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September 30, 2019

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Mr. Joel H. Peck, Clerk
State Corporation Commission
Document Control Center
Tyler Building, First Floor
1300 East Main Street
Richmond, Virginia 23219

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 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service
Case No. PUR-2019-00154

Dear Mr. Peck:

Please find enclosed for filing, an unbound original and one (1) copy of Virginia Electric and Power Company's **PUBLIC VERSION** of its Petition, Direct Testimony, Exhibits, and Schedules in the above-captioned proceeding (consisting of Public Volumes 1-3). An extraordinarily sensitive and confidential version is also being filed under seal under separate cover.

Please do not hesitate to call if you have any questions in regard to the enclosed.

Very truly yours,

Vishwa B. Link

Vishwa B. Link

Enclosures

cc: William H. Chambliss, Esq.
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Dominion Energy®

September 30, 2019

Joel H. Peck, Clerk
Virginia State Corporation Commission
C/o Document Control Center
1300 East Main Street
Richmond, VA 23219

RE: Case No. PUR-2019-00154

Dear Mr. Peck:

Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") is pleased to submit to the Virginia State Corporation Commission ("Commission") its second petition for approval of its Grid Transformation Plan (the "GT Plan" or the "Plan"). On July 24, 2018, the Company filed its initial petition for approval of the first three years ("Phase I") of its 10-year Plan intended to transform its electric distribution grid to meet the evolving needs and expectations of its customers. On January 17, 2019, the Commission issued its Final Order approving proposed Phase I investments related to cyber and physical security, including supporting telecommunications infrastructure, as reasonable and prudent ("2018 Final Order"). The Company will refer to these portions of the GT Plan approved in the 2018 Final Order as "Phase IA." In today's filing, the Company is requesting approval of the next phase of the GT 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 through 2021.

With the passage of the Grid Transformation and Security Act ("GTSA"), enacted by the Virginia General Assembly in 2018, the Commonwealth deemed electric distribution grid transformation to be in the public interest, and mandated that utilities file a plan for grid transformation. This provision of the GTSA represents an important policy declaration by the Commonwealth that transformational change in the electric distribution system is needed to respond to fundamental changes in the electric utility industry and changing customer expectations. 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. Specifically, Executive Order 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. In addition, the plan required by EO 43 sets lead-by-example targets for the Commonwealth agencies to meet these clean energy goals and to support the existing statewide goal of reducing retail electricity consumption by ten percent by 2022. Moreover, EO 43 calls for integration of energy storage technologies to support the clean energy goals and recognizes that the goals should be achieved in a manner that maximizes the economic and

[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.

environmental benefits to underserved communities while mitigating any impacts to those communities. 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 for reaching the objectives and timelines established by EO 43.

The Need for Grid Transformation

For many decades, electricity has been a basic need, vital to every institution in our society. The digitalization of 21st century society, technological shifts to electrify entire sectors of society such as transportation and demands for enhanced resiliency and reliability require the electric industry to turn its focus to the electric distribution grid. Originally engineered for one-way power flows, our current grid was not designed to accommodate the ever-increasing two-way flow of power resulting from the proliferation of distributed energy resources ("DERs"), such as solar distributed generation and battery storage. Randomly dispersed, DERs are independent nodes that can disrupt traditional grid power quality and reliability. But when paired with investments to increase visibility on and control of the distribution system, DERs can transform into a system resource that can be managed to maximize the value of other available resources, and potentially offset the need for future "traditional" generating assets or grid upgrades and maintain reliable service to customers.

As utilities across the country have recognized, these foundational shifts in technology and our society prompt the need to transform the electric grid. With this paradigm shift, we need to address the current and future needs of the grid to meet the needs of our customers, incorporate new technology, and continue to strengthen security. The Petition and GT Plan presented today detail proposed investments to implement the first three years of the Company's Plan to do so.

The 2019 Phase IB GT Plan Incorporates Commission Guidance, Statutory Objectives, and Stakeholder Vision and Goals

The Commission recognized in 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 it 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" and "a level of benefits commensurate with the projected costs." The Commission's 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.[2]

The Company carefully examined the Commission's 2018 Final Order to ensure that today's Phase IB filing fully addresses the guidance provided therein. The Company's specific actions in response include:

- Ensure proposed investments are aligned with statutory objectives of grid transformation as well as the desire to enhance the customer experience;
- Issuance of multiple requests for proposals ("RFPs") across components to strengthen the accuracy and reasonableness of the costs estimates for proposed investments;

[2] *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 of the Code of Virginia*, PUR-2018-00100, Final Order at 14-15 (January 17, 2019).

- Significant work on the preparation of project scopes and design for segments of the distribution grid on which improvement projects are proposed;
- Development of a detailed cost-benefit analysis conducted by an independent, experienced, third-party partner, West Monroe Partners; and,
- Solicitation of extensive customer feedback through customer surveys and a series of stakeholder meetings to ensure alignment with the perspective of our customers and interested stakeholders.

Beyond responding to Commission guidance and the GTSA's statutory objectives, the proposed investments in the Phase IB filing also seek to meet goals identified through collaborative conversations that occurred during the above-referenced stakeholder sessions. The following four goals were identified during these sessions: Optionality, Sustainability, Resiliency, and Affordability.

In summary, the Company sought to address, in a meaningful manner, all feedback received to date from the Commission, its Staff, customers and interested stakeholders in this Phase IB filing.

The Value of a Transformed Distribution Grid to Customers

Fundamental investments to transform the distribution grid will allow the Company to use the distribution system differently than it does today, all for the benefit of customers. Transformational investments in Advanced Metering Infrastructure ("AMI" or "smart meters"), a customer information platform ("CIP"), intelligent grid devices, automated control systems, and advanced analytics will enable the Company to fine tune operations, better forecast load, predict future behaviors. These investments will also all allow the Company to provide customers access to detailed energy usage data through convenient communication channels and empower customers to manage their energy usage through offerings such as time varying rates and innovative demand-side management ("DSM") programs that these investments will enable the Company to broadly offer. With transformational investments proposed in the GT Plan, customers will experience fewer outages and will not need to report outages. Instead, when outages occur on the more connected and resilient grid, they will be reported through smart meters and other intelligent grid devices that will prompt the dynamic system to automatically restore power to as many customers as possible, narrowing the scope of the outage and focusing employee effort on issues that require manual intervention.

Components of the GT Plan

Specifically, Phase IB of the GT Plan represents focuses on 6 components, many of which are foundational to a transformed grid: (i) AMI, (ii) CIP, (iii) grid improvements which include grid technologies and grid hardening, (iv) telecommunications infrastructure, (v) cyber security, and (vi) the Smart Charging Infrastructure Pilot Program.

- **AMI**

The Company plans to full deploy AMI over a six-year period beginning in 2019 through Phase IB. During this time, a total of approximately 2.1 million meters and 3,100 network devices will be deployed in a structured manner across the Virginia service territory. With the plan for full deployment, the Company proposes a revenue-neutral opt-out policy for residential customers including a one-time fee and ongoing monthly fees intended only to recover the costs of a customer opting out of smart meter installation.

- **CIP**

The Company proposes to implement a new CIP in Phase IB over five years that consists of the Core Project, which replaces twelve (12) existing applications, and three projects focused on providing additional customer functionality. The proposed CIP is needed to replace antiquated systems with a platform that will provide the foundation for an enhanced customer experience and desired grid capabilities. Without the foundational investment in the CIP, the value of the transformed grid will not be widely accessible to customers in a manner that is user-friendly (e.g., web self-service, smartphone apps, proactive communications).

- **Grid Improvements**

The Company proposes grid improvement projects in Phase IB of the GT Plan and describes future projects in the resulting years of the GT Plan. Proposed projects fall into two categories: (i) grid technologies and (ii) grid hardening. The grid improvement projects are needed to adapt to fundamental changes in the energy industry discussed above, facilitating the integration of DER and enhancing system operations and service to customers through automation and predictive analytics. The grid hardening projects are needed to improve reliability and resiliency by physically strengthening infrastructure. We also plan to upgrade assets that have high customer impact, address voltage islands, and implement several new vegetation management programs.

- **Telecommunications and Security**

Dominion Energy Virginia proposes to deploy a comprehensive telecommunications and security strategy requiring multiple components specifically designed as an integrated solution to meet the wide-ranging needs of a transformed distribution grid. The Company is deploying telecommunications, cyber and physical security as approved by the Commission in Phase IA, and propose telecommunications and cyber investments in Phase IB.

- **Smart Charging Infrastructure Pilot Program**

Through the Smart Charging Infrastructure Pilot Program, the Company proposes to offer rebates for the electrical infrastructure and upgrades at EV charging sites and rebates for the smart charging equipment that enables managed charging. The Company plans to offer a set number of rebates to four different segments: multi-family, workplace, direct current fast charging ("DCFC"), and transit. The Company is also proposing to own a limited number of DCFC stations to study and support electrification in the rideshare segment.

Costs and Benefits of the GT Plan

Through the Petition filed today, the Company is seeking prudency review of Phase IB of the Plan, covering investments for the period 2019-2021. The Company projects the proposed total capital investment for the three-year period covering Phase IB to be $510.5 million and the proposed operations and maintenance expenses to be approximately $83 million. The Company has committed that the costs of the Plan associated with the deployment of AMI and the new CIP will be recovered through the Company's base rates.

The cost-benefit analysis ("CBA") shows the proposed investments are beneficial to customers and represents a positive business case 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. Indeed, as supported by the West Monroe Partners testimony, this benefit estimate may be conservative and also shows additional benefits like reduced greenhouse gas emissions, savings to EV owners and economic benefits to the Commonwealth. Through the CBA, this translates to more than $1 of customer savings for every dollar spent.

The Promise for a True Transformation

As noted above, the Commission recognized in its 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."[3] Dominion Energy Virginia's Plan filed today represents a detailed and comprehensive plan, informed by competitively bid and procured third-party cost estimates and input from our stakeholders, and supported by a positive business case that delivers on that promise.

The Company respectfully requests the Commission find the programs and costs included in Phase IB to be both reasonable and prudent.

Sincerely,

Robert M. Blue /FH

Robert M. Blue

[3] *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 of the Code of Virginia*, PUR-2018-00100, Final Order at 15 (January 17, 2019)

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 1 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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<u>VOLUME 3 of 3 (PUBLIC)</u>

Nathan J. Frost Filing Schedule

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Attachment C – RFP Summary for Workplace Charging (Extraordinarily Sensitive Information Redacted)

Thomas J. Arruda Filing Schedule

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Attachment B – RFP Summary SI (Extraordinarily Sensitive Information Redacted)
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Attachment A – Locks Campus Microgrid Project Design Report (Confidential Information Redacted)
Attachment B – Locks Campus Microgrid Project Costs (Extraordinarily Sensitive Information Redacted)
Attachment C – Equipment, Labor & Materials Contracts (Confidential Information Redacted)
Attachment D – Hosting Capacity Scope of Work (Confidential Information Redacted)
Attachment E – DERMS RFI Summary (Extraordinarily Sensitive Information Redacted)
Attachment F – Advanced Analytics RFP Summary (Extraordinarily Sensitive Information Redacted)
Attachment G – Voltage Optimization Costs (Confidential Information Redacted)
Attachment H – EAMS RFI Summary (Extraordinarily Sensitive Information Redacted)
Attachment I – Ash Tree Survey Report (Confidential Information Redacted)
Attachment J – Targeted Corridor Improvement Contracts (Confidential Information Redacted)
Attachment K – Voltage Island Mitigation Costs (Confidential Information Redacted)

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Jonathan S. Bransky Filing Schedule

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CONFIDENTIAL AND EXTRAORDINARILY SENSITIVE FILING
VOLUME 1 of 5 (PUBLIC)

Petition

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VOLUME 3 of 5 (CONFIDENTIAL AND EXTRAORDINARILY SENSITIVE FILING)

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VOLUME 4 of 5 (CONFIDENTIAL AND EXTRAORDINARILY SENSITIVE FILING)

Robert S. Wright, Jr. Filing Schedule (cont.)

Attachment C – Equipment, Labor & Materials Contracts (Confidential Information)

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Attachment B – Cyber Security Cost Support (Confidential Information Redacted)

Petition

19094028 3

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

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 of the Code of Virginia, and for approval of an addition to the terms and condition applicable to electric service	))))))))	Case No. PUR-2019-00154

PETITION OF VIRGINIA ELECTRIC AND POWER COMPANY

Pursuant to § 56-585.1 A 6 ("Subsection A 6") of the Code of Virginia ("Va. Code") and Rule 80 A of the Rules of Practice and Procedure of the State Corporation Commission of Virginia (the "Commission"), 5 VAC 5-20-80 A, Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), by counsel, hereby files its petition for approval of a plan for electric distribution grid transformation projects (the "Petition"). Specifically, Dominion Energy Virginia asks for approval of three years of its ten-year plan to transform its electric distribution grid (the "Grid Transformation Plan," the "GT Plan," or the "Plan"). Dominion Energy Virginia also seeks approval of an addition to its terms and conditions applicable to electric service ("Terms and Conditions") related to the proposed deployment of advanced metering infrastructure ("AMI").

The Company further requests a waiver of the Commission's Rules Governing Utility Promotional Allowances (the "Promotional Allowance Rules") related to the proposed rebates to provide incentives for smart charging infrastructure for electric vehicles pursuant to Promotional Allowance Rule 50, 20 VAC 5-303-50.

In support of this Petition, the Company respectfully states as follows:

I. General Information

1. Dominion Energy Virginia is a public service corporation organized under the

laws of the Commonwealth of Virginia furnishing electric service to the public within its certificated service territory. The Company also supplies electric service to non-jurisdictional customers in Virginia and to the public in portions of North Carolina. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation. The Company is a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. The Company is an operating subsidiary of Dominion Energy, Inc. ("Dominion Energy").

2. The Company's name and post office address are:

Virginia Electric and Power Company
120 Tredegar Street
Richmond, Virginia 23219

3. The names, addresses, and telephone numbers of the Company's attorneys are:

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II. Legal Authority

4. Subsection A 6, as amended by the Grid Transformation and Security Act of 2018 (the "GTSA"), requires the Company to petition the Commission for approval of a plan for electric grid transformation projects:

> A utility shall, without regard for whether it has petitioned for any rate adjustment clause pursuant to clause (vi), petition the Commission, not more than once annually, for approval of a plan for electric distribution grid transformation projects. Any plan for electric distribution grid transformation projects shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security.

5. Va. Code § 56-576 defines an "electric distribution grid transformation project" as follows:

> "Electric distribution grid transformation project" means a project associated with electric distribution infrastructure, including related data analytics equipment, that is 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, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information.

6. Subsection A 6 sets forth the standard for Commission review of a plan for electric distribution grid transformation projects:

> In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. 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.

7. In accordance with Subsection A 6, the Commission must issue its final order on a petition for approval of an electric distribution grid transformation plan not more than six months after the date of filing the petition.

III. The Grid Transformation Plan

8. Fundamental changes in the energy industry have prompted the need for utilities across the country to modernize their distribution grids. There is a paradigm shift that is creating a new set of current and future needs that must be addressed. The Grid Transformation Plan is Dominion Energy Virginia's comprehensive plan to address these needs and meet the goals and objectives for grid transformation in a reasonable, prudent, and cost-effective manner. The Company presents the executive summary of Dominion Energy Virginia's Grid Transformation Plan (the "Plan Document") as Exhibit 1 to this Petition. The Plan Document explains the need for a modern distribution grid and includes a detailed description of the Company's existing distribution system. The Plan Document then reviews the Company's distribution planning process, and explains how that process will evolve going forward to meet the fundamental changes in the industry. With this context, the Plan Document then presents an overview of the Grid Transformation Plan, including the process that led to the development of this revised plan.

Finally, the Plan Document includes a look at future technologies and a quick-reference glossary of terms used in the Plan Document itself and throughout this filing.

9. Phase IB of the Grid Transformation Plan includes six components: (i) AMI; (ii) customer information platform ("CIP"); (iii) grid improvement projects, both grid technologies and grid hardening projects; (iv) telecommunications infrastructure; (v) cyber security; and (vi) the Smart Charging Infrastructure Pilot Program. Section VI.A of the Plan Document describes these six components[1] and describes the Company's plan for customer education, with Appendix A to the Plan Document providing the Company witnesses sponsoring sections of the Plan Document.

10. The Company focuses on the first three years of the GT Plan—the years 2019, 2020, and 2021 ("Phase I" of the GT Plan). The Commission has approved proposed Phase I investments related to cyber and physical security, including supporting telecommunications infrastructure, as reasonable and prudent.[2] The Company refers to these approved portions of Phase I investments as "Phase IA." In this proceeding, the Company is requesting approval for a revised set of 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

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[1] *See In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2018-00065, Final Order (Jun. 27, 2019) (directing the Company to provide specific details for identified electric distribution grid transformation projects, including "(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 integrated resource plan proceeding, individual Company witnesses address these requirements as they relate to individual Plan components.

[2] *See 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 of the Code of Virginia*, Case No. PUR-2018-00100, Final Order (Jan. 17, 2019).

review as "Phase IB." Phase IB of the GT Plan includes both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security as required by Va. Code § 56-585.1 A 6. The total proposed investment associated with Phase IB of the GT Plan is $517.6 million in capital investment and $83.2 million in operations and maintenance investments.

11. The Company retained an independent, experienced, third-party partner, West Monroe Partners ("West Monroe"), to generate a cost-benefit analysis for the Grid Transformation Plan. Company Witness Thomas G. Hulsebosch of West Monroe presents testimony explaining that analysis and presenting the results. As summarized in Figure 7 in Section VI.E of the Plan Document, the proposed investments are beneficial to customers, with a benefit to cost ratio of 1.1 on a net present value basis.

12. Subsection A 6 requires the Commission to evaluate the Petition on "a stand-alone basis":

> 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.[3]

Nevertheless, for informational purposes only, the Company presents an estimated revenue requirement for Phase I of the GT Plan of the components that could be subject to a rate adjustment clause, as summarized in Figure 6 in Section VI.D of the Plan Document and supported by Company Witness Gregory J. Morgan. The Company also presents an estimated

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[3] Va. Code § 56-585.1 A 6.

rate impact.

IV. Addition to Terms and Conditions

13. A foundational component of the Grid Transformation Plan is the full deployment of AMI across the Company's service territory. As part of this deployment, the Company will seek to install a smart meter at each customers' premises. Nevertheless, the Company understands that some customers may prefer not to have a smart meter and plans to accommodate those customers where practical. Accordingly, with the plan for full deployment, the Company proposes a revenue-neutral opt-out policy for residential customers, including a one-time fee and ongoing monthly fees, intended to only recover the costs of a customer opting out of smart meter installation.

14. The Company seeks approval of an addition to its Terms and Conditions to charge the proposed opt-out fees. The proposed update to the Company's Terms and Conditions for which the Company seeks approval to implement these proposed fees is attached to the testimony of Company Witness Nathan J. Frost as Schedule 7.

V. Waiver of Promotional Allowance Rules

15. As part of Phase IB of the GT Plan, the Company proposes the Smart Charging Infrastructure Pilot Program, which aims to provide the Company with the data and tools necessary to understand and manage future electric vehicle ("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. The Pilot Program consists, in part, of (i) rebates for the infrastructure and upgrades, if necessary, at EV charging sites, and (ii) rebates for the smart charging equipment that enables managed charging.

16. Effective since 1992, the Promotional Allowance Rules "establish the conditions

under which electric and gas utilities operating in Virginia may propose to recover reasonable costs associated with promotional allowances to customers."[4] The Rules define a promotional allowance as "any payment, subsidy or allowance, directly or indirectly, or through a third party, to influence the installation, sale, purchase, or use of any appliance or equipment."[5] The Rules permit certain activities, including those "designed to achieve energy conservation, load reduction, or improved energy efficiency," subject to prior Commission approval.[6] Promotional Allowance Rule 50 allows for "exemptions from any or all of these rules."[7]

17. Arguably, the rebates proposed as part of the Smart Charging Infrastructure Pilot Program meet the criteria set forth in the Promotional Allowance Rules. Smart charging infrastructure provides the Company with the opportunity to manage the increased demand from electric vehicles in a manner that can shift this new load from times of peak demand, ultimately reducing peak load.[8] In addition, the proposed rebates serve the overall public interest by providing incentives for the electrification of transportation.[9] Indeed, by statute, projects focused on "electrical facilities and infrastructure necessary to support electric vehicle charging systems" are in the public interest.[10]

18. If deemed necessary by the Commission, the Company seeks a waiver of the Promotional Allowance Rules under Rule 50, 20 VAC 5-303-50. The Promotional Allowance

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[4] 20 VAC 5-303-10.
[5] 20 VAC 5-303-20.
[6] 20 VAC 5-303-30.
[7] 20 VAC 5-303-50.
[8] *See* 20 VAC 5-303-30(2) (permitting approved promotional allowance programs "designed to achieve . . . load reduction").
[9] *See* 20 VAC 5-303-40(1)(e) (requiring utilities to show that a promotional allowance program "serves the overall public interest").
[10] *See* Va. Code § 56-576 (including electric vehicle charging infrastructure in the definition of "electric distribution grid transformation projects"); *see also* Va. Code § 56-585.1 A 6 (declaring that "[e]lectric distribution grid transformation projects are in the public interest.").

Rules long predate the proliferation of electric vehicles, so the Rules do not contemplate the relative benefits of EVs. In addition, as discussed above, rebates for incentives for smart charging infrastructure should be found to be in the public interest. Finally, the proposed rebates will have no effect on other public utilities. For these reasons, the Company requests that the Commission grant a waiver of the Promotional Allowance Rules for the Smart Charging Infrastructure Pilot Program, if necessary.

VI. Supporting Testimony and Filing Schedules

19. In support of its Petition, the Company submits the pre-filed direct testimonies of Company Witnesses Edward H. Baine, Thomas G. Hulsebosch, Nathan J. Frost, Thomas J. Arruda, Robert S. Wright, Jr., Bradley R. Carroll, Sr., Jonathan S. Bransky, and Gregory J. Morgan.

20. The Company also submits filing schedules that support the detailed cost estimates presented in the Petition. To the extent filing schedule information is voluminous, the Company will make these documents available electronically. Specifically, the Company submits Filing Schedule Frost, Filing Schedule Arruda, Filing Schedule Wright, Filing Schedule Carroll, and Filing Schedule Bransky which include both (i) relevant contracts and (ii) summaries of requests for information and proposals issued in support of the GT Plan. Because portions of these filing schedules contain confidential and extraordinarily sensitive information, in compliance with Rule 170 of the Commission's Rules of Practice and Procedure, 5 VAC 5-20-170, this filing is accompanied by a separate Motion for Entry of a Protective Order and Additional Protective Treatment, including a Proposed Protective Order, filed contemporaneously with this Petition.

WHEREFORE, the Company respectfully requests that the Commission: (i) approve

Phase IB of the Grid Transformation Plan in its entirety as reasonable and prudent within six months of the date of this filing; (ii) approve the proposed addition to the Company's Terms and Conditions related to the smart meter opt-out fees; (iii) grant the request for waiver of the Promotional Allowance Rules related to the proposed Smart Charging Infrastructure Pilot Program, if necessary; and (iv) grant such other relief as deemed appropriate and necessary.

Respectfully submitted,

By: ______________________
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September 30, 2019

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Plan Document

Dominion Energy

Grid Transformation Plan

Table of Contents

List of Acronyms

Acronym	Meaning
AC	Alternating current
ACE	Analytics center of excellence
ADMS	Advanced distribution management system
AMI	Advanced metering infrastructure
AMR	Automated meter reading
APT	Advanced persistent threat
AWA	Agency web access
CBA	Cost-benefit analysis
C&I	Commercial and industrial
CCRO	Customer credit reinvestment offset
CI	Customer interruptions
CIP	Customer information platform
CIS	Customer information system
CMD	Connect My Data
CMI	Customer minutes of interruption
COBOL	Common business-oriented language
DAS	Data analytics system
DC	Direct current
DCFC	Direct current fast charging
DER	Distributed energy resources
DERMS	Distributed energy resource management system
DMD	Download My Data
DSM	Demand-side management
EAMS	Enterprise asset management system
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EM&V	Evaluation, measurement, and verification
EV	Electric vehicle
FAN	Field area network
FLISR	Fault location, isolation and service restoration
GIS	Geographic information system
GT Plan	Grid Transformation Plan
GTSA	Grid Transformation and Security Act of 2018
HID	High intensity discharge
ICE	Interruption Cost Estimate
IDP	Integrated distribution planning
IGDs	Intelligent grid devices
IOCs	Indicators of compromise
IT	Information technology
KPIs	Key performance indicators
kV	Kilovolt

Acronym	Meaning
LED	Light-emitting diode
MDMS	Meter data management system
MPLS	Multi-protocol label switching
NERC	North American Electric Reliability Corporation
NIC	Network interface card
NPV	Net present value
NREL	National Renewable Energy Laboratory
NWA	Non-wires alternatives
O&M	Operations and maintenance
OACS	Operations and Automated Control Systems
OMS	Outage Management System
OT	Operational technology
Phase IA	Grid transformation projects for 2019, 2020, and 2021 approved in Case No. PUR-2018-00100
Phase IB	Grid transformation projects for 2019, 2020, and 2021 proposed in this proceeding
PII	Personal-identifying information
PTR	Peak-time rebate
QoS	Quality of Service
RAC	Rate adjustment clause
RFP	Request for proposals
ROW	Right-of-way
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition
SLAs	Service level agreements
SLMS	Streetlight management system
STATCOMs	Static compensators
SUP	Strategic Undergrounding Program
TB	Terabyte
Va. Code	Code of Virginia
VEE	Validation / estimation / editing

I. Introduction

Fundamental changes in the energy industry have prompted the need for utilities across the country to modernize their distribution grids. The 2018 Virginia Energy Plan recognizes these needs and drivers:

> The energy industry is a vital economic driver that serves as the foundation for the Commonwealth's ability to grow and thrive. Homes and businesses rely upon stable, reliable, and affordable energy systems. At the same time, there are a number of market and policy shifts that are transforming the industry in ways that cannot and should not be ignored. These include technological advances that are unlocking new opportunities in both the electricity and transportation sectors, customer preferences that are driving the expansion of new business models, a shift toward a reduction in carbon emissions, and a growing focus on the reliability and resiliency of our electric system.[1]

With the passage of the Grid Transformation and Security Act of 2018 ("GTSA"), the Commonwealth declared electric distribution grid transformation to be in the public interest, and mandated that utilities file a plan for grid transformation. The GTSA required that any such plan "shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security."

Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") fully endorses the need for transformation and fully supports these policy objectives of the Commonwealth. These policy objectives align with the four goals for grid transformation identified by a group of the Company's stakeholders:

- **Optionality**: Enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access.
- **Sustainability**: Evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles.
- **Resiliency**: Build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management.
- **Affordability**: Deliver value for customers by optimizing demand and seeking to reduce system and customer costs.

This document presents the Company's plan to transform its distribution grid ("Grid Transformation Plan," "GT Plan," or "Plan").

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[1] VIRGINIA ENERGY PLAN (Oct. 2018), *available at* https://www.governor.virginia.gov/media/governorvirginiagov/secretary-of-commerce-and-trade/2018-Virginia-Energy-Plan.pdf [hereinafter VIRGINIA ENERGY PLAN].

II. Need for a Modern Distribution Grid

Electricity has become a basic need, vital to our economy, public safety and way of life. Critical services and infrastructure increasingly rely on electricity, including homeland security, large medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pump facilities. As society has grown more dependent on electricity, customers expect highly reliable service as well as easy access to their energy usage information so that they can make informed decisions about their consumption. Another fundamental change is the emerging shift within the transportation industry as it continues toward electrification of personal vehicles, fleets, and mass transit, with the Edison Electric Institute ("EEI") projecting the number of electric vehicles ("EVs") to reach approximately 18.7 million in 2030, up from approximately 1 million EVs on the road at the end of 2018. Another vital resource powered by electricity is the internet, which drives commerce and everyday life. Even a brief interruption or power quality anomaly at, for example, a data center can be catastrophic for both the data center itself and the businesses that rely on that data center. 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.

Customers agree on the importance of reliable electric service and ensuring a quick recovery when outages do occur. In a recent survey of Dominion Energy Virginia customers, customers expressed that experiencing power outages is their primary source of frustration with the Company. Similarly, a survey of social media activity shows over nine times the comment volume appearing on major outage days.

A. Context for Distribution Grid Transformation

The electric grid was originally designed for the one-way flow of electricity, with electricity moving from large, centralized generators through high-voltage transmission lines to the distribution system. On the distribution system, electricity flowed from the substation to the customer. While originally limited to cities, the electric power grid eventually reached even the most remote areas of the country as a result of the incentives provided in the Rural Electrification Act of 1936 for the installation of distribution systems in isolated rural areas of the United States.

As reliance on electricity grew, focus shifted to the transmission system as vital to reliability of the electric grid as designed (*i.e.*, the one-way flow of electricity). The Northeast Blackout of 2003 drove new standards and investments into the transmission grid. NERC became the national electric reliability organization responsible for the reliability of the transmission system, and instituted mandatory minimum standards to which transmission owners had to plan.

In the current day, focus has now shifted to distributed energy resources ("DERs"), such as solar and wind. DERs are resources connected to the distribution system, many of which are generation resources using renewable energy, such as solar photovoltaic ("PV") and wind generation. According to the Energy Information Administration ("EIA"), the nationwide growth of clean DERs from 2009 through 2017 has been approximately 23%.[2] The Company has experienced an approximately 43% DER growth rate on its system during that same timeframe, mostly in the form of solar PV.

The rise of DERs requires a fundamental change to the electric grid. With DERs, electricity is now flowing onto the distribution system from multiple points. The distribution system that was designed for the one-way flow of electricity must now accommodate the two-way flow of electricity. In addition, the intermittent nature of some of these resources resulting from weather variability creates power fluctuations not typical of traditional generation resources. Propagated in an arbitrary manner, DERs are independent nodes that can disrupt traditional grid power quality and reliability. But when paired with investments to increase visibility on and control of the distribution system, DERs can transform into a system resource that can be equitably managed to maximize the value of other available resources, and potentially offset the need for future "traditional" generating assets or grid upgrades, and maintain reliable service to customers. As the Electric Power Research Institute ("EPRI") has outlined, the distribution grid benefits DER through (i) reliability; (ii) startup power; (iii) voltage quality; (iv) efficiency; and (v) energy transaction.[3]

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. Day to day outages as well as major weather events not only cause prolonged outages for customers, but also prevent DERs from delivering electricity. The distribution system must be reliable and resilient so that it can operate for DERs like the transmission system operates for large, centralized generators.

Aside from DERs, and as the Commonwealth has recognized, "there are a number of market and policy shifts that are transforming the industry in ways that cannot and should not be ignored."[4] These shifts include "technological advances that are unlocking new opportunities in both the electricity and transportation sectors, customer preferences that are driving the expansion of new business models, a shift toward a reduction in carbon emissions, and a growing focus on the reliability and resiliency of our electric system."[5] And throughout, severe weather events continue as a reality in the mid-Atlantic, with two storms from 2016 and two storms from 2018 ranking among those most affecting customers over the past twenty years. Peer utilities have demonstrated the value of resiliency investments in response to such events, enabling timely restoration and economic recovery when damage does occur.

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[2] Edison Electric Institute, Report: ELECTRIC VEHICLE SALES FORECAST AND THE CHARGING INFRASTRUCTURE REQUIRED THROUGH 2030 (Nov. 2018), *available at* http://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20EV%20Forecast%20Report_Nov2018.pdf.

[3] American Public Power Association, THE VALUE OF THE GRID (Jul. 2018), *available at* https://www.publicpower.org/system/files/documents/Value%20of%20the%20Grid_1.pdf (citing EPRI, THE INTEGRATED GRID: REALIZING THE FULL VALUE OF CENTRAL AND DISTRIBUTED ENERGY RESOURCES (2014)).

[4] VIRGINIA ENERGY PLAN.

[5] VIRGINIA ENERGY PLAN.

These foundational shifts prompt the need to transform the distribution grid, as utilities across the country have recognized. GridWise Alliance recognized as much in the preparation of its Grid Modernization Index 2018:

> Concepts that we discussed back in 2003 as long-term goals are now a reality in many parts of the country. Customers have access to data and tools that allow them to manage their energy use and cost while supporting more effective grid operations. Power is typically restored to customers much more quickly after an outage occurs thanks to faster and more accurate data, along with [grid] equipment that automatically responds to these interruptions. Customers are increasingly choosing to install their own energy systems and connect them to the grid and grid operators are modifying their own systems to accommodate these distributed resources, creating a more flexible and resilient grid.[6]

GridWise ranked Virginia as a "beginner" in its grid modernization efforts—25th among states and the District of Columbia based upon progress in modernizing the state's electric grid—noting many "leaders," "movers," and "believers" that can inform the effort as the Commonwealth moves to transform the electric distribution grid.[7]

B. Value of a Transformed Distribution Grid to Customers

Foundational investments to transform the distribution grid will allow the Company to use the distribution system differently than it does today, all for the benefit of customers. Transformational investments in advanced metering infrastructure ("AMI"), customer information platform ("CIP"), intelligent grid devices, automated control systems, and Advanced Analytics will enable the Company to improve operations (*e.g.*, reducing truck rolls, more predictive and efficient maintenance, and increased visibility to help reduce outages and down time), better forecast load shape, and predict future behaviors (*e.g.*, identifying and fixing grid problems before an outage occurs and overall savings and cost management of DSM programs), resulting in a better, more informed customer experience. This value of a transformed distribution grid can be seen from the view of different types of customers.

Today, all customers must take specific action to report outages and then wait for the Company to deploy resources to bring the power back on. With transformational investments in AMI, CIP, intelligent grid devices, automated control systems, and resilience, customers will experience fewer outages and will not need to take action to report outages when they do occur. Instead, when outages do occur on the more connected and resilient grid, the outages reported through smart meters and other intelligent grid devices will prompt the dynamic system to

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[6] GridWise Alliance, GRID MODERNIZATION INDEX 2018: KEY INDICATORS FOR A CHANGING ELECTRIC GRID, *available at* https://www.gridwise.org/resource-downloads/GWA_18_GMI-2018_FinalReport_12_17_18.pdf [hereinafter GRID MODERNIZATION INDEX 2018].

[7] GRID MODERNIZATION INDEX 2018.

automatically restore power to as many customers as possible, narrowing the scope of the outage and focusing effort on issues that require manual intervention. Additionally, grid visibility provided by the transformed grid will allow customers to receive proactive outage and restoration alerts—and more accurate information on expected restoration times, including detailed outage maps—allowing the fewer customers that are impacted to better adapt to the situation. By targeting over 1,000 miles of mainfeeders for hardening over the full 10 years of the GT Plan, Dominion Energy Virginia's distribution system and the customers it serves will experience fewer customer interruptions and outage minutes each year, as discussed in detail in Section VI.A.3 below.

Today, most residential customers receive monthly energy usage data at a summary level through their bills. With transformational investments in AMI and the CIP, all residential customers can receive detailed interval energy usage data through convenient communication channels. The corresponding education will inform customers on how to take control of and manage their energy usage, if desired. These customers will also have the opportunity to participate in time-varying rates and innovative demand-side management ("DSM") programs that these investments will enable the Company to broadly offer. Such rate options and DSM programs can prompt behavioral changes that benefit customers through bill savings and reduced system costs.

Today, multi-family complex customers (*e.g.*, apartment complexes) have meters that limit the efficiency of the move-in / move-out process, a process that happens more frequently than for single-family homes. With transformational investments in AMI and the CIP, customers can change accounts the same day, leading to more efficient relocation, easier owner / tenant billing, and lower costs.

Today, DER net metering customers must engage in a largely manual application process, and then wait for a meter exchange. The meter exchange process alone can take up to 10 business days to schedule and complete, leading to potential interconnection delays for the customer. With transformational investments in AMI, CIP, intelligent grid devices, automated control systems, and resilience, DER customers will experience a much faster and seamless interconnection process, will no longer need a meter exchange, and will receive detailed information on how their DERs interact with the grid. Further, customers will maximize the value of their DERs through the connection with a resilient grid, and can choose to offer grid support functions for the local distribution grid as an alternative to traditional grid upgrades. In addition, transformational grid investments will enable a dynamic hosting capacity map, allowing customers, and even localities, to evaluate optimal locations to interconnect DERs. By empowering customers with the information to optimally locate DER, customers can realize reduced interconnection costs and potentially contribute to the deferral of other system investments.

Today, the majority of EV customers do not have attractive options to encourage them to charge their vehicles during times when the demand for electricity is low. With transformational investments in AMI, CIP, and smart charging infrastructure, EV customers will have access to more innovative programs and advanced rate options that could lead to bill savings and reduced system costs.

Today, business customers are subject to sudden voltage fluctuations when outage events occur on the distribution grid. Even when a customer does not experience a sustained outage, these voltage fluctuations have the potential to impact operational processes and facility production. The intermittency and changing power flows related to renewable generation introduce new dynamics to grid operation that, if not managed properly, have the potential to similarly impact these customers. Transformational investments in reliability and resiliency will eliminate certain outage events and the associated voltage fluctuations that ripple across the distribution grid, while also ensuring power is restored more quickly when it does go out. With transformational investments in AMI, intelligent grid devices, and automated control systems, the Company will have the situational awareness and control capabilities to manage grid operation so business customers can rely on voltage stability to ensure minimal disruption to their operations.

Today, vital community resources are more dependent on grid reliability than ever before. Health and safety services, such as hospitals, water, and emergency services, carry the highest priority day-to-day and in a restoration event, closely followed by commerce and education, including internet services for home and work. More and more grid availability translates to availability for DER to contribute to system resources in the form of capacity factor. With transformation investments in resilient grid architecture, customers will have confidence that their growing reliance will be served.

Dominion Energy Virginia values the experience of its customers and believes that the Grid Transformation Plan will enable the Company to meet their changing needs and expectations.

III. Existing Distribution Grid

As discussed in Section II.A, the electric grid was originally designed for one-way flow of electricity to meet customers' demand—from the generator, through the transmission system, to the distribution system and the end-use customer. In the traditional distribution system design, electricity typically flows from a substation, through mainfeeders, to tap lines and then service lines that are connected to the end-use customer.

Dominion Energy Virginia's over 2.5 million customer accounts in the Commonwealth power the business economy and serve over 5 million residents. The Company's existing distribution system in Virginia consists of more than 53,000 miles of overhead and underground cable, and over 400 substations. The distribution system utilizes a variety of devices for functions from voltage control to power flow management, and relies on multiple operating systems for various functions from customer billing to outage management. The following sections provide a detailed description of the Company's existing distribution system.

A. Substations

The primary function of a distribution substation is to transfer power from the higher voltage transmission system, which ranges from 69 kilovolt ("kV") to 230 kV on the Company's system, to the lower voltage distribution system, which typically ranges from 4 kV to 35 kV. Once this power is "stepped down," it is placed on the distribution system for delivery to the end use customer.

There are many pieces of equipment and devices that help to facilitate this transfer of power, including the following:

Substation Transformers. Equipment that handles the stepping down of higher voltages to lower voltages.

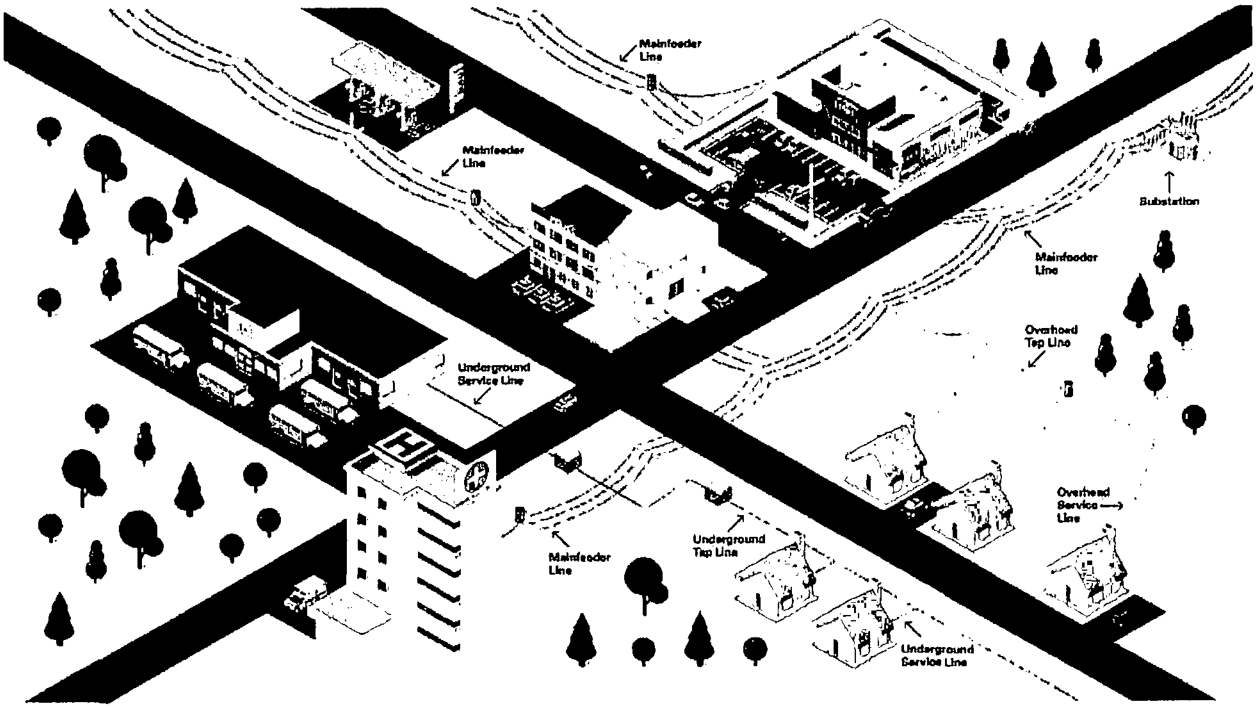
Substation circuit breakers. Devices that enable the flow of power into and out of the substation and serve to isolate faults.

Voltage regulation devices. Devices that help keep voltage within the desired bandwidth.

B. Wires

Within the distribution system, the wires—also known as conductors—transmit electricity from substations to end-use customers. A system of conductors is referred to as either a circuit or a feeder. The Company will use the term "feeder" in this document. The Company operates approximately 1,700 feeders in Virginia. There are three parts to feeders, the mainfeeders, the tap lines, and the service lines. Figure 1 provides an illustration.

Figure 1: Distribution System Illustration



1. Mainfeeders

Mainfeeders are the three-phase portion of the distribution system that carries electricity from substations to tap lines and end-use customers. Larger customers, such as certain businesses and public services, are often served directly from the mainfeeders. Mainfeeders on the Company's distribution system typically serve hundreds or thousands of customers along many miles of conductor. The Company's distribution system in its Virginia service territory has approximately 10,000 miles of overhead mainfeeders and 1,800 miles of underground mainfeeders on its approximately 1,700 feeders.

2. Tap Lines

Tap lines are the portion of the distribution system that carry electricity from the mainfeeders to neighborhoods and individual end-use customers. The Company's distribution system in its Virginia service territory includes approximately 18,000 miles of overhead tap lines and approximately 22,000 miles of underground tap lines.

Separate from, but complementary to, its plan to transform the distribution grid is the Company's Strategic Undergrounding Program ("SUP"). This program focuses on 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. In contrast, the focus of the grid transformation efforts is the *mainfeeder* portion of the distribution system.

3. Service Lines

Service lines are the low voltage portion of the distribution grid that carries electricity from service transformers to customers. For residential customers, these lines typically operate at 120/240V while commercial and industrial customers may have service lines that deliver a variety of voltages, including 120/208V, 120/240V, and 277/480V. Service lines typically connect to the service transformer on one end and the meter on the other end. In some instances, one service line can be used to serve multiple customers by connecting additional service lines to it along the route from the transformer to the meter.

C. Devices

Voltage Control Devices. Voltage control devices are used to manage grid voltage to ensure customers receive adequate voltage at the meter. The most common voltage control devices on the distribution grid are voltage regulators and capacitors. Voltage regulators monitor and adjust the voltage at the substation or along the feeder based on control programming that is loaded by Company engineers. The programming typically uses loading and specific electrical information based on the location of the equipment. Capacitors are used to manage power flow efficiency on the distribution grid. As customers use electricity, the equipment along the grid that delivers the power, such as transformers and conductors, consume additional electricity and cause electrical losses to occur, causing voltage to decrease. Capacitors are used to provide a portion of that additional electricity and reduce the losses, which in turn improves voltage.

Service Transformers. Service transformers connect to the grid and serve to lower the voltage from distribution voltages used on the mainfeeders and tap lines, typically 4 kV to 35 kV, to the service voltage used by customers. For residential customers, the most common service voltage is 120/240 volt ("V"), meaning appliances and devices using electricity can be connected to either a 120V or a 240V outlet from customers' electrical panels. Commercial and industrial service transformers deliver a variety of service voltages, including 120/208V, 120/240V, and 277/480V. The Company has approximately 540,000 service transformers in Virginia.

Protective Devices. Protection devices perform several different functions on the distribution grid, including monitoring power flows and voltages, providing switching points to reconfigure power flows, automatically disconnecting a grid segment when a problem is detected, and providing the associated communications functions to allow protection activities to occur. Electronically controlled line devices, fuses, line sensors, relays and communications gateways are examples of protection devices.

D. Meters

Dominion Energy Virginia customers primarily have one of three types of meters: automated meter reading ("AMR") meters, smart (*i.e.*, AMI) meters, or manually read meters. As of July 1, 2019, approximately 78% of Virginia customer meters are AMR meters, approximately 17% are smart meters, and approximately 5% are manually read meters.

AMR Meters. The Company began deploying AMR meters throughout the service territory over 20 years ago. Usage data from AMR meters is collected through drive-by readings. Specially equipped trucks drive throughout the service territory daily, covering approximately 450 different meter route cycles throughout each month. The Company uses meter readers to drive these routes. The equipment collects a meter reading from the AMR meters within range, which the Company then uses for monthly billing. AMR meters cannot be remotely controlled or operated, meaning that the Company must send a field representative for common requests like connecting or disconnecting service. The Company utilizes meter servicers to execute these and other requests.

Smart Meters. Smart meters are electric meters that enable two-way communications, digitally gathering energy usage data in specified increments (*i.e.*, interval data) and other related information. Smart meters are equipped with a network interface card ("NIC") and communicate with each other, creating what is referred to as a 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 back office system, also called a head-end system, receives and processes the data and serves as an operating platform for the back office team responsible for operation and maintenance. 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.

In 2008, the Company began to deploy AMI in a targeted fashion based on specific operational and customer needs. Taking a measured pace over the course of several years, the Company continued to deploy smart meters in larger quantities and densities in diverse geographical areas of the service territory to validate deployment and operational strategies. The Company used the knowledge gained from this initial deployment of AMI to develop its strategy for full deployment across the service territory. The Company currently has approximately 435,000 smart meters deployed across its service territory, primarily in the Alexandria, Herndon, and Charlottesville offices.

Manually Read Meters. As of July 1, 2019, approximately 130,000 customers have manually read meters, primarily to gather energy usage data in specified increments (*i.e.*, interval data) or monthly peak energy demand. To obtain this data, meter readers visit the customer premises and must walk up to the meter to record energy usage via an electronic "probe" approximately once per month. The meter readers that drive the AMR routes also complete these visits. The Company has deployed manually read meters to support offering time-varying rates to customers that do not have smart meters. The Company has also deployed manually read meters to provide additional information to net metering customers that do not have smart meters. Eliminating these manual meter reads with the implementation of AMI will not only provide operational benefits through reduced components of cost of service, but will also enable the Company to provide detailed energy usage data to customers and to more widely deploy time-varying rates in an efficient and cost effective manner.

E. Operating Systems

1. Customer Experience Systems

Customer Information System ("CIS"). Deployed about 23 years ago, the CIS is the 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, and rates and financial based activities. The CIS is an employee-facing system, and is also referred to internally as customer business management system ("CBMS").

CBMS 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. The vendor no longer supports the system, and service providers do not routinely hire or train COBOL programmers. The limited services that are available for CBMS come at an increasingly higher cost.

Manage Accounts. Deployed in 2003, Manage Accounts is the customer-facing web self-service platform for residential and small commercial customers.

Key Customer. Deployed in 2006, Key Customer is the customer-facing web self-service system for large customers that are assigned an account representative.

Property Manager Portal. Deployed in 2013, the Property Manager Portal is the customer-facing web self-service tool for property management companies to manage landlord agreements and turn on / turn off service for their properties.

Agency Web Access ("AWA"). Deployed in 2006, Agency Web Access is the customer-facing web self-service application for charities and third-party agencies (*e.g.*, Salvation Army) to make energy assistance payments on behalf of customers.

Meter Data Management System ("MDMS"). Deployed in 2009, the meter data management system is the employee-facing system that processes and stores interval data used for billing and calculates billable consumption for interval meter data.

Gateway. Deployed in 2013, Gateway is the employee-facing web-based front end system to CBMS and other systems used in the contact center. Gateway is the primary tool for customer service representatives to interact with customers.

Knowledge. Deployed in 2016, Knowledge is the employee-facing system that allows for systematically capturing, describing, organizing, and sharing information including alerts, work processes, and policies across customer service.

E-Gain. Deployed in 2010, E-Gain is the employee-facing system that imports and sorts emails and work tickets, creating a queue for response. E-Gain includes auto replies and templates for responses.

LanBill. Deployed in 1996, LanBill is the employee-facing system that allows back office personnel to manually edit and print bills flagged for special handling. LanBill is used to process large complex bills that are not fully automated in CBMS.

Bill Image. Deployed in 2003, Bill Image is the employee-facing software used to render an image of the bill on demand in Manage Account and Gateway.

Agiloft. Deployed in 2011, Agiloft is the employee-facing record keeping system used to track elevated customer issues and inquiries.

2. Grid Operation Systems

AMI and AMR head-end systems. The system that receives and processes the data and serves as an operating platform for the back office team responsible for operating and maintaining AMI and AMR, respectively.

Advanced distribution management system ("ADMS"). A software platform that supports a full range of distribution management and optimization tools, such as supervisory control and data acquisition ("SCADA"), fault location, isolation and service restoration ("FLISR"), voltage optimization, and distributed energy resource management ("DERMS"). The Company implemented the first phase of ADMS in 2019, which provides the basic data acquisition and control functionality.

Outage management system ("OMS"). A system that provides tools and information to efficiently restore power to customers by providing outage analysis and prediction functionality. The system enhances public and worker safety, and serves as the Company's system of record for outage history. The existing OMS was deployed in 1994. It does not have the capability to maintain a dynamic hierarchy of how each customer is being served based on the configuration of the feeder ties at any point in time.

Data Analytics System ("DAS"). A system that stores and quickly processes large amounts of data to create Advanced Analytics solutions. The existing DAS was deployed in 2017. It does not have the capability to process the amount of data that the Company will obtain from full deployment of smart meters and other intelligent grid devices.

F. Telecommunications

Dominion Energy Virginia currently has a telecommunications ("telecom") transport portfolio that consist of Company-owned fiber, leased lines, copper cables, and public carrier solutions. Approximately 6% of the distribution substations have fiber, approximately 40% use leased circuits, and approximately 10% use copper cables. The remaining approximately 44% of substation have no communications.

G. Security

The existing distribution system is protected by a comprehensive security program designed to provide adequate and cost-effective security control measures that manage the growing threat to the energy sector and that protect the Company and its customers from cyber and physical attacks. The Company's security program has been subjected to multiple third-party vulnerability assessments and penetration tests (announced and unannounced); peer reviews; and numerous internal and external audits. Results from those engagements have informed continuous improvements to both cyber and physical security.

H. Electric Vehicle Infrastructure

Electric vehicles ("EVs") are typically charged by plugging the EV into 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.
- 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.

As of August 15, 2019, there were approximately 595 Level 2 (*i.e.*, 240 volt) and direct current fast charging ("DCFC") charging stations in Virginia available for public use. However, not all of these stations are available to all EV drivers, and some are only available during limited hours.

IV. Distribution Grid Planning

The fundamental changes in the energy industry discussed in Section I drive not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs. Appendix B provides a detailed overview of the Company's current distribution planning process, the limitations of the current process, and the integrated distribution planning ("IDP") process that the Company plans to implement going forward (the "IDP White Paper"). The IDP White Paper also details how the proposed Grid Transformation Plan investments are foundational to enabling true integrated distribution planning. This section provides an overview of the IDP White Paper.

A. Current Distribution Planning Process

The Company's current distribution planning occurs through three separate processes: (i) distribution capacity planning, (ii) distribution reliability planning, and (iii) DER interconnection.

The purpose of distribution capacity planning is to evaluate grid utilization during seasonal peak loading conditions based on projected load growth, identifying any necessary improvements to the distribution system needed to satisfy thermal and voltage criteria as the demands placed on the distribution infrastructure change over time. Generally, load growth forecasting is not location specific beyond information regarding block load additions that are known in the short term. There are no inputs related to customer-level usage patterns or DER and emerging technology penetration growth included in this current forecasting process. Traditional static planning focuses on the system's summer and winter peak conditions, studying the traditional "worst case scenarios." Based on this focus, the current load growth forecasting utilizes only peak customer usage and removes DER to ensure the grid will remain reliable under these conditions.

The purpose of distribution reliability planning is to identify causes of service interruptions and risks to the grid, and to develop cost-effective and prudent solutions to improve overall grid performance and customer experience. Reliability planning is based on data analytics of service outage information.

The DER interconnection process identifies the impact to the grid of interconnecting DER. Which interconnection process DER customers must follow depends upon (i) whether the DER customer opts to sell its output wholesale to PJM Interconnection, LLC ("PJM") or to the Company; and (ii) whether the DER customer elects to interconnect directly to distribution infrastructure as a small electrical generator or behind the customer's meter via net energy metering.

Current distribution planning methodologies and processes were designed for a distribution grid in a world of centralized large-scale generation and a one-way power flow. In the evolving paradigm where DERs and other emerging technologies are increasing on the distribution grid causing two-way power flows, the Company's distribution planning process must also evolve.

B. Future Integrated Distribution Planning

The Company defines integrated distribution planning as a process to address capacity, reliability, and DER integration, accounting for uncertainties introduced by factors such as increasing DER penetration, changing usage patterns, and increasing use of new technologies such as high energy electric vehicle charging infrastructure. True IDP requires people, technologies, and processes. Throughout, trained professionals are vital to fully leverage the technologies and optimize the processes and emerging tool sets. Technologies and communications that provide visibility into the grid to the customer premises level are foundational to enable integrated distribution planning. The processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analysis tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution system.

Achieving true integrated distribution planning requires both a thorough understanding of how the grid is performing in all respects, and tools that can process information from the grid and inform or take actions. This is only possible with a full implementation of the equipment and systems that are proposed in the Company's Grid Transformation Plan. Namely, AMI; intelligent grid devices and operations and control systems; a robust and secure telecommunications network; and Advanced Analytics tools are all required to perform integrated distribution planning. 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.

These proposed investments will enable a deep examination of the current distributed pathways and a detailed analysis of feeder segments for long-term planning purposes. With this baseline view, the Company can encourage DER in a manner that supports customer demands, improves grid reliability and resiliency, and ensures reasonable costs. This process will ultimately allow the Company to utilize DER in its generation planning.

The Company plans to implement an IDP process that will evolve the current planning processes to adapt to the increasing proliferation of customer-owned DERs and other changes relevant to the modern grid. The IDP White Paper, attached as Appendix B, describes the Company's proposed evolution of integrated distribution planning over time as enabling technologies are deployed.

V. Development of Grid Transformation Plan

The Company has engaged in an iterative process to develop the Grid Transformation Plan presented in this document. Guided by the policy objectives of the Commonwealth to facilitate the integration of DER and enhance distribution grid reliability and security, the Company incorporated its experience-based knowledge with input from customers and stakeholders; with lessons from the experiences of peer utilities; and with guidance provided by the State Corporation Commission of Virginia ("Commission") in prior orders.

A. Internal Process

The Company consistently tracks developments in the energy industry and challenges for its distribution system. As shown in the Grid Modernization Index 2018, GridWise Alliance ranked Virginia as 25th among states and the District of Columbia based upon progress in modernizing the state's electric grid, noting many "leaders," "movers," and "believers" that the Company could learn from as the Commonwealth moves to transform the electric distribution grid. The Company has talked to its peer utilities and has learned from their experiences. The Company has kept current with information published by various industry groups, and has engaged with these industry groups to gain additional knowledge and perspective. The Company also engaged an industry expert, West Monroe Partners, as a knowledgeable partner in the development of a plan to modernize the distribution grid. Additionally, the Company has tested certain components of the GT Plan on a smaller scale, such as AMI. All of this knowledge coalesced to create the framework for the Grid Transformation Plan.

B. Customer Engagement

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. The Company intends to continue this customer engagement to assess the priorities included in the GT Plan.

1. Ongoing Feedback

Dominion Energy Virginia receives customer feedback on a daily basis. The Company strives not only to quickly and justly resolve any customer issue, but also to identify trends and possible process improvements.

The Company also meets directly with customers. For example, from January 2017 to May 2019, the Company conducted nearly two dozen community meetings at the request of customers to discuss grid performance and to provide information on activities to improve service. The Company will continue to engage with customers on an ongoing basis in its efforts to meet customer needs and expectations.

2. Virginia-Based Voice of the Customer Survey

The Company recently contracted with Maslansky + Partners ("Maslansky") to conduct Virginia-based research to evaluate customer priorities related to the Grid Transformation Plan. Maslansky based this effort on a nationwide survey fielded by Edison Electric Institute ("EEI") on the "Voice of the Customer," and, where applicable, compared the results of the Virginia survey and the national study.

Survey questions tested 35 attributes across a range of eight areas: (i) bills and payment; (ii) customer service; (iii) digital/digital privacy; (iv) environment/carbon/energy efficiency; (v) operational performance; (vi) outage communications; (vii) rewards; and (viii) smarter energy infrastructure. Customers expressed that experiencing power outages is their primary source of frustration followed closely by the ability (or inability) to control their electricity bills. Above all other categories, customers value reliability and affordability the most, and they expressed their desire to save on their bills and / or conserve energy. Appendix C provides the full results of the Maslansky Survey.

3. Social Media Analysis

Social media is a channel through which the Company communicates with and receives feedback from its customers. Dominion Energy Virginia recently prepared a Social Media Analysis that reviewed social media comments and sentiment to gather insights about customers' impressions of Dominion Energy Virginia, their reactions regarding power outages, and other aspects of the power delivery service they receive from the Company. West Cary Group completed the analysis, and assessed more than 28,500 social media comments identified as related to the Company over the last three and a half years.

Although only a limited number of customers use social media channels as a way to communicate with the Company or voice their concerns, the analysis clearly shows customers are frustrated during outages, as evidenced by over nine times the comment volume appearing on major outage days. While some comments share their appreciation after restoration, many customers do express frustration. The comments also illustrate an erosion of patience as time ticks by during multi-day outages. Notably, reliability and resiliency are major concerns for customers on all days—major storm or not. Appendix D provides the full results of the Social Media Analysis.

C. Stakeholder Engagement

In furtherance and development of the Company's GT Plan and related initiatives, the Company began a series of stakeholder sessions in mid-2019 to inform and develop goals for a modern grid and the customer experience. In two distinct session topics, the Company sought feedback and alignment regarding stakeholders' vision for prioritized capabilities of the grid, and how enabling infrastructure and technology can support new time-varying rates and customer programs. Each stakeholder process is further summarized below.

1. GT Plan Stakeholder Process

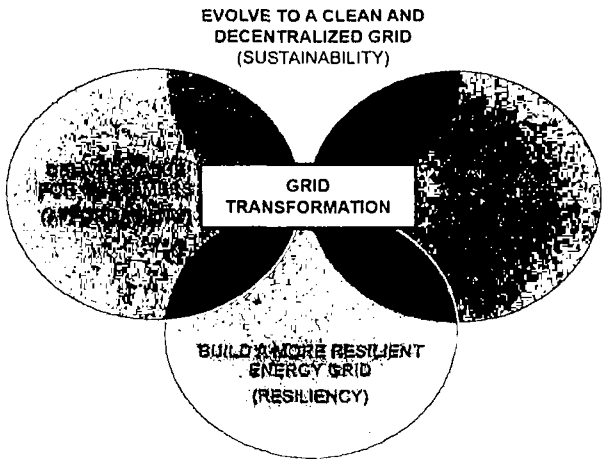
To facilitate stakeholder engagement surrounding the Company's plan for grid transformation, the Company engaged an industry expert, Navigant, to facilitate an external stakeholder process. Attendees included a range of stakeholders with varying interests, from environmental advocates to municipality representatives to low income advocates. Commission Staff also attended the stakeholder process.

Navigant facilitated a series of workshops that guided the conversation on the stakeholders' vision and objectives for grid transformation. Through collaborative conversations, a group of the stakeholders identified four goals for grid transformation:

- **Optionality**: Enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access.
- **Sustainability**: Evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles.
- **Resiliency**: Build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management.
- **Affordability**: Deliver value for customers by optimizing demand and seeking to reduce system and customer costs.

Using these goals as a guide, Navigant led an exercise for stakeholder groups to prioritize grid capabilities that any plan for grid transformation should enable. Consistent across all stakeholder groups were investments that enabled two capabilities: (i) integrate and optimize DERs and (ii) provide relevant, data-enabled options that enable customers to meet their goals. In addition, highly prioritized by at least one stakeholder group were investments that enabled the following capabilities: (iii) increase monitoring and visibility; (iv) accommodate two-way power flows; (v) enable voltage monitoring and control, supporting load management and peak shifting; (vi) simplify interconnection for residential customers; and (vii) harden for resiliency and security. Figure 2 below shows the results of a grid capabilities exercise conducted by Navigant with the stakeholders mapping the four goals of grid transformation to the customer-facing and value-enabling capabilities.

Figure 2: DEV Results of Grid Capabilities Exercise



		CUSTOMER-FACING CAPABILITIES
O O	O	Equitability of Service Offerings
O		Grid Resiliency
O O	O	Integration & Optimization of DER
	O	Streamlined DER Interconnections
	O	Transportation Electrification Enablement
		VALUE-ENABLING CAPABILITIES
O O	O	Data Collection & Communication
O O		Distributed Intelligence
O O		Grid Automation
O O		Modern System Planning
O O	O	System Visibility and Monitoring
O O	O	Voltage Management

Navigant then facilitated a discussion that mapped high-priority capabilities to key grid modernization technologies. At the final workshop, the Company presented the Grid Transformation Plan and received stakeholder feedback. Appendix E is Navigant's final report on the stakeholder process.

The Company intends to continue engagement with stakeholders as its grid transformation efforts proceed.

2. Time-Varying Rate Stakeholder Process

In 2019, the General Assembly passed legislation—HB 2547—requiring the Company to convene a stakeholder process to make recommendations concerning the development of time-varying rates and other related initiatives. After consultation with the stakeholder group, the Company engaged Navigant as an independent facilitator to conduct the process. Attendees included a range of stakeholders with varying interests, from environmental advocates to municipality representatives to low income advocates. Commission Staff also attended the stakeholder process.

Initial sessions and collaborative discussions with the stakeholder group identified two key goals of an effective time-varying rate:

- To have a rate that empowers a large number of satisfied and engaged customers to regularly manage their load for maximum benefit to the electric system; and

- The rate offering should send as accurate of price signals as possible, but with design elements that minimize negative impacts for certain customer segments.

With these goals clearly identified, Navigant facilitated a review of common rate design options, leveraging Company supplied load information to analyze various rate structures and associated customer behavioral changes and system benefits that could result.

By the third session, stakeholders aligned on a preferred rate structure and associated on/off peak periods to target and began focusing on refining the new time-varying rate structure through discussions around specific pricing differentials / signals within the rate. Current technology limitations were also discussed at length with the group to highlight the need for AMI and CIP deployment to achieve targeted rate design and goal realization.

Stakeholders acknowledged the existing systems, specifically those running on mainframe systems, do not support the functionality they seek. Stakeholders specified a need for customer data tools, easy access to view data, and customer empowerment. The feedback from the Stakeholder group along with other customer feedback provides the basis for the customer experience goals of the CIP: modernize the customer relationship, provide better information and provide value.

As the process continues, the Company is working with stakeholders to finalize the new rate structure to inform a potential filing in the future and begin crafting a customer outreach and education plan to ensure the rate empowers customers to effectively manage their load for maximum benefit to the electric system in an effort to lower peak usage.

VI. Grid Transformation Plan

The 10-year Grid Transformation Plan focuses on the overarching goals of optionality, sustainability, resiliency, and affordability, as described in Section I. Similarly, Virginia Code § 56-585.1 A 6 requires that any plan for electric distribution grid transformation projects "shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security."

Based on the development process described in Section V, the Company presents a comprehensive plan designed to achieve all of the goals and objectives for grid transformation in a reasonable, prudent, and cost-effective manner. Specifically, Phase IB of the Grid Transformation Plan includes six components: (i) AMI; (ii) CIP; (iii) grid improvements; (iv) telecommunications infrastructure; (v) cyber security; and (vi) the Smart Charging Infrastructure Pilot Program.

A. Components

1. AMI

Dominion Energy Virginia proposes to fully deploy AMI across the 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. The full deployment of AMI is a foundational component of the Grid Transformation Plan, effectively enabling all other Plan components, and is needed to unlock the capabilities that customers, stakeholders, and the Commonwealth are demanding. Simply put, without the full and timely deployment of AMI technology across the service territory, the Company cannot transform the distribution grid.

The Company expects to complete deployment of AMI over a six-year period beginning in 2019. During this time, a total of approximately 2.1 million meters and 3,100 network devices will be deployed in a structured manner across the Virginia service territory within each of the geographic areas by region and field office. The Company plans to use the AMI head-end system currently in place for the full deployment of AMI, upgrading the system as needed as the deployment of smart meters progresses and as the Company enables additional AMI capabilities.

With the plan for full deployment, the Company proposes a revenue-neutral opt-out policy for residential customers including a one-time fee and ongoing monthly fees intended to only recover the costs of a customer opting out of smart meter installation.

2. CIP

The Company proposes to implement a new CIP that will replace 12 current systems supporting different aspects of the customer experience, including the outdated CIS, described above. The CIP 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 proposed CIP is needed to replace antiquated systems with a platform that will provide the foundation for an enhanced customer experience and desired grid capabilities. Without the foundational investment in the

CIP, the value of the transformed grid will not be widely accessible to customers in a manner that is user-friendly (*e.g.*, web self-service, smartphone apps, proactive communications). For example, time-varying rates, high bill alerts, and receipt of push notifications regarding billing would not be broadly accessible to customers without a new CIP.

The Company plans to implement the CIP beginning in 2019. The foundation of CIP implementation is the replacement of the CIS. The Company has collaborated with an industry expert to assist with bid management, including the competitive process to select a system integrator. 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. During the replacement of the CIS, the Company will deliver customer functionality through early releases of technology within the CIP, such as notification preference, which will allow customers to choose the communication channels through which they prefer to engage with the Company, and an outage center app for outage communications. After the CIS replacement, the Company will continue the CIP and leverage the new technology for additional functionality, specifically redesigning the bill to make it more understandable and easy to read.

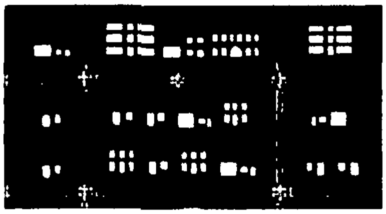
3. Grid Improvements

The Company proposes grid improvement projects over the 10-year period of the GT Plan. Proposed projects fall into two categories: (i) grid technologies and (ii) grid hardening. The grid improvement projects are needed to adapt to fundamental changes in the energy industry described in Section I, facilitating the integration of DER and enhancing system reliability and resiliency.

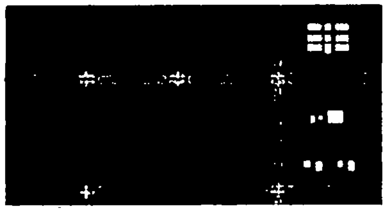
Grid Technologies. Within the category of grid technologies, the Company proposes: (a) building a self-healing grid; (b) conducting and publishing hosting capacity analysis; (c) implementing a DERMS; (d) enabling Advanced Analytics; (e) implementing voltage optimization; (f) demonstrating microgrid capabilities at the Locks Campus; (g) implementing an enterprise asset management system ("EAMS"); and (h) replacing the OMS.

Self-Healing Grid. The Company proposes to build a self-healing grid. A self-healing grid refers to a distribution network that uses smart grid devices such as switches, reclosers, and line sensors; a communications network; and a control system to automatically isolate outages to the smallest possible group of customers and reroute power to restore most customers in a matter of seconds or minutes. This type of system also provides details about the specific location of the fault, allowing crews to arrive and assess repair needs faster, speeding the restoration time for the remaining customers. This concept is also known as distribution automation or fault location, isolation, and service restoration ("FLISR"). Additionally, these smart grid devices provide situational awareness that is necessary to manage grid voltages and power flows related to DER. Figure 3 illustrates the self-healing grid.

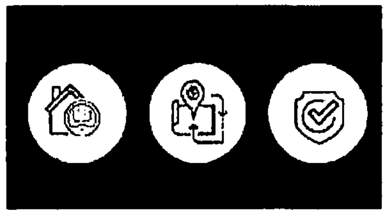
Figure 3: Self-Healing Grid



Majority of customers today do not have a smart meter



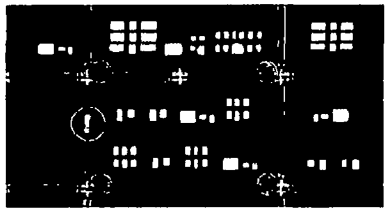
Rely on customers to notify us during outages



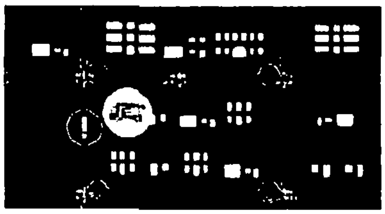
Smart meters and self-healing grid technologies use a secure network to provide visibility to the grid

Intelligent grid devices provide data to control systems

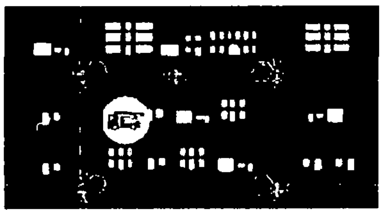
The location of the fault is identified and isolated



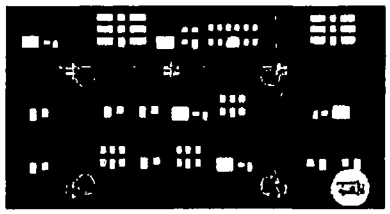
Most customers restored automatically in minutes



Crews have more precise location of fault



Remaining customers' power restored more efficiently



Crews available to move onto next outage location

To build a self-healing grid, the Company will install electronic devices on selected feeders and associated substations, and add a FLISR software module to the Company's recently installed ADMS. The electronic devices to be installed include the following:

- Electronically-controlled line reclosers. Devices that can sense grid problems and take action to de-energize and isolate line sections turn off power where necessary, and that can also receive control commands from the ADMS using a secure telecommunications network.
- Line sensors. Devices installed at select locations along the feeder that provide situational awareness regarding normal loading and voltage as well as fault related information that can be used by the ADMS to further narrow the potential outage location.
- Digital relays. Devices that provide advanced protection and control functionality, and detailed grid performance information including near real-time situational awareness about grid operation.

- Communication gateways. Devices that facilitate secure communications and function as a central data hub, sending and receiving all data and control functionality between substations and the ADMS.

To maximize the benefit of investments in a self-healing grid, the Company selected feeders that have the largest number of customers and most critical services affected when outages occur based on historical outage information from 2014 to 2018. The Company has completed detailed engineering for the feeders it intends to target in 2020 and 2021 to determine the number and types of devices to deploy on each feeder.

Hosting Capacity Analysis. The Company proposes to complete and publish a hosting capacity analysis, and to refresh this analysis on a regular basis. Hosting capacity analysis uses computer simulations to determine how much generation can be placed at each point on the distribution grid without causing voltage or loading problems. Hosting capacity results are typically communicated using online interactive maps, with colored line segments indicating the hosting capacity of each part of the circuit. This type of analysis helps customers and localities to determine the potential contribution of DERs on the distribution feeder.

The Company plans to publish initial hosting capacity maps of its system by the end of 2020. The Company will update these maps periodically. Notably, AMI and the intelligent grid devices that the Company plans to install as part of the self-healing grid will enable more advanced and dynamic hosting capacity analysis in the future.

DERMS. The Company proposes to implement DERMS to leverage the full capabilities of DERs by managing grid performance and maximizing customer benefits. The proposed DERMS will aggregate performance and status information from DERs, analyze the need for control actions (*e.g.*, charging and discharging battery energy storage systems), and issue the appropriate commands to DERs to maintain a safe and reliable energy grid. As equipment capabilities continue to mature and industry standards evolve, DERMS will also enable the use of smart inverters. In addition to the basic inverter function of converting direct current to alternating current, smart inverters enable DERs to provide grid support capabilities, such as voltage regulation, frequency support, and ride through capabilities. All of these capabilities help to achieve greater grid efficiencies and provide greater customer benefits.

Advanced Analytics. The Company proposes to expand its Advanced Analytics capabilities to maximize the data collected from smart meters and intelligent grid devices. Advanced Analytics uses mathematical and statistical formulas and algorithms to generate new information, to recognize patterns, to predict outcomes, and to determine the respective probabilities of those outcomes. To expand its Advanced Analytics capabilities, the Company proposes to upgrade its DAS and to create an Analytics Center of Excellence ("ACE"), a support organization responsible for Advanced Analytics.

Voltage Optimization. In conjunction with the installation of AMI, the Company proposes to implement a voltage control system in 2022 that uses near real-time voltage data from smart meters and issues control commands to voltage control devices to manage grid voltage more precisely. These more precise settings would result in generally lower voltage control settings, which would also lower energy consumption for most customers without a noticeable difference in service level.

Locks Microgrid. The Company proposes to study microgrids by installing one at its Locks Campus near Petersburg, Virginia. A microgrid is a small power grid consisting of interconnected loads and DERs with clearly defined electrical boundaries. A microgrid can operate both when connected to the larger electric grid and continue to operate as an "island" when there is an interruption or other grid disturbance.

Through the Locks Microgrid, the Company will obtain real-world data, better understand DER performance characteristics, perform testing of DER grid support and islanding capabilities, vet new technology integration into the distribution grid, and evaluate microgrid operations architecture for potential future applications.

EAMS. The Company proposes to implement EAMS beginning in 2020. The EAMS will enable the Company to improve asset management practices by assessing the health and performance of grid components and driving predictive maintenance activities, leading to more effective grid operation activities. The EAMS will also assist the Company with managing the procurement, deployment, and retirement of equipment and devices through improved equipment attribute analyses and planning capabilities. Once implemented, information and analytics from the proposed EAMS will drive a large part of the identification and prioritization of component upgrades included in future phases of the GT Plan.

OMS. The Company proposes to replace its OMS with a new OMS that will operate effectively with the self-healing grid. The self-healing grid 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 plan to begin implementation of a new OMS after Phase IB in 2024.

Grid Hardening. Within the category of grid hardening, the Company proposes: (a) hardening mainfeeders; (b) deploying targeted corridor improvement activities; (c) upgrading components proactively; and (d) mitigating voltage islands.

Hardening Mainfeeders. The Company proposes to complete hardening work on a targeted population of mainfeeders. Hardening projects will improve reliability by focusing on physically strengthening infrastructure using newly implemented stronger standards when rebuilding, relocating, or undergrounding targeted mainfeeder segments, as well as improving distribution system architecture and connectivity to provide feeder tie capabilities.

The Company selected mainfeeders for hardening by evaluating historical reliability information to identify segments of customers with the most outage interruptions each year excluding major events. The Company identified 312,000 customers with the worst reliability based on annual outage time between 2014 and 2018. This group of customers—approximately 12% of the Company's total customers—account for 41% of all outage minutes. While the average Dominion Energy Virginia customer averages 127 minutes of outage time annually, these customers average 421 outage minutes.

The Company has completed the detailed engineering analysis for the 11 mainfeeders it intends to target in Phase IB, serving 12,578 customers and 61 critical services. Two 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. Engineering undertaken for these projects determined the amount and type of hardening work to perform on each mainfeeder. Of the approximately 63 miles of mainfeeder hardening work that is proposed for 2020 and 2021, 61 miles involve rebuilding or relocating the mainfeeder, while only approximately 2 miles include undergrounding of the mainfeeder. The Company views mainfeeder undergrounding as a last resort for hardening given the costs and complexities associated with this work.

Targeted Corridor Improvement. The Company proposes several new vegetation management programs to improve grid reliability and resiliency while minimizing environmental impacts. Specifically, the Company proposes to remediate ash tree mortality and implement an herbicide program for ground floor maintenance.

Proactive Asset Upgrade. The Company proposes to proactively upgrade (i) substation transformers with poor health and high customer impact and (ii) service transformers that are overloaded or not providing voltage within the proper bandwidth. In 2020 and 2021, the Company proposes to replace 5 substation transformers and 1,589 service transformers.

Voltage Island Mitigation. The Company plans to mitigate voltage islands, which are single substation transformers that serve a population of customers without the support of available load transfer capability within the substation or through field tie switches to adjacent feeders. Voltage islands expose customers to the risk of an extended outage if the single substation transformer fails. The Company plans to address 18 of the 26 voltage islands through the GT Plan, including two in 2020 and 2021. To address the voltage islands, the Company will typically install a second transformer at each location and reconfigure feeder architecture both to provide the capacity to restore all customers in the event of a failure of the existing transformer and to improve day-to-day service reliability.

4. Telecommunications

Dominion Energy Virginia proposes to deploy a comprehensive telecommunications strategy requiring multiple components specifically designed and deployed as an integrated solution to meet the wide-range needs of a transformed distribution grid. The strategy envisions three tiers of communication: (i) Tier 1, a high-speed broadband with very low latency and redundancy; (ii) Tier 2, a broadband network without redundancy; and (iii) Tier 3, a field area network ("FAN") to support distribution automation equipment. The telecommunications investments are a foundational component of the Grid Transformation Plan and are needed to enable the secure communication required for a transformed grid.

The Commission approved Tier 1 and Tier 2 in Case No. PUR-2018-00100, and the Company has begun implementation of these telecommunications solutions. For Tier 3, beginning in 2020, the Company plans to deploy field device hardware, FAN base station hardware, and a FAN management system, and plans to acquire licensed spectrum for the FAN. Tier 3 supports the proposed self-healing grid by facilitating secure, real-time communications to the intelligent grid devices via wireless communications on the distribution system not directly serviced by Tiers 1 and 2.

5. Security

The Company will continue to protect the distribution grid by providing adequate and cost-effective security control measures to manage the growing threat to the energy sector and to protect Dominion Energy Virginia from cyber and physical attacks. The Company's security strategy includes both physical and cyber security at key substations and cyber security to protect the investments proposed in the GT Plan. The security investments are a foundational component of the Grid Transformation Plan, and are needed to protect the distribution grid from internal and external threats, protecting the Company and its customers.

The Commission approved investments in physical and cyber security at key substations in Case No. PUR-2018-00100, and the Company has begun assessment at 10 substations. The Company proposes to implement cyber security solutions as the Company deploys its other proposed GT Plan investments, including AMI, CIP, and grid improvements. The majority of cyber security solutions are extensions or separate rollouts of existing solutions, but the Company will evaluate additional cyber security solutions as needed to close any security gaps and address any new or emerging threats.

6. Smart Charging Infrastructure Pilot Program

Dominion Energy Virginia takes a proactive approach to understanding the trends, innovations, and progress related to new technologies in the electric utility landscape. As part of the GT Plan, the Company is proposing initiatives related to electric transportation, including the Smart Charging Infrastructure Pilot Program. The Company will continue to monitor other emerging technologies for possible inclusion in future GT Plan filings.

Through this Pilot Program, the Company proposes to offer rebates for the electrical infrastructure and upgrades at EV charging sites and rebates for the smart charging equipment that enables managed charging. The Company plans to offer a set number of rebates to four different segments: multi-family; workplace; DCFC; and transit. The Company is also proposing to own a limited number of DCFC stations in an effort to study and support electrification in the rideshare segment.

Industry experts agree that EV adoption will continue to increase across the nation and in the Commonwealth. In the Company's service territory, EV adoption is expected to increase to approximately 169,000 EVs by 2030. With increased adoption comes increased demand for electricity. 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 pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid.

7. Customer Education

The Company is committed to improving the customer experience by incorporating education into various Plan components and including general energy education. Key to achieving this goal is educating customers about their energy consumption and how to manage their costs and empowering them to take advantage of the numerous enhanced customer capabilities enabled by the GT Plan. The Company will develop and provide 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, and interactions with the customer service organization.

The Company's comprehensive approach for customer education addresses: (1) foundational education, (2) smart meters and detailed energy usage data, (3) customer information platform and engagement, (4) customer energy management programs, (5) electric transportation benefits, and (6) grid improvement projects to improve reliability. Appendix F includes the full details of the customer education plan. While this customer education plan will focus on enhanced capabilities enabled by GT Plan, it supplements the Company's overall efforts to educate its customers on topics ranging from available rate schedules to general energy education.

The Dominion Energy Virginia website will be a main hub for public education. The Company has already launched a webpage at DominionEnergy.com (https://www.dominionenergy.com/next) which provides links to factsheets, informational videos, and other informative documents. A landing page specific to the GT Plan will be launched and all materials (print and digital) will provide or include the link back to the webpage for further information. In addition, there will be a wide variety of community opportunities for customers to speak face-to-face with subject matter experts and employees about the GT Plan through the Company's "speaker's bureau" events and presentations.

The Company's consistent implementation of the customer education approach and plan will improve the customer experience. Utilizing this education approach, the Company will ensure outreach is efficient and effective in achieving the goals of educating customers, keeping them informed, and empowering them to take advantage of the numerous enhanced customer capabilities provided by the GT Plan.

B. Environmental Justice Considerations

In developing the GT Plan, Dominion Energy Virginia sought to ensure that the benefits of these investments reach all customers. For example, the Smart Charging Infrastructure Pilot Program targets the multi-family residential, transit, and rideshare segments to ensure that low income customers may benefit from transportation electrification. Upon full deployment of AMI and CIP, the Company has committed to programs including prepay, peak time rebate, and time-varying rates, all of which will be "opt-in" and available to interested customers. The corresponding education with these programs will provide information so each customer can determine whether the options will be beneficial to them. Additionally, the foundational telecommunications investments proposed as part of the Grid Transformation Plan will provide the opportunity to support expanded deployment of broadband in the Commonwealth through a Rural Broadband Program Pilot.

Further, the deployment plans for AMI and grid improvements were evaluated to ensure that minority and low income communities were considered when identifying areas and timing of those investments.

C. Alignment with Customer and Stakeholder Feedback

As discussed in Section V.B, the Company received customer feedback on a range of priorities associated with the Grid Transformation Plan as part of the recent Maslansky Survey. Figure 4 notes the top findings on what customers rank with highest importance.

Figure 4: Customer Feedback Priorities

	Customer Priorities
1	Completes scheduled work when they say they will
2	Has knowledgeable customer service representatives
3	Invests in technology to help it prevent outages and respond to outages faster when they occur
4	Keeps my energy usage data private and doesn't make any personally identifiable information available
5	Alerts me when power is out, how long it will take to restore, and when it is restored
6	Invests in a stronger energy grid that can withstand extreme weather and cyberattacks
7	Completes work without needing follow up
8	Has easy to understand bills that explain charges clearly
9	Takes the time to listen to my issues and actually help me
10	Has an outage map that includes accurate estimates of outage time and progress in restoring power

As shown in Figure 4, among attributes tested, those relating to outage communications and smarter energy infrastructure rise to the top as priority areas of focus. These findings support the proposed GT Plan investments and make clear that they will provide the types of benefits the Company's customers value most—enhanced reliability and accurate information.

As discussed in Section V.C, the Company initiated a series of stakeholder sessions to inform and develop goals for a modern grid and the customer experience. Through the GT Plan stakeholder process, four goals were identified: (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). GT Plan investments directly support each of these four goals, through deployment of technology to empower customers to make informed decisions about their energy usage, enabling increased adoption of DERs in a responsible manner, and delivering better reliability and fewer outages for customers.

D. Costs

In terms of costs, the Company focuses on the first three years of the Grid Transformation Plan—the years 2019, 2020, and 2021 ("Phase I" of the GT Plan). The Commission has 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." Figure 5 provides the Phase I costs for the GT Plan.

Figure 5: Phase I Costs ($M)

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

The Company determined these projected costs primarily using competitively-negotiated contracts and responses to competitive requests for proposals ("RFPs") and requests for information ("RFIs"), informed by prior experience. The Company's filing provides detailed information used to determine costs, and includes the relevant contracts or RFP/RFI summaries with its filing.

The Company has committed that the costs of the Plan associated with the deployment of AMI and the CIP in Phase IB will not be the subject of a rate adjustment clause petition. Instead, these costs will be recovered through the Company's existing rates for generation and distribution services ("base rates"). As to other phases and components of the Plan, the Company has not yet determined its plans for cost recovery.

Figure 6 summarizes the estimated Phase I revenue requirements for the GT Plan and provides an estimated revenue requirement for Phase IA and Phase IB of the GT Plan for the components that could be subject of a rate adjustment clause petition (*i.e.*, excluding Phase IB AMI and CIP costs). Notably, these calculations are high-level estimates based on the preliminary costs of the Plan, but do not contain the level of precision or detail contained in similar calculations typically provided with the Company's rate proceedings.

Figure 6: Annual Estimated Phase I Revenue Requirements

(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

The estimated revenue requirements shown above encompass all components of the GT Plan. However, the Company has committed that Phase IB costs of AMI and the CIP will not be the subject of a rate adjustment clause. Therefore, in evaluating rate impact, the Company focused only on those investments that could be subject to a rate adjustment clause 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.

E. Benefits

The proposed Grid Transformation Plan unlocks benefits for the Company, its customers, and the Commonwealth. The Company engaged a third-party industry expert, West Monroe Partners, to generate a cost-benefit analysis ("CBA") for the GT Plan. Figure 7 presents the results of the CBA.

Figure 7: CBA Summary

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, the CBA represents a positive business case from a financial perspective, providing over $3 billion of benefits, which represents net benefit to customers of approximately $322.5 million all on a net present value basis.

The CBA focuses on quantifiable benefits, but the Grid Transformation Plan produces other qualitative, non-quantifiable benefits. For example, there are benefits that are difficult to quantify, like avoiding a cyberattack; providing resilient service to military bases, hospitals and communities; and providing customers with accurate and timely information that have implications for their daily lives.

The following sections highlight certain GT Plan benefits important to the Company and various stakeholders.

1. Time-Varying Rates

Transformational investments in AMI and CIP, when coupled with customer education and communication, enable the Company to broadly offer time-varying rates. Time-varying rates better reflect the true cost of electricity, where customer energy prices vary over time and different prices are in effect for different hours on different days.

Time-varying rates provide more accurate price signals to customers that are better aligned with cost causation than traditional rates not based on time of use. Time-varying rates can provide incentives for behavioral changes that may cause customers taking service under such rates to reduce usage during peak demand periods and enable the system to avoid incurring higher variable operating expenses (*e.g.*, fuel) and to avoid future capacity costs. These behavioral changes can benefit customers directly through bill savings and reduced system costs.

The Company anticipates proposing new time-varying rates later this year upon conclusion of the recently-initiated, legislatively-directed stakeholder process. Currently, the Company anticipates proposing a new residential time-varying rate available to customers with a smart meter, 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 and voluntary, and will initially be limited in the number of customers that can participate as AMI and CIP are being deployed. Once AMI and CIP are fully deployed, the Company can more broadly offer time-varying rates with Commission approval. The Company is planning for the new time-varying rate to be voluntary or opt-in at first.

2. Demand-Side Management Initiatives

The foundational and transformational investments proposed as part of the Grid Transformation Plan will enable enhanced and targeted DSM initiatives. With the data provided by AMI, the Company can more effectively target the most appropriate customers for specific programs and would provide better recommendations for energy savings within any programs that involve a behavioral or educational component. AMI also provides a significant benefit to the evaluation, measurement, and verification ("EM&V") requirements of DSM programs by providing detailed energy usage data from each customer endpoint where smart meters are deployed.

Future DSM programs enabled by AMI—in conjunction with implementation of the CIP—include peak-time rebates ("PTR"). 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 10 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 reduced usage during the PTR event. Customers would not be penalized if they did not reduce usage during the event.

3. Prepay

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.

4. Load Forecasting

The data obtained from AMI can also enhance the Company's load forecasting process. AMI data will permit the Company to examine consumption patterns on an hourly basis. This data can then be used to create consumption forecast models at various segment levels, for example, at the neighborhood level, the zip code level, and the feeder circuit level. These localized forecasts can then be rolled up to a system level and compared against the Company's current forecasting methods. Having this ability will allow the Company to modify its forecasting process, which will likely lead to more accurate peak demand and energy forecasts.

5. Broadband Pilot Program

The foundational telecommunications investments proposed as part of the Grid Transformation Plan will provide the opportunity to support expanded deployment of broadband in the Commonwealth through a Rural Broadband Program Pilot. Under this Pilot, the Company could use a portion of the fiber capacity to meet its own distribution system needs, including as the supporting communications backbone for intelligent grid technologies. The Company would lease another portion to an internet service provider, which would use the fiber infrastructure to deliver high-speed Internet access to unserved residences and business.

F. Regulatory Process

The GTSA mandated that the Company petition the Commission for approval of a plan for electric distribution grid transformation projects. The GTSA also set forth the applicable standard for reviewing such petitions:

> In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. 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.[8]

The Commission must rule on any petition not more than six months after the date of filing.

In 2018, the Company submitted its first petition for approval of its GT Plan in Case No. PUR-2018-00100 ("2018 Final Order"). The Commission issued its 2018 Final Order on January 17, 2019.

As part of the regulatory process, the Company proposes performance metrics in consultation with Commission Staff to track the success of the Plan. 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. 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 going forward.

[8] Va. Code § 56-585.1 A 6.

VII. Future Technologies

Dominion Energy Virginia takes an active approach to understanding the trends, innovations, and progress related to new technologies in the electric utility landscape. The following section describes future technologies that the Company will continue to monitor as its pilot and demonstration programs progress.

A. Battery Energy Storage Systems

Battery energy storage systems ("BESS") offer a variety of support options for the distribution grid. While BESS technologies are still in the early stages of utility-scaled deployment, the Company is piloting this technology in several proof of concept applications.

On August 2, 2019, the Company submitted its first application to participate in the pilot program for electric power storage batteries established by the Commission pursuant to the GTSA. The application presents three projects for deployment, including two for applications on the distribution system. Through BESS-1, the Company proposes to deploy a 2 MW / 4 MWh AC lithium-ion BESS that will study the prevention of solar backfeeding onto the transmission grid at a specific distribution substation. Through BESS-2, the Company proposes to deploy a 2 MW / 4 MWh AC lithium-ion BESS that will study BESS as a non-wires alternative to reduce transformer loading at a specific substation. The Company may seek approval of additional BESS in future applications. For example, the Company is evaluating a potential project to study battery storage paired with DCFC infrastructure for electric vehicles.

Separately, 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.

B. MicroGrids and NanoGrids

A microgrid is a small power grid consisting of interconnected loads and DERs with clearly defined electrical boundaries. A microgrid can operate both when connected to the larger electric grid and continue to operate as an "island" when there is an interruption or other grid disturbance.

A nanogrid is a small microgrid typically consisting of a single building or primary load, and the generation needed to supply that load without a connection to a centralized grid. A nanogrid is fully capable of operating independent of the grid through a combination of sustainable generation, storage, and smart devices, all digitally connected and controlled to optimize the balance of load with available power. A nanogrid gives the individual consumer the ability to manage its own generation sources, demand, and usage independent of both the microgrid that they may be a part of and the centralized utility grid.

Microgrids offer promising solutions for critical loads, such as military installations, hospitals, and water treatment plants. At this time, microgrids are not economic to deploy on a large-scale basis. A report by the National Renewable Energy Laboratory ("NREL") reported a microgrid cost per megawatt at $2.1 million per megawatt of DERs installed.[9] Nevertheless, the Company proposes to study microgrids by installing one at its Locks Campus near Petersburg, Virginia, as discussed in Section VI.A.3.

[9] National Renewable Energy Laboratory, PHASE I MICROGRID COST STUDY: DATA COLLECTION AND ANALYSIS OF MICROGRID COSTS IN THE UNITED STATES (Oct. 2018), *available at* https://www.nrel.gov/docs/fy19osti/67821.pdf.

GLOSSARY

ACE (Analytics Center of Excellence): 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 business use cases.

ADMS (Advanced Distribution Management System): A software platform that supports and manages the full suite of distribution grid management and optimization technologies employed by the Company.

Advanced Analytics: Broadly classified as artificial intelligence, combining many technologies and methods, and is often referred to as predictive analytics (one of its salient capabilities) or Big Data (the platform used for processing analytics).

AMI (Advanced Metering Infrastructure): Another term for Smart Meters – electric meters that automatically measure and record usage data at regular intervals and provide that data to consumers and energy companies at least once daily- and the systems that use that data and communicate with the meters including the field area network and the back office system.

AMI Back Office System: Also called a "head-end "system, this system receives and processes the data recorded by the "field area network" and assists the operation and maintenance team.

AMR (Automated Meter Reading): A technology that records usage data and transmits it to the Company one-way. The Company reads these meters through drive-by readings using specially equipped trucks that receive the data through radio signals.

Automated Control Systems: Technology that allows for near real-time adjustment of the grid to changing energy loads, distributed generation or feeder fault conditions without or with limited operator intervention.

Backfeed: The flow of electric power from the distribution grid to the transmission grid. Also represents the flow of electric power from a net metering distributed energy resource to the distribution grid during periods where distributed generation exceeds consumption at the premises.

Backhaul Network: The backhaul portion of the network comprises the intermediate links between the core network and the small subnetworks at the edge of the network.

BESS (Battery Energy Storage System): A rechargeable resource that stores energy from a generating source for later discharge to the electrical grid.

Big Data: An accumulation of data that is too large and complex for processing by traditional database management tools.

CBMS (Customer Business Management System)/CIS (Customer Information 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.

CCRO (Customer Credit Reinvestment offset): A provision of the law allowing for overearnings to be reinvested into certain renewable generation projects or grid transformation investments rather than credited back to customers.

CIP (Customer Information Platform): A combination of technologies, applications and projects at the core of the customer experience, consisting primarily of the Customer Information System (CIS), Meter Data Management System (MDMS), Customer Portals, and other customer experience applications.

Collector: A device deployed as a component of AMI designed to enable two-way communications to and from meters within range of the device. The device captures meter data and transmits via a dedicated backhaul communications network to the AMI head-end system to drive business processes.

Cyber Security: Programs, techniques and technology to protect the Company's network, devices, and programs from cyberattack.

DAS (Data Analytics System): A system that stores and quickly processes large amounts of data to support advanced analytics solutions.

DCFC (Direct Current Fast Charging): Electric vehicle charging technology capable of charging batteries to a 60 to 80 mile range state of charge within 20 minutes.

Decentralization: [two-way energy flow] A concept that involves moving the electric grid away from relying solely on large centralized generating plants that supply power via the transmission grid to the distribution grid and ultimately end users, to a power grid where large generating plants and smaller distributed resources supply the grid simultaneously from two directions: the large generators through transmission lines and the smaller resources supplying from the distribution grid.

DER (Distributed Energy Resource): A generation resource or controllable load that is interconnected to the distribution grid or connected to a host facility within the distribution grid.

DERMS (Distributed Energy Resource Management System): A system that monitors and analyzes performance and status data from multiple distributed energy resources and has the ability to control those resources to maintain safety and reliability on the energy grid while maximizing benefits of the resources.

Distribution Grid: The portion of the electrical utility system that delivers electrical power from the transmission grid through a substation transformer to end-use customers- typical distribution grid operating voltages range from 4 kV to 46 kV.

DSM (Demand Side Management): Programs that encourage customers to modify their behavior in order to save on energy costs.

Earned Media: Publicity gained through promotional efforts other than paid media advertising or owned media, like branding, such as TV news segments, social media, customer reviews and word of mouth.

EAMS (Enterprise Asset Management System): A system that aggregates data and attributes of grid assets and provides capabilities to manage grid assets at all points in their life cycle, including procurement, deployment, and retirement. The system allows for collection of information related to the health and performance of grid components and analysis to drive life cycle decision making.

EM&V (Evaluation, Measurement and Verification): The collection of methods and processes used to assess the performance of demand-side management activities so that planned results can be achieved with greater certainty and future activities can be more effective.

Fault: An abnormal electrical condition caused by a short circuit on a feeder section.

Feeder: An electric distribution subsystem that begins at a substation and distributes electrical power within a localized service area. Feeders are comprised of mainfeeders, tap lines and service lines.

FLISR (Fault Location, Isolation, and Service Restoration): A distribution network system that works with intelligent grid devices such as switches, reclosers, line sensors, and a secure communications network to automatically isolate faulted feeder sections and reroute power to restore most customers in a matter of seconds or minutes.

Generation/Generator: A machine or system that converts an energy source (solar irradiance, wind, fossil fuel etc.) to electric energy.

GIS (Geographic Information System): A system designed to capture, store, analyze, and present spatial or geographic data, herein referring to distribution grid assets.

Green Screen: Common name for the user view of the existing CIS, which is a non-Windows based view of the mainframe system.

Grid Hardening: Physical grid improvements that improve reliability and resiliency by rebuilding portions of the grid to eliminate outages and reduce damage for faster restoration, and proactively upgrade assets at or near end of life with components that provide increased functionality or higher reliability.

Grid Modernization/Transformation: These are blanket terms for efforts to improve and modernize the grid.

Hosting Capacity: The estimated amount of DER that can be connected to each segment of the distribution grid without causing voltage or loading issues as determined by engineering analysis.

IGD (Intelligent Grid Devices): Various devices that provide situational awareness and control capability of the grid and enable two-way communication and centralized control of the power system.

Integrated Distribution Planning: A process to address the capacity, reliability, and DER integration needs of the distribution grid using traditional solutions as well as new solutions offered by customer-owned DER and other non-traditional technologies.

Intermittent Generation: Also known as variable energy resources, these generating types do not produce continuously available electricity due to external factors that cannot be controlled, such as solar and wind power. The power from them is non-dispatchable, meaning that they cannot be called upon at all times, only at times when the conditions for their power are present (Sun or wind) and the amount of power varies depending on those conditions.

Kilovolt (kV): Unit of measure for electric equipment and facilities representing 1000 volts.

KPI (Key Performance Indicators): The critical measurements of progress toward an intended result. KPIs provides a focus for strategic and operational improvement and create an analytical basis for decision making.

Latency (Telecomm): The amount of time it takes for a packet of data to get from one designated point to another.

LED (Light Emitting Diodes): These are semiconductor light sources that emit light when an electrical current flows through it, without emitting an arc of electricity.

Locks Campus Microgrid: A testbed microgrid site at the Company's Locks Campus focused on gaining an understanding of distributed energy resource performance characteristics, vetting new technology integration into the distribution grid, and evaluating microgrid architecture and operational requirements.

Machine Learning: A subset of artificial intelligence that allows computers to use algorithms and statistical models to perform certain tasks without needing explicit instructions from an operator, rather relying on patterns and inferences from data instead.

Mainfeeder Hardening: Activities directed at improving reliability and resiliency of mainfeeder sections through a combination of: rebuilding to newly implemented stronger design and material standards ("new standards"), relocating, converting to underground, or constructing feeder ties.

Mainfeeder: The three phase sections of a feeder that distribute electrical power from substations to tap lines and individual customers.

MDMS (Meter Data Management System): System that processes and stores interval data used for billing; calculates billable consumption for interval meter data.

Mesh network: The information network created from smart meters communicating with each other.

Microgrid: A group of interconnected loads and distributed energy resources that act as a small power grid, able to operate when connected to the larger distribution 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.

Microgrid Controller: A device that enables the establishment of a microgrid by controlling distributed energy resources and loads in a predetermined electrical system to maintain acceptable frequency and voltage while the microgrid is disconnected from the distribution grid.

MPLS (Multi-Protocol Label Switching): A mechanism for the routing of communications within a network as data travels across network nodes.

Multifamily residential charging: Electric vehicle charging located in common areas of multifamily housing communities for use by residents.

Nanogrid: A very small power grid of interconnected loads and DERs that may serve only one or a few customers within its boundaries.

NIC (Network Interface Card): A hardware component, typically a circuit board or chip, embedded within a meter so that it can connect to a network.

One-way Energy: Power flow from a centralized location, such as a substation, along a distribution feeder, to end users.

Outage Management System ("OMS"): A system that provides tools and information to efficiently restore power and communicate status updates to customers by providing outage analysis and prediction functionality, while enhancing public and worker safety.

PTR (Peak Time Rebate): Programs that reward customers who reduce electricity consumption during periods of high-cost electricity with monetary rebates. Those who do not reduce usage during peak events are simply charged the normal rate.

Physical Security: Enhancing the physical structures on the grid through hardening as well as increased security personnel at key locations with enhanced telecommunication and surveillance technology.

Predictive Analytics: The use of historical data to understand *what will happen.*

Proactive asset upgrades: Replacement of assets at or near end of life with components that provide increased functionality and higher reliability.

RAC (Rate Adjustment Clause): A mechanism to recover certain investment costs outside of the normal rate case regulatory framework.

Redundancy (Telecomm): Network redundancy is a process through which additional or alternate instances of network devices, equipment and communication mediums are installed within network infrastructure. It is a method for ensuring network availability in case of a network device or path failure and unavailability

Reliability: As used in this document, it is the ability of the distribution system to deliver uninterrupted power service to customers.

Repeater: A repeater is an electronic device that receives a signal and retransmits it. Repeaters are used to extend transmissions so that the signal can cover longer distances or be received on the other side of an obstruction.

Resiliency: The ability of the power grid to withstand outages and maintain service to customers and recover from outages to restore service to customers.

Revenue Requirement: The revenue that a regulated utility needs to earn in a test year in order to provide adequate service to its customers and a fair return for its shareholders.

RFP (Request for Proposals): This is often a competitive bidding process where vendors and contractors offer to provide a service, asset, or good for a certain cost.

SCADA (Supervisory Control and Data Acquisition): A computer system that monitors and provides control of distribution assets, primarily located at substations.

Security Information Event and Management (SIEM): A system to provide analysis of collected security events and logs to identify and detect potential security incidents as well as support incident response.

Self-healing Grid: A distribution network that uses smart grid devices such as switches, reclosers, line sensors, a secure communications network, and a control system to automatically isolate outages and reroute power to restore most customers in a matter of seconds or minutes.

Single-Phase: A segment of a power system consisting of one primary voltage conductor and one neutral conductor.

Situational Awareness: Real-time perception of the grid and its environment that allows operators to project future outcomes as well as deal with present events.

Smart Inverter: An inverter capable of modifying aspects of its output to provide grid support. Such support can include lowering or raising the voltage or shutting down when its contribution to the grid may lead to negative outcomes. Such grid support can also be executed upon receipt of communication from the grid operator to do so.

Speaker's Bureau: Consists of an experienced group of employee volunteers who share company and industry information with customers and community organization.

System Integrator: This vendor is responsible for leading the Company through design of the CIP, 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.

Tier 1: High Speed Broadband internet with very low latency and redundancy.

Tier 2: High Speed Broadband without redundancy.

Tier 3: A field area network (FAN).

Time-Varying Rates: Time-varying rates vary according to the time of day, season, and day type (weekday or weekend/holiday). Higher rates are charged during the peak demand hours and lower rates during off-peak (low) demand hours. This rate structure provides price signals to energy users to shift energy use from peak hours to off-peak hours.

Transmission Grid: The high voltage part of the electrical grid that carries bulk power directly from large generating facilities to substations throughout the Company's service territory. Typical transmission grid operating voltages range from 69 kV to 500 kV.

Three-Phase: A segment of a power system consisting of three primary voltage conductors and one neutral conductor.

Visibility (on the grid): Real-time awareness of the grid's operating conditions.

Voltage Optimization: The more precise control of distribution grid voltage that is possible with information from smart meters and a voltage control system.

Voltage Island: A single substation transformer that serves a population of customers without the support of available load transfer capability within the substation or adjacent feeders. If a single transformer fails, all customers served by the substation could face an extended outage.

Workplace Charging: Electric vehicle charging located at workplaces for use by employees.

APPENDIX LIST

A. Sponsoring Witness Chart

B. Dominion Energy Virginia's IDP White Paper

C. Maslansky Partners Survey

D. Social Media Analysis

E. Navigant Report on Stakeholder Process

F. Customer Education Approach and Plan

Appendix A

part 2

Appendix A

Sponsoring Witness Chart

The listed witness sponsors the identified sections and appendices of the Plan Document.

Section/Appendix	Company Witness
I. Introduction	Baine
II. Need for a Modern Distribution Grid	Baine
III. Existing Distribution Grid	Wright
A. Substations	Wright
B. Wires	Wright
C. Devices	Wright
D. Meters	Frost
E. Operating Systems	
1. Customer Experience Systems	Arruda
2. Grid Operation Systems	Wright
F. Telecommunications	Carroll
G. Security	Bransky
H. Electric Vehicle Infrastructure	Frost
IV. Distribution Grid Planning	Wright
V. Development of Grid Transformation Plan	Baine
A. Internal Process	Frost
B. Customer Engagement	Frost
C. Stakeholder Engagement	Frost
VI. Grid Transformation Plan	Baine
A. Components	
1. AMI	Frost
2. CIP	Arruda
3. Grid Improvements	Wright
4. Telecommunications	Carroll
5. Security	Bransky
6. Emerging Technology	Frost
7. Customer Education	Frost
B. Environmental Justice Considerations	Frost
C. Alignment with Customer and Stakeholder Feedback	Frost
D. Costs	Hulsebosch
E. Benefits	Hulsebosch
1. Time-Varying Rates	Morgan
2. Demand-Side Management Initiatives	Frost
3. Prepay	Frost
4. Load Forecasting	Wright
5. Broadband Pilot Program	Frost
F. Regulatory Process	Baine

Section/Appendix	Company Witness
VII. Future Technologies	
A. Battery Energy Storage Systems	Wright
B. MicroGrids and NanoGrids	Wright
Appendices	
Appendix A. Sponsoring Witness Chart	
Appendix B. IDP White Paper	Wright
Attachment 1. DNV GL Report	Wright
Appendix C. Maslansky Survey	Frost
Appendix D. Social Media Analysis	Frost
Appendix E. Navigant Report on Stakeholder Process	Frost
Appendix F. Customer Education Plan	Frost

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Appendix B

Appendix B

DOMINION ENERGY VIRGINIA'S INTEGRATED DISTRIBUTION PLANNING WHITE PAPER

1.0 INTRODUCTION

A major trend over the last 10-plus year period in the electric power industry has been the development of renewable generation, especially photovoltaic ("PV") and wind generation. Since 2008, wind generation capacity in the U.S. has experienced a compound annual growth rate ("CAGR") of approximately 19%, while PV has seen an approximately 61% CAGR. The Company expects these renewable energy growth trends to continue as customers demand more carbon free forms of energy. An important sub-trend is the growth of distributed energy resources ("DERs")—resources connected to the distribution system. According to the Energy Information Administration ("EIA"), the growth in U.S. of clean DERs (*e.g.*, hydroelectric, wind, PV) from 2009 through 2017 has been approximately 23%. The Company has experienced an approximately 43% DER growth rate on its system during that same timeframe, primarily in the form of PV systems. A subset of the EIA data for non-net metered PV DER experienced a CAGR of approximately 48% nationwide. This trend is expected to continue given the expected efficiency improvements and cost reductions in PV technology.

Along with this increase in distributed generation resources interconnected to the distribution system, other trends continue to develop, including the addition of high-energy electric vehicle charging, the adoption of energy storage, and a change in customer energy usage patterns driven by AMI-enabled time-varying rates. Utility planners must continue to adapt their skills, tools, and processes to integrate these new challenges into the electric energy infrastructure planning landscape. No longer is grid planning based only on load growth and the static impact during peak usage periods on the distribution grid. Now, planners must also anticipate new supply-side and demand-side resources in the form of DERs, understand the dynamic impact to the grid, and examine how DERs can provide non-traditional solutions to traditional grid challenges, such as line overloads and voltage deviations. To that end, historical distribution planning methods must change to an integrated distribution planning process.

The Company defines integrated distribution planning ("IDP") as a process to address the capacity, reliability, and DER integration needs of the distribution grid using traditional solutions as well as new solutions offered by customer-owned DER and other non-traditional technologies. IDP also accounts for uncertainties introduced by the dynamic nature of variables impacting grid operation, shifting results and associated decisions from deterministic to probabilistic outcomes. True IDP requires changes in planner's skills, technologies and tools used, and processes. Throughout, trained professionals are vital to fully leverage the technologies and optimize the processes and emerging tool sets. Technologies and communications systems that provide visibility into the distribution grid to the customer premises level are foundational to enabling integrated distribution planning. Processes and tools must then be developed to incorporate the data gathered, including advanced distribution modeling and analysis tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on different parts of the distribution system.

This white paper provides an overview of the Company's current planning process, highlights the limitations of the current process, and sets forth the initial steps the Company plans to take to transition toward integrated distribution planning.

2.0 CURRENT DISTRIBUTION PLANNING

The Company's current distribution planning occurs through three distinct processes: (i) distribution capacity planning; (ii) distribution reliability planning; and (iii) DER interconnection. Together, these efforts result in a plan designed to address customer needs to ensure safe, reliable, and cost-effective electric service using traditional utility solutions.

2.1 Current Distribution Capacity Planning

2.1.a Overview of the Current Capacity Planning Process

The purpose of distribution capacity planning is to evaluate grid utilization during seasonal peak loading conditions based on projected load growth, identifying any necessary improvements to the distribution system needed to satisfy thermal and voltage criteria as the demands placed on the distribution infrastructure change over time. Figure 2.1 provides an overview of the current process.

Figure 2.1: Current Distribution Planning Process

	Inputs	Modeling & Analysis	Alternatives Evaluation	Outputs
CAPACITY PLANNING	• Historical seasonal peak loads • Historical and projected growth • Interval data at T to D transition point only • Utility scale DER contribution removed • No visibility of net metering DER • Steady state load and voltage criteria	• Static analysis for peak loading • Manual feeder-by-feeder analysis • Only steady state system analysis performed • DER not included in model • Loading allocated based on modeling assumptions	• Traditional mitigation alternatives: equipment upgrades/additions • Solutions optimized for cost / load growth and system impact	**Multi-year Work Plan**

2.1.b Current Distribution Load Growth Forecasting

The historical distribution capacity planning process centers around assessing current and anticipated constraints on the distribution grid associated with forecasted seasonal peak load conditions. Therefore, the Company annually develops a six-year summer and winter peak load forecast (for the next 5 years and for the 10th year into the future) for each of the approximately 1,800 feeders currently on the Company's system. These forecasts are assembled based on historical data measured at the feeder head (*i.e.*, the point of demarcation between the transmission and distribution systems) and information acquired through discussions with (and formal requests from) current and future customers. Examples of the information used to develop the forecast are historical load growth trends, planned new housing developments, new high-rise buildings, information regarding data center expansions or additions and commercial and industrial development. This information is then used by the Company's distribution planners to update feeder-level load growth projections. Generally, load growth forecasting is not location specific beyond information regarding block load additions that are known in the short term (*e.g.*, a new big box retail store under construction). Of note, there are no inputs related to customer-level usage patterns or DER and emerging technology penetration growth included in this current forecasting process. Traditional static capacity planning focuses on the system's summer and winter peak conditions, studying the traditional "worst case scenarios." Based on this focus, the current load growth forecasting utilizes only peak customer demand and removes DER to ensure the grid will remain reliable under these conditions.

2.1.c Current Distribution Capacity Planning

The current distribution capacity planning process is conducted on an annual basis and evaluates the adequacies of each of the Company's distribution feeders under the forecasted annual summer and winter peak load conditions over the planning period. The primary measurable input to this is currently limited to data collected at the feeder head. This evaluation is performed under normal operations and first contingency (N-1) conditions. Normal operations are defined as seasonal peak load conditions under normal distribution system configuration. First contingency (N-1) conditions are defined as situations that simulate the loss of a single distribution substation transformer during seasonal peak loading conditions.

Under both normal and first contingency conditions, distribution planners use computer modeling tools to identify if and when violations of capacity planning criteria are projected to occur on a particular feeder, feeder component or distribution substation transformer. Using feeder head data, the model approximates the expected loading along a feeder and all of its components based on engineering assumptions. The typical engineering limitations examined are conductor, transformer or equipment thermal limits (ampacity), and high or low voltage.

Once the timing and type of violations are determined on any given feeder component or substation transformer, the next step is to identify what grid mitigation solutions are necessary to correct the violation. Mitigation solutions may include re-configuration of the feeder, the addition or replacement of equipment (*e.g.*, capacitors, transformers, protection devices), replacing conductor with larger conductor (*i.e.*, reconductoring), or adding an entirely new substation or feeder. These all are considered traditional solutions.

2.2 Current Distribution Reliability Planning

2.2.a Overview of the Current Reliability Planning Process

The purpose of reliability planning is to identify causes of service interruptions and risks to the grid, and to develop cost-effective and prudent solutions to improve overall grid performance and customer experience. Figure 2.2 provides an overview of the current process.

Figure 2.2: Current Distribution Reliability Planning

	Inputs	Modeling & Analysis	Alternatives Evaluation	Outputs
RELIABILITY PLANNING	• Historical performance data focused on blue sky days • Multiple levels of analysis o System metrics o Feeder level o Responsive to specific customers	• Root cause analysis • Manual feeder-by-feeder analysis • Specific asset health testing and assessment • Manual mitigation modeling to predict improvement	• Traditional mitigation alternatives • Solutions optimized for cost, reliability and risk	Annual Work Plan

2.2.b Current Distribution Reliability Planning

Reliability planning is based on data analytics of service outage information. The Company maintains a historical database of service outages that includes the when, where, and why associated with each service outage generated by the Company's outage management system ("OMS"). This data is analyzed to identify areas of the distribution system that have exhibited reliability performance issues, including root causes. For repeat outages on the same feeder or feeder section, the Company evaluates the cause to determine if there is a pattern to these outages. Depending on this pattern, the Company can devise mitigation measures to improve feeder performance. If, for example, lightning strikes have caused excessive amounts of outages in a specific area, the Company can mitigate future outages through the use of additional surge arresters for lightning protection, or investigate if grounding is within its operating specifications and physically improve the grounding system if it does not meet the operating specification. Another example of mitigation measures is to recondition poorly performing feeders by repairing defects and restoring the feeder to current construction standards.

This data examination process is conducted by the Company on a continual basis. The findings are gathered and used to support reliability improvement investment decisions.

2.3 DER Generation Interconnection Process

The Company's DER generation interconnection process requires the customer to request to export energy directly onto the distribution grid. Which interconnection process DER customers must follow depends upon (i) whether the DER customer opts to sell its output wholesale to PJM Interconnection, LLC ("PJM") or to the Company; and (ii) whether the DER customer elects to interconnect directly to distribution infrastructure as a small electrical generator or behind the customer's meter via net energy metering.

DER requests involving wholesale market participation requests are submitted to PJM. PJM administers the processing of the interconnection requests to its queue and coordinates the interconnection study process, as applicable, with the Company. The Company administers all other generator interconnection requests under the appropriate state jurisdictional procedures.

2.3.a Small Electrical Generator Interconnection Process

The interconnection process for small electric generators is administered in accordance with the Commission's Regulations Governing Interconnection of Small Electrical Generators, 20 VAC 5-314-10 *et seq.* The Commission initiated a rulemaking proceeding in September 2018 to possibly revise these regulations, Case No. PUR-2018-00107. The proceeding remains pending. A high level view of this current interconnect process is provided in Figure 2.3.a.

Figure 2.3.a: Overview of DER Small Electrical Generator Interconnection Process

	Inputs	Modeling & Analysis	Alternatives Evaluation	Outputs
INTER-CONNECTION PLANNING	• Customer initiated requests • Mandated queue procedures • Location specific load and grid data • Customer equipment specifications	• Static analysis for specific loading and DER output scenarios • Manual analysis for interaction with other DER	• Traditional mitigation alternatives: equipment upgrades/additions	**Interconnection Agreement Execution**

The Company must study the interconnection of all generation that operates in parallel with the electric grid to identify if grid modifications are needed to accommodate the proposed interconnection while maintaining safe and reliable operation of the grid for all customers. Under the governing standards, the interconnection customer submitting the request is responsible for the costs to study the impact of the DER on the distribution system and for the costs to modify the grid to accommodate the proposed generation.

The Company's technical study process for utility-scale solar systems ensures that the output of the renewable generator does not result in thermal overload conditions or voltage deviations outside of an acceptable bandwidth on any feeder component or substation transformer to which the PV generator interconnects. The fault current contribution of the generator is also analyzed for its potential impact to the grid. The study is a static analysis based on the ability of the PV system to operate at full-rated output during daylight hours, with secondary consideration of inverter-based DERs to provide grid support for this injection or absorption of reactive power. Based on current grid visibility and control limitations, the Company has asked a small percentage of the generators to apply a fixed power factor setting, other than unity, for voltage support as a secondary measure.

DER interconnection requests have grown significantly over the past several years. Currently there are 28 utility-scale solar generation sites totaling 275 MW interconnected to the Company's electric distribution system in Virginia. As of August 1, 2019, there are 22 interconnection requests totaling 225 MW with executed interconnection agreements that are in the construction process, and 114 requests totaling 1,584 MW that are at some level of evaluation under the state jurisdictional procedures.

2.3.b Net Energy Metering Interconnection Process

If a renewable DER is proposing to offset a portion of a customer's own load, the customer may be eligible to apply for net energy metering. Net metering is administered in accordance with the Commission's Regulations Governing Net Energy Metering, 20 VAC 5-315-10 *et seq.* The Commission initiated a proceeding in August 2019 to amend these regulations consistent with new legislation, Case No. PUR-2019-00119. The proceeding remains pending.

The technical study process for net energy metering is currently a more simplified approach than the process for small electrical generators given the much smaller DER system size. The simplified approach ensures that the interconnecting system does not create an adverse thermal or voltage issue. Any necessary system upgrades (if any) are included in the Company's current base rate structure.

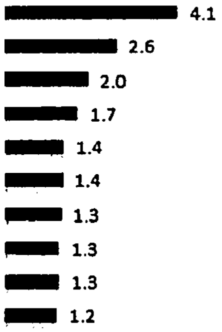
The Company has seen a dramatic growth rate in net metering interconnections, with a clear trend showing concentrated growth in certain geographic areas. Figures 2.3.b.1 and 2.3.b.2 show the total number of net metering customers for the top 10 office locations, as well as the growth in net metering by office since January 1, 2018.

Figure 2.3.b.1: Local Office Totals

Office Name	Cust	MW
Chalottesville	835	8.9
Alexandria	642	4.7
Blue Ridge	385	4.4
Richmond	352	3.1
Leesburg	269	2.7
Fairfax	324	2.3
Norfolk	100	2.1
Midlothian	201	2.1
East Richmond	258	2.0
Springfield	284	1.8
All Others	2,427	20.0
Total	6,077	53.9

Figure 2.3.b.2: Local Office Growth Since January 1, 2018

Office Name	Cust	MW
Chalottesville	407	4.1
Blue Ridge	196	2.6
Alexandria	282	2.0
Norfolk	60	1.7
Midlothian	131	1.4
Fairfax	184	1.4
Springfield	194	1.3
Richmond	161	1.3
Gloucester	66	1.3
Peninsula	190	1.2
All Others	1,480	11.9
Total	3,351	30.5



3.0 LIMITATIONS OF CURRENT PLANNING PROCESS

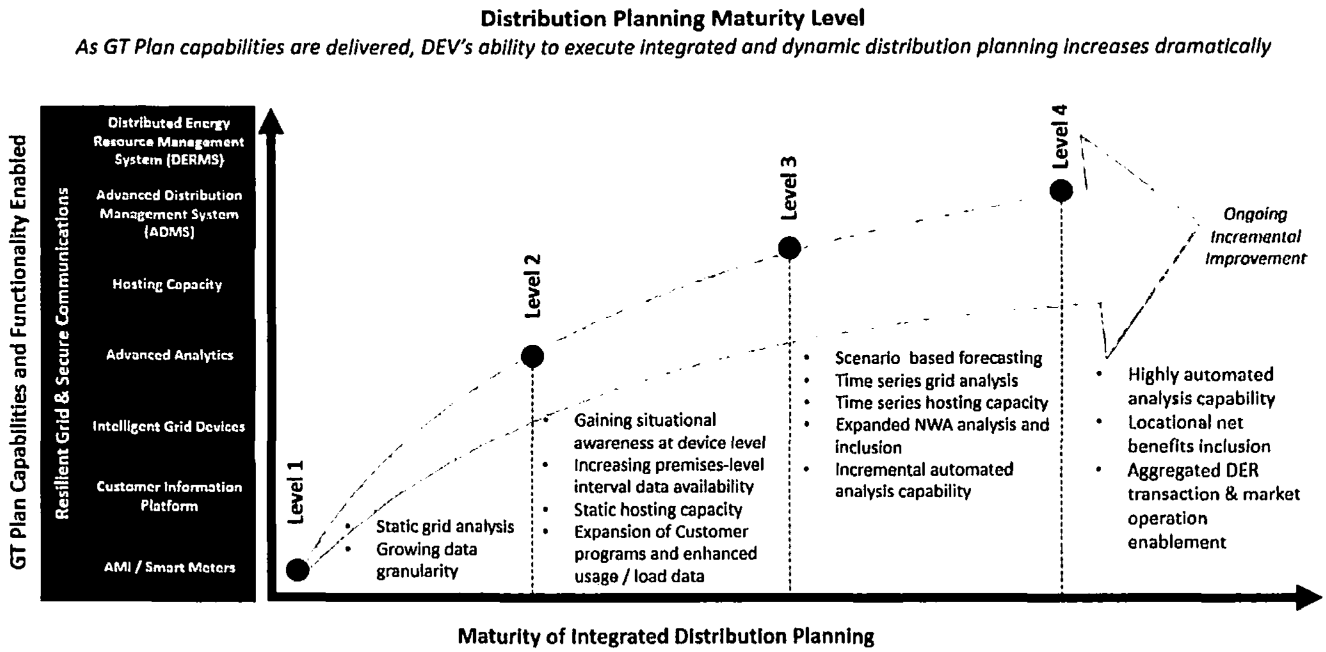
Current distribution planning methodologies and processes have been in place for decades and were designed to identify the most cost-effective means of maintaining a safe and reliable distribution grid. These practices have been effective in a world of centralized large-scale generation and one-way power flows. In that light, modeling and analyzing distribution grid limitations for discrete conditions (seasonal peak conditions) have worked effectively as a manual process. In the new paradigm of increasing DERs and other emerging end-use technologies creating a more dynamic distribution grid with bi-directional and constantly changing power flows, awareness of temporal and spatial growth and operating characteristics are necessary. Modeling the distribution grid under this necessity can no longer be done using traditional techniques. Future modeling and analysis requires the development of advanced and automated tools that are capable of using significantly more granular data and providing outputs on a much broader time scale of probabilistic distribution grid limitations. Limitations of grid visibility beyond the feeder head present uncertainty in determining non-peak characteristics of how the grid is functioning. Additionally, the ability to confidently leverage non-wires alternatives as a prudent alternative to traditional grid solutions requires a level of situational awareness, communications infrastructure, and control capabilities that do not currently exist on the Company's distribution grid.

The historical process of determining distribution system need only during forecasted seasonal peak conditions, with grid visibility limited primarily to the feeder head, is approaching obsolescence. Under the current distribution capacity planning process, anticipated growth in DERs and emerging technology are not able to be addressed. Further, the current process does not assess multiple potential scenarios of adoption rates of DER and emerging technologies. Changing distribution grid load flows along with temporal and spatial growth patterns and operating characteristics at times other than peak hours are, and will continue, to change the dynamics (*i.e.*, the load shape) of the distribution grid moving forward. Limitations of grid visibility beyond the feeder head present uncertainty in determining non-peak characteristics of how the grid is functioning.

4.0 FUTURE INTEGRATED DISTRIBUTION PLANNING PROCESS

The Company plans to implement an integrated distribution planning ("IDP") process that will evolve the current planning processes to adapt to the increasing proliferation of customer-owned DERs and other changes relevant to the modern grid. True IDP will require changes to people's skills, the technologies and tools they use, and processes for performing planning activities. The sections below describe the enhancements the Company plans to make within each of these categories. Figure 4.0 provides a chart showing the evolution of integrated distribution planning over time as enabling technologies are deployed.

Figure 4.0: IDP Evolution



4.1 People

As an initial step towards integrated distribution planning, the Company is centralizing the modeling and analysis activities for capacity planning, reliability planning, and DER interconnection as an integrated functional organization. The Company will continue to evaluate its organizational structure as integrated distribution planning matures in support of the enhancements described below.

4.2 Technologies

IDP is highly dependent on having highly granular and spatial visibility of existing grid conditions. The Company has a plan to transform its distribution grid (the "Grid Transformation Plan" or "GT Plan") to adapt to the fundamental changes to the energy industry described above and to meet its customers' needs and expectations. Many of these proposed investments are foundational to IDP, including investments in advanced metering infrastructure ("AMI"); a self-healing grid, including intelligent grid device and an advanced distribution management system ("ADMS") with system capabilities for distributed energy resources management ("DERMS"); and Advanced Analytics. Advanced Analytics 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. Also vital are secure communications between the field devices and the back office systems. The Company's executive summary of the Grid Transformation Plan (the "Plan Document") provides additional information on these proposed investments.

4.3 Processes and Tools

IDP requires advanced distribution modeling and analysis capabilities that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution system. The distribution grid needs to be analyzed at a wide range of load conditions, rather than at just peak load periods. The ability to successfully perform time series modeling analysis ("TSA") of the distribution grid is heavily reliant on a highly granular visibility of existing load and DER characteristics. Finally, given the uncertainty associated with the size and location of DER growth, probabilistic or stochastic analytical techniques will be required to evaluate the robustness of the distribution grid from the feeder head to the feeder edge.

The Company plans to implement the following process-related enhancements to its distribution planning process to move toward IDP. These enhancements are illustrated in Figure 4.3 and discussed in more detail below.

Figure 4.3: Enhanced Distribution Planning Process

	Inputs	Modeling & Analysis	Alternatives Evaluation	Final Plan
Integrated Distribution Planning	• Feeder load forecast scenarios (time series) • DER & emerging tech growth forecast scenarios • Additional planning inputs: (hosting capacity, AMI & IGD load and voltage data, all DER output data, feeder characteristics (EAM data), performance metrics, etc. • Engineering model build and framework for scenario based analysis • Network assessment (Static and Time Series Analysis) • Reliability assessment • Planning criteria	• Reliance on engineering models based on a high level of data granularity • Automated generation of time series analysis and holistic solutions • Inclusion of Non-Wire Alternatives (Storage, Advanced Inverter Functionality, DSM, etc.) • Inclusion of locational value of resources	• Traditional Grid Solutions • DER & DSM Opportunities • Grid Transformation Projects • Optimization of alternatives over time	**10 Year Distribution Forecast and Investment Roadmap** **Transmission and Generation System Planning Impacts**

4.3.a Process Enhancement 1 – Comprehensive Feeder Level Forecasting

Long-term (*i.e.*, minimum 10 year) demand growth forecasts will be refined for each individual distribution feeder and include not only the amount but also the type of future DER capacity. Utility-scale, commercial, and residential net metering-scale sites will be forecasted annually. Unlike conventional demand forecasting methods, however, these forecasts will be more granular in that they will be developed down to the customer site whenever possible and will cover all hours in a year rather than just peak demand hours. The Company initially plans to develop these forecasts utilizing data obtained from its customers currently served with AMI meters and/or intelligent grid device data, where available. Until full deployment of AMI has been achieved, the Company will develop hourly demand assumptions for its monthly-metered customers using relationships obtained from historic AMI hourly load shapes and monthly customer billing records. Comprehensive feeder level forecasts will allow the Company to simulate power flow scenarios within a planning period. This ability is critically important as the Company expects more active management of grid stability to be necessary during low demand conditions that are coupled with high DER output.

For example, during the month of April, a residential customer's electricity demand at any hour is typically low (less than 5 kW). If that same customer has a solar PV system rated at 10 kW installed at their premise, it is quite likely that for many hours during April, the supply from that customer's premise will exceed their demand and that excess power will flow onto the distribution grid. This situation could cause a localized increase in distribution voltage levels that exceed rated standards. This voltage violation could result in damage to the Company's equipment or damage to appliances of other customers that are on the same feeder. As DERs continue to grow on the Company's system, phenomena such as this can spread to all areas of the distribution feeders and even onto the transmission grid. This undesirable phenomenon is not related to overall system DER penetration but rather is specific to locational concentrations of DER penetration. The magnitude of the challenge grows as this scenario occurs at grid locations with limited host capacity available.

4.3.b Process Enhancement 2 – Hosting Capacity Analysis

The Company will also study the DER hosting capacity on every distribution feeder in order to determine the strength of the distribution system during varying degrees of DER penetration and solar irradiance levels for every hour of the day. This analysis when overlaid with the Company's DER forecast can determine the year when a specific feeder becomes at risk for exceeding feeder design specifications (both thermal and voltage parameters), and will enable the use of active power management of DER as an alternative to traditional grid upgrades. The forecasts described above will be updated annually and will form the base or expected cases for subsequent distribution analysis and planning activities. Until such time as a proper stochastic algorithm can be developed, the Company will also prepare annually, high and low DER growth forecasts for each feeder to support the scenario analysis described below. This transition requires highly manual analysis until such time as automated analytical systems are developed and validated.

If the GT Plan investments are approved by the Commission, the Company plans to publish initial hosting capacity maps for both utility-scale and net metering DER by the end of 2020. As additional grid technologies and smart meters are deployed and grid operation capabilities increase, the hosting capacity maps will become more dynamic and support opportunities to reduce interconnection costs when DER output can be informed and adjusted to avoid grid limitations through a DERMS.

4.3.c Process Enhancement 3 – Multi-Hour Capacity Planning Analysis

Consistent with conventional distribution capacity planning analysis, each feeder will be assessed under seasonal peak demand periods using the forecast for demand and DER growth described above. Also, like current state, the analysis will evaluate the distribution grid for violations with respect to loading and voltage. Beyond current state, the distribution grid will also be examined at conditions other than peak demand periods. At a minimum, the Company will evaluate the distribution grid under peak demand and minimum demand conditions for each month of the planning period. The frequency and the study time window of these studies will increase as advanced modeling techniques are refined. As discussed further below, the Company is investigating, with industry peers and research entities, the development of the necessary engineering tools and systems that can perform this analysis on a time series (*i.e.*, 8760) basis so that, when appropriate, each hour of the planning period can be examined in an automated fashion. This will ensure the Company examines all load and generation conditions associated with the base forecast for demand and DER growth. These new tools and systems will result in a more thorough analysis of each feeder under various load and generation conditions that is more representative of two-way power flows caused by DERs. Notably, specific GT Plan investments in intelligent grid devices and smart meters that gather this highly granular data are necessary to support robust analyses with greatly reduced uncertainty.

4.3.d Process Enhancement 4 – DER Scenario Analysis

The key uncertainties associated with future DER growth is with respect to rate of growth and location. As such, the enhanced distribution planning analysis will also include scenario analysis that utilizes the high and low DER growth forecasts identified above. Again, the Company will analyze each feeder for violations with respect to loading and voltage under monthly peak and low demand conditions using both the high and low DER growth rate forecasts.

4.3.e Process Enhancement 5 – Non-Wires Alternatives Analysis

In addition to traditional distribution grid solution approaches such as re-conductoring or equipment upgrades, the Company will also assess non-wires alternatives to address violations that may surface in the distribution grid analysis process. New mitigation options such as utilizing customer-owned advanced inverter capabilities, battery energy storage systems, micro-grids, or demand response will be evaluated along with traditional solutions to assure that the optimal solutions for the Company and customers are prudently implemented.

5.0 PROOF OF CONCEPT ANALYSIS AND RESULTS

The ultimate objective of the Company's IDP process is to develop a prudent distribution investments roadmap based on load growth, reliability needs, DER growth, new technology adoptions, and other changes on the distribution system over the planning horizon. To that end, the Company engaged DNV GL Digital Solutions ("DNV GL") to develop a proof of concept. The DNV GL analysis focused on the process enhancements described above, namely multi-hour capacity planning analysis, DER scenario analysis, and non-wires alternatives analysis.

DNV GL developed an analytical process using Synergi Electric software, which provides tools that are capable of automating the grid analysis. DNV GL then tested the software using three demonstration feeders identified by the Company. The analytical process involved running a multi-year time series analysis ("TSA"), identifying times where technical violations may occur due to load growth or due to DER operation, designing appropriate mitigations and evaluating the hosting capacity of the system for different capacities of DER.

The Company intends to continue to work with DNV GL as the Company implements the process enhancements described above. Notably, the DNV GL process integrates the Company's current capacity planning and DER interconnection processes, but does not incorporate the current reliability planning processes. As recognized industry-wide, incorporating the reliability planning component is the area of analysis having the greatest complexity . The Company will continue to work toward complete integration of its distribution planning process.

DNV GL produced a report providing its analyses and results. The report is Attachment 1 to this white paper.

6.0 CAPABILITIES ENABLED BY INTEGRATED DISTRIBUTION PLANNING

The evolution of IDP over time will enable capabilities and benefits for the Company and customers not available today. For instance, with people, technologies, and processes described above, locational net benefits could be identified and published, an expanding portfolio of non-wires alternatives can be developed and utilized, and lower DER integration costs can result. With proper policy and regulatory support, IDP also enables aggregated DER transactions.

7.0 GENERATION, TRANSMISSION, AND DISTRIBUTION INTEGRATION ASSESSMENT

Currently, power system analysis is performed separately for generation, transmission and distribution systems. With higher overall system penetration levels of DERs expected, the one-way flow of the Company's distribution system is being significantly altered and will impact the generation, transmission, and distribution systems. Therefore, the Company (along with the electric utility industry) needs to continue its development of new methods and tools to properly integrate the overall power system. For example, as DERs continue to grow within the Company's service territory and emerging technologies take hold, customer load shapes will change. This change in load shape will not only impact the distribution grid but also the transmission and generation systems as well. Power flows along the transmission system will change (and could even reverse) and traditional generators will be dispatched in a manner that may be quite different than has been done in the past in order to accommodate these new customer demands. Thus, it is important that the Company understand how customer energy use is changing and how those changes are impacting the entire electric network, from distribution, to transmission and generation.

Importantly, the shift to integrated distribution planning is a process that will take time, as illustrated in Figure 4.0. The Virginia Code now requires that the Company's total-system integrated resource plans evaluate long-term electric distribution grid planning. Va. Code § 56-599 B 10. The Company thus intends to continue to report on its progress toward IDP in future integrated resource plans. The Company plans to include IDP as part of the stakeholder processes used for the Company's GT Plans and integrated resource plans.

DNV·GL

Dominion Energy Services

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Contents

TABLE OF ACRONYMS

Acronym	Definition
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
DER	Distributed Energy Resources
DG	Distributed Generation
DNV GL	Det Norske Veritas Germanischer Lloyd
GIS	Geographic Information System
HCA	Hosting Capacity Analysis
IDP	Integrated Distribution Planning
IHCA	Incremental Hosting Capacity Analysis
kV	Kilo-Volts
kVAR	Kilo-volt-amperes-reactive
kW	Kilo-Watts
kWh	Kilo-Watt-Hour
LTC	Load Tap Changer
MW	Mega Watts
NWA	Non-Wires Alternatives
OH	Overhead
PV	Photo-Voltaic
SCADA	Supervisory Control and Data Acquisition
SHCA	Stochastic Hosting Capacity Analysis
STATCOM	Static Synchronous Compensator
TSA	Time Series Analysis
TX	Transformer
UG	Underground

1 INTRODUCTION

DNV GL Digital Solutions (DNV GL) has been tasked by Dominion Energy Services (Dominion) with developing the Synergi Analysis part of Dominion's new Integrated Distribution Planning (IDP) process. The ultimate objective of the IDP process is to help Dominion to develop a Distribution Investments Roadmap based on load growth, Distributed Energy Resources (DER) growth and other changes on the distribution system over a 10-year planning horizon. The IDP process is shown in Figure 1 below.

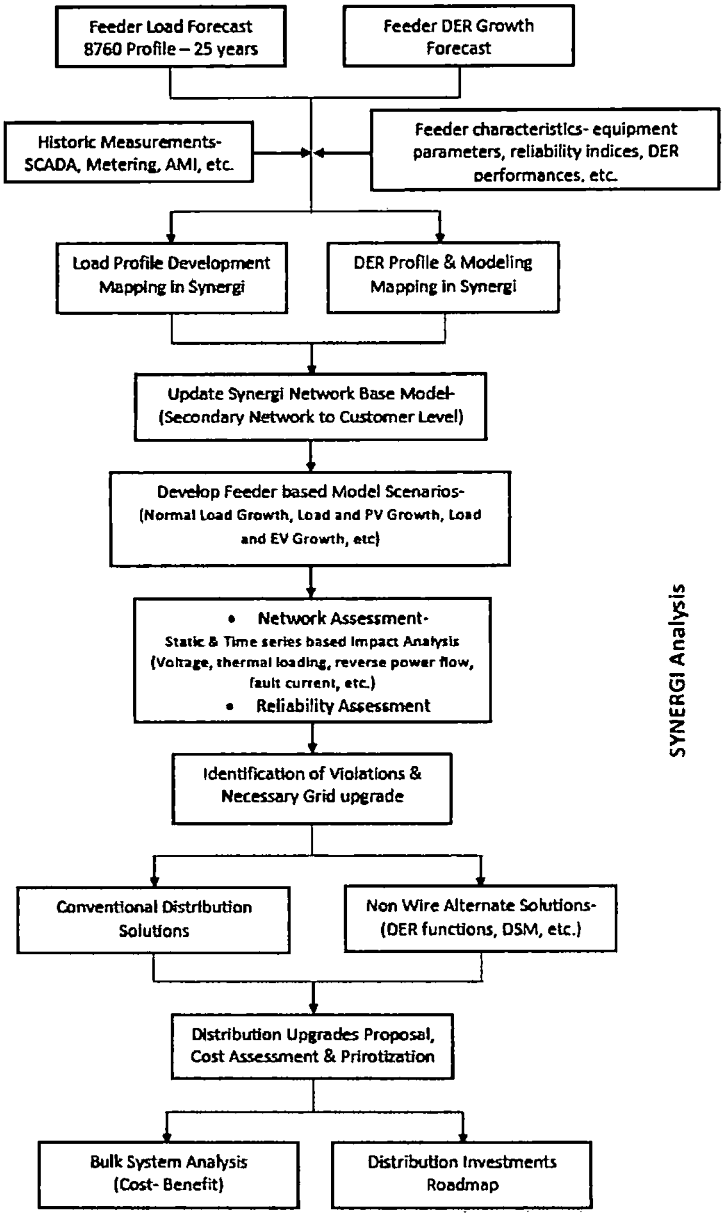


Figure 1: Integrated Distribution Planning process

DNV GL's responsibility is to provide guidance and appropriate tools to accomplish the Synergi Analysis part of the process as efficiently as possible, ideally in a manner which is suitable for implementation on the entire Dominion distribution system. DNV GL's scope includes only the processes related to analysis in Synergi, and does not encompass everything in Dominion's wider Integrated Distribution Planning scope, such as generation planning. The tools developed here are tested on three sample circuits selected by Dominion, referred to in this report as F62710, F71475 and F81305.

The objective of this document is to provide Dominion with a User Guide for the tools developed by DNV GL from the preparation of the Synergi models and input data to the outputs of the various analyses and interpretation of the results.

2 APPROACH

2.1 Introduction

As part of the Integrated Distribution Planning (IDP) process development, Dominion will run a series of analyses on their distribution system, accounting for both load growth and the impact of Distributed Energy Resources (DER). Inclusion of DER, particularly variable generation such as solar power, necessitates changes from traditional approaches to planning studies. Specifically, it is no longer satisfactory to study single load cases, such as annual peak load. The increased complexity of the system caused by interactions between load and generation requires a move to hourly profiles and Time Series Analysis (TSA). This document provides justification for using TSA and some examples of the enhanced capabilities this approach provides to utility planning departments.

2.2 Background

Traditional planning processes have centered around planning for the peak load condition. On a radial distribution system with no generation, this has the advantage of being a straightforward value to identify and can be virtually guaranteed to provide the worst-case operating condition for the circuit.

However, with the introduction of generation on the distribution system – in the form of solar generation, wind generation and energy storage – the justification for analyzing only peak load is no longer valid. Firstly, the peak load condition is no longer easy to identify – load measured at the substation is the net load on the circuit, with some of the actual load used by customers potentially masked by generation on the circuit. This results in generally lower loads being measured at the substation during hours of operation of the DER, and if this is not adequately addressed in the analysis it could cause the planners to use a lower load value in their analysis than is really the case.

Secondly, peak load is no longer the only critical operating condition. Times of low load and high generation are also important to study as these can cause different problems to peak load.

The following sections provide examples of the different drivers for moving to TSA in planning processes.

2.3 Drivers for Time Series Analysis

2.3.1 Interactions of Load and Generation

The first driver for using TSA is that it addresses the problem of measuring net load on a circuit. Even with increasing generation on a circuit, it is still important for planning departments to plan for the peak load on the circuit assuming that generation is offline. This is because there may be days where the load is high and the DER generation is not available due to lack of resource (e.g., thick clouds), or due to return from a trip condition (such as due to system frequency or voltage excursions, or return from a switched condition).

However, utilities typically measure load at the substation, which means that the measured value contains the combined effects of load and generation on the circuit, and on its own does not provide the actual load used by customers if there is any generation online. Even as utilities move to

Advanced Metering Infrastructure (AMI) – smart meters measuring individual customer loads – the measured value is almost always still the net load value for a customer with load and generation behind their meter.

Figure 2 below provides a demonstration of the importance of addressing this situation:

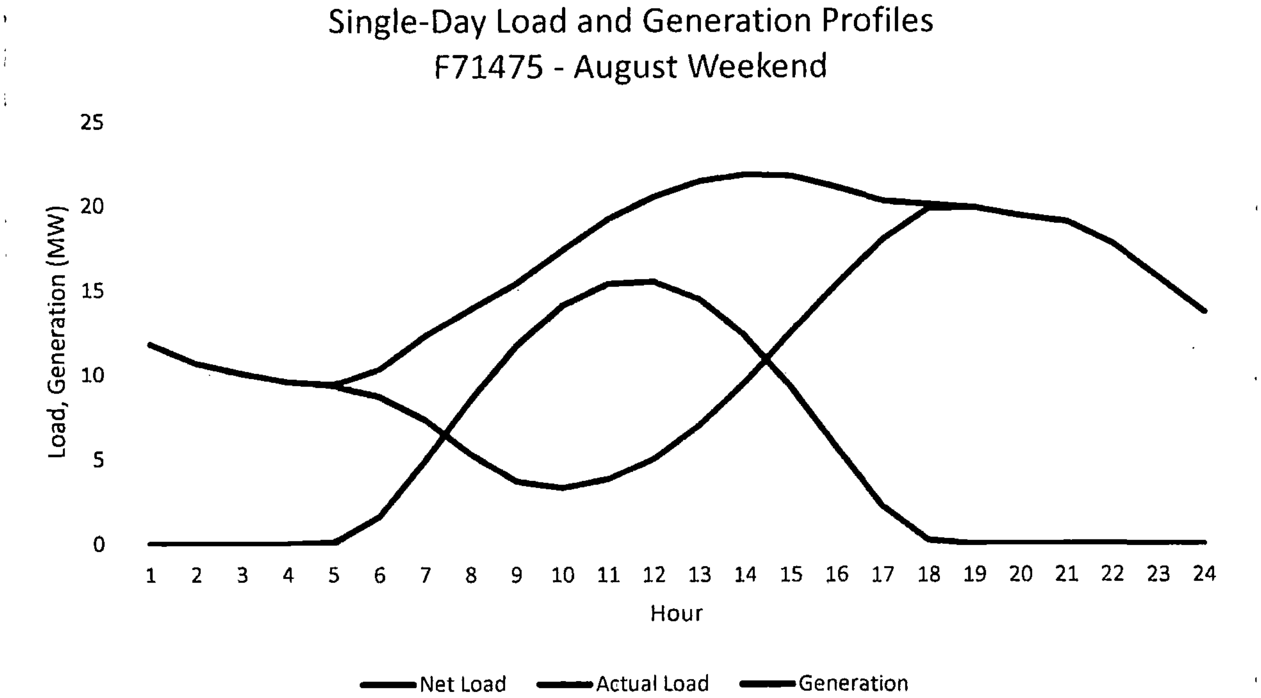


Figure 2: Load and generation profiles

In Figure 2, the Net Load curve would be the value measured at the feeder meter. Using these values alone, the utility would come up with a peak load value for this day of 20MW, which occurs at hour 18. However, the load used by the customers is masked during part of the day by the solar generation, and the Actual Load curve shows a peak value of 22MW, which occurs at hour 14. In this case, using the measured peak load without accounting for the influence of the generation would have caused the utility to study a peak load value around 2MW below the actual value, which is a significant difference.

Thus it is important for the utility to model load and generation profiles independently. As noted above, almost all load measured by the utility is a net load, either measured at the feeder meter or at the customer meter. Developing separate profiles is accomplished by estimating the generation output over the same time period as the measured load, and adding this value to the measured load to find the actual load. This approach necessitates the development of load and generation profiles in the analysis software, which provides some enhanced capabilities to planners, as described in the following sections.

2.3.2 Load Management

Separation of load and generation profiles allows for more accurate implementation of load growth assumptions. Typically, load growth is expressed as a percentage increase in the load. It is important that this percentage is applied to the actual customer load used, rather than the net load, so that the correct load increase is studied.

Separate load profiles combined with TSA allows various demand side management measures to be studied. For example, there are several examples of energy efficiency measures which are effective only at certain hours of the day. Without knowing how the customer load varies throughout the day and through the year, it would be significantly more difficult, and less transparent, to study the effects of these measures as potential non-wires alternatives.

Using TSA to study the system under high loading conditions also provides the utility planners with a measure of the severity of any technical violations. In a time-based analysis which is run over a year, it is possible to find the number of hours of a year where a technical violation persisted. This allows the planning engineers to prioritize violations that occur over a larger portion of the year versus those which may only persist for a small number of hours, which is information that is not available when analyzing single time-steps.

2.3.3 Generation Limits

Developing time-based profiles for load and generation is important for the identification of any limitations on generation output. It is generally the case that generation on a distribution circuit will have the most significant impact at times when load is low. However, simply analyzing the system with maximum generation output and minimum load may not be relevant if the generation is solar-based (and thus only operational during daylight hours) and the minimum circuit load occurs at night. Also, it can be expected that solar output is highest during the summer months and lower during the winter. It is therefore important to account for these time-based output variations and load variations in the analysis of the system, which is a major driver for using TSA. This allows the utility to determine reasonable and reliable limits on generation output without appearing overly conservative to their customers, which is important as demand for customer-sited generation increases.

2.3.3.1 Hosting Capacity Analysis

Identifying generation output limits is a necessity for running hosting capacity analysis. Hosting capacity is the maximum generation capacity on a circuit (or section of a circuit) that does not cause a technical limit to be exceeded (such as voltage limits and loading limits). Typically, hosting capacity is expressed as a single value, which is the lowest hosting capacity found for the circuit or section over a given analysis period. However, there are often cases where a developer will be interested in installing a generation facility which exceeds the hosting capacity of the circuit. In this case, the utility planning engineers will come up with options to either allow the generator to stay under the hosting capacity limit, or to increase the hosting capacity above the output of the generator. Several of these options will require TSA to provide sufficient information to the customer.

2.3.3.2 Mitigation Analysis

When a generator is found to cause a technical limit to be exceeded, the utility planning engineers will present options to the customer which are effective in remedying the situation. Traditional analysis of single worst-case time-steps may limit these options to equipment upgrades, such as re-conductoring or transformer replacements. However, providing a time-based representation of how and when the limitations occur can inform new mitigation strategies.

Figure 3 below presents the variation in hosting capacity for a section on the F81305 feeder over the course of a day. On this section, the maximum hosting capacity is around 8.9MW and the minimum hosting capacity is around 4.4MW . Traditional approaches would necessitate planning around this 4.4MW limit, and appropriate upgrades would be designed based on that. An alternative mitigation is to provide the generator customer with the option to curtail their output to follow this profile and save the costs of an upgrade. In many cases, the costs of the appropriate communications and control infrastructure between the customer and the utility (such as Distributed Energy Resource Management Systems) to implement this curtailment may be significantly less than the costs of the equipment upgrades. The cost/benefit calculation for the customer would depend on how large their facility is expected to be – an 8MW plant would lose more energy than a 6MW plant, for example – and the duration of the curtailment over a year. There may be cases where curtailment is only required for a small number of hours of the year, in which case it may be a better option for the customer than funding equipment upgrades. The cost/benefit calculation would likely be project-specific, but it could be considered as an alternative to costly upgrades.

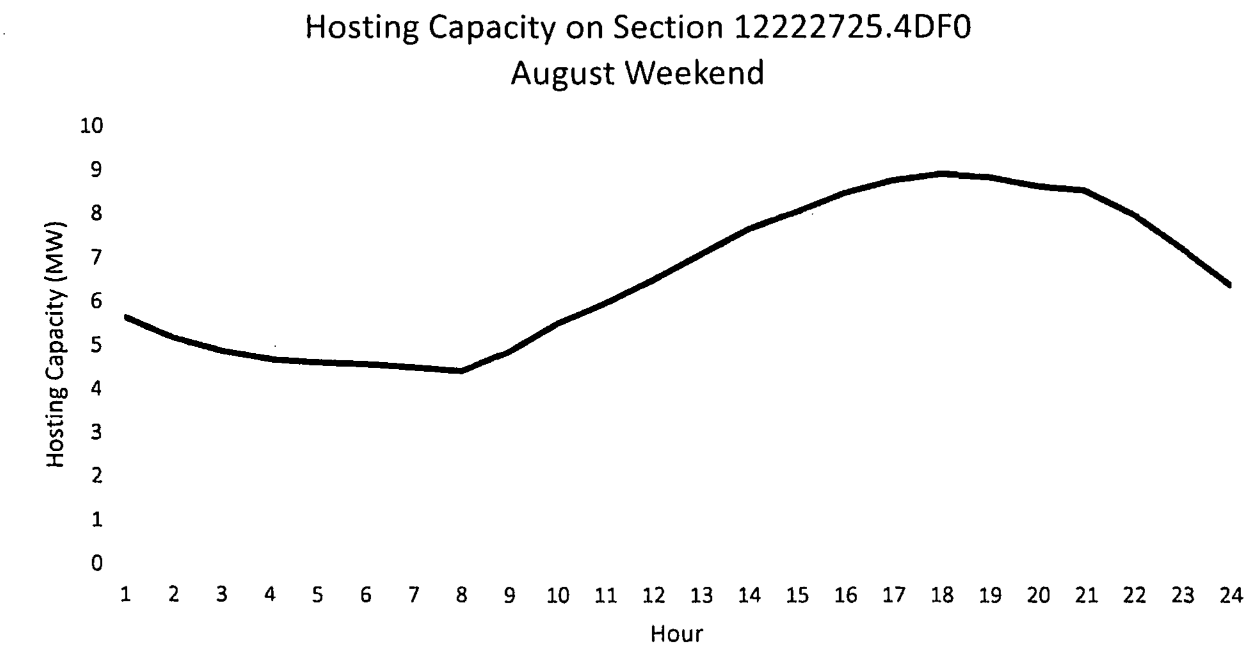


Figure 3: Example of variation in hosting capacity through a day

If the amount of energy lost to curtailment throughout the year is large, another alternative available to the customer may be to add an energy storage system to their facility. This would allow the energy storage system to absorb excess generation above the hosting capacity limit and discharge at times when the hosting capacity limit is higher. The decision to proceed with the design of an energy storage system requires this time-based information which is only available from TSA studies.

2.3.4 Impact of Variable Generation on Load Tap Changers

The Load Tap Changer (LTC), either on a transformer or voltage regulator, is responsible for maintaining the voltage on a circuit within acceptable limits. LTC's are electro-mechanical devices which operate in steps. In principal, once the voltage on the circuit moves outside a given bandwidth, the LTC will move up or down in steps, making a slight adjustment in the transformer ratio and therefore the voltage on the regulated side of the circuit. A typical step size would be 0.625%, which means each time the LTC moves one step, the voltage on the regulated circuit would change up or down by 0.625%. The voltage at the LTC is dependent on the load flowing through the LTC. On most circuits, variations in load are relatively slow and are smoothed out by the actions of hundreds or thousands of customers with varying behaviour. The number of tap changes for an LTC with only variations in load (not generation) is dependent on the circuits connected to the transformer, and can range anywhere from 10 changes per year to 10 changes per day.

However, some generation can be highly variable, such as solar PV generation. The output from a solar generation facility is dependent on the power available from the sun on the solar panel – this power is defined as 'irradiance'. The variation in irradiance – for example, due to clouds passing – causes variation in solar generation output. Variable generation in sufficient capacities can have an effect on the number of operations of an LTC. The reason for this is that multiple facilities made up of this type of generation will behave in the same way and may vary their output in the same direction virtually simultaneously. For example, if a cloud passes over a circuit, the output of all of the solar generators on the circuit will drop by a similar amount in the time it takes for the cloud to cover the circuit. If the capacity of generation on a circuit is relatively large compared to the load, this can cause the LTC to change position when a cloud passes. In areas that are prone to days with partial cloud coverage, this can cause a significant increase in the number of operations of an LTC, and therefore an increase in maintenance and replacements of LTC components.

Figure 4 below shows the difference in tap position on the F62710 Tx-2 transformer over a year between the case where all of the solar generation is off, versus the case when all of the solar generation is at 100% output. The difference in tap position is between 4 and 6 steps throughout the year. Note that this chart only compares two analyses which had the same load profile and constant PV output (0% in one case and 100% in the other case). This chart is insufficient on its own to determine how many extra tap operations are likely due to variability of solar generation as no irradiance data (which drives the output of solar generation) has yet been included in the analysis.

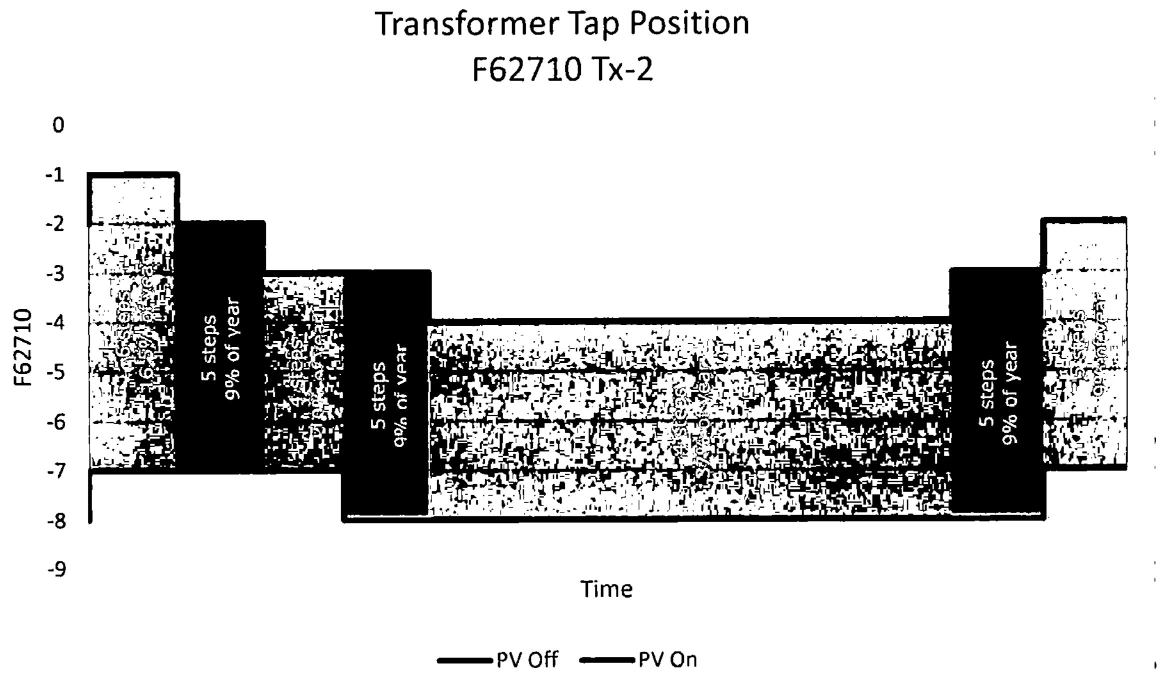


Figure 4: Tap position differences due to solar PV generation

The profile above is used to determine the change in PV output that would result in a single step change in LTC position. For example, where the difference between the tap position with PV off versus the tap position with PV on is 4 steps, it can be assumed that a PV output change of 20% to 25% of rated output was sufficient to move the LTC by one position. Table 1 below summarizes these results:

Table 1: Change in irradiance required to cause 1 LTC position change throughout the year for F62710 Tx-2

Change in Solar Output Required causing 1 LTC Position Change	Percentage of Year
20% to 100%	47.2%
16.7% to 20%	36.3%
14.3% to 16.7%	16.5%

These results are combined with SCADA data which shows the number of occurrences of different PV output changes over a year. The SCADA data is summarized below:

Table 2: Annual occurrences of solar output changes

Change in solar output (% of rated capacity)	Number of Occurrences Annually
50% - 100%	9
33% - 50%	107
25% - 33%	478
20% -25%	1118
16.7% - 20%	1699
14.3% - 16.7%	2253
12.5% - 14.3%	2628

The calculation of number of extra tap changes is carried out as shown in Table 3 below:

Table 3: Calculation of additional tap change operations

Change in Solar Output	Percentage of Year LTC Would Change Position	Number of Occurrences Annually	Number of Extra Tap Operations
20% to 100%	47.2%	1712	808
16.7% to 20%	36.3%	1699	617
14.3% to 16.7%	16.5%	2253	372
TOTAL			**1797**

For the F62710 Tx-2 transformer, the result of this calculation is an estimated 1797 extra LTC operations per year, roughly 5 extra operations per day, which could have a significant effect on LTC lifetime. Analysis of this transformer with no PV generation suggests that this transformer would normally see around 70 LTC operations per year, so there is the potential for solar generation to cause around 25 times the number of operations, with a consequent effect on LTC lifetime. This type of analysis would not be possible with a traditional peak load analysis – time series analysis is necessary to provide this important information for the utility planning department.

3 MODEL SETUP

The Dominion Synergi Electric model is built using an automated model build process linked to Dominion's Geographic Information System (GIS). The automated parts of the Synergi analysis for the IDP process require some additional data to be added to the model – primarily load forecast data, generation data and load profiles. The following sections detail the steps taken to prepare the Synergi model for analysis. In the future, it may be possible to update the model with this data automatically as part of the model build process, which would require some additional work to update the model build tool.

For the analyses conducted as part of this process it is important that load and generation are modelled separately in order to study the effects of changing DER behaviour (such as DER turning on and off, different output profiles, etc.). The following sections describe the methodology implemented here to separate the load profiles from the generation.

3.1 Load and Generation Profiles

3.1.1 Input Data

Meter data available to Dominion for customers with load and generation is net-metered data, which means it contains the combined effect of the load and generation. This data is used both to set the peak load value for each individual customer (these values may not be coincident between all customers on a feeder) and to develop customer load profiles. As such, the load profiles provided by Dominion for this work represent the net load profiles for the customers.

DER capacities are also provided for each customer. Load and generation are modelled in the Dominion Synergi model at the distribution transformer, which means that the aggregate load and generation are modelled at this level for all customers fed by the same distribution transformer. See Figure 5 below – while the customers (Cust.1, Cust.2 and Cust.3) are actually situated at the end of individual low voltage lines coming from the distribution transformer, these low voltage lines (the black lines in Figure 5) are not included in the Synergi model, which stops at the high side of the distribution transformer (the green part of Figure 5). So, the load values for customers 1, 2 and 3 are summed together, and entered in the Synergi model at the location of their distribution transformer.

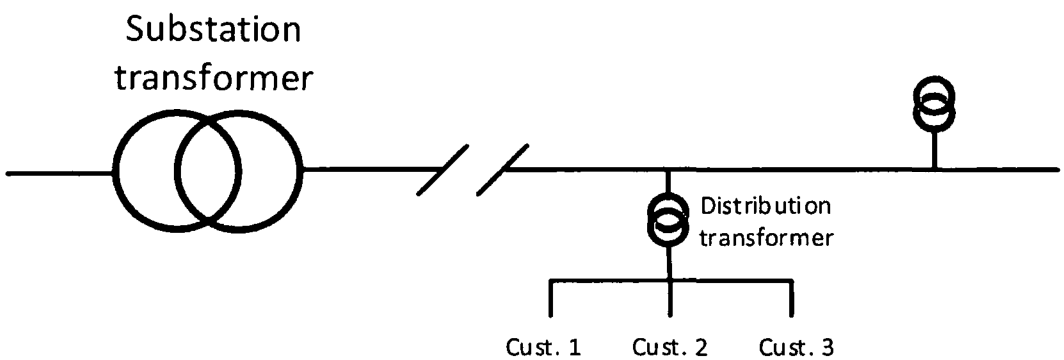


Figure 5: Representation of Synergi model with transmission system in blue, distribution system in green and low voltage secondary circuits in black

3.1.2 Recommended Approach

DNV GL recommends a multi-step approach to separating load and generation in the Synergi model. In principal, it is necessary to develop load and generation profiles at the feeder meter, based on the combined effect of all of the customer load profiles on the feeder. This results in all customers on a feeder being allocated the same load profile while maintaining the proportionality of their individual loads (e.g., if customer A's peak load value is twice that of customer B's, then customer A's load will always be twice as high as customer B's while following the same profile).

Step 1: Establish net load profile at the feeder level

With loads set up based on peak load readings, and the correct customer zones assigned at each distribution transformer, a 576 analysis is run in Synergi using weekend and weekday profiles. The 576 analysis makes use of characteristic load curves for each month in the study – either weekend and weekday curves or peak day and minimum day curves. Each curve is divided into 24 1-hour time-steps, resulting in 576 time-steps for a full year (24 time-steps per curve x 2 curves per month x 12 months = 576 time-steps). This is a more efficient way of running an '8760 analysis' which would involve analyzing every hour of a year.

All existing PV is turned off in the model for this analysis. The 576 analysis runs load flow analysis for each of the 24 time-steps in the weekend and weekday profiles for each month of the year, and Synergi produces a Total Load profile for the weekend and weekday for each month of the year, which are exported and saved.

Step 2: Establish Total PV output profile

A separate 576 analysis is run with PV output set to 'Weather based output'. The PV output profile is exported from this analysis.

Step 3: Find gross load profile on feeder

By adding the total PV output to the feeder net load profile, the result is the feeder gross load profile (i.e., what the actual customer load would have to be in each time-step to reach the measured net load value with PV operating).

Step 4: Convert kW load profiles to % values for import to Synergi

The net load and gross load profiles developed in the previous steps are converted to % values by finding the peak load on the feeder. The peak load should be taken from SCADA data measured at the feeder head, which is used to populate the Demand tab of the feeder meter. To develop the curves for import to Synergi, the kW profiles developed in previous steps are divided by the peak load value.

Step 5: Import feeder load profiles to Synergi

The net load and gross load profiles at the feeder level are formatted to the correct Data Lake schema (MTR_120 and MTR_121) for import to Synergi using the Data Lake tool. Once the import has been done, the model should be saved.

Step 6: Allocate loads

The final step is to allocate loads to the model. This should be done using existing kW in the Load Allocation settings. The Meter settings should have 'Profiles are active', 'Use demand profile when allocating' and 'Use load profile to scale downstream loads' checked. After load allocation, the feeder demand profile from the 576 analysis with DER set to 'Weather based output' should be close to the net load profile found in Step 1.

3.1.3 Notes on Load and Generation Profiles

The intention is for this process to be conservative in the absence of separate load and generation meter data. The process described here assumes that the PV output during the measurement of peak load was the maximum that it could be, due to the use of clear-sky profiles. This means that the load masked by the PV during measurements is the maximum, so when this load is added back in to the customer load profile, the load is as high as it could have been. When scenarios are analysed with PV off, the load will therefore be at the high end of its likely range, which is conservative.

When using this model set up for Hosting Capacity Analysis (HCA), the generation is also at its maximum possible level, which means that any existing limitations caused due to DER output changes should be identified. The baseline for available capacities is not changed as the combined load and generation in the model should still follow the measured net load profile.

Load profiles are modeled at the feeder level, as described in Section 3.1.2. This means that there is one load profile for each feeder, and all loads on the feeder follow the same profile. A more granular method would involve using more refined load profiles for each load on the circuit (for example, all residential customers may be assigned the same profile based on their expected behavior). However, in this study it is necessary to separate load and generation before assigning a profile, and this results in a modified load profile for a customer which has generation. This could result in unique load profiles for every customer in the system with generation, which is likely an unmanageable amount of data. The following paragraph is an example of how two customers who were originally assigned the same load profile based on their net load use could end up with different load profiles once the generator output is extracted.

> Assume Customer A and Customer B have the same customer load profile assigned, based on their net load. Customer A has 10kW of load and 5kW of PV, while Customer B has 15kW of load but no PV. To address the impact of Customer A's PV on the load, we have to develop a modified profile based on what their PV output may have been. Customer B's profile does not change, and now the two customers that previously had the same profile now have two different profiles. This is also true for different load and generation capacities, which can result in unique customer load profiles for every customer on the feeder.

For the present study load profiles are assigned at the feeder level, so all customers on the feeder follow the same load profile. In the future, Dominion may move towards an improved solution for assigning load profiles at the customer level to take advantage of the more granular approach.

The approach developed here makes use of the customer load profiles provided by Dominion to develop the feeder profiles, providing a representation of the combined effect of the various load profiles modelled on the feeder, while keeping data to a manageable capacity.

3.2 Load Growth and DER Growth

Dominion plans to study its system under various assumptions of load growth within the study planning horizon. The load growth assumptions will be implemented using global load growth assumptions which define a percentage load growth for each of the 10 study years.

The implications of DER growth are also to be studied, but a different approach is taken from the load growth assumptions used in planning studies. For DER growth there are two different types of growth - known (or planned) DER additions, and prospective DER additions. These are addressed in different ways.

Known DER additions, which have typically been requested by a customer and form part of Dominion's formal interconnection queue can be added to the model and set to energize in the correct study year. They will begin to have an impact on the planning study results from that year onwards and will form part of the typical planning analyses.

Prospective DER additions are more complex to include in a planning study due to uncertainties about where they will appear, and at what size, both of which are crucial to the results of any analysis. DNV GL has developed a set of hosting capacity tools which can be used to address this uncertainty. First, the Incremental Hosting Capacity Analysis (IHCA) tool can be used to find the limits on generation that can be installed downstream of any section of the feeder. Secondly, the Stochastic Hosting Capacity Analysis (SHCA) tool can be used to simulate a large number of dispersals of generation on the feeder. This provides valuable data on what the worst case could be when future generation is dispersed randomly on the feeder.

4 NETWORK ASSESSMENT

4.1 General

The Network Assessment is divided into two parts: The load growth studies, which aim to assess the effects of load growth; and the DER impact studies, which aim to assess the impact of increasing DER on the system. In practice the DER and load growth are modelled and analyzed together, but the results are presented such that the impacts of the different features can be determined.

In any system which includes a significant penetration of DER, it is increasingly important to analyze hourly profiles, rather than simply performing peak load analysis as has been traditionally the case. The reason for this is the complexity surrounding the interactions of load and generation - due to the impact of DER, the peak load time may not necessarily be the worst case on the system, and the peak load measured at the substation may not be representative of the actual peak load used by customers due to the masking effect of DER, particularly solar generation. As such, it is not trivial to select a worst case load condition by simply reviewing load data and finding critical times.

In these analyses, it is important to separate load and generation, as described above. This allows the planning engineers to determine what could happen on the circuit if generation output is different this year than it was last year, or to assess what happens if the load stays the same but there is no generation at all for a given time-step.

In addition to providing a robust foundation for the analysis and a good representation of what is really happening on the feeder, running hourly profile analyses provide some useful information in the results. For example, in addition to finding what the worst case voltages or thermal loading conditions are, the planning engineer can find out when those occur, and also the number of hours out of the year that there could be technical violations. It also allows the planning engineer to draw interesting conclusions on potential mitigations for future DER, such as how limitations can change from hour to hour and how much curtailment may be necessary to mitigate a potential risk on the system. These are costs that can be weighed against traditional mitigation measures, such as re-conductoring or additional voltage regulators.

The following sections describe the analyses which are recommended to provide the information required by Dominion's planning engineers from these studies.

4.2 Load Growth Studies

The first part of the network assessment process is the load flow analysis. This is conducted using a '576 analysis' in Synergi. The 576 analysis makes use of characteristic load curves for each month in the study - either weekend and weekday curves or peak day and minimum day curves. Each curve is divided into 24 1-hour time-steps, resulting in 576 time-steps for a full year (24 time-steps per curve x 2 curves per month x 12 months = 576 time-steps). This is a more efficient way of running an '8760 analysis' which would involve analyzing every hour of a year.

Technical criteria for the load flow analysis were provided by Dominion and are summarized in Table 4 below:

Table 4: Technical criteria

Criterion	Limit
Thermal Loading	Thermal loading must be less than 100% of continuous rating for all equipment
Static Voltage	Voltage must be within +/-5% of nominal voltage
Interrupt Rating	Fault current at a protective device must be less than 87.5% of the device's interrupt rating

This analysis is carried out first with all of the DER off. This allows the planning engineer to assess the effects of load growth alone and ensures the system will be reliable if there is zero DER output (which may be caused during return from a switching condition, for example). The results from the analysis in Synergi provide the worst case result for each of the technical criteria (only static voltage and thermal loading from Table 4 are relevant in this load growth study), the time that the worst condition occurs, and the number of hours where any violation was observed on the circuit. These results are provided for each study year.

4.3 DER Impact Studies

4.3.1 Introduction

As part of the IDP process development, Dominion will run analyses on the impact of DER on their distribution feeders. Dominion considers two distinct types of DER on their system – utility scale and net-metered – and these are treated differently in generation forecasting and in Synergi models. For future DER, DNV GL recommends that the two types of DER are treated differently in the analysis and planning process also. This document describes DNV GL's recommendations for which analyses to perform and how the results may be interpreted and used.

4.3.2 Existing DER

4.3.2.1 General

It is proposed that the existing DER on the system be analysed as part of the normal planning studies. It is proposed that two separate sets of load flow analyses are performed in the planning process – one with all DER off, and another with DER operating based on resource profiles (such as irradiance profiles). Any violations found within the planning horizon will be identified, along with any that are specifically caused by the existing DER.

4.3.2.2 DER Impact on LTC Operations

Increasing DER capacities, particularly variable generation such as solar PV, have the potential to increase the number of operations of Load Tap Changers on the circuit due to changes in irradiance caused by clouds passing. This can have an effect on the replacement interval for these items, so an estimation of any increase in the number of operations is required. This document describes DNV GL's recommended process to arrive at this estimation.

Process

There are two parts to the process. The first is to use analysis in Synergi to find the likelihood that a given change in PV output could cause a change in tap position based on a year of load data for a given feeder in a given year. This will then be combined with PV output data measured in 15-second intervals to find the number of additional tap changes likely to be caused by the PV over a year. It is assumed that PV output changes are independent of load.

PV Output Variation Required to Change Tap Position

The percentage change in PV output required to change the tap position will vary by feeder and by loading condition. It is therefore necessary to run a new analysis for each study year to account for load and DER growth.

The study requires two analyses to be performed in Synergi – an 8760 analysis with all PV turned off, and another with all PV at 100% output. The tap positions are compared between the two analyses to find the percentage change in PV output that would be required to cause the tap position to change in a given time-step. Figure 6 below provides two examples of how the difference in the tap position between the two analyses is used to calculate the irradiance change required to move the LTC by one step.

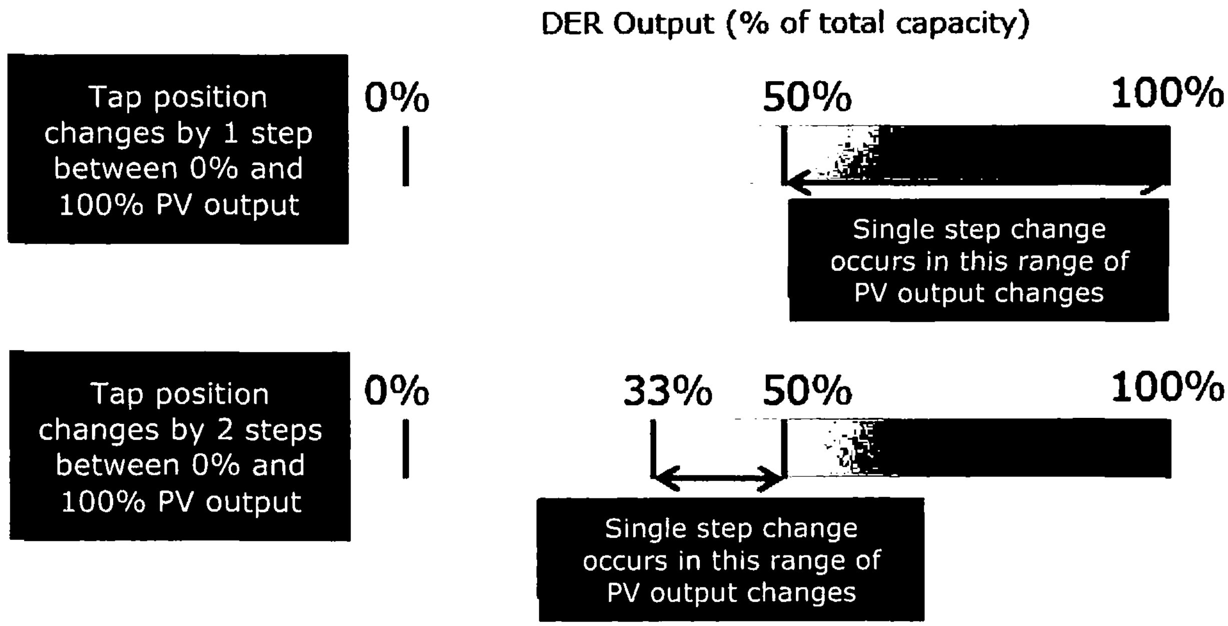


Figure 6: Examples of calculating irradiance change required to cause LTC to change position

Table 5 below describes how these results are interpreted for this study:

Table 5: PV output change required to move LTC by 1 position

Tap position change between zero and 100% PV output (number of steps)	PV output change required to move 1 LTC step (% of total rated PV capacity)
0	Greater than 100%
1	50% - 100%
2	33% - 50%
3	25% - 33%
4	20% - 25%
5	16.7% - 20%

To be conservative, it is assumed that the lower end of the ranges in Table 5 are valid – e.g., if it is seen that the LTC moved by 1 position for a 100% change in PV output, it is assumed that 50% change in PV output was all that was required to make that change in position.

After the analyses are completed, the tap positions are compared and the total number of occurrences of no change, a 1-step position change, 2-step position change, etc. are summed and divided by the total number of tests. This produces the likelihood of each PV output change (50%, 33%, 25%, 20%, 16.7%) producing a single LTC step change.

Number of Occurrences of PV Output Variations

SCADA data from an operational PV generation facility in 15-second intervals was provided by Dominion. Time delays on Dominion regulators are understood to be either 30-seconds or 45-seconds. On the demonstration systems, a time delay of 30-seconds is assumed.

The SCADA data provided covers a full year of operation. The change in PV output in every 30-second interval was calculated, and binned into those that were greater than 50% of the plant rated capacity, 33%-50%, 25%-33%, 20%-25% and 16.7%-20%. The total number of occurrences of each range of changes of output were found. These are presented in Table 6 below.

Table 6: Occurrences of output changes in 30 seconds from SCADA data

	Output change (% of rated capacity / 30 seconds)					Total Readings
	>50%/30 sec	33%-50%/30 sec	25%-33%/30 sec	20%-25%/30 sec	16.7%-20%/30 sec	
Jan-Feb	1	19	82	214	316	339,840
Mar-Apr	2	25	126	287	410	351,120
May-Jun	2	8	36	140	238	351,360
Jul-Aug	1	13	60	133	255	357,120
Sep-Oct	2	22	100	177	263	351,360
Nov-Dec	1	20	74	167	217	351,600
Total	**9**	**107**	**478**	**1118**	**1699**	**2,102,400**

Number of Additional Tap Change Operations

Finally, the results of the previous two sections are combined to produce the number of additional tap change operations due to PV on the circuit. This is done by taking the total number of occurrences of each output change from Table 6 and multiplying it by the likelihood that that change in output results in a LTC position change.

For example, if it was found that a 50% change in DER output could result in a LTC position change on 25% of time steps analysed, and a 33% change in DER output could result in a LTC position change on 10% of time steps analysed, combining these results with Table 6 would give the following result:

$$\underline{Additional\ LTC\ Operations\ per\ year = (0.25 \times 9) + (0.1 \times 107) = 12.95}$$

It is proposed that a table like Table 6 is developed and implemented as a standard table across all Dominion circuits to be analysed. The results in this table are linked to the time delay of the regulator, so another table will be required for regulators which operate with a 45 second time delay. If other time delays are in operation on the Dominion system, tables would be required for those as well. The data used for Table 6 above is based on SCADA data from one operating PV project. If Dominion would like to update or supplement this table with data from another source, this can be done at any time.

4.3.3 Future DER

4.3.3.1 Planned Utility-Scale DER

Dominion maintains a queue of active DER interconnection requests for DER of 5MW or greater capacity. This can be added to the model in the appropriate years and included in a future scenario study for planning, to identify any new violations caused by the additional generation. These analyses would follow the same process as the studies for the 'no DER' and 'existing DER' scenarios, using a 576 load flow study to identify violations. DER operation would be based on resource profiles, as described for the 'existing DER' scenario described above.

4.3.3.2 Future Potential DER

Other potential DER that may be installed in future years, but whose size and location is unknown, cannot be included in the normal planning study described above due to the lack of definition. The various DER tools available in Synergi can be used to develop feeder-specific and location-specific limits for DER in the study years. The following two analyses are recommended.

Incremental Hosting Capacity Analysis

Incremental Hosting Capacity Analysis (IHCA) in Synergi is used to determine the capacity of generation (or load) that can be added to each individual section of the model. While the analysis assumes that generation is only added to the section being studied, the results can be interpreted as the capacity that can be added downstream of that section. IHCA results can be used by Dominion as a reference as more DER (both net-metered and utility-scale) is planned on the system. Results are provided for all of the technical criteria studied, up to whichever limit is specified, so the order of any mitigation can be optimized. The analysis is carried out as a 576 analysis

Heat maps can also be developed from the IHCA which will facilitate easy identification of any areas of vulnerability on the circuit. Many utilities use these heat maps to provide information to customers on the available capacity at locations of interest. IHCA results provide a snapshot of the state of the system with respect to ease of DER deployment, and any generator interconnection requests should still go through a typical analysis process.

Stochastic Hosting Capacity Analysis

The stochastic hosting capacity analysis can be used to account for variations in generation placement when considering expansions of residential (or net-metered) DER. The stochastic analysis in Synergi is also run as a 576 analysis and involves simulating random dispersals of a given capacity of new DER, within certain parameters defined by the user (for example, individual generator size distribution and total capacity). The analysis will identify the extreme results – lowest voltage, highest voltage, highest loading, etc. – for each dispersal of generation and present the results on a scatter plot. This allows for easy identification of cases where technical criteria have been exceeded by a given distribution of generation. Examples of the scatter plots are presented below. In these charts, each dot represents the results of a different dispersal of future generation, with the total DER capacity represented by the dot plotted on the x-axis.

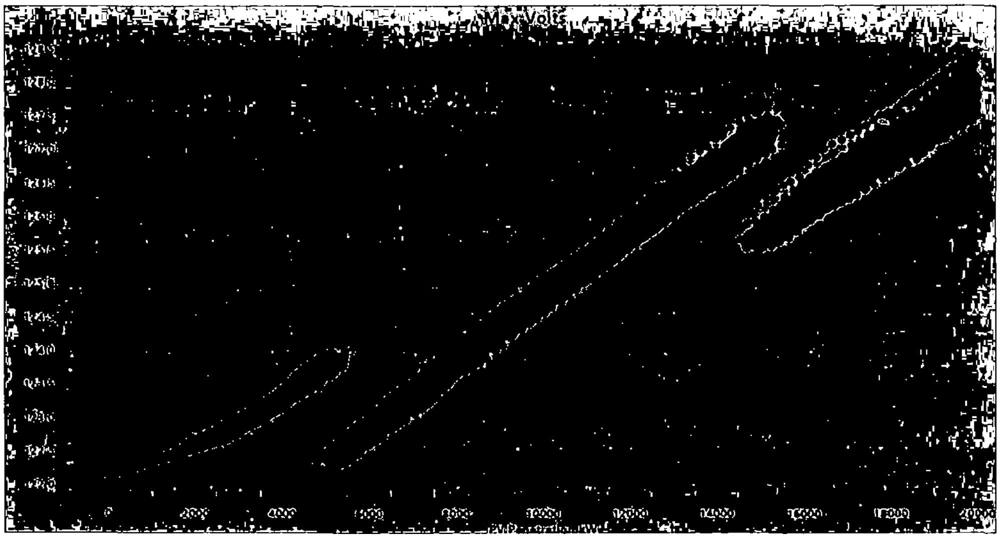


Figure 7: Stochastic hosting capacity analysis results – maximum voltage

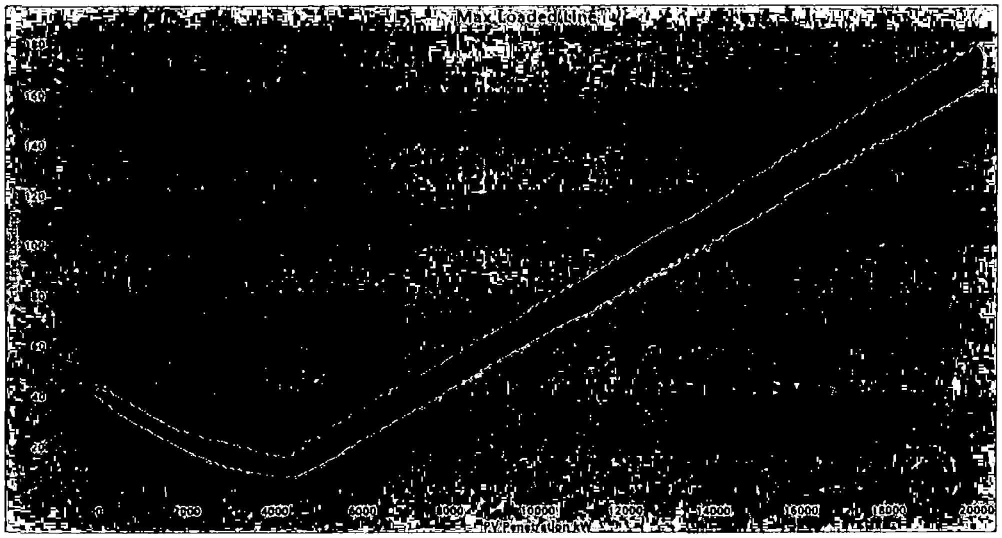


Figure 8: Stochastic hosting capacity analysis results – maximum line loading

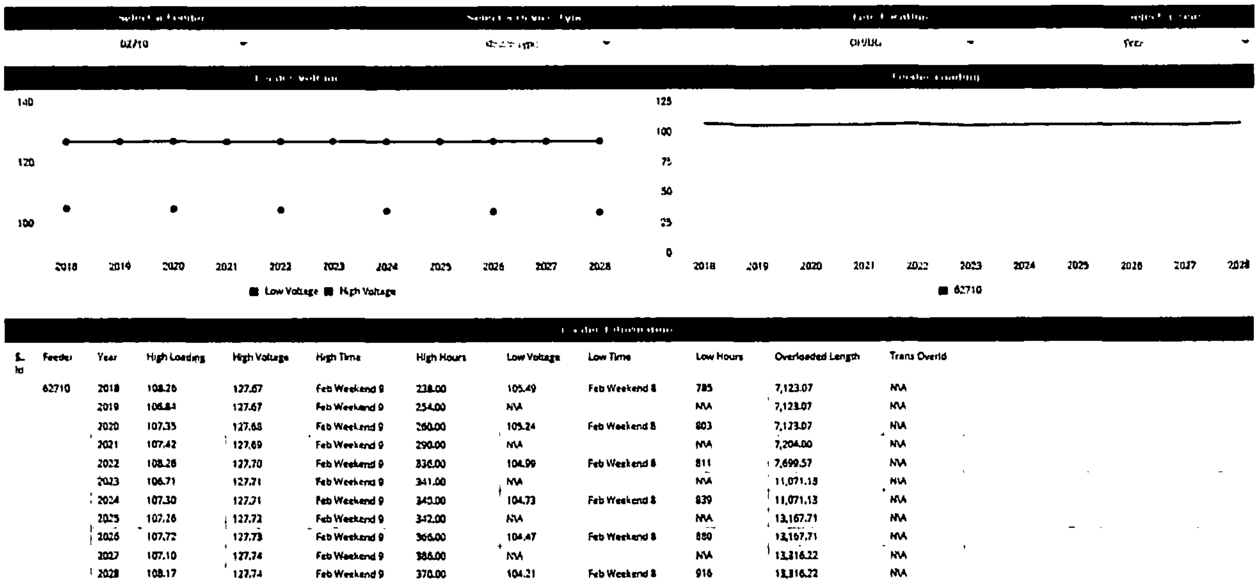
The results from these scatter plots can be translated to a set of PV capacity ranges with different levels of acceptability. Figure 9 below provides an example of this. The scatter plot in this figure shows the maximum voltage obtained for each analysis over a range of PV penetration capacities. The red line represents the high voltage technical criterion limit – 126V (120V represents nominal voltage, 126V is 5% above nominal). The color-coding is defined as follows:

- The area colored in green defines the PV capacities at which there were no high voltage violations, regardless of the dispersal of generation. Total net-metered PV capacities in this range should be considered acceptable on this feeder, regardless of how the generation is distributed.
- The area colored in yellow defines the PV capacities at which there may or may not be high voltage violations, depending on how the generation is distributed on the circuit. Acceptability of total net-metered PV capacities in this range would require further study to determine upgrade requirements.
- The area colored in red shows the PV capacities at which there were always high voltage violations, regardless of the dispersal of the generation. Total net-metered PV capacities in this range should be considered unacceptable, and circuit upgrades or other mitigation are likely to be required.

Figure 9: Example of color-coding of stochastic hosting capacity analysis results

5 IDENTIFICATION OF VIOLATIONS

DNV GL has created dashboards which can be used to quickly identify any violations caused either by organic load growth, or by operation of DER on the circuit. Results can be presented by feeder and by year, or for a selected group of feeders. The worst result for each of the technical criteria is presented along with the month, day type and hour that it occurs, and the number of hours out of the year that a violation persisted. This provides the planning engineer with useful information on the type of violations, their severity and critical times to start designing mitigation solutions. Figure 10 below provides an example of the dashboard created. This information comes directly from the outputs from the analysis, and is used as the first input to the mitigation analysis.



S. Id	Feeder	Year	High Loading	High Voltage	High Time	High Hours	Low Voltage	Low Time	Low Hours	Overloaded Length	Trans Overld
	62710	2018	108.26	127.67	Feb Weekend 9	238.00	105.49	Feb Weekend 8	785	7,123.07	N/A
		2019	106.84	127.67	Feb Weekend 9	254.00	N/A		N/A	7,123.07	N/A
		2020	107.35	127.68	Feb Weekend 9	260.00	105.24	Feb Weekend 8	803	7,123.07	N/A
		2021	107.42	127.69	Feb Weekend 9	290.00	N/A		N/A	7,204.00	N/A
		2022	108.26	127.70	Feb Weekend 9	336.00	104.99	Feb Weekend 8	811	7,699.57	N/A
		2023	106.71	127.71	Feb Weekend 9	341.00	N/A		N/A	11,071.13	N/A
		2024	107.30	127.71	Feb Weekend 9	340.00	104.73	Feb Weekend 8	839	11,071.13	N/A
		2025	107.26	127.72	Feb Weekend 9	342.00	N/A		N/A	13,167.71	N/A
		2026	107.72	127.73	Feb Weekend 9	366.00	104.47	Feb Weekend 8	880	13,167.71	N/A
		2027	107.10	127.74	Feb Weekend 9	386.00	N/A		N/A	13,316.22	N/A
		2028	108.17	127.74	Feb Weekend 9	370.00	104.21	Feb Weekend 8	916	13,316.22	N/A

Figure 10: Violations identification dashboard

6 MITIGATION PLANNING

6.1 Introduction

As part of the IDP process development Dominion seeks to identify any requirements for upgrades or mitigation to address technical violations. The process of designing mitigation, demonstrating their effectiveness and determining costs and benefits should be standardized, and this document provides DNV GL's recommendations for the mitigation design process, conventional versus non-wires alternative options, necessary analysis and cost and benefit data. Although the mitigation process itself is too complex to automate at this time, the analyses necessary to demonstrate effectiveness and calculate costs and benefits can be automated to some extent, further supporting standardization of the process.

6.2 Prioritization

Where multiple violations are found to occur on a feeder the planning engineer will prioritize the mitigation. The order of prioritization is important, as in some cases mitigation of one violation may have an effect on another violation (for example, reconductoring for a thermal overload violation may also improve a voltage problem). It is also important to understand how future mitigation measures may make earlier mitigation measures redundant. For example, there may be a high voltage violation which occurs in year 1 which could be mitigated by a new regulator or by re-conductoring a length of the line. The most cost-effective approach immediately for the voltage violation may be the addition of a new regulator. However, there may be a thermal overload in year 3 which requires the re-conductoring anyway. If this re-conductoring is sufficient to mitigate the voltage problem, then the regulator becomes redundant and that cost may have been saved by re-conductoring in year 1. The aim of the mitigation exercise is to identify the solution, or combination of solutions, that proves the most cost-effective over the study horizon.

The two violations which are most inter-dependent are thermal overloads and voltage violations as mitigations for both can include changes to load distribution or to impedances. Of the two, mitigation of thermal overloads has the fewest options available, almost all of which will have a significant impact on circuit voltages. As such it is recommended to address thermal overload violations first.

Typical mitigation solutions for voltage violations and thermal overloads are provided in Table 7 below (ordered alphabetically).

Table 7: Mitigation options

Violation	Mitigation
Static Voltage	New feeder for DG (OH)
	New feeder for DG (UG)
	New regulating device
	New STATCOM
	New storage
	Phase balancing (if unbalance is >50A)
	Power factor regulation
	Recloser settings change
	Reconductoring high loss sections
	Regulator settings change
	Shunt capacitors
Thermal Overloads	Fuse
	New feeder for DG (OH)
	New feeder for DG (UG)
	New station TX bank
	Recloser
	Reconductoring
	Upgrading 2-phase to 3-phase

The study at present covers 10 years from the base year. It should be understood that results from analyses in later years will have less certainty about them than those in earlier years due to assumptions regarding load growth and system configurations. It is therefore not expected that solid upgrade plans be made based on results in later years. However, if it is found that an upgrade planned in earlier years would require to be upgraded again in later years (such as a re-conductoring project that requires further upgrade later on), it may make more sense to implement the later upgrade from the beginning, assuming no large increase in costs.

Priority should be for mitigation of violations observed in years 1 - 3 or 1 - 5, with violations which only appear in later years noted but not necessarily actioned. However, if a violation in years 1 - 3 or 1 - 5 is mitigated, the objective should be to mitigate it for all study years.

6.3 Non-Wires Alternatives

Non-wires alternatives are mitigation measures which typically make use of DER specifically to prevent a violation from occurring (such as an energy storage system used to limit loading on a circuit) or make use of ancillary services available from existing DER (such as volt/var control on a solar generation facility's inverters) in lieu of or to defer a traditional mitigation.

If there is existing DER on the circuit, the first NWA option may be to use those facilities to mitigate the problem. Indeed, where a violation is caused by a DER facility (i.e., the violation is not present when DER is off, but it is present – or exacerbated – when the DER is on), the first option should always be to compel that facility to mitigate the problem. The options for NWA are as follows:

1. Use of existing PV systems;
2. Volt/var control or volt/watt control on inverters;
3. Additional energy storage systems;
4. Curtailment of output;
5. Additional STATCOM facilities.

As noted in Item 1 above, solar generation will be considered as potential mitigation. In this case, an assumption of the lowest recorded irradiance for each hour of each month will be considered, along with a 'N-1' scenario for utility-scale generation. In the initial applications of this process, the network assessment results with all DER off will be compared against this scenario with minimum PV output to find the effect on mitigation.

Item 2 – use of volt/var or volt/watt control – is easily implemented in Synergi, typically just requiring an inverter specification with a defined volt/var or volt/watt curve. Then the relevant analyses (starting with the worst time step, followed by full year analysis and multi-year analysis) can be performed to verify the effectiveness.

The analysis necessary for items 3 and 4 is essentially the same – the process would be to find out what the net generation from the DER facility has to be to remove the violation caused by the DER. In the case of energy storage systems, control of the net generation is achieved by varying the charge and discharge of the battery system so that excess generation is stored for discharge at a different time. In the case of curtailment, control of the net generation is achieved by reducing the output of the facility from the maximum available output.

STATCOM facilities are best suited to mitigating low voltage problems as they provide an injection of reactive power to the circuit as the voltage drops below a specified level. However, they can also be used to mitigate a high voltage problem in a similar way to fixed capacitor banks. This approach would require the STATCOM to operate with a fixed output, normally producing reactive power, helping to 'smooth' the voltage profile on the feeder (i.e., reducing the volt drop along the feeder). That in turn allows the LTC or regulator set point to be reduced to a lower voltage, as there is a lower volt drop on the circuit to compensate for. In addition, if the voltage violation still occurs in some conditions, the STATCOM can be turned off, further reducing the voltage in that area of the circuit.

For several of these non-wires alternatives, particularly those that rely on customer-sited facilities (rather than utility-owned equipment) additional infrastructure may be required to facilitate the technology. For example, an Distributed Energy Resource Management System (DERMS) and communications infrastructure would be required to provide the utility with visibility and control (where appropriate) of an energy storage system which is used for mitigation of a thermal overload. Where cost data have been included in this report for example purposes, the costs do not include the cost of the additional enabling infrastructure which would require a system-wide cost/benefit study.

6.4 Case Studies

The tools and processes described here were demonstrated using three feeders selected by Dominion as a representation of different types of feeders and data seen on the full distribution system. These feeders exhibit a range of circuit lengths, different operating voltages, different load data sources and varying types and capacities of generation. The three feeders and their characteristics are described below:

Table 8: Demonstration feeder characteristics

Feeder	Length	Voltage	Load data	Existing Generation
F62710	19.7 miles	12.5kV	AMI	Two 5MW PV units
F71475	139.0 miles	34.5kV	SCADA at substation	One 10MW PV unit, several residential units
F81305	211.6 miles	34.5kV	AMI	68 small PV units, 945kW total

The study followed all of the processes and methodologies described above. First, load data provided for each of the circuits was processed to develop load and generation profiles for each of the feeders. Annual load growth assumptions were applied to each feeder based on forecasts provided by distribution planners.

The next step was to conduct the network assessment. This involves a series of multi-year analyses using the monthly load and generation profiles developed. The analyses carried out are as follows:

1. Load flow with all DER off – this establishes the impacts of load growth alone on the feeders;
2. Load flow with all DER on, following maximum irradiance curves – this establishes the impacts of existing DER facilities on the feeders;
3. Load flow with all DER on, following minimum irradiance curves – this identifies any potential for mitigation of load growth impacts by using existing DER facilities;
4. Load flow with all DER at 100% output – this is used to estimate the impact on LTC operations due to existing DER facilities;
5. Incremental Hosting Capacity Analysis – this is used to identify capacities for utility-scale generation on the feeders;
6. Stochastic Hosting Capacity Analysis – this is used to estimate the available capacity for net-metered generation on the feeders.

Following the analyses outlined above, the results were processed to identify any potential technical violations in the study period. Depending on the location and nature of the violations, further analyses were carried out to identify suitable mitigation options, including conventional and non-wires solutions. Table 9 below provides the definition of technical criteria used in the analysis and what constitutes a technical violation.

Table 9: Technical criteria used in analysis

Criterion	Limit
High Loading	100% of continuous rating for all equipment
High Voltage	5% above nominal voltage, or higher (126V or higher on 120V base in results tables)
Low Voltage	5% below nominal voltage, or lower (114V or lower on 120V base in results tables)

6.4.1 F62710

The F62710 feeder results for the load growth analysis were as follows (note that all results tables only report violations, if there were no violations of a given type for a given year, cells would be empty or zero):

Table 10: F62710 load growth violations – all DER off

Feeder	Year	High Conductor Loading	High Voltage	Low Voltage	Overloaded Length (ft)
	2020	112.2	127.66	102.84	7,123.1
	2021	113.3	127.66	103.12	7,123.1
	2022	114.5	127.67	103.40	7,123.1
	2023	115.6	127.68	103.67	7,123.1
	2024	116.8	127.69	103.94	7,123.1
F62710	2025	118.0	127.70	104.21	7,123.1
	2026	119.1	127.70	104.47	7,123.1
	2027	120.3	127.71	104.73	7,123.1
	2028	121.6	127.72	104.99	7,123.1
	2029	122.8	127.73	105.24	7,123.1
	2030	124.0	127.73	105.49	7,123.1

Table 11: F62710 load growth violations – minimum PV output

Feeder	Year	High Conductor Loading	High Voltage	Low Voltage	Overloaded Length (ft)
F62710	2020	112.2	127.66	102.95	7,123.1
	2021	113.3	127.66	103.23	7,123.1
	2022	114.5	127.66	103.50	7,123.1
	2023	115.6	128.43	103.78	7,123.1
	2024	116.8	128.44	104.05	7,123.1
	2025	117.9	128.45	104.31	7,123.1
	2026	119.1	128.46	104.58	7,123.1
	2027	120.3	128.47	104.83	7,123.1
	2028	121.5	128.49	104.28	7,123.1
	2029	122.8	128.50	104.53	7,123.1
	2030	124.0	128.51	104.78	7,123.1

The results show that there are high voltage violations, low voltage violations and thermal overload violations on the circuit in every year studied. There are two utility-scale solar generation facilities on the feeder, rated at 5MW each which, in theory, could be used to help with mitigation of both voltage and thermal overload problems. However, the results in Table 10 and Table 11 above show that there is very little difference between the violations identified with the DER off and with PV on at minimum output. The reason for this is clear when the minimum PV output profile is viewed:

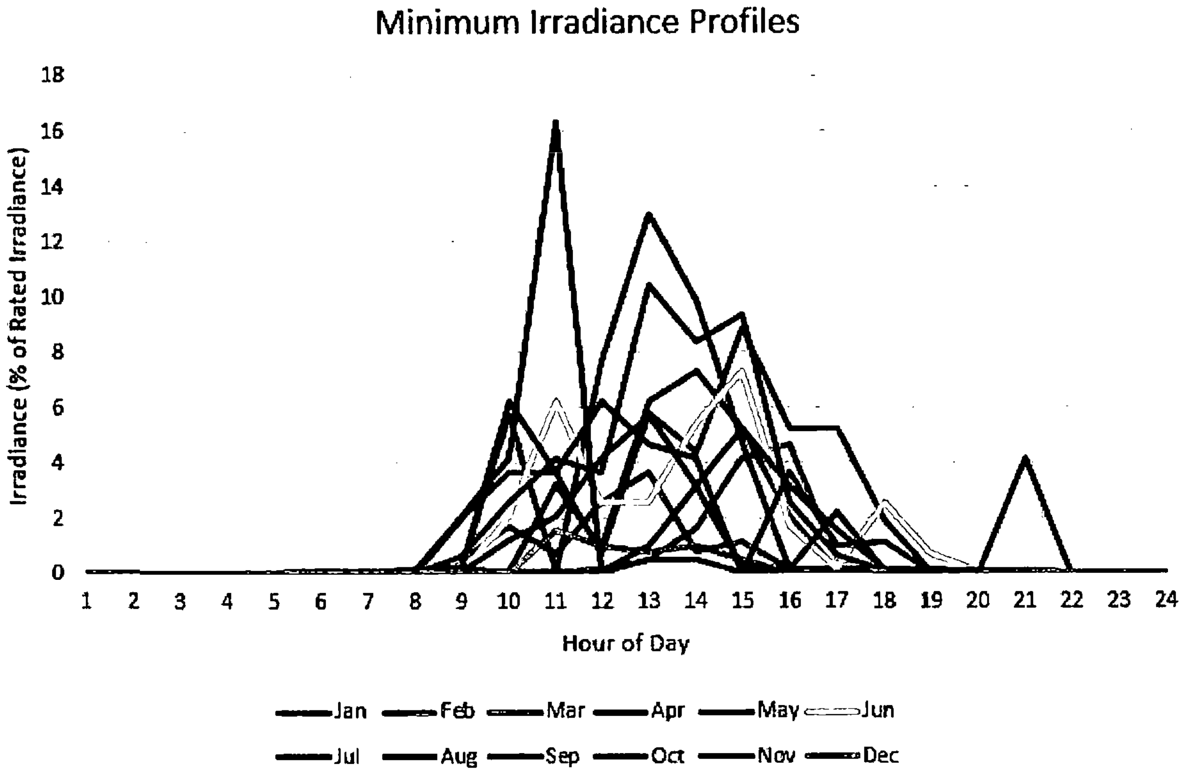


Figure 11: Minimum irradiance profiles by month

This irradiance profile is based on 15-second SCADA data taken from an operational PV project on the Dominion system. The data shows that the highest output from the PV generation never exceeds 16.25% of maximum. Further, for the times when the highest loading occurs (usually 8am to 10am) the output does not exceed 6.25%. This indicates that the minimum irradiance on the feeder, and therefore the minimum solar output, is very low (for comparison, in July and August around midday the maximum irradiance would be expected to be between 85% and 100%). Therefore, in this case it can be expected that the minimum PV output does not significantly improve the results on the feeder.

The first priority should be to mitigate the thermal overloads, which may also improve the voltage. The mitigation analysis will be carried out using both conventional and non-wires solutions, with cost-comparisons where alternatives are available.

6.4.1.1 Thermal Overloads

The 576 analysis was used to identify the worst conditions for each year, based on 2018 load data (which is the last year for which a full set of load data is available) and load growth forecasts to extrapolate to study years. The worst hour for thermal loading in 2020 was found to be a February Weekend at 8am. Load flow analysis at this time shows a maximum thermal overload on the circuit of 112.18%. A heat map is generated to identify the overloaded sections, shown in Figure 12 below. In the heat map, sections colored purple are loaded above 100% of thermal capacity.

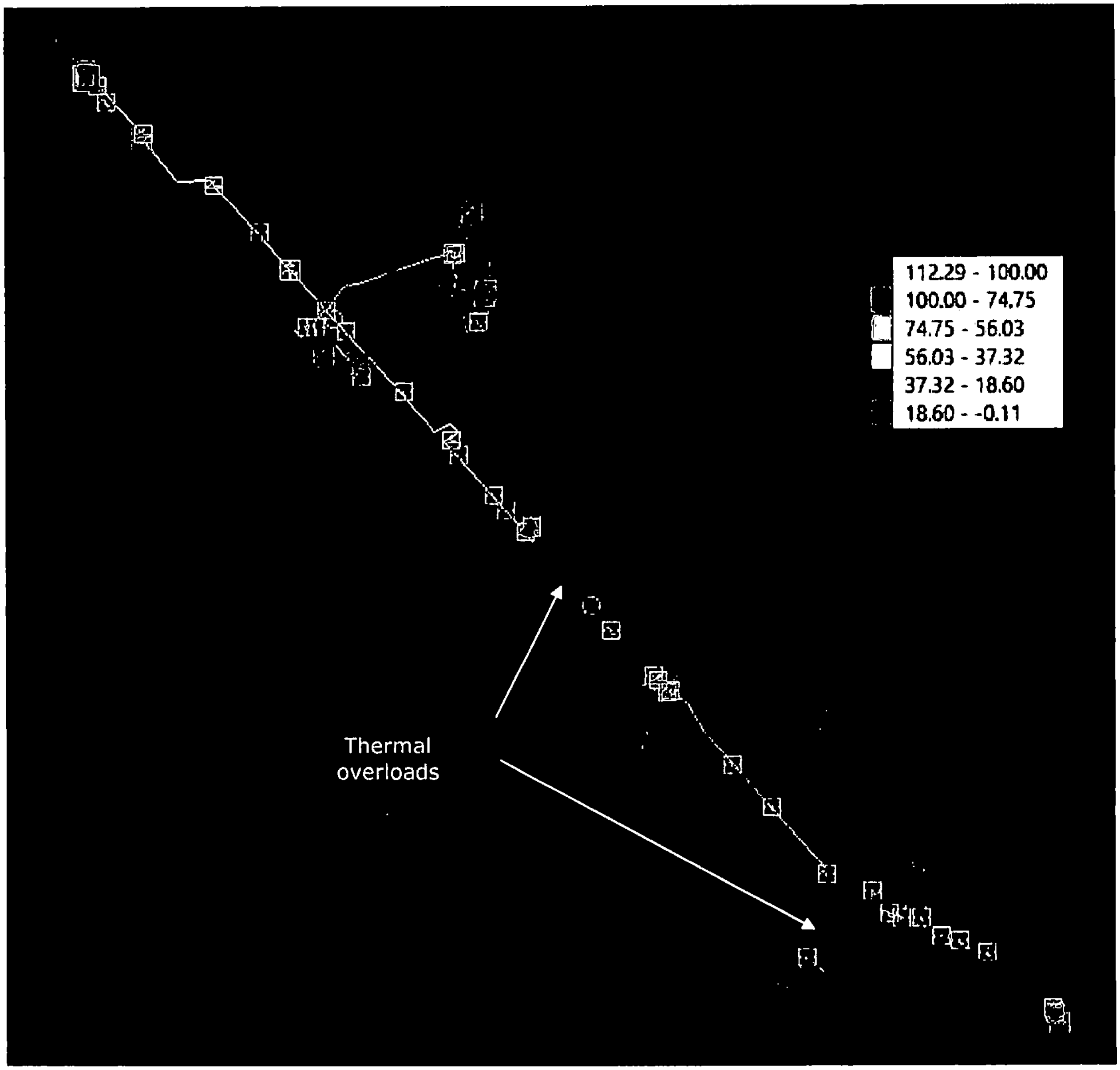
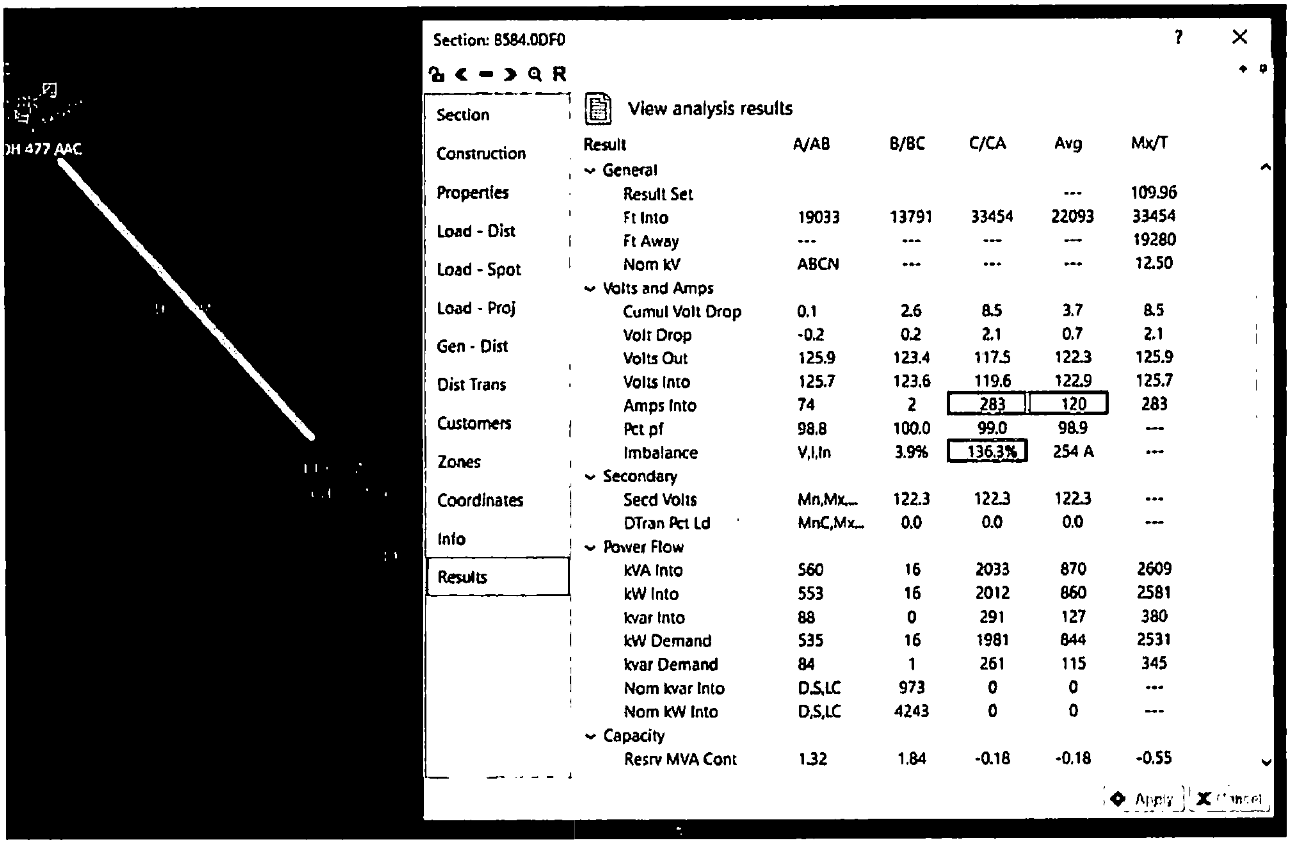


Figure 12: Thermal overloads highlighted on heat map

Two main overloaded sections can easily be seen – one on the three-phase main line and one on the single-phase branch towards the end of the feeder.

Results from the first overloaded section of the main line show that only phase C is overloaded, see Figure 13 below. It also shows that there is an excessive imbalance on this portion of the circuit, which is due to a large load appearing on a single-phase branch of the circuit. As there is only one significant load on this part of the circuit, phase balancing is not an option as it will simply shift the problem from one phase to another. Rather than re-conductoring this main line, it may be more cost-effective to upgrade the single-phase branch with the large load to a three-phase branch.



Result	A/AB	B/BC	C/CA	Avg	Mx/T
General					
Result Set				---	109.96
Ft Into	19033	13791	33454	22093	33454
Ft Away	---	---	---	---	19280
Nom kV	ABCN	---	---	---	12.50
Volts and Amps					
Cumul Volt Drop	0.1	2.6	8.5	3.7	8.5
Volt Drop	-0.2	0.2	2.1	0.7	2.1
Volts Out	125.9	123.4	117.5	122.3	125.9
Volts Into	125.7	123.6	119.6	122.9	125.7
Amps Into	74	2	283	120	283
Pct pf	98.8	100.0	99.0	98.9	---
Imbalance	V,I,In	3.9%	136.3%	254 A	---
Secondary					
Secd Volts	Mn,Mx...	122.3	122.3	122.3	---
DTran Pct Ld	MnC,Mx...	0.0	0.0	0.0	---
Power Flow					
kVA Into	560	16	2033	870	2609
kW Into	553	16	2012	860	2581
kvar Into	88	0	291	127	380
kW Demand	535	16	1981	844	2531
kvar Demand	84	1	261	115	345
Nom kvar Into	D,S,LC	973	0	0	---
Nom kW Into	D,S,LC	4243	0	0	---
Capacity					
Resrv MVA Cont	1.32	1.84	-0.18	-0.18	-0.55

Figure 13: Thermal overload on Phase C only

Figure 14 below shows the single-phase branch where the large load is located. The OH #2 AAAC 5005 conductor is overloaded at 112% of continuous rating on phase C, which suggests that upgrading this line to three-phase and splitting the load over three-phases should solve the problem.

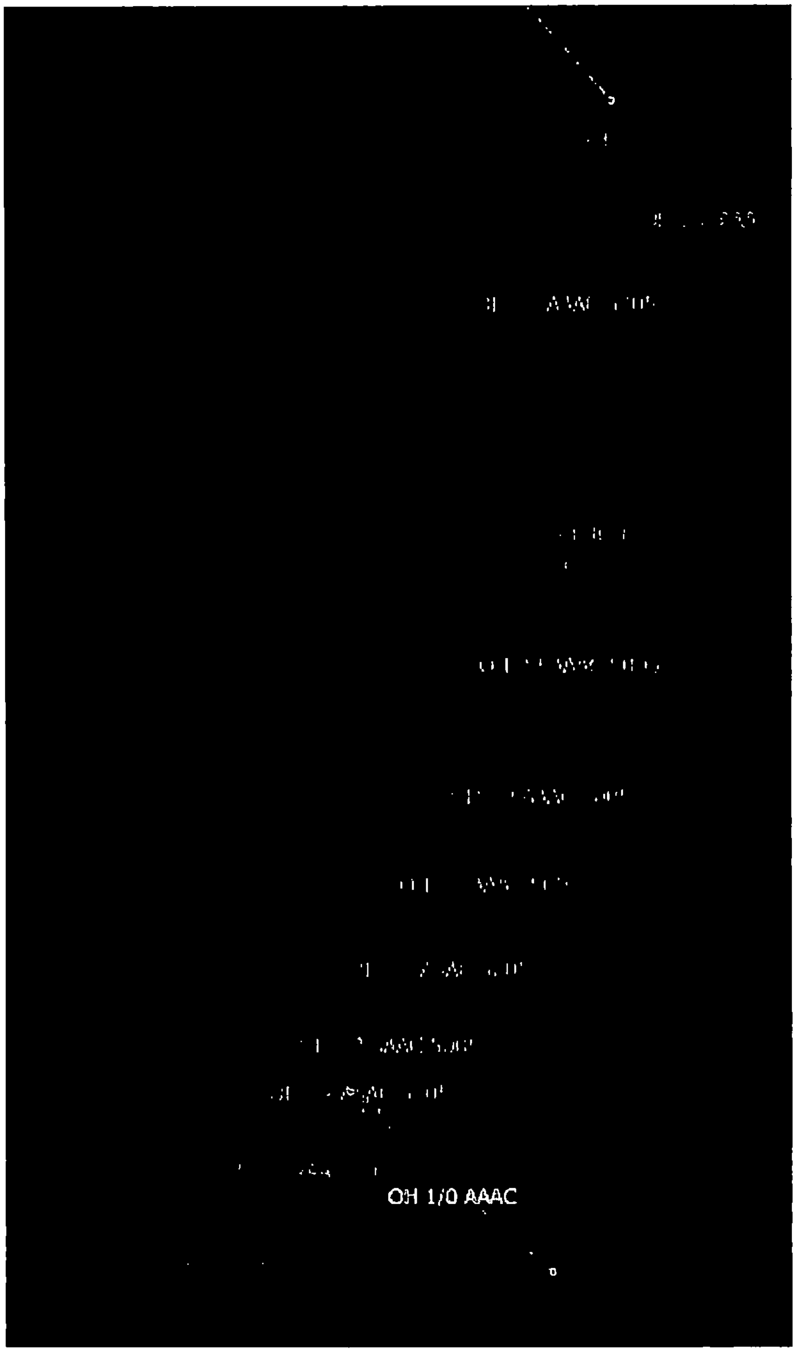


Figure 14: Overloaded single-phase branch

The total length to be upgraded to three-phase here is 2899 ft. With this mitigation implemented, there are no thermal overloads on the circuit in this time-step.

The next step is to check if the mitigation is sufficient to maintain loading below 100% in all study years. The results show that there is one new overloaded section in 2030. As it is in the last study year and is not one of the sections which was upgraded in the initial mitigation, it is recommended to note the overload for future studies, but take no other action at this time.

A non-wires alternative option may be available to mitigate the thermal overload problem described above, which starts in 2020 and progressively increases up to 2030. As described above for the conventional solutions, mitigation for 2020 is designed first. The highest overload on the circuit in 2020 is 112%, so reducing the peak load on this part of the circuit by 11% would be sufficient to mitigate the overload in 2020. An energy storage system could be used to accomplish this, by smoothing the load profile. To find the capacity required, a 576 analysis is carried out with the section with single-phase load selected. This provides a report with the load profiles of the selected section, as shown in Figure 15:

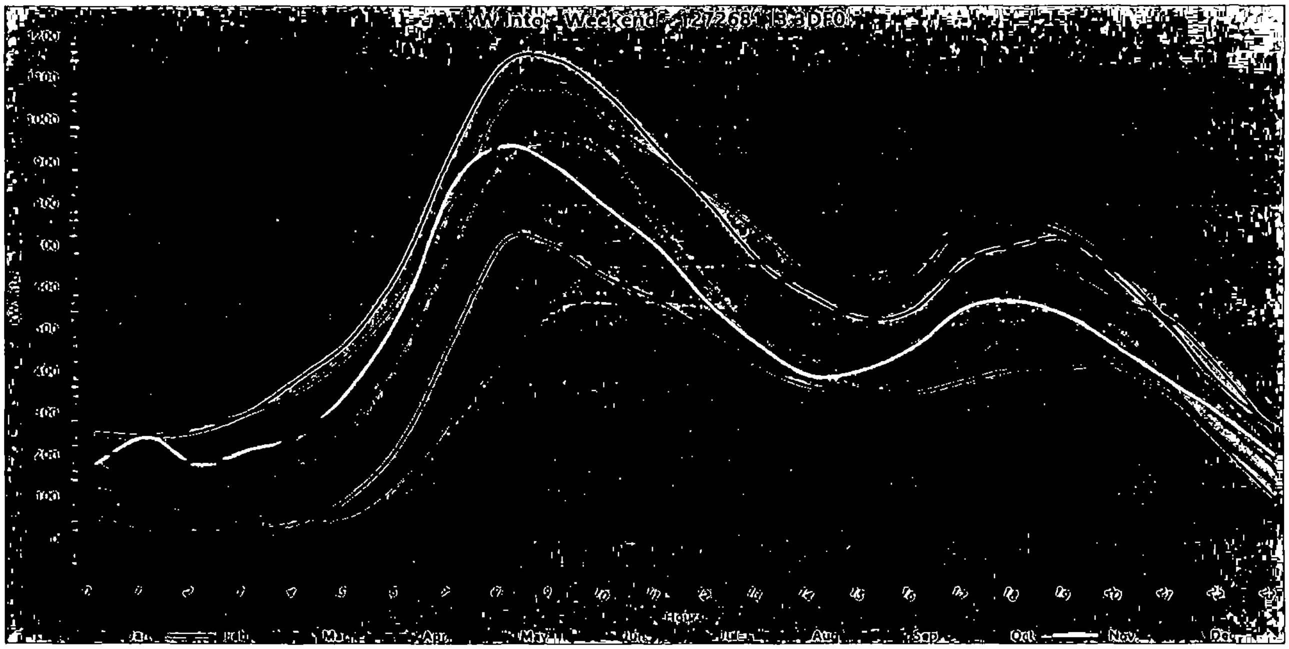


Figure 15: Load profile of section responsible for thermal overloads

The peak load on the section is found to be approximately 1387kW. An initial estimate of the required energy storage sizing is to find 11% of this value, which is 153kW. Further iterations on the model shows that an energy storage size of 170kW is sufficient to mitigate the thermal overload in the base year, and up to 3 hours of discharge capacity are required, as shown in Figure 16 below. Total discharge capacity is 385kWh.

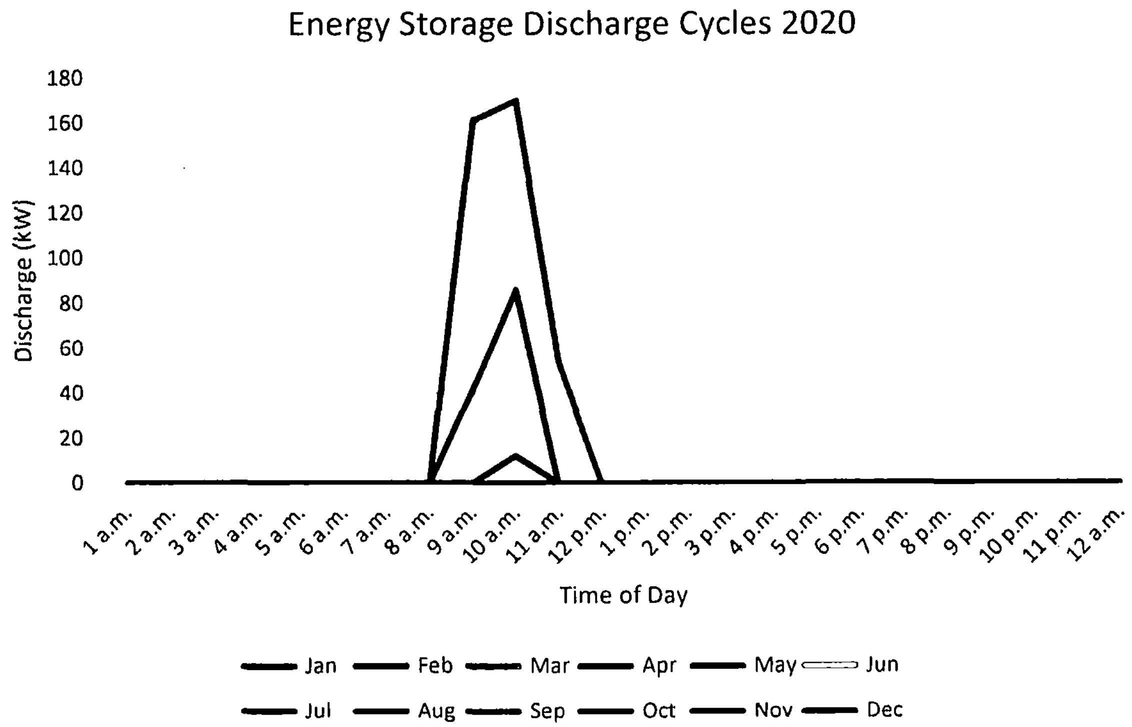


Figure 16: Energy storage discharge required to mitigate thermal overload in 2020

Once installed, the energy storage size must increase each year to keep pace with load growth on the circuit, and effectively increase by the same amount as the load on the overloaded sections. By 2030 the energy storage size must be 380kW to mitigate thermal overloads. In 2030, the required discharge cycle would be as shown in Figure 17 below:

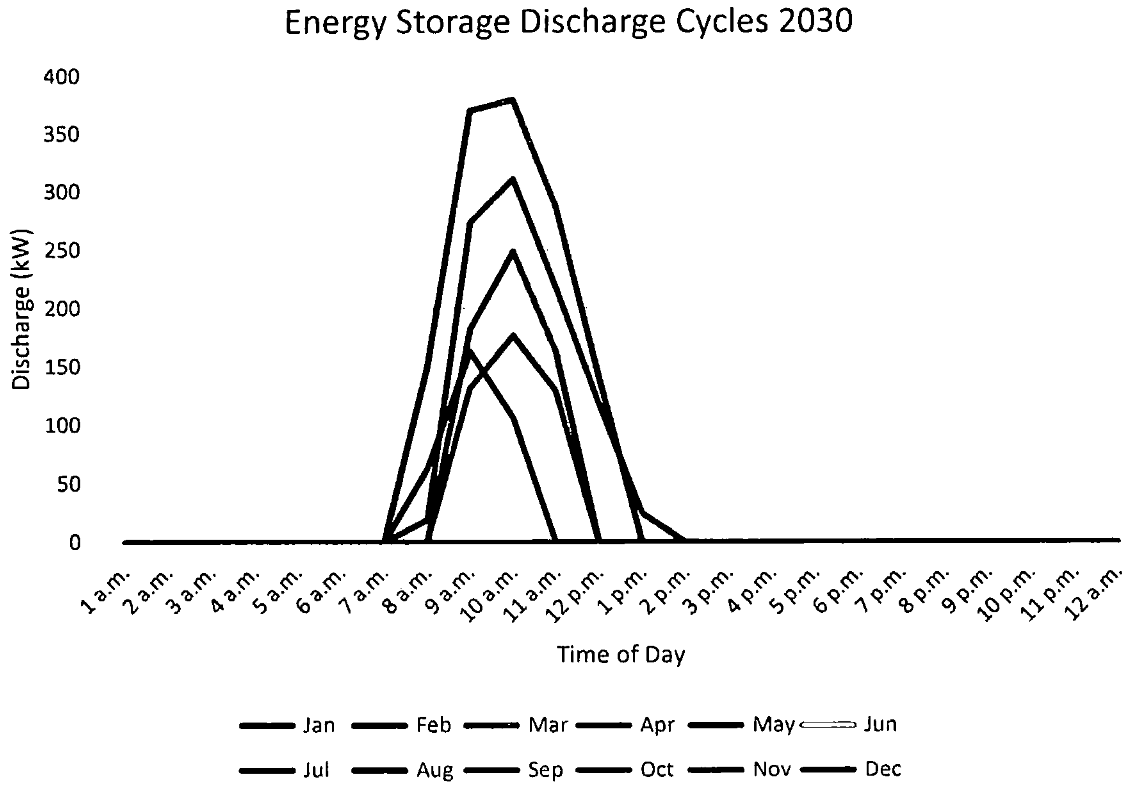


Figure 17: Energy storage discharge required to mitigate thermal overload in 2028

In 2030, up to 380kW of storage capacity would be required, with a maximum discharge duration of 6 hours. As the battery does not have to discharge to the full capacity for every hour, the total discharge capacity is calculated as around 1350kWh in 2030. As storage costs are projected to decline steadily for the next 10 years, it may be cost-effective to add storage capacity each year as required.

6.4.1.2 Voltage Violations

The results for F62710 show potential high and low voltage violations from 2020. These are mitigated to some extent by the mitigations for the thermal overloads described in Section 6.4.1.1 above. With these mitigations in place, the maximum and minimum voltages on the circuit in 2020 are 126.8V and 115.2V, respectively. Therefore, there is now only a high voltage violation.

The voltage violation was found to be only present on Phase C. The Load Tap Changer in the model was set up to be gang-operated based on Phase A. It is understood that Dominion's LTCs are all set up for three-phase operation, which means having independent phase regulation is not an option. Changing the gang-operated function to measure Phase C, which is the most heavily-loaded phase, removed the high voltage violation on Phase C, but produced a low voltage violation on Phase A. The low voltage violation occurs on the single-phase branch colored light blue in Figure 18 below:

Figure 18: Low voltage violation after LTC regulation moved to Phase C

The simplest method of mitigating the low voltage violation is to add a reactive power source to the circuit. This could be either a 1200kVAR fixed or switched capacitor bank, or an 800kVAR STATCOM placed on the two-phase line. Both of these options would mitigate the voltage violations up to 2030.

In this case, the non-wires alternative as designed for the thermal overload violation was not found to be sufficient to mitigate the voltage problems. This is because there is still a large phase imbalance with the load on Phase C which is the cause of the very low voltages. In order for the low voltage violations to be mitigated, some high voltage violations were found to be induced at the feeder head. As such it was not found to be possible to mitigate both the high and low voltage violations using a single energy storage facility.

6.4.1.3 DER Impacts

The process of mitigation should be to resolve violations due to load growth prior to mitigating violations caused by DER on the circuit. As such, the DER impacts should be re-evaluated in the base year by re-running the 576 analysis once the other mitigation has been placed.

On the F62710 circuit the initial results showed that the DER on the circuit could exacerbate the existing thermal overload and high voltage problems, but did not cause any new problems. Re-evaluation of the base year following load growth mitigation and with DER added produced the following results:

Table 12: 2020 DER impact analysis with load growth mitigation implemented

	DER Off	DER On
Maximum Voltage	**125.5**	**131.1**
Minimum Voltage	**115.2**	**115.5**
Maximum Loading	**91.60%**	**91.60%**

These results show that the DER could produce a new high voltage violation. The first option should be to investigate whether the DER facility (or facilities) can mitigate this through inverter controls.

An initial analysis with the inverter output fixed at -95% (absorbing reactive power) on both of the 5MW solar generation facilities shows that the maximum voltage in 2020 is reduced to 125.4V and the minimum voltage is 115.2V. Therefore, fixed power factor operation is shown to be sufficient to mitigate the high voltage violation caused by the DER in 2020.

A multi-year analysis out to 2020 is then carried out to verify that the mitigation is sufficient in all study years. This analysis shows that the maximum voltage in 2030 is 125.6V, while the minimum is 114.0V. Therefore, the fixed power factor operation is sufficient to mitigate the voltage violations caused by DER in all study years.

An alternative to fixed power factor operation is to implement a volt/var curve on the solar generator. This would allow the generator to operate at unity power factor until the voltage increases above a set level, after which it would start absorbing reactive power to maintain the voltage below prescribed levels. The cost of these measures depends on the inverter capacity available for the project. For example, if the inverter capacity matches the maximum project output, operation at fixed -95% power factor would result in 5% loss whenever the generator output equals the maximum allowed output. If the project output is below the inverter capacity, then losses would be between 0 and 5% at all times.

If the inverter capacity is 5.3% or more larger than the maximum project output, there would never be any losses to the project as the inverter has the capacity to provide full reactive capability without reducing the active power output.

Conventional options for mitigation of the voltage violations, if power factor control is not possible on the solar generation facilities, would be a regulator settings change, a new voltage regulator, or re-conductoring of high-loss sections.

The first option is to investigate whether the voltage set point on the LTC can be reduced to remove the high voltage violation without creating a new low voltage violation. Analysis shows that the set point would have to be set to 117.5V in order to remove the high voltage violation caused by the DER. This results in extensive low voltage violations on the circuit, so is not a viable mitigation option.

A new voltage regulator can be placed near where the voltage violation occurs. Figure 19 below shows the area where the high voltage violation occurs, with sections colored pink representing excessive voltages on Phase A.

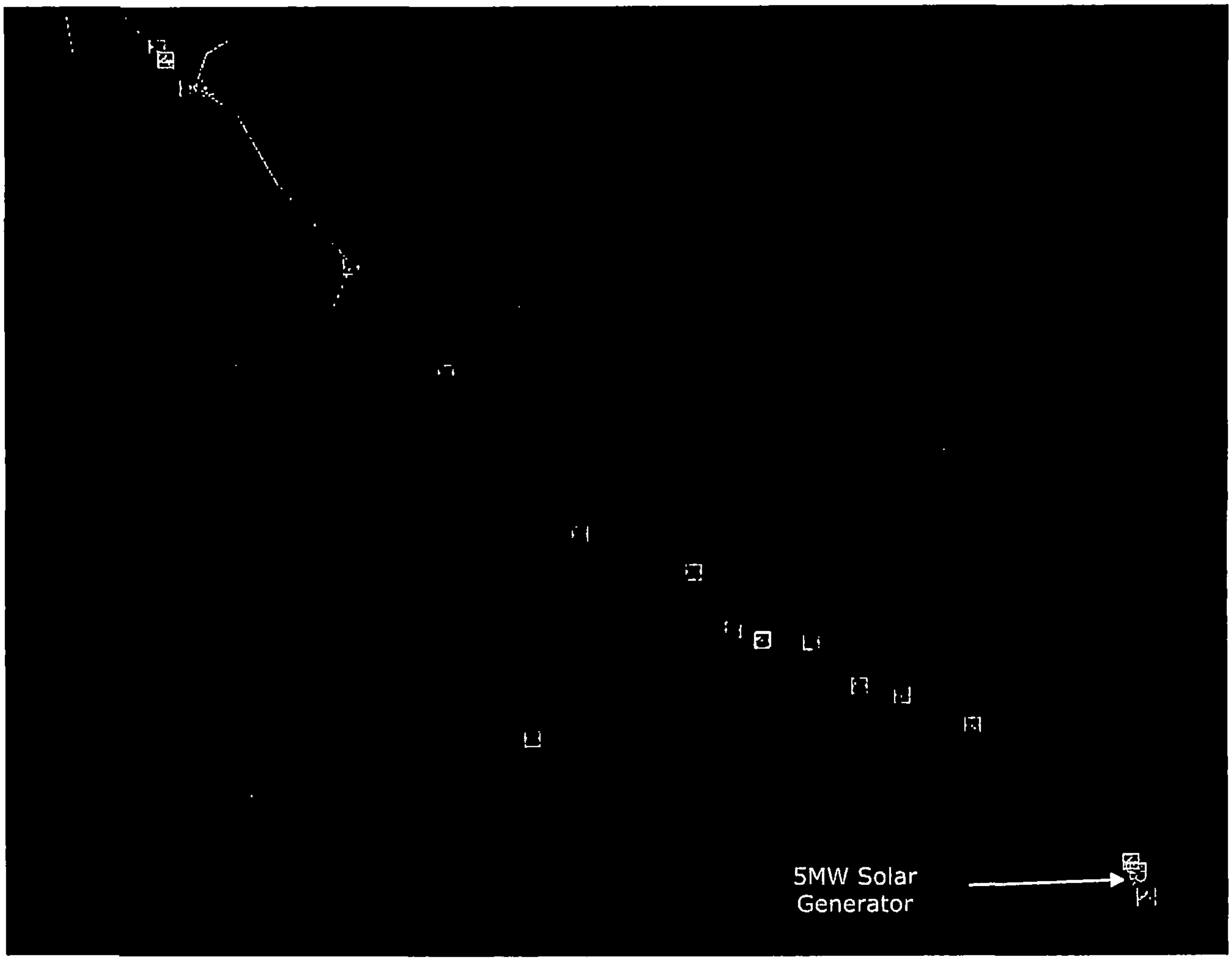


Figure 19: High voltage violations caused by DER operation

Placing a regulator ahead of this high voltage area with the setpoint at 120V and Co-Generation mode enabled reduces the highest voltage to 125.2V in the 2020 analysis, so this is sufficient to mitigate the problem. A multi-year analysis to 2030 shows the maximum voltage remains at 125.2V, and the minimum voltage is 114.3V, so this mitigation is sufficient for all study years.

Finally, re-conductoring of high-loss sections was investigated. As this is a reverse flow problem, the highest losses are near the generator where the highest currents are flowing. The re-conductoring study should start from there and move towards the feeder-head. Analysis showed that around 2.75 miles of 1/0 AAAC conductor would have to be upgraded to 477 AAC to mitigate the voltage problem.

6.4.1.4 Hosting Capacity Analysis

The IHCA simulates increasing capacities for single generators on each section of the circuit, finding the maximum capacity that can be installed without incurring any technical violations at any hour of the year. Results can be summarized at the feeder head, as shown in Table 13 below. These results are the maximum utility-scale generation capacity that can be installed on the feeder in a given year, and assume that no additional mitigation measures or upgrades have been applied beyond what is in the original model.

Table 13: Incremental hosting capacity results for F62710 feeder head by year

Feeder	Year	Hosting Capacity (MW)
F62710	2020	0.00
F62710	2021	0.00
F62710	2022	0.00
F62710	2023	0.00
F62710	2024	0.00
F62710	2025	0.00
F62710	2026	0.00
F62710	2027	0.00
F62710	2028	0.00
F62710	2029	0.00
F62710	2030	0.00

Results for a single section, like those shown above, can easily be extracted and reported in a dashboard. In addition, results for every individual section of the model can be produced for a given study year. These can also be used in heat maps, showing how the capacity changes in different areas of the feeder. This is the information typically provided to the public, showing how much generation could be installed in a single location with a low probability of incurring upgrades. Figure 20 below provides the heat map for F62710 in 2020.

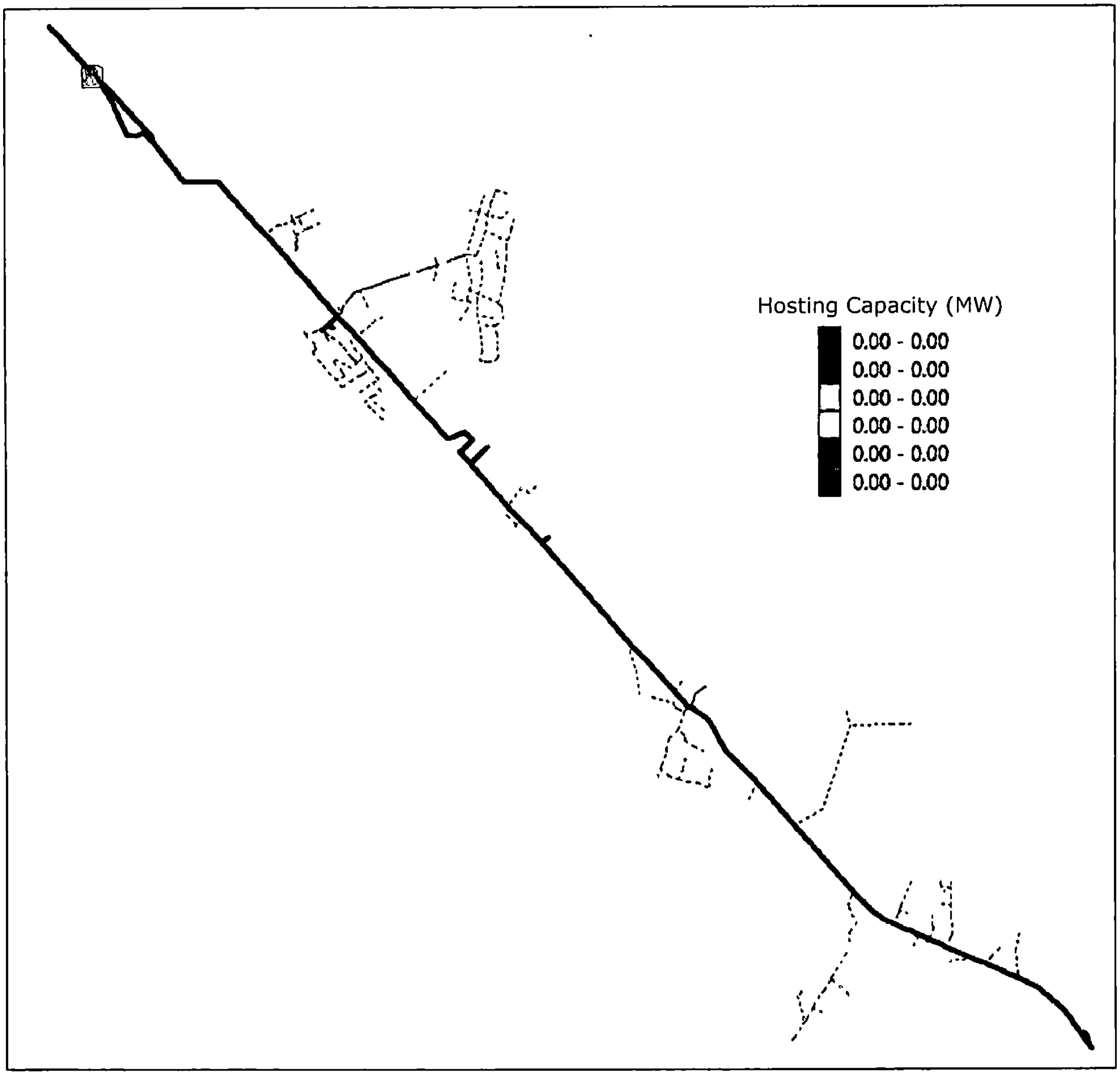


Figure 20: Incremental hosting capacity results for F62710 in 2020

The stochastic hosting capacity analysis is intended to address net-metered generation, which may be connected to a feeder in multiple locations in a short space of time. The way this generation is distributed on the feeder has a major impact on the acceptability of different capacities of generation, and the upgrades that may be required. To address this uncertainty, stochastic hosting capacity analysis can be carried out, simulating thousands of different possible distributions for every analysis year. The results can be synthesized into color-coded charts defining three different zones of acceptability:

- Ranges of PV capacities where no technical violations were found, regardless of the distribution;
- Ranges of PV capacities where there could be violations depending on the distribution of the generators, and;
- Ranges of PV capacities where technical violations were found to occur regardless of the distribution.

These can be colored green, yellow and red, respectively. Figure 21 below provides these results for all technical criteria for the F62710 feeder in each study year:

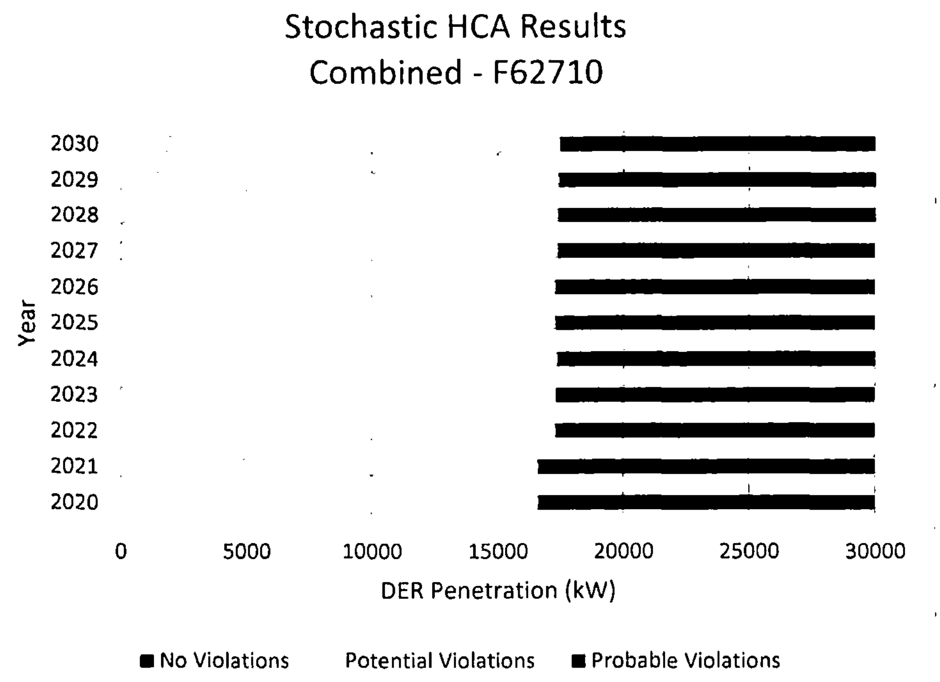


Figure 21: Stochastic hosting capacity results for F62710

6.4.1.5 Summary of Mitigation Measures

Table 14 below presents the options for mitigation of violations found on the F62710 circuit. Cost data included here is based on generic industry data for example purposes and should not be used for decision making without further scrutiny:

Table 14: Summary of mitigation options for F62710

Cause	Violation	Mitigation Option(s)	Typical Cost	Additional Benefits
Loading	Thermal Overload	Upgrade single-phase to three-phase	$219,000	Reduced losses
		Energy storage	$330,000 to $975,000	Potential frequency regulation revenue Further peak load reduction
Loading	High Voltage	LTC settings change	$5,000	
		1200kVAR capacitor bank	$25,000	
		800kVAR STATCOM	$800,000	
DER	High Voltage	Power factor settings change	$0	
		New regulator	$110,000	
		Re-conductor 2.75 miles of main line	$2,750,000	Reduced losses

Figure 22 below provides a proposed schedule of upgrades for the most cost-effective approach, and Figure 23 provides a proposed schedule of upgrades using only non-wires solutions:

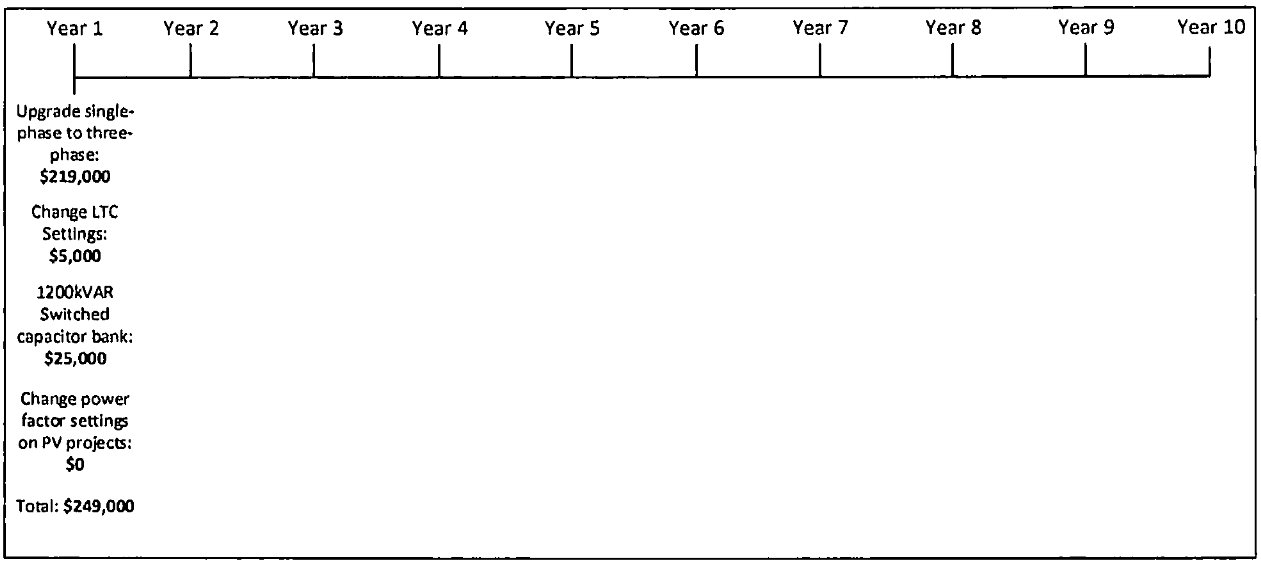


Figure 22: Proposed schedule for F62710 upgrades using most cost-effective approach

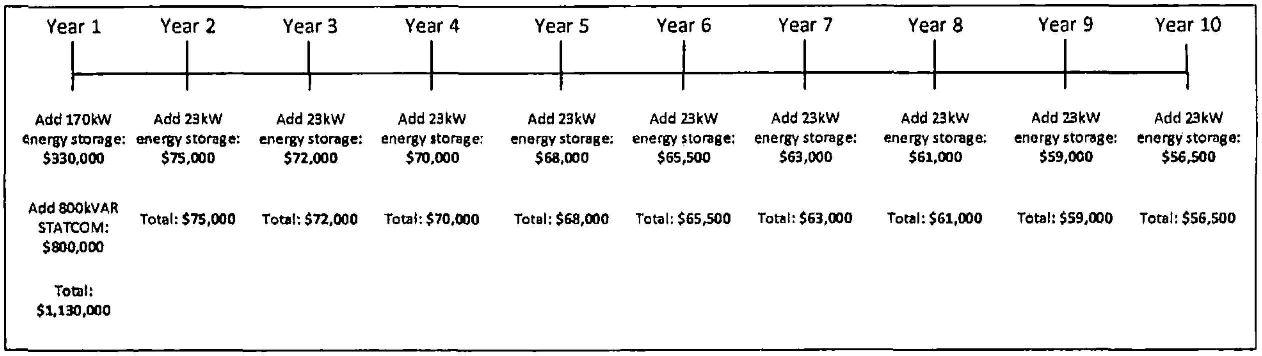


Figure 23: Proposed schedule for F62710 upgrades using non-wires approach

6.4.2 F71475

The F71475 results from the load growth analysis are shown in Table 15 below:

Table 15: F71475 load growth analysis results

Year	High Conductor Loading	High Voltage	Low Voltage	Overloaded Length (ft)
2020			107.27	N\A
2021			106.69	N\A
2022			106.27	N\A
2023			106.31	N\A
2024			105.68	N\A
2025			105.03	N\A
2026			104.58	N\A
2027			104.53	N\A
2028			103.84	N\A
2029			103.13	N\A
2030			103.23	N\A

The results show that there are only low voltage problems, which occur every year and progressively worsen as load grows. On this circuit there is one 20MW solar generation facility. The low voltage results with the PV generator on and operating at minimum output are shown in Table 16 below, alongside the low voltage results from Table 15 above. The results show that there was very little change in the low voltage violations.

Table 16: F71475 load growth results with DER off and DER at minimum output

Year	Low Voltage – DER off	Low Voltage – DER minimum
2020	107.27	107.32
2021	106.69	106.74
2022	106.27	106.14
2023	106.31	106.33
2024	105.68	105.73
2025	105.03	105.08
2026	104.58	104.42
2027	104.53	104.58
2028	103.84	103.89
2029	103.13	103.18
2030	103.23	102.94

6.4.2.1 Low Voltage Violations

The 576 analysis indicated that the worst low voltage occurs at 2pm on a July weekday. The voltage plot in Figure 24 below shows low voltage violations (voltages below 114V) in green and light blue.

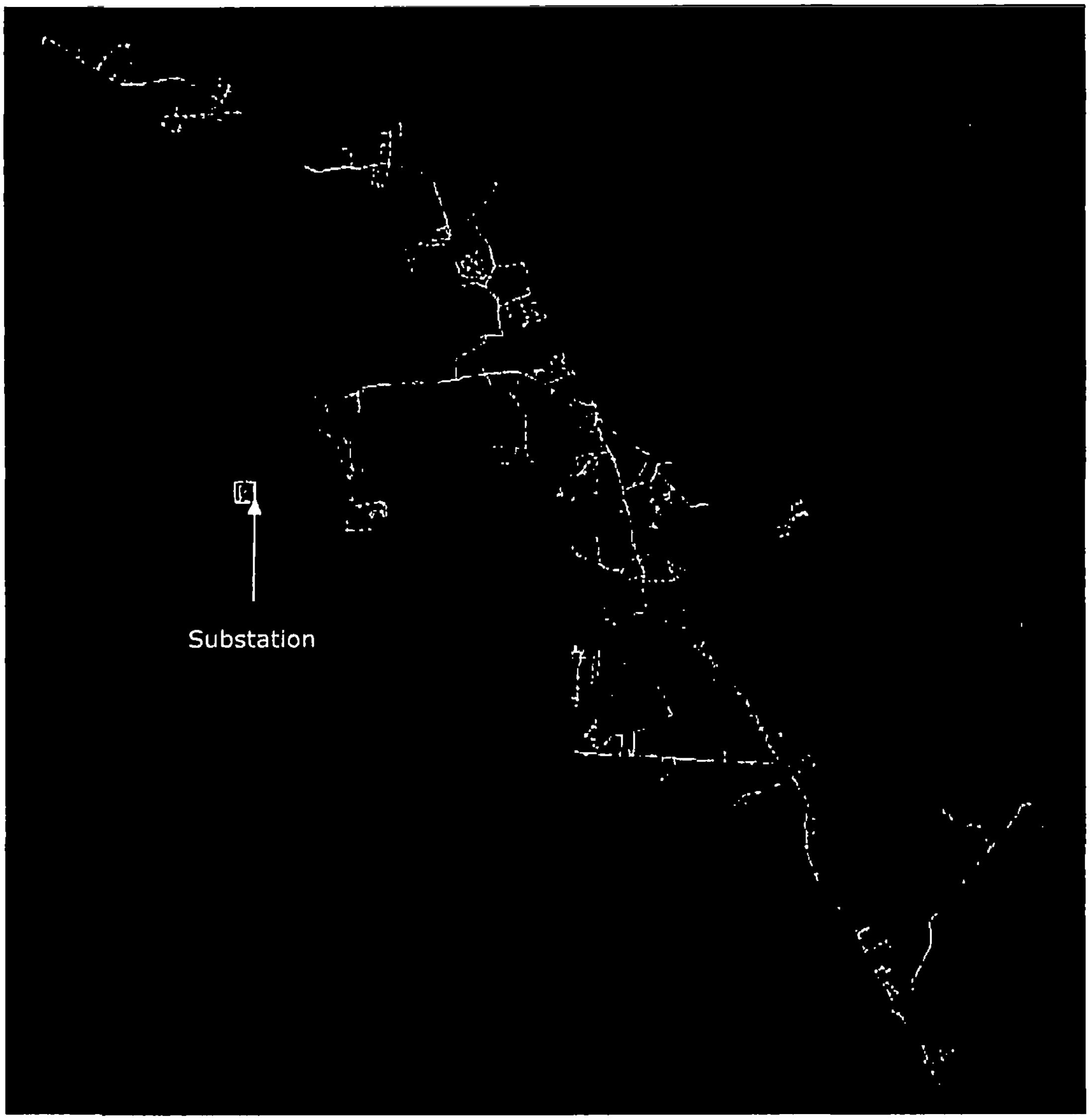


Figure 24: Voltage plot for F71475

This shows that there are multiple low voltage violations occurring on two-phase and single-phase branches of the circuit. The 20MW solar generator is located immediately outside the substation, so is unlikely to be useful for improving the voltage on the circuit.

The lowest observed voltage is 104.88V, on Phase A. Phase A is also heavily loaded, so phase balancing should be checked as a first option. Two branches were switched from Phase A to Phase B, resulting in an increase in the lowest voltage to 108.26V.

Further study of the low voltage violations in the feeder south of the substation showed that all of them were the result of voltage drop on step-down transformers. It is possible to alter the fixed tap position on these transformers, boosting the voltage on the low voltage side, so the low voltage violations can be removed on these branches without the need for investment in new equipment.

6.4.2.2 Hosting Capacity Analysis

Table 17 below provides the incremental hosting capacity results for the F71475 feeder head by year. These results are the maximum utility-scale generation capacity that can be installed on the feeder in a given year, and assume that no additional mitigation measures or upgrades have been applied beyond what is in the original model.

Table 17: Incremental hosting capacity results for F71475 feeder head by year

Feeder	Year	Hosting Capacity (MW)
F71475	2020	2.41
F71475	2021	2.79
F71475	2022	3.16
F71475	2023	3.55
F71475	2024	3.93
F71475	2025	4.48
F71475	2026	4.89
F71475	2027	5.29
F71475	2028	5.71
F71475	2029	6.30
F71475	2030	6.73

Figure 25 below provides the heat map of the incremental hosting capacity results for the F71475 feeder in year 2020:

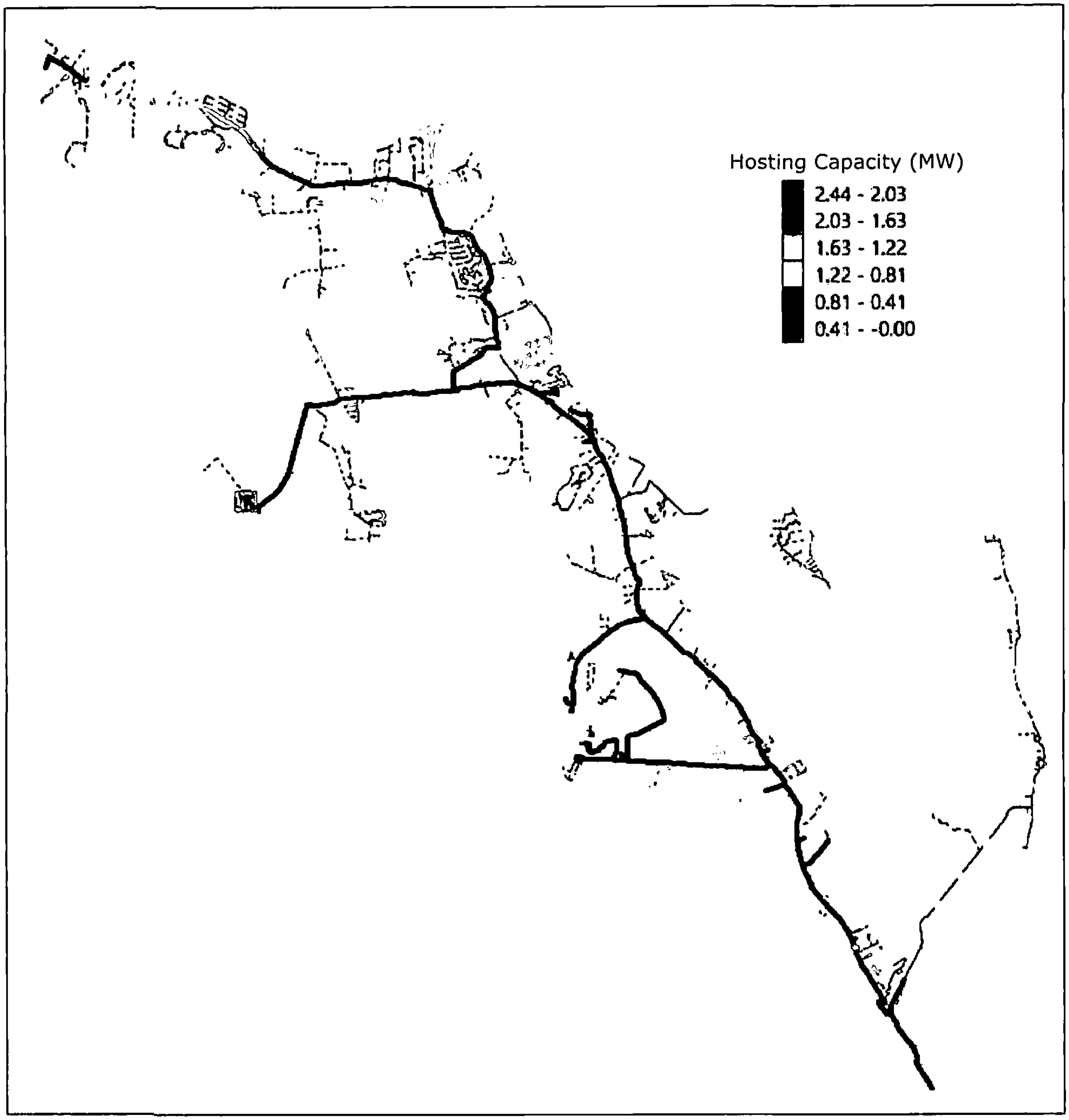


Figure 25: Incremental hosting capacity results for F71475 in 2020

Figure 26 below provides the stochastic hosting capacity analysis results for F71475 for each study year:

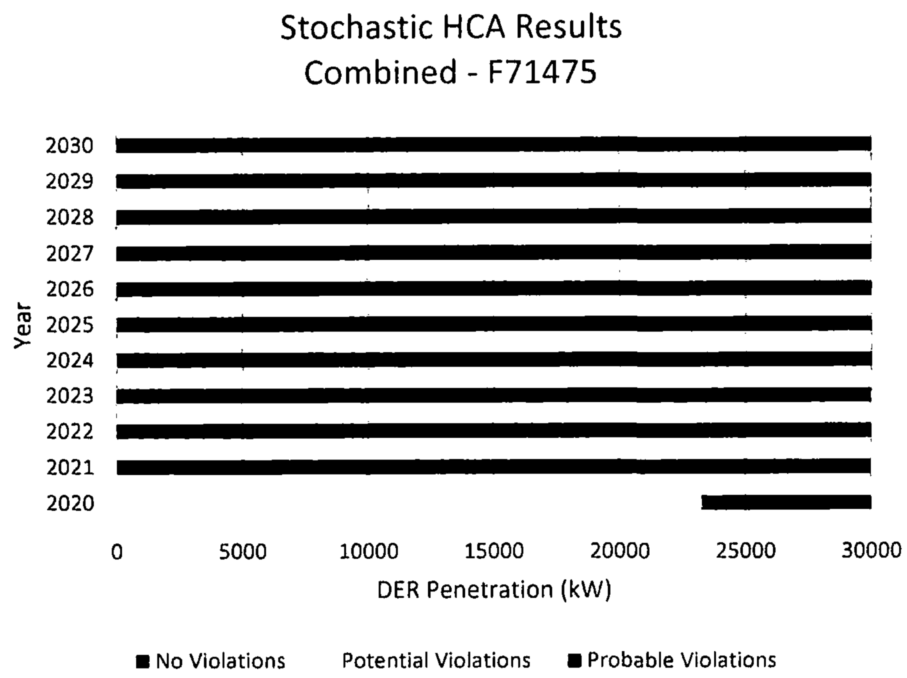


Figure 26: Stochastic hosting capacity results for F71475

6.4.2.3 Summary of Mitigation Measures

Table 18 below presents the options for mitigation of violations found on the F71475 circuit. Cost data included here is based on generic industry data for example purposes and should not be used for decision making without further scrutiny:

Table 18: Summary of mitigation options for F71475

Cause	Violation	Mitigation Option(s)	Typical Cost	Additional Benefits
Loading	Low Voltage	Phase change (2 branches)	$2,500	
		Step transformer settings changes (10 transformers)	$50,000	

6.4.3 F81305

The F81305 results from the load growth analysis are shown in Table 19Table 15 below:

Table 19: F81305 load growth results

Year	High Conductor Loading	High Voltage	Low Voltage	Overloaded Length (ft)	Transformers Overloaded
2020				N\A	0
2021				N\A	0
2022				N\A	0
2023				N\A	0
2024			113.94	N\A	0
2025			113.73	N\A	0
2026			113.52	N\A	0
2027			113.31	N\A	0
2028			113.10	N\A	0
2029			112.88	N\A	0
2030			113.07	N\A	0

The results show that there are low voltage problems beginning in 2024. There is 945kW of solar generation on this circuit, all of which is net-metered.

Table 20: F81305 comparison of low voltage violations with DER off and DER at minimum output

Year	Low Voltage – DER off	Low Voltage – DER minimum
2020		
2021		
2022		
2023		
2024	113.94	113.94
2025	113.73	113.73
2026	113.52	113.52
2027	113.31	113.31
2028	113.10	113.10
2029	112.88	112.88
2030	113.07	113.07

As with the previous two feeders, DER at minimum output has negliglble effect on the results.

6.4.3.1 Low Voltage Violations

The results indicate that the worst case voltage violations occur on January weekday at 8am. The lowest voltage observed is 112.88V in year 2029. The area of the circuit where the violation is observed is colored green, at the south end of the circuit.

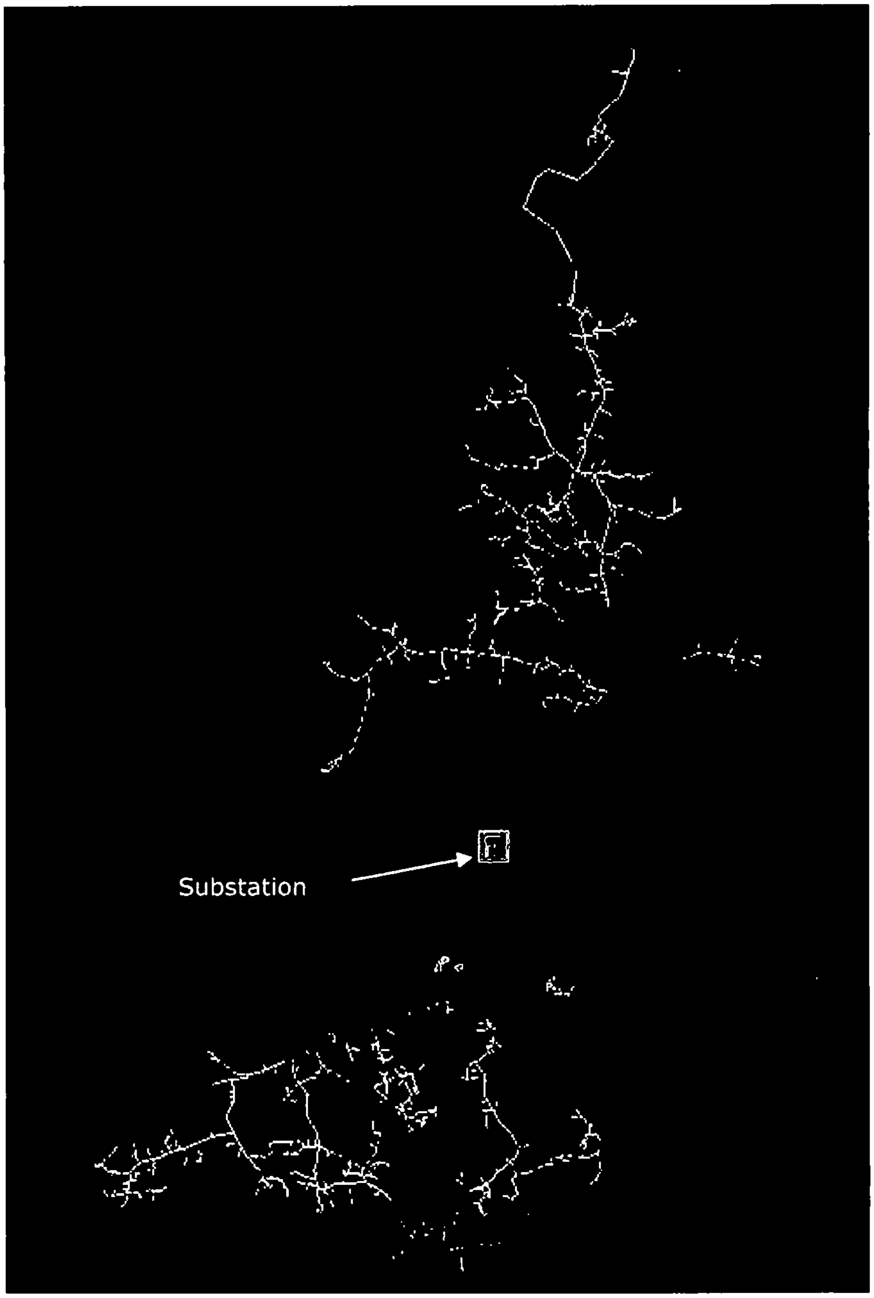


Figure 27: F81305 voltage profile for worst case voltage violation

The voltage violation occurs on a branch fed through a step-down transformer. It is possible to change the fixed turns ratio on this transformer to boost the voltage on the low voltage side by 1.25%, so the low voltage violation is removed for all study years.

If alterations in the transformer settings were not possible, an alternative option is a fixed 100kVAR capacitor bank at the end of the circuit. This also removes the low voltage violations in all study years. As the violations only start in 2024, the capacitor bank would not be required until then.

Existing PV output is only 49kW at the time when the violation occurs, so the reactive power available in the critical area of the circuit is insufficient to remove the low voltage violation. The non-wires options available are therefore limited to a new energy storage system or a STATCOM device.

An energy storage device would need to be sized at 30kW with up to 18 hours of discharge capacity (equivalent to 540kWh of storage).

A STATCOM device would be sized at 100kVAR, and placed at the end of the circuit.

6.4.3.2 DER Impacts

The analysis was re-run with the most cost-effective mitigation from the options above - the fixed capacitor bank - implemented. In this case, there were no technical violations in any of the study years.

6.4.3.3 Hosting Capacity Analysis

Table 21 below provides the incremental hosting capacity results for the F81305 feeder head by year. These results are the maximum utility-scale generation capacity that can be installed on the feeder in a given year, and assume that no additional mitigation measures or upgrades have been applied beyond what is in the original model.

Table 21: Incremental hosting capacity results for F81305 feeder head by year

Feeder	Year	Hosting Capacity (MW)
F81305	2020	0.00
F81305	2021	0.13
F81305	2022	0.39
F81305	2023	0.87
F81305	2024	0.52
F81305	2025	0.78
F81305	2026	1.11
F81305	2027	0.75
F81305	2028	1.03
F81305	2029	1.22
F81305	2030	0.86

Figure 28 below provides the heat map of the incremental hosting capacity results for the F81305 feeder in year 2020:

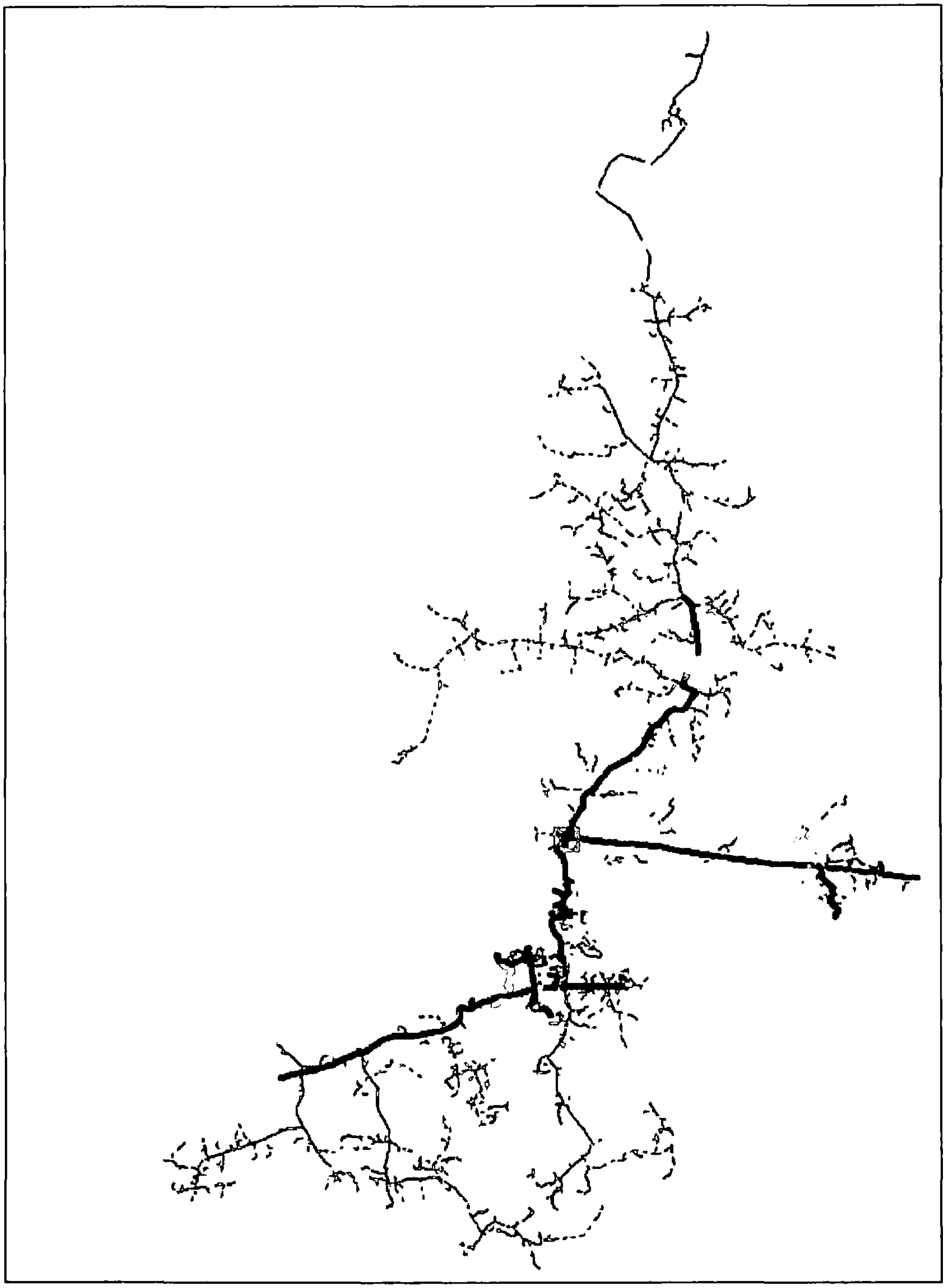


Figure 28: Incremental hosting capacity results for F81305 in 2020

Figure 29 below provides the stochastic hosting capacity analysis results for F81305 for each study year:

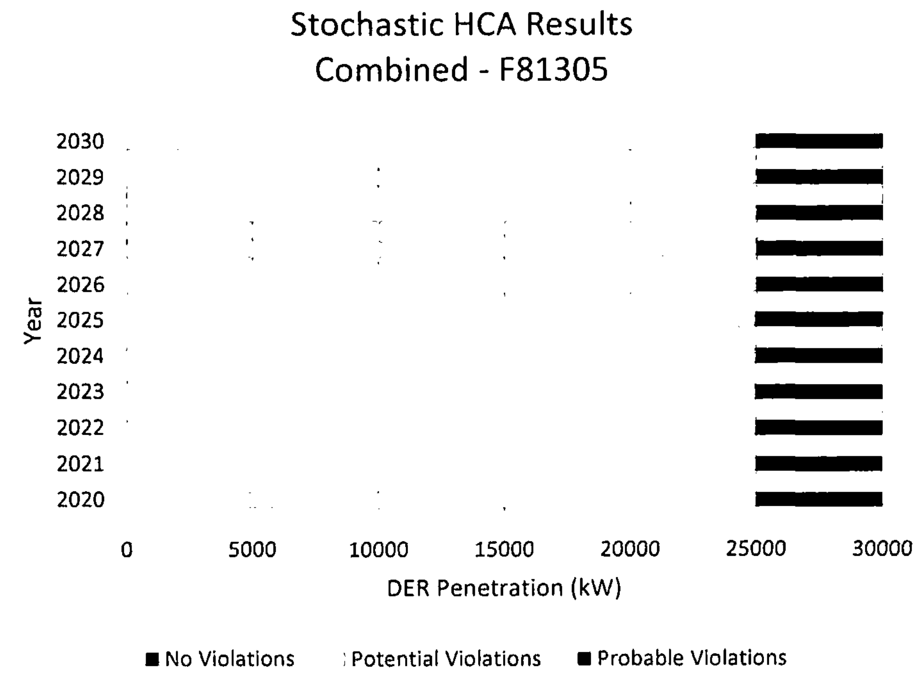


Figure 29: Stochastic hosting capacity results for F81305

6.4.3.4 Summary of Mitigation Measures

Table 22 below presents the options for mitigation of violations found on the F81305 circuit. Cost data included here is based on generic industry data for example purposes and should not be used for decision making without further scrutiny:

Table 22: Summary of mitigation options for F81305

Cause	Violation	Mitigation Option(s)	Typical Cost	Additional Benefits
Loading	Low Voltage	Step transformer settings change (1 transformer)	$5,000	
		100kVAR fixed capacitor bank	$25,000	
		Energy storage system (30kW, 540kWh)	$175,000	Potential frequency regulation revenue Further peak load reduction
		100kVAR STATCOM	$160,000	

7 SUMMARY

DNV GL worked with Dominion to develop tools and processes for the implementation of Dominion's Integrated Distribution Planning (IDP) process. The IDP process is an evolution of Dominion's distribution planning process which aims to incorporate the impacts and opportunities provided by expansion of Distributed Energy Resources (DER) on the distribution system. The process involves running a multi-year Time Series Analysis (TSA), identifying times where technical violations may occur due to load growth or due to DER operation, designing appropriate mitigation and evaluating the hosting capacity of the system for different capacities of DER.

The TSA approach is a necessary change from traditional planning processes, which would typically focus on peak load analysis. TSA allows the planning engineer to address the interactions between load and generation on the system. This interaction increases the complexity of the system, making it difficult to immediately identify the worst-case condition. In addition, TSA offers several other opportunities including addressing the impact of variable generation on voltage regulation equipment, assessing the extent of technical violations in terms of the number of hours out of the year they may persist, and designing non-wires alternatives such as energy storage systems.

To implement the TSA approach, a process has been developed to develop estimated customer load and generation profiles. At present, utility load measurements are mostly net-load measurements, which include the combined effects of load and generation. For the analyses carried out in the IDP process, load and generation must be separated so that different assumptions regarding generation capacity and output can be used without changing the load on the system (which is generally independent of generation output).

Once load and generation profiles are developed, the process requires a set of multi-year circuit analyses to be carried out. These analyses are conducted using Synergi Electric software, which provides tools that are capable of automating every part of the network analysis. The results from the analysis are exported to a database where they can be interrogated by planning engineers and used to create dashboards, making identification of extent and persistence of violations straightforward.

Once violations have been identified, appropriate mitiation measures can be investigated. Outputs from the analysis can be used to prioritize upgrades so that a proactive approach is followed, and redundant mitigation is less likely to occur. In addition to conventional distribution mitigation, non-wires alternatives can also be designed such as changes in operation of existing DER, or addition of energy storage systems. The costs can be compared against the effectiveness and potential benefits of each as input to the utility upgrade planning process.

Finally, hosting capacity is assessed using two different tools in Synergi Electric to address different types of DER. First, utility-scale DER hosting capacity is assessed by finding the hosting capacity (the capacity of new generation which can be installed on a section before a technical limit is exceeded) for each individual section of the model. This is applicable to generation which is typically low in number and has long lead-times for the utility to plan and implement any necessary upgrades. Secondly, net-metered DER hosting capacity is assessed using a stochastic method. This analysis is intended to address the uncertainty in location and size of net-metered generation, which may be high in number and short on lead times (which can lead to several installations coming online in the same year). The uncertainty is addressed by simulating several thousand different distributions of new generation capacities and finding the critical technical parameters (high voltage, low voltage and thermal loading).

Ultimately, the objective of this work is to implement a process which is automated as much as possible, making the distribution planning process more efficient and allowing distribution planning engineers to focus on areas where the sytem can be improved. The tools and processes described here have been developed with this in mind and at present everything up to the end of the analysis can be automated. This has been tested on three demonstration feeders provided by Dominion. Further development is required to automate other parts of the analysis and implement it on the full Dominion distribution system.

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Appendix C

part 3

maslansky
+ partners

Grid Transformation Plan

Voice of the Customer Survey Findings

June 2019

Dominion Energy®

Appendix C

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it's not what you say,
it's what they hear.®

our philosophy.

Assess customer feedback on a range of electric company priorities associated with the Grid Transformation Plan

the objective.

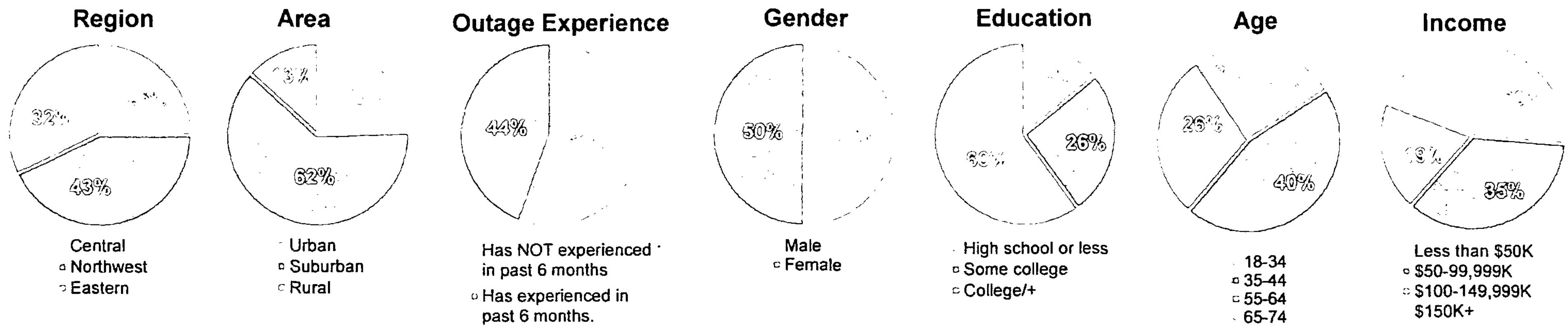
Adapt EEI survey instrument*, aligning on attributes and content

Field survey with residential Dominion Energy Virginia customers, n=805
(primary/shared decisionmaker)

Deliver key findings

* **NOTE on EEI survey instrument:** In December 2018, EEI fielded a nationwide "Voice of the Customer" survey with residential energy decisionmakers from EEI member companies, age 18-74. This survey was adapted to be more specific and relevant to Dominion Energy. Where applicable, we compare these survey results to the national study.

SURVEY SAMPLE, n=805



methodology.

bill management

Q. Which of the following would you say best describes you?		
1) I don't do anything to keep my electric bill low	5%	4%
2) I don't go out of my way to keep my electric bill low	15%	12%
3) I take reasonable steps to keep my electric bill low	67%	69%
4) I go out of my way to keep my electric bill low	12%	15%

20% (n=166) coded as **"not active bill manager"** (responses 1 & 2)	80% (n=639) coded as **"active bill manager"** (responses 3 & 4)

bill familiarity

Q. Would you say you are ... with the way your electric bill is calculated?		
1) Very familiar	16%	14%
2) Somewhat familiar	45%	53%
3) Not very familiar	26%	29%
4) Not at all familiar	13%	4%

61% (n=489) coded as **"familiar with bill"** (responses 1 & 2)	39% (n=316) coded as **"not familiar with bill"** (responses 3 & 4)

NOTE: National comparison data is from EEI Rate Design Survey (2016, n=1000)

a closer look at self-reported behaviors.

where there was generally consistency

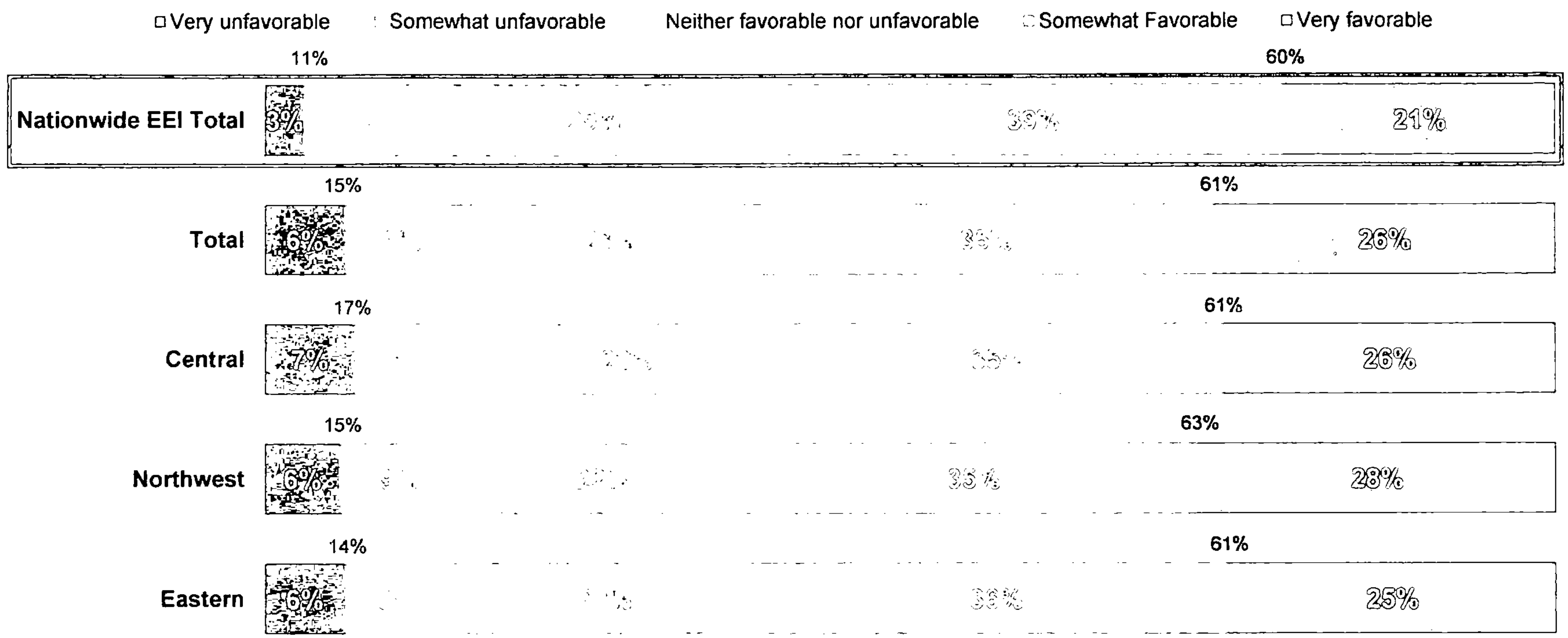
+ **Eastern**, **Northwest**, and **Central** customers reacted consistently across key metrics (favorability and likelihood to recommend) and were largely aligned in their frustrations, what they value most, how they think Dominion is performing today, and what they believe is most important. This consistency is most clearly demonstrated on slides 19 and 21. While the order of some of their selections differs, there is significant overlap in their "Top 10" / "Bottom 10" selections.

where we saw some differences

+ **Age** played a role in how customers answered questions about digital privacy / the Dominion website, with younger customers being more open to new technology options.
+ **Behaviors** (like **whether or not you actively take steps to use energy more responsibly** and **how familiar you are with how your bill is calculated**) played a role in how favorably customers tended to respond; those who are more engaged / aware feel more positive toward Dominion.

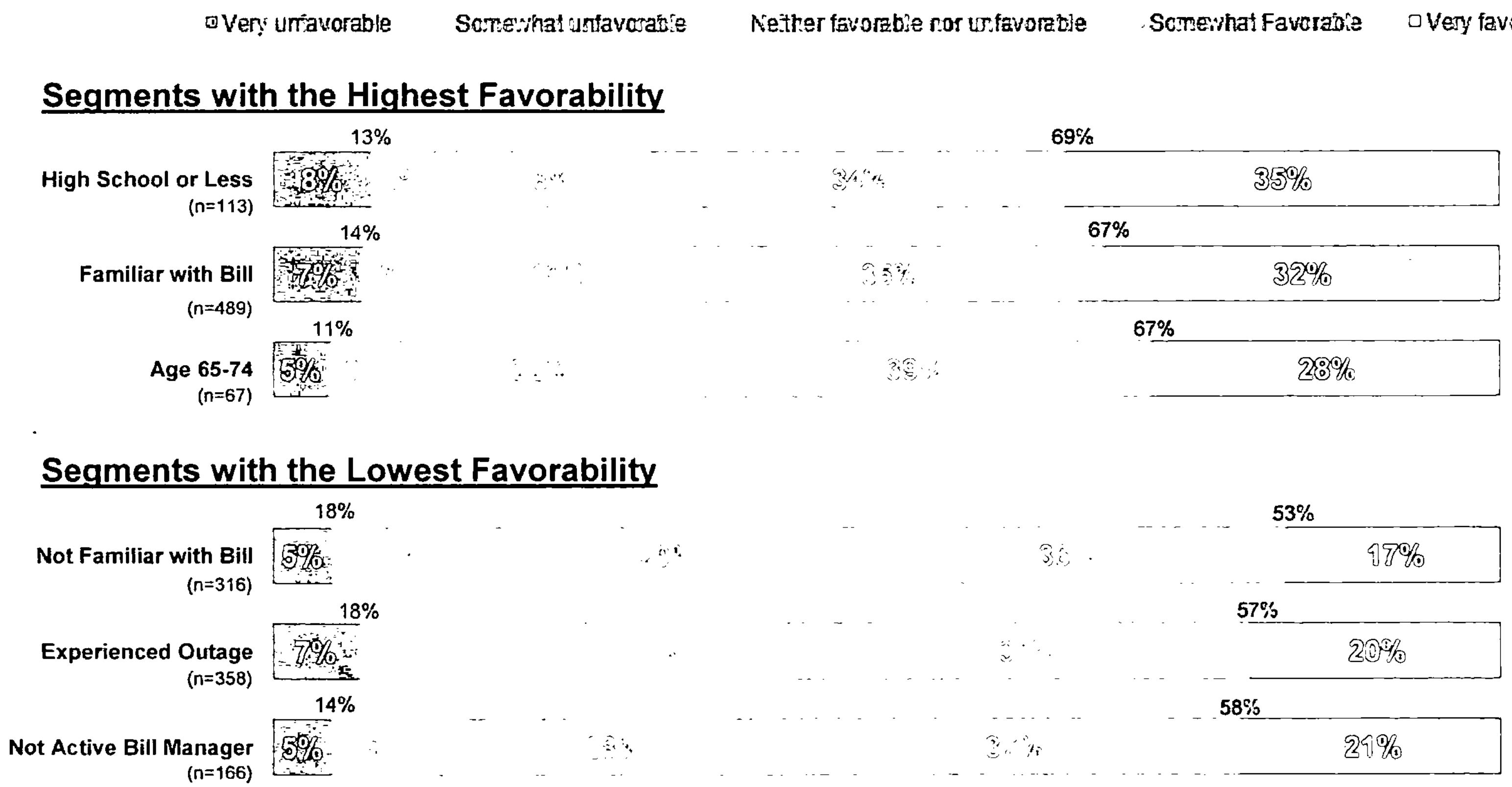
opinions about Dominion

Q. Overall, is your opinion of Dominion Energy … ?



opinions of Dominion are favorable overall.

Q. Overall, is your opinion of Dominion Energy … ?



vs. "familiar with bill"
67% very/somewhat favorable
14% very/somewhat unfavorable

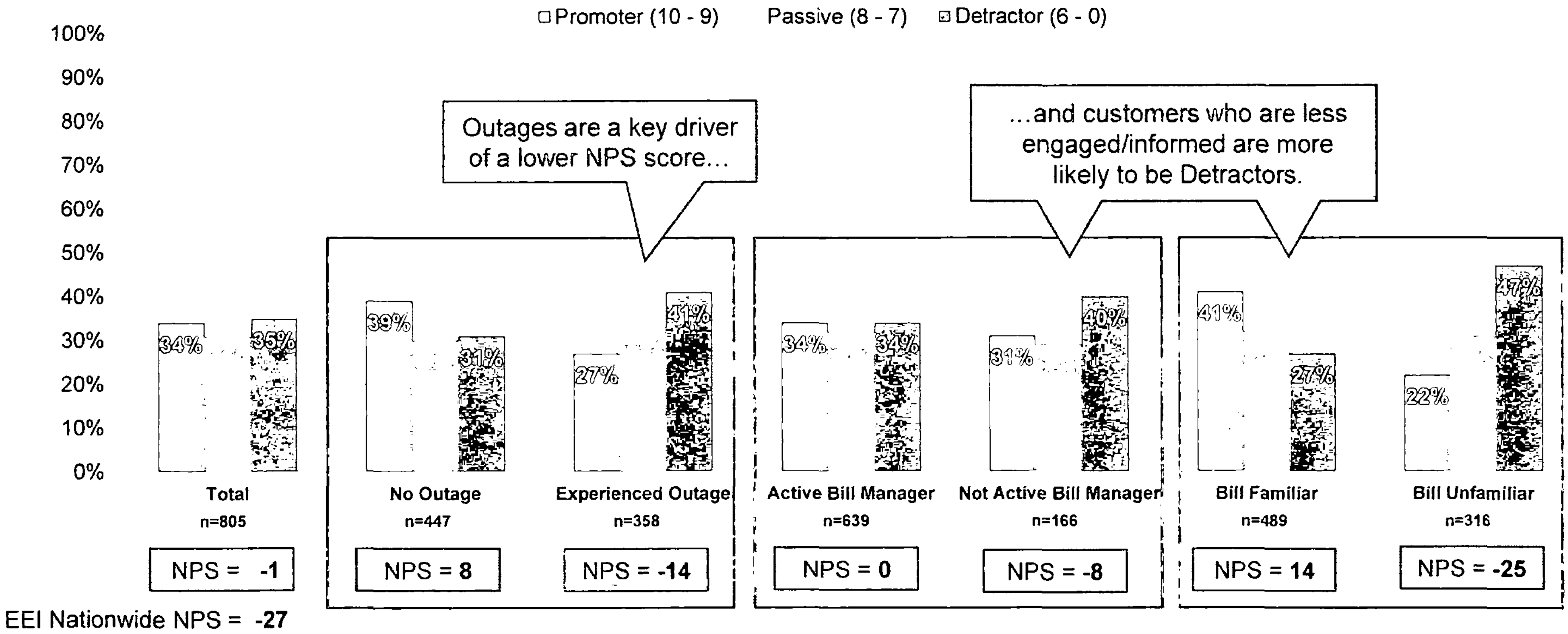
vs. "has not experienced outage"
66% very/somewhat favorable
13% very/somewhat unfavorable

vs. "active bill manager"
63% very/somewhat favorable
15% very/somewhat unfavorable

outages and passive behaviors drive low favorability.

Q. How likely is it that you would recommend Dominion Energy to a friend or colleague? (11-point scale, "very unlikely" to "very likely")

NPS scores calculated based on Likelihood to Recommend. Detractors (rate 0-6) are subtracted from Promoters (rate 9 or 10). Scores range from a low of -100 (if every customer is a Detractor) to a high of 100 (if every customer is a Promoter).



NPS score reveals favorability doesn't equal advocacy.

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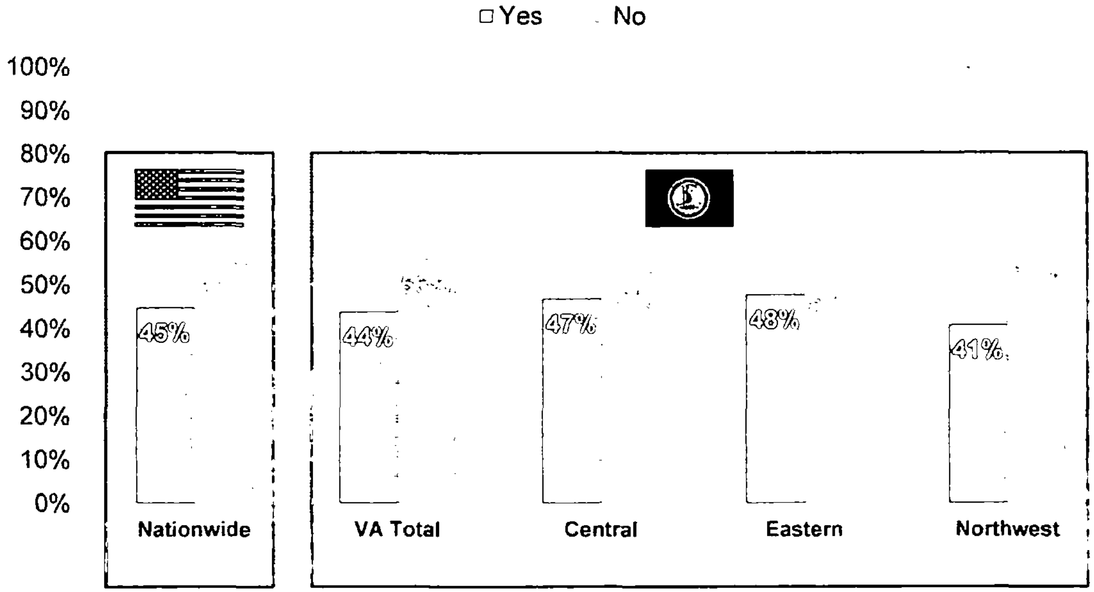
Q. In the past 6 months, have you experienced a power outage in your home?



Q. [ALL] Thinking about the last outage that you experienced, was your power restored in a timely manner?

	Nationwide	Virginia
Yes	72%	69%
No	16%	19%
I don't know	12%	12%

outage experiences are on par with national data.

Q. Below is a list of situations that electric company customers like you might face. Please indicate how frustrating each situation is for you. (5-point scale; "this is not an issue for me" - "extremely")

61% of customers are at least "moderately frustrated" by one aspect of their experience with Dominion

Moderately, Very, Extremely	Frustrations that rise to the top for those customers
57%	**I don't receive accurate information about when my power will be restored during outages**
54%	**The electric company takes too long to respond to a power outage**
53%	**There aren't enough options to help me conserve energy and save money**
50%	**My bill each month is unpredictable**
47%	**I experience unexpected outages**
46%	Customer service representatives aren't able to efficiently resolve my issues
46%	I can't track my energy usage to conserve energy
41%	I can't understand the charges on my bill
39%	There aren't enough different billing plan options
35%	I can't contact my electric company in the way that's most convenient for me (phone, web chat, app, etc.)
7%	I don't know how my energy usage affects my bill each month

outages are a primary source of frustration.

Q. For you personally, how valuable is it that Dominion Energy can ... ?
(5-point scale; "not at all" to "extremely")

Action	Top 2 Box (extremely / very)
Restore my power more quickly	**82%**
Improve reliability so I experience fewer outages	**75%**
Prevent physical and cyber-attacks on the power grid	**75%**
Improve the resiliency of the grid for extreme weather events	**74%**
Help me save money on my electric bill	**73%**
Help me conserve energy	66%
Use more energy that will have less of an impact on the environment	63%
Improve customer service so I can get the answers I need more quickly	62%
Help me have more control over my electric bill	59%
Help me understand my energy usage	58%
Invest in emerging green technologies, like charging stations for electric vehicles and battery storage, to create a cleaner environment	57%
Provide additional tools to track my energy usage	54%

customers value reliability and affordability most.

reliability is a priority regardless of geography or outage experience

Action	Top 2 Box (extremely / very) Total	Central	Northwest	Eastern	Urban	Rural	Suburban	No Outage	Experienced Outage
Restore my power more quickly	**82%**	78%	82%	84%	79%	81%	83%	82%	81%
Improve reliability so I experience fewer outages	**75%**	74%	74%	78%	72%	75%	76%	74%	77%
Prevent physical and cyber-attacks on the power grid	**75%**	73%	74%	77%	72%	72%	77%	74%	76%
Improve the resiliency of the grid for extreme weather events	**74%**	71%	74%	75%	69%	71%	76%	74%	73%

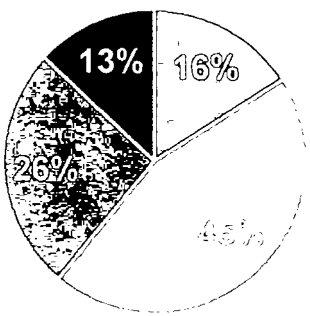
affordability is a priority regardless of age or income

Action	Top 2 Box (extremely / very) Total	Low Income	$50K+	Active Bill Manger	Not Active	Bill Familiar	Bill Unfamiliar	18-34	35-54	55-64	65-74
Help me save money on my electric bill	73%	74%	72%	76%	63%	74%	73%	71%	77%	70%	69%

this is true across segments.

most customers are at least "somewhat familiar" with how their bill is calculated...

Q. Would you say you are ... with the way your electric bill is calculated?



Very familiar · Somewhat familiar · Not very familiar · Not at all familiar

they believe a fair bill is based on how much energy they use...

Q. There are different ways that your bill could be determined at the end of the month. Which of the following do you think is the fairest?

How much energy you use	**69%**
How much your energy use costs Dominion Energy	13%
When you use energy	10%
How you stagger the energy you use	3%
How you use the energy grid	3%

and they're looking for ways to conserve energy and save money

Q. For you personally, how valuable is it that Dominion Energy can ... ? (5-point scale; "not at all" to "extremely")

TOP 2 BOX

73% **Help me save money on my electric bill**

66% **Help me conserve energy**

customers are looking for ways to save / conserve.

how we **perform** today

Bills and payment

Customer service

Digital / digital privacy

Environment / carbon / efficiency

Operational performance

Outage communications

Rewards

Smarter energy infrastructure

Full list of attributes on slide 45

we tested 35 attributes across a range of areas.

Q. Please rate how good a job you think Dominion Energy is doing on each action today. ("poor" to "excellent" scale; mean scores)

Attribute	Total
Has a range of payment options (like online, autopay, mobile pay, phone, or by check)	1
Has a user-friendly website that makes it easy to find the information I need and pay my bill	2
Keeps my energy usage data private and doesn't make any personally identifiable information available	3
Has easy to understand bills that explain charges clearly	4
Has knowledgeable customer service representatives	5
Has a range of options to get customer service (like phone, chat, email)	6
Completes work without needing follow up	7
Completes scheduled work when they say they will	8
Invests in a stronger energy grid that can withstand extreme weather and cyberattacks	9
Has level billing so I can pay roughly the same monthly amount all year and avoid seasonal spikes	10

what customers think we do well: top 10.

Q. Please rate how good a job you think Dominion Energy is doing on each action today. ("poor" to "excellent" scale; mean scores)

Attributes	Total
Offers a rewards program for taking actions to manage my energy use	1
Shares benchmarks that show how my energy use compares to other homes in my area	2
Has no convenience fees on credit card payments	3
Alerts me when power is out, how long it will take to restore, and when it is restored	4
Proactively communicates about storms and potential outages	5
Gives me the ability to sell extra energy back to the energy grid if I generate it at home	6
Proactively shares insights about my energy usage and recommendations on how to conserve energy and lower my bill	7
Helps make the air in my community cleaner by investing in public charging stations for electric vehicles	8
Considers my needs and impact on my day-to-day activities when scheduling work	9
Allows me opt-in to a "peak and off-peak rate" program which enables me to save money when I cut down my energy usage during peak times	10

what customers think we don't do well: bottom 10.

top 5, total and by segment

Attributes	Total	Central	Northwest	Eastern	Experienced Outage	Less than $50K	Not active Bill Manager
Has a range of payment options (like online, autopay, mobile pay, phone, or by check)	1	2	1	1	1	1	1
Has a user-friendly website that makes it easy to find the information I need and pay my bill	2	4	2	2	2	2	2
Keeps my energy usage data private and doesn't make any personally identifiable information available	3	1			3	5	4
Has easy to understand bills that explain charges clearly	4	3	4		5		3
Has a range of options to get customer service (like phone, chat, email)	5						
Has knowledgeable customer service representatives			3	3	4	3	
Completes work without needing follow up			5			4	
Has level billing so I can pay roughly the same monthly amount all year and avoid seasonal spikes		5					
Helps makes my community more environmentally-friendly by proactively replacing streetlights with LED bulbs							5

bottom 5, total and by segment

Attributes	Total	Central	Northwest	Eastern	Experienced Outage	Less than $50K	Not active Bill Manager
Offers a rewards program for taking actions to manage my energy use	1	1	1	1	1	1	2
Shares benchmarks that show how my energy use compares to other homes in my area	2	2	2	3	2	2	1
Has no convenience fees on credit card payments	3	5	4	2		4	
Alerts me when power is out, how long it will take to restore, and when it is restored	4		5	4	4	3	4
Proactively communicates about storms and potential outages	5	3	3		3		
Gives me the ability to sell extra energy back to the energy grid if I generate it at home		4				5	
Helps make the air in my community cleaner by investing in public charging stations for electric vehicles				5	5		3
Considers my needs and impact on my day-to-day activities when scheduling work							5

there's consistency among key segments.

top 5, total and by segment

Attributes	Total	Unfavorable	Detractors	Favorable	Promoters
Has a range of payment options (like online, autopay, mobile pay, phone, or by check)	1	1	1	1	5
Has a user-friendly website that makes it easy to find the information I need and pay my bill	2	4	2	2	3
Keeps my energy usage data private and doesn't make any personally identifiable information available	3	2	3		
Has easy to understand bills that explain charges clearly	4	5		4	2
Has a range of options to get customer service (like phone, chat, email)	5		5	5	
Has knowledgeable customer service representatives		3	4		1
Completes work without needing follow up				3	4

A positive customer service experience correlates with a higher NPS

bottom 5, total and by segment

Attributes	Total	Unfavorable	Detractors	Favorable	Promoters
Offers a rewards program for taking actions to manage my energy use	1	2	2	1	2
Shares benchmarks that show how my energy use compares to other homes in my area	2		1	2	3
Has no convenience fees on credit card payments	3			3	1
Proactively communicates about storms and potential outages	4	1	3		
Alerts me when power is out, how long it will take to restore, and when it is restored	5	3	4	4	
Gives me the ability to sell extra energy back to the energy grid if I generate it at home			5	5	
Proactively shares insights about my energy usage and recommendations on how to conserve energy and lower my bill					4
Allows me opt-in to a "peak and off-peak rate" program which enables me to save money when I cut down my energy usage during peak times		4			
Allows me to customize alerts so I'll be notified when I am close to a pre-set dollar threshold or usage limit					5
Uses innovative technologies and data to predict and prevent outages before they happen		5			

Those who are unfavorable / detractors are more likely to say we underperform in outage communications

a closer look at favorability / NPS.

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what's most **important** to customers

**Q. Please rate how important it is to you that Dominion Energy takes each action.
("not at all" to "extremely"; mean scores)**

Attributes	Total	Central	Northwest	Eastern	Less than $50K	Experienced Outage	Not active Bill Manager
Completes scheduled work when they say they will	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Has knowledgeable customer service representatives	2	2	5	2	2	4	2
Invests in technology to help it prevent outages and respond to outages faster when they occur	3	3	2	3	5	5	3
Keeps my energy usage data private and doesn't make any personally identifiable information available	4	5	3	6	3	2	5
Alerts me when power is out, how long it will take to restore, and when it is restored	5	4	6	4	7	3	7
Invests in a stronger energy grid that can withstand extreme weather and cyberattacks	6	6	4	5		6	6
Completes work without needing follow up	7	7	7	10	8	9	4
Has easy to understand bills that explain charges clearly	8	9	8	8	4	8	8
Takes the time to listen to my issues and actually help me	9	8		9	6	10	
Has an outage map that includes accurate estimates of outage time and progress in restoring power	10		9			7	
Uses innovative technologies and data to predict and prevent outages before they happen			10				9
Has a user-friendly website that makes it easy to find the information I need and pay my bill					9		10
Has no convenience fees on credit card payments				7			
Proactively communicates about storms and potential outages		10					
Has a range of payment options (like online, autopay, mobile pay, phone, or by check)					10		

most important attributes: top 10.

Q. Please rate how important it is to you that Dominion Energy takes each action.
("not at all" to "extremely"; mean scores)

Attributes	Total	Unfavorable	Detractors	Favorable	Promoters
Completes scheduled work when they say they will	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Invests in technology to help it prevent outages and respond to outages faster when they occur	3	10	5	3	2
Has knowledgeable customer service representatives	2	3	2	2	3
Alerts me when power is out, how long it will take to restore, and when it is restored	5	5	6	4	4
Invests in a stronger energy grid that can withstand extreme weather and cyberattacks	6	8	3	6	5
Completes work without needing follow up	7	7	7	8	6
Keeps my energy usage data private and doesn't make any personally identifiable information available	4	2	4	5	7
Has easy to understand bills that explain charges clearly	8	9		7	8
Takes the time to listen to my issues and actually help me	9	6	9	9	
Has an outage map that includes accurate estimates of outage time and progress in restoring power	10		10	10	
Uses innovative technologies and data to predict and prevent outages before they happen		4			9
Has a user-friendly website that makes it easy to find the information I need and pay my bill					10
Has no convenience fees on credit card payments			8		

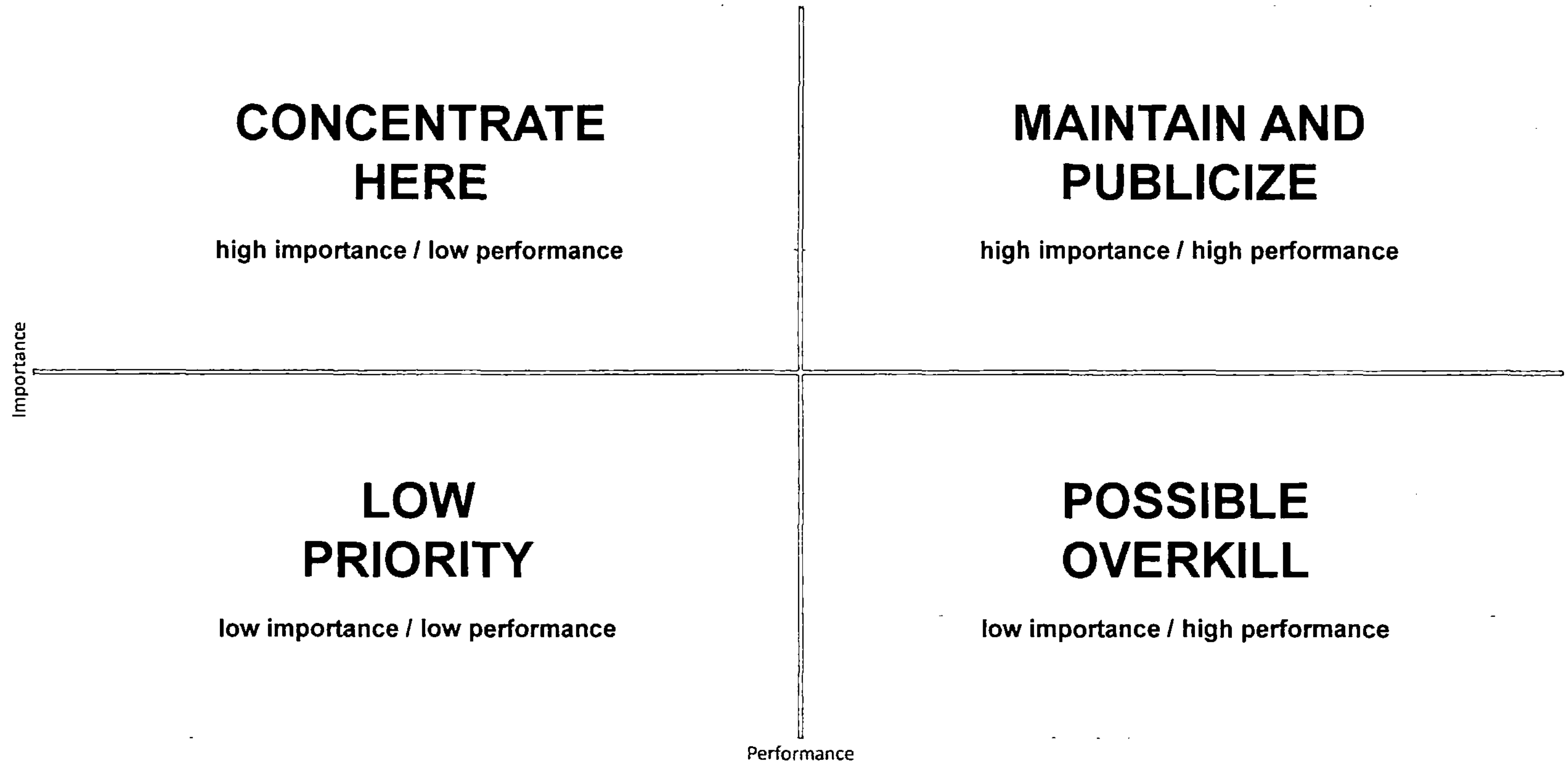
most important attributes: top 10 (favorability/NPS).

Q. Which is most important? That your electric company is… (Rank 1 + 2)

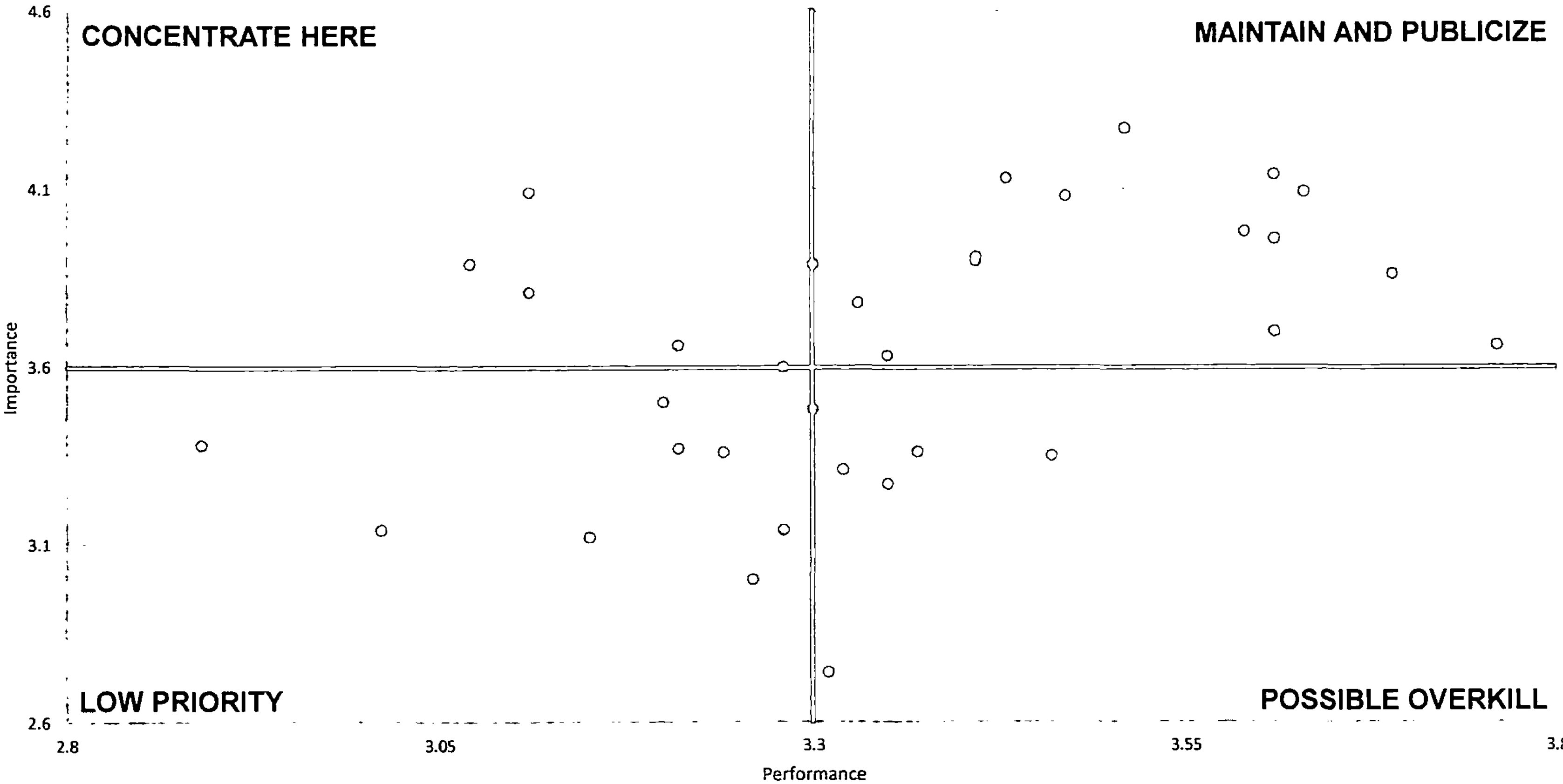
	Total	Central	Northwest	Eastern	Experienced Outage	Less than $50K	Not active Bill Manager
Investing in **smarter energy infrastructure**	**44%**	43%	52%	36%	47%	31%	41%
Continuously improving how it operates	**40%**	38%	39%	41%	39%	33%	41%
Supporting efforts related to **clean energy** and **carbon reduction**	**37%**	35%	42%	31%	37%	33%	28%
Serving customers in ways that **make their experience easy**	**33%**	35%	29%	37%	30%	41%	36%
Working with customers to create **customized solutions**	**24%**	28%	21%	25%	24%	37%	25%
Investing in **digital tools** to help customers manage their energy	**22%**	22%	17%	30%	23%	25%	29%

we tested 6 ways of framing what we're doing.

prioritizing where we focus



understanding which attributes can move the needle.



where the attributes fall.

Note: *Performance and Importance were both measured using 5-point scales. This chart – and the charts that follow – are scaled to reflect the range of means: highest/lowest importance = 4.27-2.59; highest/lowest performance: 3.76-2.89.*

N = 804

Among attributes tested, these rise to the top as priority areas of focus. Attributes relating to **outage communications** and **smarter energy infrastructure** are of particular focus, both because customers rank them so highly in importance and because they help 1) solve for key frustrations and 2) represent what they find most valuable from Dominion.

Maintain and publicize
- Invests in technology to help it prevent outages and respond to outages faster when they occur
- Has an outage map that includes accurate estimates of outage time and progress in restoring power

Concentrate here
- Alerts me when power is out, how long it will take to restore, and when it is restored
- Proactively communicates about storms and potential outages

Maintain and publicize
- Invests in a stronger energy grid that can withstand extreme weather and cyberattacks
- Uses innovative technologies and data to predict and prevent outages before they happen

Maintain and publicize
- Has knowledgeable customer service representatives
- Takes the time to listen to my issues and actually help me
- Has a range of options to get customer service (like phone, chat, email)

Maintain and publicize
- Completes scheduled work when they say they will
- Completes work without needing follow up

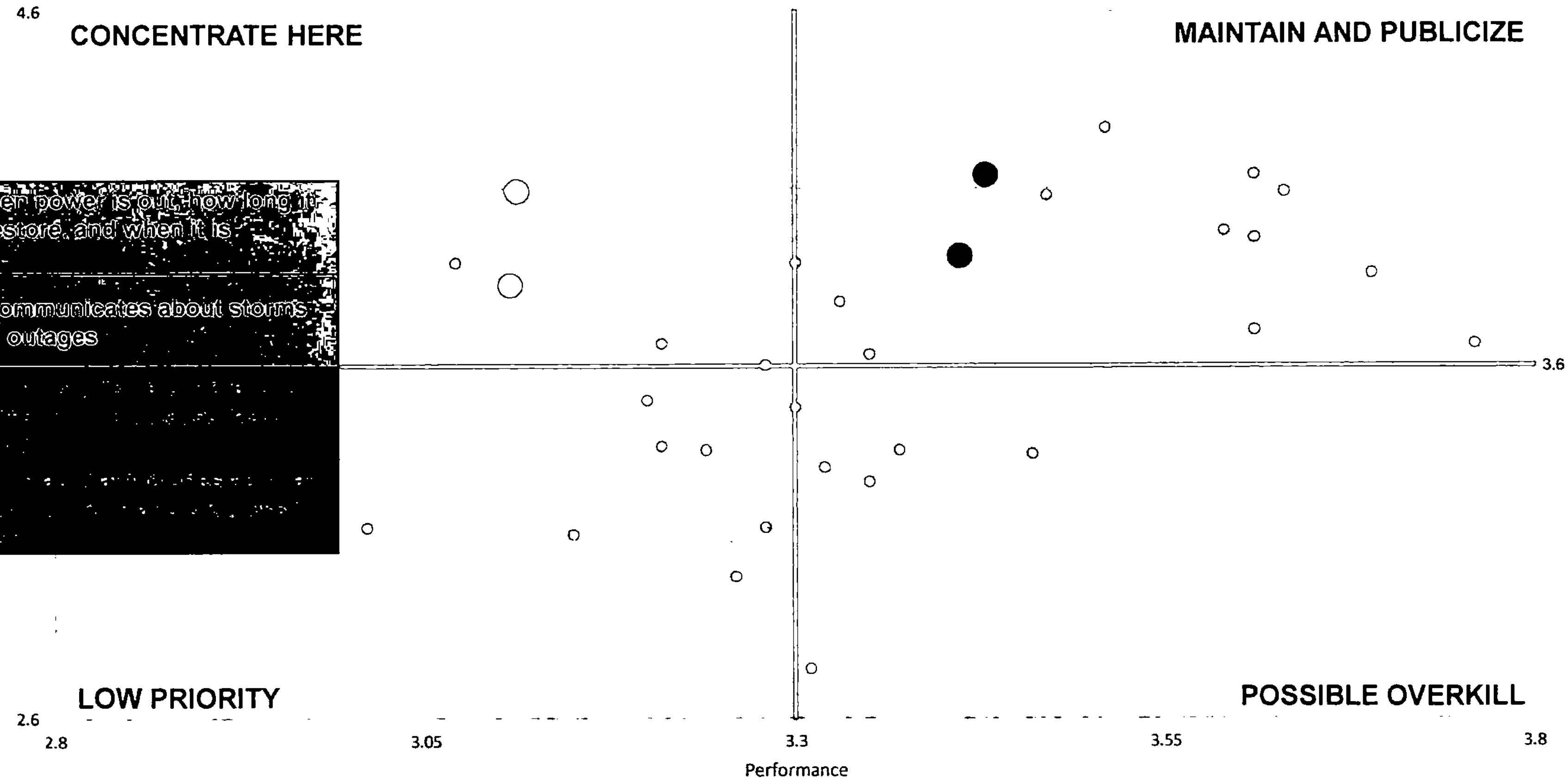
Concentrate here
- Considers my needs and impact on my day-to-day activities when scheduling work

Maintain and publicize
- Has easy to understand bills that explain charges clearly
- Has a user-friendly website that makes it easy to find the information I need and pay my bill

Concentrate here
- Has no convenience fees on credit card payments

Maintain and publicize
- Keeps my energy usage data private and doesn't make any personally identifiable information available

summary of priorities.



outage communications.

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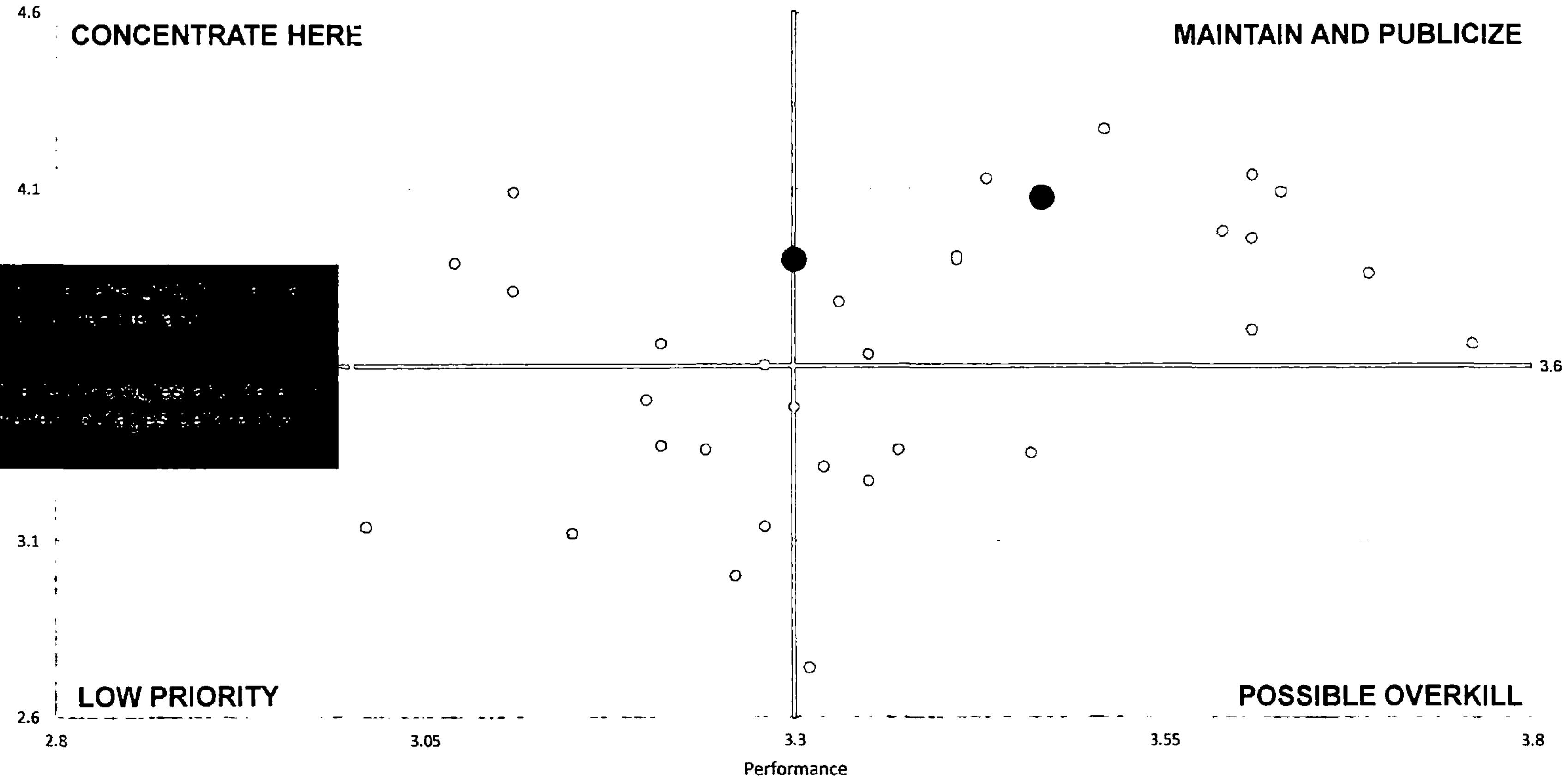
NOTE: *Chart scaled to reflect the range of means: highest/lowest importance = 4.27-2.59; highest/lowest performance: 3.76-2.89.*

N = 804

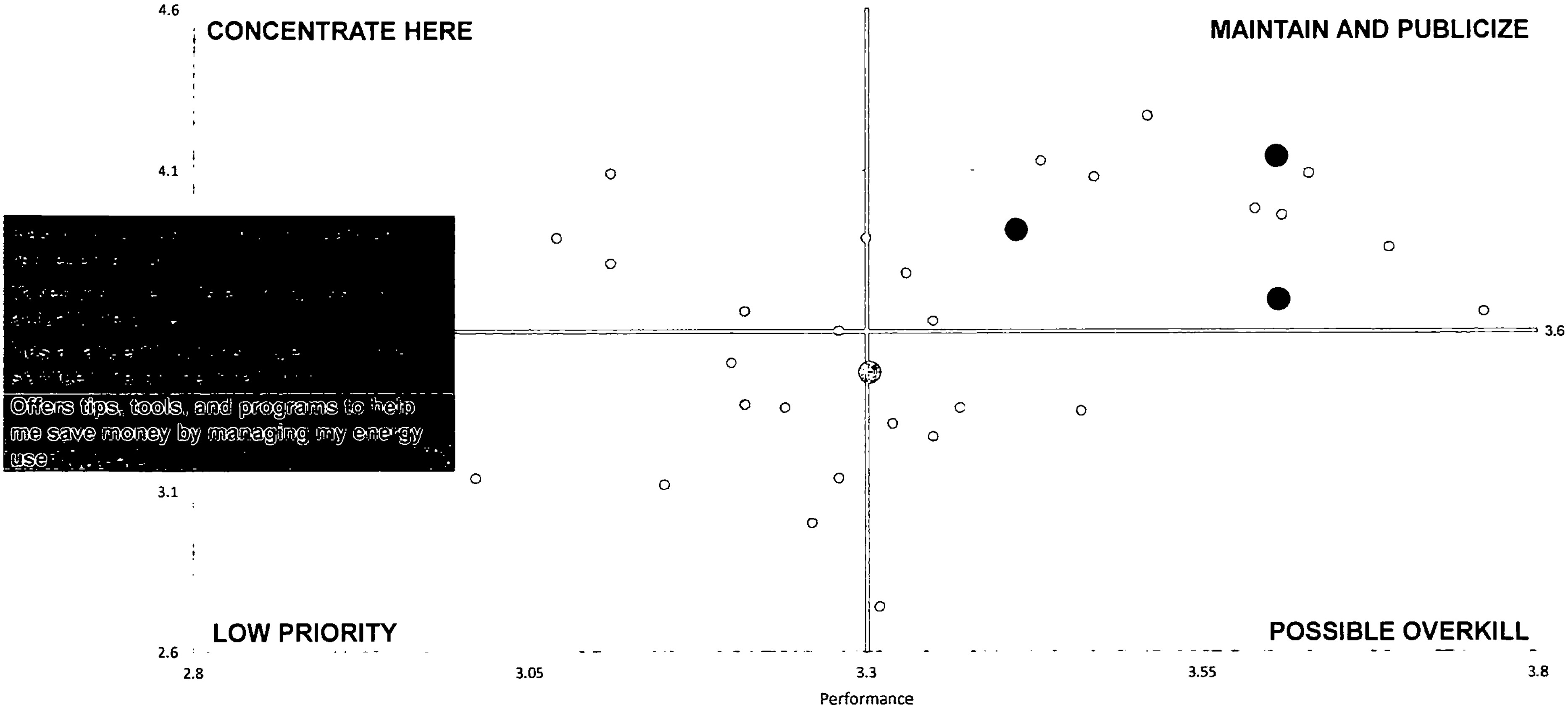


smarter energy infrastructure.

maslansky + partners | 31

NOTE: *Chart scaled to reflect the range of means: highest/lowest importance = 4.27-2.59; highest/lowest performance: 3.76-2.89.*

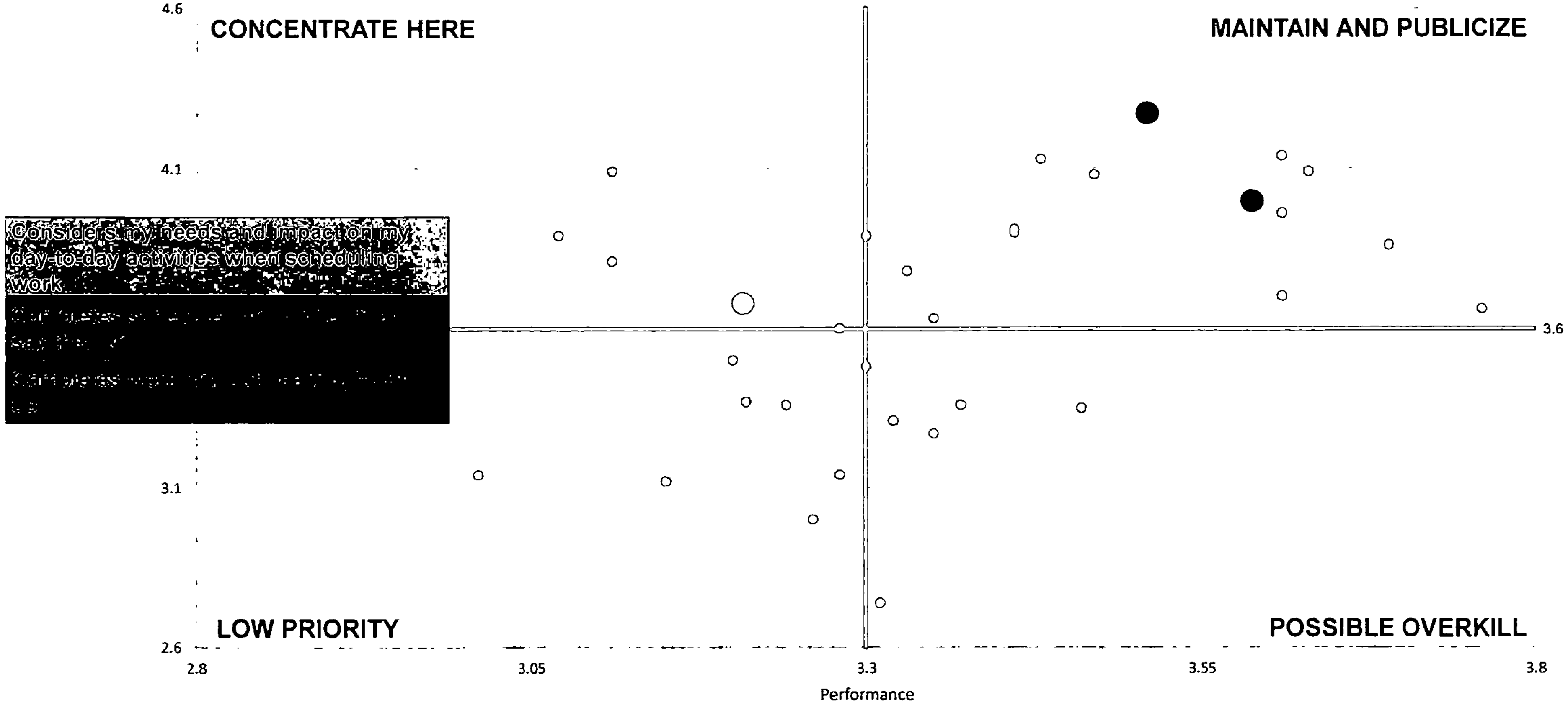
N = 804



customer service.

NOTE: *Chart scaled to reflect the range of means: highest/lowest importance = 4.27-2.59: highest/lowest performance: 3.76-2.89.*

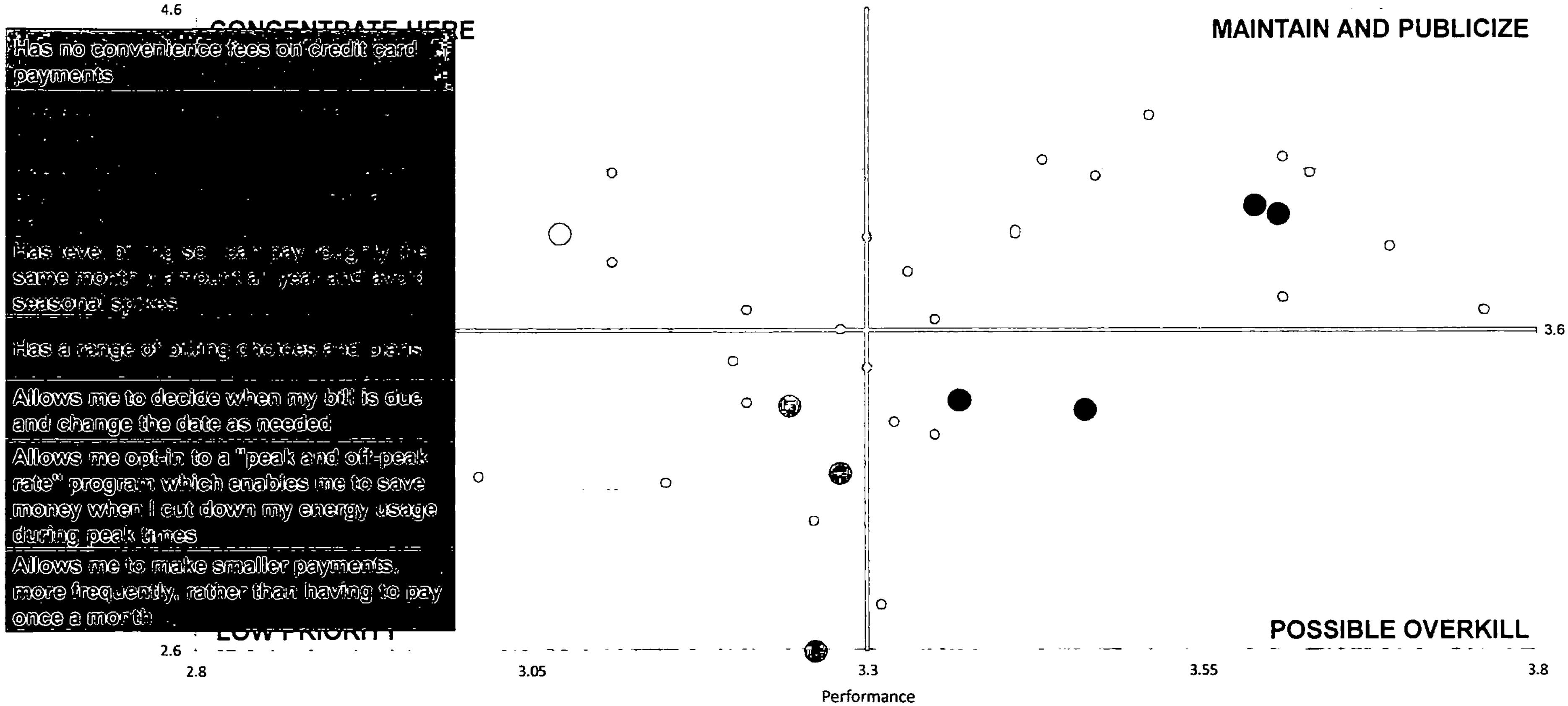
N = 804



operational performance.

NOTE: *Chart scaled to reflect the range of means: highest/lowest importance = 4.27-2.59; highest/lowest performance: 3.76-2.89.*

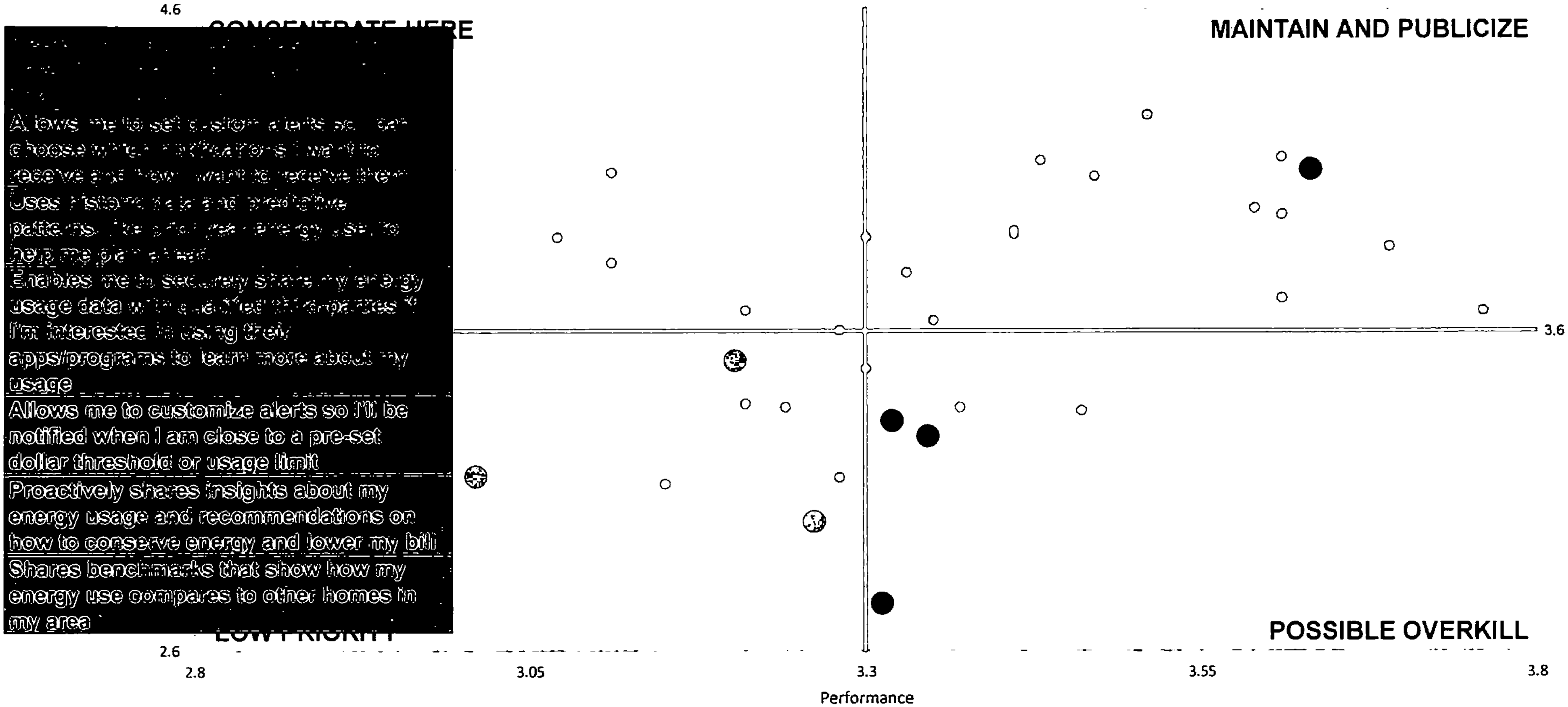
N = 804



bills and payment.

NOTE: *Chart scaled to reflect the range of means: highest/lowest importance = 4.27-2.59: highest/lowest performance: 3.76-2.89.*

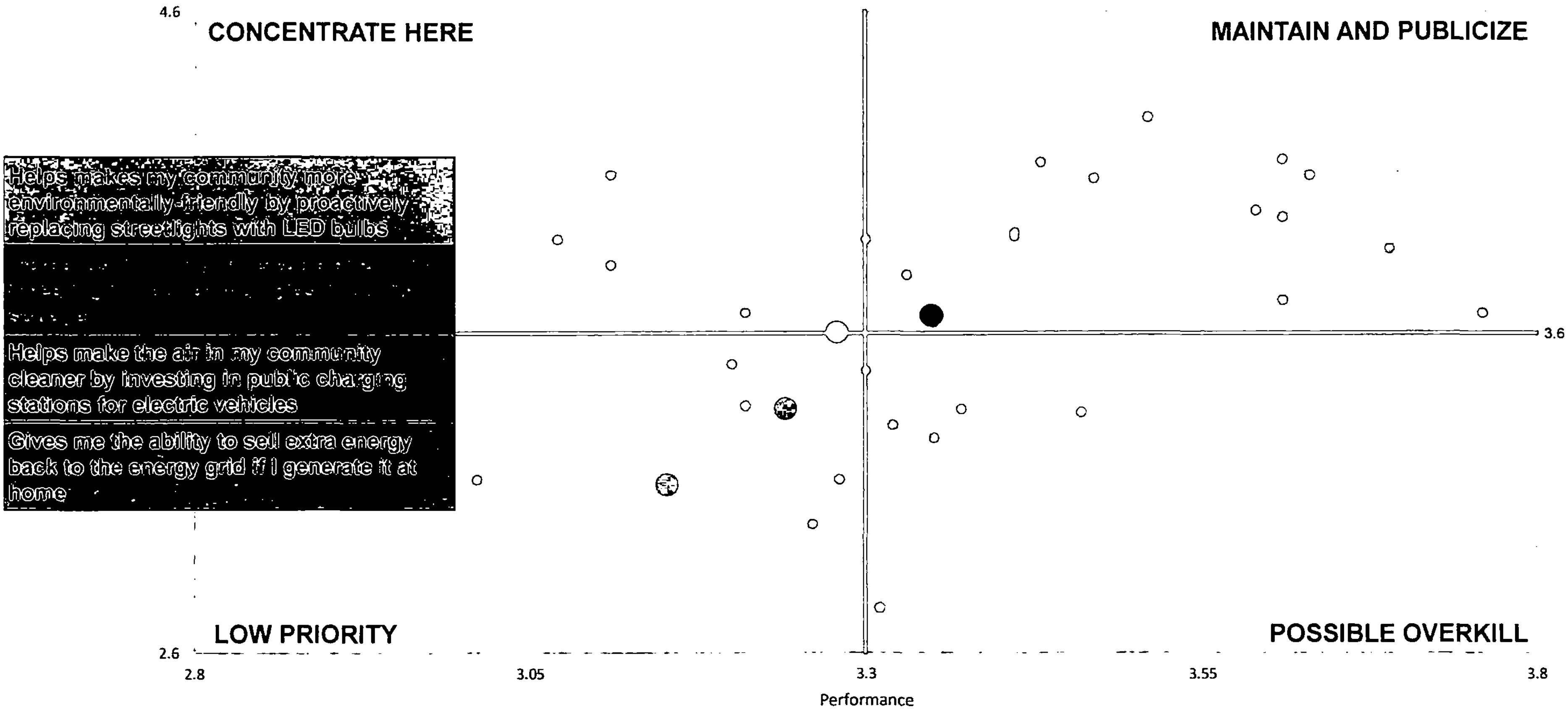
N = 804



digital / digital privacy.

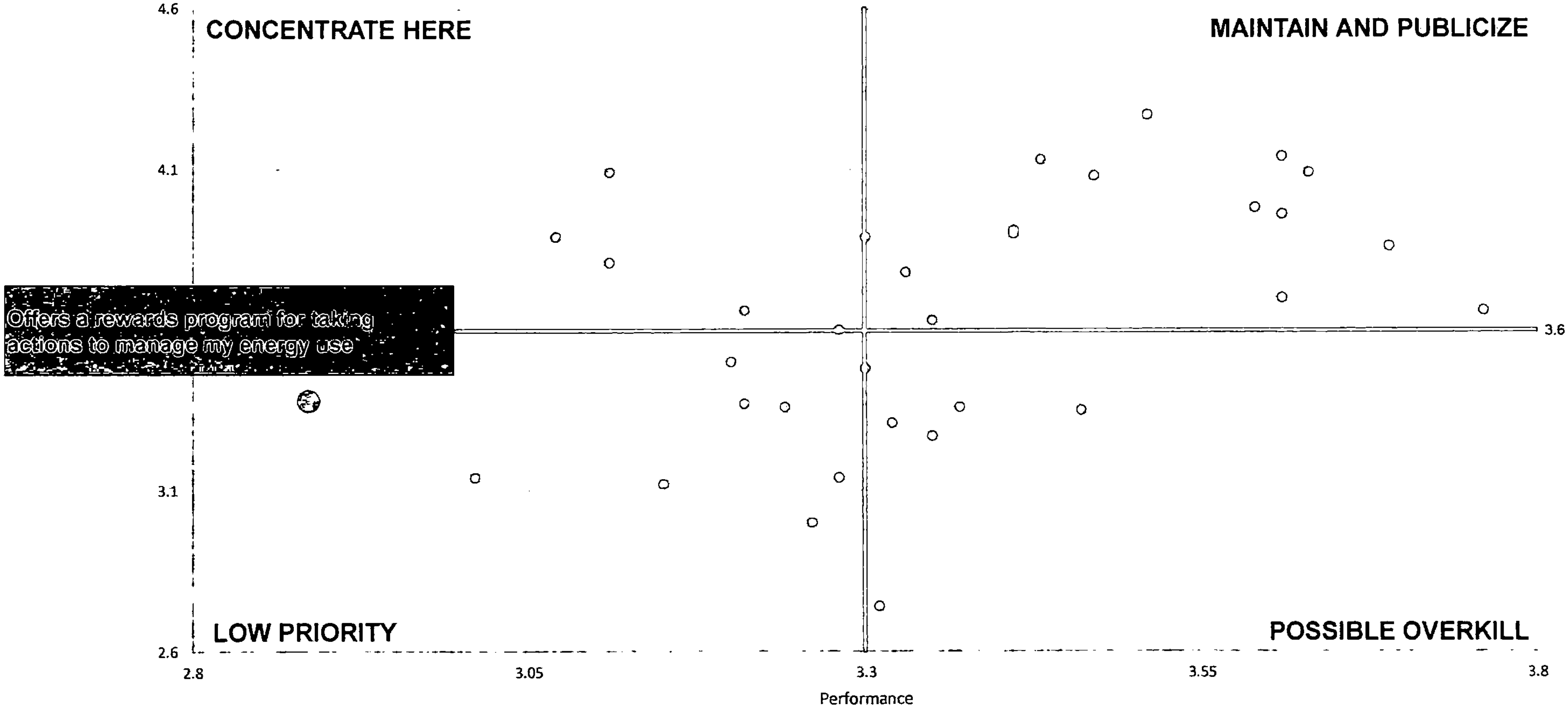
NOTE: *Chart scaled to reflect the range of means: highest/lowest importance = 4.27-2.59; highest/lowest performance: 3.76-2.89.*

N = 804



environment / carbon / efficiency.

N = 804



rewards.

N = 804

a majority of customers visit the Dominion Website...

Q. In the last year, how have you interacted with Dominion Energy? Select all that apply.

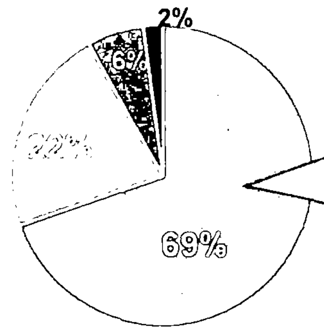
"visited their website"

52%

37%

it's their go-to source when it comes to checking their energy usage...

Q. There are a number of ways you can check your energy usage. Which of the following would be your go-to source when it comes to getting this information?

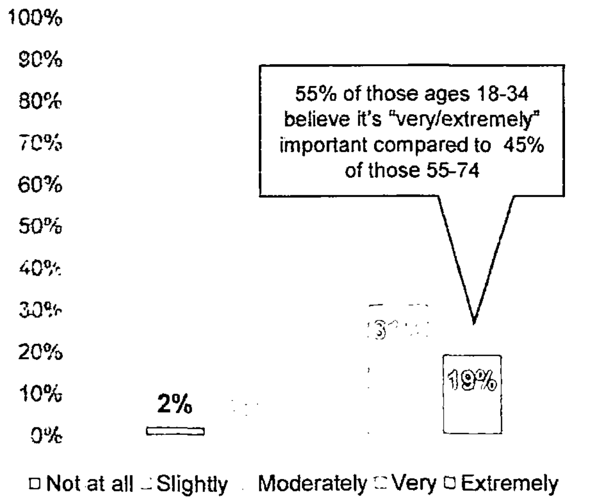


Older customers are more likely to use the website than younger ones (18-34=63% vs. 55-74=74%), who are starting to use smart thermostats instead.

the Dominion site is a go-to resource.

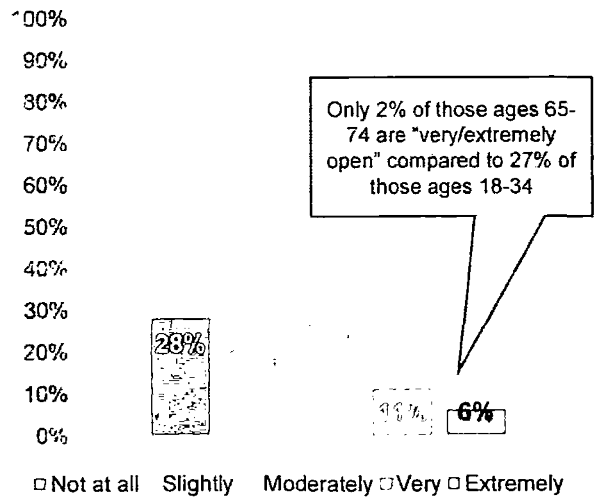
most customers think having access to information about their energy usage is important...

Q. New technologies are enabling customers to have access to more information about their energy usage. How important is it for you to have access to this information?



but they're less interested in opting-in to share data with third-party providers...

Q. Some electric companies give customers the option to voluntarily opt-in and securely share their energy usage data with qualified third-party providers.



and they think sticking with the Dominion site is the more convenient option

Q. There are different ways to view your energy usage data. How convenient is each of the following ways?

TOP 2 BOX

54% **Logging into my Dominion account and viewing my energy usage data**

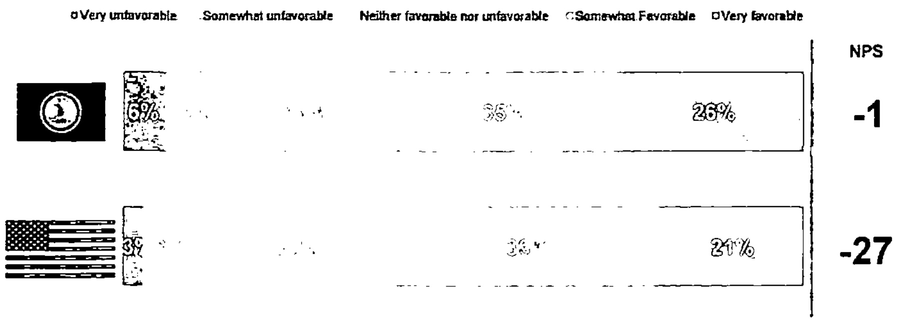
Consistent across ages

22% **Sharing my energy usage data with a qualified-third party by downloading or connecting it to their system and viewing in on their website/app**

the site is more convenient than other options.

appendix

favorability & NPS



active bill manager

Q. Which of the following would you say best describes you?		
I don't do anything to keep my electric bill low	5%	4%
I don't go out of my way to keep my electric bill low	15%	12%
I take reasonable steps to keep my electric bill low	67%	69%
I go out of my way to keep my electric bill low	12%	15%

outages

Experienced outage in past 6 months	44%	45%

Q. [ALL] Thinking about the last outage that you experienced, was your power restored in a timely manner?		
Yes	69%	72%
No	19%	16%
I don't know	12%	12%

customer service interactions

Visited their website	52%	37%
Called customer service	32%	23%
Received a communication (a phone call, text message, or e-mail)	23%	25%
Received an alert (by phone, text, or e-mail)	20%	21%
Had a worker come to my home (to fix an issue, restore power, read the meter, etc.)	8%	7%
Sent an email	6%	4%
Visited their social media page	4%	2%
None of the above	24%	32%

snapshot: comparing Dominion to national survey data.

190940285

Q. Please rate how good a job you think Dominion Energy is doing on each action today. ("poor" to "excellent" scale; mean scores)

top 10 performing attributes

Attributes	Total (n=805)	Less than $25K (n=80)
Has a range of payment options (like online, autopay, mobile pay, phone, or by check)	[illegible]	2
Has a user-friendly website that makes it easy to find the information I need and pay my bill	2	3
Keeps my energy usage data private and doesn't make any personally identifiable information available	3	9
Has knowledgeable customer service representatives	4	[illegible]
Has easy to understand bills that explain charges clearly	5	
Has a range of options to get customer service (like phone, chat, email)	6	4
Completes work without needing follow up	7	6
Completes scheduled work when they say they will	8	7
Invests in a stronger energy grid that can withstand extreme weather and cyberattacks	9	5
Has level billing so I can pay roughly the same monthly amount all year and avoid seasonal spikes	10	
Enables me to securely share my energy usage data with qualified third-parties if I'm interested in using their apps/programs to learn more about my usage		8
Proactively shares insights about my energy usage and recommendations on how to conserve energy and lower my bill		10

performance: less than $25K income segment.

NOTE: *"Less than $25K" data is directional because of smaller sample size, n=80.*

1909402385

Q. Please rate how important it is to you that Dominion Energy takes each action.
("not at all" to "extremely"; mean scores)

top 10 most important attributes

Attributes	Total (n=805)	Less than $25K (n=80)
Completes scheduled work when they say they will	[illegible]	[illegible]
Has knowledgeable customer service representatives	2	2
Invests in technology to help it prevent outages and respond to outages faster when they occur	3	3
Alerts me when power is out, how long it will take to restore, and when it is restored	4	8
Keeps my energy usage data private and doesn't make any personally identifiable information available	5	6
Invests in a stronger energy grid that can withstand extreme weather and cyberattacks	6	
Completes work without needing follow up	7	
Has easy to understand bills that explain charges clearly	8	4
Takes the time to listen to my issues and actually help me	9	5
Has an outage map that includes accurate estimates of outage time and progress in restoring power	10	
Uses innovative technologies and data to predict and prevent outages before they happen		
Has no convenience fees on credit card payments		10
Has a range of options to get customer service (like phone, chat, email)		7
Has a range of payment options (like online, autopay, mobile pay, phone, or by check)		9

importance: less than $25K income segment.

NOTE: *"Less than $25K" data is directional because of smaller sample size, n=80.*

favorability & NPS

	Total (n=805)	Less than $25K (n=80)
Favorability *(top 2)*	61%	60%
Unfavorability *(bottom 2)*	15%	13%
NPS score	-1	2.5

what they value most

Q. For you personally, how valuable is it that Dominion Energy can … ? (5-point scale; "not at all" to "extremely")

top 3, total

1 Restore my power more quickly
2 Improve reliability so I experience fewer outages
3 Prevent physical and cyber-attacks on the power grid

top 3, less than $25K

1 Restore my power more quickly
2 Improve reliability so I experience fewer outages
3 Help me save money on my electric bill

Ranked #5 (out of 12 actions) among total sample

frustrations

Less than $25K index higher on frustrations, particularly those related to cost

Q. Below is a list of situations that electric company customers like you might face. Please indicate how frustrating each situation is for you. (5-point scale; "this is not an issue for me" - "extremely") TOP 3 BOX [moderately – extremely] SHOWN

Total (n=805)	Less than $25K (n=80)	Frustrations
35%	38%	I don't receive accurate information about when my power will be restored during outages
33%	44%	The electric company takes too long to respond to a power outage
32%	39%	There aren't enough options to help me conserve energy and save money
31%	46%	My bill each month is unpredictable
29%	31%	I experience unexpected outages
29%	39%	I don't know how my energy usage affects my bill each month
28%	35%	Customer service representatives aren't able to efficiently resolve my issues
28%	43%	I can't track my energy usage to conserve energy
25%	39%	I can't understand the charges on my bill
24%	35%	There aren't enough different billing plan options
22%	21%	I can't contact my electric company in the way that's most convenient for me (phone, web chat, app, etc.)

a closer look: less than $25K income segment.

NOTE: *"Less than $25K" data is directional because of smaller sample size, n=80.*

CATEGORY	ATTRIBUTE
bills and payment	Has easy to understand bills that explain charges clearly
	Has a user-friendly website that makes it easy to find the information I need and pay my bill
	Has no convenience fees on credit card payments
	Has a range of payment options (like online, autopay, mobile pay, phone, or by check)
	Has level billing so I can pay roughly the same monthly amount all year and avoid seasonal spikes
	Allows me to decide when my bill is due and change the date as needed
	Allows me opt-in to a "peak and off-peak rate" program which enables me to save money when I cut down my energy usage during peak times
	Allows me to make smaller payments, more frequently, rather than having to pay once a month
	Has a range of billing choices and plans
customer service	Has knowledgeable customer service representatives
	Takes the time to listen to my issues and actually help me
	Has a range of options to get customer service (like phone, chat, email)
digital / digital privacy	Offers tips, tools, and programs to help me save money by managing my energy use
	Allows me to set custom alerts so I can choose which notifications I want to receive and how I want to receive them
	Allows me to customize alerts so I'll be notified when I am close to a pre-set dollar threshold or usage limit
	Proactively shares insights about my energy usage and recommendations on how to conserve energy and lower my bill
	Uses historic data and predictive patterns, like prior year energy use, to help me plan ahead
	Shares benchmarks that show how my energy use compares to other homes in my area
	Enables me to securely share my energy usage data with qualified third-parties if I'm interested in using their apps/programs to learn more about my usage
	Keeps my energy usage data private and doesn't make any personally identifiable information available
environment / carbon / efficiency	Is taking steps to reduce carbon emissions and protect the environment
	Gives me the ability to sell extra energy back to the energy grid if I generate it at home
	Helps make the air in my community cleaner by investing in public charging stations for electric vehicles
	Helps makes my community more environmentally-friendly by proactively replacing streetlights with LED bulbs
	Increases the use of renewable energy by investing in new technologies like battery storage
operational performance	Completes scheduled work when they say they will
	Completes work without needing follow up
	Considers my needs and impact on my day-to-day activities when scheduling work
	Invests in technology to help it prevent outages and respond to outages faster when they occur
outage communications	Alerts me when power is out, how long it will take to restore, and when it is restored
	Has an outage map that includes accurate estimates of outage time and progress in restoring power
	Proactively communicates about storms and potential outages
rewards	Offers a rewards program for taking actions to manage my energy use
smarter energy infrastructure	Invests in a stronger energy grid that can withstand extreme weather and cyberattacks
	Uses innovative technologies and data to predict and prevent outages before they happen

attributes tested.

1909402385

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Dominion Energy

Grid Transformation Plan – Attribute Importance (total and by key segment)

maslansky + partners

Survey Question: Please rate how important it is to you that Dominion Energy takes each action.
("not at all" to "extremely"; mean scores; n=805)

	Total	GEOGRAPHIC REGION			INCOME		OUTAGES		BILL MANAGEMENT	
		Central (n=202)	Northeast (n=343)	Eastern (n=260)	$50K or less (n=216)	$50K+ (n=589)	Experienced (n=358)	Has not (n=447)	Not active (n=166)	Active (n=639)
Completes scheduled work when they say they will	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Has knowledgeable customer service representatives	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3.97	[illegible]
Invests in technology to help it prevent outages and respond to outages faster when they occur	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3.87	[illegible]
Keeps my energy usage data private and doesn't make any personally *identifiable information available*	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3.76	[illegible]
Alerts me when power is out, how long it will take to restore, and when it is restored	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3.67	[illegible]
Invests in a stronger energy grid that can withstand extreme weather and cyberattacks	[illegible]	[illegible]	[illegible]	[illegible]	3.97	[illegible]	[illegible]	[illegible]	3.74	[illegible]
Completes work without needing follow up	3.98	[illegible]	3.98	3.93	4.02	3.97	3.95	[illegible]	3.77	[illegible]
Has easy to understand bills that explain charges clearly	3.96	3.97	3.95	3.96	[illegible]	3.91	3.95	3.97	3.63	3.85
Takes the time to listen to my issues and actually help me	3.91	[illegible]	3.82	3.96	4.08	3.85	3.89	3.93	3.54	[illegible]
Has an outage map that includes accurate estimates of outage time and progress in restoring power	3.9	3.93	3.93	3.83	3.8	3.93	4.01	3.79	3.53	3.89
Uses innovative technologies and data to predict and prevent outages before they happen	3.89	3.9	3.88	3.89	3.87	3.9	3.89	3.89	3.59	3.97
Has no convenience fees on credit card payments	3.89	3.78	3.88	[illegible]	3.99	3.86	3.88	3.9	3.57	3.97
Has a user-friendly website that makes it easy to find the information I need and pay my bill	3.86	3.93	3.87	3.81	4.02	3.8	3.82	3.9	3.59	3.94
Proactively communicates about storms and potential outages	3.81	3.95	3.72	3.83	3.91	3.78	3.7	3.9	3.47	3.89
Is taking steps to reduce carbon emissions and protect the environment	3.78	3.77	3.76	3.8	3.87	3.74	3.7	3.84	3.31	3.89
Has a range of options to get customer service (like phone, chat, email)	3.7	3.87	3.54	3.78	3.89	3.63	3.67	3.73	3.34	3.79
Considers my needs and impact on my day-to-day activities when scheduling work	3.66	3.72	3.62	3.56	3.75	3.62	3.66	3.65	3.37	3.73
Has a range of payment options (like online, autopay, mobile pay, phone, or by check)	3.66	3.68	3.53	3.81	4.02	3.52	3.66	3.65	3.26	3.76
Increases the use of renewable energy by investing in new technologies like battery storage	3.63	3.66	3.58	3.65	3.58	3.64	3.55	3.69	3.27	3.72
Helps makes my community more environmentally-friendly by proactively replacing streetlights with LED bulbs	3.6	3.61	3.51	3.71	3.69	3.57	3.56	3.64	3.13	3.72
Proactively shares insights about my energy usage and recommendations on how to conserve energy and lower my bill	3.5	3.72	3.42	3.44	3.72	3.42	3.43	3.55	3.11	3.6
Offers tips, tools, and programs to help me save money by managing my energy use	3.48	3.6	3.36	3.55	3.77	3.37	3.38	3.56	3.18	3.56
Offers a rewards program for taking actions to manage my energy use	3.38	3.52	3.28	3.4	3.54	3.32	3.34	3.41	2.97	3.48
Helps make the air in my community cleaner by investing in public charging stations for electric vehicles	3.37	3.29	3.41	3.37	3.44	3.34	3.3	3.41	2.82	3.52
Has a range of billing choices and plans	3.36	3.54	3.1	3.55	3.78	3.2	3.33	3.38	3.11	3.42
Allows me opt-in to a "peak and off-peak rate" program which enables me to save money when I cut down my energy usage during peak times	3.36	3.35	3.26	3.49	3.63	3.27	3.29	3.41	2.9	3.48
Has level billing so I can pay roughly the same monthly amount all year and avoid seasonal spikes	3.35	3.62	3.18	3.37	3.79	3.2	3.26	3.43	3.02	3.44
Uses historic data and predictive patterns, like prior year energy use, to help me plan ahead	3.31	3.46	3.26	3.26	3.51	3.23	3.29	3.33	3.05	3.38
Allows me to set custom alerts so I can choose which notifications I want to receive and how I want to receive them	3.27	3.14	3.27	3.39	3.5	3.2	3.23	3.31	2.92	3.37
Shares benchmarks that show how my energy use compares to other homes in my area	3.14	3.12	3.17	3.11	3.25	3.1	3.1	3.16	2.91	3.19
Allows me to decide when my bill is due and change the date as needed	3.14	3.26	2.98	3.25	3.72	2.94	3.08	3.19	2.8	3.23
Gives me the ability to sell extra energy back to the energy grid if I generate it at home	3.12	3.17	3.08	3.13	3.29	3.06	3.18	3.06	2.61	3.25
Allows me to customize alerts so I'll be notified when I am close to a pre-set dollar threshold or usage limit	3	3.11	2.87	3.09	3.41	2.86	2.93	3.06	2.66	3.09
Enables me to securely share my energy usage data with qualified third-parties if I'm interested in using their apps/programs to learn more about my usage	2.74	2.67	2.73	2.79	3.08	2.62	2.67	2.79	2.57	2.78
Allows me to make smaller payments, more frequently, rather than having to pay once a month	2.59	2.81	2.27	2.83	3.3	2.31	2.48	2.67	2.41	2.63

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Appendix D

Dominion Energy: Social Media Analysis Final Report

June 28, 2019

Appendix D

Executive Summary

- WCG evaluated over 28.5k social media comments spanning Jan 2016 - May 2019 combined with power outage information by location, storm type, etc.
  - Most analysis was focused on 2017+ as comment capture was not robust in 2016

- Regression modelling showed that the number of customers without power is a very significant driver of comment volume
  - Major Storm events spike comment volume materially
  - People go to social media even for small/sporadic outages

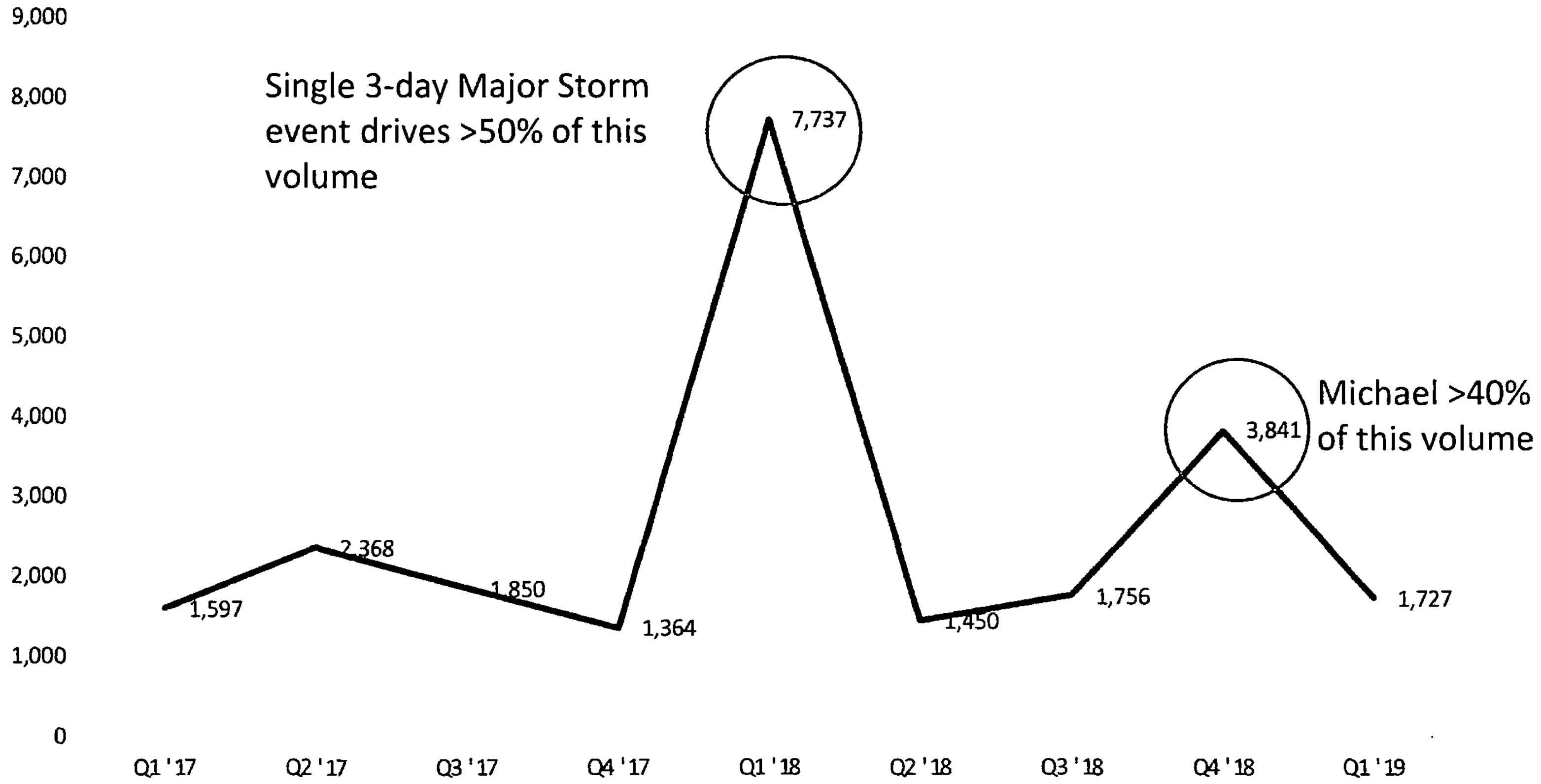
- We cannot draw conclusions from social media regarding frustration with having to report outages

- Customers may be more shocked by high bills in cold weather vs warm

Excludes Messenger

We evaluated 25k+ social media comments over 2+ years to develop insights – Major Storm events create high variability

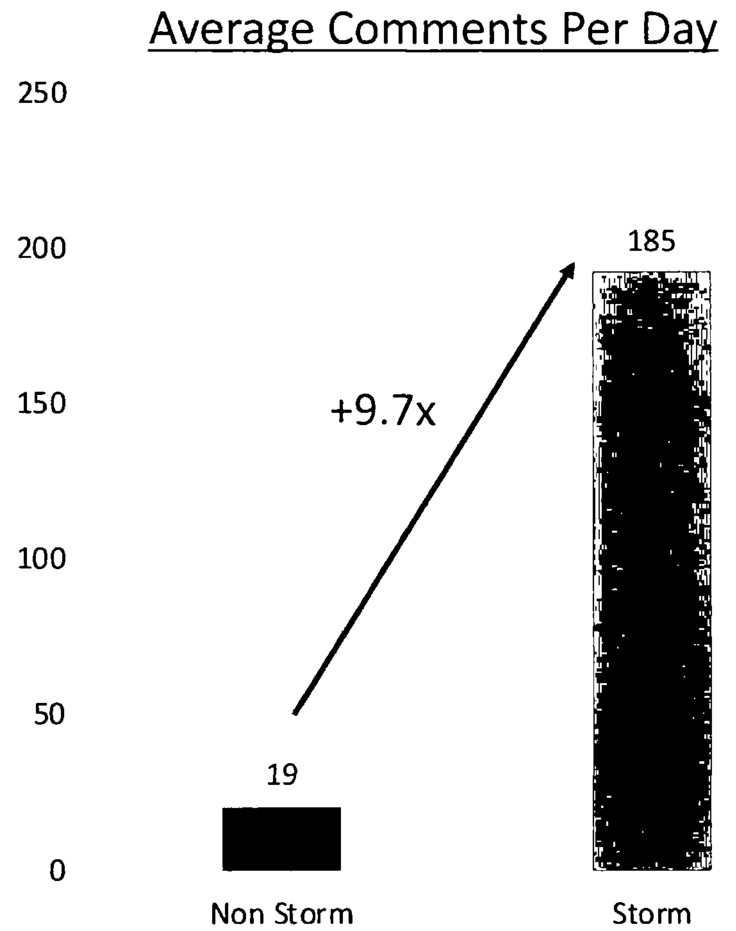
Quarterly Comment Volume

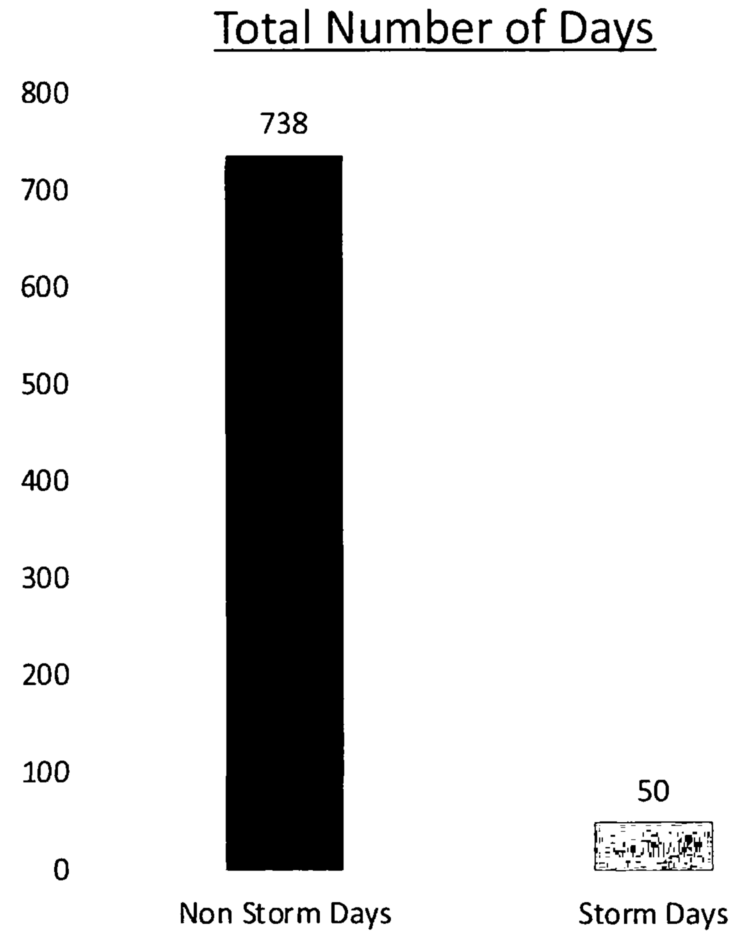


Note: FB Messenger removed as it is primarily a customer service channel

Excludes Messenger

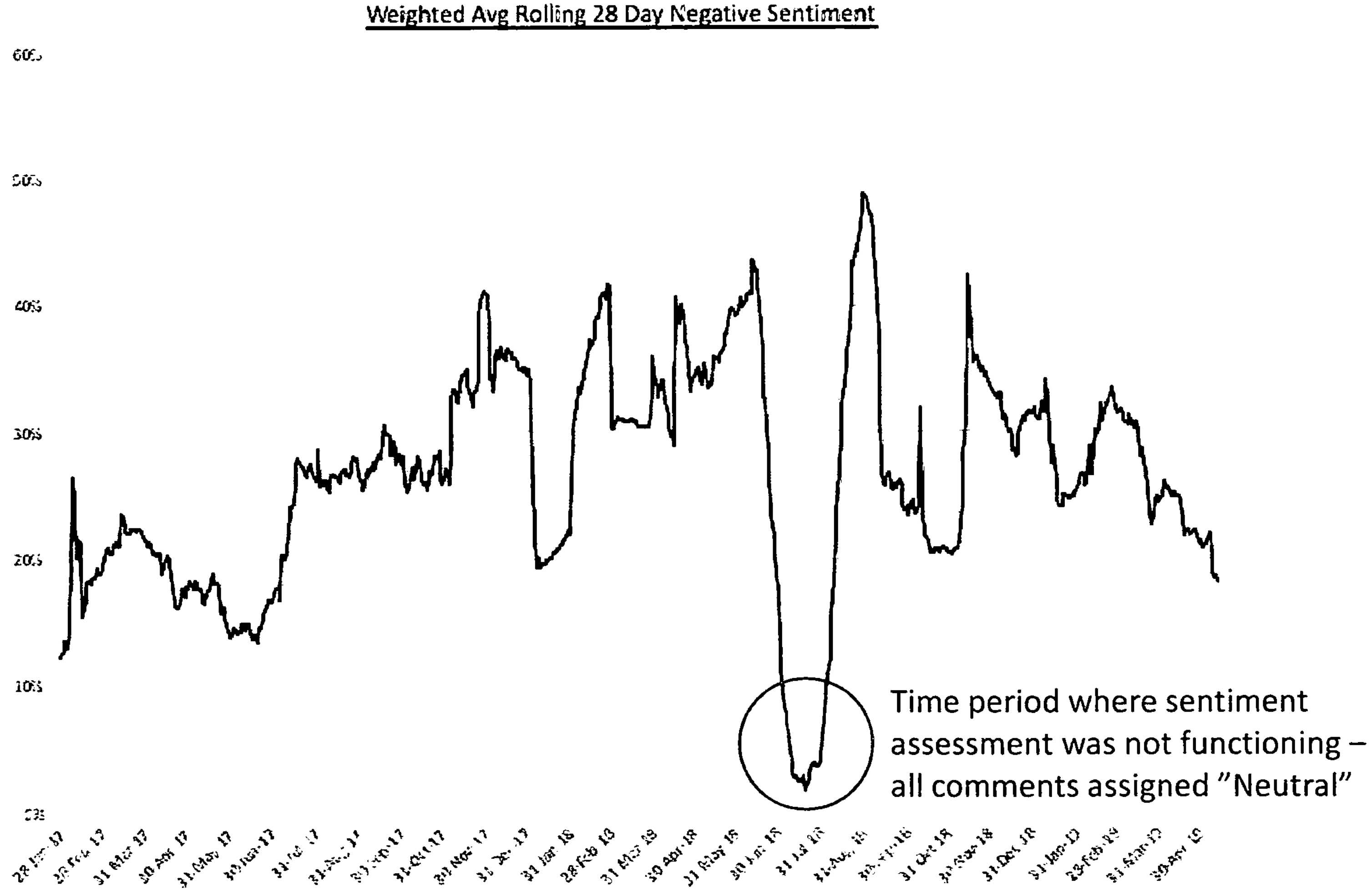
Average comment volume on the 50 Major Storm days was over 9x the comment volume on non-Major Storm days





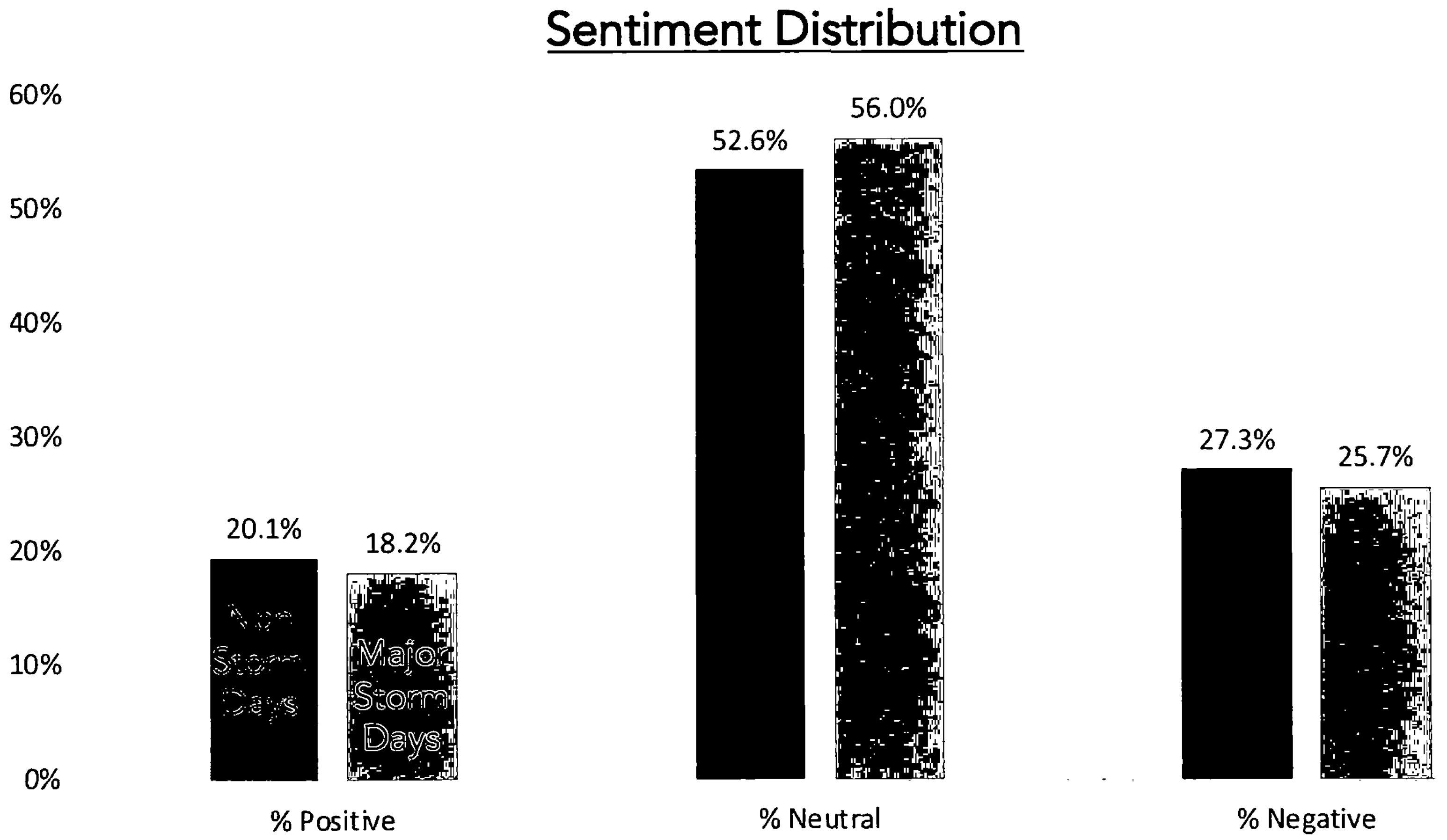
Note: Data is from Jan 1, 2017-Feb 28, 2019 (788 days)

The Negative Sentiment has been trending down since Q3 2018 after rising for over a year and a half



Excludes Messenger

Average sentiment does not change a lot between Major Storm and non storm days

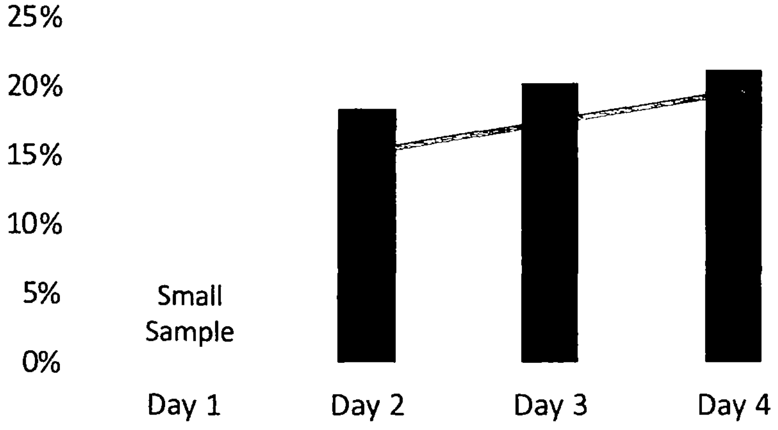


Notes:
Includes data from Jan 2017-Feb 2019
Non-Major Storm excludes day after Major Storms

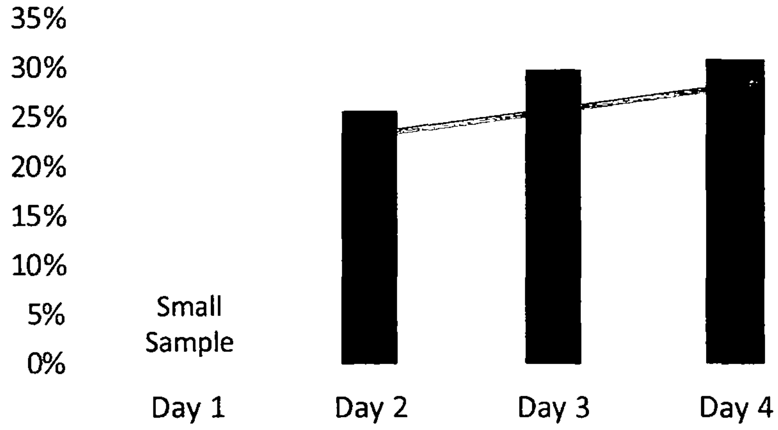
Excludes Messenger

However, isolating multi-day Major Storms shows sentiment usually trends progressively worse as storm impacts drag on

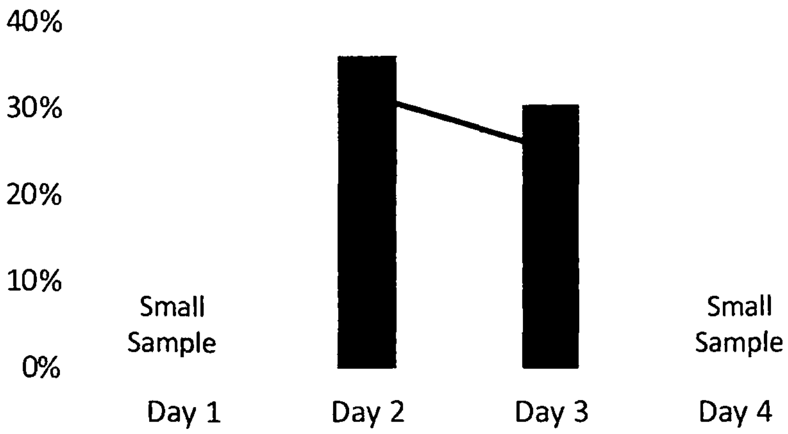
Negative Sentiment Oct-18 Major Storm



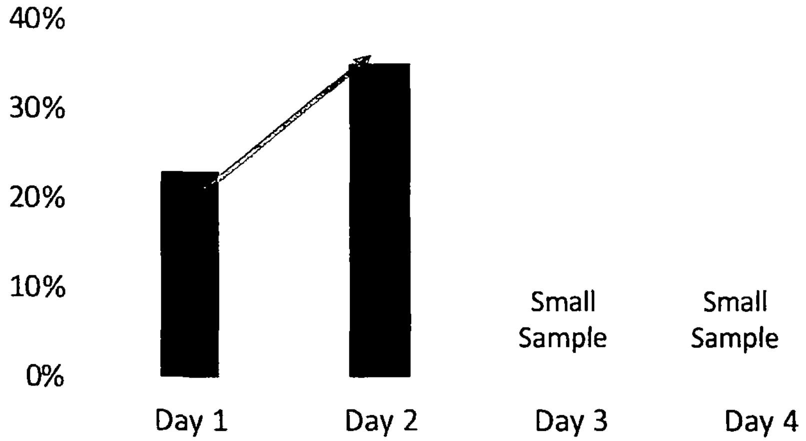
Negative Sentiment Mar-18 Major Storm



Negative Sentiment Nov-18 Major Storm



Negative Sentiment Jan-19 Major Storm



Note: Only showing days with more than 100 total comments

Excludes Messenger

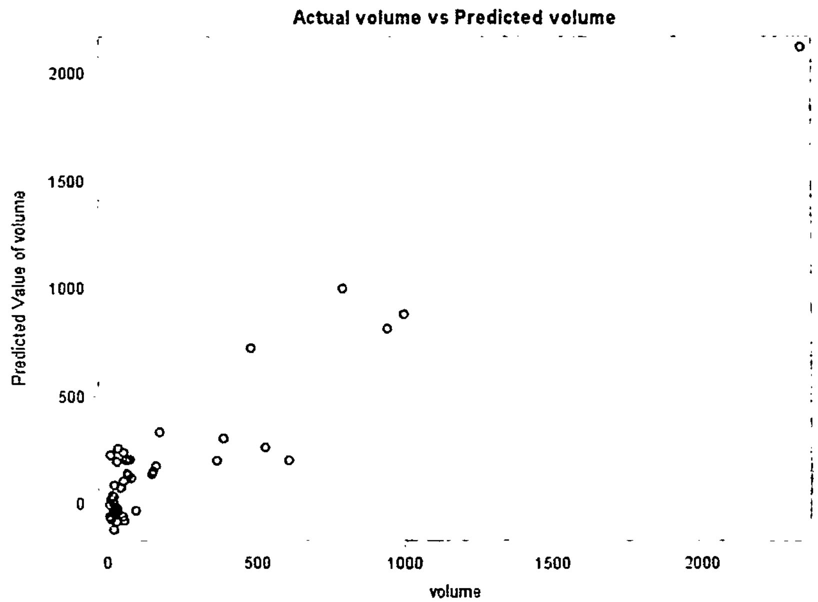
Multivariate regression of Major Storm days showed that there are 4 primary drivers of comment volumes

Multivariate Regression Variables

Parameter	Parameter	t Value	Pr > |t|
# customers out in most recent Major Storm	0.002	8.29	<.0001
# social comments in most recent Major Storm	0.338	4.06	0.0004
# customers out in current Major Storm day	0.001	3.12	0.0042
Major Storm is Day 2+	172.2	1.85	0.0742
Major Storm impacted Rockbridge, Blue Ridge, Shenandoah	134.2	1.53	0.138
Northwest region	-187.5	-1.50	0.145
Major Storm impacted Springfield, Leesburg, Fairfax, Fred'burg, Herndon	160.7	1.23	0.230
Major Storm is Ice/Snow	223.3	1.09	0.283
Major Storm is electrical/tornado/thunderstorm	161.3	0.82	0.419
Number of cities impacted	-11.7	-0.74	0.463
Major Storm impacted Alleghany, C'Ville, Orange	61.0	0.65	0.523
Major Storm is Hurricane or Wind	120.9	0.62	0.539
Recency of last Major Storm	0.9	0.39	0.699
Central region	5.9	0.08	0.939
Flag for Weekend	7.1	0.12	0.905

Observations	44
Parameters	16
Error DF	28
MSE	29185
R-Square	0.8889
Adj R-Square	0.8294

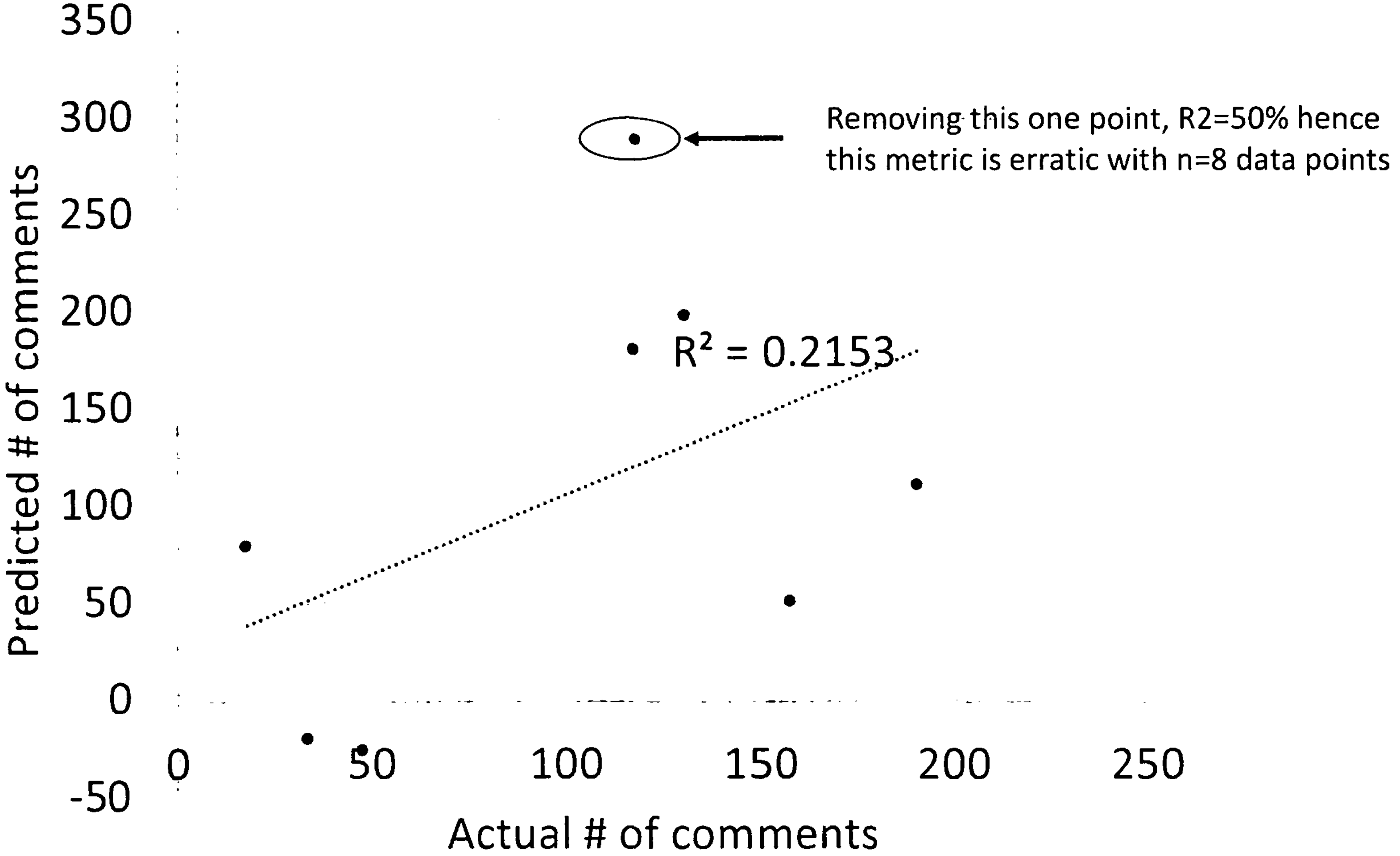
Actual vs. Predicted Comment Vol.



The first 4 variables generate 95%+ of the power.
No 2019 Major Storms in this data/build. Could use as validation sample.

Validation is a challenge with only 8 Major Storms in 2019 – the model does not predict very well on this small set

Validation Regression on 2019 Major Storm events



Recommend continuing to gather data for validation

However, the top variables are powerful in the 2019 Major Storms also – just not in the same order/magnitude

2019 Storms / N=8

Day 2 comment vol dropped

Major Storm	Date	storm_number	num_comments	Customers_out	Customers_out_prior	Comments_prior	Day2_plus
510 01 SNOW & ICE - C	1/13/2019	510	191	61957	15820	387	0
511 01 SNOW & ICE - C DAY 2	1/14/2019	511	119	5810	61957	191	1
512 WINTER STORM - C & W	2/20/2019	512	48	16673	5810	119	0
513 03 WIND - W	2/24/2019	513	34	21057	16673	48	0
514 03 WIND - N DAY 2	2/25/2019	514	131	52103	21057	34	1
515 04 WIND - C	3/22/2019	515	18	21511	52103	131	0
516 05 WIND - C & E	4/15/2019	516	158	99917	21511	18	0
517 06 WIND E NC	4/19/2019	517	118	11547	99917	158	0

- N=8 storms is a small sample size but there appears to be directional correlations in 3 of the top 4 predictors from the model based on 2017-2018 (N=45) storms:
  - # of customers out in current Major Storm (p-value = 0.039)
  - # of social comments in prior Major Storm (p-value = 0.10)
  - An indicator for day 2+ of a Major Storm (p-value = 0.18) (marginally significant)
  - # of customers out in prior Major Storm (p-value = 0.29) (not significant)
- Recommend continuing to build up this dataset over time, re-estimate the volume model, and establish use-case(s)

Variable	Parameter	Standard	t Value	p-value
Number of customers out (current Major Storm)	0.0017	0.00048	3.52	[redacted]
Number of comments (prior Major Storm)	0.275	0.117	2.35	[redacted]
Major Storm is day 2+	51.86	30.12	1.72	0.184
Number of customers out (prior Major Storm)	0.00069	0.00048	1.28	0.29

2019
N=8
R-squared=85.5%

2017-2018
N=45
R-squared=89.9%

Regression on all days shows that the number of customers without power is a fundamental driver of comment volume

Total Comment volume regression

Description	Parameter	t Value	p-value
Intercept	14.60225	4.28	<.0001
# customers out	0.00087	7.95	<.0001
Flag for major storm day	121.54359	7.95	<.0001

Interpretation: 1) # customer out and Major Storms are both significant drivers of comments
2) Major Storms increase comment volume by an average of 121

Negative Comment volume regression

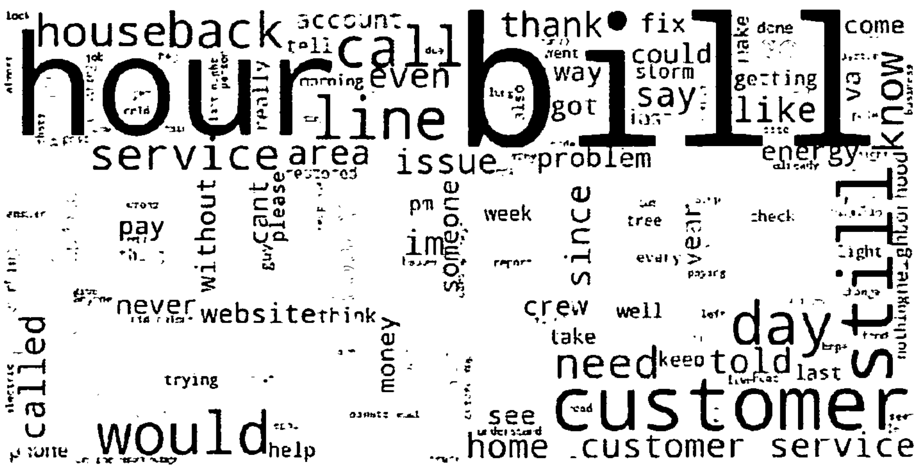
Variable	Description	Estimate	Error	t	pvalue
Intercept	Intercept	3.8	1.16101	3.25	0.0012
sum_Customers	# customers out	0.00020	0.00003234	6.13	<.0001
fri_sat	Flag for Friday or Saturday	1.6	2.08853	0.75	0.4527
storm	Flag for major storm day	31.9	4.50305	7.08	<.0001

Interpretation: 1) # customer out and Major Storms are both significant drivers of Negative comments
2) Major Storms increase negative comments by an average of almost 32

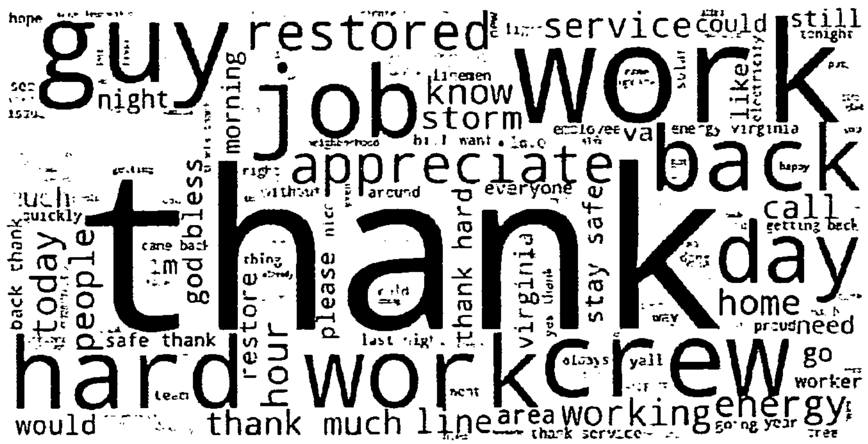
Non Storm Days

Word frequency evaluations shows that Outages and Bill are common on Non-Storm days

Negative



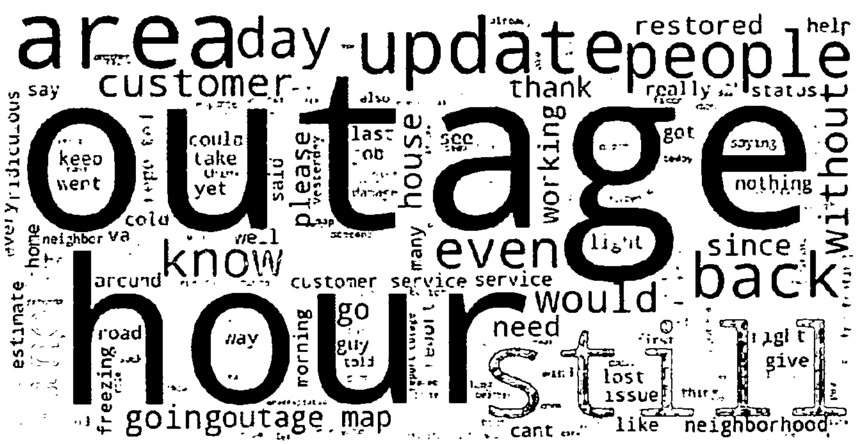
Neutral



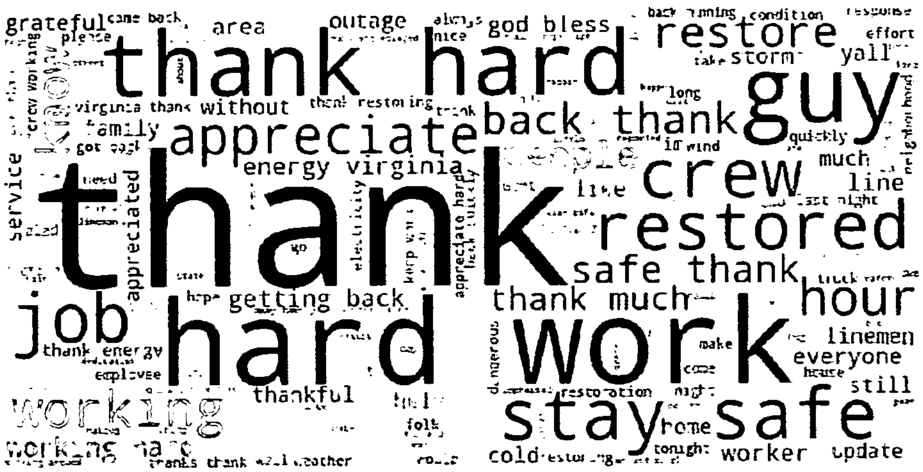
Positive

On Major Storm days, comments are dominated by "Outage" and "Thank" (for getting power back on)

Negative



Neutral



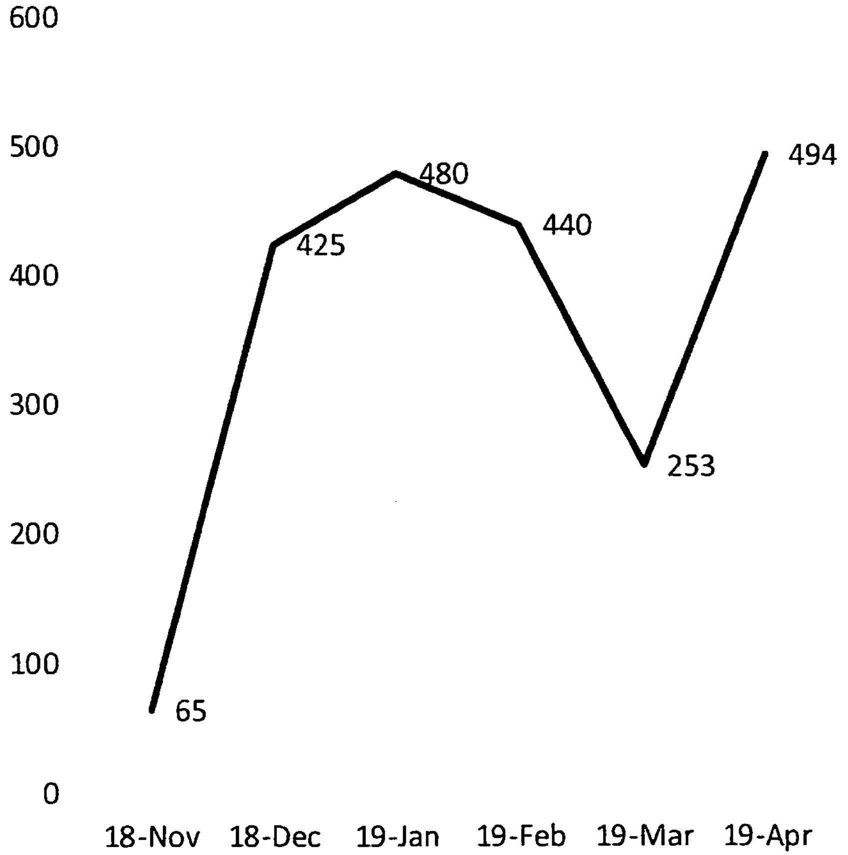
Positive

Specific other refining analysis outputs

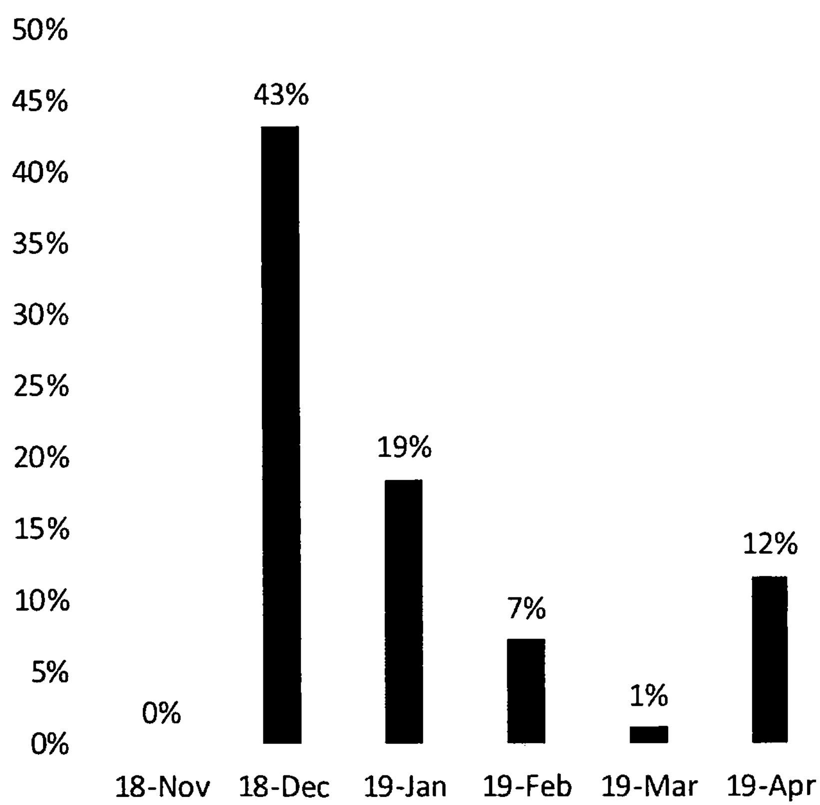
1. FB Messenger independent analysis and removal from rest:
   - Repeating most analysis without this channel – modeling, frequency, sentiment, etc.
   - Evaluate FB messenger as channel alone on sentiment, Major Storm/non-storm distro, etc.
   - This would include re-running the regression with day of the week included.
   - Get 2019 outage information and use as validation sample
2. Evaluating if reliability/resiliency is a pain point in the non-storm days too:
3. Evaluate why "Outage" appears in Non-Storm Negative comment cloud?
4. Evaluate customer frustration with having to report power outage:
5. Perform a sentiment/frequency of the word "Bill"

FB Messenger channel first appeared in Nov 2018 and quickly ramped volume

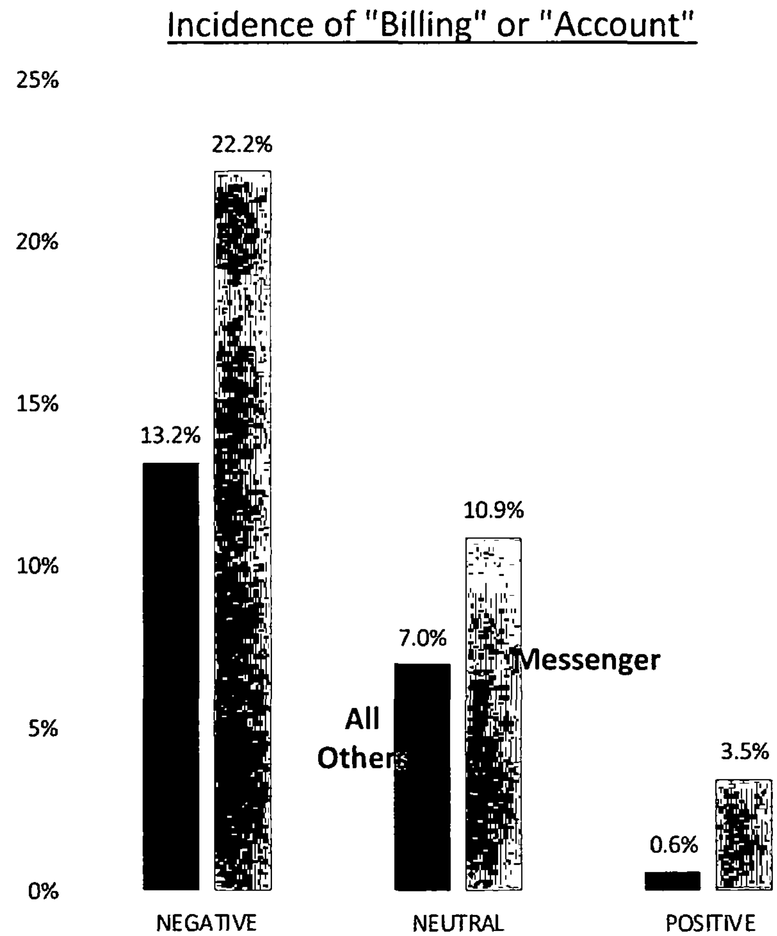
FB Messenger Total Comments



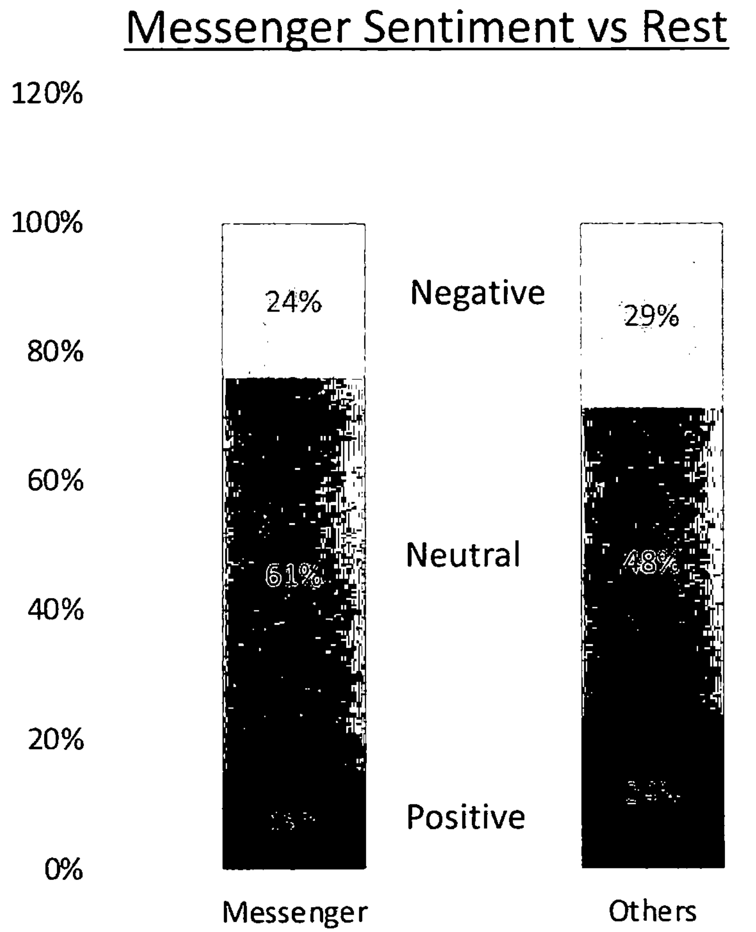
% FB Messenger Major Storm Days

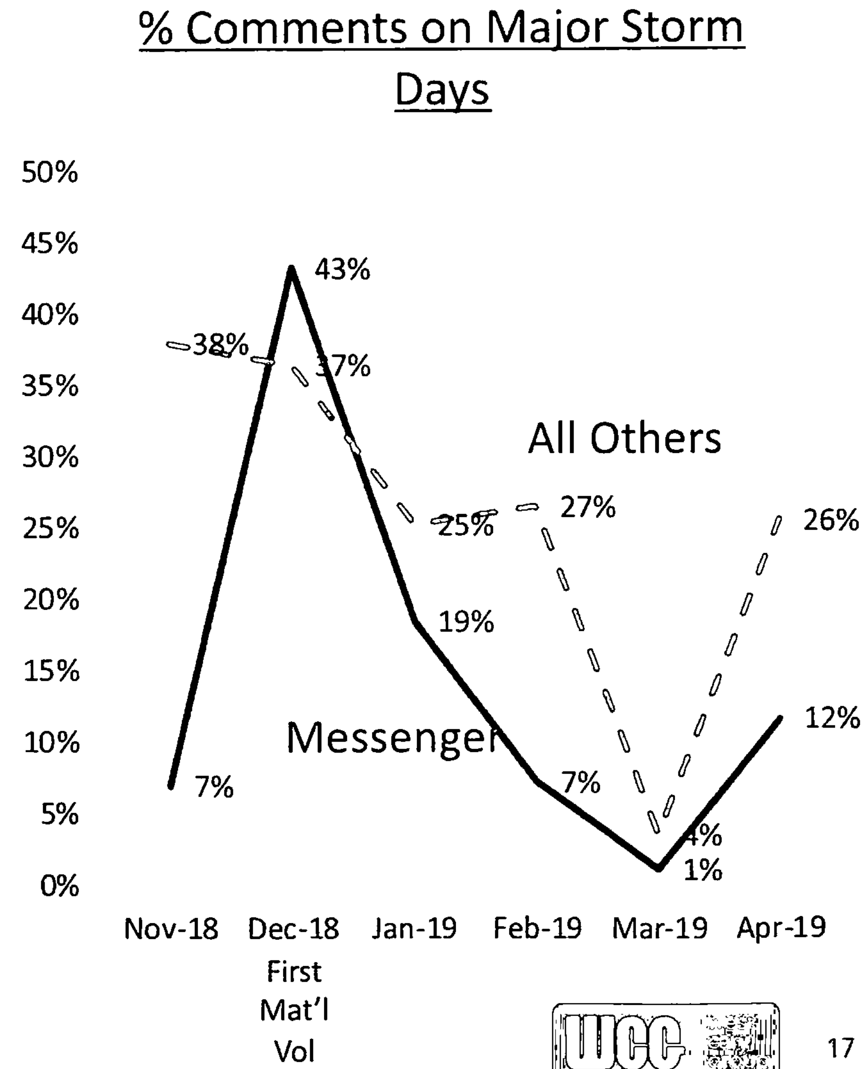


Billing and Account appear much more frequently in FB Messenger vs other channels



The channel has >60% neutral comments and after December has been primarily used on Non-Major Storm days

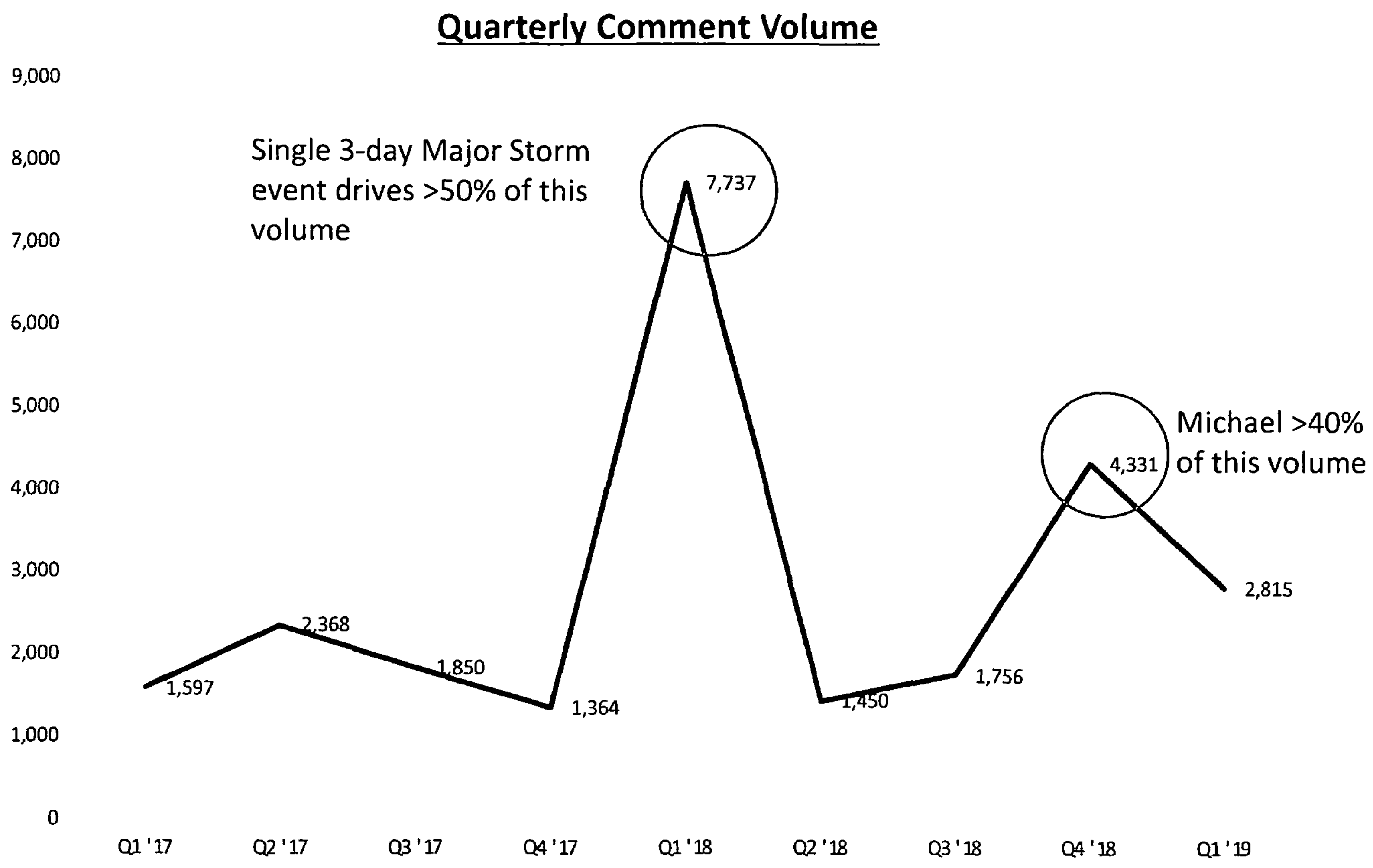




Word Frequency for FB Messenger – most comments are neutral and most frequent are thanks, address, account, & bill

Positive comments	Freq Measure	Neutral comments	Freq Measure	Negative comments	Freq Measure
{'thank'	1.0,	{'thank'	1.0,	{'bill'	1.0,
'thank you'	0.298	'address'	0.798	'please'	0.814
'thank much'	0.243	'account'	0.798	'call'	0.790
'appreciate'	0.119	'bill'	0.701	'would'	0.765
'help'	0.104	'need'	0.663	'account'	0.753
'day'	0.094	'please'	0.653	'told'	0.740
'back'	0.094	'would'	0.615	'service'	0.716
'much'	0.089	'know'	0.605	'day'	0.666
'guy'	0.074	'help'	0.596	'line'	0.666
'know'	0.069	'name'	0.519	'still'	0.617
'yes'	0.064	'back'	0.519	'thank'	0.617
'would'	0.059	'yes'	0.509	'issue'	0.617
'call'	0.054	'line'	0.5,	'hour'	0.604
'you'	0.049	'house'	0.490	'pay'	0.580
'hard'	0.049	'payment'	0.480	'back'	0.555
'line'	0.049	'hello'	0.423	'called'	0.555
'address'	0.049	'road'	0.413	'outage'	0.543
'work'	0.049	'pay'	0.403	'need'	0.530
'working'	0.044	'number'	0.403	'going'	0.530
'me'	0.044	'call'	0.394	'payment'	0.530
'well'	0.044	'rd'	0.384	'cant'	0.518
'wanted'	0.039	'account numbe	0.375	'even'	0.518
'that'	0.039	'today'	0.355	'customer ser	0.518
'make'	0.039	'new'	0.346	'way'	0.506
'nice'	0.039	'energy'	0.346	'today'	0.506
'see'	0.039	'want'	0.336	'since'	0.506

We evaluated 25k+ social media comments over 2+ years to develop insights – Major Storm events create high variability

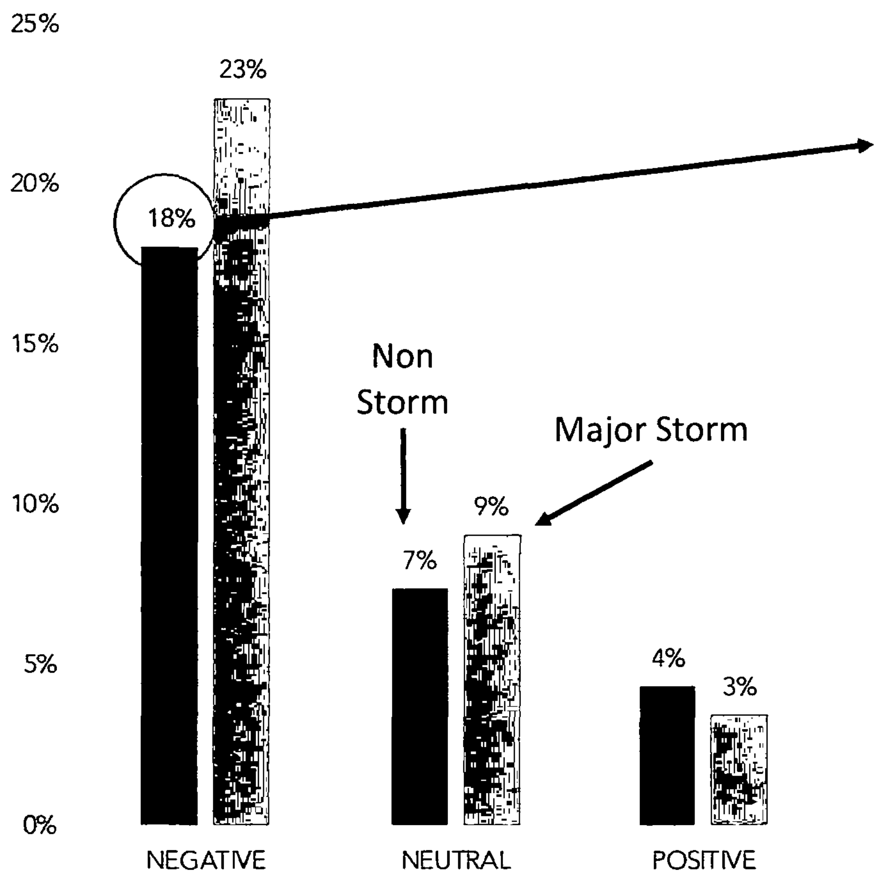


Specific other refining analysis outputs

1. FB Messenger independent analysis and removal from rest:
2. Evaluating if reliability/resiliency is a pain point in the non-storm days too:
   – This is more exploratory. #3 may give us insight into this.
3. Evaluate why "Outage" appears in Non-Major Storm Negative comment cloud?
   – When is this mentioned - Is it near Major Storm days or on blue sky days?
   – How many customers were out of power the days it is mentioned?
4. Evaluate customer frustration with having to report power outage:
5. Perform a sentiment/frequency of the word "Bill"

"Outage" appears with similar rates and sentiment both Major Storm and non-Major Storm days – highest occurrence is day after Major Storm

% of comments containing "Outage"

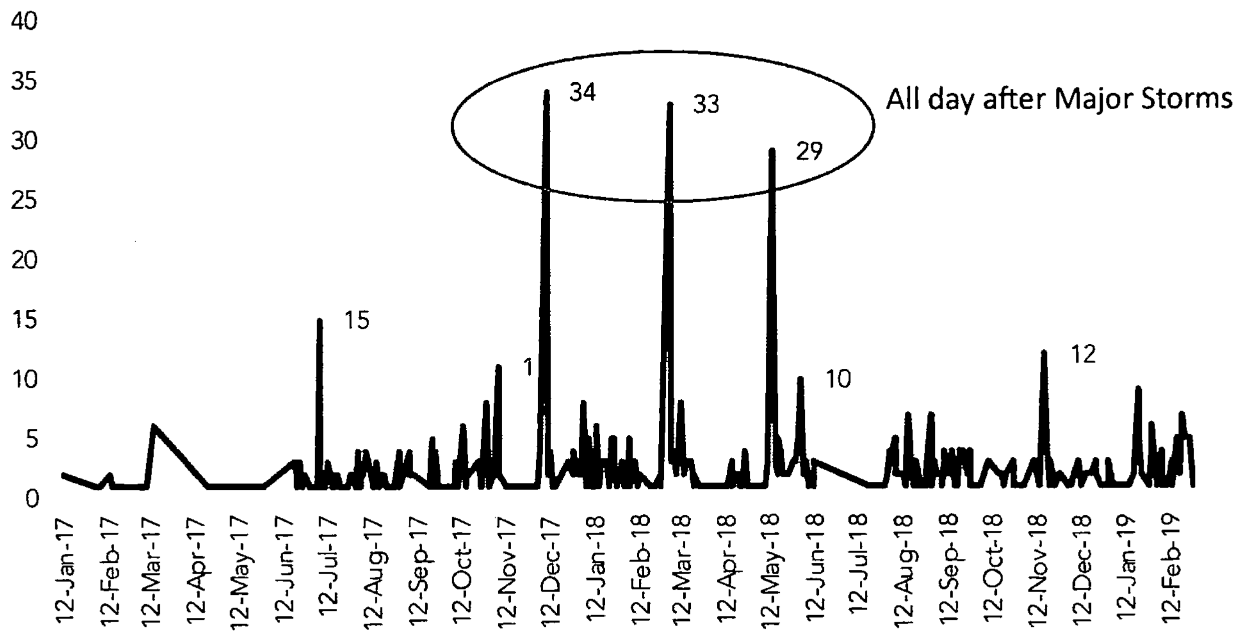


Of 775 'outage' negative comments on non storm days (the 18%):

- 21% are received day after Major Storm (most likely still recovering)
- 25% are received within 2 days after a Major Storm
- 28% are received within 3 days after a Major Storm
- 32% are received within 4 days after a Major Storm
- 35% are received within 5 days after a Major Storm

Day after major storms – "outage" is most prevalent

"Outage" Negative comments – Non Major Storm days



"Outage" negative Comments by Major Storn day

Date	Count
8-Jan-17	1
1-Mar-17	3
14-Mar-17	7
19-Jun-17	2
14-Jul-17	1
15-Jul-17	2
29-Aug-17	2
8-Dec-17	5
9-Dec-17	24
3-Jan-18	6
4-Jan-18	22
7-Jan-18	10
1-Mar-18	2
2-Mar-18	74
3-Mar-18	158
4-Mar-18	52
15-Apr-18	1
14-May-18	5
10-Jun-18	2
11-Aug-18	3
12-Aug-18	1
30-Aug-18	3
14-Sep-18	5
17-Sep-18	4
11-Oct-18	3
12-Oct-18	30
13-Oct-18	18
14-Oct-18	15
15-Nov-18	2
16-Nov-18	11
17-Nov-18	8
9-Dec-18	1
10-Dec-18	28
13-Jan-19	15
14-Jan-19	5
24-Feb-19	7
25-Feb-19	21

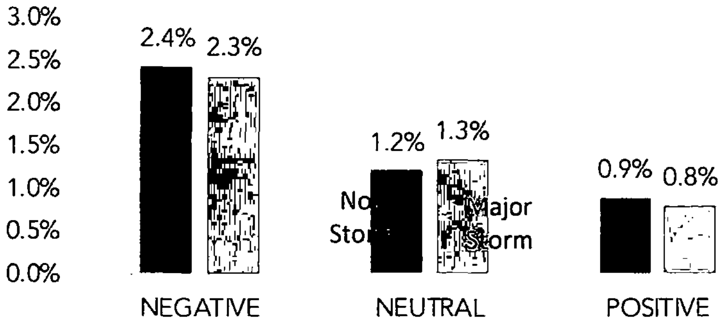
Looking at a 'blue sky' negative Outage comments, it becomes clear that small outages are being referenced

Random sample n=20 of 'blue sky' (>5 days after Major Storm) negative "outage" mentions. These appear to be related to outages in specific locations

Message
So @DomEnergyVA is here with a new definition to add to @MerriamWebster #PowerOutage pic.twitter.com/rclHLWKONc
I understand the increase in energy usage but the power being out due to a Dominion issue caused the temperature in my house to go up so then the air conditioner had to work harder to cool it back down. I have a one year old in my house I can't just leave it in the high 80s. Dominion did not fix the issue properly the first time causing the second power outage. That is not my fault.
2nd #RVA non wx power outage in a week. Nothing compared to what others dealing with but concerning re US infrastructure woes @DomEnergyVA
What happened with the power outage in Fredericksburg/Spotsylvania tonight?
I am in North Suffolk. Power was out about an hour this morning. Maggs and Linda, where are you located? Are you still out? When I called, the nice customer service lady (Cassandra) said it is always good to report it, even if it is resolved (blinking alarm clock is my clue) to report the outage. Paula, not really, she was doing her job. ??
@DomEnergyVA I had reported a power outage and you are sending someone out, but the power just came back on. How can I cancel the person coming. I've tried calling customer service but there is no option to.
400 customers in @NorfolkVA Diamond Springs area are still in the dark. @DomEnergyVA crews working to get them back on by 11am. That's the last of the 8500 customers affected by morning power outage.
@DomEnergyVA major power outage 800 block of holly springs ave Richmond 23224
Unimpressed. We've experienced more power outages with Dominion Energy than we ever did living in 2nd and 3rd world countries. Our area seems to have more outages than most in Northern Virginia. Find a permanent fix, please.
Judges are valuing Energy's service- mistake my 3 week electric outage disk injury anywhere from $25 million plus interest to $120 million dollars. GRS 757-423-2196- 544-5083- 5441658 other lines were used to call for help - heat did it no air conditioning after the sun came up for a few days.no trees standing to shade it.
There is a power outage in the Westend VCU Randolph Area . Any ideas what's going Dominion Energy Virginia?
@DomEnergyVA any idea what's the deal with the power outage at the oceanfront? Been out for over an hour.
Power is out in Triangle,Va. Reported the outage but not current update available
Urgent Alert: Power Outage in parts of the neighborhood 26AUG18 @DomEnergyVA #columbiaPike #poweroutage columbiaforest.org/2018/08/urgent... pic.twitter.com/cdxs468fNj
@muttistacy @MetropolisGal There are outages along the west end too. But @DomEnergyVA would have more specific info than APD.
@DomEnergyVA power outage in Shirlington/ Fairlington area status?
@DomEnergyVA I tried to report it, but it requires the account holder's SSN. He is away on business. Other people in the house should be able to report outages! That is why I tweeted at you. The power is back now.
@DomEnergyVA I'm trying to find out the area affected for a planned outage this upcoming Saturday. Is there list of planned outages on your website?
And another one... Really @DomEnergyVA? The fourth outage in 30 days...
No fun waking up to power outage in @CityofNN this AM. The good news is @domenergyva crew on the scene! 1600 already restored. 3600 customers still in the dark, including @nnschools Woodside HS, Greenwood ES & New Horizons. Report outages at dominionenergy.com.

"Reliability/Resiliency" trends

% of comments containing "Reliability-related" words



* reliable, equipment, medical, depend

- 1.5% of comments contain words related to "reliability, equipment, dependability, medical" and these skew toward Negative sentiment
- Random sample of such comments during non Major Storm day is shown and concerns about medical equipment is 20% of the comments

Message
Emily Haverkamp, how about I give you my receipts and let you pay for the appliances that are now garbage.... my wife has medical equipment she can't use in fear of a surge hitting that and destroying it.... have a dominion investigator come to your house and caution tape off your road and driveway and report back to their operations center that it is a dead line, when in fact I know it is live.... tell me you wouldn't be frustrated....especially when they tell you "we will get to you when we have time"....
@DomEnergyVA Yes, power is back on. Thank you. Given the frequency of power outages this year, what's being done to improve *reliability* so this doesn't keep happening?
#BreakingUpdate: @DomEnergyVA says the cause of the outage is an equipment fire. Estimated restoration time is still between 9am-12pm. We will have full details for you on FOX43 through 9am. @WAVY_News twitter.com/KatieCollettTV...
@aharristweets @DomEnergyVA Actually, we are still out, as are Bombay Curry House, Tsim Yung, and Los Tios. There is a worker in a truck, sitting and telling me that he can't fix the problem by he doesn't have permission to open the equipment box. He says it's Friday, and everyone is off for the weekend.
Every neighbor on but two of us...every cough, 5 mile an hour wind or major storm-5-7 days we're out. Snow, rain, wind of the slightest amount, we're down. No one sees us out because in a group of 15 houses there's only three of us out. Every time. Out now, neighbors on and they didn't even flicker.. 3rd one to move in the neighbirhood, worst reliability. Each time a crew of 4 trucks finally make it to us, as we're last in loudoun co,, it's a two second fix at the bix in my yard...but s 5-7 day wait. Go figure. Thousands on hotels, food, etc.
Hey @DomEnergyVA thanks a lot for 3 days & counting w no power, and the estimated restoration time last night that you blew past w no fix. At least today you have no estimate when my street might be fixed, so you won't fail to make that target!
The power is out for 2nd time in 2 weeks. Maybe if you could stop paying into politians charities you would have the money to maintain the powrr grid. You have elderly with no power or lifeline, you have medically compromised with no equipment and you have babies without heat. Do your job!
most of the workers that come from USA are leaving disappointed because they didnt have a chance to work because of lack of equipment the electrical company from PR got raided by feds for hiding thousands of poles wires Etc , here in Puerto Rico they are called the mafia , I Pray all coruption is delt with now that Puerto Rico is in World eye thousands have died because of lack of electricity that is needed for medical treatment bit no ones heres that on the news ! Thank full for help but sad fir the corruption that is facing them ahead!
No wonder our last bill was so high. They're raising our rate on the bills in Virginia 3% more to help pay for this. I spoke to a lady at VA Dominion Power and asked why my last bill was so high and she told me they regulate the bills depending on what you set your thermostat at in your house. When I asked her how she knew what our thermostat was set at (Did they come in when I wasn't home), she told me they use a temperature rate above 69 deg and the bill goes up 3%. Oh yes and the supervisor told me they don't physically read the meters they go off a machine in the trucks that reads them automatically. Oh like networks are so reliable that they never get a false reading or accidently read your rate off of a near by residence by mistake. No computer program is fail safe. VA Dominion should leave slips at the house when they read the meters. Stop price gauging to help your own costs.
@andyrankin @FallsChurchGov @DomEnergyVA is reporting it'll be restored between 2 and 6 pm. Pretty sure it was an equipment failure at the substation.
Many families are freezing. Including those who need medical equipment. A propane heater hooked up to grill tank makes a great back up!
Neither, it will produce very expensive power some of the time and require other expensive but more reliable standby plants ready to take up the slack at night and short cold winter days. in Europe this green at any cost idiocy has tripled electricity prices or worse
I have a question that you can direct me who to call for some information. My mother (85 years old) is bedridden at home due to a broken hip (3 places). She also has alzheimer's which does not help this at all. She has a hospital bed set up in her home. They lost power around 2:30 this morning which has been recently restored (thank you). Is there someway to notify Dominion of the use of medical equipment in a home so that power may be restored first in an area? Thank you for any information you are able to provide.
Over 7.5 hours without power (hence no water, either) due to faulty equipment and malfunction for less than 800 customers and no natural phnomenon is ridiculous. Hope to get a refund for the time and for the spoiled food. Sheesh. I heard the were waiting on parts, then had another problem with parts. Are the parts THAT far away? Give them a call. 866-366-4357
Cannot think of a worse experience than trying to work through billing issues, due to defective equipment from dominion. Asked to be included in findings. Lots of runaround with ou[illegible] don't have consumer choice.

Specific other refining analysis outputs

1. FB Messenger independent analysis and removal from rest:
2. Evaluating if reliability/resiliency is a pain point in the non-Major Storm days too:
3. Evaluate why "Outage" appears in Non-Major Storm Negative comment cloud?
4. Evaluate customer frustration with having to report power outage:
   - People have to report power outages; can we analyze how surprised/mad they are about this?
   - Link together words/comments as a group related to this and evaluate
     - I expect you to know when power is out
     - Don't you know when my power is out?
     - I didn't report it, I thought you knew I was without power
     - Your equipment doesn't tell you when power is out?
     - Smart meter/smart equipment comments
5. Perform a sentiment/frequency of the word "Bill"

Frustration with having to report outages cannot be shown via the analysis performed

Table of frustration by report

	report		
frustration	**0**	**1**	**Total**
0	23658	1177	24835
	93.63	4.66	98.29
	95.26	4.74	
1	410	23	433
	1.62	0.09	1.71
	94.69	5.31	
Total	24068	1200	25268
	95.25	4.75	100.00

- "Frustration" was defined by comments containing "expected/expect" or "frustration/frustrated" (1.7% of comments)
- Report was defined by comments containing "report/reporting/reported" (4.75% of comments)
- There is very little overlap (23 comments) containing both dimensions
- Also searched for phrases like "should know", "not know" and incidences are miniscule
    - Saw some comments "REMINDER; @DomEnergyVA does not know your power is out unless you call or go online to report the outage! Website: dominionenergy.com/outage-center/… Phone: 866-366-4357" so if anything, it's not having to report outages that are frustration points but what happens when you do report it (outage map not current, have to provide SSN/account number, power not back as soon as what customer was expecting)

Specific other refining analysis outputs

1. FB Messenger independent analysis and removal from rest:
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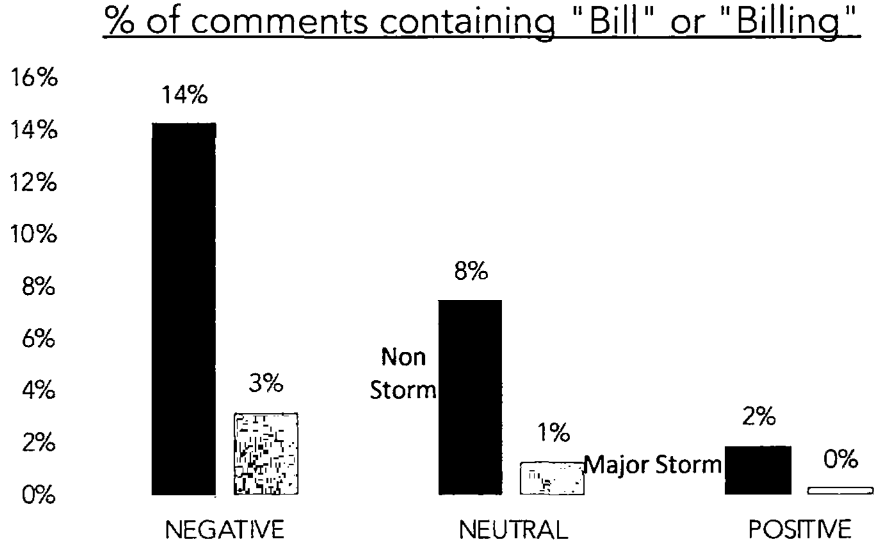
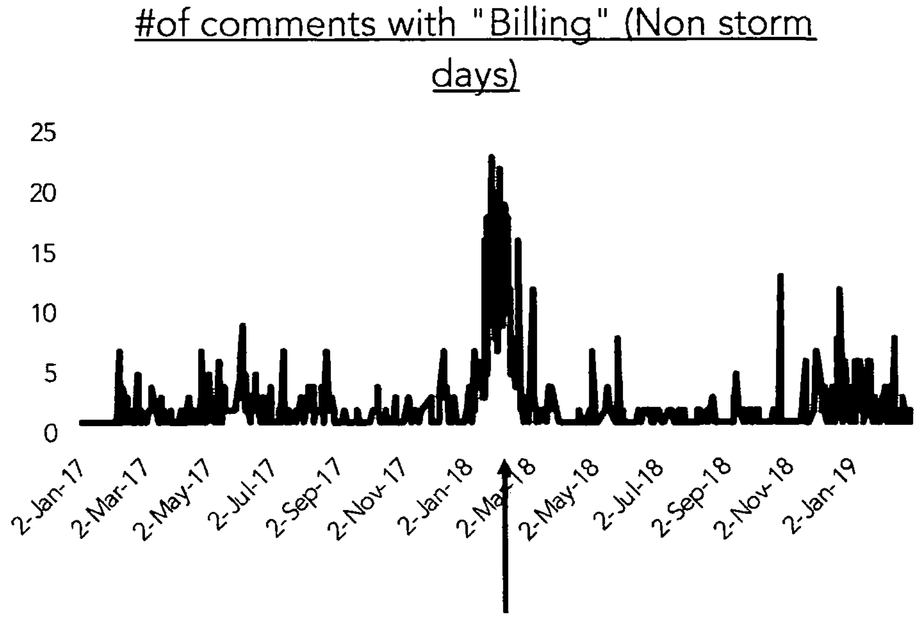
"Bill" is far more common non Major Storm days and it appears cold weather bills may frustrate customers the most





- Billing-related comments
  - Primarily on non-Major Storm days
  - Negative skew

- There is a large spike (smaller spike Dec '19)
- Based on reading a random sample of these comments
  - Customers are responding to higher than expected bills during colder months
  - Shocked by cost to stay warm in cold snap vs expect higher bill during heat
  - Flat areas could be 'open window' months (Sept-Oct)

Other conclusions

- Specific word frequency is low overall, and spikes are likely driven by things like news reports, legislation, etc.
- Analyzing word clouds shows the appearance of some common words over time and reveals outage notifications and map likely have some room for improvement
- A manual independent check by 2 individuals showed that sentiment assessment is around 70% accurate

Keyword Search and Word Clouds

None of the keywords investigated has a high incidence of occurrence, which limits detailed analysis possibilities

- Incidence of "Underground/Buried," "Equipment" and "Pipeline" is low (each is <1% of comments)
- All 3 terms tend to occur more often during non-storm days (especially "Equipment" and "Pipeline")
- All 3 over-index on negative sentiment (as expected)

			"UG/Buried"		"Equipment"		"Pipeline"	
Storm	Sentiment	# comments Overall	# containing UG/Buried	%	# containing equipment	%	# containing pipeline	%
No	NEGATIVE	4,482	47	1.0%	47	1.0%	78	1.7%
	NEUTRAL	8,935	60	0.7%	43	0.5%	97	1.1%
	POSITIVE	3,335	14	0.4%	12	0.4%	19	0.6%
Yes	NEGATIVE	2,467	13	0.5%	10	0.4%	11	0.4%
	NEUTRAL	5,376	48	0.9%	17	0.3%	7	0.1%
	POSITIVE	1,746	3	0.2%	3	0.2%	0	0.0%
Overall		26,341	185	0.7%	132	0.5%	212	0.8%

Low Incidence

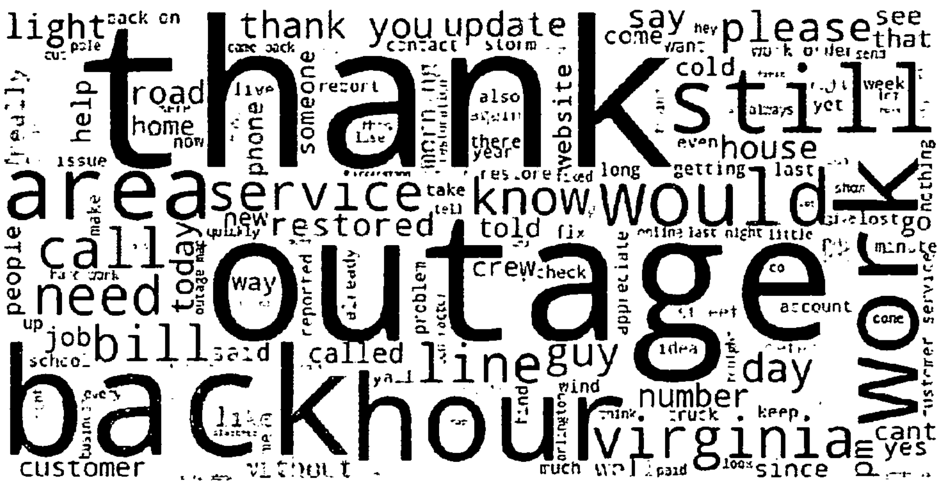
Keyword	% storm	% Positive	% Neutral	% Negative
UG/Buried	33%	9%	58%	32%
Equipment	23%	11%	45%	43%
Pipeline	8%	9%	49%	42%
Overall	36%	19%	54%	26%

All Skew Negative

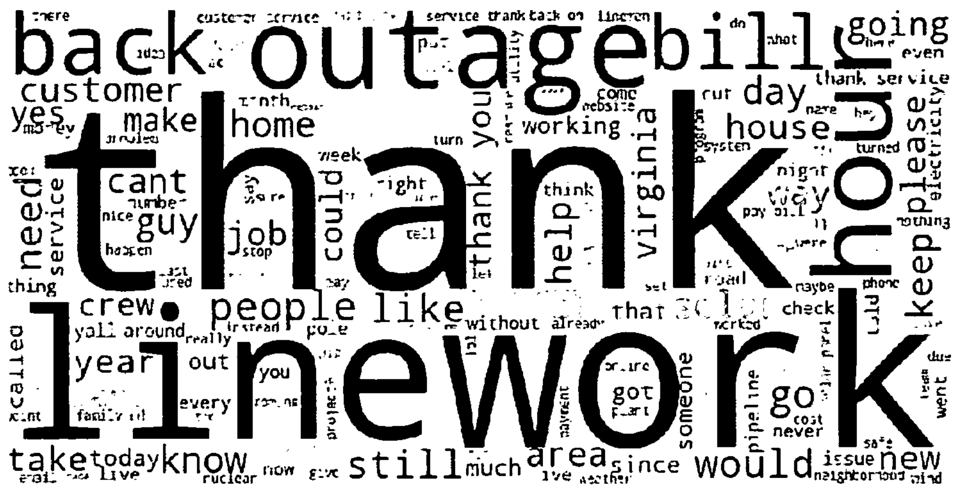
Word Cloud Evaluation

- The word "thank" is common in most clouds
- "Outage" is another common word in both Major Storm and non-storm situations – there is likely an opportunity to improve the outage notifications/outage map
- Commenters mention their bills often
- There does not appear to be a shifting trend over time

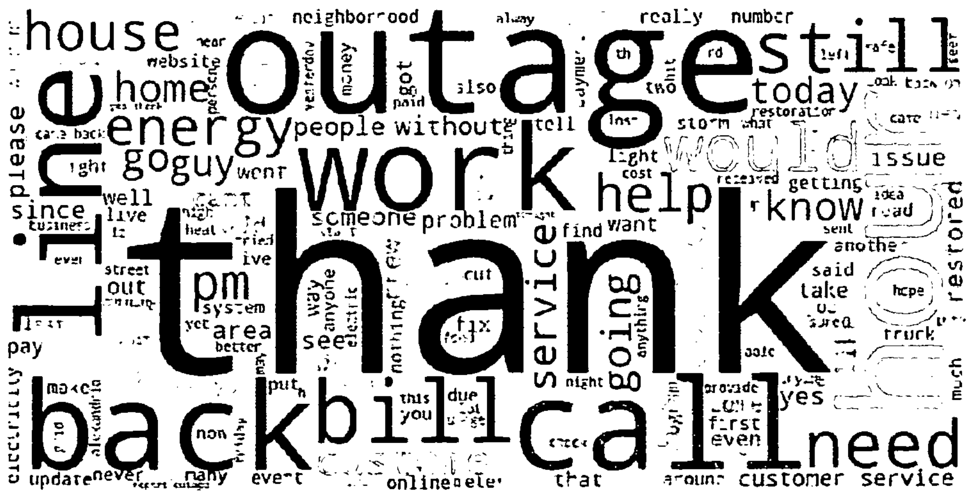
Q1 2017



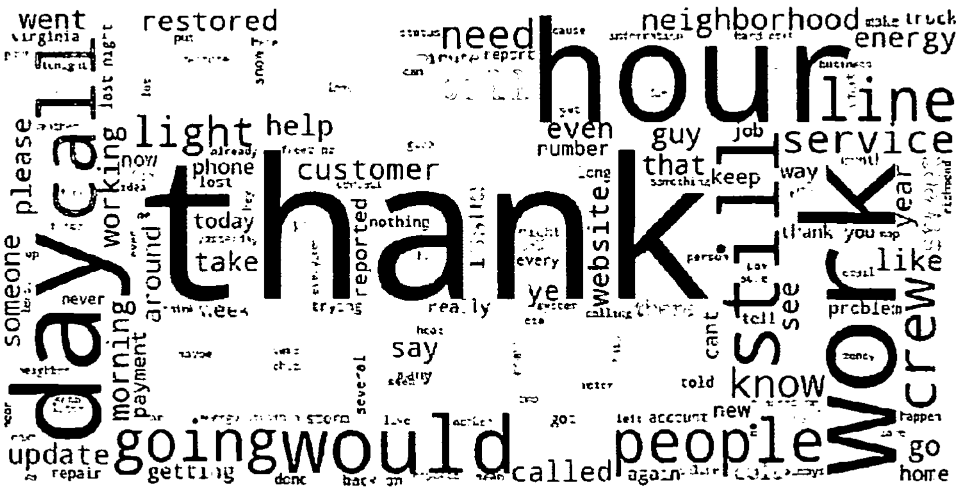
Q2 2017



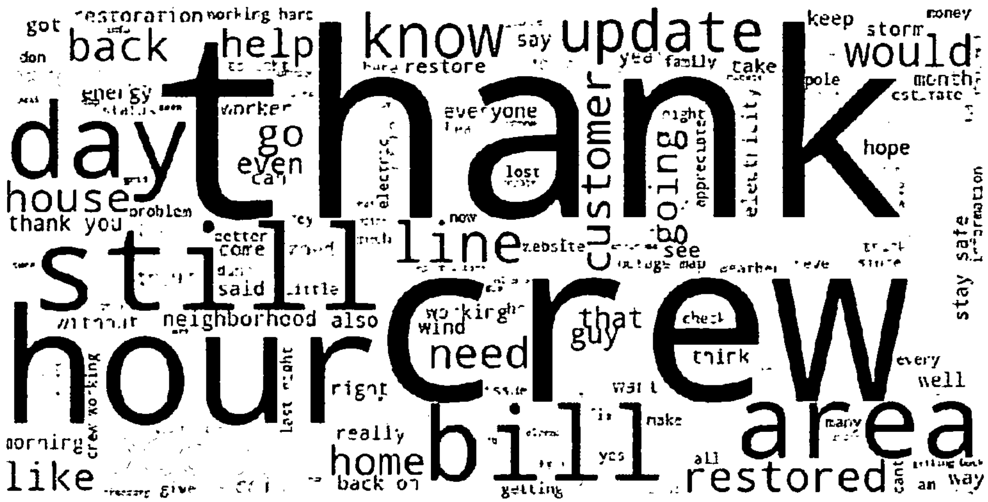
Q3 2017



Q4 2017

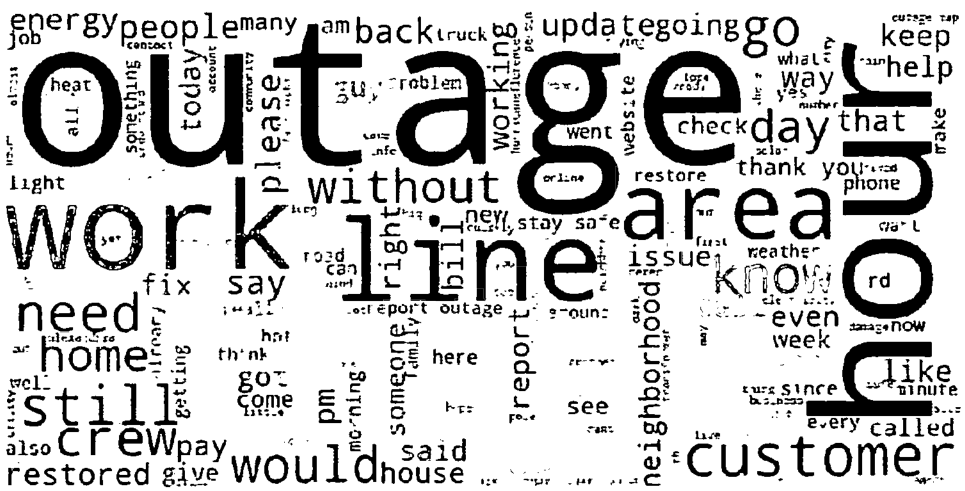


Q1 2018

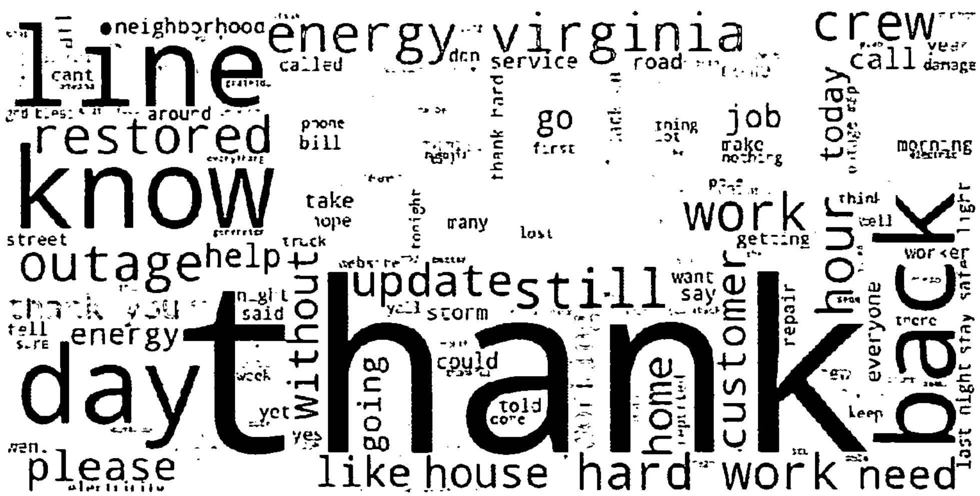


Q2 2018

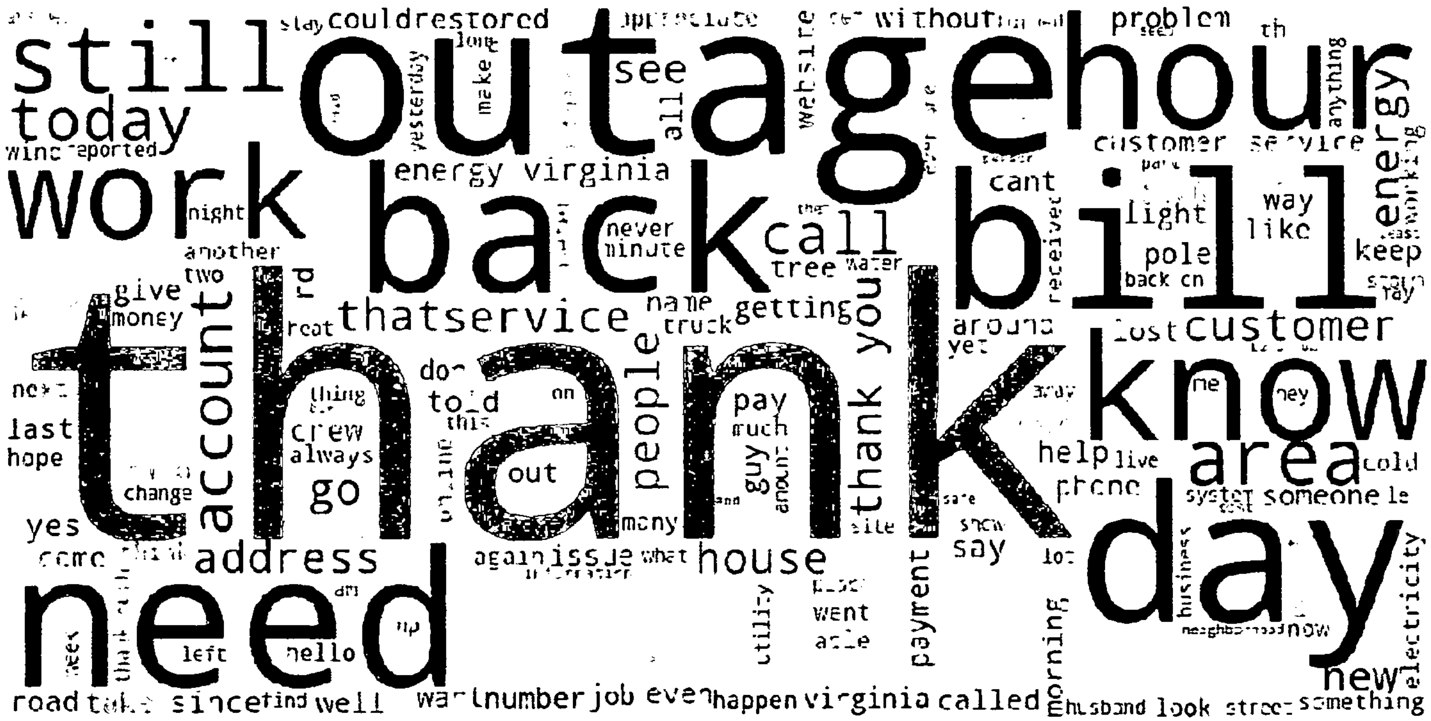
Q3 2018



Q4 2018



Q1 2019


thank
outage
hour
back
bill
know
day
need
still
today
work
account
address
people
thank you
call
customer
customer service
energy virginia
energy
area
thatservice
house
could
restored
see
problem
without
website
getting
cant
light
pole
way
like
keep
help
phone
payment
say
go
out
told
pay
crew
always
hello
left
last
hope
yes
road
since
well
number
job
happen
virginia
called
look
something
new
electricity
someone
lost
around
went
utility
night
another
give
money
change
issue
again
never
minute
tree
name
truck
yesterday
make
received
business
morning

Manual Sentiment Check

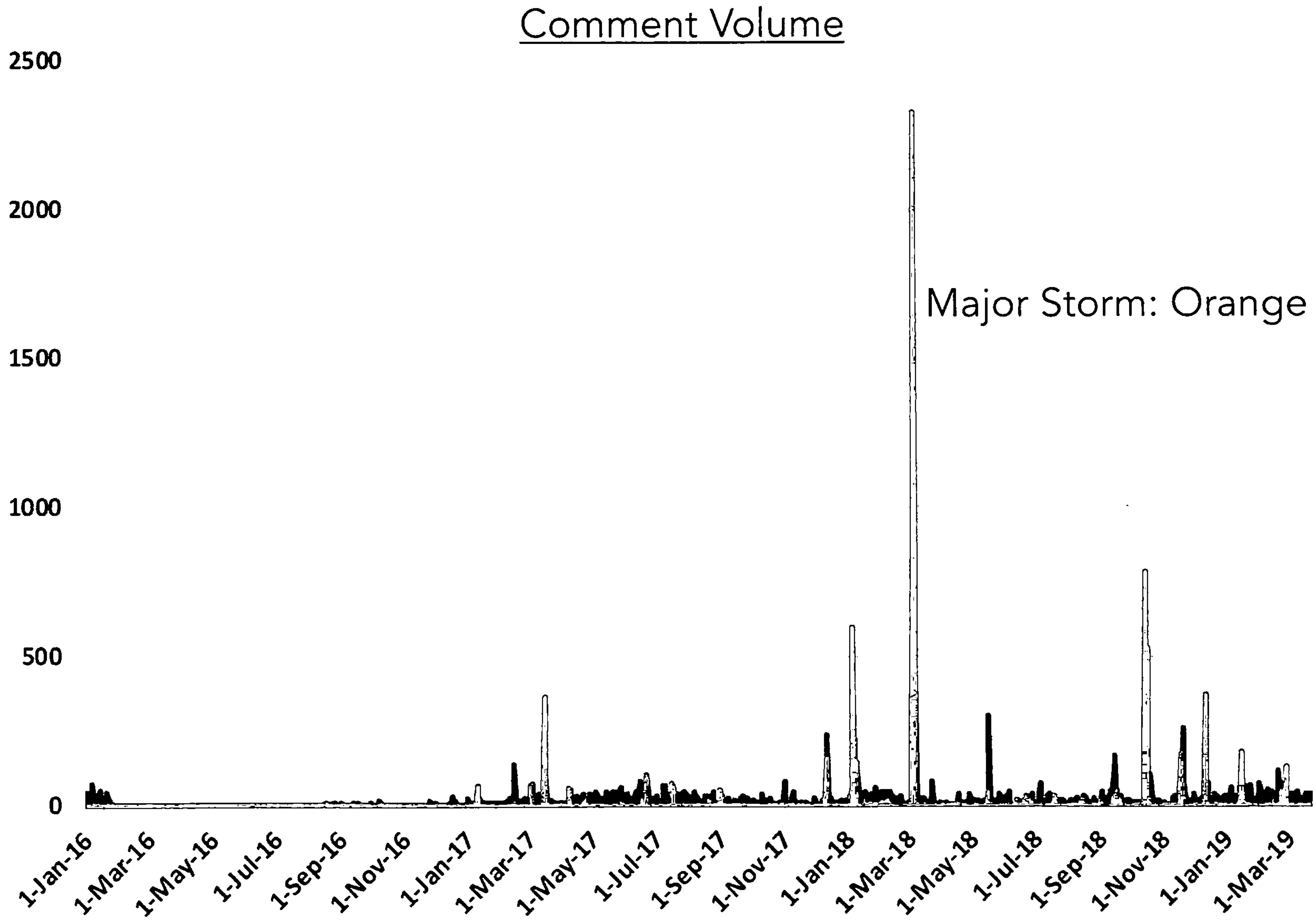
Manually checking sentiment showed that 70% accuracy is a reasonable assumption

- Assuming 70% accuracy in sentiment tagging, manually scoring 400 gives a +/- 5%
- Based on manually tagging 400 random comments:
  - 69% agreed with the current tagging (highest agreement (80%) in positive sentiment)
  - Overall agreement is higher in Major Storm comments vs. non-storm comments (73% vs. 66%)
- Very few comments (6, or 1.5%) were "way off" on sentiment

	Manually Assigned				
DE Sentiment	**NEGATIVE**	**NEUTRAL**	**POSITIVE**	**Total**	**% Agreement**
NEGATIVE	63	31	2	96	66%
NEUTRAL	58	146	19	223	65%
POSITIVE	4	12	65	81	80%
Overall	125	189	86	400	69%

Appendix/Other Analysis

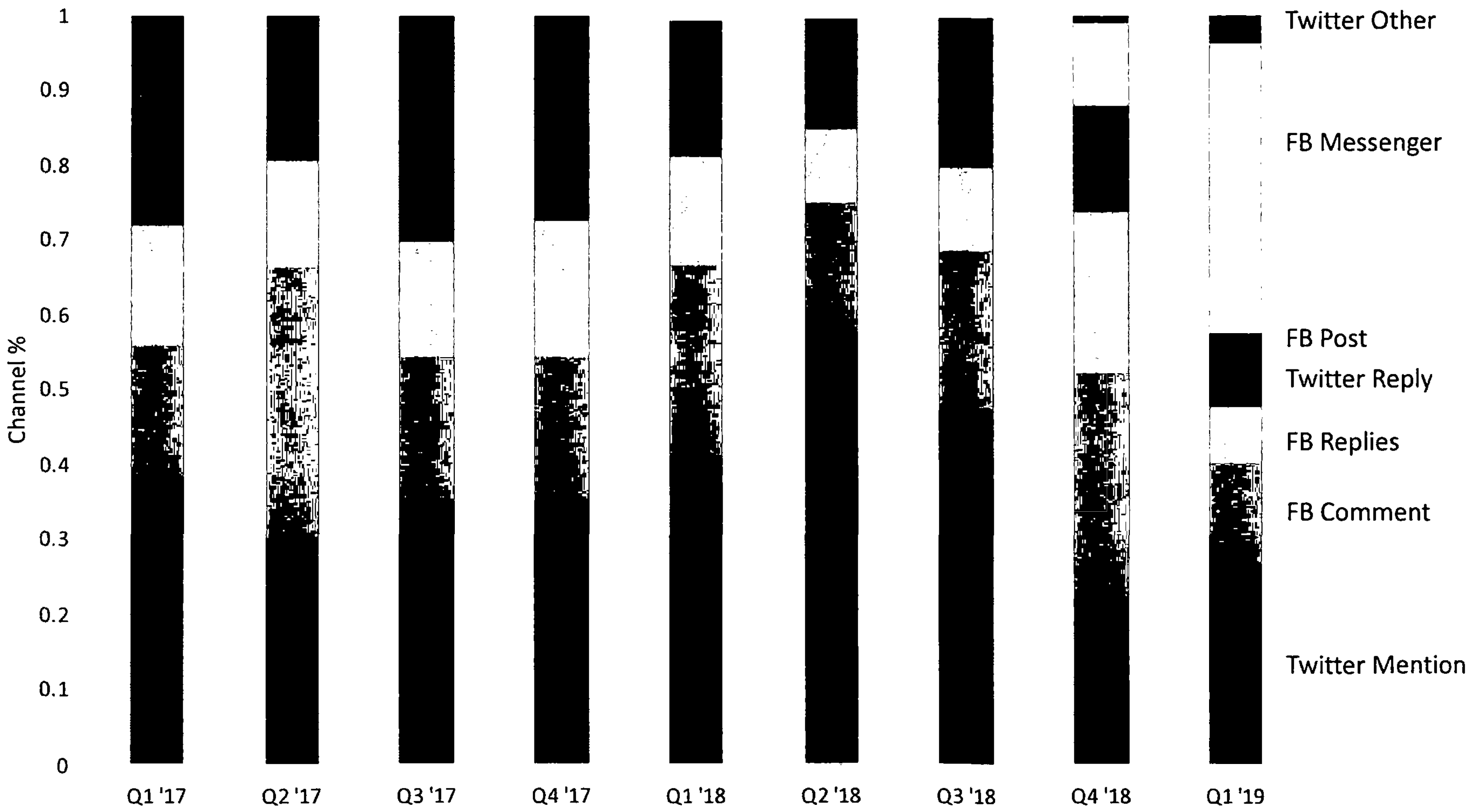
Entire data set comment volume (very little data was available for 2016, so it was excluded from most analysis)



Non-Storm: Blue

Facebook Messenger has been taking share from all other FB channels starting Q4 2018

Social Channel composition

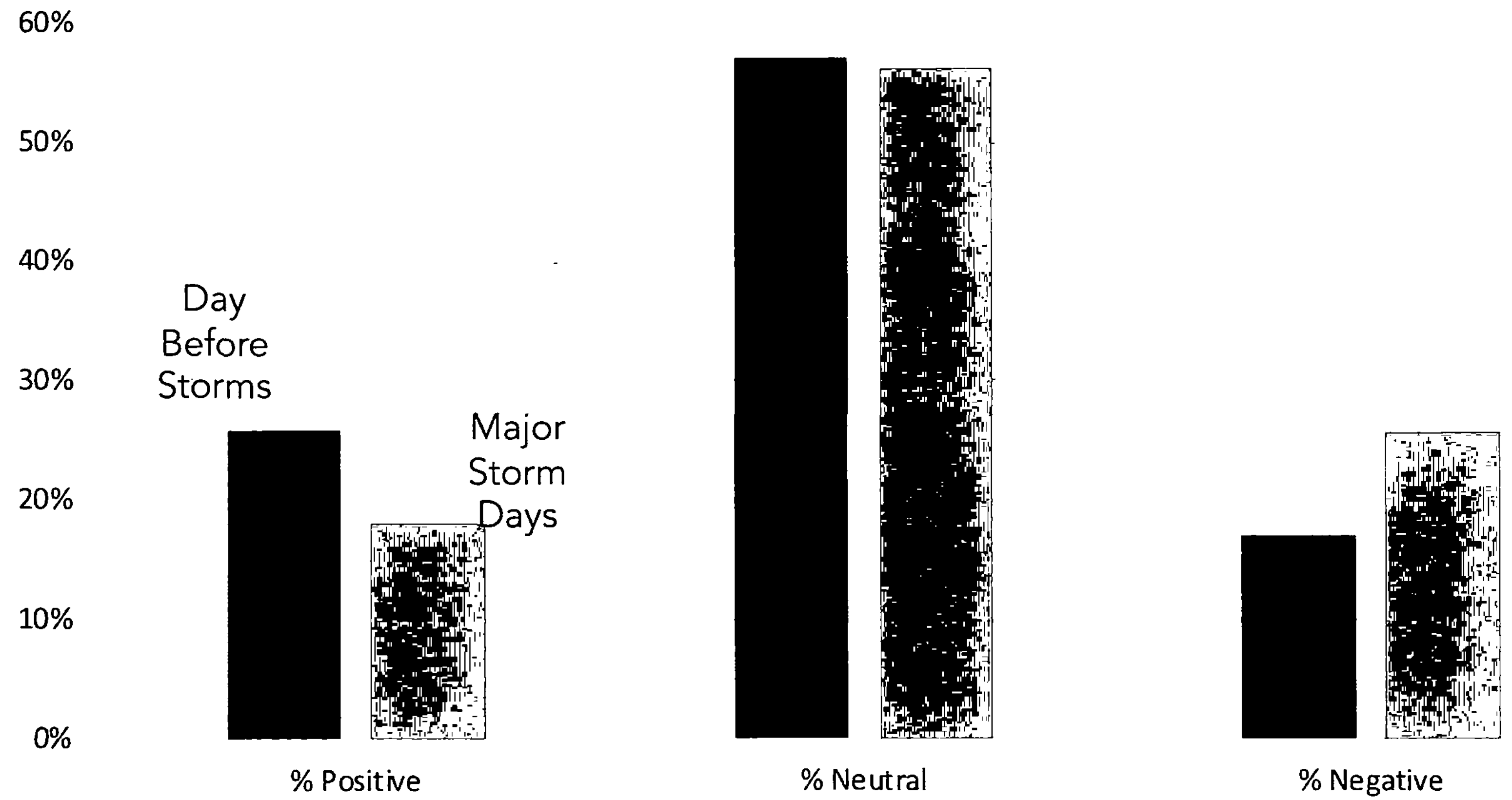


Note: Q1 2019 is Jan/Feb only

Looking at the purest "non-storm" days, there is a more material sentiment change

Note: Positive skew may be due to Dominion's proactive "Storm Prep" messaging.

Sentiment Distribution



Notes:
Excludes all 2016 data
Non-Storm excludes day after Major Storms

Hourly Major Storm Charting

Hourly Major Storm comment graphing led us to a significant insight on comment volume drivers

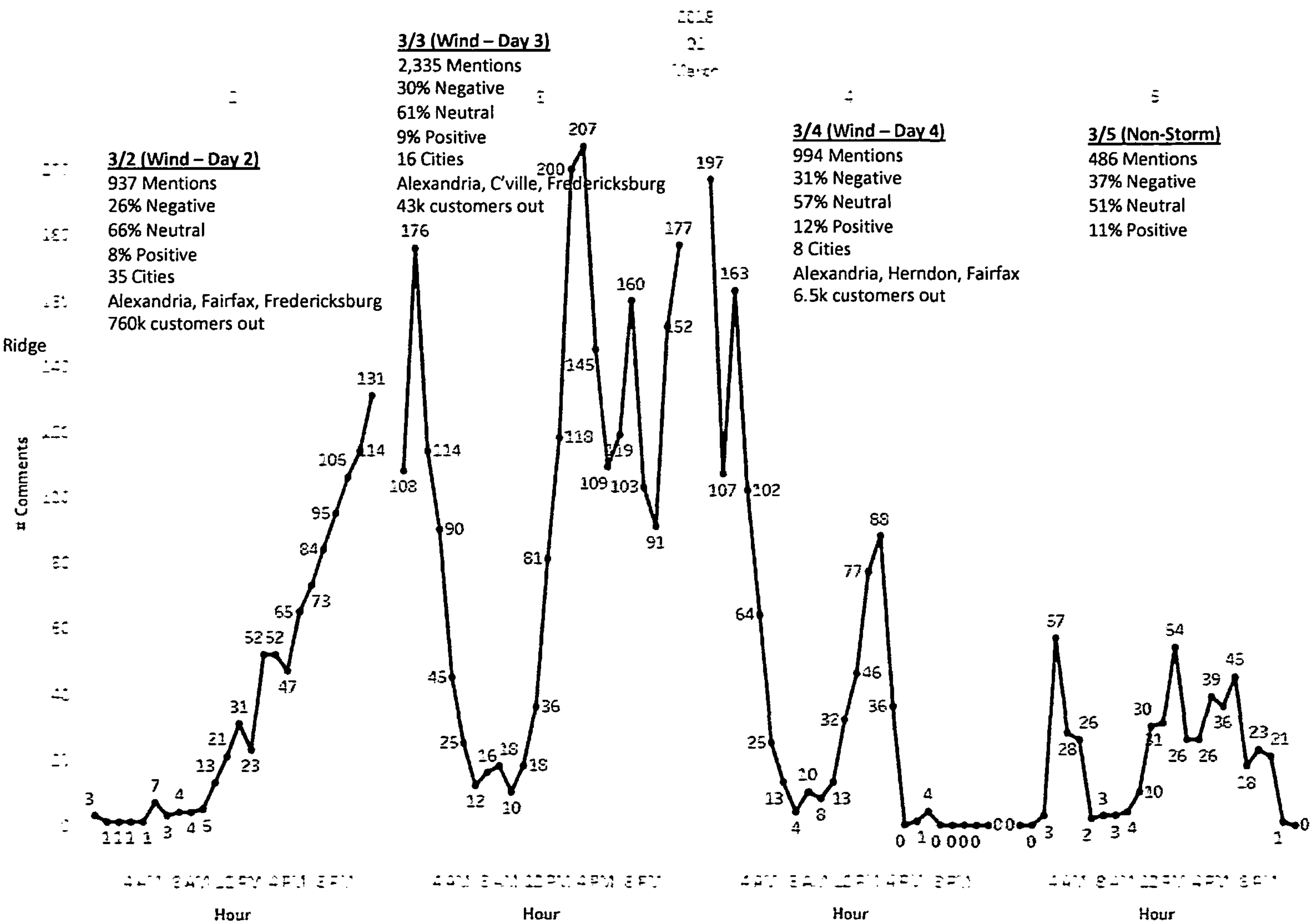
- Comment volume correlates heavily with the number of people without power the previous day
  - Outage volume is available only by day, so hourly correlations are not possible
  - Given the strong previous-day correlation, we can tell volume does not ramp instantaneously with outages

- We show 5 Major Storms diagrammed by hour – the effect of "next-day ramp" is most clearly shown on multi-day Major Storms (first 3 Major Storms shown)

- Normal sleep patterns drive nightly comment fall-off, although Major Storm events can keep people and comment volume up to a certain extent

NOT GRAPHED

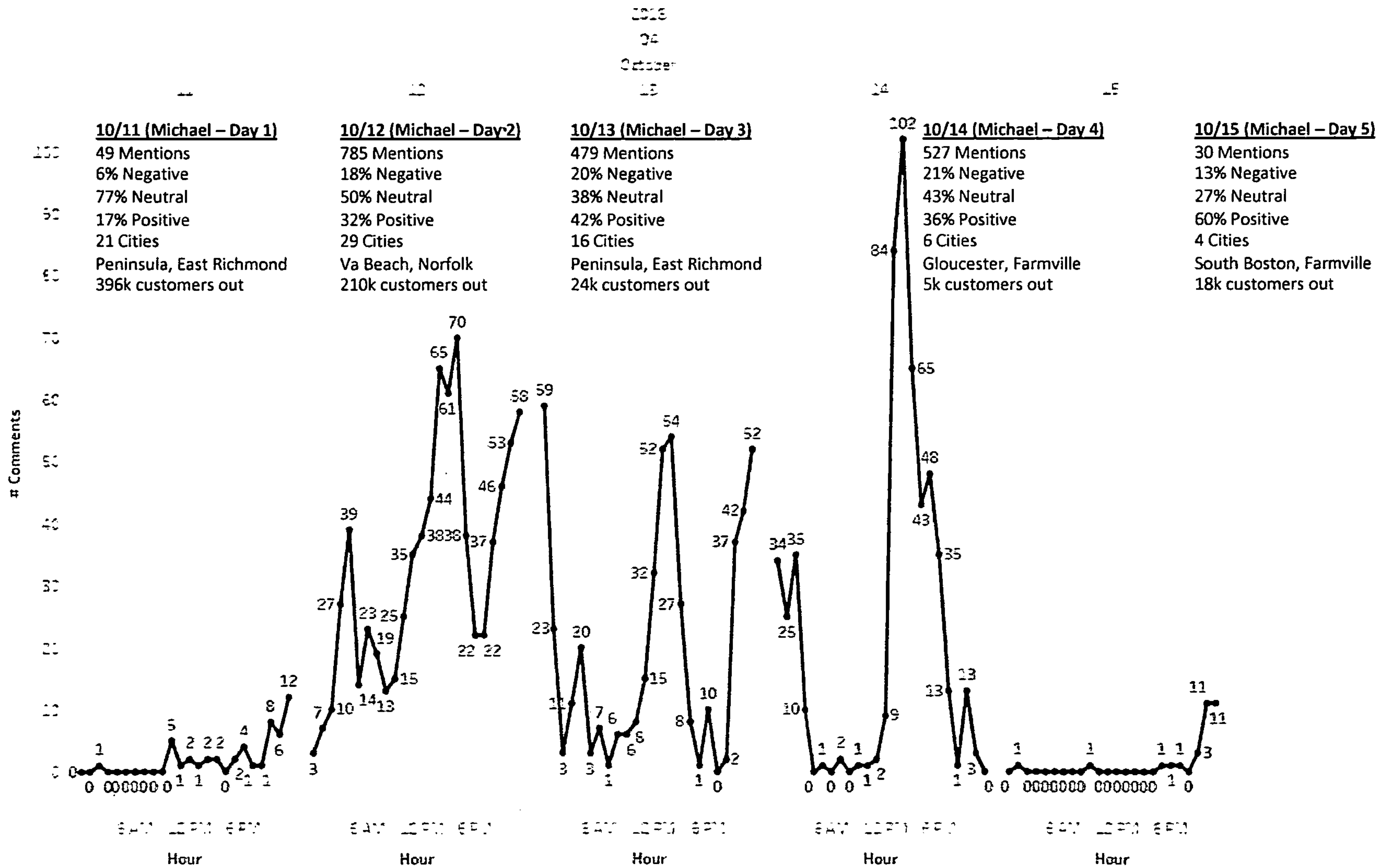
3/1 (Wind – Day 1)
27 Mentions
30% Negative
67% Neutral
3% Positive
5 Cities
C'ville, Alleghany, Blue Ridge
6.1k customers out

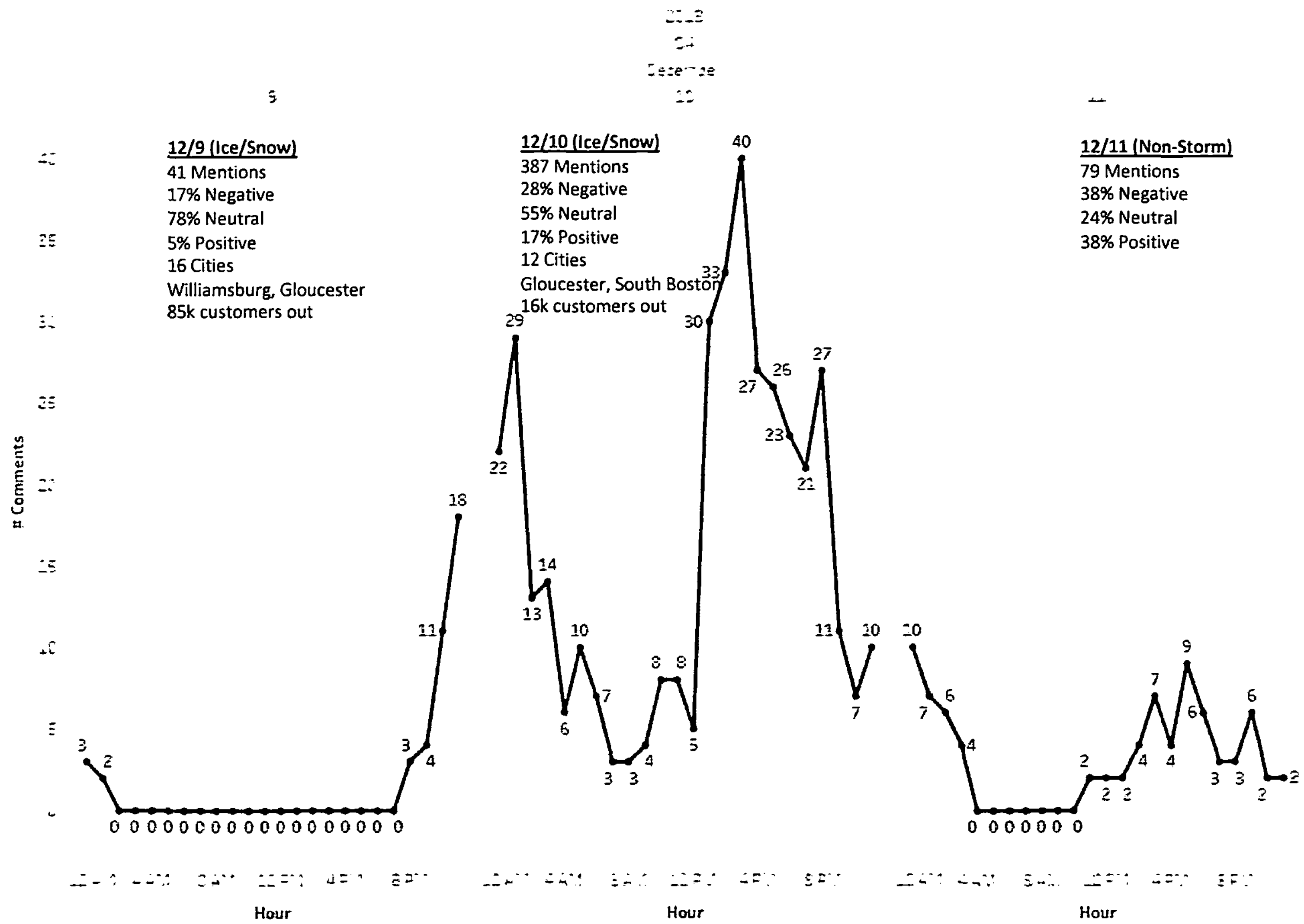


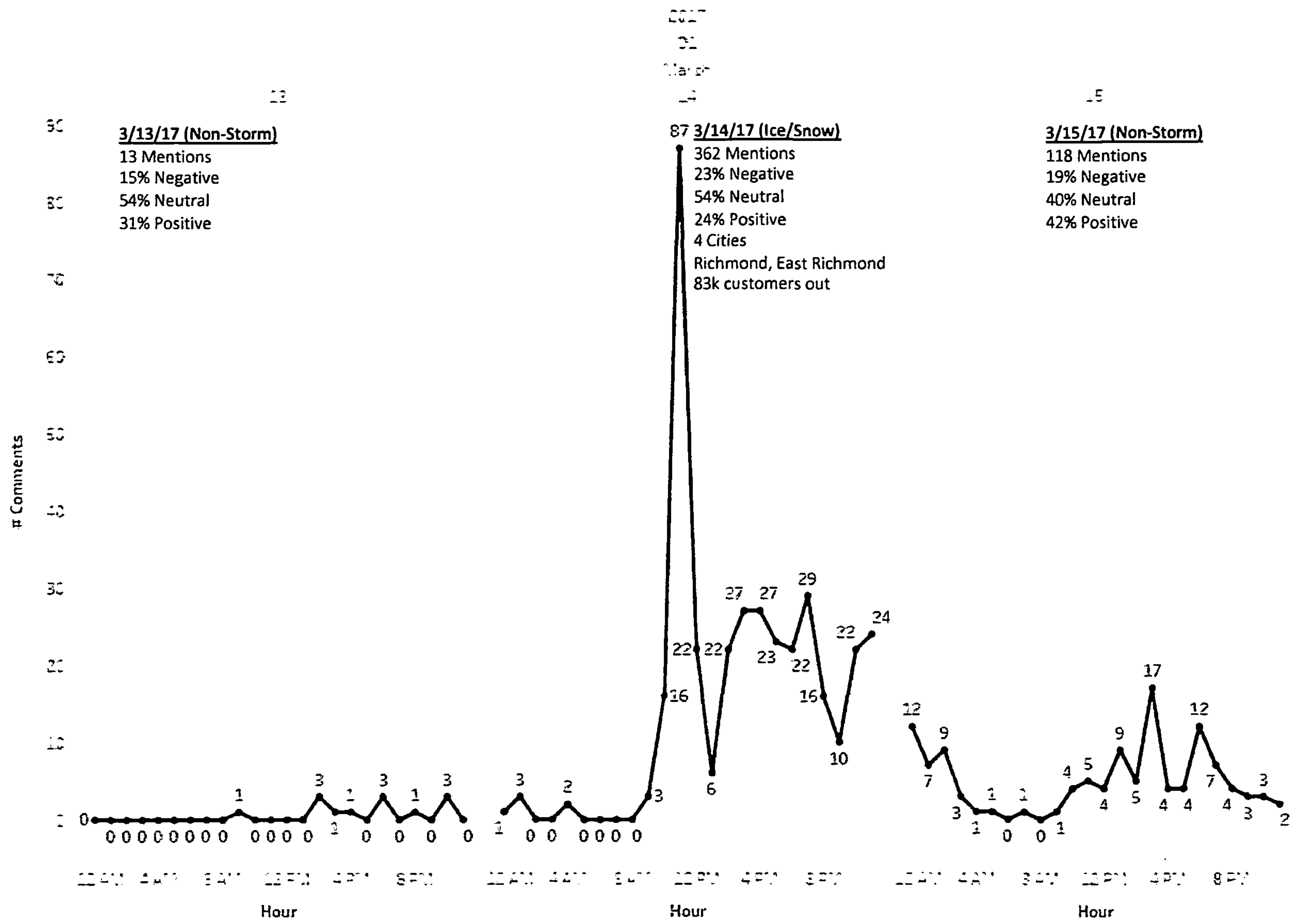
44

NOT GRAPHED

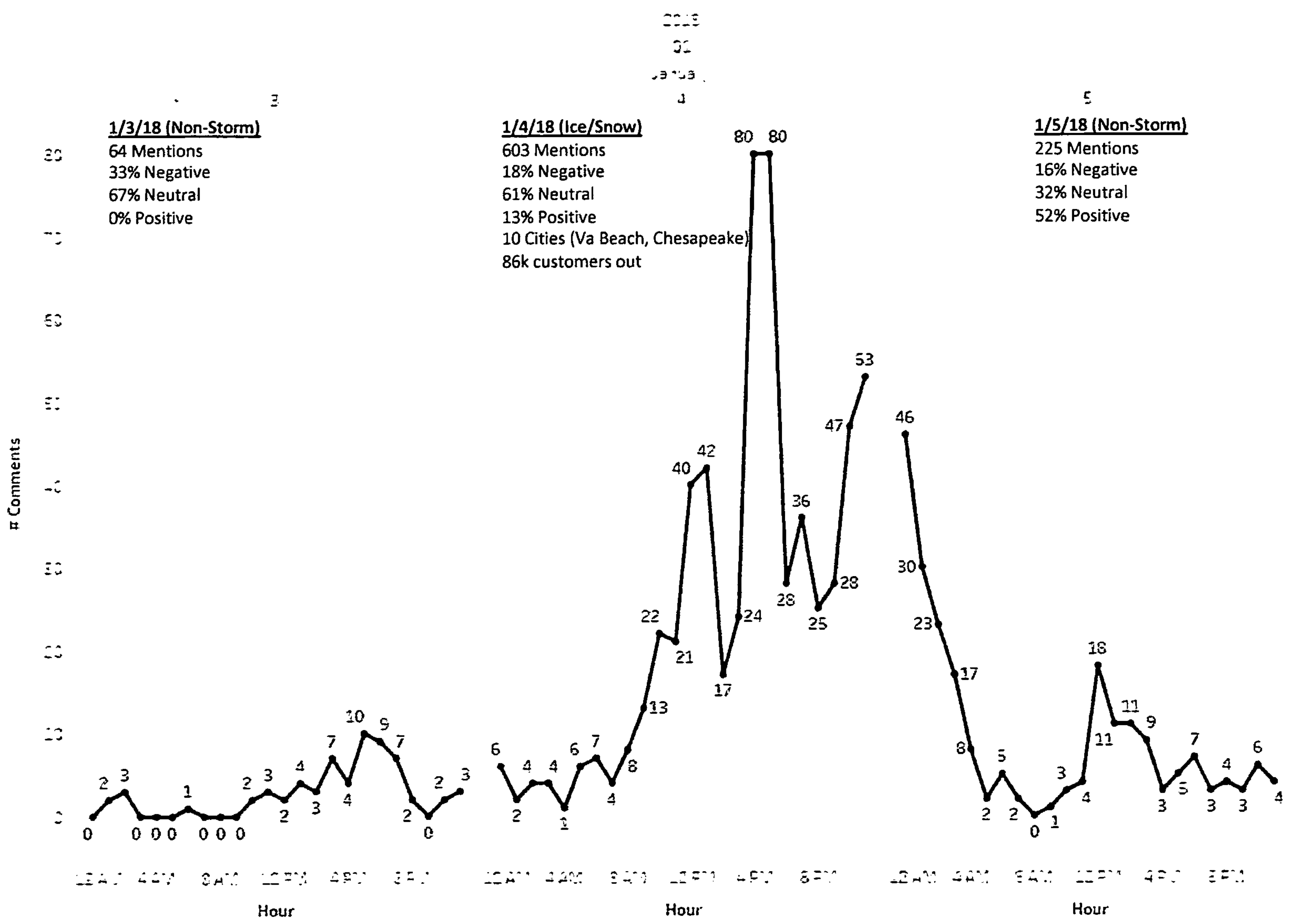
10/10
13 Mentions
38% Negative
62% Neutral
0% Positive




12/9 (Ice/Snow)
41 Mentions
17% Negative
78% Neutral
5% Positive
16 Cities
Williamsburg, Gloucester
85k customers out
12/10 (Ice/Snow)
387 Mentions
28% Negative
55% Neutral
17% Positive
12 Cities
Gloucester, South Boston
16k customers out
12/11 (Non-Storm)
79 Mentions
38% Negative
24% Neutral
38% Positive
Comments
Hour
Hour
Hour

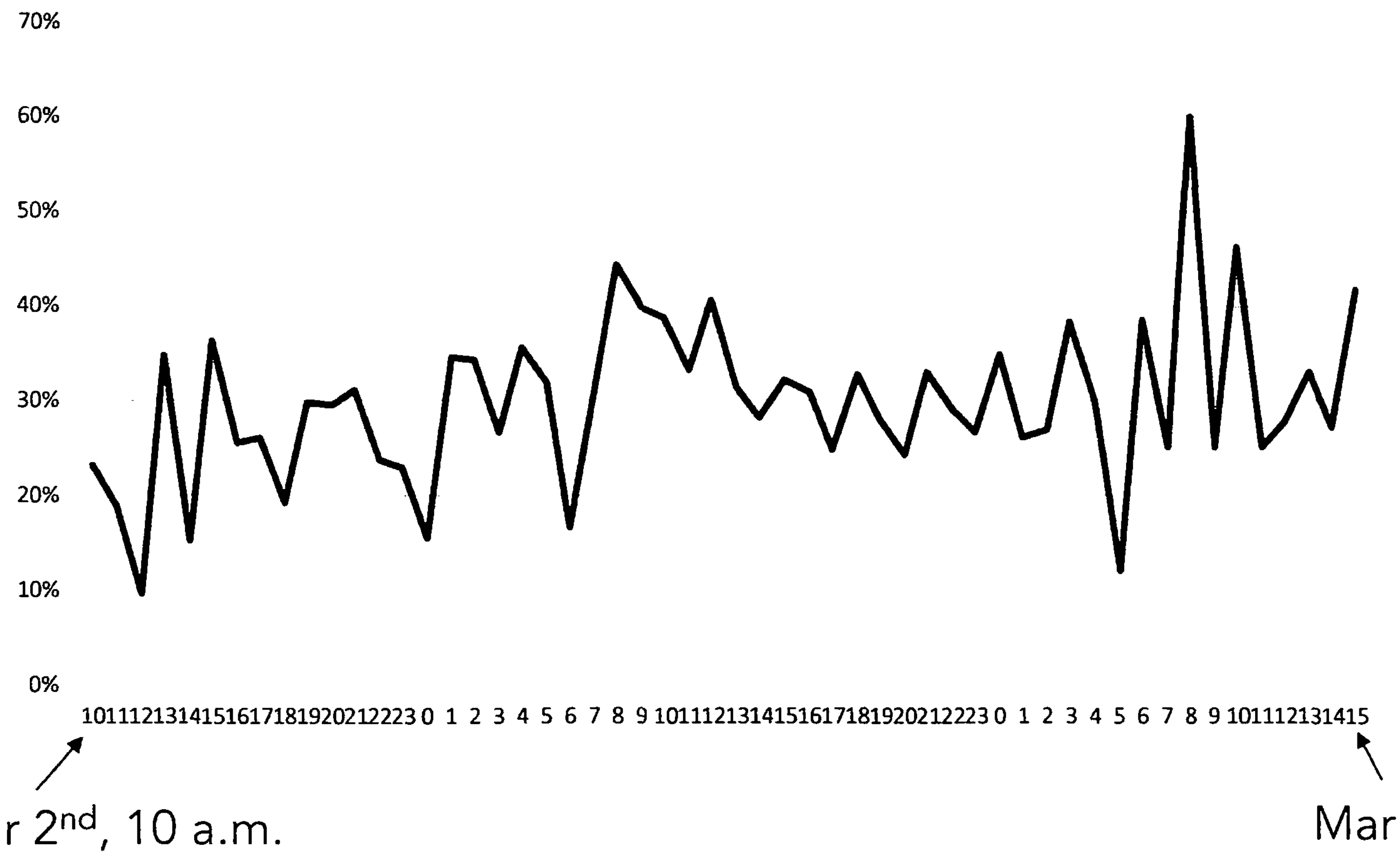

3/13/17 (Non-Storm)
13 Mentions
15% Negative
54% Neutral
31% Positive
87 3/14/17 (Ice/Snow)
362 Mentions
23% Negative
54% Neutral
24% Positive
4 Cities
Richmond, East Richmond
83k customers out
3/15/17 (Non-Storm)
118 Mentions
19% Negative
40% Neutral
42% Positive
Comments
Hour
Hour
Hour

DOMINION ENERGY I SOCIAL MEDIA SENTIMENT ANALYSIS



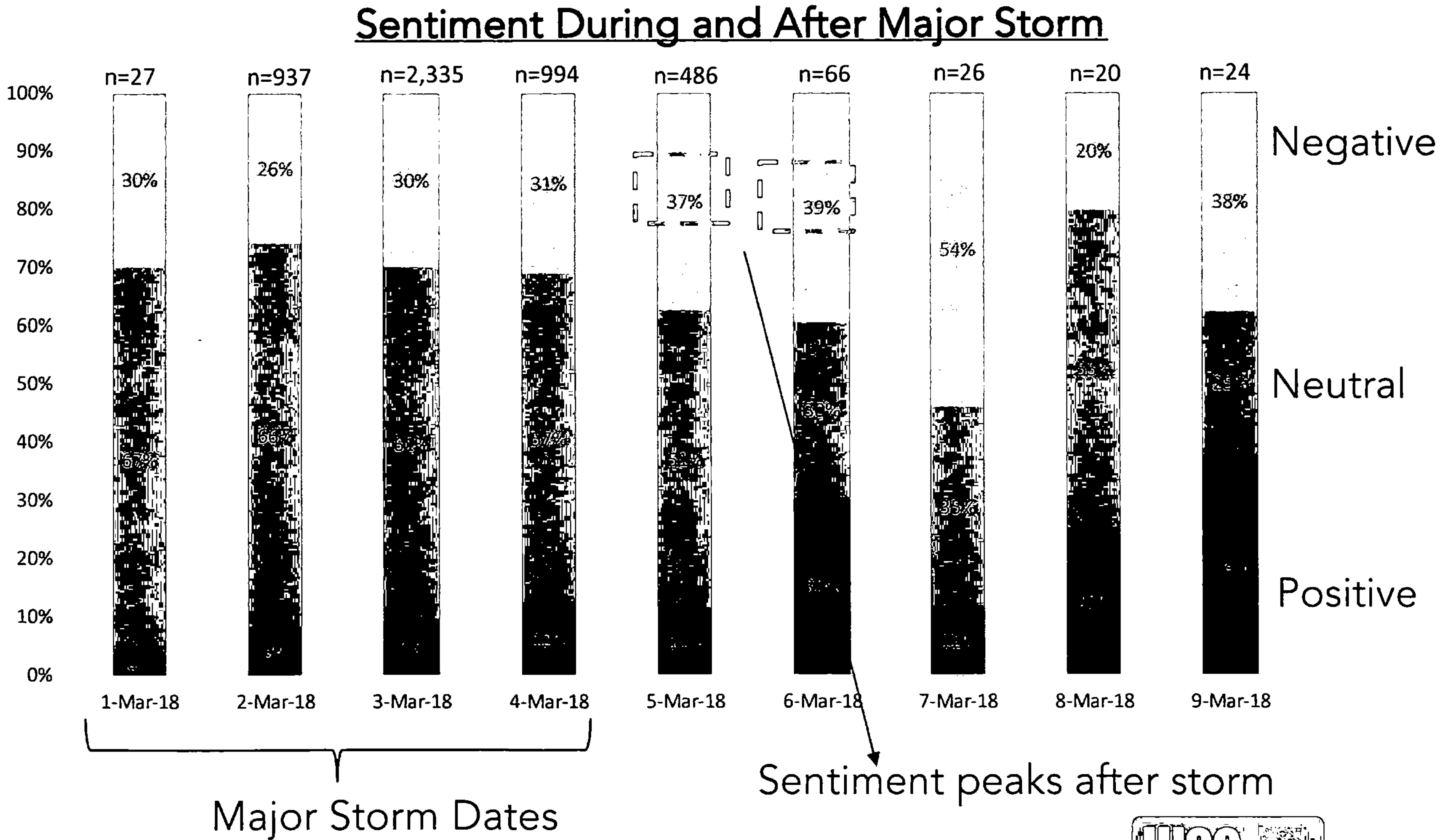
Hourly negative sentiment is jumpy, but it rises slowly for the March 2018 multi-day Major Storm

March 2018 Major Storm Hourly Negative Sentiment

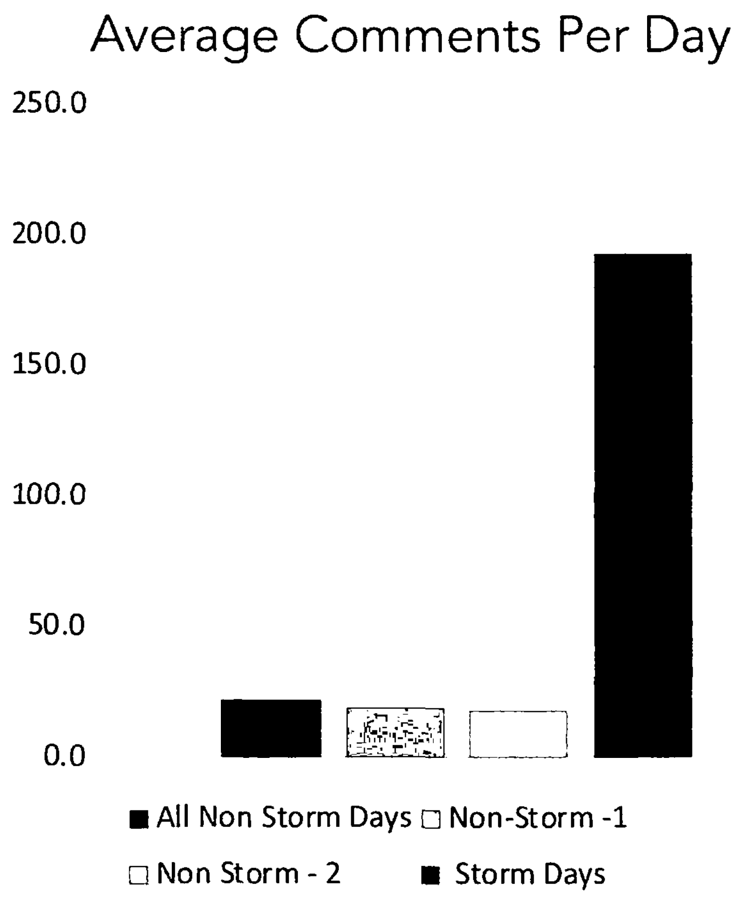


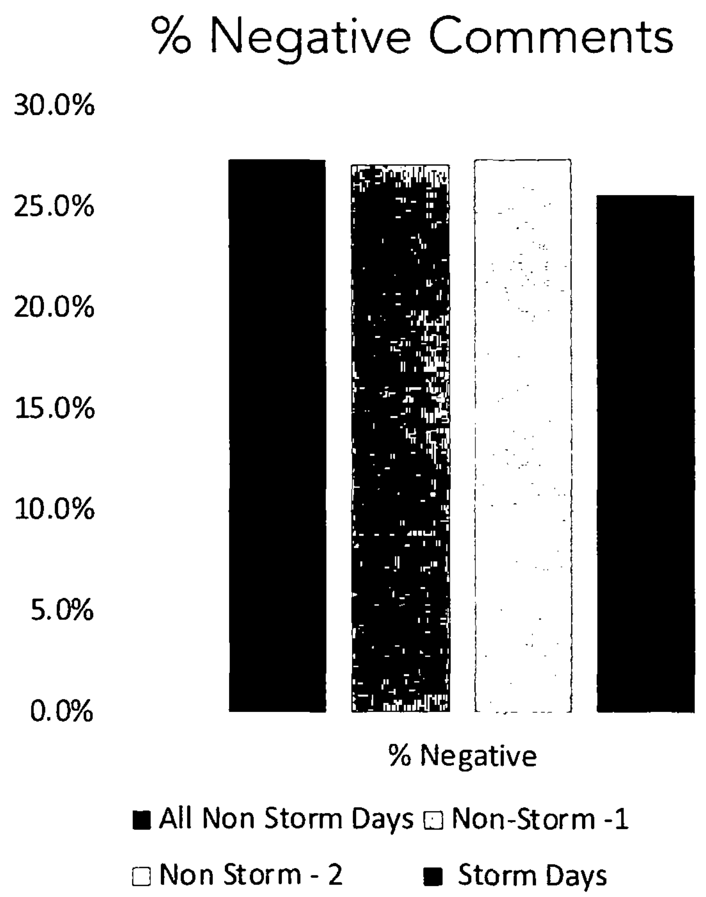
Notes: Sentiment shown only for time period with comment volume

Strangely, the March 2018 Major Storm triggered a negative comment peak immediately following the storm



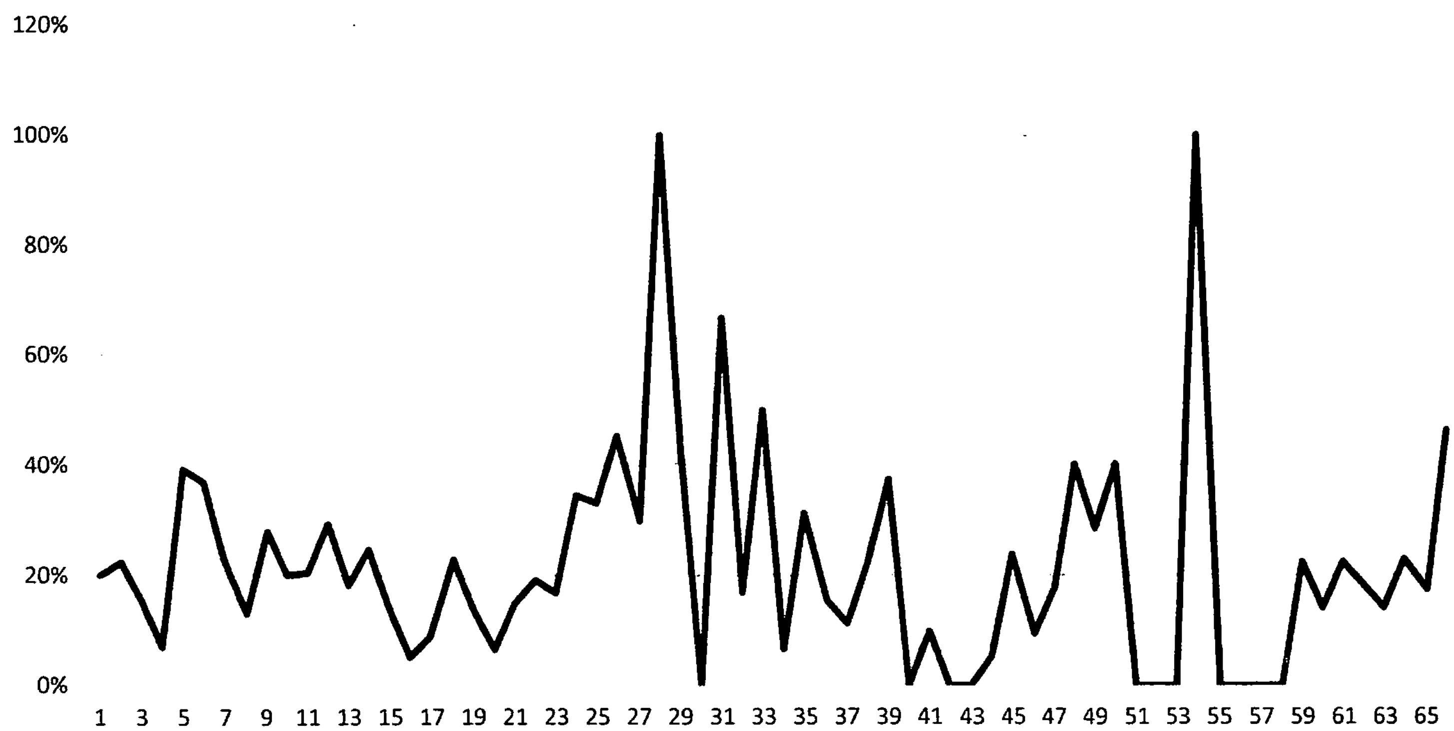
Removing the days immediately following Major Storms does not impact conclusions





It is difficult to draw conclusions from Oct 2018 Major Storm hourly sentiment

Oct 18 Major Storm Hourly Negative Sentiment



Note: Data from 10/12 at 2 a.m. through 10/14 at 7 p.m.

NAVIGANT

2019 DEV Workshop Series: Grid Transformation

Prepared for:

Dominion Energy Virginia

Dominion Energy®

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Reference No.: 209540
September 2019

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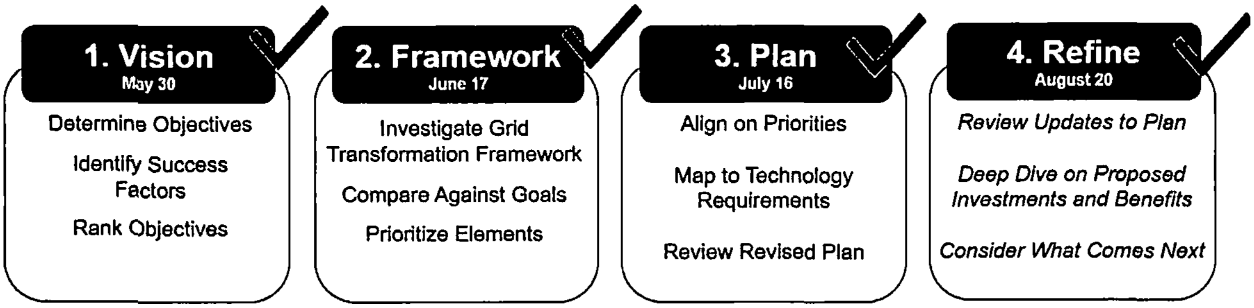
SUMMARY REPORT

Dominion Energy Virginia (DEV) engaged Navigant Consulting, Inc. (Navigant) to facilitate a series of four workshops from May through August 2019 to offer a forum for stakeholders to provide input on DEV's 2019 Grid Transformation Plan (GTP) filing.

1. Grid Transformation Workshop Series

Over the course of the workshop series, stakeholders engaged in facilitated discussions and exercises that helped the group establish a vision for the transformed grid of 2030, and its key capabilities. The capabilities were dissected and mapped to specific technologies and applications needed to enable desired grid functionality. In the final two workshops, DEV shared its proposed Grid Transformation Plan at a draft overview level that could change with the final version of the filing, and how it mapped to the desired capabilities of a transformed grid. An online portal ("Trello board") was utilized to support digital stakeholder engagement throughout the process. Stakeholders had access to all presentation material and post workshop notes shortly following each session through the workshop's online platform and had the ability to upload content or ask questions directly to facilitators or other stakeholders between sessions.

Figure SR-1. DEV Stakeholder Workshop Series for Grid Transformation



1.1. Stakeholder Workshop I

Twelve (12) stakeholders convened in Richmond, Virginia in May for the first of four grid transformation workshops. The stakeholder workshop was facilitated by Navigant Consulting. Workshop I supported three primary objectives:

- Providing stakeholders an overview of the national landscape, driving forces and regulatory activity related to grid modernization;
- Reviewing the background and context of Virginia's new Grid Transformation and Security Act, DEV's 2018 GTP filing and the subsequent SCC order; and
- Engaging stakeholders in developing a long-term vision for the transformed electric grid in DEV's service area.

Following a facilitated visioning exercise during which stakeholders were asked to articulate what functionality and benefits the electric grid of 2030 should provide, Navigant facilitators asked stakeholders to help in prioritizing the long-term goals identified.

1.2. Stakeholder Workshop II

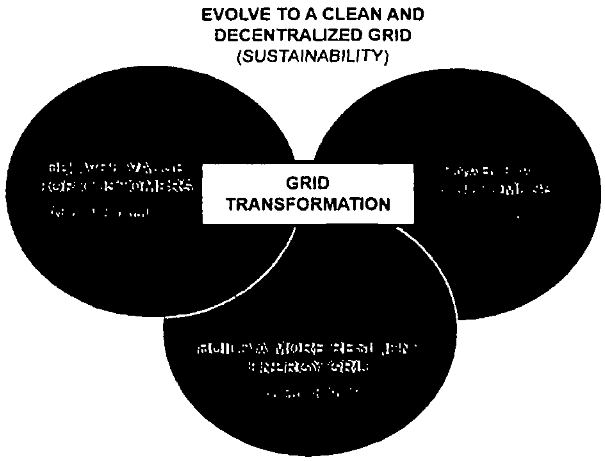
Twenty-three (23) stakeholders convened at the second grid transformation workshop in June to review and validated the goals generated and success criteria discussed during Workshop I. Navigant facilitators presented various examples of grid modernization activity from across the nation, including state-wide collaborative initiatives in Ohio[1] and Minnesota[2], as well as the next generation distribution grid framework[3] defined by the U.S. Department of Energy and its national lab partners.

As part of facilitated exercises, the Navigant team asked stakeholders to identify specific capabilities a transformed grid should have and when those capabilities should be available. Navigant facilitators helped to establish a line-of-site mapping of those highly prioritized grid capabilities to specific technologies required to enable them. Supplemental material about specific technologies was made available to stakeholders following the session.

1.3. Stakeholder Workshop III

Twenty (20) stakeholders convened at the third grid transformation workshop in July. As part of this workshop III, Navigant facilitators shared the capabilities prioritization exercise results of the previous workshop. A Navigant subject matter expert presented overviews of relevant grid transformation systems, applications and technologies associated with each of the customer-facing capabilities and many of the value-enabling capabilities. A Dominion Energy representative presented a high-level draft of DEV's 10-year investment plan for the GTP filing.

Figure SR-2. DEV Results of Grid Capabilities Exercise



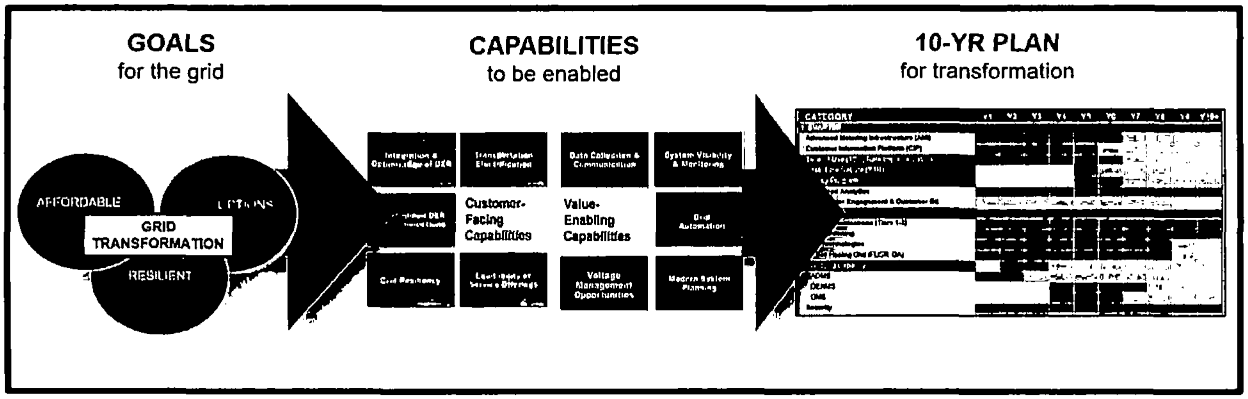
			CUSTOMER-FACING CAPABILITIES
●	●	●	Equitability of Service Offerings
	●		Grid Resiliency
●	●	●	Integration & Optimization of DER
		●	Streamlined DER Interconnections
		●	Transportation Electrification Enablement
			VALUE-ENABLING CAPABILITIES
●	●	●	Data Collection & Communication
●	●		Distributed Intelligence
●	●		Grid Automation
●	●		Modern System Planning
●	●	●	System Visibility and Monitoring
●	●	●	Voltage Management

1.4. *Stakeholder Workshop IV*

During the final session of the grid transformation workshop series, Dominion presented detailed plans of its proposed major investment categories to the 27 stakeholder attendees. Dominion presenters shared details about sub-programs as well as cost and benefit drivers for AMI investments, customer information platform (CIP) investments, its proposed TOU experimental rate, specific grid technologies, grid hardening investments, and its transportation electrification investments.

In its closing presentation, Dominion connected its proposed grid technology investments to the its forecasted maturity of its integrated distributed planning (IDP) capability. Dominion presenters noted that DEV's 2019 GTP filing is still in its final development stages and welcomed additional thoughts and recommendations from stakeholders on additional elements to be included in DEV's 2019 GTP filing.

Figure SR-3. Grid Transformation Workshop Series Progress



2. Stakeholder Engagement and Feedback

Including DEV staff and its legal support team, a total of 43 individuals participated in the total Grid Transformation Workshop series. Workshop guest participants represented 14 distinct state and regional organizations, many of which offered comments on DEV's 2018 GTP filing. Throughout the workshop series, stakeholders raised issues, provided input and expressed support for various elements of DEV's proposed 2019 GTP filing.

Table SR-1. Grid Transformation Workshop Participating Stakeholder Groups

Participating Stakeholder Groups	
• Arlington County	• State Corporation Commission
• MDV Solar Energy Industries Assoc	• VA Advanced Energy Economy (AEE)
• Natural Resources Defense Council	• VA Association of Counties (VACO)
• Richmond Region Energy Alliance	• VA Dept of Mines, Minerals and Energy
• Sierra Club	• VA Energy Efficiency Council
• Solar United Neighbors	• VA Municipal League
• Southern Environmental Law Center	• VA Poverty Law Center

In general, stakeholders offered several points of key feedback.

- Ultimately, stakeholders want GTP investments to result in more informed customers, customer-empowering tools, and cost savings opportunities for customers
- Stakeholders would find value in DEV providing examples of how it prioritized reliability investments including alternative analyses performed, specific project selection criteria and current-state/future-state capabilities assessments.
- Overall stakeholders expressed higher favorability towards more DER enablement and integration, and they supported benefits that enabled customers to save energy and energy costs.
- Stakeholders saw future opportunities to engage around pilot program rollouts, customer outreach activities and EV policy.
- Certain stakeholders were cautious towards reliability investments that were not strategically targeted to achieve specific net benefits.

3. Next Steps for DEV's GTP

DEV expects to file a new petition for approval of its 2019 Grid Transformation Plan with Virginia's State Corporation Commission in the third quarter of 2019. DEV signaled to stakeholders that the 2019 GTP filing will include updates to initiatives approved as part of its 2018 GTP filing (Phase IA investments) along with its 10-year plan for its stakeholder-informed investments (Phase IB investments) and their respective cost benefit analyses.

Appendix F

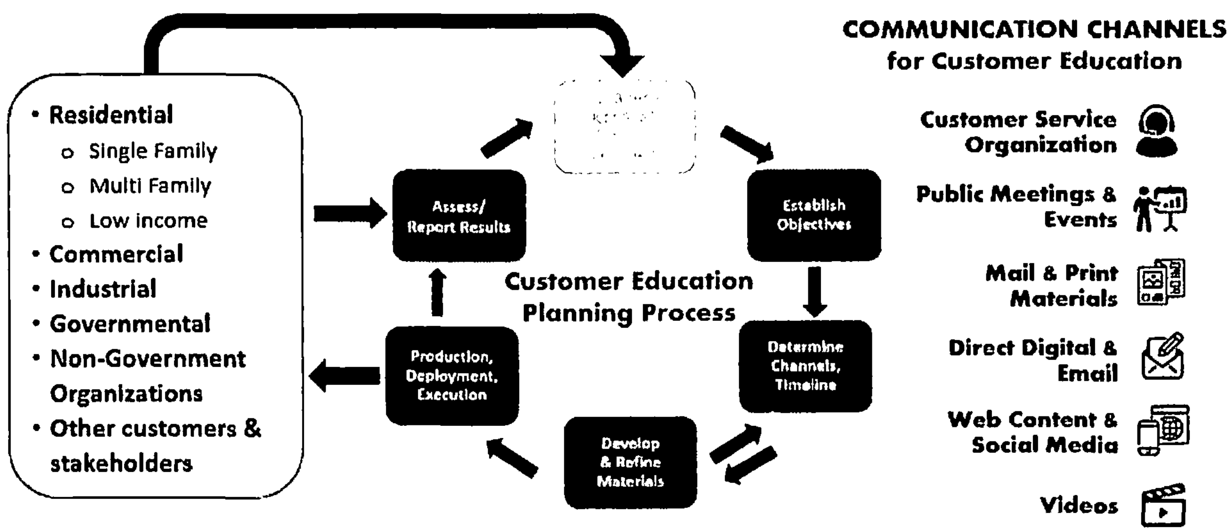
Customer Education Approach & Plan

The Company is committed to improving the customer experience. Key to achieving this goal is educating customers about their energy consumption and how to manage their costs and empowering them to take advantage of the numerous enhanced customer capabilities enabled by the GT Plan.

The foundation for transforming how the Company enhances and improves the customer experience is the GT Plan investments. For example, investments in smart meters, the customer information platform, and new time varying rate offerings combine to provide customers the ability to determine if new rate offerings will save them money. Similarly, the addition of grid improvements and new communication channels will provide customers additional information and new ways to receive timely updates related to service outages. The education plan utilizes multiple channels to engage with customers and showcase ways to reduce costs.

As shown in Figure 1 below, the approach to education includes leveraging feedback from customers and stakeholders, reviewing results from prior project experience and industry best practices, establishing objectives for educating customers, developing timelines for communications, creating and distributing education materials for multiple customer classes, assessing performance, and incorporating lessons learned.

Figure 1: Customer Education Planning Process



The Company plans to develop and provide 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, and interactions with the customer service organization. The timing of education initiatives will sync with the implementation of the GT Plan and its elements.

This plan provides a summary of the education initiatives related to increasing customer capabilities and describes the capabilities with the corresponding GT Plan investments. Specifically, this customer education plan addresses (1) foundational education, (2) smart meters and detailed energy usage data, (3) customer information platform and engagement, (4) customer energy management programs, (5) electric transportation benefits, and (6) grid improvement projects to improve reliability.

CUSTOMER EDUCATION TOPICS

(1) Foundational Education

The GT Plan investments enable the Company to improve the customer experience by providing basic, foundational "energy 101" information to ensure customers can learn basic terms and concepts of energy consumption (like peak-time and kilowatt hours) and understand the various ways to save. This foundational education will support the Company's efforts to educate customers on energy consumption, how to manage their costs, and how to take advantage of the numerous customer capabilities provided by the GT Plan.

The GT Plan elements are interdependent and work together to provide long-term value and benefits to customers. In addition to providing information and materials to educate customers on specific elements, materials will be developed regarding the need and benefits for the overall GT Plan and how the individual components complement each other and work together to deliver those benefits. Education of the overall GT Plan is important to provide context for why the Company is investing in individual elements such as smart meters and grid improvement projects and how the benefits of cost savings, new tools, and reliability improvements will be delivered over time.

To this end, the Dominion Energy website will be a main hub for public education. The Company has already launched a webpage at DominionEnergy.com providing links to factsheets, informational videos, and other informative documents, to begin laying the foundation of educating customers on enhanced capabilities associated with the GT Plan. A landing page specific to the GT Plan will be launched by early 2020, and all print and digital materials will link back to the page for further information. Public meetings and presentations will be a mainstay for educating customers about the comprehensive GT Plan; additionally, there will be a wide variety of opportunities for customers to learn about the plan from subject matter experts as well as other employees through the Company's "speaker's bureau" program. The Company will also provide information on the overall GT Plan benefits using other proven communications channels, including social media, print, and delivery of digital content.

(2) Smart Meters and Detailed Energy Usage Data

To ensure that the customer experience associated with the installation of smart meters is a positive one, the smart meter deployment team will execute an outreach and education strategy. Outreach will include targeted communications to each customer prior to and during the deployment phase of the new smart meters. Examples of educational communications include postcards, door hangers, and factsheets/brochures. Example education materials are attached to the testimony of Company Witness Nathan J. Frost.

Smart meter education goes beyond what has previously been provided in conjunction with the Company's prior smart meter deployment. Going forward, the channels will not only include web, print, and direct mail but will also provide digital content, social media delivery, educational videos, presentation materials for hosting and/or supporting public events, meetings and workshops. The customer communications will alert customers of the upcoming meter exchange, direct customers to the website for frequently asked questions ("FAQs") and provide options for setting an appointment for property access if needed. These communications will also serve as a mechanism to educate and inform customers on the capabilities resulting from the smart meter installation.

Customer education for smart meters will focus on their advantages and enhanced capabilities (now and in the future), safety and data security, understanding radio frequency, as well as the timing of advanced metering infrastructure deployment in communities. Materials will also be developed to address questions related to the policy allowing eligible, residential customers to "opt out" and receive a non-communicating meter and associated charges for such opt out. Messaging will focus on improved customer experiences available today such as remote connect / disconnect of service and instructions on how to access energy usage data. Over time, the Company will further educate customers on additional capabilities as they become available. For example, the Company will provide education on rate comparison and what/if analyses available through the CIP, and available customer energy management programs.

More specifically, the education plan provides awareness of smart meter deployment timelines before, during, and after installation. Initially, the education and outreach for smart meters will address questions such as:

- What are smart meters?
- How does the smart meter system work?
- Why is Dominion Energy Virginia investing in smart meters?
- When is the deployment of smart meters planned in my community?

Educational materials for smart meters will also:

- Highlight the available and future advantages provided by smart meters and address FAQs;
- Address concerns such as radio frequency and data security;
- Provide Notice of Installation of Smart Meters to customers and information regarding the transition process;
- Provide opt-out information for eligible residential customers; and
- Provide key contact information to ensure a smooth transition and allow for the Company to follow up as needed for access.

After installation of smart meters, customer outreach will include educating customers on enhanced capabilities, such as new tools and rate options once they become available. The Company will also continue to collect, analyze, and review customer feedback to refine communications and content based on feedback and effectiveness. Communications will be delivered through several channels, including direct mail, bill inserts, social media, web, digital, and public presentations.

(3) Customer Information Platform ("CIP") and Engagement

The implementation of the CIP is foundational to enhancing the customer experience and offering customers more capabilities. To ensure customers can take advantage of the enhanced capabilities, the education approach as described above will be utilized for each capability. The new capabilities include a what/if analysis tool, alert options, and enhancements to e-bill. Additional capabilities are listed in Table 4 of Company Witness Thomas J. Arruda Direct Testimony. The Company will provide customers with the knowledge to access and effectively use the new tools to save them time and money as each functionality is implemented. For each of the capabilities, the Company's education approach will consist of multi-channel engagement including but not limited to website content, direct digital (text, emails, and push notifications), bill inserts, and letters. The approach will also include incorporating lessons learned and adjustments as necessary.

(4) Customer Energy Management Programs

As the Company implements customer energy management programs, including time varying rate offerings, prepay program, and peak time rebates, the educational approach as described above will be used to encourage customers to participate in these programs and empower them to make decisions and monitor their success.

Education initiatives to support these programs will include education relevant to enrollment in the program as well as afterward to optimize ongoing savings. Initial education will provide information to eligible customers regarding the potential savings, enrollment process, and how to manage usage to optimize savings on the specific program. After enrollment, ongoing messaging to participants will be developed to bring about continued behavioral changes. The education approach will highlight other enhanced capabilities such as what-if analyses provided through CIP, detailed energy usage available through AMI, and new messaging channels through the CIP. The Company will analyze the success of the educational efforts and refine the outreach process and strategies as needed. Additional details of the education initiatives to support the Customer Energy Management Programs will be further developed as programs are closer to implementation.

(6) Grid Improvement Projects to Improve Reliability

As evidenced in recent Virginia surveys, customers generally support investments in technology to help prevent outages. The Company's fundamental goal with grid improvement projects is to build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management. Customers in specific areas with particularly poor service reliability have shared their frustrations and suffered real-world consequences of long duration outages, such as replacing spoiled food and making alternative lodging arrangements. The grid improvement projects outlined in the testimony of Company Witness Robert S. Wright, Jr., are designed to avoid outages and speed restoration when they do occur. While customers welcome reliability improvements, Dominion Energy Virginia recognizes that any work conducted in the field has the potential to impact the communities we serve; so it is important to educate customers before, during, and after project completion.

Proposed projects include grid technologies, such as self-healing grid investments, and hardening efforts like replacing and rebuilding targeted mainfeeder segments, targeted corridor improvements, and proactive asset upgrades. To the extent that these projects impact the communities served by the Company, Dominion Energy Virginia is committed to educating customers and the public on the need, location, and duration of this work.

The focus in this area will be on safety and the Company's commitment to completing scheduled work in a timely manner. The timing for customer education on individual projects will address any significant construction impacts, especially in the limited areas where easements and/or permits may be required before work can commence. In addition, the education materials will address enhanced vegetation management practices within the targeted corridor upgrade program, such as ash tree removal and herbicide usage across the entire width of the right of way. Customer education for each of the grid hardening projects will focus on ensuring residents and localities are aware of the need for improvement, informing them of the scope and duration of the project, keeping them apprised of the progress during construction, and continuing customer engagement to address any concerns and announce completion. Communications will be delivered through several channels including print materials, social media, web, digital, and public presentations. Homeowner associations and other community groups will be particularly helpful in disseminating educational materials and hosting meetings as needed.

<u>SUMMARY</u>

The Company's consistent implementation of the customer education approach and plan will improve the customer experience. Utilizing this education approach, the Company will ensure outreach is efficient and effective in achieving the goals of educating customers, keeping them informed, and empowering them to take advantage of the numerous enhanced customer capabilities provided by the GT Plan.

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

191033 3

Case Number (if already assigned)	PUR-2019-00154
Case Name (if known)	Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects
Document Type	OTHR
Document Description Summary	Corrected pages of the Company's filing

Total Number of Pages	15
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ERRATA FILING

October 25, 2019

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Joel H. Peck, Clerk
State Corporation Commission
c/o Document Control Center
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

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 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service
Case No. PUR-2019-00154

Dear Mr. Peck:

Please find enclosed for electronic filing in the above-referenced matter corrected pages of the Company's filing, which are intended to correct three identified errors. First, the improved reliability benefits in the cost-benefit analysis should be $1.9743 billion. This correction adjusts the total customer benefits and the total net benefit to customers. Notably, the total benefit to cost ratio remains at 1.1 for the Grid Transformation Plan. This correction affects page 32 of the Plan Document; page 15 of the pre-filed direct testimony of Company Witness Edward H. Baine; and the summary, pages 4 and 5, and Schedule 2 of the pre-filed direct testimony of Company Witness Thomas G. Hulsebosch. Second, Table 1 on page 21 of the pre-filed direct testimony of Robert S. Wright, Jr., contains a typographical error. The number of crossarms replaced during the March 2018 wind storm under the new standards scenario should be 1,271. Third, the customer education plan presented in Appendix F to the Plan Document inadvertently omitted Section 5, which describes the customer education plan related to electric transportation benefits. The corrected pages enclosed are intended to replace the versions filed on September 30, 2019.

Please do not hesitate to contact me if you have any questions in regard to this filing.

Highest regards,

Vishwa B. Link

Vishwa B. Link

Enc.

cc: Paul E. Pfeffer, Esq.
Audrey T. Bauhan, Esq.
Joseph K. Reid, III, Esq.
Sarah R. Bennett, Esq.
Jontille D. Ray, Esq.
Service List

Figure 7: CBA Summary

Cost/Benefit Summary (Revenue Requirement Basis)
(in Millions)

BENEFITS & COSTS	PV[1]
BENEFITS *(Asset Life)*:	
Customer	$2,972.3
Avoided/Deferred Capital	$375.6
O&M Savings	$265.9
Energy & Demand Savings	$237.5
Improved Reliability	$1,974.3
Reduction of Bad Debt & Energy Diversion	$118.9
COSTS *(Revenue Requirement)* :	$2,703.6
Total Net Benefit (Cost):	**$268.7**
Total Benefit/Cost Ratio:	**1.10**

[1] *Present Value (PV) 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):	**$354.0**
Total + Additional Benefit/Cost Ratio:	**1.1**

[2] *Adjusted to apply 7.2% benefits correlation factor to reduction associated with GT Plan EV investment*
[3] *Economic Benefits are neither included in the Total + Additional Net Benefit nor in the Total + Additional*

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, the CBA represents a positive business case from a financial perspective, providing ~~over~~ nearly $3 billion of benefits, which represents net benefit to customers of approximately ~~$322.5~~ $268.7 million all on a net present value basis.

The CBA focuses on quantifiable benefits, but the Grid Transformation Plan produces other qualitative, non-quantifiable benefits. For example, there are benefits that are difficult to quantify, like avoiding a cyberattack; providing resilient service to military bases, hospitals and communities; and providing customers with accurate and timely information that have implications for their daily lives.

shows the proposed investments are beneficial to customers and represent a positive business case from a financial perspective providing ~~over~~ nearly $3 billion of customer benefits, which represents net benefit to customers of approximately $268.7 ~~$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

WITNESS DIRECT TESTIMONY SUMMARY

Witness: Thomas G. Hulsebosch

Title: Senior Managing Director with West Monroe Partners, LLC

Summary:

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~~ nearly $3 billion of customer benefits, which represents net benefit to customers of approximately ~~$322.5~~ $268.7 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.

Figure 1

Cost/Benefit Summary (Revenue Requirement Basis)
(in Millions)

BENEFITS & COSTS	PV[1]
BENEFITS *(Asset Life)*:	
Customer	**$2,972.3**
Avoided/Deferred Capital	$375.6
O&M Savings	$265.9
Energy & Demand Savings	$237.5
Improved Reliability	$1,974.3
Reduction of Bad Debt & Energy Diversion	$118.9
COSTS *(Revenue Requirement)* :	**$2,703.6**
Total Net Benefit (Cost):	**$268.7**
Total Benefit/Cost Ratio:	**1.10**

[1] Present Value (PV) 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):	**$354.0**
Total + Additional Benefit/Cost Ratio:	**1.1**

[2] Adjusted to apply 7.2% benefits correlation factor to reduction associated with GT Plan EV investment
[3] Economic Benefits are neither included in the Total + Additional Net Benefit nor in the Total + Additional

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~~ nearly $3 billion of customer benefits, which represents net benefit to customers of approximately ~~$322.5~~ $268.7 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.

Company Exhibit No. ___
Witness: TGH
Corrected Schedule 2 (rev. Oct. 25, 2019)

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	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		$ -	$ -	$ 11,354,656	$ 1,974,308,424	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	$ 32,599,633	$ 2,972,287,152	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
96	Peak Demand Reduction from Managed Charging *(kW)*		$ -	$ 1,218	$ 1,931		
97	T&D Value of Peak Demand Reduction ($/kW)		$ 232	$ 232	$ 232		
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	$ -	$ 113,147	$ 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							

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Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
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*
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		$ -	$ -	$ 11,354,656	$ 1,974,308,424	Sum Lines 241-273
240							
241	Annual Residential Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 193,794	$ 36,037,744	*Dominion Projection*
242							
243	Annual Small C&I Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 1,802,803	$ 292,789,098	*Dominion Projection*

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Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
244							
245	Annual Large C&I Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 285,773	$ 139,933,865	*Dominion Projection*
246							
247	Service Transformer - Reliability Benefit (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 5,466,451	$ 183,848,576	Sum Lines 248-250
251							
252	THA Transformer - Reliability Benefit (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 154,761,679	Sum Lines 253-255
256							
257	Residential Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 1,722,778	*Dominion Projection*
258							
259	Small C&I Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 11,397,124	*Dominion Projection*
260							
261	Large C&I Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 122,853,117	*Dominion Projection*
262							
263	Residential Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 342,986	$ 60,785,322	*Dominion Projection*
264							
265	Small C&I Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 2,788,276	$ 638,790,355	*Dominion Projection*
266							
267	Large C&I Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 474,572	$ 263,321,585	*Dominion Projection*
268							
269	Residential Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 1,783,351	*Dominion Projection*
270							
271	Small C&I Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 11,834,288	*Dominion Projection*
272							
273	Large C&I Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 154,449,542	*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							

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	~~1,530~~ 1,271	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

After installation of smart meters, customer outreach will include educating customers on enhanced capabilities, such as new tools and rate options once they become available. The Company will also continue to collect, analyze, and review customer feedback to refine communications and content based on feedback and effectiveness. Communications will be delivered through several channels, including direct mail, bill inserts, social media, web, digital, and public presentations.

(3) Customer Information Platform ("CIP") and Engagement

The implementation of the CIP is foundational to enhancing the customer experience and offering customers more capabilities. To ensure customers can take advantage of the enhanced capabilities, the education approach as described above will be utilized for each capability. The new capabilities include a what/if analysis tool, alert options, and enhancements to e-bill. Additional capabilities are listed in Table 4 of Company Witness Thomas J. Arrùda Direct Testimony. The Company will provide customers with the knowledge to access and effectively use the new tools to save them time and money as each functionality is implemented. For each of the capabilities, the Company's education approach will consist of multi-channel engagement including but not limited to website content, direct digital (text, emails, and push notifications), bill inserts, and letters. The approach will also include incorporating lessons learned and adjustments as necessary.

(4) Customer Energy Management Programs

As the Company implements customer energy management programs, including time varying rate offerings, prepay program, and peak time rebates, the educational approach as described above will be used to encourage customers to participate in these programs and empower them to make decisions and monitor their success.

Education initiatives to support these programs will include education relevant to enrollment in the program as well as afterward to optimize ongoing savings. Initial education will provide information to eligible customers regarding the potential savings, enrollment process, and how to manage usage to optimize savings on the specific program. After enrollment, ongoing messaging to participants will be developed to bring about continued behavioral changes. The education approach will highlight other enhanced capabilities such as what-if analyses provided through CIP, detailed energy usage available through AMI, and new messaging channels through the CIP. The Company will analyze the success of the educational efforts and refine the outreach process and strategies as needed. Additional details of the education initiatives to support the Customer Energy Management Programs will be further developed as programs are closer to implementation.

(5) Benefits of Electric Vehicles ("EV")

Customer education on the benefits of electric vehicle (EV) ownership is essential to expanding broad adoption of EVs. The Company's plan seeks to address common customer questions related to electric vehicle ownership as well as market specific incentives and investments outlined in Company Witness Frost's testimony. Customer uncertainties include consumer "range anxiety" about electric vehicles potentially running out of power due to prospective EV owners not "seeing" public charging stations. Education materials will also address the misconception of high cost of EV ownership (often from the perception of initial "high" EV purchase cost) by illustrating that a lifetime value cost of EV ownership (*e.g.*, maintenance, gas) can be less than that of gasoline fueled vehicles.

Furthermore, the Company will reach out to the appropriate customer segments to achieve enrollment goals for the Smart Charging Infrastructure Pilot Program rebates, including multi-family residential, workplace charging, public direct current fast charging ("DCFC"), and transit buses. The education and communications that will accompany the deployment 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. Customer education for each of the specific rebate programs proposed in the Pilot Programs will focus on awareness, information, implementation, and engagement, tailored to the offering timeline.

Showcasing the numerous tangible benefits of owning and driving an electric vehicle is essential to supporting wide-scale adoption. The Company has already endeavored to provide educational information 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 website and EV webpage will continue to be a primary hub for information on electric vehicles ownership, charging, and links to time-varying rate options as they become available. Other channels for education and engagement with customers include social media, print, digital and support of public events, such as those held by local chapters of electric vehicle advocacy groups.

(6) Grid Improvement Projects to Improve Reliability

As evidenced in recent Virginia surveys, customers generally support investments in technology to help prevent outages. The Company's fundamental goal with grid improvement projects is to build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management. Customers in specific areas with particularly poor service reliability have shared their frustrations and suffered real-world consequences of long duration outages, such as replacing spoiled food and making alternative lodging arrangements. The grid improvement projects outlined in the testimony of Company Witness Robert S. Wright, Jr., are designed to avoid outages and speed restoration when they do occur. While customers welcome reliability improvements, Dominion Energy Virginia recognizes that any work conducted in the field has the potential to impact the communities we serve; so it is important to educate customers before, during, and after project completion.

Proposed projects include grid technologies, such as self-healing grid investments, and hardening efforts like replacing and rebuilding targeted mainfeeder segments, targeted corridor improvements, and proactive asset upgrades. To the extent that these projects impact the communities served by the Company, Dominion Energy Virginia is committed to educating customers and the public on the need, location, and duration of this work.

The focus in this area will be on safety and the Company's commitment to completing scheduled work in a timely manner. The timing for customer education on individual projects will address any significant construction impacts, especially in the limited areas where easements and/or permits may be required before work can commence. In addition, the education materials will address enhanced vegetation management practices within the targeted corridor upgrade program, such as ash tree removal and herbicide usage across the entire width of the right of way. Customer education for each of the grid hardening projects will focus on ensuring residents and localities are aware of the need for improvement, informing them of the scope and duration of the project, keeping them apprised of the progress during construction, and continuing customer engagement to address any concerns and announce completion. Communications will be delivered through several channels including print materials, social media, web, digital, and public presentations. Homeowner associations and other community groups will be particularly helpful in disseminating educational materials and hosting meetings as needed.

SUMMARY

The Company's consistent implementation of the customer education approach and plan will improve the customer experience. Utilizing this education approach, the Company will ensure outreach is efficient and effective in achieving the goals of educating customers, keeping them informed, and empowering them to take advantage of the numerous enhanced customer capabilities provided by the GT Plan.

CERTIFICATE OF SERVICE

I hereby certify that on this 25th day of October 2019, a true and accurate copy of the foregoing filed in Case No. PUR-2019-00154 was hand delivered, electronically mailed, and/or mailed first class postage pre-paid to the following:

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