit is the result of avoiding the maintenance of legacy mainframe systems. Each year, the Company has operating expenses associated with maintaining and upgrading this technology to allow the CIS to continue to run and generate customer bills. With a transition to a vendor-supported system, these costs are eliminated once the full deployment of the new CIS is complete.

Benefits also include the reduction in capital costs moving forward by avoiding replacement of the mainframe hardware. These ongoing costs are entirely avoided with the implementation of a new CIS. There is also a reduction of the ongoing capital needs for the CBMS application to meet changing customer needs.

Q. **Describe the Company's future plans for the development and use of the CIP beyond Phase IB.**

A. The CIP project plan includes activities in Phase IB of the GT Plan as well as beyond. The Core Project implementation is scheduled for the second quarter of 2023, which will occur in the next phase of the GT Plan. Similarly, additional customer capabilities, such as the bill redesign project, will be implemented after the Go-Live date of the Core Project.

<u>Alternatives</u>

Q. **Did the Company consider alternatives to the CIP?**

A. As an alternative to a comprehensive CIP, the Company would have to continue to build silos and patchworks of applications and engage in manual processes to perform certain functions. This would be more costly, time-consuming, and increase the risk of errors. In addition, the Company would be required to replace the mainframe system that supports the CIS, as well as continue the maintenance on the mainframe. In order to maintain the legacy CIS for an extended period, resources that understand COBOL and mainframe systems would be required. Because these skills are no longer readily supported by the market, specific training and reskilling efforts would be required. Continuing operations with a patchwork of applications and using older technology hinders the Company's ability to offer the customer options and functionality available with the CIP. For these reasons, the Company would not support any alternative that does not replace the legacy CIS with a comprehensive CIP. The Company considered two systems used by major utilities that meet the requirements for the core system within the CIP. After thorough evaluation and analysis, the Company selected SAP, which is also the system currently used as a general ledger for CIS financial transactions.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

Appendix A

BACKGROUND AND QUALIFICATIONS
OF
THOMAS J. ARRUDA

Thomas Joseph Arruda is the Director of Customer Information Platform at Dominion Energy Virginia. He is responsible for the development and deployment of the customer facing and customer supporting technology known as the customer information platform.

Mr. Arruda has been with Dominion Energy for 21 years with more than 15 years of leadership experience. He has worked in numerous roles within the IT department including application build and support for all Dominion Energy business units and IT Risk Management.

Mr. Arruda is a former member of the advisory board of the Virginia Cyber Security Partnership.

Mr. Arruda received a bachelor's degree in business administration from the University of Richmond.

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of CIP Capital Costs**					
2						
3	Hardware / Software Costs	$ 100,000	$ 14,710,313	$ 932,820	$ 15,743,133	$ 15,743,133
4	Implementation Costs	$ 7,160,000	$ 23,640,107	$ 44,217,729	$ 75,017,835	$ 181,988,630
5						
6	**Total CIP Capital Costs**	**$ 7,260,000**	**$ 38,350,420**	**$ 45,150,549**	**$ 90,760,968**	**$ 197,731,763**
7						
8						
9	**Summary of CIP O&M Costs**					
10						
11	Hardware / Software Maintenance	$ 2,100,000	$ 5,628,294	$ 8,470,676	$ 16,198,970	$ 115,488,355
12	Maintenance Labor	$ 2,100,000	$ 3,060,958	$ 2,353,077	$ 7,514,035	$ 44,797,536
13						
14	**Total CIP O&M Costs**	**$ 4,200,000**	**$ 8,689,252**	**$ 10,823,753**	**$ 23,713,004**	**$ 160,285,891**
15						

Key Inputs	
Asset Life	15 yrs
Core-Project Go-Live	Year 5

Legacy CIS

```
                                                                      6300
    SECOND AVE                                                    13 21425
FARMVILLE          VA 23901                    F 01      L 2 1 H RES
CLIAGE  CING                      ACCOUNT INQUIRY              01/21/11 16:11
                                                          ELIGIBLE
PP AMOUNT.          0.00  AMT BILLED             113.15  SUB DEPOSIT.          105.00
BILL DATE:     12/26/10  LATE CHARGE:              1.55
DUE DATE :     01/13/11  LATE AMOUNT.            114.70
PREV DUE DT:  12/13/10
 CATEGORY          CURRENT BILL    BAL FORWARD      TRANS AMOUNT   CATEGORY TOTAL
ELECTRIC     :          113.15            0.00           -113.15             0.00
TOTAL        :          113.15            0.00            113.15             0.00

BOTTOM OF LIST
NEXT FUNCTION          DATA                                                   S
13 CREDIT    14 CURR SERV 15 BILL HIST 17 PYMT HIST 18 ANALYSIS  19 HIGH BILL
20-ADDL CUST 21-CUST CNTC 22-ACCT INFO 23-BILL INQ
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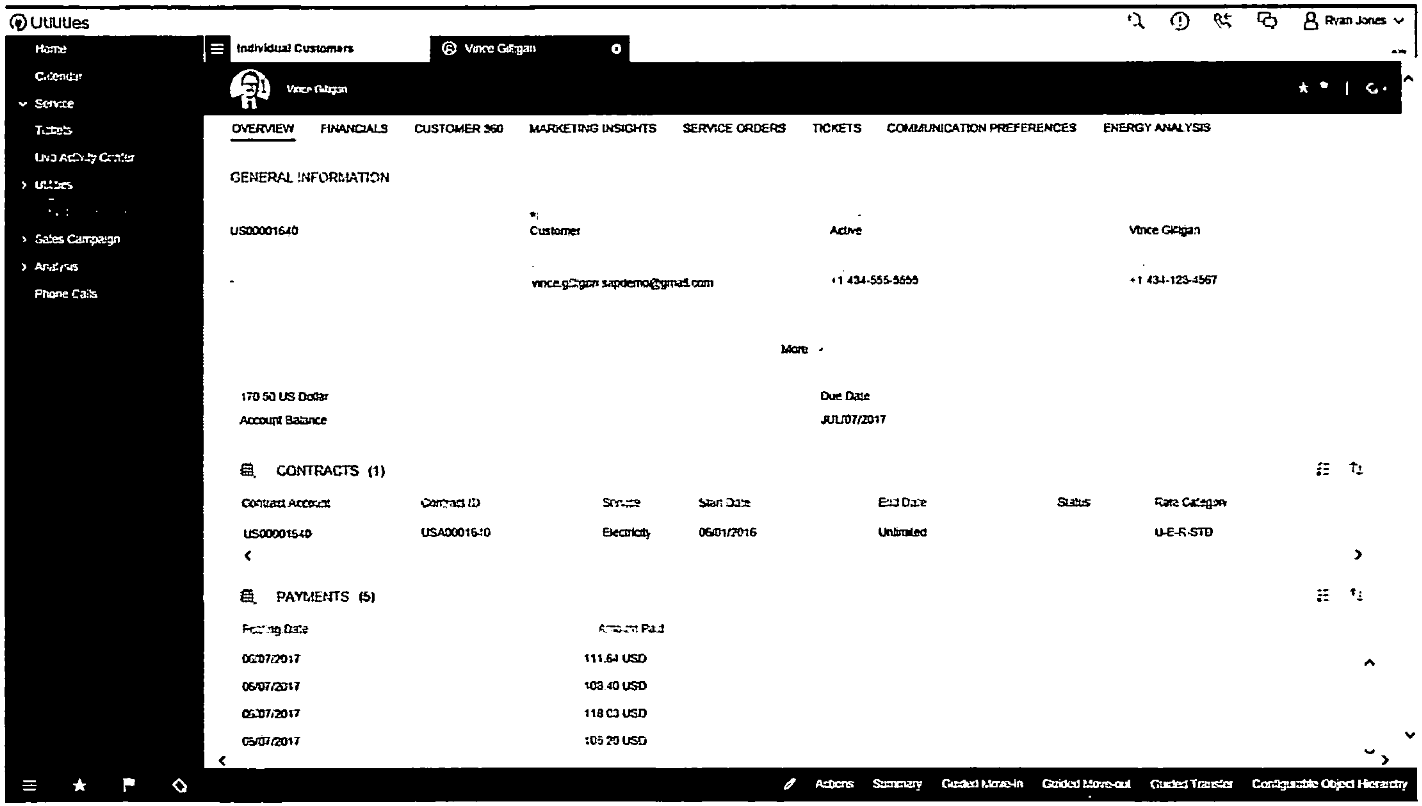
1 9 9 9 5 0 0 0 4

Modern CIS



Company Exhibit No. __
Witness: TJA
Schedule 2
Page 2 of 2

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Dominion Energy®

SAP CIS Replacement

System Integrator Bid Manager Project Kickoff

February 19, 2019

TMG Consulting

Where Business and Technology Intersect

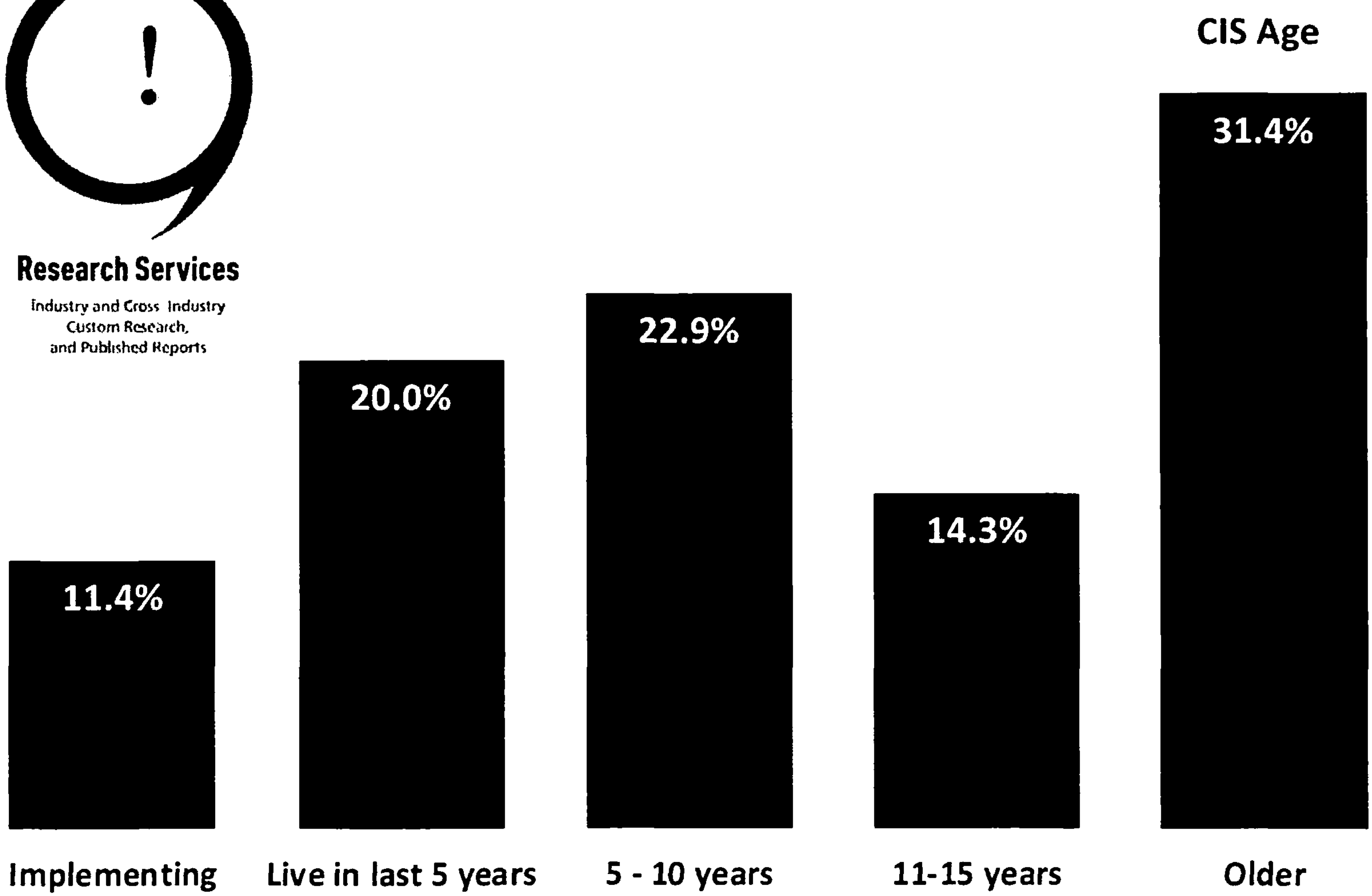
Customer System Industry Perspective

TMG Consulting

Where Business and Technology Intersect

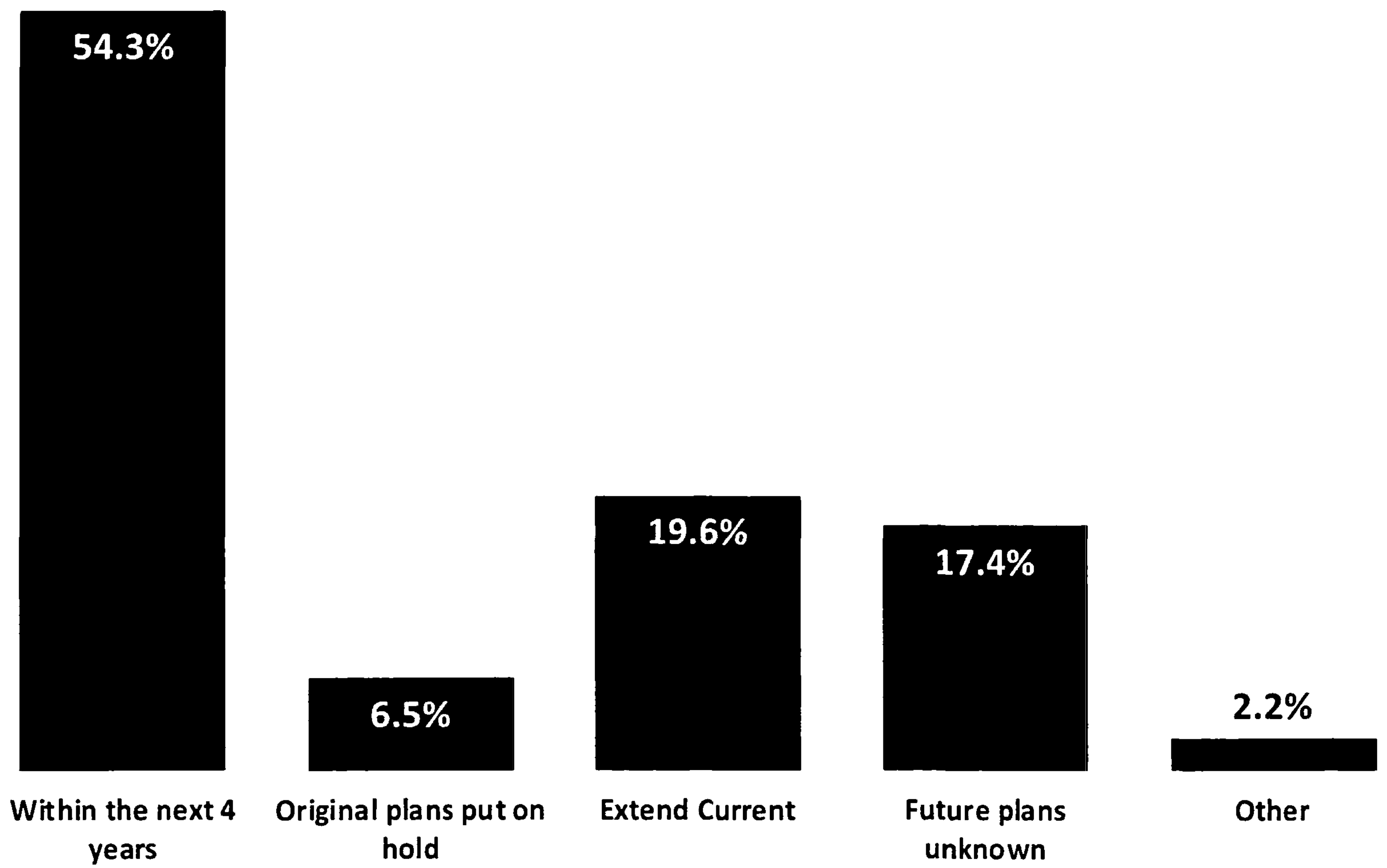
Current Age of Industry CIS

Research Services
Industry and Cross Industry
Custom Research,
and Published Reports

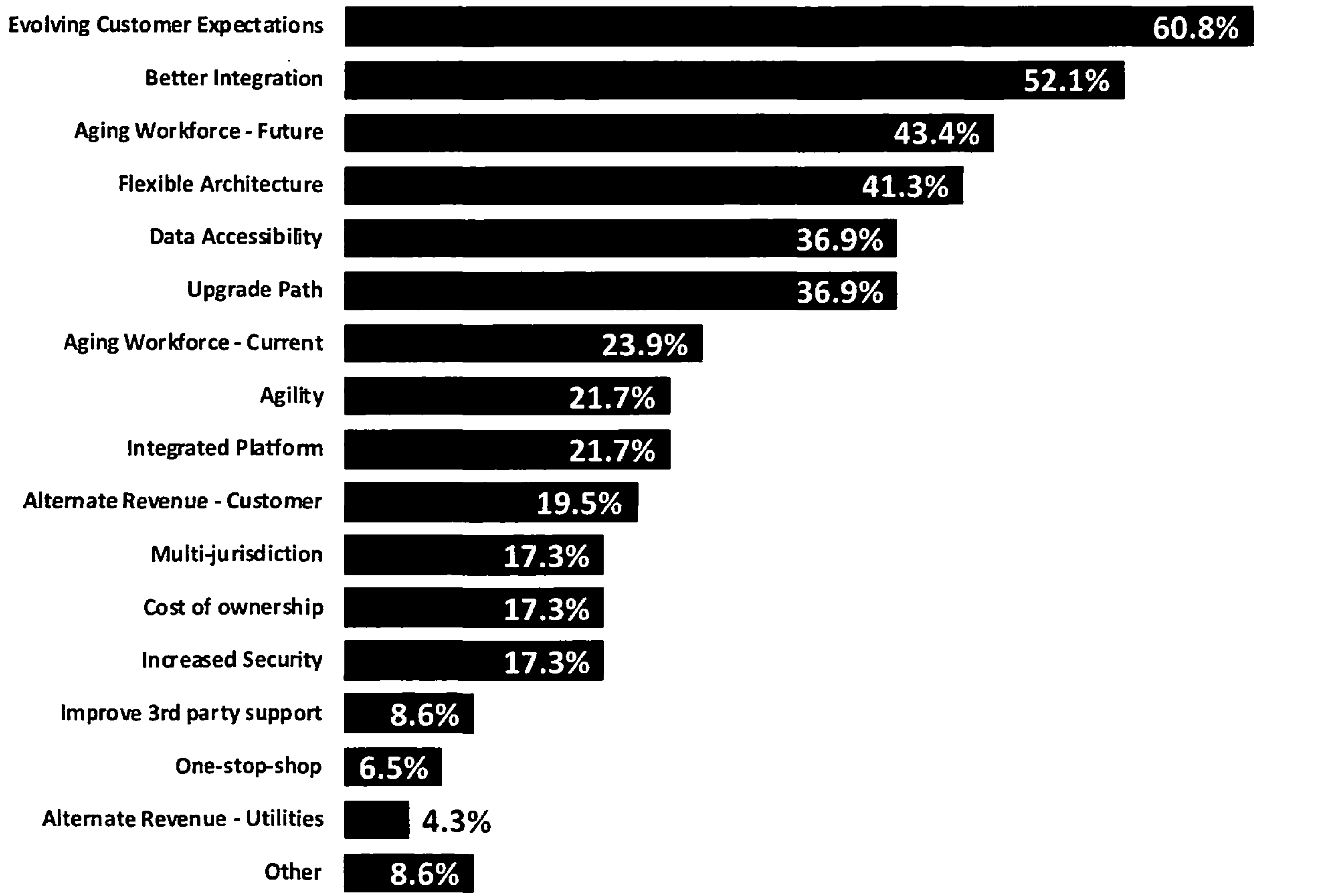


Planned CIS Projects

"When do you plan to replace your CIS?"

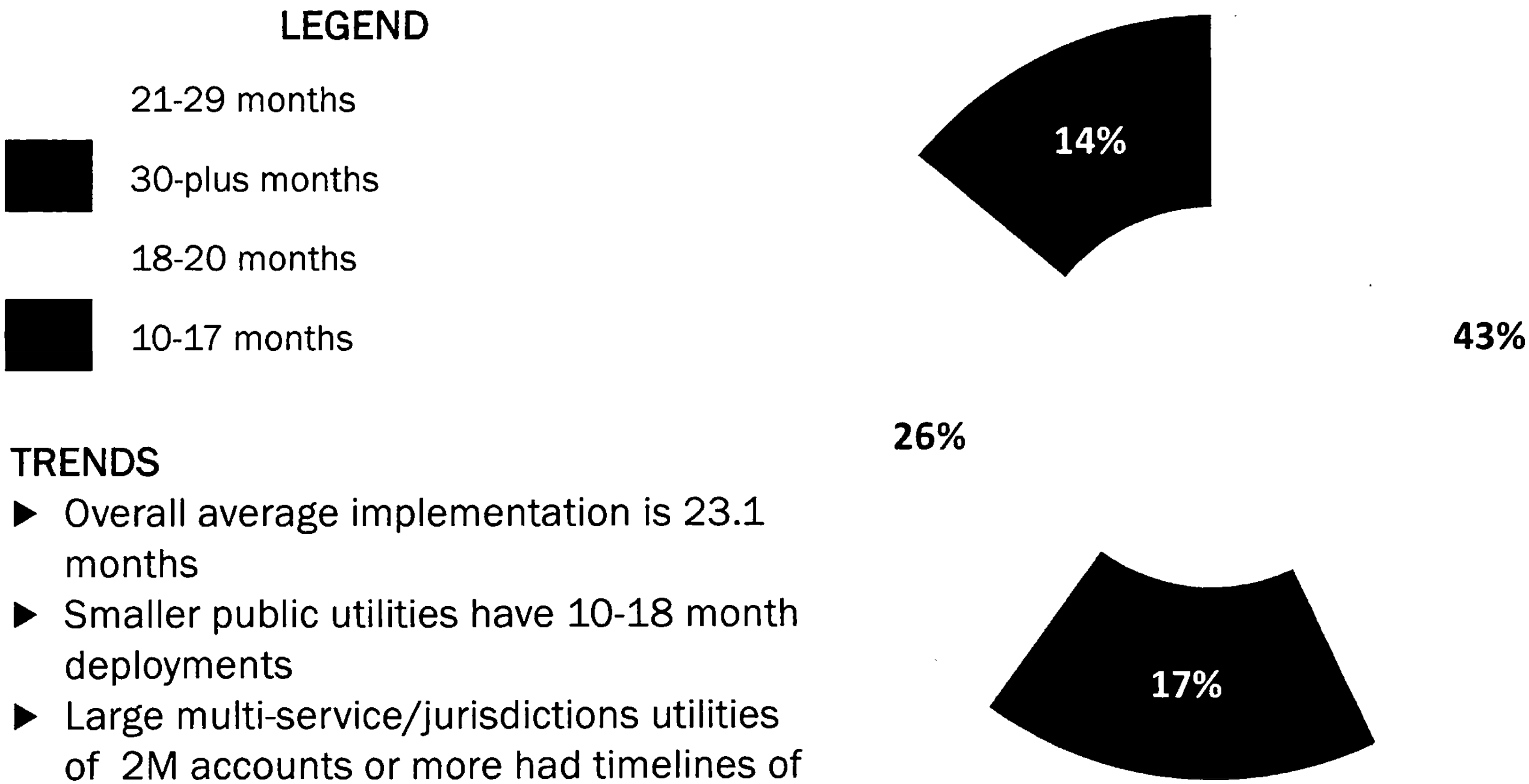


Upcoming Projects – CIS Modernization Drivers



Implementation Timeframes

LEGEND



TRENDS

- Overall average implementation is 23.1 months
- Smaller public utilities have 10-18 month deployments
- Large multi-service/jurisdictions utilities of 2M accounts or more had timelines of 30 months or more
- Cloud solution appear to reducing implementations timelines by 25-33%.

Source:
Insight™, TMG Project Database, retrieved May 2018

Tier 1 SAP CR&B Implementations

Recent Implementations

Name	Customer Accounts	Services	Product	System Integrator	Go-Live Year
PEPCO	1,936,074	E, G	SAP CR&B	Accenture	2013
Direct Energy	1,000,000	E, G	SAP CR&B	HCL	2013
National Fuel Gas	750,000	G	SAP CR&B	HCL	2017
Washington Gas	1,000,000	G	SAP CR&B	HCL	2018
DTE	3,300,000	E, G	SAP CR&B	Accenture	2016
UGI	700,000	G	SAP CR&B	Deloitte	2017
Tampa Electric (TECO)	1,100,000	E, G	SAP CR&B	Deloitte	2017
Hawaii Electric	500,000	E	SAP CR&B	HCL	2012
Idaho Power	500,000	E	SAP CR&B	HCL	2013

Current Implementations

Name	Customer Accounts	Services	Phase	Product	System Integrator	Deployment Model
Southern California Edison	4,900,000	E	Implementing	SAP CR&B and Hybris(C4C)	HCL	Hybrid
Sempra	2,170,000	E, G	Implementing	SAP CR&B	Accenture	
National Grid	7,400,000	E,G	Procurement	SAP CR&B Vendor of Choice	Selecting	PaaS
Southwest Gas	2,400,000	G	Procurement	SAP CR&B/Hybris C4C Vendor of Choice	Selecting	Hybrid
Duke Energy	8,300,000	E,G	Implementing	SAP CR&B/Hybris C4C	Accenture	Hybrid

Alignment of CIP Goals and Customer Feedback

Modernize the Customer Relationship

Customer Surveys - Maslansky	Existing Functionality Feedback
• Compared to national averages, DEV Customers: – Visit the utility website more – Call customer service more – Receive fewer communications and alerts	• Dominionenergy.com: Mobile use up from 35% in 2017 to 46% in 2018 • Manage Account: 40% of sessions conducted on mobile devices in 2018 • Manage Account: Online account users increased by 16% in 2017 and another 22% in 2018. • E-Bill survey: Qualitative conclusion – customers prefer e-mail alerts. • High Usage Alerts Pilot Program: 24% of customers signed up for email alerts; 71% signed up for text alerts; 5% signed up for both. • Dynamic Pricing Pilot Program: 74% of customers requested both email and text notifications

Conclusion: DEV customers are reaching out more to the Company, but are receiving less proactive communication than other utilities. Customers are using more digital devices and are interested in different communication methods depending on the information being sent.

Provide Better Information

Customer Surveys - Maslansky	Existing Functionality Feedback
• 13% of customers not familiar with how their bill is calculated; compared to a national average of 4% • Engaged customers are more satisfied	• Manage Account – Detailed Energy Usage Page up 22% from 2016 to 2018 • Dynamic Pricing Pilot End of Pilot Survey - #1 suggestion in feedback was to provide a comparison of various plans

Conclusion: Customers do not necessarily understand their bills, but more are actively seeking more information.

Deliver Value

Customer Surveys - Maslansky	Existing Functionality Feedback
• Customers that are more engaged are more satisfied • Customers ranked the lack of enough options to help conserve energy and save money as their third most frustrating aspect • 73% of customers rank saving money on their electric bill as a top priority	• e-Bill: 1.1M total customers enrolled in program at end of 2018 • Payments: Currently provide 7 different bill payment methods; in 2018 highest method is mail at 27%; lowest is walk-in payments at 4% • Green Power Program: Over 30,000 participants. • Energy Conservation: Over 300,000 participants.

Conclusion: Customers seek different options and are signing up for features that provide environmental benefits, provide opportunities to save money, and provide ways to simplify their transactions.

Why a Proven Risk Mitigation Methodology Matters

Area	Other Procurements	TMG Procurements	TMG Differentiators	Why it Matters
Project Fees	Time & Materials; Payments based on time elapsed	**Fixed Fees for Fixed Functionality**	Utility Requirements accelerators; Prior SOW language	**✓ Keeping budgetary commitments**
Software Functionality	Limited to a certain number of hours/workdays or "programs"/RICEFWs	**Agreement to Satisfy Well-Defined Utility Functional & Technical Requirements**	Utility Requirements accelerators; Prior SOW language	**✓ Keeping system improvement commitments**
Utility Staffing Expectations	Not well defined; projects are understaffed or always demanding resources	**Proposals and contracts contain clear and realistic expectations on utility staffing**	RFP Staffing Template accelerators; Prior project staffing information	**✓ Keeping commitments related to tight staffing conditions**
Project Timeline	Vague delivery schedule that can introduce time, financial, and completion risks	**Realistic timeline based on fixed outcomes and fixed fees**	RFP Template accelerators; Prior project timelines (planed vs. actual)	**✓ Keeping business disruption limitation commitments**

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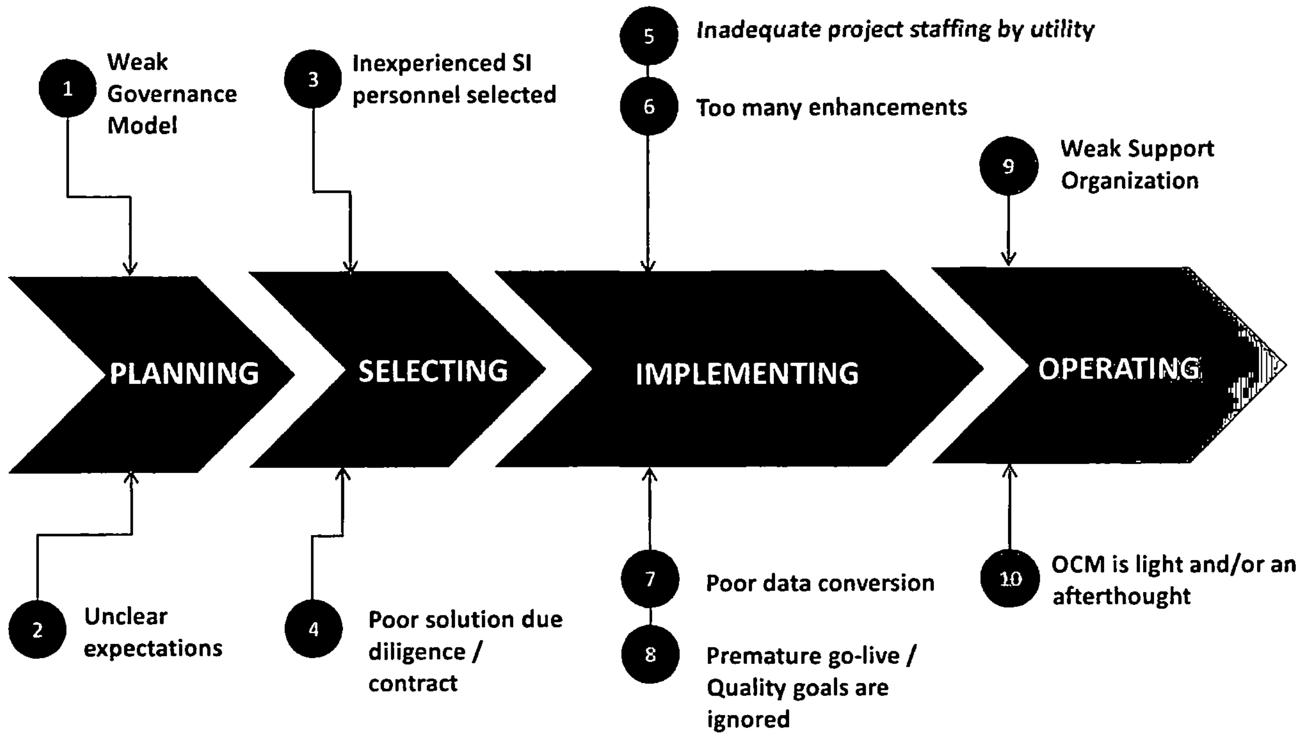
Why a Proven Risk Mitigation Methodology Matters

Area	Other Procurements	TMG Procurements	TMG Differentiators	Why it Matters
Project Cost	Few incentives to limit increasing costs; Environment for future change orders	**Fixed Fees for Fixed Delivery; Market or even "Below Market" Pricing**	Prior Fixed Fee contract terminology, Guidelines based on actual recent projects	✓ **Keeping spending commitments**
Deployment & Support Models	No exploration of On-Premise, IaaS, PaaS, SaaS, In-house, AMS and other deployment & support models	**Clear deployment and support expectations in RFP based on informed decisions made by utility leadership**	Deployment and support model decision accelerators; Recent project experience	✓ **Keeping on-going operational commitments**
Regulatory & Recovery Support	Lack of documentation on why decisions were originally made	**Summarizations and artifacts that outline rationale for decisions**	Standard deliverable artifacts, Project Memorandum accelerators	✓ **Keeping financial commitments**
Project Responsibility Matrices	Unclear delineation of responsibility of tasks between parties	**Clear RACI tables for each step of project formalized in Statements of Work**	Prior SOW RACIs; Project experience	✓ **Keeping delivery commitments**

Top 10 Reasons Why Projects Fail



Risk Mitigation: Planning

- Define measurable success criteria
- Define a set of principles to guide your teams
- Establish detailed project scope
- Design a governance model that works
- Plan your procurement, project, and support teams
- Secure a realistic budget
- Identify and manage risk starting Day 1

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Risk Mitigation: Selecting

- Your business is complex, the solutions are complex; hire someone who understands both
- Establish expectations early and often with vendors
- Keep your executives engaged in the process
- Make your selection team accountable for their decisions
- Consider your limitations and strengths – they will help determine the best solution for you

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Wright

WITNESS DIRECT TESTIMONY SUMMARY

Witness: Robert S. Wright, Jr.

Title: Director – Distribution Grid Planning and Asset Management

Summary:

Company Witness Robert S. Wright, Jr. explains the reliability and resiliency projects ("Grid Improvement Projects") that Dominion Energy Virginia plans to deploy as part of the GT Plan. Specifically, Mr. Wright explains that the Company is proposing two categories of Grid Improvement Projects: (1) grid technologies, and (2) grid hardening. The type of Grid Improvement Project planned for each category are:

A. The grid technologies projects include:
   1. Self-healing grid
   2. Hosting capacity analysis
   3. Distributed Energy Resource Management System
   4. Advanced analytics
   5. Voltage optimization
   6. Locks Campus Microgrid Project
   7. Enterprise Asset Management System ("EAMS")
   8. Outage Management System

B. The grid hardening projects include:
   9. Mainfeeder hardening
   10. Targeted corridor improvements
   11. Proactive asset upgrades
   12. Voltage island mitigation

Mr. Wright overviews each category of Grid Improvement Project and explains the associated costs, benefits, and alternatives.

Finally, Mr. Wright testifies that the Grid Improvement Projects enable the Company to operate the grid differently to meet 21st century needs in performance levels and to allow the Company and customers to maximize the benefits of the growing amount of connected renewables. He introduces the Company's Integrated Distribution Planning ("IDP") White Paper, which provides a detailed overview of the Company's current distribution planning process, the limitations of the current process, the investments needed to evolve the process, and the Company's vision of integrated distribution planning for the future.

DIRECT TESTIMONY
OF
ROBERT S. WRIGHT, JR.
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company").

A. My name is Robert S. Wright, Jr. My business address is 600 East Canal Street, Richmond, VA 23219. I am the Director of Distribution Grid Planning and Asset Management in the Company's Power Delivery Group. A statement of my background and qualifications is included as Appendix A.

Q. Please describe your area of responsibility with the Company.

A. I am responsible for overseeing grid planning to support customer load needs and reliability performance for the electric distribution system. I also am responsible for vegetation management as well as asset and data management activities.

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

A. The purpose of my testimony is to explain the reliability and resiliency projects ("Grid Improvement Projects") that Dominion Energy Virginia plans to deploy as part of its proposal to transform its electric distribution grid (the "Grid Transformation Plan," "GT Plan," or "Plan") over the next three years ("Phase IB"). In addition to improving the reliability and resiliency of the electric distribution grid, the Grid Improvement Projects proposed herein will support the integration of distributed energy resources ("DER").

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes, Company Exhibit No. ___, RSW, consisting of Schedules 1 through 8, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules.

Schedule	Description
1	Cost Schedule
2	Self-healing Grid Projected Benefits
3	Self-healing Grid Analysis and Project Scope Example
4	Self-healing Grid Equipment Installed
5	Advanced Analytics White Paper
6	Mainfeeder Hardening Analysis and Project Scope Example
7	Mainfeeder Hardening Projected Benefits
8	Voltage Island Mitigation List

Additionally, I sponsor Filing Schedule Wright, Attachments A – K, which provide executed contracts, requests for information ("RFI") summaries, request for proposals ("RFP") summaries, and final project reports from which detailed pricing estimates were prepared. The table below provides a description of these filing schedules:

Filing Schedule Wright	Description
Confidential Attachment A	Locks Campus Microgrid Project Design Report
Extraordinarily Sensitive Attachment B	Locks Campus Microgrid Project Costs
Confidential Attachment C	Equipment, Labor & Materials Contracts
Confidential Attachment D	Hosting Capacity Scope of Work
Extraordinarily Sensitive Attachment E	DERMS RFI Summary
Extraordinarily Sensitive Attachment F	Advanced Analytics RFP Summary
Confidential Attachment G	Voltage Optimization Costs
Extraordinarily Sensitive Attachment H	EAMS RFI Summary
Confidential Attachment I	Ash Tree Survey Report
Confidential Attachment J	Targeted Corridor Improvement Contracts
Confidential Attachment K	Voltage Island Mitigation Costs

I also sponsor certain sections of the Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document. Finally, I sponsor the metrics identified in Company Witness Edward H. Baine's Schedule 2.

Q. Did you provide information to West Monroe Partners, LLC ("West Monroe") for use in the cost-benefit analysis ("CBA")?

A. Yes, I provided costs and additional inputs for Grid Improvement Projects to West Monroe for use in the CBA. I also support the benefits reflected in Thomas G. Hulsebosch's Schedule 2, as identified therein.

The specific costs I support in Phase IB are:

Nominal $, in Millions	**2019**	**2020**	**2021**	
	Year 1	**Year 2**	**Year 3**	**3-year Total**
Phase IB	**$10.7**	**$60.0**	**$92.5**	**$163.3**
Capital	$4.7	$52.8	$82.6	**$140.0**
O&M	$6.0	$7.3	$9.9	**$23.2**

My Schedule 1 provides detailed cost information for the GT Plan components that I sponsor.

Q. How is your testimony organized?

A. My direct testimony is organized as follows:

I. Grid Improvement Projects

A. Grid Technologies Projects

B. Grid Hardening Projects

II. Costs, Benefits, and Alternatives

III. Integrated Distribution Planning

Q. Before you begin, do the proposed Phase IB Grid Improvement Projects meet the definition of an electric distribution grid transformation project under Va. Code § 56-576?

A. Yes. The proposed activities involve the application of "automated control systems for electric distribution circuits and substations" that are "designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability" and involve "intelligent grid devices for real-time system and asset information."

I. GRID IMPROVEMENT PROJECTS

Q. What are the Grid Improvement Projects the Company is proposing for the GT Plan?

A. The Company is proposing two categories of Grid Improvement Projects: (1) grid technologies, and (2) grid hardening. The type of Grid Improvement Project planned for each category is detailed below.

A. The grid technologies projects include:

1. Self-healing grid
2. Hosting capacity analysis
3. Distributed Energy Resource Management System
4. Advanced analytics

5. Voltage optimization
6. Locks Campus Microgrid Project
7. Enterprise Asset Management System ("EAMS")
8. Outage Management System

B. The grid hardening projects include:

9. Mainfeeder hardening
10. Targeted corridor improvements
11. Proactive asset upgrades
12. Voltage island mitigation

Q. What are the main drivers behind the proposed Phase IB Grid Improvement Projects?

A. Dependency on reliable electric service is growing. Everyday activities related to business, communications, education, transportation, and security all require the electric grid to be reliable on a daily basis and resilient to recover from severe weather events when they occur. Additionally, DER integration requires that the distribution grid be available to accept and transport energy generated by customer sources. In this sense, the distribution grid is evolving to look and act like the transmission grid, with availability being as important a measure of service quality as reliability. For both availability and reliability, the Company receives feedback from customers on a regular basis regarding the need to improve service. This feedback is received through various channels such as the Customer Service call centers, Customer Relations, local Operations or Reliability teams or our regulators. Furthermore, feedback during stakeholder sessions in 2019, facilitated by Navigant Consulting, Inc. on behalf of Dominion Energy Virginia validated the need for a reliable and resilient grid to meet customer needs into the future. A survey of Dominion Energy Virginia customers conducted by Maslansky + Partners on behalf of the Company also confirmed that eliminating outages, shortening duration and utilizing technology to improve service are top priorities for customers. The Company's Plan Document provides further detail on customer feedback regarding the need for better reliability and availability on the distribution grid.

Q. Why are the proposed Phase IB Grid Improvement Projects needed?

A. The Grid Improvement Projects proposed herein are needed to improve service for customers and critical services that are vital to maintaining health and public safety such as hospitals, water and waste treatment facilities, key communications facilities, military facilities, and emergency dispatch centers that consistently experience poor performance as measured by annual interruption time and speed of recovery after severe weather events. The Grid Improvement Projects are also needed to support the integration of DER. The proposed Grid Improvement Projects will meet these needs by:

- leveraging technology to improve situational awareness and automatically restore large segments of customers;
- rebuilding poorly performing grid segments to stronger standards and upgrading specific components to eliminate outages and minimize damage when outages occur;
- improving the availability of the grid to accept and transport customer-generated energy;
- enabling visibility of grid capacity available to host customer-owned generation through technology and grid support; and
- continuing to investigate the use of new technologies and systems such as microgrids and smart inverters for grid support and expanded customer benefits.

A. Grid Technologies Projects

1. <u>Self-Healing Grid</u>

Q. What is a self-healing grid?

A. A self-healing grid, also known as distribution automation or fault location, isolation, and service restoration ("FLISR"), refers to a distribution network that uses intelligent grid devices such as switches, reclosers, line sensors, communications network, and a control system to automatically isolate outages and reroute power to restore most customers in a matter of seconds or minutes. This type of system also provides situational awareness to the distribution operator about the specific location of the fault, allowing crews to arrive and identify repair needs faster, speeding the restoration time for the remaining affected customers.

Q. What benefits would a self-healing grid provide for Dominion Energy Virginia customers?

A. A self-healing grid would result in fewer sustained outages for customers, and shorter outage times for customers that do experience a sustained outage. For example, with a self-healing grid, an outage that would have caused 3,000 customers to lose power for approximately 2 hours would now have 2,500 customers experiencing a "momentary outage" of less than two minutes, and the remaining 500 customers having a sustained outage of less than 2 hours, since the self-healing grid is able to automatically isolate the problem, reroute power to restore most of the customers, and give grid operators a smaller feeder segment to inspect to locate and fix the problem. The Company is proposing to implement this self-healing grid technology on more than 50% of the distribution feeders, benefiting more than 75% of the Company's customers, including all customers providing critical services. The Company designates approximately 1,400 accounts as critical services in Virginia, which include hospitals, water treatment facilities and emergency dispatch centers.

Q. You said this would result in fewer outages for customers. Please quantify this.

A. As detailed in my Schedule 2, the Company's proposed self-healing grid projects in Phase IB will result in 61,000 fewer customer interruptions and 4.2 million fewer outage minutes for 88,000 customers; an average reduction of 47 minutes of outage time annually. This represents a 24% improvement in service reliability for these 88,000 customers. Also of note, 9 of the 23 proposed Phase IB projects will improve service for customers located in economically distressed Opportunity Zones as certified by the Internal Revenue Service. Likewise, the proposed self-healing grid projects over the full 10 years of the GT Plan would result in 1.1 million fewer customer interruptions, and 68 million fewer outage minutes; achieving an average reduction of 33 minutes of outage time annually for 2 million customers, resulting in a 26% improvement in service reliability for 2 million customers.

Q. How did the Company identify the targeted population of feeders for self-healing grid work that is part of the Phase IB Grid Improvement Projects?

A. The Company is proposing to target feeders that have the largest number of customers and most critical services affected when mainfeeder outages occur. By prioritizing feeders by the amount of potential improvement that can be achieved, the Company expects to maximize the benefits of the investments. As an example, the self-healing grid work that is proposed as part of the Phase IB Grid Improvement Projects will reduce the number of customers affected by each mainfeeder outage from an average of 1,668 customers to an average of 555 customers based on detailed engineering analysis. An example of the analysis that is performed and the resulting project scope package for an identified feeder is attached as my Schedule 3. Upon request, the Company can provide the remaining project scope packages as they are voluminous.

Q. In what grid technologies must the Company invest to build this self-healing grid?

A. To build a self-healing grid, the Company will need to install intelligent grid devices on the selected feeders and associated substations, and expand the functionality of the Company's Advanced Distribution Management System ("ADMS"). Currently, the Company's ADMS is limited to basic data acquisition and control functionality. The functionality that would be added is the FLISR module of the ADMS. My Schedule 4 provides details on the amounts and types of equipment that will be installed as part of the self-healing grid.

2. <u>Hosting Capacity</u>

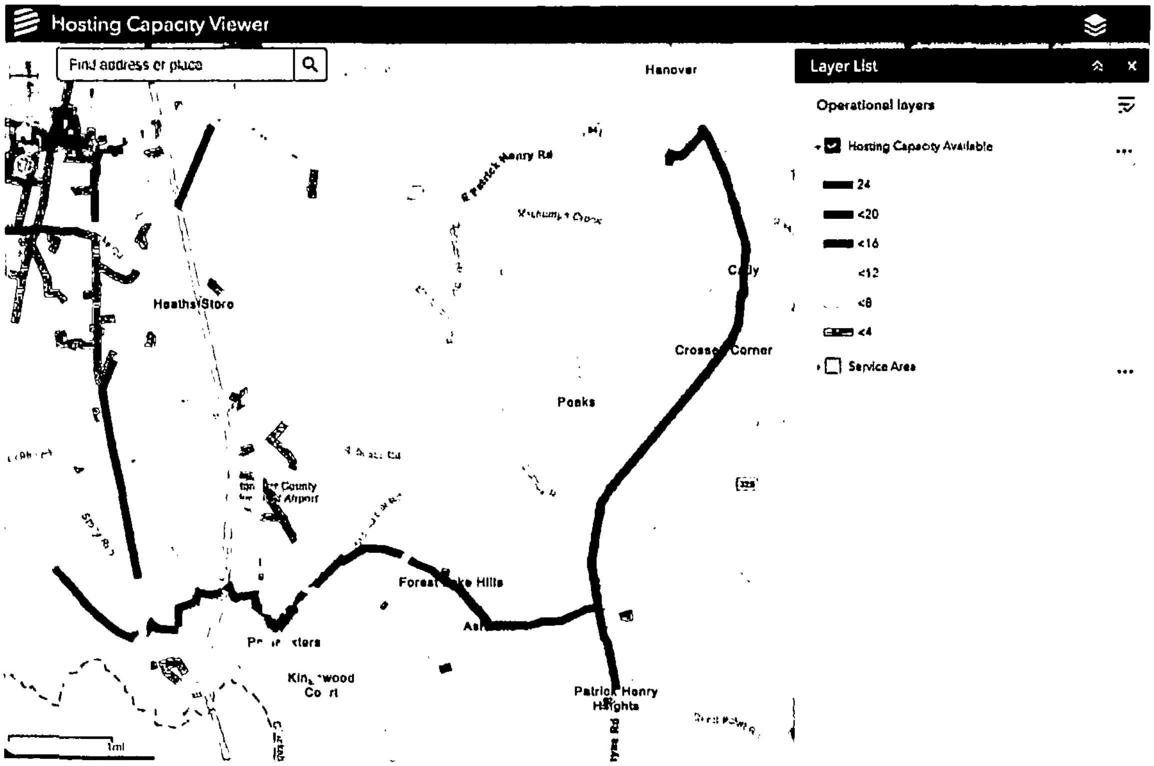
Q. What is hosting capacity?

A. The distribution grid has traditionally been designed for a one-way flow of power from the utility to the customer, with equipment sized larger at the feeder head and smaller at the feeder end to handle the expected peak load while maintaining proper voltage without exceeding thermal limits of equipment. DER that are connected along the distribution feeder can create reverse power flows that affect customer voltages and loading on equipment. Hosting capacity defines the amount of DER that can be connected to each segment of the distribution grid without causing voltage or loading issues and indicates to customers whether distribution grid improvements may be necessary to integrate their DER, while also allowing the Company to determine when a more detailed engineering analysis needs to be performed.

Q. What is the Company proposing related to hosting capacity?

A. The Company is proposing to perform hosting capacity analysis for both utility scale and net metering DER and publish the results using online interactive maps. An example of such a map for utility scale DER is shown below in Figure 1. This map is from a preliminary exercise conducted by Dominion Energy Virginia engineers to understand the process and tools necessary to perform the utility scale hosting capacity analysis. As shown, colored line segments indicate the hosting capacity of each part of the circuit. These maps would be available by the end of 2020, for the Company's service territory, to guide customers in making decisions regarding generation additions.

Figure 1: Example of Hosting Capacity Results



Because hosting capacity for each segment of the distribution grid depends on the physical makeup of the grid, *i.e.*, the size of wires and transformers, presence of voltage regulating equipment, existing load, and other DER that is already connected to the feeder, the hosting capacity analysis is typically automated to update on a recurring basis to capture distribution system changes using customized computer programs and tools. This process is computationally demanding because it requires that thousands of simulations be conducted for each feeder each time the hosting capacity analysis is performed. The hosting capacity analysis will continue to improve as additional grid information becomes available from the proposed intelligent grid devices and smart meters.

3. Distributed Energy Resource Management System

Q. What is a Distributed Energy Resource Management System ("DERMS")?

A. Unlike conventional centralized power plants where the Company typically has continuous monitoring, communications, and control capabilities, the growing population of DER sites generally operate autonomously without the Company having visibility of the status or power output of the generating equipment or having control capability to manage impact on the grid. Visibility and control capability of this growing population of energy resources connected to the distribution grid is necessary to ensure safe and reliable energy delivery to customers and to eventually leverage the full capabilities of these resources for grid support and to maximize customer benefits while ensuring overall grid stability.

The proposed DERMS, in conjunction with real-time data from intelligent grid devices and a secure telecommunications network, will aggregate performance and status information from DER sites, analyze the need for control actions, and issue the appropriate commands to maintain a safe and reliable energy grid. As equipment capabilities continue to mature and industry standards evolve, the proposed DERMS will enable the use of smart inverter grid support capabilities to achieve greater grid efficiencies and customer benefits, eventually allowing the Company to use these DER to resolve grid constraints, while potentially reducing interconnection costs by using active power management and other advanced inverter capabilities.

For initial DERMS functionality as part of Phase IB, the Company will focus on developing a repository of DER locations and key attributes, and an aggregated view of DER status and performance information for grid operators. Because this functionality is available in the existing ADMS, the Company is not requesting approval for DERMS investments in Phase IB but expects to start investments in 2022, subject to future Commission approval.

4. Advanced Analytics

Q. What is Advanced Analytics?

A. Advanced Analytics, which combines many technologies and methods, is broadly classified as artificial intelligence, and is often referred to as predictive analytics (one of its salient capabilities) or Big Data (the platform used for processing analytics). Advanced Analytics is comprised of Machine Learning ("ML") and Deep Learning. ML is a collection of algorithms and statistical models that computer systems use to perform a specific task effectively and to proactively learn without explicit programming; relying instead on patterns and inferences from historically collected data. Deep Learning is based on artificial neural networks.

Advanced Analytics can perform or support the following type of analytics:

- Descriptive Analytics: helps analyze the data and informs on *what happened.*
- Diagnostic Analytics: helps understand the factors affecting the outcome and *why something happened.*
- Predictive Analytics: uses historical data to understand *what will happen.*
- Prescriptive Analytics: helps with *what should I do?* Put another way, prescriptive analytics informs on how to handle specific situations by factoring in knowledge of possible situations, available resources, past performance and what is currently happening.

In addition to the above, Advanced Analytics can also help the Company optimize objective function(s) without violating established constraints. My Schedule 5 provides a white paper describing Advanced Analytics and discusses its use cases and benefits.

Q. Does the Company currently use Advanced Analytics to improve service to customers?

A. Yes, it does. One example is with data collected from existing smart meters. The Company is able to use this data to identify and address failing equipment or other system issues before an outage occurs. Figures 2 through 4 demonstrate this capability. As shown therein, in all the instances, an operational issue was identified and addressed before the customer experienced an unplanned outage or damage to their equipment. This means the customer benefitted from an improved level of service and the Company benefitted through more efficient management of repair work as part of planned activities as opposed to responding to unplanned events.

Figure 2: Problem Fixed – Loose Connection

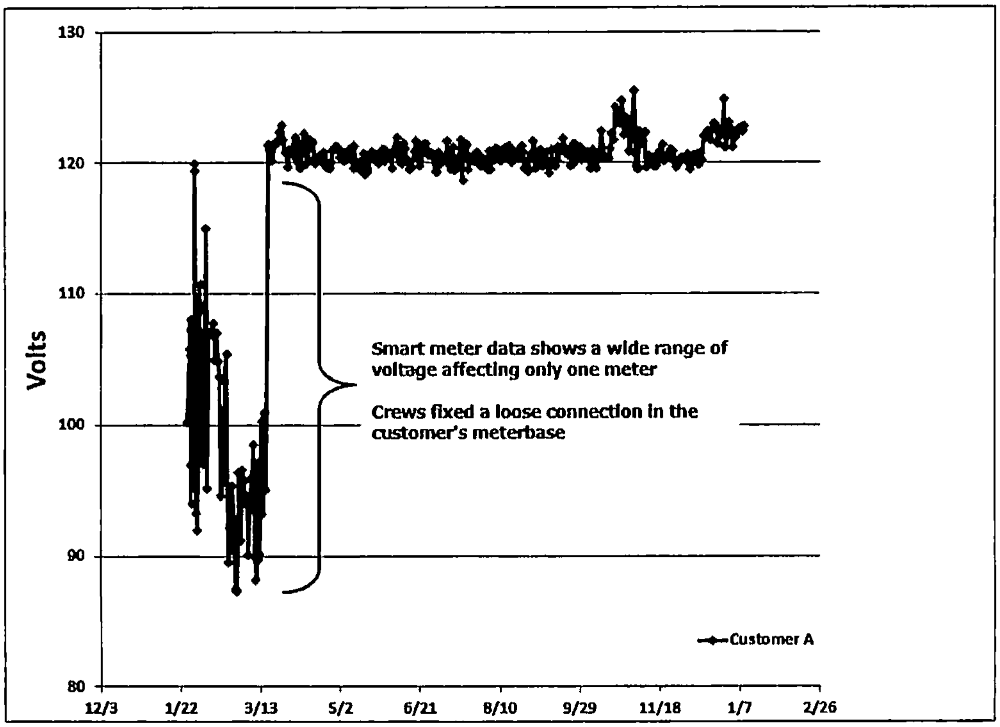


Figure 3: Problem Fixed – Overloaded Secondary Wire

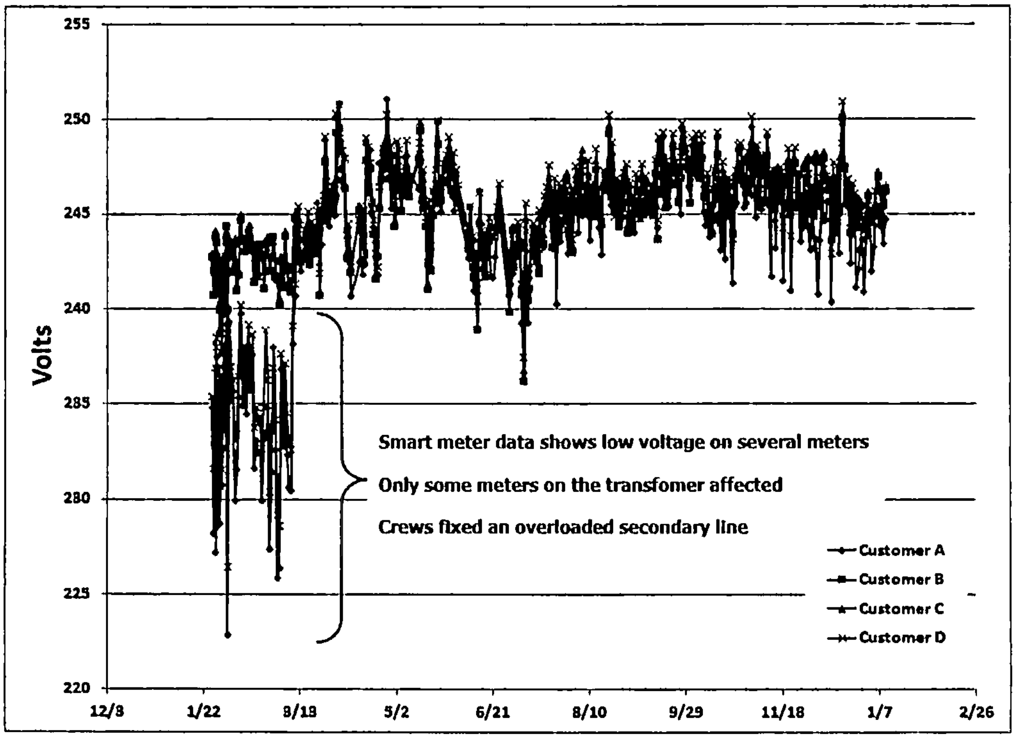
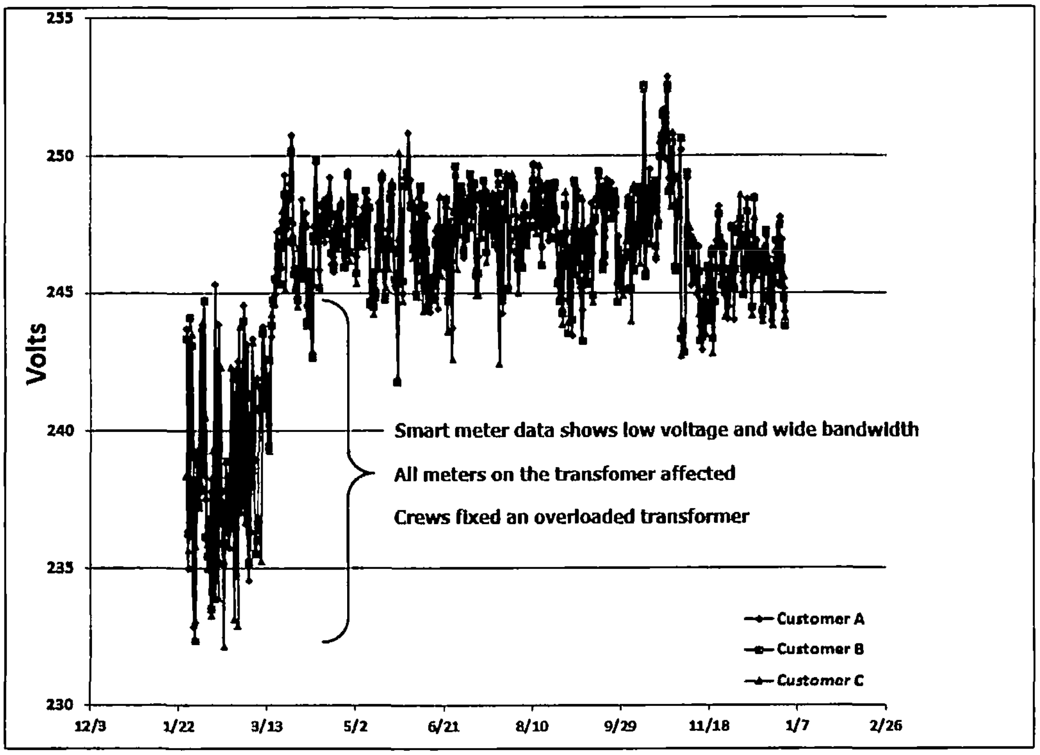


Figure 4: Problem Fixed – Overloaded Transformer



Q. How will the Company use Advanced Analytics in the future?

A. Customer expectations of a transformed grid require building, operating and maintaining the grid in a new way. To meet these customer expectations, the Company will install intelligent grid devices as part of a self-healing grid. Installation of these devices, along with smart meters, will provide valuable information about the distribution grid, allowing the Company to perform Advanced Analytics to identify issues, take action and improve service to customers while also managing grid activities, including performing integrated distribution planning, more efficiently. Additionally, the data and Advanced Analytics capabilities, coupled with the proposed EAMS (a system focused on managing assets and associated activities) will enable the Company to analyze life cycle costs, determine anomalies in failure rates, identify where proactive replacement is most cost-effective and beneficial, identify the condition of feeder segments, and drive a transition from time and cycle-based preventive maintenance to predictive maintenance activities.

5. Voltage Optimization

Q. Please explain voltage optimization.

A. The Company must operate the distribution grid in a manner that ensures customers receive proper voltage at the point of delivery as defined in the Company's filed Terms & Conditions. Without visibility of the actual voltage along the distribution feeder or being delivered to each customer, the Company must apply engineering assumptions to system modeling to estimate voltages when determining target settings for voltage control devices. These settings are typically higher than necessary to ensure customers farthest from the substation receive voltage within the proper bandwidth (*i.e.*, 114V to 126V for residential customers). This can cause some customers' energy consumption to be higher than necessary.

With visibility of the actual voltage at each smart meter, and a control system that can receive near real-time voltage readings and issue voltage control commands to regulation devices, more precise voltage control settings can be applied. These more precise settings would generally result in lower voltage levels that are still within prescribed limits, which would also result in lower energy consumption for most customers without a noticeable difference in service level. Because the actual customer voltage information from smart meters is needed to determine the degree of voltage management that is possible, the Company is estimating a 1 volt reduction in delivered voltage initially, which would lower energy consumption approximately 0.5% on average for customers. Resolving voltage issues that are identified as smart meters are installed is a precursor to implementing voltage optimization and is anticipated to take approximately 6 to 12 months after smart meter deployment is completed for customers served by each substation. This work is discussed in more detail in the Proactive Asset Upgrade section of my testimony. The Company is proposing to install a control system in 2022, to better optimize the voltage delivered to customers; and, while not part of Phase IB, the costs and benefits are included in the CBA to provide a total view of investments necessary to achieve the benefits of voltage optimization.

6. <u>Locks Campus Microgrid Project</u>

Q. What is a microgrid?

A. A microgrid is a group of interconnected loads and DER that act as a small power grid, able to operate when connected to the larger electric grid and also able to continue to operate as an "island" when there is an interruption or other grid disturbance that affects normal power flow from the grid.

Q. Please describe the Locks Campus Microgrid Project.

A. The Locks Campus Microgrid Project (or "Locks Microgrid") is proposed for the Company's new Locks Campus near Petersburg, Virginia. This campus will host a local operations and construction office as well as a fleet maintenance facility, electrical test labs, and warehousing space for critical substation and transmission equipment. As part of Phase IB, the Company is proposing to install a microgrid on the campus (*i.e.*, a non-wires alternative ("NWA")) to obtain real-world data, understand DER performance characteristics, perform testing, vet new technology integration into the distribution grid, and evaluate microgrid architecture and operational requirements for potential future applications of NWAs.

The Company engaged Quanta Technology, Inc. ("Quanta") to complete a feasibility, design and implementation plan to construct and commission the Locks Campus Microgrid, including a design package with detailed major component cost estimates, as discussed below.

Load requirements and generation needs for the site were analyzed to ensure accurate understanding of the site and its power requirements. The utilization of various DER technologies, and mixes of those technologies, to meet site requirements were investigated to ensure achievement of project targets and prove operational concepts.

Like any other grid facility, proper protection, control, and visibility of this site and its equipment is essential to maintain reliability, both of the site and the grid as a whole. To accomplish this, protection, control, and communications strategies were developed to ensure understanding of critical microgrid operational requirements, gather valuable performance information, and ensure all assets are properly protected. Additional detail, including a cost breakdown and justification of the selected technologies and strategies, can be found in Filing Schedule Wright, Attachments A and B.

7. Enterprise Asset Management System

Q. What is an EAMS and why is it important?

A. An EAMS is a system that aggregates data and provides capabilities to manage many aspects of distribution assets and related aspects at all points in their life cycle. The EAMS will assist the Company with managing the procurement, deployment, and retirement of equipment and devices through improved equipment attribute analyses and planning capabilities. The EAMS will also enable the Company to improve asset management practices by assessing the health and performance of grid components and driving both predictive and prescriptive maintenance activities, leading to more effective grid operation and management. Once implemented, information and analytics from the proposed EAMS will drive a large part of the identification and prioritization of ongoing maintenance and upgrade work performed by the Company.

8. <u>Outage Management System</u>

Q. What is an Outage Management System ("OMS") and why is it important?

A. An OMS is a system that provides tools and information to efficiently restore power to Dominion Energy Virginia customers by providing outage analysis and prediction functionality, while enhancing public and worker safety. The OMS also plays an important role in providing outage notifications and restoration updates to customers. The implementation of intelligent grid devices and the self-healing functionality of ADMS will create constant changes in grid connectivity as feeders are reconfigured to restore customers or manage power flows from DER. The result is a dynamic electric distribution grid that requires an OMS capable of maintaining the hierarchy of how each customer is being served based on the configuration of the feeder ties at any point in time. The Company's current OMS does not have the capability to support this dynamic hierarchy aspect of the electric distribution grid. The Company plans to begin implementation of a new OMS after Phase IB in 2024.

B. Grid Hardening Projects

9. <u>Mainfeeder Hardening</u>

Q. Please describe the mainfeeder hardening work proposed in the Phase IB Grid Improvement Projects.

A. Mainfeeder is the portion of the distribution system that carries electricity from substations to tap lines and individual customers. This part of the system typically serves hundreds or thousands of customers along many miles of line, including critical services. Hardening involves improvements that eliminate outages altogether, reduce damage for faster restoration, and provides the ability to isolate damage and restore customers using feeder ties.

The proposed mainfeeder hardening activities will improve reliability and resiliency for poorly performing feeder sections through a combination of: rebuilding to newly implemented stronger design and material standards ("new standards"), relocating, converting to underground, or constructing feeder ties. The new standards minimize the amount of damage and associated repairs needed during blue sky days as well as severe weather events, allowing the grid to recover more quickly so customers and community activities can return to normal. Testing conducted for the Company by the Electric Power Research Institute ("EPRI") at their research facility in Lenox, MA showed that, for their simulation of a large tree falling on the distribution line, the new standards will result in significantly less infrastructure damage. A video of this testing and its results is available at https://youtu.be/rxGgeO2YkkQ.

Notably, three of the four tests conducted using the Company's existing standard resulted in a broken pole. Replacing a broken pole involves additional resources and equipment such as an auger truck and operator to dig the pole hole, and 8-1-1 notification to have underground utilities located before digging can begin. The one test conducted by EPRI that did not result in a broken pole appears to have been related to an insulator that failed prematurely. On the other hand, the four tests conducted using the Company's new standards resulted in broken cross-arms only, which translates to a faster and less expensive restoration.

Q. How will building to these new standards improve resiliency during severe weather events?

A. The Company anticipates the new standards will improve resiliency by reducing the time to recover from severe weather events. The Company conducted an analysis to estimate how the new standards, if already in place, could have reduced outage durations during severe weather events that affected the Company's service territory. Table 1 shows the results of this analysis. Table 1 shows the estimated difference in restoration activities for several notable historical weather events.

Table 1: Estimated Storm Experience Based On New Standards

		Existing Standards			Estimated Based On New Standards					
Storm Name	Affected Customers	Poles Replaced	Crossarms Replaced	Duration (Days)	Poles Replaced	Crossarms Replaced	Additional Other Repairs	Duration (Days)	Reduction (Days)	Reduction (Percent)
Hurricane Isabel	1,800,000	10,705	14,610	15	2,676	17,902	4,737	11	**-4.4**	-29%
Hurricane Irene	1,300,000	1,869	4,168	9	467	4,743	827	8	**-1.3**	-15%
Derecho	1,000,000	994	1,285	8	249	1,591	440	7	**-0.9**	-11%
Hurricane Ernesto	600,000	508	1,250	5	127	1,406	225	4	**-0.8**	-15%
Hurricane Matthew	470,000	480	1,181	5	120	1,329	212	4	**-0.7**	-14%
March 2018 Wind Storm	690,000	555	1,100	5	139	1,536	246	4	**-0.8**	-16%
Hurricane Michael	607,000	675	1,021	5	169	1,229	299	4	**-1.0**	-20%

As demonstrated, with 75% fewer broken poles based on the testing results, the new standards would have reduced storm duration by an average of 17%. These estimated reductions in storm duration are based on labor calculations for replacing poles, crossarms, insulators and restringing downed wires under normal work conditions from the Company's work management system. As an example, replacing a simple three-phase pole is estimated to require 48 manhours of work, while replacing a crossarm is estimated at 18 manhours.

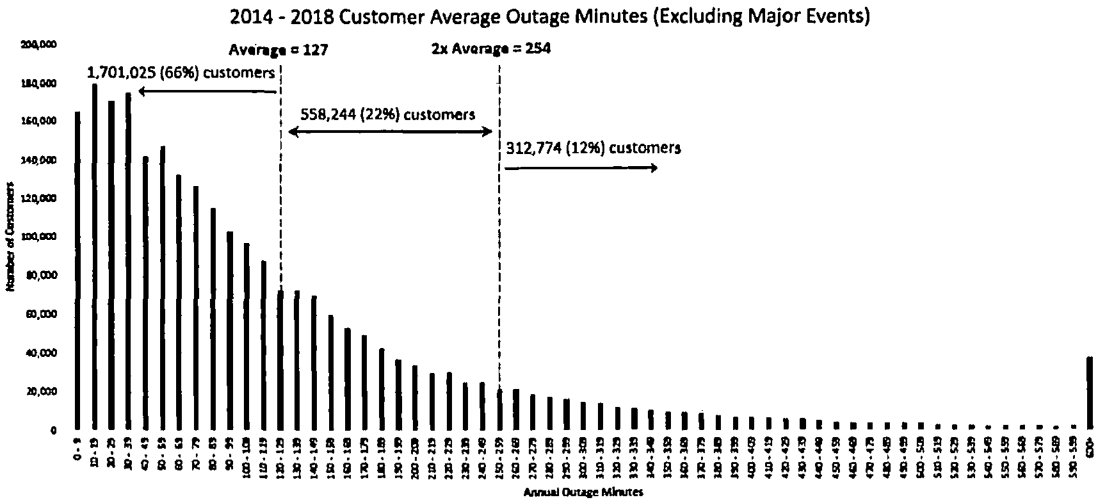
The Company considers the results in Table 1 to be conservative since basic repair scenarios were used. These scenarios do not take into account actual field conditions during storm restoration that are likely to impact repair times, such as truck access, specialty equipment needs, and complex pole configurations that exist. In addition to the labor calculations from the work management system, the Company also used available information regarding the number of broken poles and crossarms during each event, the number of line resources engaged in restoration activities for each event, and assumed an average of 10 hours of restoration work time each day for those line resources.

The Company acknowledges that the above analysis and potential reduction in storm restoration time assumes that all affected facilities would be subject to the new standards, when in reality it will be a subset of the total distribution grid. Nevertheless, this analysis demonstrates that by eliminating broken poles and shifting the damage to grid components that are more quickly repaired, the Company can speed time to repair and reduce outage times in the future.

Q. How did the Company identify the targeted population of customers for mainfeeder hardening for the Phase IB Grid Improvement Projects?

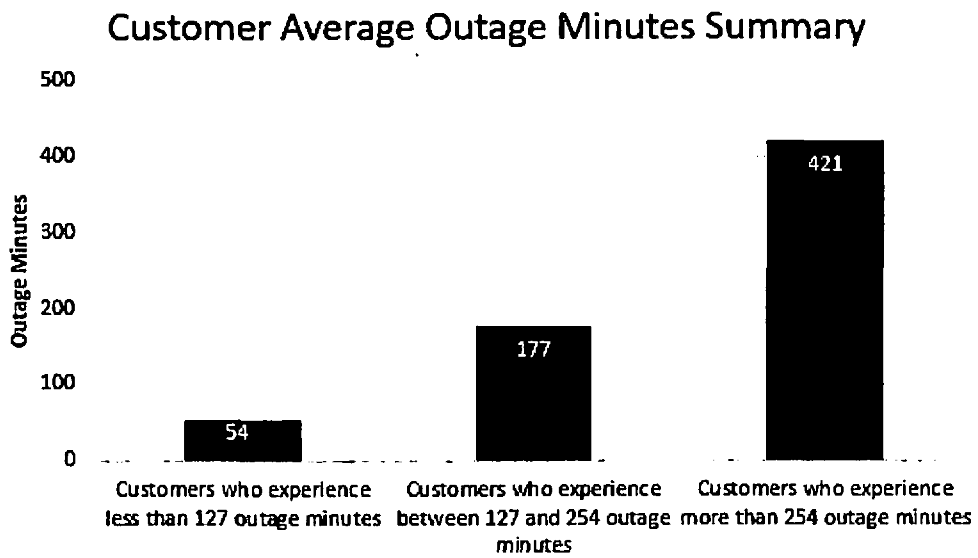
A. The Company evaluated historical reliability information from 2014 to 2018, to identify customers with poor performance. As shown in Figure 5 below, while the average Dominion Energy Virginia customer experiences 127 outage minutes annually excluding major events based on a 5-year average, there are approximately 312,000 customers, including 329 critical services, that average more than 254 outage minutes annually, more than twice the average.

Figure 5: Dominion Energy Virginia Customer Average Outage Minutes



In fact, as shown in Figure 6, this group of approximately 312,000 customers average 421 outage minutes annually, which is more than three times the average customer. Put another way, these 12% of Dominion Energy Virginia customers account for 41% of all outage minutes experienced by customers each year.

Figure 6: Dominion Energy Virginia Customer Average Outage Minutes Summary



So, the Company began with this 12% of customers as the target population for the proposed mainfeeder hardening work in the GT Plan. The next step was to assess which feeders these approximately 312,000 customers were served from and to identify and focus on those feeders with the highest concentration of these poor performance customers. The Company used 500 targeted customers per feeder as a minimum threshold for inclusion in the mainfeeder hardening effort. Using this process, the Company identified approximately 187 mainfeeders (consisting of approximately 1,028 miles of hardening required) to target the full 10 years of the GT Plan. These 187 mainfeeders serve approximately 177,000 out of the 312,000 customers experiencing the worst performance.

For Phase IB specifically, the Company will target 11 mainfeeders for hardening, specifically targeting 12,578 customers and 61 critical services (out of the approximately 312,000 customers and 329 critical services that represent the bottom 12% of reliability performance over the past five years).

Q. Are the benefits of this mainfeeder hardening limited to this group of targeted customers?

A. No, they are not. Since work on the mainfeeder system will also improve service for downline portions of the distribution grid, additional customers beyond those in the targeted population will also benefit from the proposed work. Indeed, even though our efforts specifically target 177,000 customers, approximately 491,000 customers will see improved reliability.

Q. What specific work will the Company do as part of mainfeeder hardening in Phase IB?

A. For each of the 11 feeders identified for hardening in Phase IB, the Company performed detailed engineering analysis to identify the appropriate solution. This analysis evaluated solution options, cost estimates and associated benefits from which the engineer chose the optimal solution. See my Schedule 6 for an example of the detailed engineering analysis completed for each project, as well as project scoping documents and cost estimates.

The work that is proposed on these feeders includes applying overhead strengthening options such as rebuilding or relocating 61 miles of mainfeeder line and converting an additional two miles of overhead mainfeeder line to underground.

The Company continues to identify specific work, compile project scoping and cost estimate documents and complete construction design estimates in order to have a clear view of the specific work that will be performed as part of future mainfeeder hardening activities.

Q. What benefit will customers receive from the proposed mainfeeder grid hardening work?

A. As detailed in my Schedule 7, the Company's proposed mainfeeder hardening projects in Phase IB will result in 22,000 fewer customer interruptions and 2.2 million fewer outage minutes each year for approximately 24,000 customers. This represents a 27% improvement in service reliability for customers that historically average 348 outage minutes each year, excluding major events. Also of note, 2 of the 11 proposed Phase IB projects will improve service for customers located in economically distressed Opportunity Zones as certified by the Internal Revenue Service.

Likewise, the proposed mainfeeder hardening projects over the full 10 years of the GT Plan would result in 303,000 fewer customer interruptions and 30.3 million fewer outage minutes each year, achieving an average reduction of 61 minutes of outage time annually for the 491,000 customers that benefit from these efforts.

Q. Did the Company consider additional tree trimming as an alternative to mainfeeder hardening?

A. The Company executes a thorough vegetation management program that uses scheduled maintenance trimming, removal of hazard trees, and operational hotspot trimming to maintain clearances for safe and reliable operation of the distribution grid. From a resiliency perspective, because of the number of tree-related outages during severe weather events that are caused by live trees, the Company does not consider additional trimming in terms of shorter trim cycles or more aggressive trimming to be an effective alternative to the mainfeeder hardening work proposed in Phase IB. Additionally, expanding rights-of-way for this purpose is not considered a feasible alternative.

10. <u>Targeted Corridor Upgrades</u>

Q. Describe the targeted corridor upgrade programs proposed in the Phase IB Grid Improvement Projects.

A. As part of Phase IB, the Company is proposing two new targeted programs to improve grid reliability and resiliency while concurrently minimizing environmental impact:

1. <u>Remediate ash tree mortality</u> – the emerald ash borer ("EAB") was first discovered in North America in 2002, and became established in Virginia in 2008. Currently, the infestation has been detected in over 70 counties throughout western, central, and southern portions of Virginia. EAB causes 100% mortality to the ash tree population, which accounts for approximately 5% of the trees along the approximately 6,700 miles of overhead distribution lines in the Company's affected areas. Since the damage results in a brittle tree that cannot be safely climbed for removal, trees that cannot be accessed by a bucket truck require specialized equipment. Identifying and proactively removing impacted trees before they become too brittle will reduce the safety risk, reduce the cost of removal, and eliminate dead hazard trees that could cause outages.

   The Company has been removing affected ash trees in the western parts of the service territory for several years, but with the progression of the insect and the time since initial infestation, the pace of impact to the system is growing as indicated by more trees showing decline and dying. Recognizing the need to understand the full extent of risk and solution options to address ash trees, the

Company engaged Environmental Consultants, Inc. ("ECI") to quantify the ash tree population along distribution corridors, assess tree health, project reliability risk, and quantify costs of removal. Based on a random sample survey of 361 miles of distribution corridor, ECI estimates the Company has approximately 19,550 ash trees along distribution rights-of-way capable of impacting distribution lines. The survey also determined that approximately 75% of these ash trees are already dead or in declining health. The Company therefore is proposing a 4 year removal program, with the first two years of costs included in Phase IB. According to ECI projections, ash trees will cause approximately 5,770 outages if not removed proactively.

2. <u>Herbicide program for ground floor maintenance</u> – applying selective herbicides reduces the amount of incompatible growth on the Company's distribution corridors. This incompatible growth causes outages and, just as impactful, inhibits accessibility to Company facilities for routine inspections or unplanned restoration work. Limiting the growth of incompatible vegetation creates an environment that encourages grassy growth, thus creating a habitat for flowering plants and wildlife to thrive. The Company has completed several pilot projects to determine the most effective approach for implementation of an herbicide program. Based on application cost and efficacy, the Company's proposed plan would initiate treatment of corridors one year after maintenance trimming occurs. Herbicide application across the entire width of the corridor will control the significant number of woody stems that exist from years of brush hogging activities that occur as part of maintenance trimming, and allow grasses to

establish and inhibit further woody plant growth.

11. Proactive Asset Upgrades

Q. Describe the upgrading of assets proposed in the Phase IB Grid Improvement Projects.

A. While mainfeeder hardening focuses on the performance of the distribution grid as a system, there are also individual components that can have an impact on reliability and resiliency. New technologies in material and equipment provide the opportunity to improve situational awareness and proactively upgrade assets at or near end of life with components that provide increased functionality and higher reliability.

Q. What specific equipment is the Company proposing to upgrade in Phase IB?

A. In Phase IB, the Company is proposing to proactively upgrade substation transformers with poor health scores, and service transformers identified by smart meters as either being overloaded or not providing voltage within the proper bandwidth. For substation transformers with poor health scores, the Company is proposing to install continuous gas monitoring to identify changes to gas in oil measurements that indicate approaching end of life. This monitoring will allow the Company to proactively replace units, avoiding unplanned outages and potential environmental impact from mineral oil being released. For service transformers, the Company is proposing to proactively upgrade service transformers that are determined to be overloaded based on load data from smart meters. The Company is also proposing to resolve voltage issues identified by information from smart meters where customers may not be receiving voltage within the proper bandwidth. These voltage issues are typically resolved by upgrading the service transformer.

Q. How did the Company identify the targeted population of substation transformers to proactively upgrade for Phase IB?

A. The Company maintains a Transformer Health Assessment ("THA") score for all substation transformers larger than 7 MVA based on age, manufacturer performance, design, operating history, and testing of dissolved gasses in the oil. Based on historical experience, a THA score of less than 5.95 is deemed high risk or poor health. Of the more than 1,000 transformers serving the distribution grid, there are 243 in Virginia with a high risk THA score. Of those high risk transformers, 159 would impact one or more critical services. This is the population of transformers that the Company is proposing to install continuous digital gas monitoring to identify proactive upgrades as part of Phase IB of the GT Plan.

On average, the Company replaces five high risk THA transformers per year as a result of failure or imminent failure signaled by equipment alarms. Through the use of continuous gas monitoring technology, the Company expects to be able to proactively identify and replace these transformers. Additionally, as the population of transformers on the system continues to age, the Company expects to escalate to proactively replace 10 high risk transformers per year.

Q. What is the rationale behind proactively installing gas monitoring and replacing transformers before failure?

A. Transformers are the largest capital investment of any single distribution substation device. Not only do they carry significant cost, but the complexity of manufacture results in a very long lead time for orders, often exceeding 12 to 18 months. This requires careful management of spares and replenishment orders as transformer failures occur.

Additionally, failure of a substation transformer will likely affect a large population of customers and has the environmental risks associated with the release of mineral oil as these transformers typically contain large volumes of mineral oil. While the Company installs oil containment systems for large transformers to reduce the potential impact to the environment, preventing the failure of the transformer is the primary defense against such an event.

Q. How will the Company identify the targeted population of service transformers to upgrade for Phase IB?

A. The Company will use interval data from smart meters to identify service transformers to upgrade due to load or voltage. For overloaded service transformers, the interval data from smart meters and the network hierarchy of premise to service transformer will be used to calculate interval loading for service transformers. The peak loading of each transformer will be compared to the nameplate capacity of the service transformer. Transformers that are loaded beyond 130% of nameplate will be identified for replacement.

The Company has approximately 540,000 service transformers in Virginia, of which approximately 53,700, or 10%, currently serve customers with smart meters. Using interval data from these smart meters, the Company determined that approximately 5.5% of these service transformers had exceeded the thermal rating as described above. As additional smart meters are installed across the service territory, similar analysis will be conducted to identify additional overloaded service transformers. Applying the 5.5% overload rate from past experience results in approximately 26,000 additional overloaded service transformers that will be identified using smart data and replaced proactively. For

Phase IB the Company expects to upgrade 635 service transformers due to loading issues identified by smart meters.

For customers not receiving voltage within the proper bandwidth as identified by voltage information from smart meters, the Company anticipates service transformer upgrades to be the typical solution. Based on previous experience with voltage readings from smart meters that have been deployed, the Company has estimated that 2.25 transformer upgrade projects will be needed for every 1,000 new smart meters installed. Applying this rate to the additional smart meters proposed to be installed results in approximately 4,600 upgrade projects anticipated for the full smart meter deployment. For Phase IB the Company expects to upgrade 954 service transformers due to voltage issues identified by smart meters.

Q. What is the rationale behind proactively replacing these service transformers before failure?

A. Overloaded transformer failures typically occur at peak loading times (the coldest and hottest days of the year), when service interruptions are most impactful to customers. Proactively replacing these transformers eliminates unplanned customer outages, improves the overall customer experience, and allows the Company to manage the work during normal business hours. Voltages that are not within the proper bandwidth have the potential to impact customer equipment such as appliances and electronics, and Company equipment such as transformers, by contributing to premature failures.

12. Voltage Island Mitigation

Q. What is a voltage island?

A. The Company operates small discrete portions of the distribution grid, typically serving remote communities, as islands without any available system redundancy. The communities served by these islands are exposed to the risk of an extended outage, in the range of 24 hours, if the single substation transformer fails and mobile equipment must be deployed and energized as the only means of restoring electric service. Because these communities are served by a single source, all local services including emergency response, schools, gas stations, banks, and grocery stores are affected during such an event.

Q. How many of these voltage islands does the Company plan to address?

A. The Company currently operates 26 voltage islands that exceed 5 MVA at peak loading conditions, the limit for alternative distribution solutions that can be used to restore service in the event of a transformer failure. These transformers serve a total of approximately 41,000 customers. The Company proposes to implement solutions to address 18 voltage islands over the 10 years of the GT Plan that involve transformers with a high THA score as described earlier in my testimony, and that serve critical services, or that serve customers in an economically distressed Opportunity Zone as certified by the Internal Revenue Service. The 18 targeted voltage islands serve more than 30,000 customers, 59 critical services, and 5 Opportunity Zones.

Q. How does the Company propose to address these voltage islands?

A. The Company has evaluated various solutions that would eliminate the risk of an extended outage for these customers and proposes to install a second transformer at each location and reconfigure feeder architecture to provide both the capacity to restore all customers in the event of a failure of the existing transformer, but also to improve day-to-day service reliability as well.

Q. How will you prioritize this work?

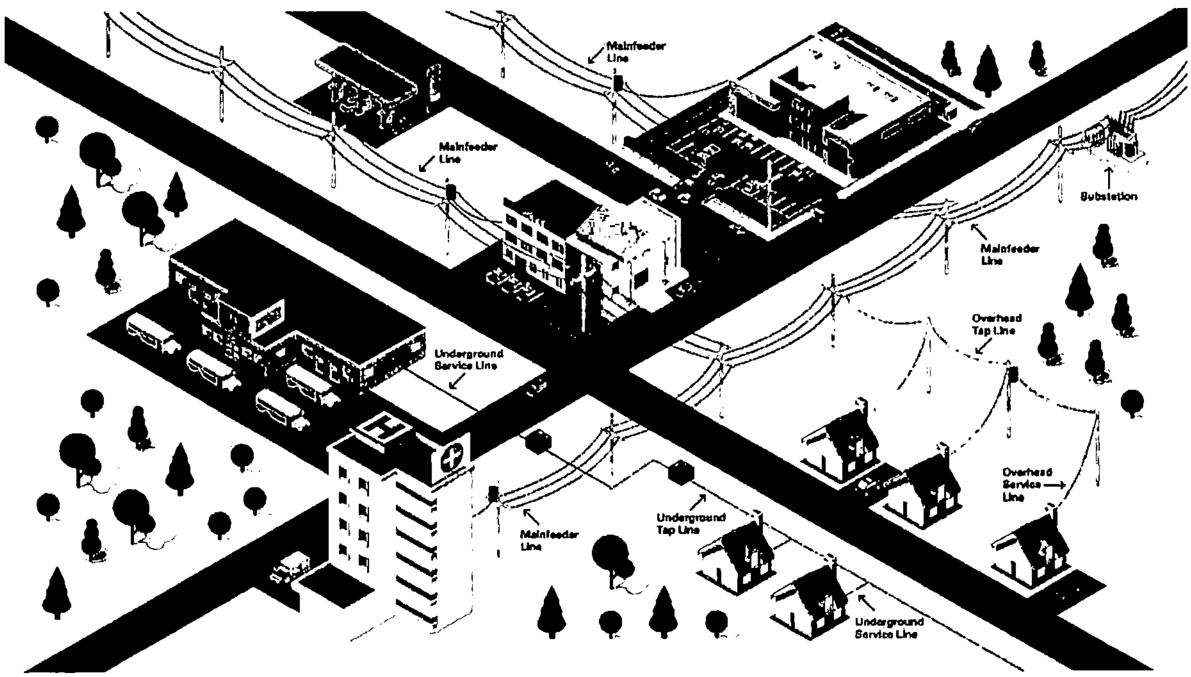
A. The year-to-year prioritization will be based upon the presence of an Opportunity Zone, the transformer's THA score described earlier in my testimony, and the total number of customers and critical services within the respective voltage islands. My Schedule 8 provides a list of the 18 voltage islands the Company proposes to mitigate over the ten year course of the GT Plan. For Phase IB, the Company plans to mitigate 2 voltage islands, which serve approximately 2,600 customers, 16 critical services and 2 Opportunity Zones.

Q. What is the difference between the mainfeeder hardening work proposed in Phase IB of the Grid Improvement Projects and the Company's strategic undergrounding program ("SUP")?

A. Figure 7 below shows major components of a typical distribution feeder, notably the mainfeeder system and tap lines. The Company's SUP creates distribution resiliency by undergrounding tap lines to decrease downed wires and work repair locations, enabling crew redeployment to other outage locations, and allowing a faster recovery after severe weather events. The proposed mainfeeder hardening activities create distribution resiliency by focusing on eliminating outage events and shortening the duration of outages by minimizing damage on the mainfeeder system as described earlier in my testimony. These two programs complement each other by improving performance on different parts of the distribution grid, resulting in fewer outages and shorter outages for

Dominion Energy Virginia customers during blue-sky weather and a faster recovery after severe weather events.

Figure 7: Typical Distribution System Schematic



II. COSTS, BENEFITS, AND ALTERNATIVES

Q. On page 12 of the Commission's June 27, 2019 Final Order in Case No. PUR-2018-00065, the Company's 2018 Integrated Resource Plan ("IRP"), it ordered the Company in future IRPs to "systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects. For identified grid transformation projects, the Company shall include: (a) a detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) detailed cost estimates of each proposed investment; (c) the benefits associated with each proposed investment; and (d) alternatives considered for each proposed investment." Although this is not an IRP proceeding, can you address these requirements as they relate to the Grid Improvement Projects?

A. Yes. I will address those requirements as they relate overall to the Grid Improvement Projects, and then provide further detail broken down by category (grid technologies and grid hardening). The detailed description of the existing distribution system is included in the Integrated Distribution Planning white paper document.

a. <u>Costs</u>

Q. What is the Company's projected investment schedule (capital and O&M) for the Phase IB Grid Improvement Projects?

A. As noted earlier in my direct testimony, detailed cost information for the 12 categories of GT Plan Grid Improvement Projects is provided in my Schedule 1.

Q. What is the basis of the cost information presented for each component?

A. The basis for the costs for each proposed Grid Technologies investment is detailed below.

1. <u>Self-healing grid</u>: The costs for materials and equipment associated with a self-healing grid are based on existing contracts with suppliers. Labor cost estimates are based on the Company's actual construction costs at similar installations in recent years and fully designed projects for most of the work that is proposed in Phase IB. The FLISR control system functionality was included as a future functionality requirement in the Company's RFP in 2018 for the initial phase of the ADMS implementation, with the costs included in the existing vendor contract obtained through the competitive bid process. Please see Filing Schedule Wright, Attachment C, for details.

2. <u>Hosting capacity analysis</u>: The Company worked with DNV-GL to establish a long-term plan and evaluate functionality deliverables based on experience with similar projects at other investor owned utilities. Costs are based on information provided by DNV GL. Please see Filing Schedule Wright, Attachment D, for details.

3. <u>DERMS</u>: The initial functionality for the DERMS implementation was included as a future functionality requirement in the Company's RFP in 2018 for the initial phase of the ADMS implementation, with the costs included in the existing vendor contract obtained through the competitive bid process. Costs associated with future DERMS functionality are not expected to start until after Phase IB, and are estimated based on information obtained from OSI, the Company's ADMS vendor. Please see Filing Schedule Wright, Attachment E, for details.

4. <u>Advanced Analytics</u>: Hardware and software costs are based on RFP responses from suppliers as part of the competitive bid process. Internal and external resource cost estimates are based on experience with other system implementations and feedback from

RFP respondents. Please see Filing Schedule Wright, Attachment F, for details.

5. **Voltage optimization**: Costs associated with voltage optimization will not start until 2022, and are based on budgetary estimate information obtained from Dominion Voltage, Inc. Please see Filing Schedule Wright, Attachment G, for details.

6. **Locks Campus Microgrid**: Cost estimates are based on detailed engineering and design estimates performed by Quanta. Please see Filing Schedule Wright, Attachments A and B, for details.

7. **EAMS**: Costs are based on roadmapping work with assistance from West Monroe to establish a long-term plan and evaluate functionality deliverables based on previous experience with similar projects at other peer utilities, as well as RFI responses from suppliers. Please see Filing Schedule Wright, Attachment H, for details.

8. **OMS**: Costs associated with the OMS implementation will not start until 2024. Expected costs are estimated based on information obtained from West Monroe of similar installations at peer utilities.

The basis for the costs for each proposed Grid Hardening investment is detailed below.

9. **Mainfeeder hardening**: The costs for materials and equipment are based on existing contracts with suppliers. Installation cost estimates are based on the Company's actual construction costs for similar work and fully designed projects for a portion of the work that is proposed in Phase IB. Please see Filing Schedule Wright, Attachment C, for details.

10. **Targeted corridor improvements**: The cost estimates are based on existing

contracts with suppliers, an ash tree study conducted for the Company by ECI and herbicide pilot programs. Please see Filing Schedule Wright, Attachments I and J, for details.

11. Proactive asset upgrades: The costs estimates are based on the Company's actual construction costs for similar work in recent years.

12. Voltage island mitigation: The cost estimates are based on the Company's actual construction costs for similar work in recent years and budgetary cost estimates. Please see Filing Schedule Wright, Attachment K, for details.

c. Benefits

Q. What quantifiable customer benefits does the Company expect will be realized from the Phase IB Grid Improvement Projects?

A. The Company has projected quantifiable customer benefits related to fewer outages and less outage time, reductions in future capital, operating and maintenance expenses related to outage response, distribution grid maintenance and repair. Please see Company Witness Hulsebosch's Schedule 2 for details.

Q. What qualitative benefits does the Company expect will be realized from the Phase IB Grid Improvement Projects?

A. In addition to the quantifiable benefits that have been projected, the Company expects many qualitative benefits related to a more reliable and resilient grid. As customers adopt electric vehicles, a reliable grid is necessary to ensure they are able to travel for work or leisure. Customers with DER, such as solar or wind generation, are not able to utilize their energy resources while the grid is down. A resilient grid will recover more quickly after severe weather events, allowing daily customer activities such as education, communication, banking, and commerce to return to normal. Additionally, benefits related to outages affecting daily operation of critical services such as hospitals, emergency dispatch centers, government facilities, military installations and water pumping stations cannot be quantified. Redirecting ambulance services to other hospitals or relocating patients during extended outages, managing emergency calls in a dispatch center while the grid is down, responding to false security alarms triggered by a power outage, and having to issue "boil water" alerts for public safety when water treatment plants are down all have a very real and significant impact on citizens, but cannot be quantified. As basic public services and activities such as communications, banking, security and retail become more integrated and more dependent on technology, the importance of providing reliable and resilient electric service continues to grow.

d. <u>Alternatives</u>

Q. Did the Company consider alternative solutions before finalizing the proposed Phase IB Grid Improvement Projects?

A. Yes. Similar to the normal course of business, the Company evaluated different solutions to identify the most cost-effective plan to achieve the objectives of the proposed Grid Improvement Projects, specifically improving reliability and resiliency and integrating DER. This included modeling different intelligent grid device locations to determine the most beneficial self-healing grid architecture and studying alternative solutions, such as rebuilding, relocating, or undergrounding for mainfeeder hardening. Additionally, the Company engaged Quanta to evaluate opportunities to use non-traditional solutions such as battery storage, typically referred to as NWA, to achieve the reliability and resiliency objectives of the Grid Transformation Plan.

Q. Please expand on NWA.

A. While there are examples of utilities applying NWAs in very specific use cases, it is typically to solve a localized issue where traditional upgrade solutions were determined to be cost prohibitive or unfeasible. Examples include remote load centers with significant upgrade costs due to terrain or water crossings, or substation locations that are landlocked, preventing equipment upgrades or additions. The Company does not consider these type of NWA applications as feasible alternatives for the Grid Improvement Projects proposed in Phase IB because they only address localized issues, meaning they serve small pockets of customers, unlike the Grid Improvement Projects that typically eliminate outages and improve reliability for thousands of customers. The Company engaged Quanta to evaluate a sample of 11 grid upgrade projects planned to address either a load, voltage or reliability issue. For each project, Quanta determined an appropriate battery storage solution to mitigate the issue that each project was established to address, then performed a cost-benefit analysis to compare the cost-effectiveness of each solution to the traditional solution. Of the 11 projects, only 1 NWA was determined to be cost-effective across a spectrum of different storage costs and market benefits scenarios. Two were determined to be marginally cost-effective with a high sensitivity to storage costs and/or market benefits.

Based on the results of Quanta's evaluation, the Company does not consider NWAs to be a viable alternative to the grid work being proposed on the mainfeeder system as part of the GT Plan's Grid Improvement Projects, which are projected to improve service to thousands of customers over many miles of the distribution grid.

Q. Is the Company investigating NWA solutions for other grid projects or activities?

A. Yes. The Grid Transformation and Security Act of 2018 ("GTSA") allows up to 30 MW of pilot projects for energy storage systems to learn about their operational challenges and benefits when integrated into the distribution grid. The Company has evaluated several use cases for batteries to provide grid support and filed for approval of three projects for deployment of battery energy storage systems ("BESS") as part of a pilot program in Case No. PUR-2019-00124 on August 2, 2019. Similar to solar technology, the Company expects costs of BESS to decrease as the technology matures, with the potential for it to reach the point where the value proposition warrants expanded applications in the distribution grid. Until that time, the Company believes it prudent to continue to learn about the technology and gain valuable experience with pilot projects. Also, the proposed Locks Campus Microgrid project will provide the Company a testbed to gain valuable experience in the application of various new technologies to support grid reliability and resiliency.

Q. Are NWAs the only alternative considered by the Company?

A. No. The Company considered the option of making no investments in Grid Improvement Projects.

Q. And what did the Company determine?

A. Based on past reliability performance trends, the Company expects that ongoing investments made in the normal course of business will maintain or incrementally improve reliability with minimal impact on resiliency during severe weather events. Essentially, the Company believes that making no investments in the Grid Improvement Projects will, at best, have customers experiencing a similar level of reliability as today during normal "blue sky" weather days, while having the same exposure to extended outages during severe weather events such as hurricanes. The Company does not consider this to be an acceptable alternative for achieving the transformational objectives of the GTSA.

Q. What makes the Grid Improvement Projects transformational?

A. The proposed projects are transformational because they enable the Company to operate the grid differently to meet 21st century needs in performance levels and to allow the Company and customers to maximize the benefits of the growing amount of connected renewables.

Investments in grid technologies that automatically take action to isolate grid problems and restore customers without operator intervention will improve service reliability more than 24% for over 2 million customers. These technology investments will also provide valuable insights into grid operations that enable more proactive activities and new opportunities for customers. Information from devices and smart meters will identify grid problems for action before outages occur and drive predictive maintenance programs, replacing reactive work and time-based maintenance. This information will also inform hosting capacity maps and allow the DERMS to manage renewables for maximum grid and customer benefits. Investments in grid hardening will address poorly performing grid segments, improving service reliability by more than 26% for almost 500,000 customers that consistently experience service levels significantly worse than average. Customers interconnecting distributed energy resources will have access to a grid with high availability that recovers from severe weather events more quickly, supporting participation in market activities and providing the Company the option to leverage those resources for grid support in lieu of traditional upgrade work.

III. Integrated Distribution Planning

Q. Va. Code § 56-599 B 10 now requires that the Company's total-system IRPs evaluate long-term electric distribution planning with the first one being the 2020 IRP. What steps has the Company taken to perform integrated distribution planning in the meantime?

A. The Company's IDP White Paper, attached as Appendix B to the Plan Document, outlines the current and future states of distribution planning and describes the changes necessary to achieve integrated distribution planning. The Company recognizes the value in using a holistic view of the distribution grid in terms of variables such as performance, capacity, asset condition, and distributed resource integration to provide safe and reliable electric service while providing customers with the information and control that they require.

Achieving true integrated distribution planning requires both a thorough understanding of how the grid is performing in all respects and the tools needed to process the information collected and enabled by the GT Plan. This in turn allows the Company to take action and to apply distributed resources that resolve grid issues while allowing customers to realize the full potential of their resources through activities such as aggregation. This ability is only possible with a full implementation of the equipment and systems that are proposed in the Company's Grid Transformation Plan. Namely, smart meters, intelligent grid devices, operations and control systems, a robust and secure telecommunications network, and Advanced Analytics tools are all necessary prerequisites to perform true integrated distribution planning. Likewise, the Grid Improvement Projects ensure a reliable and resilient grid so that customers can maximize the full benefit of these investments. Without a full deployment of the devices and systems that the Company is proposing in its Grid Transformation Plan to achieve situational awareness and control capabilities, true integrated distribution planning is not possible.

Given the 2028 deadline of the GTSA, the Company is proposing to begin transforming the grid by making the necessary Grid Improvements investments upon Commission approval with a thoughtful implementation plan over the full timeline of the proposed GT Plan. Delaying these investments serves only to shorten the timeline from which to work and further delay achievement of fully integrated distribution planning. The IDP White Paper provides a detailed overview of the Company's current distribution planning process, the limitations of the current process, the investments needed to evolve the process, and the Company's vision of integrated distribution planning for the future.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS OF ROBERT S. WRIGHT, JR.

Robert S. Wright, Jr. is Director of Distribution Grid Planning and Asset Management for Dominion Energy Virginia's Power Delivery Group. He is responsible for load planning and reliability performance of the electric distribution grid, as well as vegetation management and asset data management activities.

Mr. Wright joined Dominion Energy Virginia in 1993 as an associate engineer and has held numerous engineering, operational and management positions related to the design, construction and operation of the distribution system. In 2007, he was named Manager-Central Region Operations Center and Manager-Distribution System Planning in 2013. He was promoted to his current position in September 2015.

Mr. Wright earned his bachelor's degree in Electrical Engineering with a minor in Mathematics from North Carolina State University. He is registered as a professional engineer in Virginia.

Line No.	Description		2019 Yr 1		2020 Yr 2		2021 Yr 3		3 Yr Total Sum (C)-(E)		10 Yr Total Sum (C)-(L)
(A)	(B)		(C)		(D)		(E)		(F)		(G)
1	**Summary of Self-Healing Grid Capital Costs**										
2											
3	Line Construction Costs	$	-	$	6,011,216	$	4,443,542	$	10,454,758	$	220,058,698
4	Line Engineering Costs	$	931,738	$	688,749	$	4,004,692	$	5,625,179	$	34,109,098
5	Substation Costs	$	-	$	850,000	$	1,180,000	$	2,030,000	$	114,754,800
6											
7	ADMS - Hardware/Software	$	160,000	$	-	$	-	$	160,000	$	160,000
8	ADMS - Vendor Implementation	$	750,000	$	2,302,484	$	-	$	3,052,484	$	3,052,484
9	ADMS - CLC	$	423,446	$	1,180,921	$	-	$	1,604,367	$	1,604,367
10	ADMS - Configuration/ Implementation	$	200,000	$	613,996	$	-	$	813,996	$	813,996
11											
12	**Total Self-Healing Grid Capital Costs**	$	**2,465,184**	$	**11,647,366**	$	**9,628,234**	$	**23,740,784**	$	**374,553,443**
13											
14											
15	**Summary of Self-Healing Grid O&M Costs**										
16											
17	Maintenance Labor	$	-	$	-	$	-	$	-	$	-
18	ADMS - Ongoing Support	$	-	$	-	$	428,763	$	428,763	$	3,784,418
19											
20											
21	**Total Self-Healing Grid O&M Costs**	$	-	$	-	$	**428,763**	$	**428,763**	$	**3,784,418**
22											

Key Inputs	
Asset Life	31.6 yrs
Feeders Addressed	963
Electronic Reclosers Installed	2,393
Line Sensors Installed	2,871
Digital Relays Installed	308
Communication Gateways Installed	347

Company Exhibit No.
Witness: RSW
Schedule
Page 1 of

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Hosting Capacity Capital Costs**					
2						
3	Automated Hosting Capacity Process	$ -	$ 94,146	$ -	$ 94,146	$ 94,146
4	Hosting Capacity Analysis Results	$ -	$ 61,400	$ -	$ 61,400	$ 61,400
5						
6	**Total Hosting Capacity Capital Costs**	$ -	$ 155,546	$ -	$ 155,546	$ 155,546
7						
8						
9	**Summary of Hosting Capacity O&M Costs**					
10						
11	Maintenance Labor	$ -	$ -	$ 52,288	$ 52,288	$ 447,234
12						
13	**Total Hosting Capacity O&M Costs**	$ -	$ -	$ 52,288	$ 52,288	$ 447,234
14						

Key Inputs	
Asset Life	10 yrs

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of DERMS Capital Costs**					
2						
3	OSI Cost Estimation	$ -	$ -	$ -	$ -	$ 2,630,055
4	Systems Integration	$ -	$ -	$ -	$ -	$ 2,000,000
5	Telecom Integration	$ -	$ -	$ -	$ -	$ 2,000,000
6	Implementation Labor	$ -	$ -	$ -	$ -	$ 5,400,000
7						
8	**Total DERMS Capital Costs**	$ -	$ -	$ -	$ -	$ 12,030,055
9						
10						
11	**Summary of DERMS O&M Costs**					
12						
13	Ongoing Labor	$ -	$ -	$ -	$ -	$ 5,580,000
14						
15	**Total DERMS O&M Costs**	$ -	$ -	$ -	$ -	$ 5,580,000
16						

Key Inputs	
Asset Life	10 yrs

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Advanced Analytics Capital Costs**					
2						
3	Hardware Costs	$ -	$ 1,353,535	$ 149,589	$ 1,503,124	$ 2,103,613
4	Software Costs	$ -	$ 1,548,066	$ 19,812	$ 1,567,877	$ 1,851,346
5	Implementation Costs	$ -	$ 1,527,221	$ 3,296,808	$ 4,824,030	$ 10,941,531
6						
7	**Total Advanced Analytics Capital Costs**	**$ -**	**$ 4,428,822**	**$ 3,466,209**	**$ 7,895,031**	**$ 14,896,490**
8						
9						
10	**Summary of Advanced Analytics O&M Costs**					
11						
12	Ongoing Labor / Center of Excellence Operations	$ -	$ -	$ -	$ -	$ 4,698,406
13	Software Maintenance	$ -	$ 1,076,239	$ 1,258,566	$ 2,334,805	$ 15,694,804
14						
15	**Total Advanced Analytics O&M Costs**	**$ -**	**$ 1,076,239**	**$ 1,258,566**	**$ 2,334,805**	**$ 20,393,210**
16						

Key Inputs	
Asset Life	5 yrs

5 0 0 0 5 6

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Voltage Optimization Capital Costs**					
2						
3	Hardware Costs	$ -	$ -	$ -	$ -	$ -
4	Software Costs	$ -	$ -	$ -	$ -	$ 5,328,276
5						
6	**Total Voltage Optimization Capital Costs**	$ -	$ -	$ -	$ -	$ 5,328,276
7						
8						
9	**Summary of Voltage Optimization O&M Costs**					
10						
11	Maintenance Labor	$ -	$ -	$ -	$ -	$ 4,208,762
12						
13	**Total Voltage Optimization O&M Costs**	$ -	$ -	$ -	$ -	$ 4,208,762
14						

Key Inputs	
Asset Life	15 yrs
Software Deployment	Year 4

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Locks Campus Microgrid Capital Costs**					
2						
3	Development Costs	$ -	$ 2,617,136	$ -	$ 2,617,136	$ 2,617,136
4	Equipment	$ -	$ 4,347,425	$ -	$ 4,347,425	$ 4,347,425
5	System and Spare Equipment	$ -	$ 244,000	$ -	$ 244,000	$ 244,000
6						
7	**Total Locks Campus Microgrid Capital Costs**	$ -	$ 7,208,561	$ -	$ 7,208,561	$ 7,208,561
8						
9						
10	**Summary of Locks Campus Microgrid O&M Costs**					
11						
12	Hardware/Software Maintenance	$ -	$ -	$ 79,478	$ 79,478	$ 679,796
13						
14	**Total Locks Campus Microgrid O&M Costs**	$ -	$ -	$ 79,478	$ 79,478	$ 679,796
15						

Key Inputs	
Asset Life	15 yrs
Full Deployment	Year 2

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of EAMS Capital Costs**					
2						
3	*Planning Costs*	$ -	$ 1,543,687	$ 530,887	$ 2,074,574	$ 2,074,574
4	Software Costs	$ -	$ 875,000	$ -	$ 875,000	$ 875,000
5	Implementation Costs	$ -	$ 5,999,822	$ 7,627,292	$ 13,627,115	$ 21,290,338
6						
7	**Total EAMS Capital Costs**	**$ -**	**$ 8,418,510**	**$ 8,158,180**	**$ 16,576,689**	**$ 24,239,912**
8						
9						
10	**Summary of EAMS O&M Costs**					
11						
12	Maintenance Labor	$ -	$ -	$ -	$ -	$ 2,717,341
13	Software Maintenance	$ -	$ -	$ -	$ -	$ 1,225,000
14						
15	**Total EAMS O&M Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,942,341**
16						

Key Inputs	
Asset Life	10 yrs
Full Deployment	Year 4

50005695

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of OMS Capital Costs**					
2						
3	Software Costs	$ -	$ -	$ -	$ -	$ 1,864,927
4	Implementation Costs	$ -	$ -	$ -	$ -	$ 11,732,526
5						
6	**Total OMS Capital Costs**	$ -	$ -	$ -	$ -	$ 13,597,453
7						
8						
9	**Summary of OMS O&M Costs**					
10						
11	Maintenance Labor	$ -	$ -	$ -	$ -	$ 6,130,000
12						
13	**Total OMS O&M Costs**	$ -	$ -	$ -	$ -	$ 6,130,000
14						

Key Inputs	
Asset Life	10 yrs
Full Deployment	Year 7

500056

Line No.	Description		2019 Yr 1		2020 Yr 2		2021 Yr 3		3 Yr Total Sum (C)-(E)		10 Yr Total Sum (C)-(L)
(A)	(B)		(C)		(D)		(E)		(F)		(G)
1	**Summary of Mainfeeder Hardening Capital Costs**										
2											
3	Engineering Costs	$	2,189,766	$	3,134,532	$	8,216,856	$	13,541,155	$	89,619,952
4	Construction Costs	$	-	$	14,127,525	$	20,222,790	$	34,350,314	$	578,193,240
5											
6	**Total Mainfeeder Hardening Capital Costs**	$	**2,189,766**	$	**17,262,057**	$	**28,439,646**	$	**47,891,469**	$	**667,813,192**
7											
8											
9	**Summary of Mainfeeder Hardening O&M Costs**										
10											
11	**Total Mainfeeder Hardening O&M Costs**										
12											

Key Inputs	
Asset Life	34.5 yrs
Hardened Miles	1,028
Hardened Feeders	187

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Targeted Corridor Improvement Capital Costs**					
2						
3	**Total Targeted Corridor Improvement Capital Costs**					
4						
5						
6	**Summary of Targeted Corridor Improvement O&M Costs**					
7						
8	Ash tree removal - EAB	$ 4,200,000	$ 4,297,970	$ 4,251,827	$ 12,749,796	$ 17,013,348
9	Herbicide - Establish ground floor	$ 1,846,520	$ 1,889,592	$ 3,862,043	$ 7,598,155	$ 19,671,145
10						
11	**Total Targeted Corridor Improvement O&M Costs**	$ 6,046,520	$ 6,187,562	$ 8,113,869	$ 20,347,951	$ 36,684,493
12						

Key Inputs	
Miles of Herbicide Application	26,800
Cost per Mile	$689

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Proactive Component Upgrades Capital Costs**					
2						
3	Service Transformer Replacement - AMI Overload	$ -	$ -	$ 4,051,904	$ 4,051,904	$ 179,809,151
4	Service Transformer Replacement - AMI Voltage	$ -	$ 707,769	$ 5,511,061	$ 6,218,830	$ 31,498,245
5	THA - Poor Health Transformers Replacement	$ -	$ -	$ 14,640,675	$ 14,640,675	$ 285,332,994
6	THA - Poor Health Transformer Monitoring	$ -	$ 2,750,000	$ 2,210,000	$ 4,960,000	$ 7,575,000
7						
8	**Total Proactive Component Upgrades Capital Costs**	**$ -**	**$ 3,457,769**	**$ 26,413,640**	**$ 29,871,408**	**$ 504,215,389**
9						
10						
11	**Summary of Proactive Component Upgrades O&M Costs**					
12						
13	**Total Proactive Component Upgrades O&M Costs**					
14						

Key Inputs	
Asset Life	34.5 yrs
Estimated Service Transformers to Replace for Load	26,700
Estimated Service Transformers to Replace for Voltage	4,634
Poor Health Transformers to Replace	90
Transformers to Monitor	159

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Voltage Island Mitigation Capital Costs**					
2						
3	Planning Costs	$ -	$ 205,825	$ 318,532	$ 524,357	$ 2,042,543
4	Implementation Costs	$ -	$ -	$ 6,169,999	$ 6,169,999	$ 59,121,981
5						
6	**Total Voltage Island Mitigation Capital Costs**	$ -	$ 205,825	$ 6,488,531	$ 6,694,356	$ 61,164,524
7						
8						
9	**Summary of Voltage Island Mitigation O&M Costs**					
10						
11	**Total Voltage Island Mitigation O&M Costs**					
12						

Key Inputs	
Asset life	34.5 yrs
Total Substations to be Upgraded	18

Company Exhibit No.
Witness: RSW
Schedule 2
Page 1 of 1

Self-healing Grid Projected Benefits

	3-Year Total	10-Year Total
Critical Services Improved	27	1,433
Total Customers Improved	88,412	2,035,736
Total Customer Interruptions Eliminated	61,593	1,139,484
Total Customer Minutes of Interruption Eliminated	4,216,196	68,198,853
Average Outage Minutes Before	200	126
Average Outage Minutes Eliminated	47	33
Average Outage Minutes After	153	93
Average Interruptions Before	2.1	1.3
Average Interruptions Eliminated	0.7	0.6
Average Interruptions After	1.4	0.7

*Improvements are independent of the proposed Mainfeeder Hardening work

43384 Self-Healing Grid

Project Component(s):

✓ Self-Healing Grid

Grid Hardening:

- ☐ Rebuilding Existing Mainfeeder
- ☐ Voltage Conversion for Existing Mainfeeder
- ☐ Relocating Existing Mainfeeder
- ☐ Adding Phases to Existing Mainfeeder
- ☐ Build New Mainfeeder
- ☐ Reconductor Existing Mainfeeder
- ☐ Mainfeeder OH to UG Conversion
- ☐ Capacity Addition

Problem Statement: 43384 was identified as a FLISR candidate due to high customer counts behind protective devices and outage history.

Alternatives Considered: Numerous device locations were analyzed prior to determining preferred solution.

Project Description: Install electronic recloser in the vicinity of C0614IO28 and in the vicinity of C0615HE53. Replace 43384 R22 with new electronic recloser and manual tie switch 43384 T475 with new electronic recloser. Reprogram 475 R93 to work with new scheme. Install line sensors at 384 S3, 384 D19 and near 384 N148 on the mainline.

Date: 1/22/2019

Cost Estimate: $259,032

Project Initiated By: Erika Floyd

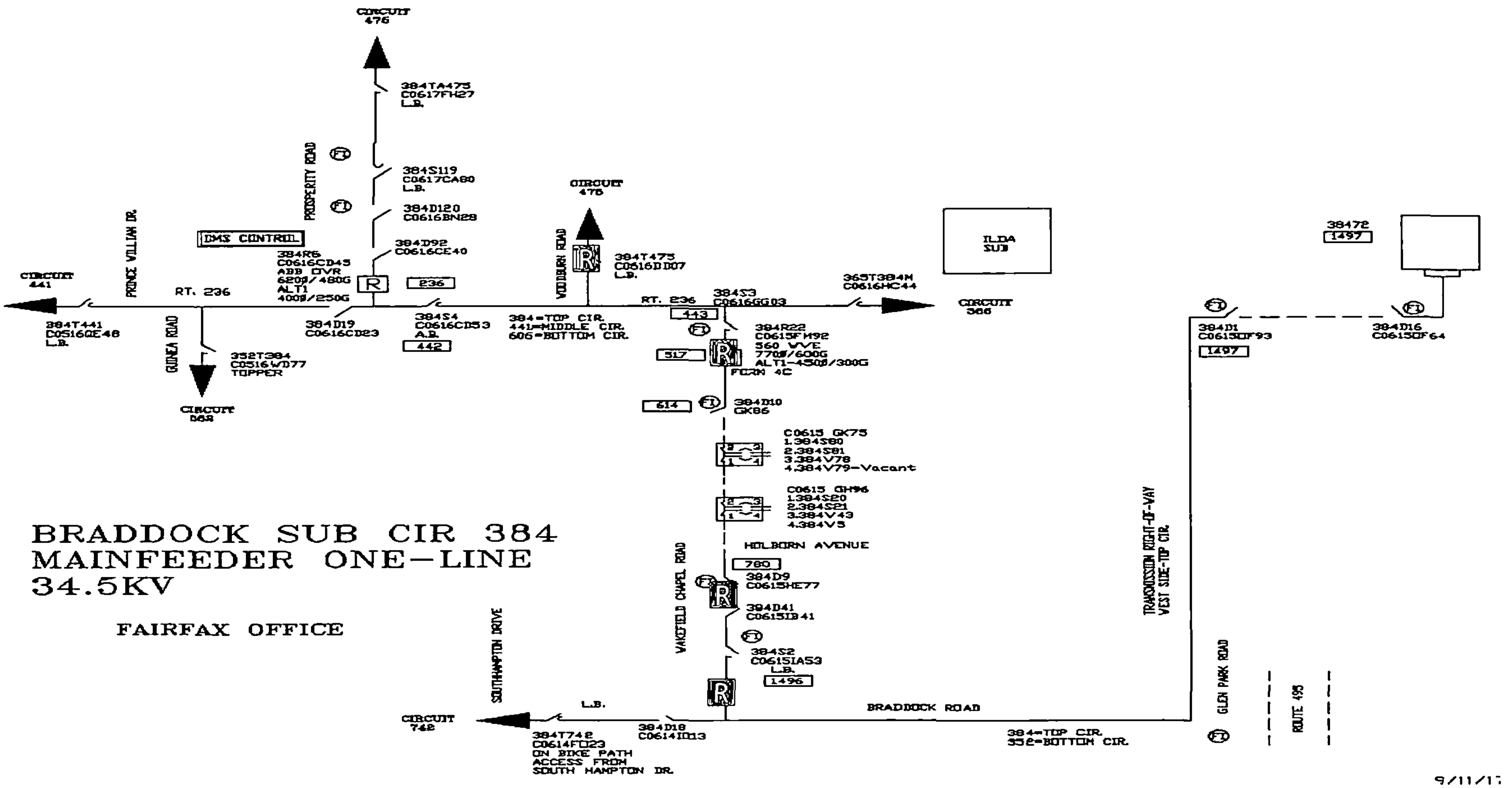
Regional Reliability Contact: Leslie McMillan

Project Manager: TBD

WMIS #: 10286382

500056001

43384 Self-Healing Grid Scope



Set new pole and install electronic recloser just north of Braddock Road. Refeed customers on transformer C0615HE53, replace pole, remove transformer and install new electronic recloser. Replace 43384 R22 with new electronic recloser; replace pole if needed. Remove 43384 T475 and install electronic recloser. Replace pole if necessary.

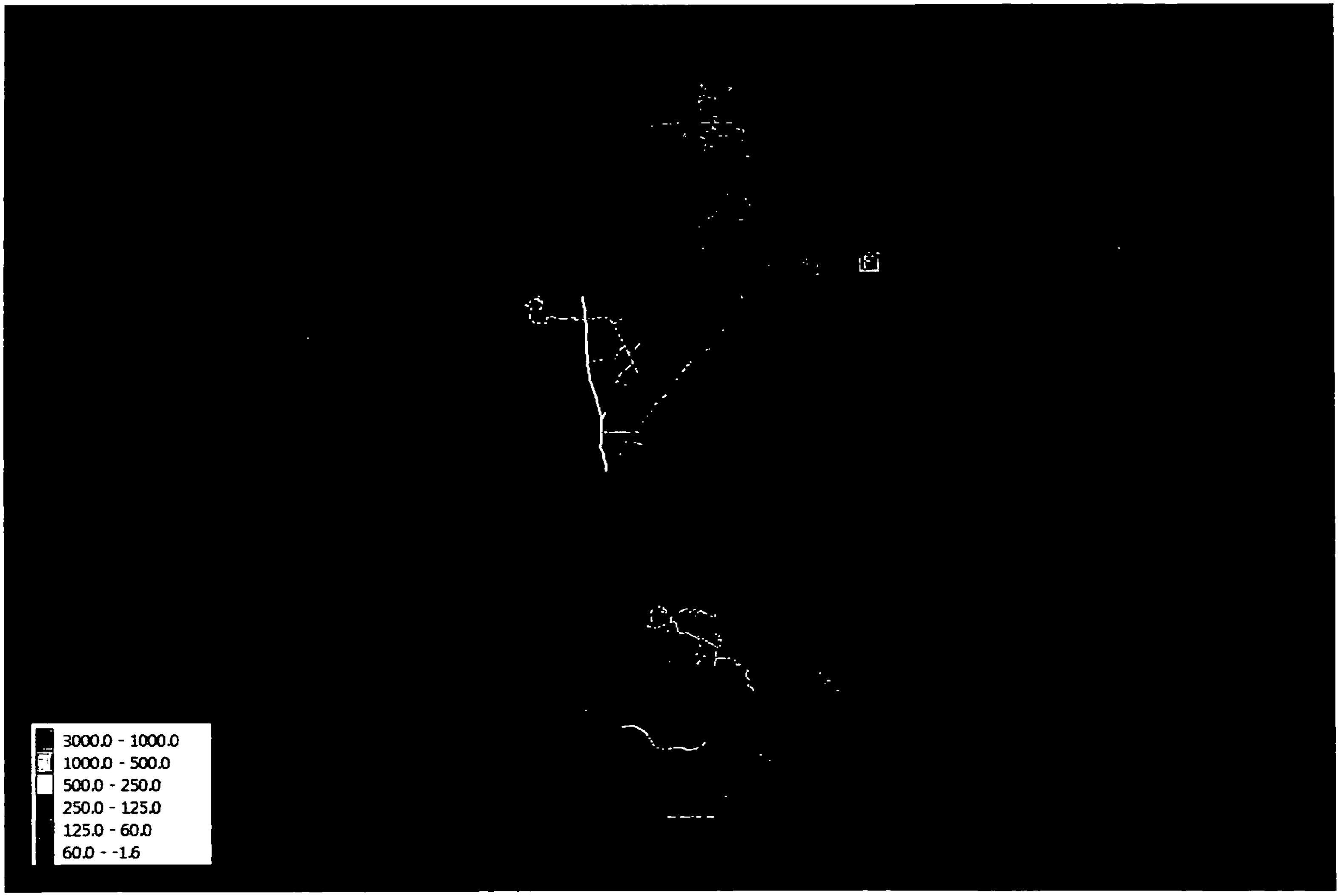
43384 Self-Healing Grid Results

	Before		
Feeder	Average Interruptions	Average Minutes of Interruption	Population
	2.51	188.30	2631
43384	3.21	235.31	1471
46475	1.63	128.68	1160

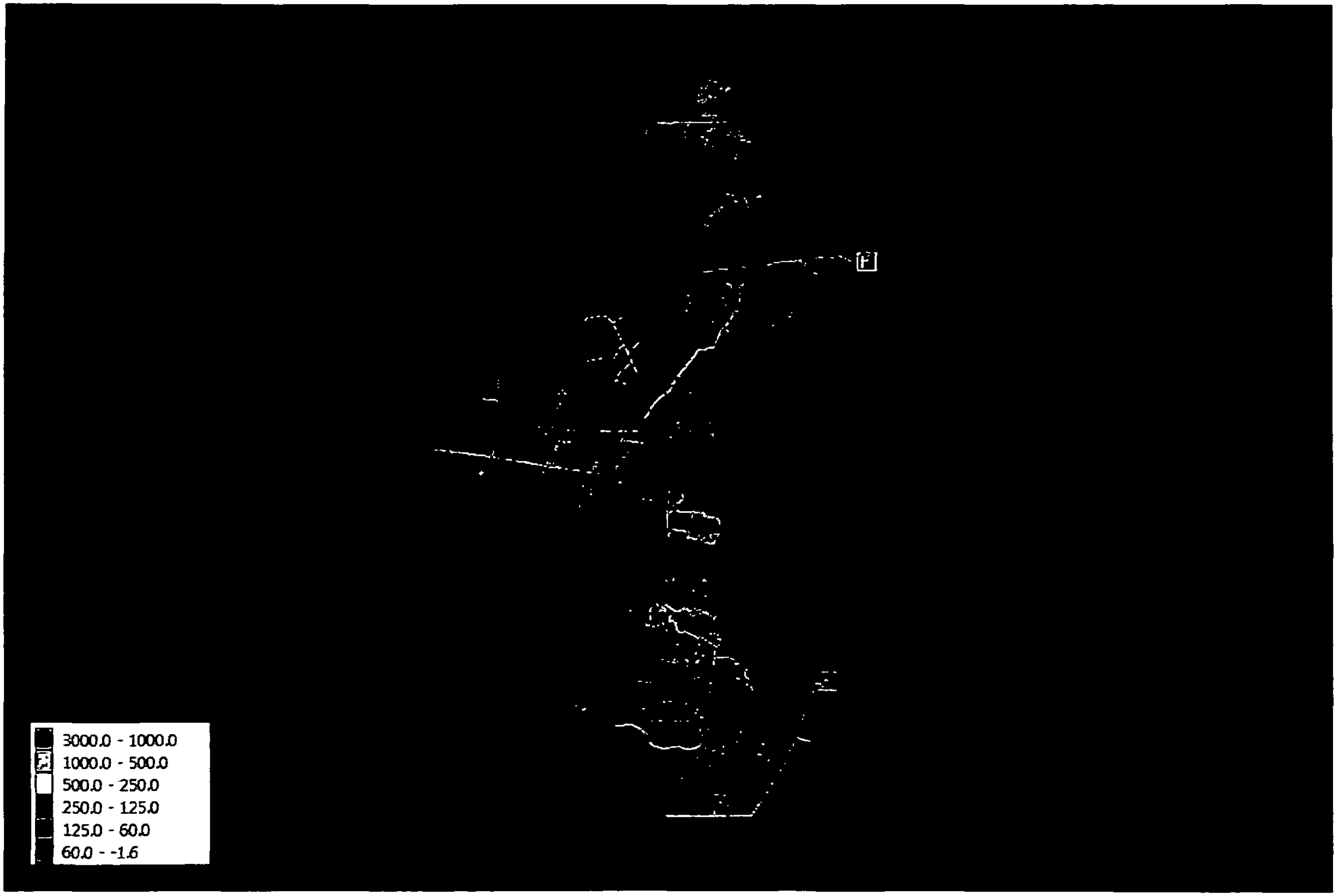
	After		
Feeder	Average Interruptions	Average Minutes of Interruption	Population
	1.35	120.56	2631
43384	1.43	127.57	1471
46475	1.24	111.68	1160

Improved Population	2,631
Average Minutes of Interruption - Before	188.30
Total Minutes of Interruption - Before	495,410
Average Minutes of Interruption - After	120.56
Total Minutes Interruption - After	317,204
Number of Devices	4
Number of Line Sensors	3
Total Net Metering Customers	7

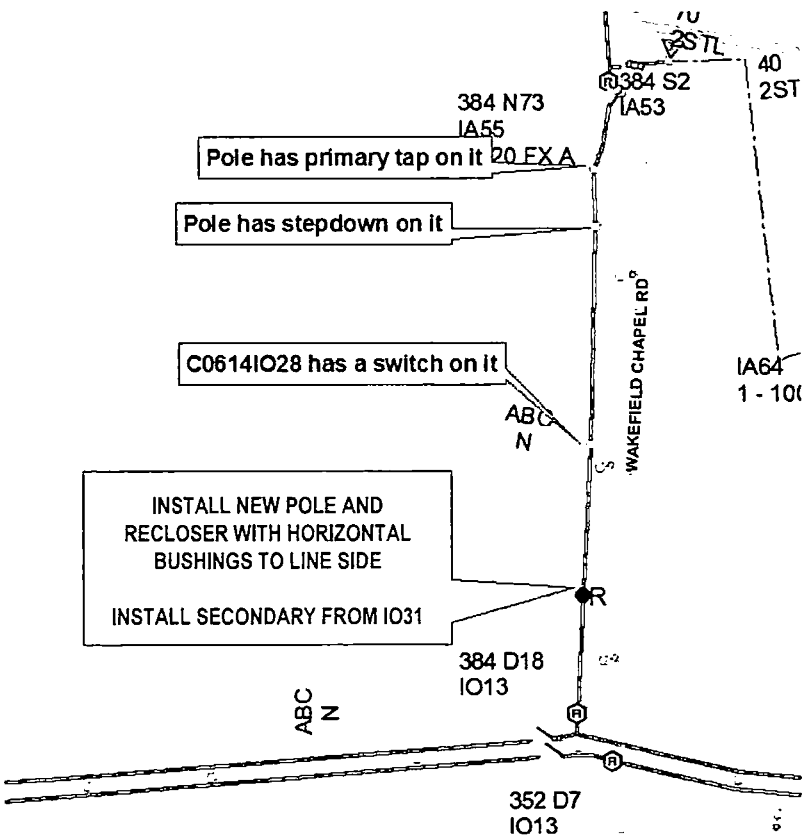
43384 Average Minutes of Interruption - Before

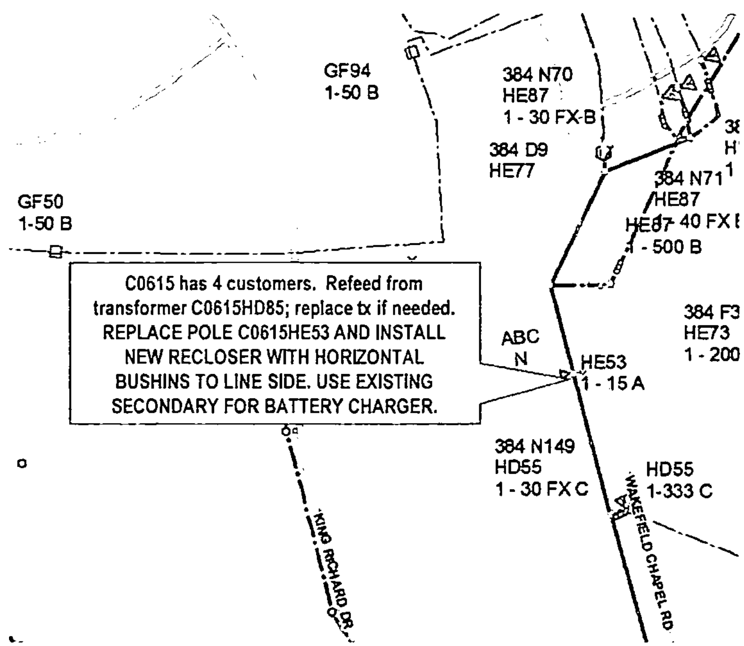


43384 Average Minutes of Interruption - After



43384 Self-Healing Grid Detailed Scope





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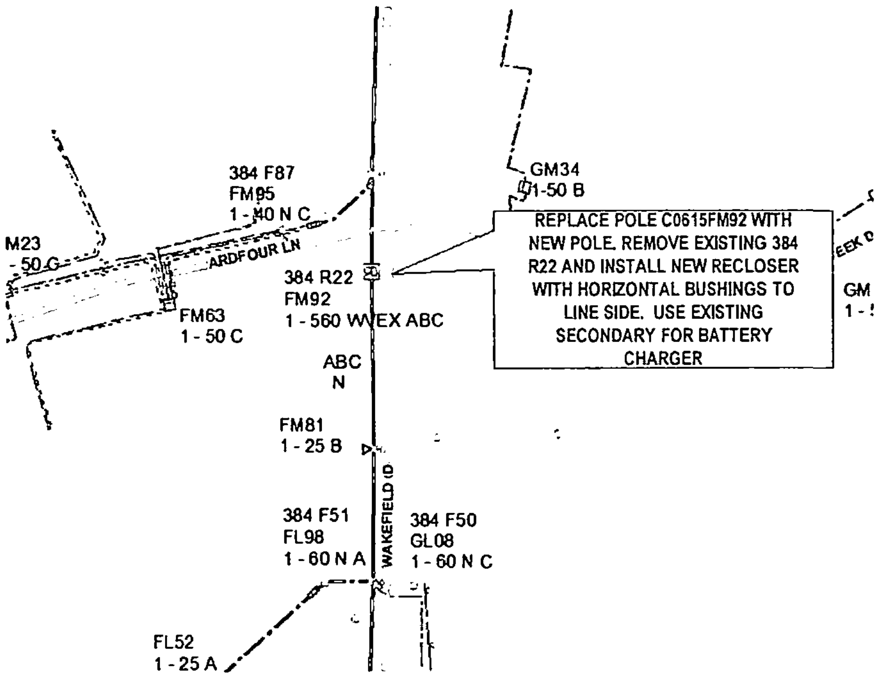
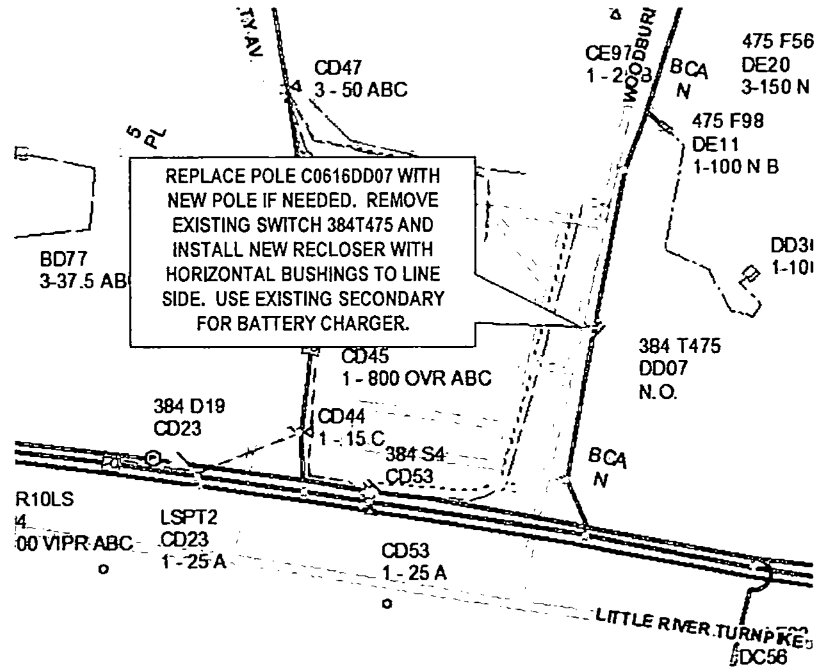
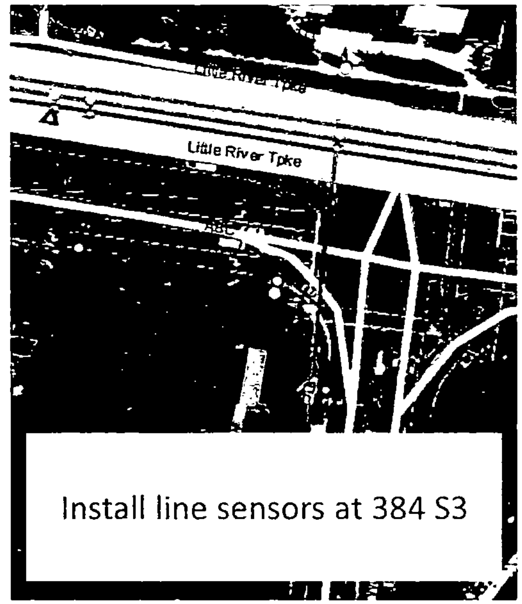
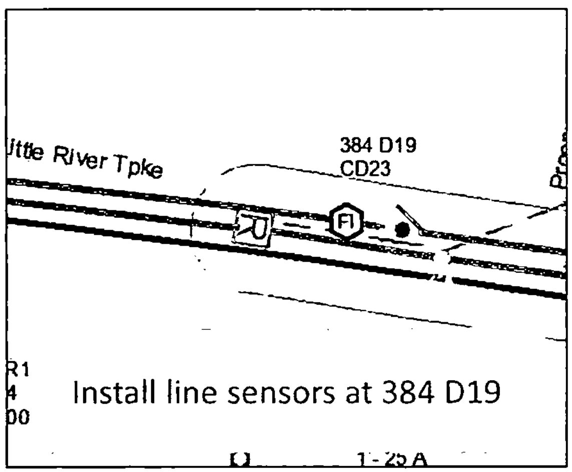
43384 Self-Healing Grid Detailed Scope





43384 Self-Healing Grid Detailed Scope





Self-healing Grid Equipment Installed

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	3-Year Total	10-Year Total
Feeders Affected		12	11	135	135	134	134	134	134	134	23	963
Electronically Controlled Line Devices		54	36	284	373	366	339	306	374	261	90	2,393
Line Sensors		52	55	341	447	439	407	367	449	314	107	2,871
Digital Relays		4	3	43	43	43	43	43	43	43	7	308
Communication Gateways		4	4	49	49	49	48	48	48	48	8	347

5000560

Advanced Analytics for the Grid Transformation Plan

I. OVERVIEW OF ADVANCED ANALYTICS

Advanced Analytics describes data analysis that goes beyond simple mathematical calculations such as sums and averages, or filtering and sorting. Advanced Analytics uses mathematical and statistical formulas and algorithms to generate new information, to recognize patterns, and also to predict outcomes and their respective probabilities. Advanced Analytics is also broadly classified as Artificial Intelligence ("AI"), and is sometimes referred to as Predictive Analytics (one of its salient capabilities) or Big Data (the platform used to perform Advanced Analytics).

Advanced Analytics is comprised of Machine Learning ("ML") and Deep Learning. ML is a collection of algorithms and statistical models that computer systems use to perform a specific task effectively and to proactively learn without explicit programming; relying instead on patterns and inferences from historically collected data. Deep Learning is a subset of ML and is based on artificial neural networks.

A. Types of Analytics

Advanced Analytics can be used to perform the following type of analytics:

- *Descriptive Analytics*: helps analyze the data and informs on *what happened.*
- *Diagnostic Analytics*: helps understand the factors affecting the outcome and *why something happened.*
- *Predictive Analytics:* uses historical data to understand *what will happen.*
- *Prescriptive Analytics*: helps with what should I do? In other words, prescriptive analytics informs on how to handle specific situations by factoring in knowledge of possible situations, available resources, past performance and what is currently happening.
- *Optimization:* in addition to the above, Advanced Analytics can help with optimization where the objective would be to maximize or minimize certain objective function(s) without violating resource constraints.

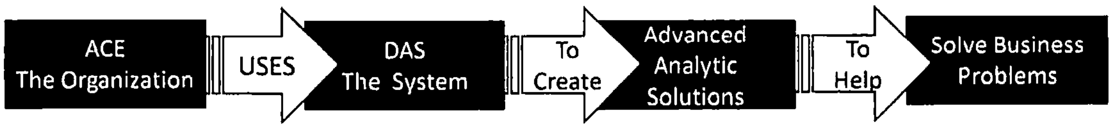
B. Infrastructure needed for Advanced Analytics

Advanced Analytics draws power from the Data Analytics System (a.k.a., Big Data platform or "DAS") which can store and quickly process massive amounts of data. It can process many varieties of data such as:

- Structured data: data in tables with rows and columns.
- Semi-structured data: data in logs, emails, and social media.
- Unstructured data: images, sound, spatial, and video.

The DAS will be the data storage and processing platform to support Advanced Analytics and it will be maintained by the Analytics Center of Excellence ("ACE"), a support organization dedicated to maintain the DAS and responsible for Advanced Analytics competency. Figure 1 shows the interaction of the ACE, the DAS and Advanced Analytics.

Figure 1



The experience of our industry peers supports the value of investing in a DAS to fully leverage the benefits of grid modernization by processing and analyzing massive amounts of the digital data generated from smart meters and other intelligent grid devices.

i. DAS Technology

The DAS is the platform consisting of hardware and software. At the core, it uses Hadoop software utilities that facilitate using a network of many computers to solve problems involving massive amounts of data and computation. It provides a software framework of distributed storage and parallel processing of data, needed for Advanced Analytics. This technology has its roots in Google and Yahoo search technologies. Hadoop with Spark has become the de facto standard/model for Big Data technology. Utility peers known to be using similar DAS technology (i.e., Hadoop) include: American Electric Power Company, Centerpoint Energy, ConEdison, Duke Energy, Exelon, and Southern Energy.

ii. Analytics Center of Excellence

The ACE is an analytics team consisting of system administrators, data scientists, data engineers, business analysts, user interface developers (*i.e.*, people who develop visualizations like dashboards and reports), and other IT and business professionals responsible for identification, prioritization, business case evaluation, testing, and implementation of Advanced Analytics-driven use cases for the Company. This centralized approach establishes a governance and execution structure that provides internal operating groups and customers with the best-in-class business intelligence ("BI") and Advanced Analytic solutions.

a. Benefits of the ACE

The ACE will provide the following benefits:

- A dedicated team with expertise in data science, data engineering and development of analytic solutions, able to work with business partners based on identified business priorities.
- Implementation of best practices and methodologies to keep pace with technology and industry advances. It will live, grow, and change as the Company's needs evolve.
- Assurance that data collected within the DAS is treated as an asset by providing a strong technical foundation and mechanisms to govern the handling and access to data.
- Reduction in analytic/data silos and increased reusability of data/solutions to provide consistent solutions with focus on data quality, proper governance, faster turnaround, and reduced cost.
- The ACE will focus on organizational enablement, collaboration and consistency with focus on analysis, not just tools.

b. Development Process used by the ACE

The ACE will utilize a five-step process to develop analytic solutions and ensure successful executions of various projects including:

- system assessment and requirements gathering;
- design and use case prioritization;
- verification;
- implementation; and
- run and maintain.

Every analytic use case begins with a proof of concept to help all stakeholders understand the analytic capabilities of the proposed solution. A requirement gathering session is performed after completion of the proof of concept to understand the volume of data involved and computational capacity needed. This information is then compared to the existing system capacity, and additional hardware and software is acquired to meet the additional need. The analytic solution is then designed and developed, and verified by user acceptance testing ("UAT") to ensure the final solution meets the expected objectives. After successful completion of the UAT, the solution is implemented in production where it is automated and supported by the operations team.

II. HARNESSING THE POWER OF ADVANCED ANALYTICS FOR THE GT PLAN

The DAS and dedicated ACE organization will provide the critical capability to unlock and reap the benefits of true grid modernization and the proposed projects of the Company's Grid Transformation Plan. The DAS will serve as the central data processing and intelligence tool to integrate data from a wide range of intelligent grid devices and other resources and provide valuable insights to enable a wide range of customer and operational benefits. Synergies attained from integrating data from various internal systems like AMI head end, Advanced Distribution Management System ("ADMS"), Outage Management System ("OMS"), Enterprise Asset Management System ("EAMS"), and Customer Information System ("CIS") with external data like weather will enable the Company to fine tune operations, forecast load shape, and predict future behaviors, resulting in a better, more informed customer experience. Examples of Advanced Analytics use cases, and benefits therein, are provided in the Advanced Analytics Use Case Examples Section at the end of this white paper, with a focus on the following goals:

A. Continued delivery of reliable electric service

Weather is still the biggest factor for utility planning, and it is getting more and more challenging. Various studies have concluded that storm-related power outages alone cost the U.S. economy up to $50 billion per year.

Outages are inevitable. However, when they do happen, it is important to react fast. Advanced Analytics can help the Company quickly identify service break points, perhaps several at once on the distribution system. This allows the Company to determine which part of the distribution system demands attention first and can help it decide where to send crews first for greatest impact. Advanced Analytics also help system operator's route service crews to assess the damage, restore service, and inform customers regarding service restoration.

Moreover, grid-focused analytics help identify and fix outages more quickly, keep customers informed throughout the process with timely notifications, and provide information essential to utility business success.

B. Ability to proactively fix issues with the distribution system

Advanced Analytics on the distribution system provides the Company operational visibility into the entire distribution network across different geographies. Advanced Analytics drawn from near-real-time data can help quickly identify impending problems and send alerts, so system operators can take immediate remedial actions. Geospatial visualization can reveal the hot spots within the grid and point out areas where system planners and operators should focus their attention.

Advanced Analytics driven from feeder and transformer operational data can point out situations where frequent overloading of transformers, feeders, and other devices occur. Examples are when Company service areas gain new load, such as new homes, industrial facilities or hospitals, which create the overload conditions. With Advanced Analytics, the Company can clearly identify the enhancements needed for the grid infrastructure in that area. As problems in the distribution system become apparent, the Company is able to address them with system upgrades and improvements before customers experience outages.

C. Ability to integrate distributed energy resources

In the past, generation typically operated upstream on the grid with respect to distribution. Today, the Company must manage generation within the distribution network, with the added issue of distributed energy resources ("DER") often operating intermittently. This poses new challenges in managing the distribution network. Advanced Analytic applications and the analytics drawn from them can help the Company integrate DER and better plan its grid operations.

Analytic applications can suitably model the behavior of the entire distribution network including the renewable resources. These applications can analyze weather patterns along with past generation profiles and forecast the generation that will be available from the DER. Advanced Analytics will highlight opportunities for non-wires alternatives to be evaluated. Advanced Analytics are foundational to integrated distribution planning ("IDP").

Through sophisticated management of DER, the Company can be at the forefront of the major shift toward grid modernization, improve customer satisfaction, and meet regulatory compliance.

D. Better management of peak demand

The Company continuously seeks new ways to manage rising peak demand and offers demand response programs with events that engage customers to reduce energy use in order to shed load from the distribution network.

Utilities can benefit in multiple ways by integrating the distributed energy response management system ("DERMS") with distribution planning and management systems and drawing advanced distribution analytics from the integrated system. Distribution analytics enables utilities to reduce demand when and where it is needed and helps mitigate increasing power costs for the distribution utilities. Integration of the DERMS and distribution management systems can also enable the measurement and verification or M&V of actual demand reductions that occurred through the demand response events.

In order to take advantage of Advanced Analytics across distribution planning and operations, utilities must educate themselves on the data they have, the data they need to overcome challenges, and the best approach for managing data to develop better business processes.

Table 1 shows examples and benefits of Advanced Analytics use cases the Company intends to develop.

Table 1: Examples of Advanced Analytics Use Cases

Use Case	Benefits
Analytic Support for post AMI rollout phase	Provides post roll-out support to ensure that the reads from thousands of additional smart meters are monitored electronically as it is impossible to do this manually. The Advanced Analytics will provide: • Geospatial reporting of coverage and heat maps based on consumption. • Detection of any post roll-out meter latency issues, and help detect and analyze network fluctuation. • Detection of any other anomalies such as defective meters and stale/missing measurements.
Load and Voltage Analysis	Ensures good power quality for Dominion Energy Virginia customers by: • Detecting load and corresponding voltage imbalances to corrective actions before customer complaint or equipment damage due to voltage levels. • Isolating problem source from low primary voltage to transformer loading or secondary service. • Providing long-term analysis for infrastructure planning (Generation, Transmission and Distribution). • Providing greater insight into DER impacts and trends by geography.
Detect Systemic Load and Phase Imbalance	Increases efficiency, reliability, and power quality for Dominion Energy Virginia customers by: • Avoiding phase imbalances to reduce losses, voltage imbalance, and malfunctioning protective relays. • Detecting load imbalance on multi-phase distribution system that varies over time due to single-phase load turn on/off or with increase/decrease of energy consumption. • Supporting planning needed to deploy utility-owned DER or other secondary equipment to reduce load.
DER Management	Helps support DER Integration in a safe and reliable manner by: • Integrating the DERs safely and ensuring reliable grid operation (interconnection). • Forecasting the "new" load based on weather conditions and voltage. • Identifying previously unknown EVs and DERS.
Asset Management	Increases reliability and decreases reactive maintenance work by: • Establishing Condition Based Maintenance Program using Predictive Analytics. • Enabling an equipment replacement strategy based on asset health and not age, through analysis of the equipment's historical data and operating conditions. • Right-sizing equipment based on actual needs for full-life utilization of assets. • Identifying equipment that is under-loaded or overloaded regularly, which in turn increases the benefits of metering to non-metered assets such as conductors, distribution transformers, and protection devices. It also reduces technical loss, premature asset failures and unplanned outages, allows for more accurate management of inventory levels.
Demand Side Management ("DSM")	Supports energy conservation by: • Leveraging data to assess DSM program effectiveness before expanding them. • Analyzing overall savings and cost management of the energy conservation programs. • Quantifying/forecasting demand and capacity impacts due to energy conservation programs. • Providing customers with recommendations to improve energy conservation programs.
Outage Management Analytics	Reduces power outage and/or the duration of power outage and keeps customers well-informed by: • Providing situational awareness using power outage and restoration notification using aggregated data and geospatial visualization. • Predicting the number of outages by area based on weather forecast to support logistics for fast and effective restoration. • Providing field crew visibility for the Operations Center. • Providing high priority alerting and fault location indication. • Predicting restoration times and nested outages. • Leveraging drone/satellite LIDAR images for better vegetation management programs.

Regulatory Reporting	Supports data driven decision making with: • Improved risk assessment response time. • Lower technical and non-technical losses. • More accurate metrics with Advanced Analytics to pinpoint factors influencing them. • More accurate outage start/end times improve calculations for SAIDI, SAIFI, CAIFI and CAIDI

Use Case	Benefits
Smart Metering and Grid Operations	Increases visibility to help reduce down time and provide more accurate estimates of losses by: • Reducing outage and down time. • Detecting energy loss, theft, and fraud.
Load and Demand Forecasting	*Forecasting for better utilization of renewables and reduce wastage/cost* by: • Improving load and demand forecasting for more reliable and efficient power delivery. • Improving DER load forecasting for better utilization of renewables, allowing solar and DER to work together and provide consistent energy. • Helping to reduce peak load. To reduce peak load, it is critical to know which customers are contributing to the peak load and their consumption patterns. Annual, seasonal, and daily peak demand periods can be identified at the system level so the relative contribution from individual meters can be determined. This information supports the design of rate structures based on customer demographics and consumption patterns, as well as the focus and quantification of demand response programs and energy efficiency initiatives. For example, special rate structures could be designed to discourage consumption during peak loading periods and financial incentives may be offered for demand management programs. This type of analysis enhances the demand management tools available to the utility by providing greater precision in how to apply those tools to achieve the best results.
Smart Metering and Customer Service	Increase energy conservation and customer service by: • Improving acceptance for targeted offerings (DSM, for example). Because smart meters are deployed at customer premises, the data can be used to improve customer service by providing notifications of power outages and restorations, analysis of power quality (including voltage sags/swells and momentary outages) at the premise, and recommendations on improving energy efficiency.
Outage Management and Vegetation Management	Innovative ways to prevent power outages for customers through: • Use of /satellite images (LIDAR, Infrared) with image analytics to provide a more reliable and targeted vegetation management solution.
Support for Locks Micro Grid	Due to the existence of multiple sources of power in a Microgrid, Advanced Analytics can help not only with load forecasting, but can also provide optimization support in choosing power sources to maximize renewables and meet the needed demand at the lowest cost. Advanced Analytics could help improve power reliability by managing the electricity demand against the supply, increasing the grid stability. Collecting the data from all of the power sources and load information can be leveraged to help gain newer *insights to help with DER integration and battery technologies in the distribution grid. The current role of* storage is primarily to smooth the intermittency of renewables generation, which occur in a Micro Grid.

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23325 Mainfeeder Hardening

Project Component(s):
- ☐ Self-Healing Grid

Grid Hardening:
- ✓ Rebuilding Existing Mainfeeder
- ☐ Voltage Conversion for Existing Mainfeeder
- ☐ Relocating Existing Mainfeeder
- ☐ Adding Phases to Existing Mainfeeder
- ☐ Build New Mainfeeder
- ✓ Reconductor Existing Mainfeeder
- ☐ Mainfeeder OH to UG Conversion
- ☐ Capacity Addition

Problem Statement: 23325 feeds a total of 2,180 customers, with 985 customers having a 5 year average CMI of 459 minutes. This feeder has multiple long radials with high customer counts and poor reliability. This project addresses the radial behind the 325 R8, which feeds 761 customers, and has had 9 outages in the 5 year period ending 12/31/2018, and an additional 4 outages during major events.

Alternatives Considered: No prudent alternatives found for the targeted area.

Project Description: Rebuild to 477 AAAC and rebuild 5.4 miles behind the 321 R8, from N0703EJ90 to 325R154 and 325 F71. Replace 325 X384 with new electronic recloser. Install new disconnects and line sensors near N0703NM99 and N0804MA19. Install line sensors on the main line at 325 D2, 325 S4, 325 D47, 325 S6, 325 D220, 325 D58.

Date: 6/24/2019

Cost Estimate: $2,226,700

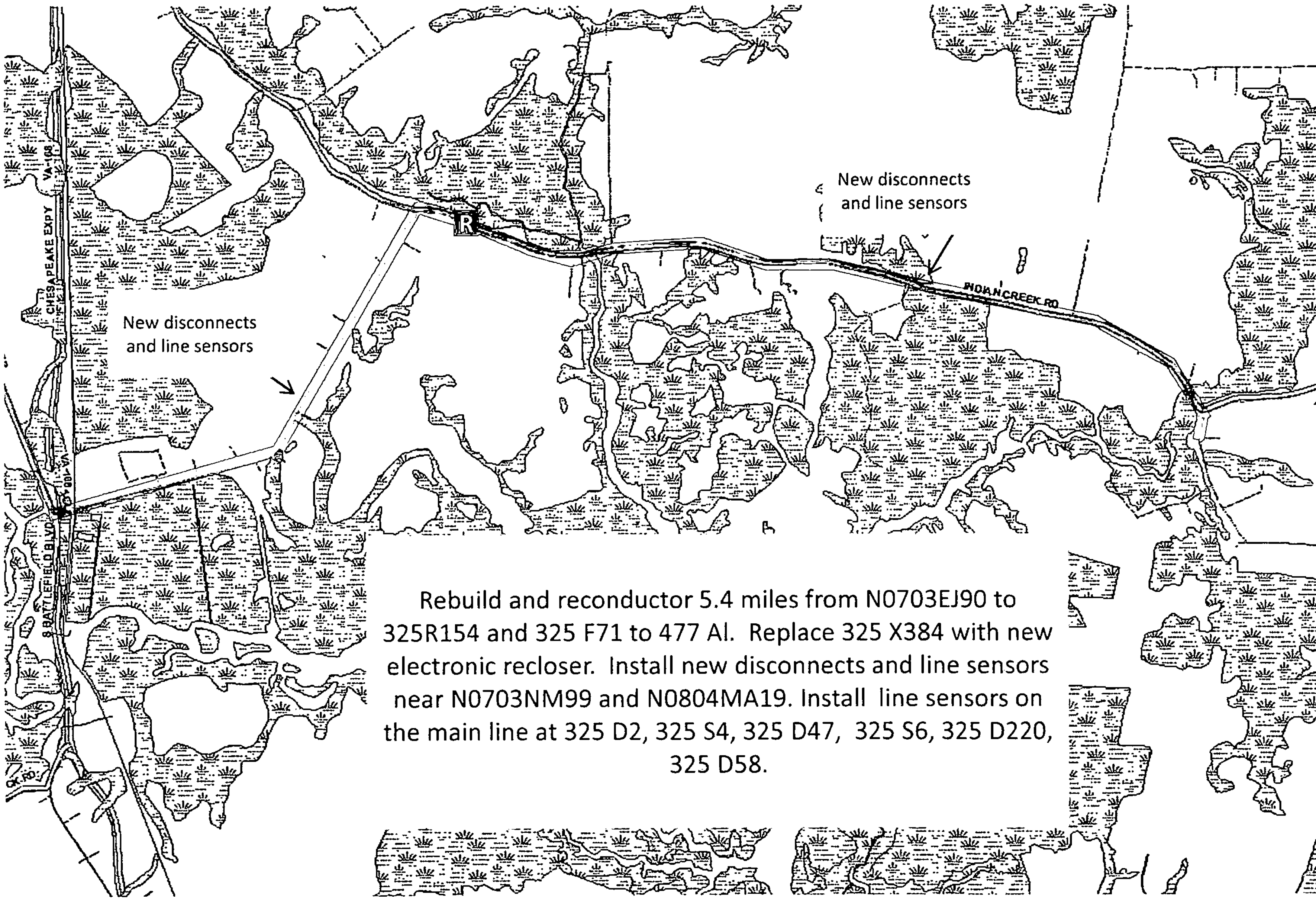
Project Initiated By: Jackie Merrick

Regional Reliability Contact: Keaton Alvis

Project Manager: TBD

WMIS #: 10304571

23325 Mainfeeder Hardening Scope



Rebuild and reconductor 5.4 miles from N0703EJ90 to 325R154 and 325 F71 to 477 Al. Replace 325 X384 with new electronic recloser. Install new disconnects and line sensors near N0703NM99 and N0804MA19. Install line sensors on the main line at 325 D2, 325 S4, 325 D47, 325 S6, 325 D220, 325 D58.

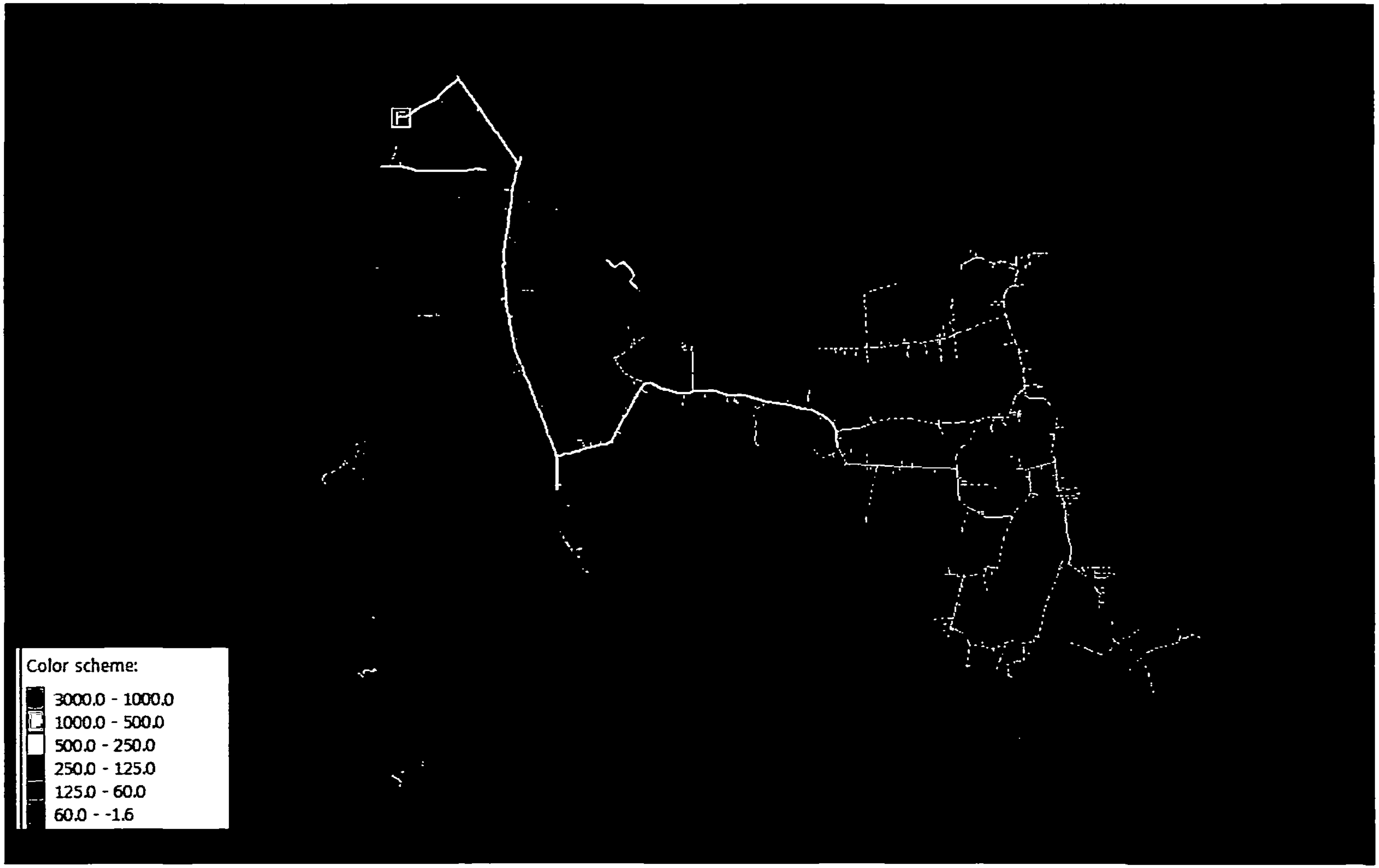
23325 Mainfeeder Hardening Results

	Before		
Feeder	Average Interruptions	Average Minutes of Interruption	Population
	1.76	275.42	2180
23325	1.76	275.42	2180

	After		
Feeder	Average Interruptions	Average Minutes of Interruption	Population
	1.42	201.85	2180
23325	1.42	201.85	2180

Improved Population		2,180
Average Minutes of Interruption - Before		275.42
Total Minutes of Interruption - Before		600,416
Average Minutes of Interruption - After		201.85
Total Minutes Interruption - After		440,033
OH Mileage - New Construction		0.00
OH Mileage - Hardening		5.40
UG Mileage - New Construction		0.00
UG Mileage - Converted from OH to UG		0.00
"Downline" Affected Mainline Mileage		0.00
Total DER Impacted	0 sites	0 MW
Total Net Metering Customers		3

23325 Average Minutes of Interruption - Before



23325 Average Minutes of Interruption - After

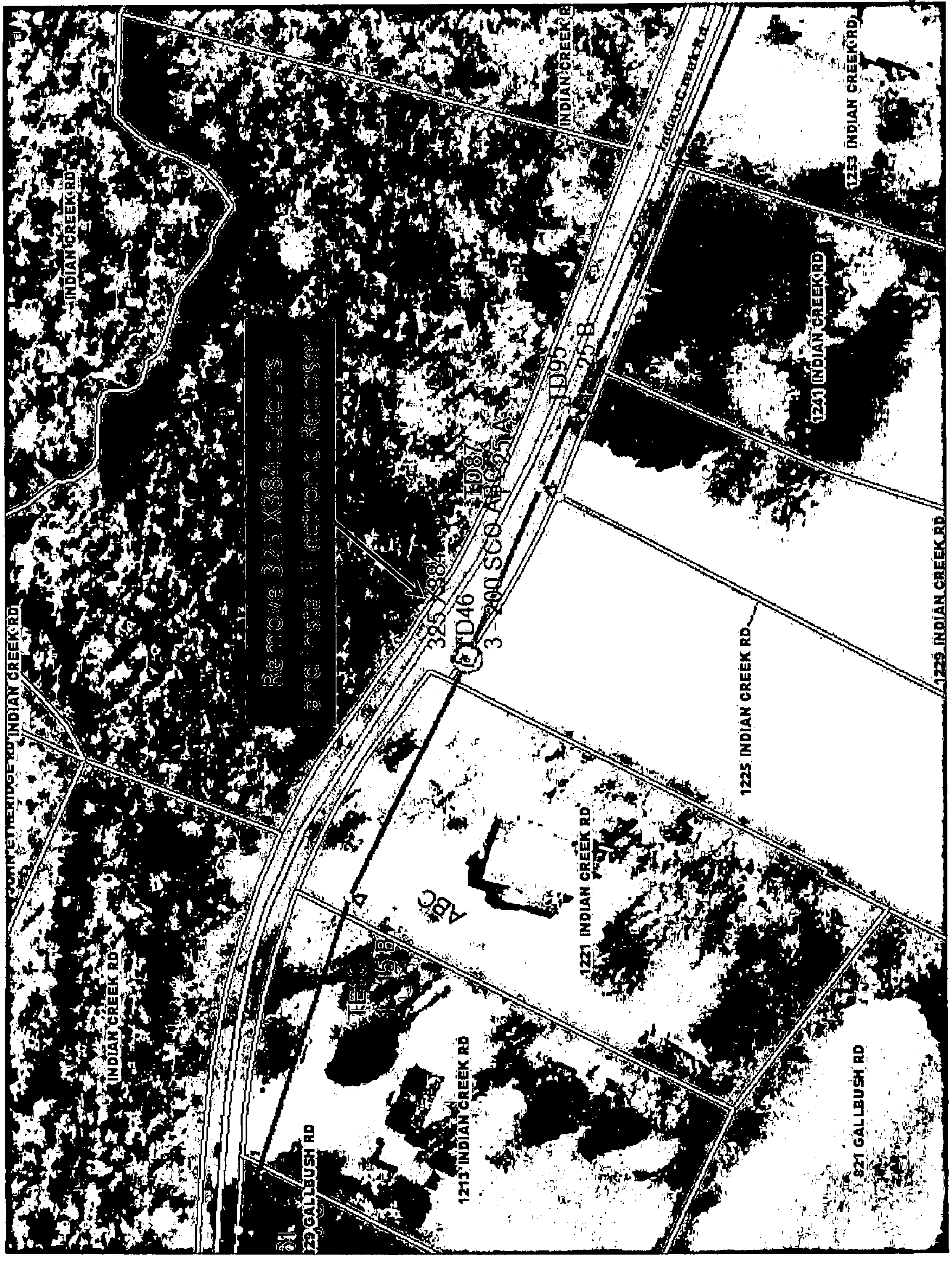
23325 Mainfeeder Hardening Detailed Scope

Rebuild +/- 5 miles of line behind the 23325 R8 to the 325 F71 and 325 R154

- Upgrade primary size to 477 AAAC
- Remove and install approximately 123 poles
- Replace 52 transformers
- Replace the 325 X384 with new electronic recloser
- Install 3 cutouts on unfused taps (contact coordination for fuse sizes)
- Install new 600A line tension disconnects and line sensors at two locations
  - N0703NM99
  - N0804NA36 (More accessible location)

Note: Due to two lane roads, flagging will be needed for most of the job

Company Exhibit No. __
Witness: RSW
Schedule 6
Page 7 of 18



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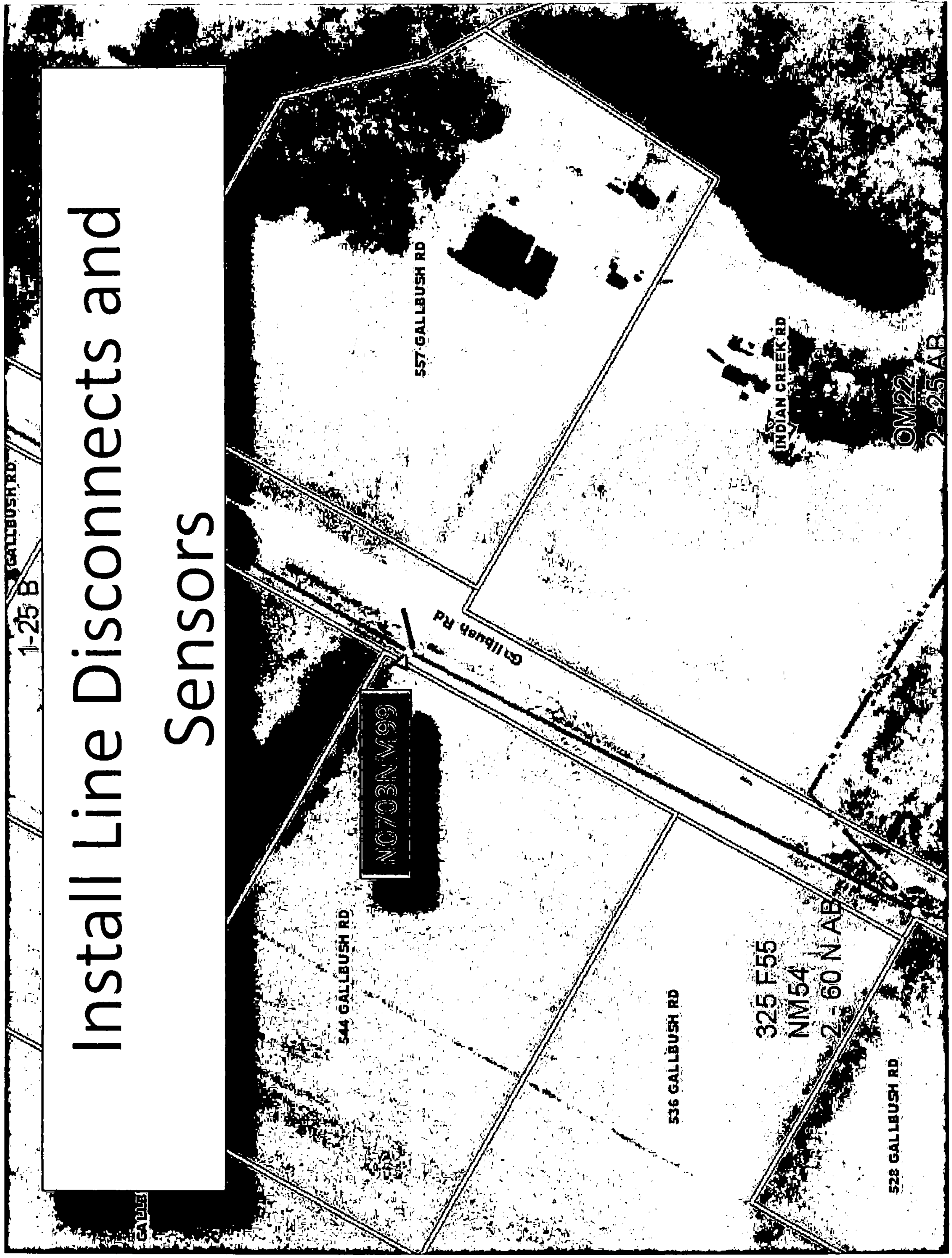
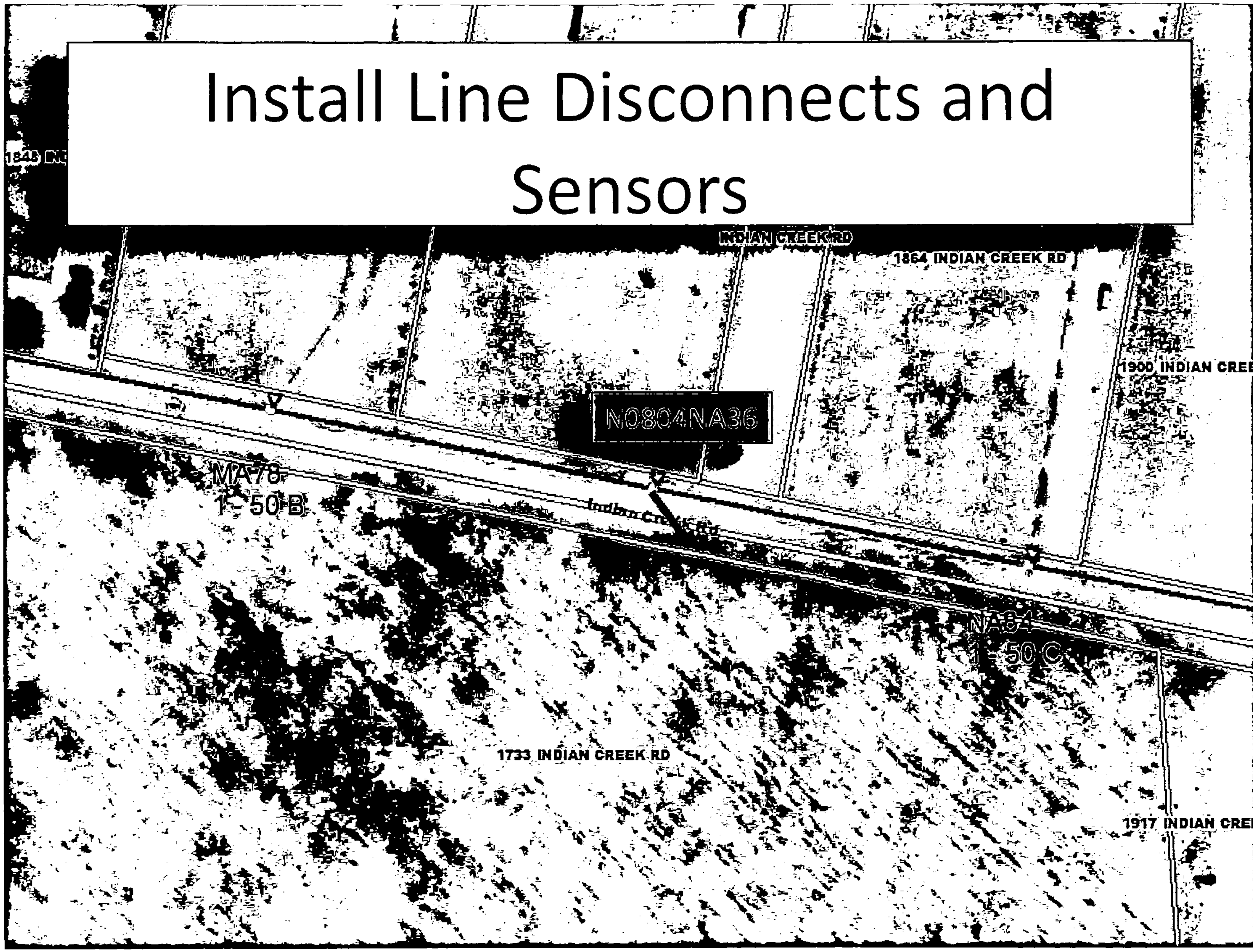

Install Line Disconnects and Sensors
1-25 B
GALLBUSH RD
557 GALLBUSH RD
Gallbush Rd
INDIAN CREEK RD
OM22
2-25 AB
NC703NM99
544 GALLBUSH RD
536 GALLBUSH RD
325 F55
NM54
2-60 N AB
528 GALLBUSH RD

Install Line Disconnects and Sensors



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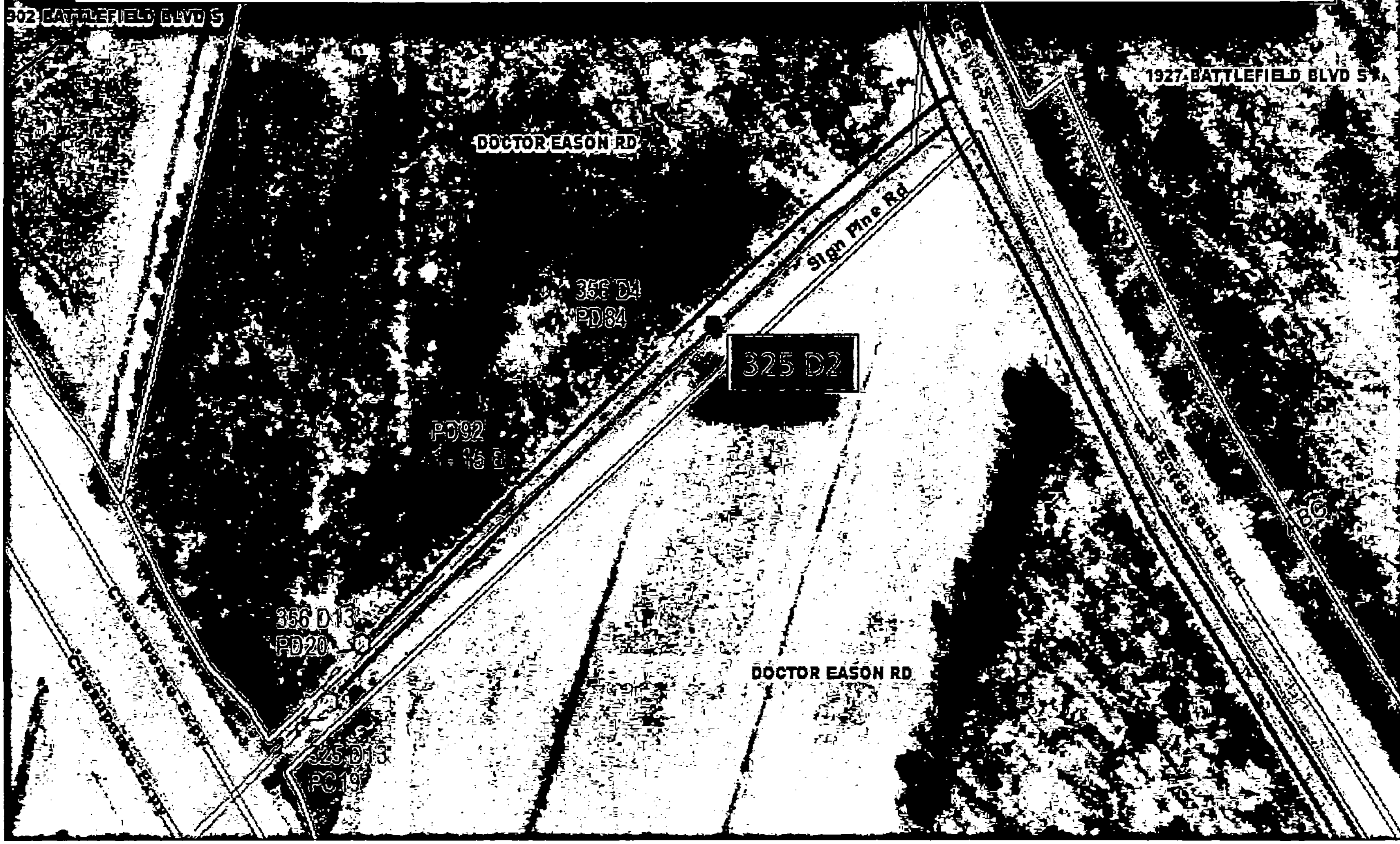

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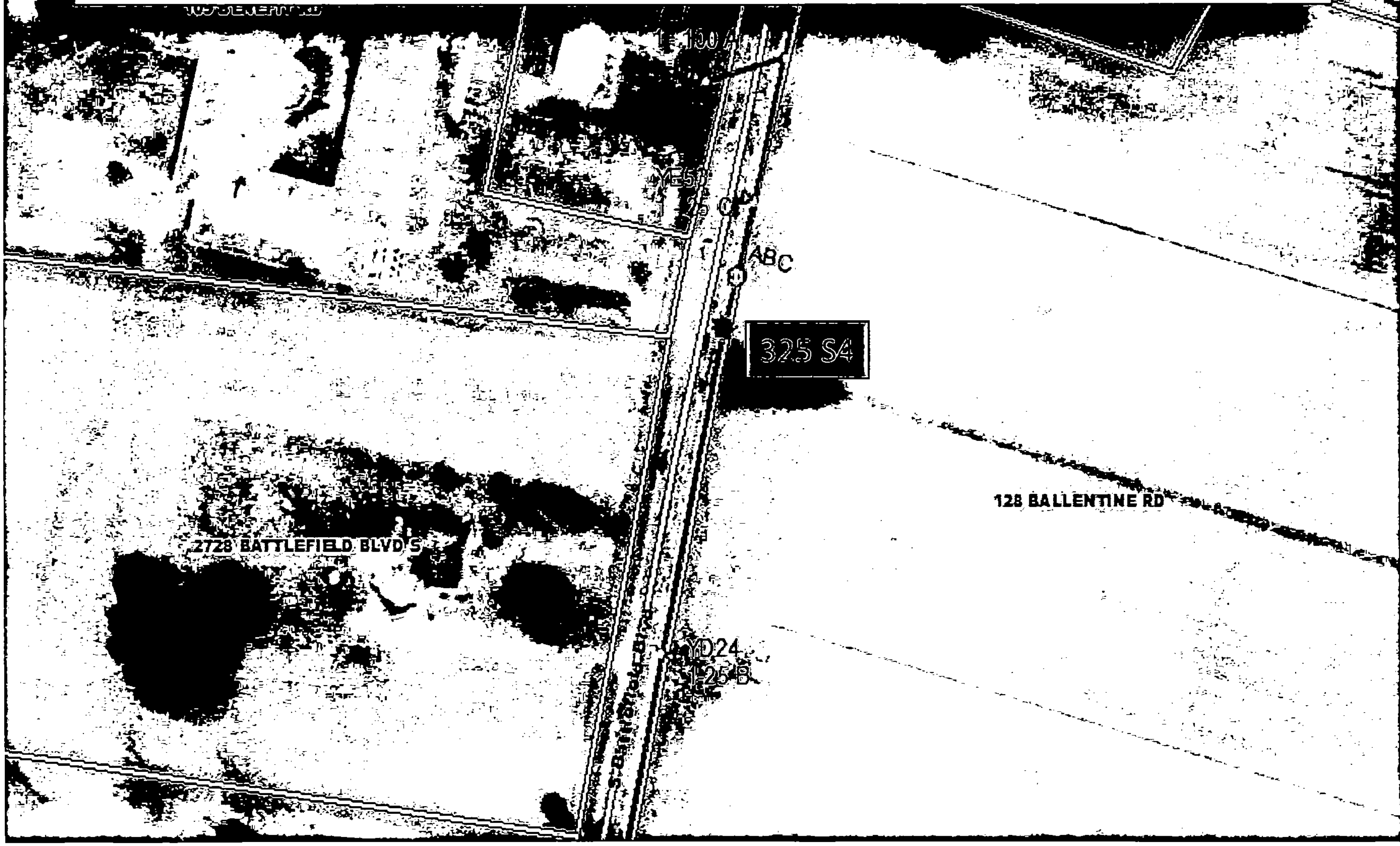
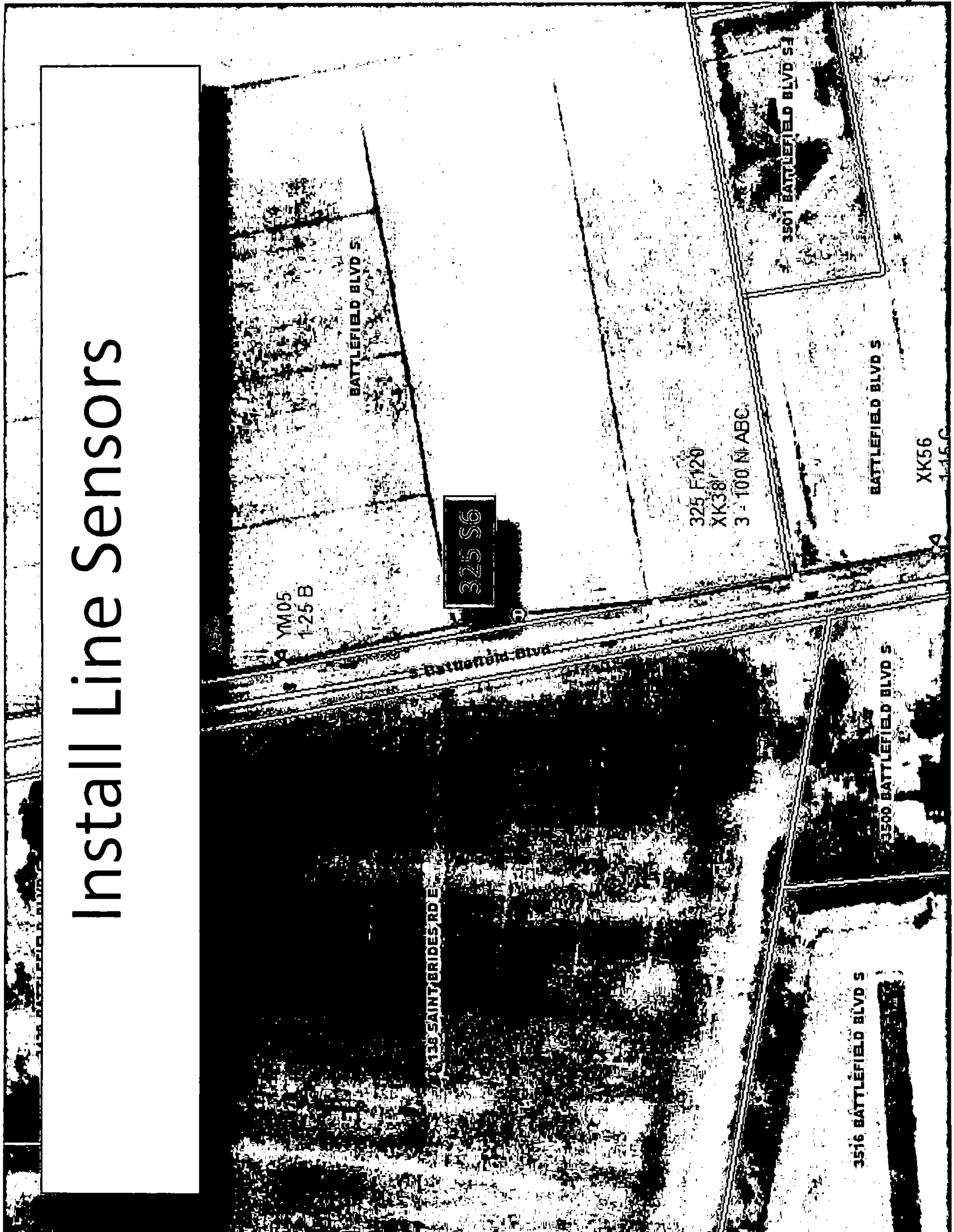
Install Line Sensors



Install Line Sensors



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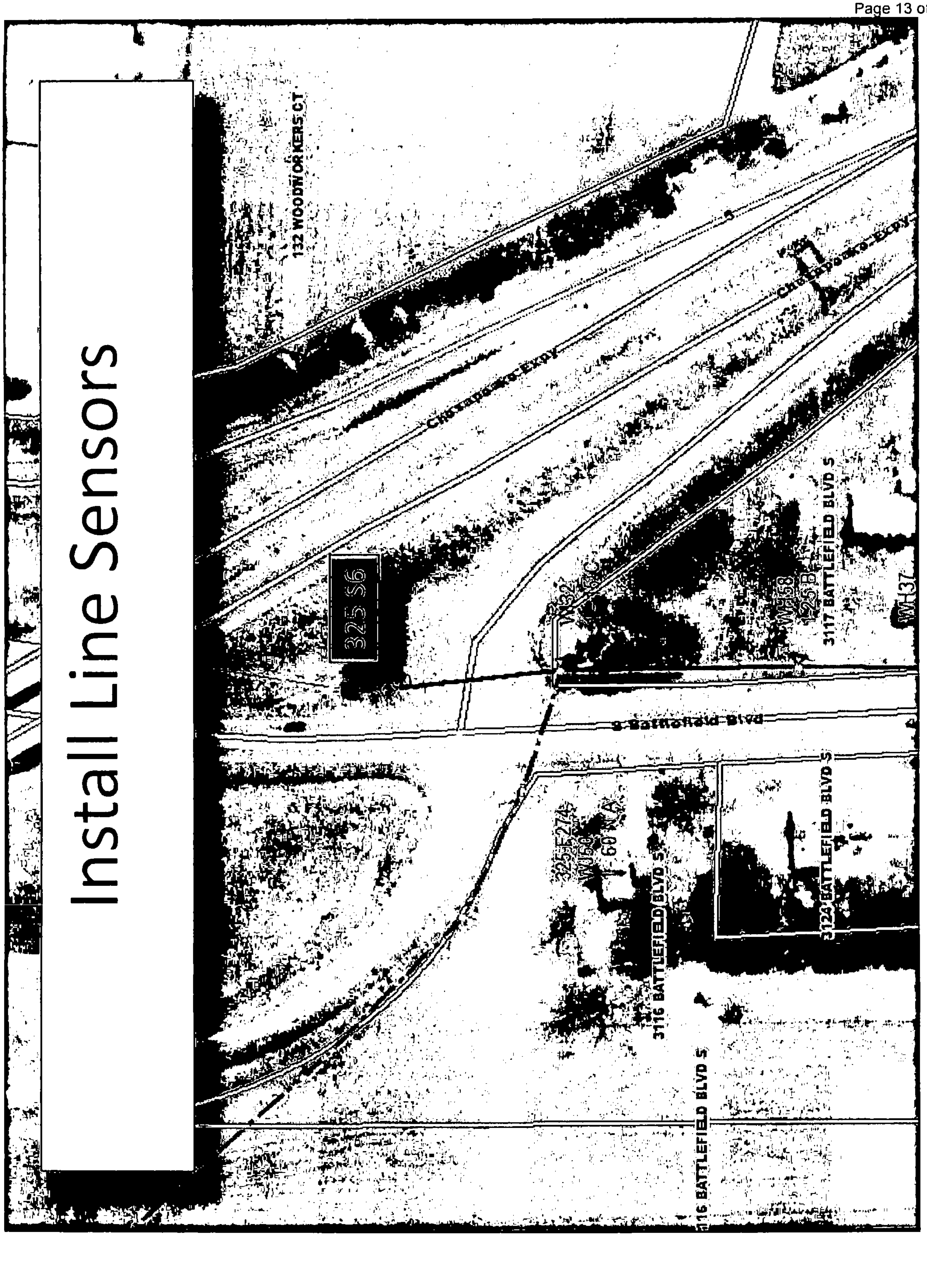
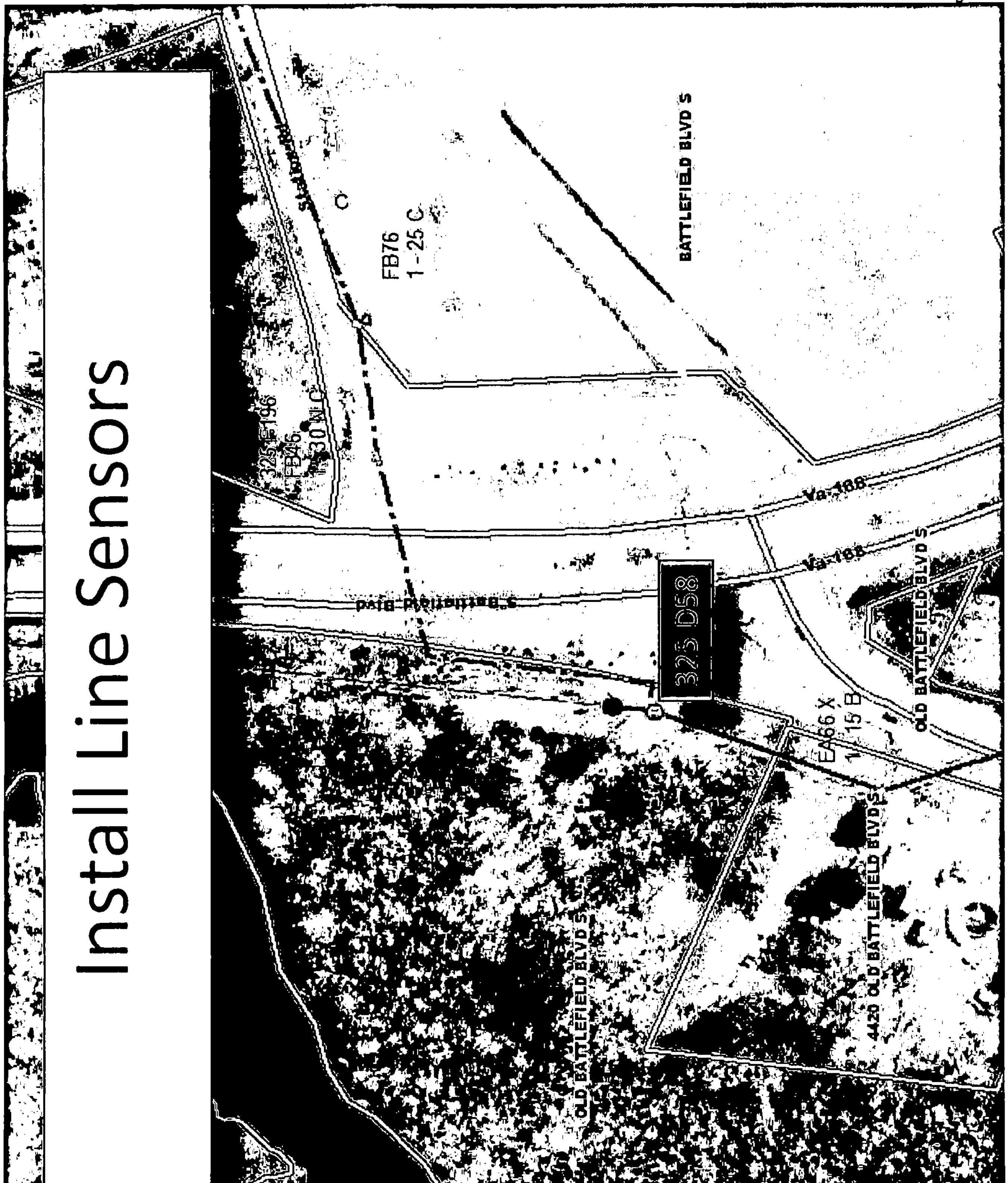

Install Line Sensors
132 WOODWORKERS CT
Chesapeake Expy
325 S6
S Battlefield Blvd
3117 BATTLEFIELD BLVD S
WH37
3124 BATTLEFIELD BLVD S
3116 BATTLEFIELD BLVD S

Install Line Sensors

190050005

190950005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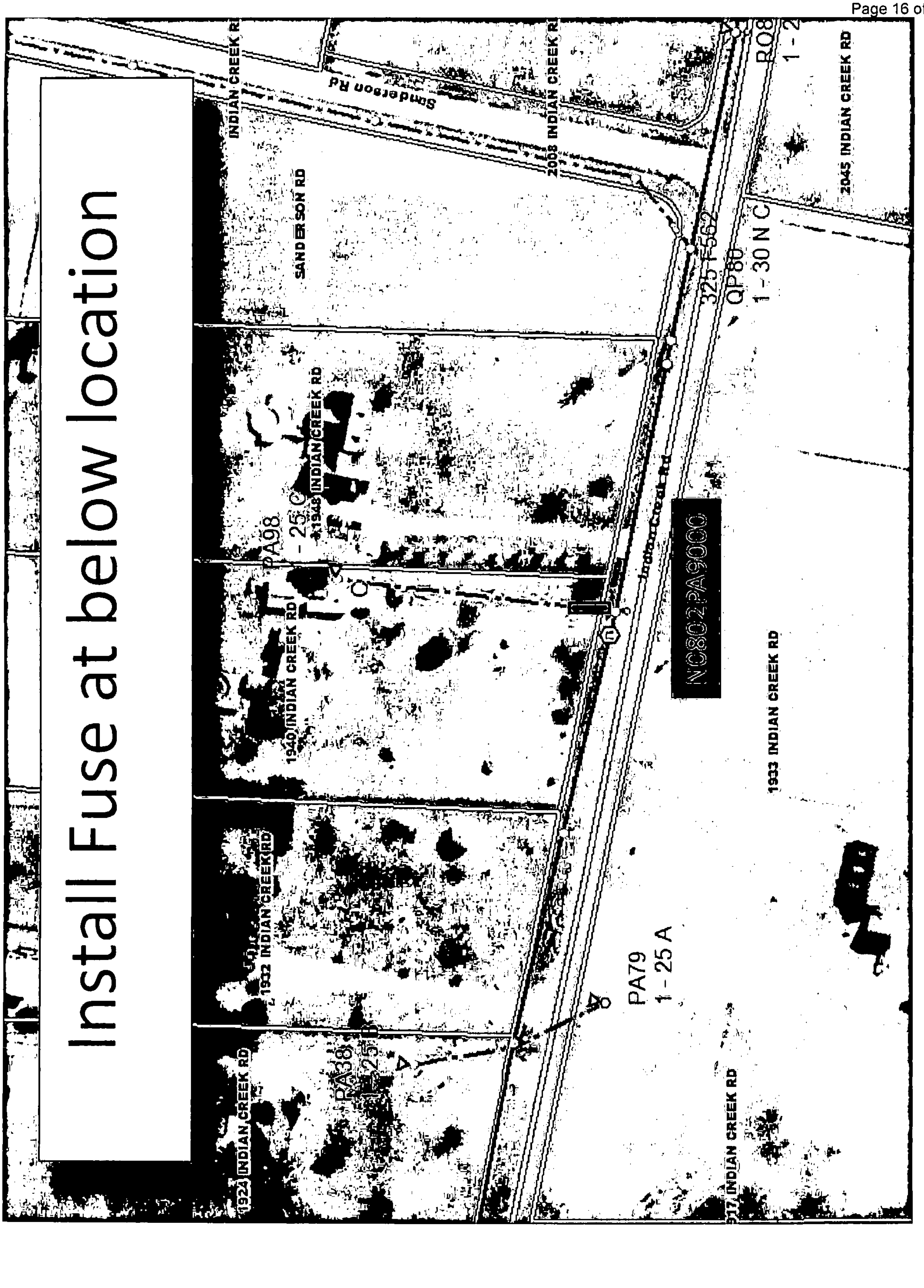
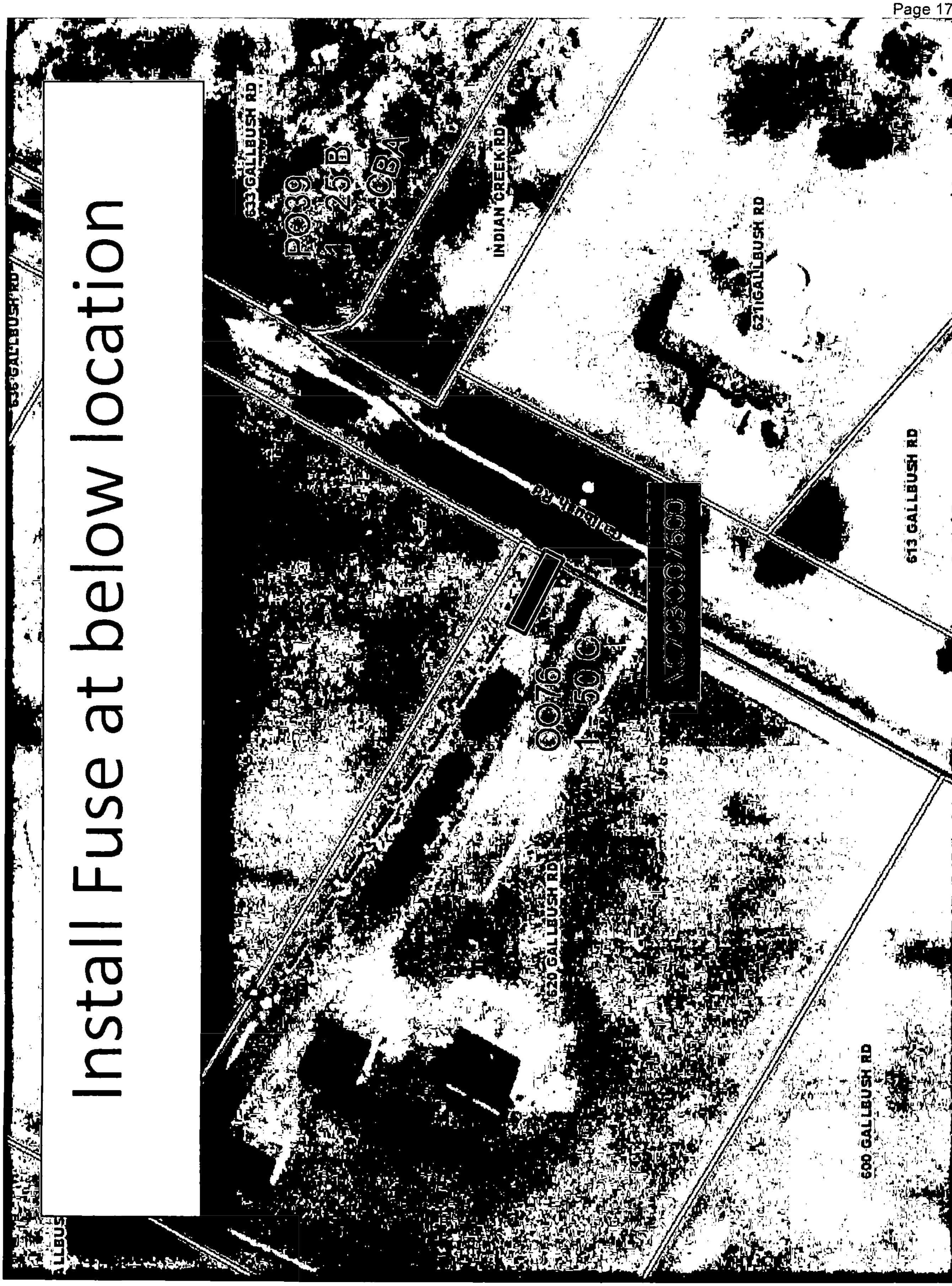
BATTLEFIELD BLVD S
FB76
1 - 25 C
325 F196
FB46
1 - 30 N C
Va-168
Va-168
Battlefield Blvd S
325 D58
EA66 X
1 - 15 B
OLD BATTLEFIELD BLVD S
4420 OLD BATTLEFIELD BLVD S
OLD BATTLEFIELD BLVD S


Install Fuse at below location
NC802PA9000
PA79
1 - 25 A
QP80
1 - 30 N C
Sanderson Rd
SANDERSON RD
Indian Creek Rd
1924 INDIAN CREEK RD
1932 INDIAN CREEK RD
1940 INDIAN CREEK RD
1933 INDIAN CREEK RD
2008 INDIAN CREEK RD
2045 INDIAN CREEK RD


Install Fuse at below location
633 GALLBUSH RD
P039
25B
CBA
INDIAN CREEK RD
621 GALLBUSH RD
613 GALLBUSH RD
0076
50 C
620 GALLBUSH RD
600 GALLBUSH RD


Install Fuse at below location
1924 INDIAN CREEK RD
1902 INDIAN CREEK RD
1900 INDIAN CREEK RD
1864 INDIAN CREEK RD
1933 INDIAN CREEK RD
1917 INDIAN CREEK RD
1733 INDIAN CREEK RD
Indian Creek Rd
N0802NA4600
0A04
1-50 B
ABC

Company Exhibit No. __
Witness: RSW
Schedule 7
Page 1 of 1

Mainfeeder Hardening Projected Benefits

	3-Year Total	10-Year Total
Critical Services Improved	61	428
Total Customers Improved	24,038	491,308
Total Miles Hardened (miles)	63	1,028
Total Customer Interruptions Eliminated	22,240	303,351
Total Customer Minutes of Interruption Eliminated	2,293,393	30,343,840
Average Outage Minutes Before	348	236
Average Outage Minutes Eliminated	94	61
Average Outage Minutes After	254	175
Average Interruptions Before	2.9	2.0
Average Interruptions Eliminated	1.0	0.6
Average Interruptions After	1.9	1.4

Voltage Island Mitigation List

Year	Transformer	Office	Stranded Load (MVA)	Customer Count	Critical Service Count	Opportunity Zone Impact?	THA
2021	St Johns #1	FBG	10	1,230	12	Y	HIGH
2021	Warsaw #1	NNK	10	1,371	4	Y	HIGH
2022	Emporia #2	SHL	16	2,761	7	Y	LOW
2022	Massanutten #1	SHN	8	1,153	1	Y	MEDIUM
2022	Dominion #1	ALT	10	1,348	3	Y	LOW
2023	Chase City #1	SHL	15	2,621	7	N	HIGH
2023	Ft Pickett #1	FVL	14	4	4	N	HIGH
2023	Grottoes #1	BLU	19	3,123	2	N	HIGH
2024	Gretna #1	ALT	7	1,709	1	N	HIGH
2024	Charlottesville #1	CVL	9	2,291	0	N	HIGH
2025	King George #1	FBG	7	884	0	N	HIGH
2025	Crewe #1	FVL	16	2,722	6	N	LOW
2026	Hanover #4	RIC	17	2,895	4	N	LOW
2026	Deltaville #1	GLO	5	1,417	3	N	LOW
2027	Flaggy Run #1	CHK	9	565	1	N	LOW
2027	Trego #1	SHL	7	527	2	N	LOW
2028	Glasgow #2	ROK	8	2,165	1	N	LOW
2028	Sandbridge #1	VAB	15	2,020	1	N	LOW

part 1D

Carroll

190950006

<u>WITNESS DIRECT TESTIMONY SUMMARY</u>

<u>Witness</u>: Bradley R. Carroll, Sr.

<u>Title</u>: Director – IT Infrastructure

<u>Summary</u>:

Company Witness Bradley R. Carroll, Sr., supports the telecommunications projects ("Telecom Projects") that Dominion Energy Virginia plans to deploy as part of its Grid Transformation Plan over the next two years ("Phase IB"). He also supports the telecommunications projects approved by the Commission in Case No. PUR-2018-00100 ("Phase IA") through its Final Order dated January 17, 2019.

As Mr. Carroll discusses, the Commission found the Company's proposed Phase IA telecommunications investments reasonable and prudent, with the exception of the proposed spending related exclusively to components of the Plan not approved. Specifically, the Company calculated the $54.6 million (excluding financing costs) approved spend for Tier 1 and Tier 2 telecommunications by removing cost associated with Tier 3 – Cost for FAN.

Mr. Carroll details the Phase IB Telecom Projects, or Tier 3 Field Area Network ("FAN"), that will facilitate connectivity to equipment on the distribution system not directly served by the Telecom Projects approved by the Commission in Phase IA. The Tier 3 FAN investments will include field device hardware that connects intelligent grid devices to the Company's communication network, FAN base station hardware, licensed spectrum acquisition for the FAN, installation services, project management, engineering, along with network management and support. As Mr. Carroll explains, the deployment of the Phase IB Telecom Projects will begin in 2020, with an initial deployment to validate equipment connectivity and vendor compliance with the requirements outlined in the Tier 3 FAN request for proposal. Full scale deployment of the Tier 3 FAN will begin in 2021, with additional FAN equipment being deployed through the duration of Phase IB. The FAN field devices will be deployed in conjunction with the intelligent grid devices during Phase IB. The Company anticipates an estimated $84.6 million in capital investment and estimated $4.7 million in O&M investment over a 2-year period to support the new FAN investments.

As offered by Mr. Carroll, the FAN will provide the necessary situational awareness into the power quality along the feeders as the bi-directional power flows changes due to distributed energy resources ("DER"). The FAN will also provide the capability to change power quality in response to changing conditions on the distribution grid. This will enable the Company to maintain voltage stability for safe and reliable service to customers when the DER causes changes in power quality.

DIRECT TESTIMONY
OF
BRADLEY R. CARROLL, SR.
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company").

A. My Name is Bradley R. Carroll, Sr. and I work at Dominion Energy Virginia located at 707 East Main Street Richmond, VA. I am the Director of IT Infrastructure. A statement of my background and qualifications is included as Appendix A.

Q. Please describe your area of responsibility with the Company.

A. I am responsible for the strategy, reliability, security and leadership of the voice, data and transport networks servicing Dominion Energy Virginia.

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

A. The purpose of my testimony is to explain the telecommunications projects ("Telecom Projects") that Dominion Energy Virginia plans to deploy as part of its proposal to transform its electric distribution grid (the "Grid Transformation Plan," "GT Plan," "GTP," or "Plan") over the next two years ("Phase IB"). Specifically, I discuss the Telecom Projects approved by the State Corporation Commission of Virginia (the "Commission") in Case No. PUR-2018-00100 ("Phase IA") through its Final Order dated January 17, 2019 (the "2018 Final Order") and the Telecom Projects proposed in Phase IB of the Company's Grid Transformation Plan.

Q. During the course of your testimony, will you introduce any exhibits?

A. Yes. Company Exhibit No. __, BRC, consisting of Schedules 1-2, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules:

Schedule	Description
1	Cost Schedule
2	Functional and Technical Requirements for Field Area Network Solution and Scoring Summary of RFP Responses

Additionally, I sponsor Filing Schedule Carroll, Attachment A, which provides a request for proposal ("RFP") summary based on the RFP issued by the Company, from which detailed pricing estimates were prepared. The table below provides a description of this filing schedule:

Filing Schedule Carroll	Description
Attachment A	Field Area Network RFP Summary

I also sponsor certain sections of the Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document.

Q. Did you provide information to West Monroe Partners, LLC ("West Monroe") for use in the cost-benefit analysis ("CBA")?

A. Yes, I provided costs and additional inputs for Telecom Projects to West Monroe for use in the CBA. I also support the benefits reflected in Thomas G. Hulsebosch's Schedule 2, as identified therein.

The specific costs I support in Phase IA and Phase IB are:

Nominal $, in Millions	**2019**	**2020**	**2021**	
	Year 1	**Year 2**	**Year 3**	**3-year Total**
Phase IA	**$7.6**	**$14.2**	**$32.8**	**$54.6**
Capital	$6.4	$14.1	$32.5	**$53.0**
O&M	$1.2	$0.1	$0.3	**$1.6**
Phase IB	**$0.0**	**$53.2**	**$36.1**	**$89.3**
Capital	$0.0	$51.1	$33.6	**$84.6**
O&M	$0.0	$2.2	$2.5	**$4.7**

My Schedule 1 provides detailed cost information for the GT Plan components that I sponsor.

Q. How is your testimony organized?

A. My testimony is organized into two sections:

I. Telecom Projects approved by the Commission in Phase IA

II. Telecom Projects proposed by the Company in Phase IB

Q. Before you begin, do the Phase IB Telecom Projects meet the definition of an electric distribution grid transformation project under Va. Code § 56-576?

A. Yes. The proposed activities provide the required communication networks needed to support the application of "automated control systems for electric distribution circuits and substations" that are "designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability" and involve "intelligent grid devices for real-time system and asset information."

I. TELECOM PROJECTS APPROVED BY THE COMMISSION IN PHASE IA

Q. What Telecom Projects were approved by the Commission in Phase IA of the Grid Transformation Plan through the 2018 Final Order?

A. As detailed in the 2018 Final Order, the Commission found the Company's proposed Phase IA Cyber and Physical Security and Telecommunications proposal reasonable and prudent, with the exception of the proposed spending related exclusively to components of the Plan not approved. The Company interprets the 2018 Final Order as giving approval for the Tier 1 and Tier 2 telecommunications investments in the amount of approximately $54.6 million (excluding finance costs). As shown in Table 1 below, the Company provided the following projected investments for the Telecom Projects in the first three years of the GT Plan. Specifically, the Company calculated the $54.6 million (excluding financing costs) approved spend for Tier 1 and Tier 2 telecommunications by removing cost associated with Tier 3 – Cost for FAN.

Table 1: Approved Phase IA Telecommunications Spend for GT Plan

Telecommunications Infrastructure ($ in Millions)	Phase IA Approved	
	Capital	O&M
Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ -	$ 1.2
Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ 14.1	$ -
Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ 37.3	$ 0.4
Tier 3 - Cost for Field Area Network - (Not approved in 2018)	$ -	$ -
Cost to Increase the Capacity of the Network Operating Center	$ 1.6	$ -
TELECOMMUNICATIONS INFRASTRUCTURE - TOTAL	**$ 53.0**	**$ 1.6**

Q. Could you please provide an overview of the Phase IA Telecom Projects approved by the Commission?

A. Yes. As detailed in the 2018 GT Plan proceeding, the Company determined that a comprehensive telecommunications strategy would require multiple components specifically designed and deployed as an integrated solution to meet the wide-range needs of a modernized electric grid. The components were broken out into three specific tiers of communication:

- Tier 1: High-speed broadband with very low latency[1] network with redundancy
- Tier 2: Broadband network without redundancy
- Tier 3: Field Area Network ("FAN") to support distribution automation equipment

The Tier 1 solution component will be an upgraded high-speed, low latency network backbone solution using multi-protocol label switching ("MPLS") for connectivity with new and existing microwave and fiber assets.

MPLS is a mechanism for the routing of communications within a network as data travels across network nodes. These enhancements will provide the added security, reliability, efficiency, and bandwidth to support the growth of Internet Protocol ("IP") traffic between the various office locations and critical substations. The added improvements are achieved by replacing existing SONET technology with a more modern IP-MPLS technology.

[1] Low latency describes a computer network that is optimized to process a very high volume of data messages with minimal delay (latency). These networks are designed to support operations that require near real-time access to rapidly changing data.

The security enhancements of IP-MPLS include:

1. Enhanced cyber intelligence analytics capabilities to identify, protect, detect, respond, and restore services;
2. Common domain encryption zones with different cipher security keys per domain to provide a defense in depth approach where the security of one domain is independent of another domain;
3. Enhanced granularity of IP filtering for network and service control;
4. Separation and isolation of IP-MPLS nodal management control traffic to protect against cyber threats;
5. Ability to provide unique and secure Layer 2 or Layer 3 VPN services to separate traffic flows;
6. Ability to maintain encrypted critical distribution automation ("DA") applications when communications to cipher key management systems is not available.

Reliability is improved by using equipment protection and enhanced services protection at each site along with enhanced Quality of Service ("QoS") to ensure critical traffic maintains communications. Communication reliability and efficiency gains are achieved by the ability of IP-MPLS to leverage the full bandwidth of the communication system when available while also ensuring a minimum bandwidth or QoS when the communication channel is busy. All of these benefits come with a technology that maintains low latency communications which is critical for secure and reliable control of the new automation equipment in the substations and on the feeders enabling the improved system reliability.

The Tier 2 network will be used to connect Company-owned broadband to substations and key facilities throughout the Company's service territory to increase the digital services supported at these substations including physical and cyber security, surveillance, digital access, supervisory control and data acquisition ("SCADA") services, and remote access by operations and engineering to the substations.

The Company's Network Operations Center ("NOC"), is responsible for provisioning, testing, monitoring, troubleshooting, and dispatching the Company's telecommunication network 24 hours a day, seven days a week, and 365 days a year. This includes provisioning and testing of new equipment before it is accepted into the production system. As the Company builds out the Tier 1 and Tier 2 telecommunications infrastructure, the capacity of the Company's NOC will also need to increase to ensure that the NOC can keep up with the expected pace of deployments and keep pace with the expected increase in alarms, troubleshooting, and dispatching.

As detailed in Table 1 above, the Tier 1 and Tier 2 projects and the increase for NOC capacity approved by the Commission in Phase IA total approximately $53 million in capital and approximately $1.6 million in O&M over three years.

Q. To date, has the Company made investments into the Phase IA Telecom Projects?

A. Yes. The Company is scheduled to complete the implementation of MPLS into its Core Network by November of 2019. Converting the Core Network to MPLS is a foundational first step in enabling remote sites such as substations and key facilities to realize the benefits of the MPLS technology.

Q. How do the Phase IA Telecom Projects relate to potential rural broadband deployment?

A. The Phase IA Telecom Projects provide the foundation for the rural broadband options outlined in Dominion Energy's Broadband Feasibility Report published on December 1, 2018.[2] The Phase IA Telecom Projects include the extension of the Company's fiber network to substations and key facilities for a period of three years. The Company plans to continue these programs in years four through ten of the GT Plan to meet its objective of extending Company-owned broadband to substations and key facilities.

The expansion of the Company's fiber network, particularly in rural unserved areas, will provide opportunities to leverage the fiber network for the benefit of middle-mile expansion in unserved and underserved markets. Not only will the fiber serve Dominion Energy Virginia's connectivity needs at key facilities, but it could also support potential Internet Service Providers that will use the fiber capacity to improve availability of broadband for commercial, government, institutional and residential customers in Virginia. Support of the rural broadband services will require additional investment beyond Phase IA or the proposed equipment and services in Phase IB.

II. TELECOM PROJECTS PROPOSED BY THE COMPANY IN PHASE IB

Q. What Telecom Projects were not approved by the Commission as part of the Company's 2018 Grid Transformation Plan?

A. As explained earlier, the Commission in the 2018 Final Order found the Company's proposed Phase IA Cyber and Physical Security and Telecommunications proposal reasonable and prudent, with the exception of the proposed spending related exclusively to components of the Plan not approved. The Company interprets the 2018 Final Order as giving approval for the Tier 1 and Tier 2 telecommunications investments, while rejecting the Tier 3 FAN investments.

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[2] *See* Dominion Energy's, *Broadband Feasibility Report*, 1 December 2018. Retrieved from Virginia's Legislative Information System *at* https://rga.lis.virginia.gov/Published/2019/RD281/PDF.

The Tier 3 FAN investments proposed by the Company in its 2018 Grid Transformation Plan exclusively supported components of the Plan not approved by the Commission in Phase IA, such as intelligent grid devices on the electric distribution network located outside of the substation fence.

Table 2 below shows the previously approved Phase IA capital and O&M with the Phase IB requested capital and O&M to cover the FAN and incremental enhancements to the NOC needed to support it.

Table 2: Phase IA Approved and Proposed Phase IB Telecommunications Investments for GT Plan

Telecommunications Infrastructure ($ in Millions)	Phase IA/IB Capital	Phase IA/IB O&M	Phase IA Approved Capital	Phase IA Approved O&M	Phase IB Proposed Capital	Phase IB Proposed O&M
Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ -	$ 1.2	$ -	$ 1.2	$ -	$ -
Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ 14.1	$ -	$ 14.1	$ -	$ -	$ -
Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ 37.3	$ 0.4	$ 37.3	$ 0.4	$ -	$ -
Tier 3 - Cost for Field Area Network - (Not approved in 2018)	$ 79.9	$ 4.5	$ -	$ -	$ 79.9	$ 4.5
Cost to Increase the Capacity of the Network Operating Center	$ 6.4	$ 0.3	$ 1.6	$ -	$ 4.8	$ 0.3
TELECOMMUNICATIONS INFRASTRUCTURE - TOTAL	**$ 137.6**	**$ 6.3**	**$ 53.0**	**$ 1.6**	**$ 84.6**	**$ 4.7**

Q. **What investments does the Company anticipate making in the Phase IB Telecom Projects?**

A. As detailed in Table 2 above, the Company anticipates making investments in a Tier 3 FAN. The Phase IB Telecom Projects, or Tier 3 FAN, will facilitate connectivity to equipment on the distribution system not directly serviced by Tiers 1 and 2. This includes devices that are outside of the substation fence. A secure and robust communications network is a foundational and required investment to enable the Grid

Improvement Projects, both grid technologies and grid hardening, supported by the pre-filed testimony of Company Witness Robert S. Wright, Jr.

The Tier 3 FAN investments will include field device hardware that connects intelligent grid devices to the Company's communication network, FAN base station hardware, licensed spectrum acquisition for the FAN, installation services, project management, engineering, along with network management and support. As shown in my Schedule 1, the Company anticipates an estimated $84.6 million in capital investment and estimated $4.7 million in O&M investment over a 2-year period to support the new FAN investments.

Q. Please explain the proposed timeline for deployment of the Phase IB Telecom Projects.

A. The deployment of the Phase IB Telecom Projects will begin in 2020, with an initial deployment to validate equipment connectivity and vendor compliance with the requirements outlined in the Tier 3 FAN request for proposal ("RFP"). Full scale deployment of the Tier 3 FAN will begin in 2021, with additional FAN equipment being deployed through the duration of Phase IB. The FAN field devices will be deployed in conjunction with the intelligent grid devices during Phase IB. In years four through ten of the GT Plan, FAN equipment will continued to be deployed to the remaining intelligent grid devices within the Company's Virginia service territory.

Q. In the Commission's June 27, 2019 Final Order in Case No. PUR-2018-00065, the Company's 2018 IRP, it ordered the Company in future IRPs to "systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects. For identified grid transformation projects, the Company shall include: (a) a detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) detailed cost estimates of each proposed investment; (c) the benefits associated with each proposed investment; and (d) alternatives considered for each proposed investment." Although this is not an IRP proceeding, can you address these requirements as they relate to Phase IB Telecom Projects?

A. Yes, I will address them in order. The detailed description of the existing distribution system and proposed changes for Phase IB is detailed in the Company's Plan Document. I will address how the FAN Telecom investments in Phase IB support the overall GT Plan goals and the new equipment being deployed throughout the distribution grid. I will also address the costs, benefits, and alternatives associated with Phase IB Telecom Projects.

__Need__

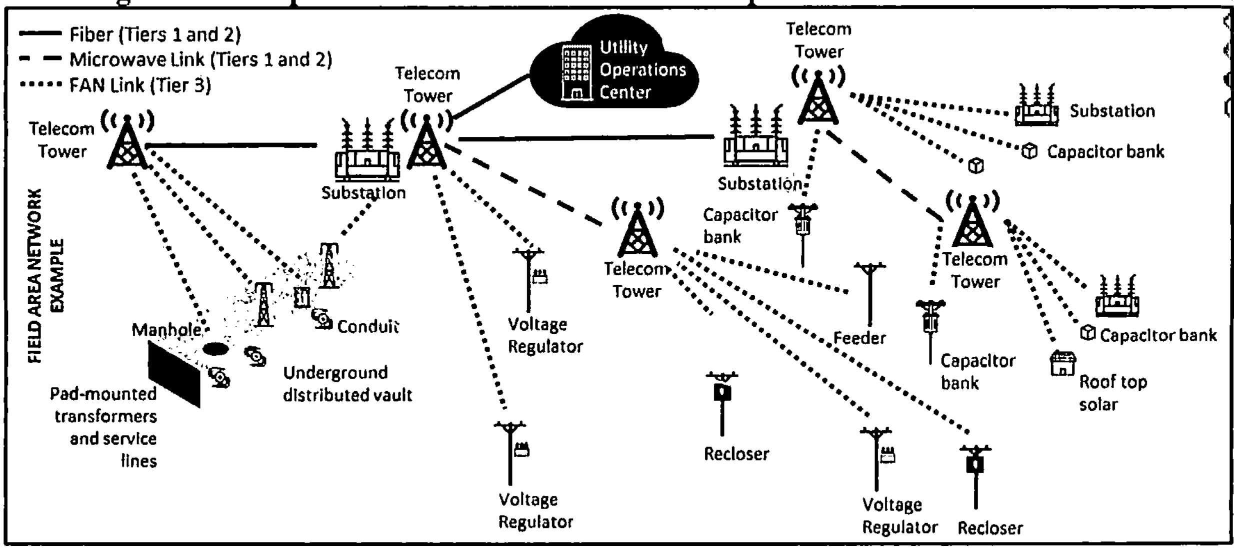
Q. Why are the Phase IB Telecom Projects needed and how do they support other Phase IB GT Plan Projects?

A. The Phase IB Telecom Projects, or Tier 3 FAN, will facilitate connectivity to equipment on the distribution system not directly serviced by Tiers 1 and 2. This includes devices that are outside of the substation fence. As detailed by Company Witness Wright, the Company plans to install intelligent grid devices as part of a self-healing grid. These devices will capture and communicate information about the distribution grid, including voltage, fault current, and anomalies. The Tier 3 FAN will provided secure, real-time communications to the intelligent grid devices via wireless communications. Without the Tier 3 FAN, the Company will not be able to communicate to intelligent grid devices and therefore will not have visibility into grid conditions

In addition, and as explained by Company Witness Wright, a transformed grid will enable greater integration of renewables, and the FAN will provide the necessary situational awareness into the power quality along the feeders as the bi-directional power flows changes due to distributed energy resources ("DER"). The FAN will also provide the capability to change power quality in response to changing conditions on the distribution grid. This will enable the Company to maintain voltage stability for safe and reliable service to customers when the DER causes changes in power quality.

Figure 1 below shows the overall GT Plan Telecom Network, including the FAN. As demonstrated therein, the FAN provides the secure and robust two-way communications between control systems in the Operations Centers and intelligent grid devices in the substations and on the feeders, which will allow the Company to respond to changing conditions to the grid in real time to meet demand, maintain grid stability, and optimize equipment and system reliability.

Figure 1: Sample Illustration of the Overall Proposed Telecom Network



Costs

Q. What process did the Company follow to ensure that its proposed costs for the Phase IB Telecom Projects are reasonable?

A. The Company issued an RFP in May 2019, which detailed the technical and functional requirements for the Phase IB Telecom Projects across various technology solutions. The RFP also captured anticipated vendor capital and O&M costs for years four through ten of the GT Plan to ensure the Company's proposed Phase IB Telecom Projects are viable long-term. Filing Schedule Carroll, Attachment A, provides a summary of the RFP process and its results.

Suppliers were asked to respond with proposed turn-key solutions, which included the yearly capital costs to build the network as well as ongoing operations and maintenance costs that meet the Company's coverage, throughput, reliability, resiliency, and cyber-security requirements.

This RFP process gave the Company insight into the different types of technology solutions utilized by peer utilities across the United States. It also provided insight into each supplier's solution(s) and approach through written RFP responses and oral presentations, thereby ensuring that the proposed solutions and corresponding costs were aligned with the Company's proposed Phase IB scope. Suppliers' pricing proposals were compared against each other and industry benchmarking data to ensure proposed costs for the Phase IB Telecom Projects are reasonable.

In addition to the supplier capital and operational costs, additional incremental infrastructure costs needed to support the Tier 3 FAN such as fiber backhaul, communication towers, NOC expansion, and additional deployment resources were accounted for to evaluate the different suppliers' total cost of ownership of their proposed FAN solution. The selected FAN solution based upon the RFP, as well as the incremental fiber backhaul, communication towers, NOC expansion, and additional deployment resources are contained in my Schedule 1, which sets forth the incremental capital and O&M costs of the Phase 1B Telecom Projects.

Q. Phases IA and IB cover the first three years of the GT Plan. What Telecom Projects are contemplated in years four through ten of the GT Plan?

A. The Company plans to continue executing its tiered communications strategy explained herein in years four through ten of the GT Plan.

The Tier 1 and 2 projects approved in Phase IA will continue the extension of high-speed connectivity from remaining substations and key facilities. The continued build out of the Tier 3 FAN will be necessary to provide communications to intelligent grid devices as the Company deploys the Grid Improvement Projects proposed in the GT Plan.

As explained above, the RFP captured anticipated vendor capital and O&M costs for years four through ten of the GT Plan to ensure the Company's proposed Phase IB Telecom Projects are viable long-term.

Benefits

Q. What quantifiable benefits does the Company expect to realize from the Phase IB Telecom Projects?

A. The main purpose of deploying the Phase IB Telecom Projects is to enable other GT Plan Project benefits, such as those described in Witness Wright's testimony, which require a secure and robust FAN that will provide reliable two-way communications between control systems and intelligent grid devices. There are, however, some potential savings for the Company through the elimination and avoidance of O&M costs, such as those incurred for wireless carrier backhaul.

Company Witness Hulsebosch's Schedule 2 provides the benefits associated with the Phase 1B Telecom Projects through the avoided costs of leased telecommunication service that will be replaced with the new Tier 3 FAN, and details the number of current devices that will be moved off of the leased telecommunication service and onto the Tier 3 FAN.

Alternatives

Q. How did the Company determine which solutions to deploy for Phase IB Telecom Projects?

A. To start, the Company evaluated its current and future telecommunication use cases for the Tier 3 FAN. This involved reviewing the current DA devices that require connectivity, as well as the anticipated future grid devices that will require connectivity as part of Phase IB of the GT Plan Projects.

Based on the current and future connectivity and coverage needs across Dominion Energy's Virginia service territory, the Company identified 115 technical and functional requirements focused around cyber-security, reliability, resiliency, bandwidth, and scalability as shown in my Schedule 2. To validate the identified requirements, the Company hosted suppliers at its Richmond, Virginia headquarters to get a better idea of the technology solutions that exist on the market and see which ones would be best-suited to provide a technology solution(s) that could meet the Company's diverse needs. The Company compiled the identified requirements and issued the RFP to Tier 3 telecommunication suppliers that supply FAN solutions. These suppliers use different technical approaches which include narrowband frequency solutions, mesh architectures, as well as private and carrier-based Long-Term Evolution ("LTE") solutions. These solutions used both licensed and unlicensed frequencies as part of their solutions. The various suppliers included the most popular vendors as well as some of the more innovative FAN solutions being deployed in the utility industry today.

Once supplier responses were received back, the Company performed an extensive review of the proposals to determine how each met the Company's identified requirements. The proposals were evaluated based on their technical merits, their ability to meet Dominion Energy Virginia's functional and operational requirements, and the proposed price for their Tier 3 solution.

After reviewing the supplier responses, the Company selected a few suppliers for oral presentations. Each supplier was given an opportunity to present their solution in more detail as well as to answer specific questions from Company representatives.

Based on RFP proposal and oral presentation evaluation, the Company has determined that a hybrid approach is the best path forward for the Tier 3 FAN, as it meets the technical and functional requirements set forth above as well as the diverse topology and device densities across Dominion Energy Virginia's service territory. The hybrid FAN will leverage a private LTE wireless communication solution in the more densely populated, urban areas, where Dominion Energy Virginia can leverage its existing infrastructure to connect to devices in those areas while meeting the use case needs. In rural areas of the Company's service territory, the hybrid FAN will leverage a narrowband point-to-multipoint ("PtMP") solution due to its long range of coverage, so that the Company can use its existing infrastructure to reach devices in rural areas. Both the private LTE and narrowband PtMP technologies have the ability to leverage a carrier LTE solution for redundancy and failover.

The Company believes that this hybrid approach is the most prudent way to deploy a FAN across the diverse topology and population density while increasing reliability, resiliency, and security of the grid.

Q. What alternative solutions did the Company consider for the FAN?

A. Through the competitive RFP process, the Company considered private point-to-multipoint wireless network solutions across 600 MHz, 700 MHz, 900 MHz, and 2.3 GHz licensed spectrums. The Company also considered mesh-based wireless network solutions in the 900 MHz and 2.4 GHz unlicensed spectrums. The Company chose the hybrid FAN solution chosen over the alternative options because it will meet the Company's Tier 3 FAN technical and functional requirements, while covering the diverse topology and density of the Company's territory at a reasonable cost.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS
OF
BRADLEY R. CARROLL, SR.

Bradley R. Carroll, Sr. honorably served as a Veteran Non-Commissioned Officer of the United States Marine Corps and holds a Bachelor of Science degree in Information Systems. He has held multiple certifications in his technology career.

Mr. Carroll joined Dominion Energy as a contractor in 2000, later converting to an employee in 2001. Prior to joining Dominion Energy he held technology positions at both Circuit City and SuperValu. He has more than 24 years of experience in Information Technology designing, implementing, supporting and leading teams responsible for internetworking technologies. Mr. Carroll has been in leadership at Dominion Energy for the past 7 years assuming his current role of Director - IT Infrastructure in 2018. In his current role Mr. Carroll is responsible for the strategy, reliability, security and leadership of the voice, data and transport networks servicing Dominion Energy Virginia. Mr. Carroll is responsible for delivering and maintaining telecommunications in support of distributed solar generation, substation automation, operations centers, contact centers and mobile workforce enablement within Dominion Energy Virginia's regulated service territory.

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Telecommunications Phase 1A Capital Costs**					
2						
3	Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ -	$ -	$ -	$ -	$ -
4	Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ 5,500,000	$ 3,712,500	$ 4,875,000	$ 14,087,500	$ 19,806,996
5	Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ 900,000	$ 9,440,102	$ 26,987,290	$ 37,327,391	$ 235,747,831
6	Tier 3 - Cost for Field Area Network - (Not Approved in 2018)	$ -	$ -	$ -	$ -	$ -
7	Costs to Increase the Capacity of the Network Operating Center	$ -	$ 1,000,000	$ 612,000	$ 1,612,000	$ 9,406,496
8						
9	Total Telecommunications Phase 1A Capital Costs	$ 6,400,000	$ 14,152,602	$ 32,474,290	$ 53,026,891	$ 264,961,324
10						
11						
12	**Summary of Telecommunications Phase 1A O&M Costs**					
13						
14	Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ 1,200,000	$ -	$ -	$ 1,200,000	$ 4,310,586
15	Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ -	$ -	$ -	$ -	$ 11,196,461
16	Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ -	$ 101,250	$ 315,541	$ 416,791	$ 9,556,720
17	Tier 3 - Cost for Field Area Network - (Not Approved in 2018)	$ -	$ -	$ -	$ -	$ -
18	Costs to Increase the Capacity of the Network Operating Center	$ -	$ -	$ -	$ -	$ 4,540,086
19						
20	Total Telecommunications Phase 1A O&M Costs	$ 1,200,000	$ 101,250	$ 315,541	$ 1,616,791	$ 29,603,852
21						
22	Total Telecommunications Phase 1A Costs	$ 7,600,000	$ 14,253,852	$ 32,789,830	$ 54,643,682	$ 294,565,176
23						
24						
25	**Summary of Telecommunications Phase 1B Capital Costs**					
26						
27	Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ -	$ -	$ -	$ -	$ -
28	Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ -	$ -	$ -	$ -	$ -
29	Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ -	$ -	$ -	$ -	$ -
30	Tier 3 - Cost for Field Area Network	$ -	$ 49,064,538	$ 30,775,929	$ 79,840,467	$ 183,473,678
31	Costs to Increase the Capacity of the Network Operating Center	$ -	$ 1,975,000	$ 2,788,000	$ 4,763,000	$ 4,763,000
32						
33	Total Telecommunications Phase 1B Capital Costs	$ -	$ 51,039,538	$ 33,563,929	$ 84,603,467	$ 188,236,678
34						
35						
36	**Summary of Telecommunications Phase 1B O&M Costs**					
37						
38	Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ -	$ -	$ -	$ -	$ -
39	Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ -	$ -	$ -	$ -	$ -
40	Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ -	$ -	$ -	$ -	$ -
41	Tier 3 - Cost for Field Area Network	$ -	$ 2,163,001	$ 2,291,540	$ 4,454,541	$ 44,511,729
42	Costs to Increase the Capacity of the Network Operating Center	$ -	$ -	$ 250,000	$ 250,000	$ 250,000
43						
44	Total Telecommunications Phase 1B O&M Costs	$ -	$ 2,163,001	$ 2,541,540	$ 4,704,541	$ 44,761,729
45						
46	Total Telecommunications Phase 1B Costs	$ -	$ 53,202,539	$ 36,105,470	$ 89,308,008	$ 232,998,407
47						

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	<u>Summary of Telecommunications Capital Costs</u>					
2						
3	Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ -	$ -	$ -	$ -	$ -
4	Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ 5,500,000	$ 3,712,500	$ 4,875,000	$ 14,087,500	$ 19,806,996
5	Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ 900,000	$ 9,440,102	$ 26,987,290	$ 37,327,391	$ 235,747,831
6	Tier 3 - Cost for Field Area Network - (Not Approved in 2018)	$ -	$ 49,064,538	$ 30,775,929	$ 79,840,467	$ 183,473,678
7	Costs to Increase the Capacity of the Network Operating Center	$ -	$ 2,975,000	$ 3,400,000	$ 6,375,000	$ 14,169,496
8						
9	**Total Telecommunications Capital Costs**	$ 6,400,000	$ 65,192,140	$ 66,038,219	$ 137,630,359	$ 453,198,002
10						
11						
12	<u>Summary of Telecommunications O&M Costs</u>					
13						
14	Site by Site Telecom Design and Strategy Development, RFP Creation, and Vendor(s) Selection	$ 1,200,000	$ -	$ -	$ 1,200,000	$ 1,200,000
15	Tier 1 Network Deployment - Costs to convert from SONET to MPLS and Microwave Upgrade	$ -	$ -	$ -	$ -	$ 3,110,586
16	Tier 1 and Tier 2 Sites - Costs for Fiber and Microwave Deployment	$ -	$ 101,250	$ 315,541	$ 416,791	$ 20,753,181
17	Tier 3 - Cost for Field Area Network - (Not Approved in 2018)	$ -	$ 2,163,001	$ 2,291,540	$ 4,454,541	$ 44,511,729
18	Costs to Increase the Capacity of the Network Operating Center	$ -	$ -	$ 250,000	$ 250,000	$ 4,790,086
19						
20	**Total Telecommunications O&M Costs**	$ 1,200,000	$ 2,264,251	$ 2,857,081	$ 6,321,332	$ 74,365,581
21						

Key Inputs	
Asset Life	32 yrs
Required Sites for Conversion from SONET to MPLS	108
Number of Microwave Sites to Offices/Substations	55
Miles of Fiber to Offices/Substations	619
Required Base Stations for Private LTE Solution	70
Required Base Stations for 700 MHz Solution	60
Existing DA Devices Requiring new FAN CPE	3,737
New DA devices requiring FAN CPE	1,200

Dominion Energy
Tier 3 FAN RFP - Evaluation
Requirements Matrix

ID	Requirement Description
REQ 1	All FAN components shall have the ability to support complex passwords. These passwords must comply with the following: • At least 8 characters long, including support for special characters. Describe the solution's password strength standards / complexity requirements, enforcement capability, and history.
REQ 2	All FAN components should have the ability to change the Administrator or Root password
REQ 3	All FAN components should have the ability to change the password for all users
REQ 4	All RF links will need to be encrypted using AES-256 encryption, or better
REQ 5	FAN will need to support mutual authentication schemes which may include certificates from a standards based Certificate Authority, a pre-shared key, or MAC address authentication. Describe the authentication protocols supported by the FAN devices.
REQ 6	FAN will support the protocol for creation of secure tunnels between devices
REQ 7	Management of the FAN devices should support role based security
REQ 8	The FAN must support the logical separation of different data streams.
REQ 9	Supplier must document baseline security configuration for devices
REQ 10	System must have automated *identification of configuration deviation from baseline*
REQ 11	Supplier must implement baseline security configuration for devices
REQ 12	System must have automated enforcement of the security configuration
REQ 13	FAN must provide centralized device management and network transport that supports industry standard (NIST 800-131) encryption
REQ 14	FAN must support multi-factor authentication for administrative console access to centrally managed infrastructure
REQ 15	FAN must support multi-factor authentication for individual device access
REQ 16	Devices must require authentication and authorization for configuration access
REQ 17	Devices must support the least privilege model (e.g., read-only, read/write)
REQ 18	Device administration communications must be isolated from data communications (out of band management)
REQ 19	In-band management access to the device is secured using FIPS 140-2 approved encryption or hash algorithms such as AES, 3DES, SSH, or TLS / SSL[2] Describe how you protect in band traffic.
REQ 20	System must have capability to increase situational awareness to identify and potentially alert upon anomalous behavior, including IDS / IPS capabilities, or capability to allow implementation of other security solutions which provide such capabilities
REQ 21	Devices must support unique identification for Network Access Control
REQ 22	Devices using certificates or keys must support centrally managed key rotation
REQ 23	System must *support native PKI and DE provided PKI capabilities*
REQ 24	Traffic on the system must remain flowing when visibility to PKI servers is lost
REQ 25	Devices must not use obsolete or insecure protocols, including but not limited to telnet, SNMP v1, ftp, http, RIP v1, and RIP v2
REQ 26	Devices must support firmware validation. Please provide further explanation
REQ 27	Devices support port and protocol restrictions (local firewall)
REQ 28	Devices must support NTP for time synchronization
REQ 29	Device must support the use of encrypted keys to authenticate time stamps provided by a time server.
REQ 30	Devices must support tamper detection notification
REQ 31	Devices must generate all security events to local logs
REQ 32	Devices must support security log and event forwarding in near real-time
REQ 33	FAN communications must be baselined to understand normal traffic patterns. Provide description of communication protocols, ports, and expected communication flows.
REQ 34	Routing protocols used for management or for carrying services must have the ability to encrypt protocol peering handshakes
REQ 35	FAN devices must be able to provision security policies to protect/mitigate CPU resources from potential security risks like DoS and broadcast storm[2]
REQ 36	System must have capability to recover from cybersecurity events, including centralized backup, recovery capabilities, system backups, and device replacemen[2]
REQ 37	System must have capability to enhance response activities, including forensic investigation of cybersecurity events
REQ 38	System must have the capability to harden the system and devices to minimize exposure and reduce the capability for malicious threat actors to compromise systems
REQ 39	FAN devices must be able to implement security protections for management ports or service ports, including the capability of disabling unused ports
REQ 40	FAN vendor must submit to Dominion a list of all built-in accounts, including undocumented backdoor accounts, and provide a procedure to change these account names and passwords
REQ 41	All RF connectors shall have a standard type (e.g., Type C, Type N, or SMA). Please state which ones.
REQ 42	All FAN components must allow for remote retrieval of communication event log. Please state for how long event logs locally stored.
REQ 43	FAN components shall be hardened to operate in a noisy electrical environment. Vendor shall provide their certifications for Electromagnetic Compatibility (e.g. IEEE 1613 class 2, ANSI C12.20, IEC 61000-4-[2]
REQ 44	FAN components shall have a failure rate of less than *0.3% per annum over the required operating life of the system (15 years) and less than 1.00% per annum during the extended operating life of the system (years 16-20)*
REQ 45	The FAN must support industry accepted modulation techniques such as, but not limited to, OFDM, QAM, PSK, FHS[2]
REQ 46	Field radios shall support a polling interval with a minimum of 1 second. Are there any limitations to your equipment from a polling interval perspective?
REQ 47	RF communications must be compliant with FCC Rules. Please list all type-acceptance and the FCC ID.

Company Exhibit No. ___
Witness: BRC
Schedule 2
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REQ 48	What is the maximum data rate for each modulation rate at the peak of your solution?
REQ 49	What are the aggregate committed and peak throughput of your base stations? Please provide information on a per frequency/channel size and per modulation basis.
REQ 50	What are the aggregate committed and peak throughput of your base stations towards core network? Please provide information and scaling factors.
REQ 51	What are the committed and peak data rates for your CPE devices? Please provide information on a per frequency/channel size and per modulation basis.
REQ 52	The FAN shall support a maximum round trip latency time of 100 milliseconds.
REQ 53	The FAN shall support MODBUS, MODBUS/TCP, and MODBUS over TCP/IP protocols.[2]
REQ 54	The FAN shall support the DNP3 and DNP3 over TCP/IP protocols.[2]
REQ 55	The FAN must be IP based with Dual IP Stack (IPv4 and IPv6)
REQ 56	The FAN must support connection to an MPLS backhaul. Please state where your end-to-end encryption terminates (e.g., MPLS to the edge).
REQ 57	The FAN must support GOOSE messaging
REQ 58	Upon installation, equipment shall self-register on the Network.
REQ 59	The FAN devices must support, at a minimum, the following transport/routing protocols - LLDP, VRRP, BFD, NTPv4, OSPF v2/v3, ISIS, IEEE 1588v2 PTP, SyncE, Multicast (L2/L3 support), LAG/LACP, BGP, MPLS with Traffic Engineering (e.g. RSVP-TE, LDP, LSP (with ADSPEC/CSPF/FRR), SDP, etc.)[2]
REQ 60	The FAN devices must support, at a minimum, the following security/authentication protocols - SSH, HTTPS, SFTP/SCP, TACACS+, RADIUS, IPSEC, DMVPN/NGE, or other Group Encryption Framewor[2]
REQ 61	The FAN devices must support, at a minimum, the following management protocols - Syslog, SNMPv3, OAM/CFM (e.g.Y.1731[2]
REQ 62	The FAN device must support Jumbo Frames equal to or greater than 9212
REQ 63	The FAN device must support VLAN tags for Dot1Q and Q-in-Q
REQ 64	The FAN device must separate management plane from Control/Data planes. Please provide details.
REQ 65	FAN traffic should not be affected while performing port mirroring (remote and local mirroring)
REQ 66	The FAN device must support GPS capabilities to prevent any potential data service impact and provide location information of the FAN devices
REQ 67	The FAN LTE CPE device (if proposed) must have redundant Cellular SIM cards to allow the FAN CPE device to roam between LTE networks. Please provide details on switchover process and time to recover services.
REQ 68	All equipment must operate in an environment with an ambient temperature range of -40 to +70C.
REQ 69	All equipment must operate in the an environment with a relative humidity of 5 - 95%, non-condensing.
REQ 70	All FAN equipment must comply with IEC 60255-21-1 and 21-2 standards and have at least a vibration response class I and vibration endurance class 1 rating
REQ 71	Collectors and repeater (if included with solution) shall support prioritized message processing
REQ 72	FAN components shall support a DIN rail mounting option, rack mounting option, and a flat plate mounting optior[2]
REQ 73	FAN equipment must comply with IEC-61850.
REQ 74	FAN equipment must comply with IEEE-1613.
REQ 75	FAN radios deployed to support field devices shall be equipped with at least (2) RS-232 ports for serial traffic and (1) RJ-45 connection, or (1) RS-232 port and (2) RJ-45 connection of which (1) can be configured for RS-232 for Ethernet traffic.
REQ 76	FAN radios support SFP based optical transceivers
REQ 77	FAN radios shall support serial baud rates of 1200, 4800, 9600, and 19.2k; odd, even or no parity, 8 data and 1 stop bi[2]
REQ 78	Ports shall be able to be disabled at an administrator's level to prevent access to networks that are not being used at a particular facility/site.
REQ 79	Suppliers should have the ability to provide a battery backed-up power source that will supply a minimum of twelve (12) hours of power.
REQ 80	System must have the capability to generate and maintain a detailed, accurate inventory of all devices and systems, including applications, firmware versions, and hardware models.
REQ 81	FAN must have the capability to set a default configuration baseline from the console
REQ 82	All FAN components must allow for battery monitoring (e.g., battery alarm reporting on loss of AC)
REQ 83	FAN radios shall support 120v AC input voltages and 60 Hz.
REQ 84	CPE radio DC input voltages operate in the range of 7v to 36v
REQ 85	Base Station radio DC voltages should operate at a range of 10v to 52v
REQ 86	System must comply with NERC CIP 013-1, once the standard is adopted.
REQ 87	Equipment shall log firmware download and upgrade attempts, failures, successes, and reversions with timestamp
REQ 88	Equipment shall report important or critical failures following a software/firmware upgrade within 15 minutes after start-up. Ability to program what failures report immediately shall be configurable.
REQ 89	The awarded supplier will be responsible for final site and path surveys.
REQ 90	Supplier shall provide and determine from path analysis the antenna and elevation requirements required to meet a minimum o99.999% annual path availability.
REQ 91	The Supplier shall include and show all propagation profiles used to develop the path data criteria.

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REQ 92	Supplier shall provide Dominion with topology-based Wireless FAN Site Propagation prediction diagrams, per base-station site with associated field sites, included in Supplier's design, including a reliability factor (expressed as a percentage of expected availability) for each field site.
REQ 93	For the implementation of the proposed wireless FAN, Suppliers will provide their own personnel, contractors, transportation, tools, test equipment, supplies, and services necessary to implement and complete the installation of the equipment.
REQ 94	Supplier must have centralized device Management System to include configuration changes, firmware updates, configuration backups, availability detection, and security patches.
REQ 95	All traffic flow events from FAN components will need to integrate with an existing flow collector solution. Please specify which one(s) your solution integrates with.
REQ 96	All event logs from FAN components will need to integrate with an enterprise logging solution.
REQ 97	FAN components shall have the capability to be provisioned utilizing a GUI or CLI interface.
REQ 98	The FAN will honor all prioritization tags passed into the network from Dominion's core network.
REQ 99	The FAN will honor all quality of service tags passed into the network from Dominion's core network.
REQ 100	For bulk operations (e.g. software patching), Management System shall support leveling of event messages so as to minimize impacts to the system and support personnel.
REQ 101	In the event that an event message is not acknowledged (if expected), Management System shall be able to automatically retry the operation. The frequency and timing of this functionality shall be configurable, dependent on the event message type and device target.
REQ 102	Management System shall be able to detect installation of new equipment onto the communications network and shall also detect when existing equipment has been removed
REQ 103	Supplier's Management System shall support standard API for integration with other network management systems. Please list out which ones Supplier's solution supports.
REQ 104	Management System shall log all messages (event and informational) sent to and received from all FAN components with the message date/time, event/message type identifier, and source/target(s) identifier
REQ 105	Management System shall log each instance when a event message has been sent to a FAN component, but no (anticipated) receipt is received within the configured time frame.
REQ 106	Management System shall not allow for scheduling of conflicting events
REQ 107	Management System shall provide mechanisms for remotely correcting system/component problems, which at a minimum shall include the ability to remotely recycle (or restart) a component.
REQ 108	Management System shall support a cancellation capability for scheduled events
REQ 109	Management System will support multiple message prioritization schemes. The priority and limits by class, source and destination shall be configurable by Dominion. Please state which one(s).
REQ 110	Log in for the Management System must be able to be processed through a centralized user authentication system. Please describe how this works for your proposed solution.
REQ 111	Management System must support TACACS or RADIUS for authentication, authorization, and accounting (AAA[2]
REQ 112	Management System should support role based access control
REQ 113	Management System should allow for mapping of roles to specific custom-defined groups
REQ 114	The management system should have the ability to centrally push Global policies (e.g. security, user management, QoS, OAM/Y.1731, services, etc[2]
REQ 115	The management system must have GEO redundant architecture

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Vendors	Written Response Weighted Pct	Technical Response Weighted Score	Weighted Technical Score	Technical Rank	Weighted Cost Score	Pricing Rank	Technical + Pricing Score	Final Rank	Down-Selected for Orals
Narrowband PtMP (Vendor A)	80.6	80.7	72.6	2	100.0	1	75.4	1	[redacted]
Narrowband PtMP (Vendor B)	78.8	81.2	72.5	3	80.0	2	73.2	2	[redacted]
Private LTE (Vendor C)	62.9	93.5	76.5	1	0.0	6	68.9	3	[redacted]
Unlicensed Mesh (Vendor D)	59.4	87.2	71.5	4	40.0	4	68.4	4	✖
Unlicensed Mesh (Vendor E)	55.3	73.4	61.5	6	60.0	3	61.4	5	✖
Private LTE (Vendor F)	57.1	75.6	63.4	5	20.0	5	59.1	6	✖

Supplier Proposal	Weight
Written Response	25%
Technical Response	65%
Security	25%
FAN	20%
Equipment	20%
Path and Site Survey	15%
Network Mgmt & Monitoring	20%
Pricing	10%

part II

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Bransky

<u>WITNESS DIRECT TESTIMONY SUMMARY</u>

<u>Witness</u>: Jonathan S. Bransky

<u>Title</u>: Director – Threat Intelligence

<u>Summary</u>:

Company Witness Jonathan S. Bransky explains the cyber security protections that Dominion Energy Virginia plans to deploy as part of the GT Plan in 2020 and 2021 ("Phase IB") and discusses the cyber and physical security projects approved by the Commission's Final Order in Case No. PUR-2018-00100 ("Phase IA").

Mr. Bransky first testifies that the Company interprets the Final Order as giving approval for the Phase IA Security Projects in the amount of approximately $8.7 million (excluding finance costs). The Company plans to implement physical security controls at 10 substations along with all associated cybersecurity and telecommunications controls approved in Phase IA. He notes that the Company is not requesting approval for any additional physical security projects as part of Phase IB.

Next, Mr. Bransky explains that the planned Cyber Investments for Phase IB include those necessary to protect the proposed Phase IB GT Plan projects. These investments include:

- Firewalls;
- Security Information Event and Management integration to facilitate a common operating picture through security event aggregation and correlation;
- Application whitelisting, malware protection, and operational technology environments monitoring solutions to enhance situational awareness;
- Privilege access management for remote access and use of privilege accounts;
- Network access control to detect and prevent unauthorized devices on the network; and
- Field device inventory, configuration management, remote access, and patch and vulnerability management.

The Company will also evaluate cloud security posture management tools to secure cloud related deployments if the Company determines the use of cloud tools is required to protect these service provider-hosted solutions. He notes that deployment and implementation of the Phase IB Cyber Investments will align with other proposed Phase IB GT Plan project timelines, as the Cyber Investments will have to secure those new assets and technologies.

Finally, Mr. Bransky details the identified need for the proposed GT Plan security investments, provides detailed cost estimates, explains the benefits associated the security investments, and the alternatives considered by the Company.

DIRECT TESTIMONY
OF
JONATHAN S. BRANSKY
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, position with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), and business address.

A. My name is Jonathan Bransky, and I am the Director – Threat Intelligence at Dominion Energy Services. My business address is 600 East Canal Street, Richmond Virginia 23219. A statement of my background and qualifications is included as Appendix A.

Q. Please describe your area of responsibility with the Company.

A. I am one of the three senior leaders in the Security organization reporting to the Vice President and Chief Security Officer. In my current role, I lead the teams responsible for the development and distribution of security threat intelligence for physical and cyber security for Dominion Energy. I am also responsible for the Company's Insider Threat program. In addition, I am a strategic security advisor to Dominion Energy Virginia's cyber and physical substation security programs. I work closely with federal and state agencies, national laboratories, industry associations, peer utilities in both natural gas and electricity sectors, and the Intelligence Community to inform decision-makers on matters related to the Company's overall security posture.

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

A. The purpose of my testimony is to explain the cyber security protections ("Cyber Investments") that Dominion Energy Virginia plans to deploy as part of its proposal to transform its electric distribution grid (the "Grid Transformation Plan," "GT Plan," or "Plan") in 2020 and 2021 ("Phase IB"). Additionally, I discuss the cyber and physical security projects ("Security Projects") approved by the State Corporation Commission of Virginia (the "Commission") in Case No. PUR-2018-00100 ("Phase IA") through its Final Order dated January 17, 2019 ("2018 Final Order").

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes, Company Exhibit No. ___, JSB, consisting of Schedule 1, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules:

Schedule	Description
1	Cost Schedule

Additionally, I sponsor Filing Schedule Bransky, Attachments A through B, which are vendor pricing and scoping materials from which detailed pricing estimates were prepared. The table below provides a description of these filing schedules:

Filing Schedule Bransky	Description
Confidential Attachment A	Physical Security Cost Support
Confidential Attachment B	Cyber Security Cost Support

I also sponsor certain sections of Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document. Finally, I also sponsor the metrics related to the reporting of cyber and physical security threats in Company Witness Edward H. Baine's Schedule 2.

Q. Did you provide information to West Monroe Partners, LLC ("West Monroe") for use in the cost-benefit analysis ("CBA")?

A. Yes, I provided costs and additional inputs for Physical and Cyber Security Projects to West Monroe for use in the CBA. I also support the benefits reflected in Thomas G. Hulsebosch's Schedule 2, as identified therein.

The specific costs I support in Phase IA and Phase IB are:

Nominal $, in Millions	**2019**	**2020**	**2021**	
	Year 1	**Year 2**	**Year 3**	**3-year Total**
Phase IA	**$0.9**	**$3.6**	**$4.2**	**$8.7**
Capital	$0.9	$3.5	$4.0	**$8.4**
O&M	$0.0	$0.1	$0.2	**$0.3**
Phase IB	**$0.0**	**$3.8**	**$2.7**	**$6.5**
Capital	$0.0	$2.8	$1.4	**$4.2**
O&M	$0.0	$0.9	$1.3	**$2.3**

My Schedule 1 provides detailed cost information for the GT Plan components that I sponsor.

Q. How is your testimony organized?

A. My direct testimony is organized into two sections:

I. Security Projects approved by the Commission in Phase IA

II. Cyber Investments proposed by the Company in Phase IB

Q. Before you begin, do the Phase IB Cyber Investments meet the definition of an electric *distribution grid transformation project* under Va. Code § 56-576?

A. Yes. The Phase IB Cyber investments will be in support of the other Grid Modernization Projects that fall under the definition of an "electric distribution grid transformation project."

I. SECURITY PROJECTS APPROVED BY THE COMMISSION IN PHASE IA

Q. What Security Projects were approved by the Commission in Phase IA of the GT Plan through the 2018 Final Order?

A. As detailed in the 2018 Final Order, the Commission approved the Company's investments for the Phase IA Security Projects. The Company interprets the 2018 Final Order as giving approval for the Phase IA Security Projects in the amount of approximately $8.7 million (excluding finance costs) as detailed in my Schedule 1. The Company plans to implement physical security controls at 10 substations along with all associated cybersecurity and telecommunications controls approved in Phase IA.

Q. To date, has the Company made investments into the Phase IA Security Projects?

A. While no physical security construction work has been completed, Dominion Energy Virginia has begun implementation of the Phase IA Security Projects' plan. To date, the Corporate Security team has completed threat and vulnerability assessments on a designated list of critical substations. The Corporate Security team provided these assessments to the Engineering team who will conduct their own assessment and develop a scope of work for the identified substations. The Company is not requesting approval for any additional physical security projects as part of Phase IB.

Q. What Security Projects were not approved in Phase IA of the GT Plan through the 2018 Final Order?

A. The only Security Projects not approved by the Commission were those related exclusively to projects or programs not approved in the 2018 Final Order, such as AMI, intelligent grid devices, and automated control systems.

II. CYBER INVESTMENTS PROPOSED BY THE COMPANY IN PHASE IB

Q. What investments does the Company anticipate making in Cyber Investments for Phase IB of the GT Plan?

A. Planned Cyber Investments for Phase IB include those necessary to protect the proposed Phase IB GT Plan projects. These investments include:

- Firewalls;
- Security Information Event and Management integration to facilitate a common operating picture through security event aggregation and correlation;
- Application whitelisting, malware protection, and operational technology environments monitoring solutions to enhance situational awareness;
- Privilege access management for remote access and use of privilege accounts;
- Network access control to detect and prevent unauthorized devices on the network; and
- Field device inventory, configuration management, remote access, and patch and vulnerability management.

The Company will also evaluate cloud security posture management tools to secure cloud related deployments if the Company determines the use of cloud tools is required to protect these service provider-hosted solutions. Because cloud-hosted solutions are a shared accountability model between the Company and the Cloud Provider, there are aspects of the cyber security administered, managed, maintained, and operated by the

Cloud Provider as well as cloud security settings chosen by the Company. Cloud security posture management tools are used to proactively and reactively discover and continuously assess the risk and trust level of the configuration and security settings for cloud services (such as account privileges and encryption). This toolset allows the Company to ensure security posture in the cloud deployment aligns with Company expectations, identify and remedy any changes, and assist in providing a root cause analysis of how the identified change came into being.

Q. Does the Company plan to utilize the same cyber security processes and technologies used in Phase IA of the GT Plan for Phase IB?

A. Yes. The majority of the proposed Phase IB Cyber Investments are extensions or separate rollouts of existing Dominion Energy Virginia cyber security solutions. However, the Company will evaluate additional cyber security solutions, as needed, to close any security gaps unique to Phase IB Cyber Investment deployments, including field device access control, monitoring, and configuration management.

Q. Please explain the process and proposed timeline for deployment of the Phase IB Cyber Investments.

A. Deployment and implementation of the Phase IB Cyber Investments will align with other proposed Phase IB GT Plan project timelines, as the Cyber Investments will have to secure those new assets and technologies.

Q. On page 12 of the Commission's June 27, 2019 Final Order in Case No. PUR-2018-00065, the Company's 2018 Integrated Resource Plan ("IRP") proceeding, it ordered the Company in future IRPs to "systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects. For identified grid transformation projects, the Company shall include: (a) a detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) detailed cost estimates of each proposed investment; (c) the benefits associated with each proposed investment; and (d) alternatives considered for each proposed investment." Although this is not an IRP proceeding, can you address these requirements as they relate to Phase IB Cyber Investments?

A. Yes, I address those requirements below. The detailed description of the existing distribution system is included in the Plan Document.

<u>Need & Alternatives</u>

Q. Why are these Phase IB Cyber Investments needed?

A. The Company takes its responsibilities to provide critical and cost-effective service to its customers very seriously and recognizes its role in the country's national security, in part because Virginia is home to 27 military bases. Dominion Energy Virginia and a few dozen other energy companies are designated "Section 9" companies under Presidential Executive Order 13636, Improving Critical Infrastructure Cyber Security on February 12, 2013. As a Section 9 company, Dominion Energy Virginia has a responsibility "to identify critical infrastructure where a cybersecurity incident could reasonably result in catastrophic regional or national effects on public health or safety, economic security, or national security."[1]

As documented in reports by the US Department of Homeland Security ("DHS") Industrial Control Systems Cyber Emergency Response Team ("ICS-CERT"), the energy sector experienced more cyber incidents than any sector from 2013 to 2015, accounting for 35% of the 796 incidents reported by critical infrastructure sectors. In fiscal year 2016, ICS-CERT completed work on 290 incidents, 63 of which stemmed from the critical manufacturing sector, 62 from the communications sector, and 59 from the energy sector.[2] Insight into the magnitude and sophistication of possible cyber-attacks in the electricity sector can be gleaned from the 2015 and 2016 cyber security attacks on the Ukrainian grid which resulted in widespread power outages and represented the first ever known malware framework designed and developed to attack electric grids. Similar insight into the magnitude of possible physical attacks on the electric grid can be gained from the April 2013 attack on Pacific Gas and Electric's ("PG&E") Metcalf transmission substation, which resulted in the loss of over 52,000 gallons of oil and damaged 17 transformers. It cost PG&E approximately $15 million and took 27 days to bring the breached substation back online.

In an attempt to prevent these types of cyber and physical security attacks, the DHS and the Federal Bureau of Investigation continually issue technical alerts on advanced persistent threat ("APT") actions targeting government entities and organizations in the energy, nuclear, water, aviation, and critical manufacturing sectors. DHS assesses this

[1] *See* https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/executive-order-improving-critical-infrastructure-cybersecurity.
[2] *See* https://www.us-cert.gov/sites/default/files/Annual_Reports/Year_in_Review_FY2016_IR_Pie_ Chart_ S508C.pdf.

APT activity as a multi-stage intrusion campaign by threat actors targeting low security and small networks to gain access and move laterally to networks of major, high value asset owners within the energy sector. Based on malware analysis and observed indicators of compromise, DHS has confidence that this campaign is still ongoing, and threat actors are actively pursuing their ultimate objectives over a long-term campaign. For example, DHS issued an alert (TA18047A) on March 15, 2018, regarding "Russian Government Cyber Activity Targeting Energy and other Critical Infrastructure Sectors," which detailed a "multi-stage intrusion campaign by Russian government cyber actors who targeted small commercial facilities' networks where they staged malware, conducted spear phishing, and gained remote access into energy sector networks. After obtaining access, the Russian government cyber actors conducted network reconnaissance, moved laterally, and collected information pertaining to Industrial Control Systems."[3]

Dominion Energy Virginia is susceptible to the same type of cyber and physical threats described above. In 2017 and 2018, the Company blocked on average 85% of the 58 million emails sent to the Company each quarter. In fact, the Company blocks, on a quarterly basis, around 4,300 advanced email attacks, where employees are targeted hoping to capture legitimate user credentials ("phishing"), and internet applications used by the Company's customers (*i.e.*, dominionenergy.com) are targeted over 720,000 times every three months. In the past two and a half years, the Company has experienced over 230 physical security events, including theft of materials and supplies from substations,

[3] *See* https://www.us-cert.gov/ncas/alerts/TA18-074A (parenthetical omitted).

sites, and offices, suspicious incidents, threats, vandalism, and trespassing.

Q. How did the Company determine which solutions or technology to deploy for the Phase IB Cyber Investments?

A. As noted above, the proposed Cyber Investments are extensions or separate rollouts of existing Company cybersecurity solutions. These existing Company standards have already been vetted and tested for security and reliability by the Company outside of the GT Plan. The Company leverages independent market research, evaluates vendor requests for proposals ("RFP") and requests for information ("RFI"), and conducts proof of concepts to validate new cybersecurity technology solutions before deployment.

The Phase IB Cyber Investments efforts have been planned according to the functional requirements and schedule of other proposed Phase IB GT Plan projects. For example, based on the substation, remote terminal unit, and sensor counts in Company Witness Robert S. Wright, Jr.'s direct testimony, I estimated the cost to provide cyber security to protect these devices and locations. The Company assessed the security posture of the proposed Phase IB GT Plan solutions and will deploy applicable cyber security solutions to mitigate any identified risks. For cyber security controls necessary to protect the proposed Phase IB GT Plan solutions, the Company will use, where possible, the same make and model or version of software and hardware currently used by the Company in its information technology/operational technology infrastructure. This will allow the Company to rely on proven and understood technologies, configuration and change management processes, and procedures and existing licensing arrangements. In addition, the Company will use an average 5-year refresh cycle to re-evaluate and re-design the Cyber Investments in future years to adapt to new technology and protections.

Throughout the timeframe of the GT Plan, the Company will continuously assess emerging threats and adjust the system design and security solutions being deployed as necessary to mitigate risks against the continuously changing threat landscape.

Costs

Q. What is the Company's projected investment schedule for Phase IB of the Cyber Investments?

A. My Schedule 1 provides details regarding the capital and O&M costs associated with cyber security in Phase IB.

Q. What processes did the Company follow to ensure that the proposed costs for the Phase IB Cyber Investments are reasonable?

A. As explained above, most of the proposed Cyber Investments are extensions or separate rollouts of existing Company cybersecurity solutions. My Filing Schedule Attachment B provides additional support for the pricing associated with the selected security measures.

Benefits

Q. Have the benefits associated with the Phase IB Cyber Investments been included in the CBA?

A. No. It is impossible to quantify benefits from a physical and cyber security perspective because the Cyber Investments allow the Company to detect, mitigate and prevent potential threats to reduce the likelihood of a successful cyber-attack associated with the proposed projects in the GT Plan; actions that simply cannot be assigned a numerical value. The qualitative benefits, however, include minimization in the disruption of services to customers, reduction in loss of critical information including customer personally identifiable information, and continued assurance of reliable and safe operation and service.

Q. **Does this conclude your pre-filed direct testimony?**

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS
OF
JONATHAN S. BRANSKY

Jonathan Bransky is a 1990 graduate of Cornell University's College of Engineering, with a Bachelor of Science degree in Operations Research and Industrial Engineering. He received a Master of Science degree in Operations Research from The George Washington University in 1997. He has maintained a Computer Information System Security Professional (CISSP) certification since 2006.

Mr. Bransky joined Dominion Energy in the fall of 2018 as a Senior Enterprise Security Advisor and is currently the Director - Threat Intelligence. He leads teams responsible for the development and distribution of physical and cyber security threat intelligence to Dominion Energy business leaders and the operational security teams as well as the company's Insider Threat program. In addition, he continues to be a strategic security advisor to Dominion Energy's cyber and physical substation security programs, working closely with federal and state agencies, national laboratories, industry associations, the Intelligence Community, and peer utilities in both natural gas and electricity sectors to inform decision makers on matters related to the Company's overall security posture.

Prior to joining Dominion Energy, Mr. Bransky spent over 20 years at Public Service Enterprise Group (PSEG) developing, leading and overseeing its cybersecurity program. Over those 20 years, he held numerous leadership positions in its Information Technology department including Director - Chief Information Security Office, Director - IT Engineering and Security, and IT Security Manager. He was a Senior Network Analyst at NetReference, Inc. where he developed network architectures for Fortune 500 companies and supported network vendors in positioning and marketing their technical solutions. He also worked for almost seven years as a consultant for Ernst & Young LLP where he delivered network and technology architectures to large enterprises in the utility, pharmaceutical, healthcare, manufacturing, financial, and government sectors.

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Cyber & Physical Security Phase 1A Capital Costs**					
2	Cyber Security					
3	Firewalls - Hardware, Refresh, & Maintenance	$ -	$ 20,983	$ 23,394	$ 44,377	$ 276,215
4	Future Security Controls for Field Devices	$ -	$ -	$ 480,000	$ 480,000	$ 1,480,000
5	Physical Security					
6	Hardware Costs	$ 870,000	$ 3,480,000	$ 3,530,000	$ 7,880,000	$ 50,660,000
7						
8	Total Cyber & Physical Security Phase 1A Capital Costs	$ 870,000	$ 3,500,983	$ 4,033,394	$ 8,404,377	$ 52,416,215
9						
10						
11	**Summary of Cyber & Physical Security Phase 1A O&M Costs**					
12	Cyber Security					
13	Security Log & Event Aggregation	$ -	$ 7,681	$ 15,698	$ 23,379	$ 381,758
14	Firewalls - Software Maintenance	$ -	$ 1,069	$ 2,186	$ 3,255	$ 53,152
15	Physical Security					
16	Hardware Maintenance	$ 20,000	$ 90,000	$ 160,000	$ 270,000	$ 5,210,000
17						
18	Total Cyber & Physical Security Phase 1A O&M Costs	$ 20,000	$ 98,750	$ 177,884	$ 296,634	$ 5,644,910
19						
20	Total Cyber & Physical Security Phase 1A Costs	$ 890,000	$ 3,599,733	$ 4,211,278	$ 8,701,011	$ 58,061,125
21						
22						
23	**Summary of Cyber Security Phase 1B Capital Costs**					
24						
25	Network Management Labor	$ -	$ 1,132,037	$ 1,167,951	$ 2,299,989	$ 11,471,745
26	Network Communications, Traffic Control, and Visibility - Hardware & Deployment	$ -	$ 358,164	$ 125,491	$ 483,656	$ 2,219,051
27	Network Access Control - Hardware Deployment & Refresh	$ -	$ 76,749	$ 78,432	$ 155,182	$ 1,077,719
28	Security Log & Event Aggregation - Hardware	$ -	$ 1,157,671	$ -	$ 1,157,671	$ 2,471,452
29	Firewalls - Future Phases - Hardware, Deployment & Maintenance	$ -	$ 123,478	$ 28,727	$ 152,205	$ 1,941,448
30						
31	Total Cyber Security Phase 1B Capital Costs	$ -	$ 2,848,100	$ 1,400,602	$ 4,248,703	$ 19,181,415
32						
33						
34	**Summary of Cyber Security Phase 1B O&M Costs**					
35						
36	Network Management Labor	$ -	$ -	$ -	$ -	$ -
37	Operating System Hardening & Patch Management	$ -	$ 16,087	$ 16,816	$ 32,903	$ 217,230
38	Non-Field Device Endpoint & Server Controls	$ -	$ 26,850	$ 41,383	$ 68,233	$ 778,898
39	Network Communications, Traffic Control, and Visibility - Software	$ -	$ 319,789	$ 326,801	$ 646,590	$ 4,490,496
40	Privilege & Credential Management	$ -	$ 191,555	$ 216,534	$ 408,089	$ 2,366,594
41	Network Access Control - Software & Maintenance	$ -	$ 430	$ 868	$ 1,298	$ 20,085
42	Network Access Control -Hardware Maintenance	$ -	$ 15,350	$ 31,373	$ 46,723	$ 762,942
43	Field-Level Device Controls	$ -	$ 335,494	$ 486,407	$ 821,902	$ 19,457,546
44	Security Log & Event Aggregation - Software & Deployment	$ -	$ 29,929	$ 206,970	$ 236,899	$ 3,189,977
45	Cloud Security Posture Management/Assessment (CSPM)	$ -	$ 3,045	$ 4,752	$ 7,797	$ 69,314
46	Firewalls - Future Phases - Software Maintenance	$ -	$ 924	$ 1,810	$ 2,734	$ 342,043
47						
48	Total Cyber Security Phase 1B O&M Costs	$ -	$ 939,454	$ 1,333,714	$ 2,273,167	$ 31,695,125
49						
50	Total Cyber Security Phase 1B Costs	$ -	$ 3,787,554	$ 2,734,316	$ 6,521,870	$ 50,876,540
51						

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Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Cyber & Physical Security Capital Costs**					
2	Cyber Security					
3	Network Management Labor	$ -	$ 1,132,037	$ 1,167,951	$ 2,299,989	$ 11,471,745
4	Network Communications, Traffic Control, and Visibility - Hardware & Deployment	$ -	$ 358,164	$ 125,491	$ 483,656	$ 2,219,051
5	Network Access Control - Hardware Deployment & Refresh	$ -	$ 76,749	$ 78,432	$ 155,182	$ 1,077,719
6	Security Log & Event Aggregation - Hardware	$ -	$ 1,157,671	$ -	$ 1,157,671	$ 2,471,452
7	Firewalls - Future Phases - Hardware Deployment & Refresh	$ -	$ 123,478	$ 28,727	$ 152,205	$ 1,941,448
8	Future Security Controls for Field Devices	$ -	$ -	$ 480,000	$ 480,000	$ 1,480,000
9	*Firewalls - Phase 1A Approved - Hardware Deployment & Refresh*	$ -	$ 20,983	$ 23,394	$ 44,377	$ 276,215
10						
11	Physical Security					
12	Hardware Costs	$ 870,000	$ 3,480,000	$ 3,530,000	$ 7,880,000	$ 50,660,000
13						
14	Total Cyber & Physical Security Capital Costs	$ 870,000	$ 6,349,084	$ 5,433,996	$ 12,653,080	$ 71,597,630
15						
16						
17	**Summary of Cyber & Physical Security O&M Costs**					
18	Cyber Security					
19	Network Management Labor	$ -	$ -	$ -	$ -	$ -
20	Operating System Hardening & Patch Management	$ -	$ 16,087	$ 16,816	$ 32,903	$ 217,230
21	Non-Field Device Endpoint & Server Controls	$ -	$ 26,850	$ 41,383	$ 68,233	$ 778,898
22	Network Communications, Traffic Control, and Visibility - Software	$ -	$ 319,789	$ 326,801	$ 646,590	$ 4,490,496
23	Privilege & Credential Management	$ -	$ 191,555	$ 216,534	$ 408,089	$ 2,366,594
24	Network Access Control - Software & Maintenance	$ -	$ 430	$ 868	$ 1,298	$ 20,085
25	Network Access Control -Hardware Maintenance	$ -	$ 15,350	$ 31,373	$ 46,723	$ 762,942
26	Field-Level Device Controls	$ -	$ 335,494	$ 486,407	$ 821,902	$ 19,457,546
27	Security Log & Event Aggregation - Software & Deployment	$ -	$ 29,929	$ 206,970	$ 236,899	$ 3,189,977
28	Cloud Security Posture Management/Assessment (CSPM)	$ -	$ 3,045	$ 4,752	$ 7,797	$ 69,314
29	Firewalls - Future Phases - Software Maintenance	$ -	$ 924	$ 1,810	$ 2,734	$ 342,043
30	Security Log & Event Aggregation - Phase 1A Approved	$ -	$ 7,681	$ 15,698	$ 23,379	$ 381,758
31	*Firewalls - Phase 1A Approved - Software Maintenance*	$ -	$ 1,069	$ 2,186	$ 3,255	$ 53,152
32						
33	Physical Security					
34	Hardware Maintenance	$ 20,000	$ 90,000	$ 160,000	$ 270,000	$ 5,210,000
35						
36	Total Cyber & Physical Security O&M Costs	$ 20,000	$ 1,038,204	$ 1,511,598	$ 2,569,801	$ 37,340,035
37						

Key Inputs	
Asset life	5 yrs
Number of Devices Secured	5,372
Critical Substations Secured	213
Substation Secured	454
Software License Cost per Endpoint	$40
Software License Cost per Server	$100
Cost per Substation Hardware Upgrade	$15,000
Cost per Substation Upgrade - Deployment	$15,000
Head-End Software Deployment (cost per deployment)	$150,000
Cost per Splunk Server (Hardware)	$450,000
Cost per Splunk Server (Deployment)	$527,444
Substations to Secure	45

part 12

19950008

Morgan

WITNESS DIRECT TESTIMONY SUMMARY

Witness: Gregory J. Morgan

Title: General Manager – Regulatory Affairs

Summary:

Company Witness Gregory J. Morgan provides a rate perspective on the Company's proposal to transform its electric distribution grid (the "GT Plan" or "Plan") by calculating the estimated revenue requirements for Phase IA and IB GT Plan investments and addressing the proposed rate treatment of certain GT Plan components. However, as Mr. Morgan explains, the Company is not required to provide information related to cost recovery as part of its GT Plan prudence filing, but the Company understands that such calculations could provide additional, relevant information to the Commission regarding the "all-in" costs of Phase I of the Plan. Therefore, these calculations are high-level estimates based on the preliminary costs of the Plan, but still do not contain the level of precision or detail contained in similar calculations typically provided with the Company's RAC or other rate proceedings.

Mr. Morgan also discusses the Company's plans for introducing a new time-varying rate as a corollary to the GT Plan. The Company anticipates proposing a new time-varying rate later this fall. As described by Mr. Morgan, this rate will be experimental, voluntary, and will initially be limited in the number of customers that can participate as AMI and the CIP are being deployed. The rate will be designed to be revenue neutral with residential Rate Schedule 1. Upon Commission approval, this rate would be applicable to residential customers where AMI has been installed.

DIRECT TESTIMONY
OF
GREGORY J. MORGAN
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, business address, and position of employment with Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company").

A. My name is Gregory J. Morgan, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am General Manager of Regulatory Affairs for the Company. A statement of my background and qualifications is attached as Appendix A.

Q. What are your responsibilities as General Manager of Regulatory Affairs?

A. I lead the team that is responsible for the Company's electric rate-related activities, including the preparation and support of rate filings with the State Corporation Commission of Virginia (the "Commission") and the implementation of rates. I also have responsibility for regulatory accounting, customer load research, cost allocation, and cost of service studies as required in supporting our rate activities. Additionally, I am responsible for the development and administration of contracts with non-jurisdictional or special contract customers, and for responding to customer requests concerning rates.

Q. Mr. Morgan, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide a rate perspective on the Company's proposal to transform its electric distribution grid (the "Grid Transformation Plan," "GT Plan," or "Plan"). Specifically, I will address the proposed rate treatment of certain GT Plan components. I will also discuss the Company's plans for introducing a new time-varying rate as a corollary to the GT Plan, and will address the specific directives from the Commission in its Final Order dated January 17, 2019, in Case No. PUR-2018-00100 (the "2018 Final Order") related to the Plan for such rates.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, GJM, consisting of Schedules 1 through 3, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Schedule	Description
1	Time-Varying Rates Cost Schedule
2	Estimated Annual Revenue Requirement Summary
3	Rates per Kilowatt Hour – Residential Class

I also sponsor certain sections of the Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document.

Q. Did you provide information to West Monroe Partners, LLC ("West Monroe") for use in the cost-benefit analysis ("CBA")?

A. Yes, I provided costs and additional inputs for the time-varying rates to West Monroe for use in the CBA. I also support the benefits reflected in Thomas G. Hulsebosch's Schedule 2, as identified therein.

Please note, there are no costs associated with time-varying rates within Phase IB because, as discussed herein, a new time-varying rate would be a corollary to the GT Plan rather than an investment that is included within the planned Phases. However, because this component was modeled in the CBA, my Schedule 1 provides detailed cost information for this investment.

Finally, I provided West Monroe with revenue requirement calculations for use in the CBA so that it could be presented on a revenue requirement basis. Differences between the costs used to calculate the revenue requirement that I sponsor and the CBA revenue requirement are discussed in detail in my testimony.

Q. Mr. Morgan, how is your testimony organized?

A. My testimony is organized as follows:

I. Recovery of GT Plan Investments

II. Time-Varying Rate

I. RECOVERY OF GT PLAN INVESTMENTS

Q. Is the Company required to provide information related to cost recovery as part of a GT Plan prudence filing?

A. No. The language of the relevant statute, Va. Code § 56-585.1 A 6, states that the nature of cost recovery should not be considered in evaluating the prudence of grid transformation plan proceedings:

> Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d.

Furthermore, without determining the method of cost recovery, the direct impact on customer rates cannot yet be calculated. That is, recovery of incremental costs through a new rate adjustment clause ("RAC") could directly increase customer rates, whereas recovery of incremental costs through the Company's existing rates for generation and distribution services ("base rates") or as a customer credit reinvestment offset ("CCRO") under Va. Code § 56-585.1 A 8 d may not.

Q. The statutory language notwithstanding, has the Company determined how it plans to seek recovery for the costs of the GT Plan if approved?

A. The Company has committed that the costs of the Plan associated with the deployment of advanced metering infrastructure ("AMI") and the new customer information platform ("CIP") for Phase IB will not be the subject of a RAC petition. Instead, these costs will be recovered through the Company's base rates and could be, in whole or in part, the subject of a future CCRO. As to other phases and components of the Plan, the Company has not yet determined its plans for cost recovery.

Q. Has the Company calculated an estimated revenue requirement for the GT Plan investments?

A. Yes, the Company has calculated an estimated revenue requirement for Phase IA and Phase IB of the GT Plan for the components that could be the subject of a future RAC petition (*i.e.*, excluding Phase IB AMI and CIP costs). In the 2018 Final Order, the Commission approved proposed Phase I investments related to cyber and physical security, including supporting telecommunications infrastructure, as reasonable and prudent. The Company refers to these approved portions of Phase I investments as "Phase IA." In this proceeding, the Company is requesting approval for projects during the years 2019, 2020, and 2021, that were not previously approved by the Commission. The Company will refer to these portions of Phase I investments under review as "Phase

IB." Phase IB includes the following components: (1) AMI; (2) CIP; (3) grid improvements; (4) telecommunications infrastructure; (5) cyber security; (6) the Smart Charging Infrastructure Pilot Program. While not a separate component of the GT Plan, customer education is envisioned for every Plan component.

Q. Why has the Company decided to include these estimated revenue requirements in this proceeding?

A. While acknowledging the language in Va. Code § 56-585.1 A 6 noted earlier in my testimony, the Company understands that such calculations could provide additional, relevant information to the Commission regarding the "all-in" costs of Phase I of the GT Plan, when taken in the proper context. In other words, these calculations are high-level estimates based on the preliminary costs of the Plan, but still do not contain the level of precision or detail contained in similar calculations typically provided with the Company's RAC or other rate proceedings. Therefore, these estimated revenue requirements may not necessarily be representative of the final actual costs or actual revenue requirements of the Plan.

Q. What are the key components of the estimated revenue requirements?

A. The estimated revenue requirements are based on the estimated costs of the Plan. In general, these estimated costs consist of capital expenditures, operations and maintenance expenses ("O&M") and the related financing costs of the components of the Plan for the applicable recovery period. Although the Company is only requesting approval for Phase IB in this proceeding, my Schedule 2 includes estimated revenue requirements for Phases IA and IB.

Q. Please summarize the results of the estimated revenue requirement calculations.

A. Schedule 2, page 1 of my testimony was calculated using the following inputs and presents the following results of the annual estimated revenue requirements for Phase IA and IB of the GT Plan:

(millions)	Phase IA	Phase IB
Capital Spend (2019-2021)	$ 61.4	$ 232.8
O&M Spend (2019-2021)	2.1	50.2
Annual Revenue Requirement (2021)	6.4	50.4

Using cost information provided by the Company's witnesses in this proceeding, I developed the estimated revenue requirements by projecting the following elements for each component of the GT Plan on an annual basis:

- Depreciation expense over the useful lives of the underlying assets;
- O&M expense over the program period; and
- Debt and equity financing costs on average rate base, net of accumulated deferred income taxes ("ADIT").

Q. What impact would the estimated revenue requirements have on a typical residential customer's bill using 1,000 kilowatt-hour ("kWh") per month?

A. The estimated revenue requirements shown above encompass all components of Phase I of the GT Plan. However, as discussed, the Company has committed that Phase IB costs of AMI and the CIP will not be the subject of a RAC petition.

Therefore, in evaluating rate impact, the Company focused only on those investments that *could* be subject to a RAC in the future. Based on 1,000 kWh usage per month, the implementation of these Phase IA and Phase IB estimated annual revenue requirements in the year 2021 would increase the typical residential customer's monthly bill by $0.12 and $1.03, respectively. The year 2021 was used to calculate the customer impact of the estimated revenue requirements for Phases IA and IB as the Company expects its rate base to be at the maximum level, for each of these phases, during this period. Page 1 of my Schedule 3 provides a workpaper showing the calculation of this estimated rate impact.

Q. If the Company were to prepare a revenue requirement for these projects in the future, as might be required in a future rate proceeding, what are some variables that could significantly affect the calculation as compared to the estimated revenue requirements shown in this proceeding?

A. It is important to note that these estimated revenue requirements are hypothetical estimations and do not necessarily represent what the revenue requirement impacts would be if the Company includes these investments as part of its cost of service for recovery through its base rates, designates any or all of these of investments as a CCRO, or seeks recovery of these costs through a RAC.

If the Company were preparing a revenue requirement as part of a specific future filing, some significant differences compared to the estimated revenue requirements contained in this proceeding would include:

- *Nature of cost recovery* – Recovery of costs through a RAC, for example, would generally result in higher financing costs over the assets useful lives as compared to the accelerated recovery of investments designated as a CCRO. The estimated revenue requirements in this proceeding assume lifetime recovery (similar to a RAC) rather than any accelerated recovery.

- *Updated cost of capital* – Future revenue requirement calculations would be based on future capital structure and costs of debt and equity financing, which will likely differ from those used in the calculations of this proceeding.
- *Updated project costs* – Other refinements would arise for final projects costs, in-service dates, and depreciable lives. Furthermore, additional cash working capital items could also be captured.

Q. Are the costs and resulting estimated revenue requirements presented in your testimony in this proceeding consistent with those modeled in the CBA presented by Company Witness Hulsebosch?

A. Yes, the capital and O&M costs used in the calculation of the estimated revenue requirements presented in my testimony are consistent with those used to prepare the CBA presented by Company Witness Hulsebosch. However, there are some cost categories associated with time-varying rates and other programs presented in the CBA that are not reflected in my estimated revenue requirements, because the Company does not plan to seek recovery of these costs through the GT Plan. These excluded cost categories include time-varying rates, peak time rebate, prepay and the Single-Family Residential charging program (Managed Charging) component of the Electric Vehicle program.

The Company expects to address recovery of these excluded costs categories in appropriate future filings with the Commission.

Q. Are the potential benefits associated with the implementation of the GT Plan included in the estimated revenue requirements presented in this proceeding?

A. The estimated revenue requirements presented in this proceeding do not directly incorporate the financial impact of potential benefits to cost of service; however, the Company does expect to experience a reduction in certain components of cost of service as a result of the implementation of the GT Plan. The potential quantitative benefits of the GT Plan are discussed in more detail by Company Witness Hulsebosch.

II. TIME-VARYING RATE

Q. Will the Company be proposing a new time-varying rate?

A. Yes. To address the specific directive from the Commission in its 2018 Final Order, the Company anticipates proposing a new time-varying rate later this fall upon conclusion of the stakeholder process initiated pursuant to HB 2547 passed by the 2019 General Assembly. Currently, the Company anticipates proposing a new residential time-varying rate, which will include a basic customer charge and energy charges, differentiated by season and by time periods within each season. This rate will be experimental, voluntary, and will initially be limited in the number of customers that can participate as AMI and the CIP are being deployed. The rate will be designed to be revenue neutral with residential Rate Schedule 1. Upon Commission approval, this rate would be applicable to residential customers where AMI has been installed.

Q. What are the benefits of time-varying rates?

A. Time-varying rates can provide more accurate price signals to customers that are better aligned with cost causation than standard rates not based on time of use. Through better price signals, such rate structures can incent behavioral changes that may cause customers taking service under such rates ("participants") to reduce usage during peak periods and enable the system to avoid incurring higher variable operating expenses, such as fuel, and also avoid future capacity costs. These behavioral changes can benefit participants directly through bill savings and can also benefit participants and non-participants through the reduction of system costs. Another benefit is that time-varying rates can serve to reduce subsidies inherent in standard rates with pricing that does not vary with time of usage.

Q. **The 2018 Final Order requested information on whether any time-varying rate offerings associated with AMI "would be the default tariff for a customer with an installed smart meter." Please comment.**

A. The Company does not intend to propose the time-varying rate as the default tariff for customers with an installed smart meter. In fact, the Company cannot change the default tariff for customers until the conclusion of the first triennial rate review proceeding.

As discussed earlier, the Company will be proposing the time-varying rate as an experimental, voluntary rate with a limit in the number of customers that can participate. The limitation on the number of customers able to participate is based on the limitations of the Company to manage the rate with its existing systems as discussed in the pre-filed direct testimony of Company Witness Thomas J. Arruda.

Q. In the 2018 Final Order, the Commission stated that "[e]vidence from other states demonstrates that purely 'opt-in' tariffs result in extremely low participation rates." Do you have any comments?

A. The Company does not disagree. However, with regard to the new tariff that the Company is planning to propose later this fall, the Company is planning for such tariff to be voluntary or opt-in, at first. The Company believes it will not be appropriate to require residential customers to take service or even be required to "opt out" of taking service under a new tariff that is time-varying and involves time of use pricing at this time for the following reasons.

First, such pricing will be a change compared to the standard residential tariff, Rate Schedule 1, that currently serves approximately 2.2 million customers. The Company believes that an action to change the standard residential tariff from Rate Schedule 1 to a time-varying rate would be appropriately considered in a future triennial review and, although I am not a lawyer, I understand from a legal perspective is required to be considered in a base rate proceeding.

Second, considerable education will need to be provided to customers before the Company would change the default tariff. The Company intends to develop this education and utilize it during the time period that the experimental tariff is in effect. The Company will learn about the success of such efforts and will want to make any refinements that may be required in the education process prior to any Commission order that may require residential customers to take service under such a tariff.

Company Exhibit No. __
Witness: GJM
Schedule 1
Page 1 of 1

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Time-Varying Rates Capital Costs**					
2						
3	Implementation Costs	$ -	$ 514,562	$ -	$ 514,562	$ 514,562
4						
5	Total Time-Varying Rates Capital Costs	$ -	$ 514,562	$ -	$ 514,562	$ 514,562
6						
7						
8	**Summary of Time-Varying Rates O&M Costs**					
9						
10	Program Management	$ -	$ 411,650	$ 424,710	$ 836,360	$ 4,171,544
11	Maintenance and Support	$ -	$ 102,912	$ 106,177	$ 209,090	$ 1,042,886
12	Marketing and Communications	$ -	$ 154,369	$ 159,266	$ 313,635	$ 1,564,329
13	Ongoing Customer Marketing	$ -	$ 1,023	$ 3,137	$ 4,161	$ 336,402
14	Acquisition of new customers	$ -	$ -	$ -	$ -	$ 1,424,971
15	Processing of new customers	$ -	$ 494	$ 1,019	$ 1,513	$ 77,232
16						
17	Total Time-Varying Rates O&M Costs	$ -	$ 670,448	$ 694,310	$ 1,364,758	$ 8,617,363
18						

Key Inputs	
Asset life	15 yrs
Experimental Rate Customer Enrollment	5,000
Experimental Rate Deployment	Year 2

190959008

Company Exhibit No.__
Witness: GJM
Schedule 2
Page 1 of 1

Virginia Electric and Power Company
Grid Transformation Plan
Estimated Annual Revenue Requirement Summary
(millions)

Phase IA (Year 2021)

Program	Depreciation Expense	O&M Expenses	Financing Costs	Total Revenue Requirement
Telecommunications Infrastructure	$ 2.0	$ 0.4	$ 3.0	$ 5.5
Cyber and Physcial Security	0.2	0.2	0.5	0.9
Total Annual Revenue Requirement	$ 2.2	$ 0.6	$ 3.6	$ 6.4

Phase IB (Year 2021)

Program	Depreciation Expense	O&M Expenses	Financing Costs	Total Revenue Requirement
Grid Improvements	$ 4.5	$ 10.2	$ 8.1	$ 22.8
Telecommunications Infrastructure	3.8	2.8	5.6	12.2
Cyber Security	0.7	1.3	0.2	2.3
Electric Vehicles	0.2	10.9	0.2	11.4
Customer Education	-	1.8	-	1.8
Total Annual Revenue Requirement	$ 9.3	$ 26.9	$ 14.2	$ 50.4

Company Exhibit No. ___
Witness: GJM
Schedule 3
Page 1 of 1

VIRGINIA ELECTRIC AND POWER COMPANY
GRID TRANSFORMATION PLAN RATE IMPACT - PHASE 1A AND PHASE 1B
RATES PER KWH - RESIDENTIAL CLASS

	(1)	(2)	(3)	(4)	(5)	(6)
PHASE	TOTAL SYSTEM REVENUE REQUIREMENT	VIRGINIA JURISDICTION REVENUE REQUIREMENT	RESIDENTIAL REVENUE REQUIREMENT	12 MONTHS ENDED 12/31/2021 NET FORECASTED KWH FOR RESIDENTIAL CLASS	RATE IMPACT PER KWH RESIDENTIAL CLASS (3) / (4)	RATE IMPACT PER 1,000 KWH RESIDENTIAL BILL
Phase 1A	$6,428,706	$5,648,622	$3,565,433	29,779,794,093	$0.00012	$0.12
Phase 1B	$50,371,101	$45,395,105	$30,664,093	29,779,794,093	$0.00103	$1.03