OLSON, BZDOK & HOWARD

June 22, 2021

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-filing

RE: MPSC Case No. U-20963

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Direct Testimony of Robert G. Ozar PE on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan;

Exhibits MEC-19 through MEC-41 (with MEC-37 and MEC-41 reserved); and

Proof of Service.

Sincerely,

Digitally signed by Tracy Jane Andrews
DN: cn=Tracy Jane Andrews, email=tjandrews@envlaw.com, c=US
Date: 2021.06.22 18:41:48 -04'00'

Tracy Jane Andrews
tjandrews@envlaw.com

xc: Parties to Case No. U-20963

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	U-20963 ALJ Sharon Feldman

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TESTIMONY OF ROBERT G. OZAR P.E.

ON BEHALF OF

MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND
CITIZENS UTILITY BOARD OF MICHIGAN

June 22, 2021

TABLE OF CONTENTS

DIRECT TESTIMONY OF ROBERT G. OZAR P.E. FOR MNSC
CASE NO. U-20963

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Robert G. Ozar, I am a Senior Consultant at 5 Lakes Energy LLC, located at Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan (CUB), collectively referred to as "MNSC".

Q. Please summarize your experience in the field of utility regulation.

A. I have worked in the area of energy policy and utility regulation for over forty years. I began employment with the Michigan Public Service Commission in 1979, retiring in 2019. I began my employment with 5 Lakes Energy LLC in 2020.

During my tenure with the Michigan Public Service Commission, I testified as an expert witness in a multitude of contested regulatory proceedings, in both the gas and electric industries. I supported the Commission in its role advising the Michigan Legislature regarding energy related bills, and participated in legislative committees, providing technical input regarding draft energy legislation. I was Chair of the Energy Efficiency Workgroup, providing input to the Michigan integrated resource plan called: "The 21st Century Energy Plan". I was a lead Staff in the Michigan Electric Vehicle Preparedness Task Force. I initiated and led the MPSC Smart Grid Collaborative. I also led the Michigan Energy Optimization Collaborative, overseeing the development of the framework for implementing energy efficiency programs for all Michigan Utilities, including development of the technical resource manual (TRM) called: "The Michigan Energy Savings Database." I was lead technical advisor for the MPSC Incentive Ratemaking Workgroup and a contributing author of the MPSC report to the legislature. I was a lead technical advisor to the MPSC's stakeholder workgroup charged to study a cost based distributed generation tariff. I was the author of the 2016 white paper, "A Reasoned Analysis For a New Distributed Generation Paradigm The Inflow & Outflow Mechanism A Cost of Service Based Approach." I was a principal author of the 2018 study: "Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff."

During my final decade with the MPSC Staff, I served as Manager of various Staff sections, supervising both engineering and other technical staff. I was Manager of the Electric Operations Section, having responsibility for electric reliability issues, resource adequacy, renewable energy, smart grid, electric meters, and advanced electric technologies, including plug-in electric vehicles and battery storage. I subsequently served as Manager of the Energy Efficiency Section, overseeing the implementation and enforcement of the Energy Optimization Program requirements of PA 295, emerging demand response issues, and revenue decoupling issues. Finally, I ended my tenure at the MPSC as Assistant Director of the Electric Resources Division, retiring in December 2019. My resume is provided as Exhibit MEC-19.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. Yes. I have previously testified before the Michigan Public Service Commission (Commission) in multiple cases over a period of over 40 years.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of MNSC regarding various distribution system matters. First, I address some policy considerations related to the Company's distribution system capital investment spending plan. Second, I review several of the Company's proposed 2022 distribution system investments, and I provide recommendations to reduce or disallow spending based on my review. These include recommendations to limit cost recovery through rates of projected test year costs associated with the Standish portable battery project and the Neeley/Gun Lake flow battery project. I also recommend that the Commission defer to a future case the Company's request for rate recovery of its Distributed Energy Resource Management System (DERMS) investment. Next, I discuss the Company's lack of a continuous distribution system monitoring, and introduce Distribution Fault Anticipation (DFA) technology as a potentially cost-effective tool to improve the Company's present approach to distribution system monitoring and repairs. Then I address the Company's proposed test year HVD Line Rebuild projects, particularly those projects that propose to rebuild "non-standard construction" line segments. In addition to these distribution capital projects, I address the Company's proposed Storm Restoration O&M investment. Finally, I recommend modifications to the Company's proposed Home Battery Pilot.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit MEC-19:	Resume of Robert G. Ozar P.E.
Exhibit MEC-20:	ST-CE-143
Exhibit MEC-21:	MEC-CE-481, 483, 484

Exhibit MEC-22	MEC-CE-476, 477
Exhibit MEC-23	MEC-CE-1056 + Attachment
Exhibit MEC-24	MEC-CE-878
Exhibit MEC-25	MEC-CE-1057 + Attachment 1
Exhibit MEC-26	Application Public III Attachment 126
Exhibit MEC-27	MEC-CE-478, 479, 877
Exhibit MEC-28	MEC-CE-527
Exhibit MEC-29	Incipient Conditions on Electric Power Circuits
Exhibit MEC-30	DFA Project Presentation and Case Studies
Exhibit MEC-31	DFA Manual, FAQs, and Tutorials
Exhibit MEC-32	MEC-CE-880 + Attachments 1, 2
Exhibit MEC-33	MEC-CE-882, 1058
Exhibit MEC-34	ELPC-CE-746
Exhibit MEC-35	AG-CE-867 + Attachment 1
Exhibit MEC-35	MEC-CE-881, Attachments 1, 2
Exhibit MEC-37	Reserved
Exhibit MEC-38	HVD Line Rebuild Non-Standard Construction Projects
Exhibit MEC-39	Service Restoration O&M Calculation
Exhibit MEC-40	NPV Deferral Loss Advancing the Neeley and Gun Lake Capacity Upgrades
Exhibit MEC-41	Reserved

II. DISTRIBUTION SYSTEM CAPITAL SPENDING PLAN

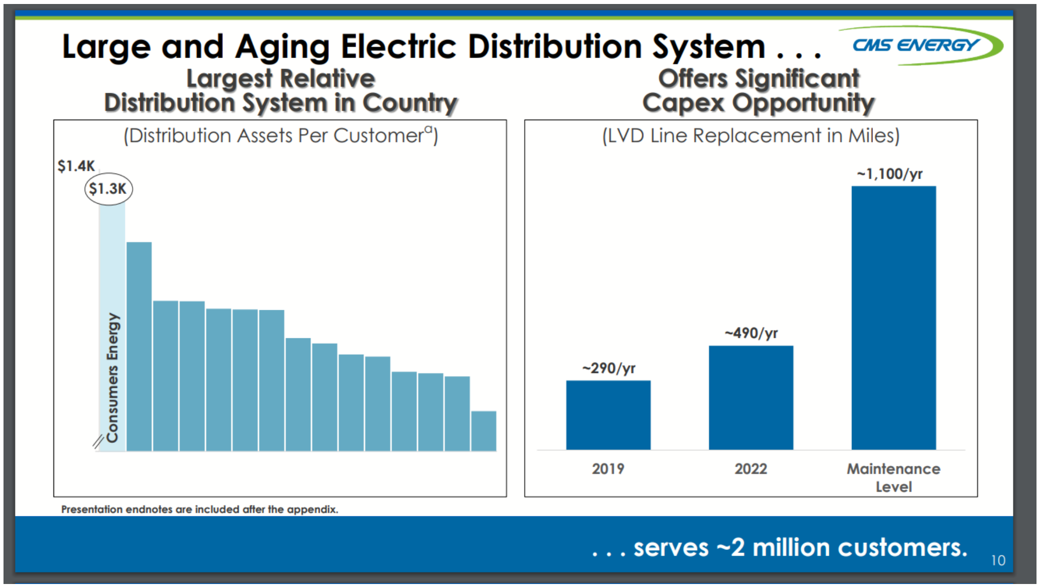
Q. Do you have concerns about Consumers Energy Company's distribution system capital spending plan and its impact on rates?

A. Yes. I have some observations relating to Consumers Energy Company's (hereafter, the Company) electric distribution capital spending plan. The distribution capital spending is growing enormously year-over-year, reaching unprecedented levels. In the instant case, the Company's distribution capital spending plan is the largest ever proposed. MNSC is concerned that the Company has a bias toward high-cost investment over lower cost, but equally effective, alternatives, or toward capital investment in place of alternative operating expenses.

Q. What observations lead you to the conclusion that the Company has a bias toward expensive methods of expanding its distribution system assets?

A. Two core observations: (1) the Company has explicitly identified to its investors that it has a strategic plan to massively expand its distribution investments; (2) Defects in the capital spending plan proposed in this proceeding appear consistent with such plan. Regarding the first observation, see the following slide taken from a recent investor meeting:[1]

[1] CMS Energy, *Investor Meetings: Leading the Clean Energy Transition,* Marcy 2021, p10, available at https://s26.q4cdn.com/888045447/files/doc_presentations/2021/02/March-2021-Meetings.pdf, last checked June 16, 2021. See also CMS Energy, *Strategic Sale of EnerBank,* June 8, 2021, p. 8 (identifying "Upside Opportunities: Electric distribution reliability; Grid modernization … Delivers rate base growth without dilution.") available at: https://s26.q4cdn.com/888045447/files/doc_presentations/2021/06/EnerBank-Presentation-FINAL.pdf last checked June 16, 2021.



Q. How should this presentation slide be interpreted?

A. The interpretation of the slide is obvious. The Company is highlighting for investors that it has the most expensive electric distribution system in the country on a dollar asset per customer basis.[2] On the same slide, the Company is highlighting an unprecedented 70% increase in annual LVD line replacements from 2019 to the 2022 projected test-year of 200 miles (70% increase from 2019). The Company refers to these projected replacements as a capex "opportunity". In evaluating the Company's proposed distribution capital plan, the Commission should be aware of what the Company is telling investors, as it is a highly relevant and a missing component to the story the Company presents to the Commission in its filing. It is bad enough that the Company's electric distribution system is the costliest of comparable utilities in the country. That ratepayers, in particular residential customers, many of whom struggle to pay their electric bills, must bear the cost of extensive LVD line

[2] Per the slide notes on page 23 of the presentation, the graph reflects "Largest electric regulated utility by customers, includes above ground electric distribution assets."

replacements is not an "opportunity" but a burden.[3] Balancing reliability improvements with rate impact is a critical issue for the Commission in assessing the reasonableness and prudence of the Company's distribution system spending proposals.

Q. What role do regulatory deficiencies play in the Company's ability to continue its massive expansion of electric distribution assets?

A. First, the Commission should note that the utility's most recent Distribution Investment Plan is out of date. The new Distribution Investment Plan is in draft form at the time of this testimony, will not be subject to any opportunities for parties and the Commission to assess or contest its contents through a contested proceeding, and will come too late to impact the rate request in this proceeding. As such, this case lacks foundation and perspective that a robust distribution system plan has the potential to provide.

Second, the Commission should note that most reliability improvements are related to O&M spending, not to mushrooming distribution capital investments. As the Company does not earn a return on O&M, there exists a regulatory-structure bias toward capex solutions to distribution reliability. It would be naïve to assume that this regulatory bias has no effect on the Company's electric distribution spending plan.

Third, the Commission should make clear that the MIPowerGrid's work around technology and pilots should not be viewed by utilities as providing a blank check on spending with respect to technology and pilots. The goal of that workgroup was to develop clear rules of the road for what makes an effective pilot project. When it comes to pilots that test new

[3] See generally the testimonies filed in this proceeding by Douglas Jester and Tanya Paslawski, for discussions on distribution system cost allocations and the burdens of electric bills, respectively.

distribution connected technology or non-wires alternatives, one of the key goals is to identify new methods for meeting reliability that are more cost-effective that traditional methods.[4] Therefore any pilot utilities want to undertake to integrate new technology in the distribution system should have <u>cost effectiveness</u> as paramount consideration and key metric for evaluation. The Commission should make clear the goal of cost effectiveness, particularly in distribution related pilots and technology investments, by critically evaluating the proposed pilots and technology investments in this proceeding and the recommendations that some of the core pilots proposed by the Company are not cost effective and should be disallowed or revised.

Fourth, the Commission has a responsibility to balance spending with rate impact. Refined performance-based ratemaking (PBR) mechanisms are essential to evaluation of the efficacy of proposed continuous and massive capital spending growth.[5] PBRs should address the regulatory incentives that bias capitalization instead of O&M spending, and should link incentives on the Company hitting performance goals, such as SAIDI, SAIFI, CAIDI, or other service quality goals, in a cost-effective way. The Company's plans for advance planning for restoration crews is on the right track. PBR mechanisms may expand the pool of innovations such as this. Until appropriate PBRs are approved, the Commission should hold massive increases in distribution spending in check. Without a PBR it is extremely difficult for the Commission and stakeholders to thoroughly vet the performance

[4] Case No. U-20147, Aug. 20, 2020, Order, p. 37 (reiterating that new technologies should be integrated in a manner that helps "displace or defer costly gride improvements").

[5] Case No. U-20697, Dec. 17, 2020, Order, pp. 270-72 (recognizing importance of PBR mechanisms, given significant distribution system expenditures).

benefits and cost effectiveness of every component of the company's projected test-year budget.

A contested and well-vetted distribution planning process, realignment of utility incentives, cost-effectiveness as a planning and evaluation metric for all distribution pilots and distribution integration of new technology, and effective PBR mechanisms are essential to offset information asymmetry built into the regulatory process and ensure ratepayers are protected from unnecessary or ineffective distribution system investments.

A. <u>Standish Battery Project</u>

Q. Please summarize the Company's Standish Battery project for substation deferral?

A. The Company intends to couple a battery to a distribution circuit at the Standish substation. By doing so, a station upgrade (necessary due to projected future capacity overloads) may be deferred several years.[6] The project is intended to be portable, thus it could potentially be relocated to a different substation.

Q. In its order in the Company's prior rate case, U-20697, did the Commission disallow the proposed Standish battery project for deferring a substation upgrade?

A. Yes. The proposed pilot was disallowed on the basis that the project was exceptionally expensive as compared to the alternative of a traditional substation upgrade.[7] The Commission noted that, "in light of the fact that Consumers has other pilot projects through which to gain experience, the Standish project appears to lack sufficient benefits given the

[6] Direct Testimony of Richard T. Blumenstock, p. 215; Ex MEC-23 (MEC-CE-1056, Concept Approval).

[7] Case No. U-20697, Dec. 17, 2020, Order, pp. 38-40.

need for the substation upgrades."[8]

Q. Do battery distribution asset deferral projects have unique characteristics among the various uses for battery storage on the electric grid?

A. Yes. The core intrinsic value of this project is related to the time-value-of-money in deferring distribution upgrades. However, the cost of a portable battery combined with the short service life of a battery vis-à-vis the hard infrastructure that it defers, makes an economic case for high-cost battery deferral projects problematic to yield a positive net present value. The saving grace for a battery deferral project may be additional revenue streams created by the battery, such as the provision of ancillary services. This is something a pilot could investigate, but the case for deferral must be solid regardless of such benefits. Clearly, the level of battery costs is key to solidity, though not necessarily making the project economic on its own.

Q. What did the Standish project Concept Approval (3/25/2020) estimate as to the net cost of the portable battery system (not including the cost of the substation upgrades) if it were to be relocated to two additional substations in addition to the Standish substation?

A. The Company's 2020 Concept Approval estimated a total capital cost of the battery system of $11,022,000 and a net present worth of $14,714,000.[9] The Company confirmed that the original Concept Approval and benefit cost analysis are still valid, although Mr. Blumenstock states the Company did scale back less critical tasks such as a dispatch

[8] *Id.* at p. 29.

[9] Ex MEC-23 (MEC-CE-1056 Concept Approval).

optimization analysis and a third-party analysis on the battery's performance.[10]

Q. Did the Company anticipate additional revenue streams in the original Standish project that was disallowed by the Commission in U-20697?

A. In discovery, the Company suggested that there may be other revenue streams related to circuit power-quality or market interaction.[11] However, such additional services appeared to be an afterthought, with a total absence of detailed or strategic planning. For instance, the Concept Approval contains no hint of registering the project with MISO as a market participant. The Company subsequently assessed potential value streams of providing fast frequency-regulation if it were to register the project with MISO.[12] The Company projected annual frequency regulation revenues through 2040, implicitly assuming a 20-year life of the battery system. Recognizing that a potential third substation (Pickerel) would be upgraded in 2030, only revenues through 2030 are relevant ($1.4 million). In my opinion, even if the battery system had a moderately longer assumed life, (the Company's assumption of a 20-year life of a grid connected Li-ion battery appears liberal) such revenues would have a negligible offsetting impact on the project.[13]

Q. Despite the Commission disallowance, has the Company made a decision to go forward with the pilot?

A. Yes. The Company committed by contract with its supplier to move forward with the

[10] Blumenstock Direct, pp. 216-27; Ex MEC-21 (MEC-CE-481).

[11] Ex MEC-23 (MEC-CE-1056(a)).

[12] *Id.*

[13] *Id.*

project. This was done during the pendency of the U-20697 proceeding. The Company did not have the final Commission Order at the time a go-decision was made.[14] However, the Company was certainly aware that the issue of disallowance was a possibility, as MNSC had raised the issue of disallowance in testimony and briefing. Rather than defer a decision on the project until a final Commission order, the Company's apparent risk mitigation strategy was to scale-back the project once the Commission issued its order. The Company is requesting approval of the scaled-back Standish pilot in the instant proceeding.[15]

Q. What is the Company's total projected investment in the portable battery project?

The total projected "scaled back" cost of this portable battery project is not clear. As noted above, the 2020 Concept Approval indicates a total cost of $11.022 million. In Case No. U-20697, the projected 2021 investment for the Standish portable battery project was $8.131 million.[16]

According to Mr. Blumenstock's testimony in this case, the Company invested $2.1 million by the time the Commission issued its final order in the 2020 rate case (Dec. 17, 2020).[17] Mr. Blumenstock further states the $3,942,500 that the Company is contractually obligated to pay is 85% of "the project's final cost" and also that the Company expects to invest a total of "over $5 million" for the battery asset.[18] Company Exhibits A-35 and A-37 identify $5.98 million in 2021 Grid Storage spending; however, the Company failed to provide an

[14] Ex MEC-21 (MEC-CE-483(c)).

[15] Blumenstock Direct, pp. 215-18.

[16] Case No. U-20697, Ex A-42, p. 27 of 30 (Standish Portable Battery – 2021 work).

[17] Blumenstock Direct, p. 217.

[18] *Id.* pp. 217-218.

updated project budget for 2021 bridge year distribution capital investments.[19] While Mr. Blumenstock states that 2022 test year spending will fund "final wrap-up work" for the portable battery (Standish),[20] there is no line item for the portable battery project in the 2022 Grid Storage $10 million spending request in Exhibit A-48, page 14, lines 85 to 87.

Mr. Blumenstock explained that the Company "scaled back" the project by limiting expenditures "to those related to critical tasks," while eliminating "less critical tasks," "like dispatch optimization analysis and a third-party analysis on the battery's performance one year after commissioning."[21] The Concept Approval included $48,000 for dispatch optimization consulting and $48,000 for a "white paper on findings from review of real data."[22] It is unclear what other cost items are "less critical" and may have been eliminated.

As a result, I am uncertain far how the Company scaled back the project from a total capital cost of $11,022,000, (not including the cost of the deferred substation upgrades) and what the Company presently expects for the total investment in this portable battery project.

Q. How should the Commission view the Company's contractual commitment?

A. The Commission's contracting decision should not affect the Commission's review of this proposed expenditure. In the prior rate case, the Company proposed this project for the following year, and the Commission disallowed the project and its estimated costs because

[19] Ex MEC-20 (ST-CE-143).

[20] Blumenstock Direct, p. 218.

[21] Ex MEC-21 (MEC-CE-481(c)).

[22] Ex MEC-23 (MEC-CE-1056, Concept Approval).

the project lacked sufficient benefits.[23] The fact that the Company made a contractual commitment while the issue was being contested (no notification was made in the U-20697 proceeding) should not excuse this project from full scrutiny in this proceeding. If a capital project has not been adequately supported, those costs should be excluded from rate base – regardless of whether those dollars are spent in the bridge year or project test year. Put differently, the Company's decision to enter a contract should not tip the scales, so to speak, in favor of approval.

Q. **What is your recommendation regarding cost recovery of the Standish battery project?**

A. The Standish project has presumably been scaled back, and the Company has considered potential revenue streams to offset a small portion of the cost of the project. Even so, the fundamental economics and limited potential insights of this project remain unchanged since the last case. The Company's rate request is saddled with massive distribution related capital investments whose costs are heavily borne by residential customers. On balance, and from a holistic perspective, Consumers has not shown that the Standish pilot a critical and necessary expense. Additionally, I am concerned about the precedent it sets if the Commission approves a project that the Company moved forward with despite a previous disallowance.

Importantly, my recommendations to reject full cost recovery of the Standish portable battery system acknowledge that a successful pilot investment is not dependent upon a positive net present value (NPV), where the NPV of the pilot is calculated as the present

[23] Case No. U-20967, Dec. 7, 2020, Commission Order, p. 39.

value of the benefits of the pilot less the present value of the costs of the pilot. This acknowledgement leads me to conclude that an appropriate standard for full recovery from ratepayers requires the satisfaction of these conditions:

(1) the pilot has a reasonable possibility of being cost effective (*i.e.* a positive NPV); or

(2) the learnings have sufficient value to offset a potential deficiency in net benefits.

It is my opinion that the Company's Standish pilot as implemented by the Company does not meet this standard.

Q. Please elaborate on why the Standish portable battery pilot does not meet an appropriate standard for cost full cost recovery?

A. I calculated the NPV of the proposed pilot to be negative $12,724,000. The staggering difference should have given the Company pause to initiate the pilot. It would be hard to imagine how the pilot's learnings justify such massive losses, as the core benefit of the project is the monetary value of deferral of the three substations, which is a meager $590,000.

Q. Please explain how you calculated the NPV of the proposed Standish portable battery system?

A. I began the calculation with a determination of the NPV of the pilot's benefits using data the Company provided in its Concept Approval. As the present value of the revenue requirements of traditional substation upgrade of the three substations (Alternative 1) is $5,052,000, and the present value of the revenue requirements of the battery system with deferred substation upgrades is $19,176,000 (Alternate 2).[24] The difference of a negative $14,124,000 represents the net present value (NPV) of the project pursuant to the Concept Approval. However, the value of potential ancillary services revenues of $1,400,000 can be added to this NPV.[25] The upshot is that the NPV of the portable battery pilot considering all benefits is *negative* $12,724,000. From a financial perspective, the project is undertaken at a considerable loss. This loss constitutes the effective cost to ratepayers of the learnings elicited by the pilot if the Company were granted full cost recovery of the project.

Q. How did you calculate the core benefit of the pilot?

A. The core benefit of the pilot is the time value of the of the deferral of the three substations. A possible secondary benefit is the value of potential MISO fast frequency regulation Market revenues, at approximately $1,400,000. The core benefit is calculated as follows. The present value of the revenue requirements of the battery and deferred substations is $19,1756,000. Subtracting the present value of revenue requirements of only the battery system, of $14,714,000, is the present value of the revenue requirements of the deferred substations. Subtracting this from the present value of the revenue requirements of the three substation upgrades (Alternative 1) of $5,052,000 yields the NPV of the deferral, which is $590,000. This matches the estimated deferral value included in the Concept Approval.[26]

Adding to this amount the value of potential ancillary service revenues of $1,400,000 yields the total present value of the net benefits of the proposal of $1,990,000. The total net benefits

[24] Ex MEC-23, p. 5.

[25] *Id.*, p. 1, and as discussed above.

[26] *Id.* at p. 6.

represent the maximum present value of the difference between the revenue requirements of the pilot (Alternative 2) and the traditional substation upgrades (Alternative 1), that would yield a zero NPV, *i.e.,* the break-even point of the project where net benefits equal net costs. Since both Alternative 2 and Alternative 1 include the substation upgrades, the $1,990,000 also represents the maximum present value of the revenue requirements of the battery system itself, that would yield a zero NPV for the pilot. In the Concept Approval, the ratio of total capital to present value of revenue requirements for the battery system, excluding substation upgrades is 0.75. Multiplying $1,990,000 by 0.75 approximates the maximum total capital for the battery system in order to break-even on a NPV basis, which is $1,500,000. This should have been the Company's starting point for a decision to move forward with the Standish battery for substation deferral project, recognizing that the actual cost for a pilot may exceed the break-even point by a reasonable amount, if one were to monetize the value of learnings associated with the pilot (see my comments above regarding a reasonable standard for full recovery).

Q. How should the Commission resolve this problem, knowing that the Company is moving toward completion of the project?

A. It is my opinion that the combined recommendations of: (1) a limited rate base allowance; and (2) institution of an outcome base Performance Base Ratemaking (PBR) mechanism; have the potential to negate the core financial deficiencies of the project. These recommendations collective would allow the pilot to go forward with reasonable equity for customers, while concurrently providing an opportunity for the Company to minimize the adverse financial impact of a rate base disallowance.

I recommend that the Commission disallow full recovery of the project costs by capping the total amount the Company is allowed to include in its rate base for the battery system at an amount equal the Company's contractual commitment of $3,942,500. This is approximately $2.5 million above the break-even threshold. The recommended inclusion of $3,942,500 in rate base sets a cap on the aggregate 2020 and 2021 bridge year capital spending, and any 2022 test year spending for the battery system. As noted above, the Company's total capital spend for the portable battery is unclear – somewhere between the original $11.2 million and more than $5 million. When the Company ultimately upgrades the Standish and two additional substations after 3-5 years of battery deferral each, following rate review of the specific upgrade projects, such distribution assets may go into rate base at cost.

Q. How do you recommend that the Commission treat any potential future revenue streams from the portable battery?

A. I recommend an outcome based PBR mechanism related to realized revenue streams, such as fast frequency regulation dispatched into the MISO market. Specifically, I propose a PBR that would allow the Company to retain 30% of the realized cash benefits, which referencing the Fast Frequency Regulation revenues delineated in the table included in MEC-CE 1056, would be approximately $410,000.[27] Such an outcome-based incentive mechanism, combined with a reasonable (but not full) allowance for rate base, would give the Company considerable motivation to complete the project, and to realize additional value streams, (beyond the time value of upgrade deferral), which at this time are highly

[27] Ex MEC-23 (MEC-CE-1056(a)).

uncertain. Non-cash benefits accrue to the customers. Should the Company file its application for the Standish Battery as a MISO Market Participant and demonstrate value streams created by the project, then it may request in its subsequent general rate case proceedings, that PBR reconciliations be implemented.

B. Neeley and Gun Lake Battery Energy Storage System (BESS) Pilot

Q. Should the Commission approve the Company's proposed grid automation project/pilot involving a Li-Ion BESS system at the Neeley/Hooper and Gun Lake/Trails End feeders?

A. No. I recommend that the Commission disallow the proposed project/pilot as it has an excessive cost[28] and, in its place, approve an alternative and much lower-cost approach using a traditional capacity upgrade/rebuild of the adjacent feeders in 2022 rather than 2027, as in Alternative 1, with an automatic transfer scheme (ATS) implementation to allow for energy transfers between the adjacent feeders. This proposed alternative was not included in the Company's revised concept approval for the battery pilot.[29] There are other issues related to how the Company calculated the annual reliability improvements that I address below.

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[28] See Ex A-48, p. 14, line 87 (2022 spending request of $$8.698 million for Distribution Automation Battery); see also Blumenstock Direct, p. 216, 218-19.

[29] Ex MEC-25 (MEC-CE-1057(b); Concept Approval, revised June 14, 2021).

Q. Can you provide a background on this proposed pilot?

A. Yes. The Company's original Concept approval selected a redux flow battery (Alternative 3) at the Neeley/Hooper and Gun Lake/Trails End feeders. A revised Concept Approval dated June 14, 2021 selected a lower priced alternative (Alternative 2) using a Li-Ion battery system.[30] The original, Alternative 3, is the costliest project among the top 25 costliest distribution projects included by Consumers Energy in its filing.[31] The cost of the revised choice (Alternative 2) is approximately 70% of cost of the redux flow battery (Alternative 3). The Company considers a BESS project a grid automation pilot.[32] The Company revised its Concept Approval to reject the redux flow battery, but did not amend its rate request. I reasonably assume that the Company is no longer requesting cost recovery of a redux flow battery pilot, and thus will focus my review on the recently-selected Li-Ion BESS alternative.

The cost of the LI-Ion BESS is over and above all the other work the company needs to do at the two circuits <u>irrespective of whether the battery pilot moves forward</u>. Additional work identified by the Company includes an upgrade of the Neeley substation transformer and a reconductoring of all 5.7 miles of feeder backbone including all new poles, at a capital cost of $2,207,000, but this work would be deferred until 2031, 2032, and 2033.[33] The alternative option (Alternative 1) included in the Company's concept approval is to simply

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[30] *Id.*

[31] Ex MEC-26 (Application Public Folder III Attachment 126). This project is the first Concept Approval in the Attachment.

[32] Blumenstock Direct, p. 216.

[33] Ex MEC-25 (Revised Concept Approval).

wait until 2027 to complete the unavoidable upgrades, at a capital cost of $2,507,000 including ATS. Because the traditional upgrade-only alternative forfeits five-years of reliability benefits (at a present value of $5,365,000), Alternative 1's cost premium is increased commensurately above the present value of the revenue requirements of the upgrade. The NPV of the Li-Ion BESS pilot with respect to a traditional upgrade (Alternative 1) is a negative $972,000 ($10,482-$11,454).[34]

Referencing a reasonable standard for full cost recovery of pilot costs, as I outlined above with respect to the Standish pilot, the Neely/Gun Lake Li-Ion battery pilot could be viewed as in the public interest with respect to full rate base recovery -- *if* the unavoidable 2027 upgrade (Alternative 1) were the only other viable alternative, and *if* the Company were able to obtain other revenue streams in the range of what was estimated for the Standish project.[35] Such revenues may convert the NPV for this battery project into a positive However, this also assumes the estimated revenues streams are reasonably accurate, which is dubious, as discussed further below.

Q. **Why did the Company choose the Neeley and Gun Lake feeders as the location of the pilot?**

A. The Company asserts that these adjacent feeders are in a remote and heavily wooded/swampy area, and that new automatic transfer scheme (ATS) is not viable here due to poor reliability and capacity limitations.[36] The Company notes that the lines

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[34] *Id.*

[35] See Ex MEC-23 (MEC-CE-1056(a)).

[36] Ex MEC-25 (Revised Concept Approval).

experience a high level of faults (most likely from the dense tree cover), and that frequent faults damage the reclosers.[37] Notable, the Company has apparently undertaken significant reliability improvement projects to improve the performance on the Gun Lake and Neeley substation circuits since 2017, including rebuilding the Gun Lake 46kV line, full forestry line clearing in 2018, and repetitive outage projects in 2019 and 2021.[38] Consumers estimates an O&M cost of $3/customer-minute of outage for an annual reliability cost of $1,499,000 per year.[39] The Company provided reliability performance data associated with this project for 2015-2019, but did not identify the dates or causes of outages, nor does its assessment account for reliability performance benefits achieved as a result of the 2018, 2019, 2020, and 2021 reliability improvement investments. The Company asserts that the ATS project could potentially impact up to 278 customers.

Q. Does the $1.5 million annual O&M cost for service restoration of up to 278 customers seem out of proportion to the number of customers affected?

A. Yes. Evidently, there are (or were) major reliability issues related to this portion of the Company's distribution system. These issues bring into question the level of the Company's forestry work on the Neeley and Gun Lake feeders and whether the Company could have in past years (or whether its recent reliability projects have already) reduced service restoration O&M through more aggressive tree trimming. This may be significant in that the Company's estimated annual reliability penalty of $1,499,000 does not appear to have incorporated the substantial reliability improvements such as the Gun Lake 46 kV

[37] *Id.*

[38] Ex MEC-25 (MEC-CE-1057(e)).

[39] *Id.* (Revised Concept Approval, Reliability Improvement Penalty).

rebuild, forestry line clearing, etc. that have been implemented in the near term. I would be hard pressed to accept that subsequent to such near-term reliability efforts related to these feeders, that the Company will incur $1.5 million per year in reliability O&M. Despite the lack of support for its projected annual reliability expenses incorporated into the cost/benefit analysis, it does appear reasonable that ATS would enable some degree of additional improvement to the challenging power restoration issues the Company faces on these feeders. However, the overstatement of reliability improvements may result in an overstatement of the present value of revenue requirements of the traditional upgrade with ATS (Alternative 1), as the projected annual reliability O&M costs are incorporated as a penalty.

Q. Please explain in more detail the reliability improvements associated with the BESS pilot.

A. The Company has determined that automatic load transfers between the Neeley and Gun Lake feeders would provide a pathway to <u>eliminate</u> recurring customer outages on the lines. The lines currently have insufficient capacity to allow for the installation of ATS devices. According to the Company, the BESS project (with ATS) will allow power transfers between circuits subsequent to 2022, five years before cumulative load growth on the circuits requires substation and feeder upgrades and ATS (2027) to be completed. Those upgrades are required even if the BESS pilot is implemented, although they would be deferred until 2031 through 3033 timeframe. It is important to note that the upgrades completed in 2027 (Alternative 1) would also allow for ATS equipment to be installed and allow for power transfers between circuits subsequent to 2027. The point is that automatic load transfers between feeders do not require a battery if the lines have sufficient capacity to accommodate ATS, something the reconductoring and substation upgrade would accomplish. Thus, the main economic benefit of the Li-Ion BESS pilot vis-à-vis the 2027 upgrade-only option is 5 years earlier outage reduction.

Q. **What is the core basis that the Company relies upon to support its request for approval of the Li-Ion BESS pilot?**

A. Three core reasons: (1) that 5 years of reliability O&M savings offset the direct capital cost of the pilot, (in the amount of $5,365,000 on a NPV basis; (2) that distribution upgrades are deferred from 2027 to 2033, at a NPV of $1,342,000; and (3) that the lower-cost option precludes the Company from learning about long duration battery-storage and how to forecast the dispatch of such long-duration batteries, which CE asserts will be needed for the coming renewable energy expansion. These are clearly the core reasonings for moving forward with the pilot. However, there is an even better approach.

Q. **What is that alternate approach?**

A. With respect to Alternative 1, move the timeline of capacity upgrades/ATS from 2027 up to 2022 and altogether eliminate the need for a battery to accommodate ATS. In this manner, ATS could be installed in 2022, the same timeframe as in the Li-Ion BESS pilot (Alternative 2). This removes the five-year reliability penalty from Alternative 1, making it significantly more cost effective. The significance of this new alternative, which I am denoting as **Alternative 4**, is that automatic load transfers between feeders do not require a battery if the lines have sufficient capacity to accommodate ATS, something the reconductoring and substation upgrade would accomplish if moved forward by five years to 2022.

Q. **Have you calculated the NPV of this new alternative, Alternative 4?**

A. Yes. The present value of the revenue requirements of Alternative 4 is equal to the present value of the revenue requirements of Alternative 1, of $10,482,000, less the estimated present value of O&M savings due to 5 years earlier reliability improvement of $ 5,365,000,[40] plus the cost of forfeited capacity upgrade deferrals from 2022 to 2027, which I estimated at $1,021,000.[41] The resulting present value of the revenue requirements of Alternative 4 is $6,138,000. The resulting NPV of the Li-Ion BESS pilot is a negative $5,316,000 ($6,138,000-$11,454,000), if Alternative 4 is considered the low-cost option. The break-even present value of the Li-Ion BESS pilot is thus $ 6,138,000. Multiplying that The Commission is thus faced with a difficult policy decision if the Company moves forward with the Li-Ion BESS alternative. The question then facing the Commission is to establish the reasonable allowed rate base, **Alternative 4** provides an equivalent quality of service as in the Company's choice of Alternative 2, the Li-Ion BESS pilot, at a cost savings of $5,316,000 on NPV basis.

Q **What is your recommendation regarding Commission approval of the Company's Neeley and Gun Lake Li-Ion BESS pilot?**

A. I recommend the Commission reject this project on two alternative bases. First, the Company changed this project on June 14, 2021, just about a week before I am filing this testimony. The Company changed the type of battery this project would use. The Company's original Concept Approval for this project specifically *rejected* using a li-ion

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[40] Ex MEC-25, p. 17 (Revised Concept Approval, p. 15).

[41] Ex MEC-40 (NPV calculation).

battery on the basis such batteries “have relatively short lifetimes, require strict depth-of-discharge and state-of-charge controls to suppress degradation, and need constant temperature monitoring for safe operation.”[42] The Company revised the project on June 14, 2021, potentially in response to discovery inquiry into the economics of this project, to change the type of battery to be employed. This late change in the project suggests the Company is not entirely certain as to how it will proceed with this project. The Commission should not approve rate recovery for a project that appears to be in flux.

The Commission should reject this project for the additional reason that there is a more cost effective and reasonable approach (Alternative 4), which the Company failed to consider. It is acknowledged that the Company’s claimed existence of extraordinary reliability costs (penalty) with the Neeley and Gun Lake adjacent feeders radically improve the BESS economics. Unfortunately, those same cost savings equally impact the comparative economics of advancing the timeline of required upgrades/ATS from completion in 2027 to 2022, thus neutralizing the proposed pilot benefits associated with reliability improvements. I recommend that the Commission disallow this pilot, as the Company failed support the reasonableness of the project, particularly in light of recent reliability investments at this location. In addition, the Company failed to consider a significantly lower-cost alternative of advancing an otherwise required capacity upgrade (with installation of ATS) from 2027 to 2022, allowing for the avoidance of substantial O&M reliability costs equivalent to the proposed Li-Ion BESS pilot. The NPV of the reliability savings is $5,365,000. Given the massive increases in distribution capital

[42] Ex MEC-26, p. 6 (original Concept Approval, p. 2).

spending in the bridge and projected test-year, it would not be in the public interest, in my opinion, for the Commission to approve the proposed Neeley and Gun Lake redux flow-battery pilot.

C. Distributed Energy Resource Management Solutions (DERMS)

Q. According to Mr. Blumenstock, the Company seeks $1.191 million for its test year DERMS investment. Noting that the Commission rejected early deployment of DERMS in the prior rate case, should the Commission approve the proposed DERMS deployment at this time?[43]

A. No. The Company has not justified early deployment of DERMS.

Q. Why is that?

A. The Commission should look at the core reasons that Company is proposing early deployment. First, the Company claims that if DERMS does not move forward in the projected test-year, then the Company will fail to have ability to manage the Company's expected near-term acceleration in new DERs.[44] However, the Company has no idea of timing of DER deployments and has made no effort to forecast the various segments of DER (such as customer sited, utility owned, or third party).[45] This fact alone is sufficient evidence for the Commission to confirm its prior disallowance of DERMS as the Company's claimed need to manage a surge in DER is without support.

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[43] Blumenstock Direct, pp. 159-162, 168; Ex A-35, lines 15 and 16.

[44] Ex MEC-22 (MEC-CE-476, 477).

[45] *Id.* (MEC-CE-476).

Secondly, the Company asserts that "Even when DER penetration is relatively low, DERMS allows for dynamic discovery and coordination of DER's on the system" and that even in early stages of this phase-in, DER can deliver benefits.[46] It is true that the Company currently has a very low level of customer-sited renewable generation on its DG tariffs. The Company virtually guarantees continuation of relatively low levels as it has self-imposed a low cap on participation in the DG program, thus limiting future growth. The alternative of a PURPA contract in lieu of a standard DG tariff is not a realistic alternative for most residential or commercial customers, again limiting their future participation in DER. In addition, new customers on the Company's DG tariff, or new DER associated with third-party generators wanting to connect to the Company's distribution system, would be known to the Company as they are required to enter into an interconnection agreement with the Company. Any new Company-owned DER is self-evident. Although the Company notes that early deployment of DERMS can deliver benefits, the Company has not quantified those benefits. These factors conflict with the Company's perceived need for early deployment.

In my opinion, at a minimum, prior to requesting approval for a DERMS project, the Company should: (1) undertake an extensive forecast of all segments of new DER, thus verifying the timing and quantity of any surge in DER, (2) voluntarily eliminate the cap on DER participation in the Company's DG program, and (3) conduct a benefit cost analysis, and demonstrate that early deployment is justified.

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[46] *Id.* (MEC-CE-477(b)).

Q. Are there other reasons why early deployment of DERMS is not justified by the Company?

A. Yes. The Company has indicated that DERMS is not necessary for controlling the proposed Home Battery Pilot.[47] Noting that the Home Battery Pilot is being proposed at a level of 2,000 participants, this is evidence that DERMS is not a pre-requisite for controlling battery resources and additional confirmation that early deployment is premature. The bottom line is that the Commission rejected DERMS in the last rate case, little has changed in the interim, so the Commission should reaffirm that decision in this case.

D. <u>Continuous Distribution System Monitoring</u>

Q. Have you raised concerns about the Company's approach to planning for reliability?

A. Yes. In Consumers' prior rate case, on behalf of MNSC, I testified regarding the need for additional distribution system monitoring in lieu of aggressive replacement of distribution assets based primarily on age, rather than condition.[48] Mr. Blumenstock claimed that the Company is already doing everything possible with respect to monitoring:

> I have explained, in my direct testimony, how the Company already engages in various inspection regimes to identify assets at risk of imminent failure – see, for example, page 171, line 13, through page 174, line 5; page 178, line 1, through page 180, line 6; and page 186, line 1, through page 188, line 15.[49] Through these existing inspections, the Company has already identified assets at risk of imminent failure, and the Company is proposing to address these imminent failures through its projected $95,497,000 in investments in Rehabilitation in 2021. ***Since existing monitoring has***

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[47] *Id.* (MEC-CE-477(k)).

[48] Case No. U-20697, Ozar Direct, 8 TR 3658-59, 3662.

[49] Identical testimony is found in this case: U-20967 pages 171-174 (6 TR 1194-1198) = U-20963 pages 188-191; U-20697 page 178-180 (6 TR 1201-1203) = U-20963 pages 196-198; U-20697 page 186-188 (6 TR 1209-1211) = U-20963 pages 204-206).

> ***already identified these assets at risk of imminent failure, it is not clear how even more monitoring would suddenly allow these projects to now be deferred without simply increasing the risk of actual failure.*** Instead, further increases to monitoring will likely result in even more specific examples of asset deterioration being identified, generating even more potential cases of imminent failure.[50]

This specific issue was not resolved in the final order in U-20697.

Q. Have you revisited the issue of the Company's approach to monitoring to anticipate reliability issues in this proceeding?

A. I attempted to better understand Consumer's distribution system condition monitoring in the instant proceeding. Unfortunately, I obtained little information of value, despite numerous discovery attempts on this topic.[51] For instance, when asked a critical question about the Company's ability to detect "incipient failures," the Company responded that "incipient" is not a term that the Company uses.[52] The only information of value that I was able to obtain is the absence of any <u>continuous</u> asset condition monitoring of the Company's HVD or LVD lines.[53] Based upon the Company's collective responses to discovery, it appears that the Company has no present interest in monitoring technologies capable of detecting incipient adverse conditions on its distribution system.

[50] Case No. U-20697, Blumenstock Rebuttal, 6 TR 1348-49 (emphasis added).

[51] Ex MEC-27 (MEC-CE-478, 479, 877).

[52] *Id.* (MEC-CE-877).

[53] *Id.* (MEC-CE-877(c)).

Q. **What is the value of adding a continuous distribution monitoring system to the Company's toolbox?**

A. Mr. Blumenstock summarized Consumers' existing distribution system monitoring tools:

> The Company undertakes … four key inspection programs to help inform of potential actions to address lines failures. These proactive replacements are more economical, safer, and can save customer outage minutes compared to waiting for an actual failure. The four key HVD lines inspection programs informing the HVD Lines and Substations Rehabilitation sub-program are: (i) pole inspections; (ii) helicopter inspections; (iii) biannual ground patrols; and (iv) MOABS testing. (Blumenstock Direct, p. 188.)

I acknowledge that these monitoring actions clearly constitute important reliability tools for the Company. Incipient adverse conditions of the distribution system that may result in a fault can be identified at the time of such monitoring.[54] For example, a helicopter flyover with a corona camera could identify a failing distribution asset. However, because the Company's distribution system monitoring occurs on a scheduled basis, with <u>significant</u> time periods in between asset evaluations, it has an obvious inherent limitation. It is incapable of flagging incipient adverse conditions that occur in the interim between the scheduled monitoring. Decreasing the timespan between scheduled monitoring, under this paradigm, could improve asset evaluation but cannot eliminate this limitation. Moreover, continuous monitoring using Company crews under the current monitoring paradigm would be unthinkably costly. The Company admits that faults occur in those interim

[54] Ex MEC-29 (Incipient Conditions on Electric Power Circuits).

periods.[55] An advanced continuous distribution monitoring system mitigates this limitation because it monitors the system instantaneously.[56]

Q. **Witness Blumenstock (page 168, Figure 445) indicates the Company's intent to invest $5,710,000 in line sensors in 2022. Would those line sensors provide the same functionality as the advanced continuous asset monitoring systems you have been discussing?**

A. No. The primary purpose of those line sensors is to optimize the determination of fault locations. They are strategically located to divide circuits into approximate 1-to-2-mile zones for this purpose, although there are other applications.[57] Traditional line sensors are used for locating faults after the fact, not to anticipate adverse conditions that may result in a future fault or system failure.

Q. **Do you have an example of available continuous monitoring technology?**

A. Yes. Researchers at Texas A&M University have developed a continuous distribution monitoring technology that utilizes machine learning, called *Distribution Fault Anticipation* Technology (DFA).[58] This DFA technology was funded by the Electric Power Research Institute (EPRI), and the researchers worked with EPRI and the industry for 20 years to implement real-time monitoring on more than 100 distribution circuits. The basic concept of DFA technology is that software embedded in DFA system reports identify

[55] Ex MEC-27 (MEC-CE-877).

[56] Ex MEC-29 (Incipient Conditions on Electric Power Circuits); Ex MEC-30 (DFA Presentation).

[57] Ex MEC-28 (MEC-CE-527).

[58] Ex MEC-30 (DFA Technology Presentation & Texas Case Studies).

events that may persist for weeks ahead of an event, but which convention technology ignores.[59]

Several Texas electric utilities participated in the Texas Powerline-Caused Wildfire Mitigation project to test and document the potential reliability and safety benefits of DFA technology.[60] Notably, as reported in the utility case studies, participating utilities tested DFA technology on long, rural circuits, and involved conditions influenced by weather (wind and moisture). For example, the Pedernales Electric Cooperative manages 22,000 miles of primary lines in a rural area covering 8,100 square miles in central Texas.[61] This utility showed that DFA technology, in combination with existing AMI technology, detected a tree branch on a 153-mile rural primary line. Mid-South Synergy tested DFA technology on a 103-mile rural line, which identified unusual but similar momentary trips repeated a day apart, leading personnel to diagnose a line conductor displaced from its normal position on the insulator and lying on its crossarm.[62] Combining DFA with existing circuit model software and remote polling allowed the utility to avoid an outage and a potential fire.

This is a state-of-the-art technology that has the potential to detect adverse conditions, including as follows:

[59] *Id.* at p. 5 (DFA Presentation).

[60] *Id.* at p. 6, 20-22.

[61] *Id.* at pp. 25, 34-40.

[62] *Id.* at p. 27.

- Detect and repair a substantial number of routine outages, without customer calls.
- Detect and locate tree branch hanging on line and causing intermittent faults.
- Detect and locate intact tree intermittently pushing conductors together
- Detect and locate broken insulator that resulted in conductor lying on and heavily charring a wooden crossarm.
- Detect and locate catastrophically failed lightning arrester.
- Detect and locate arc-tracked capacitor fuse barrel.
- Detect and locate multiple problems involving capacitor banks.[63]

It is notable that this technology not only has the potential to identify a fault before an outage event occurs, but it has the potential to identify "upstream" conditions that may cause "downstream" events. As a result, where traditional corrective action may address the manifest cause of an event (*e.g.*, broken conductor), DFA technology has the ability to detect underlying conditions and provide proactive repairs.

Further details about DFA technology are in Exhibit MEC-31, which contains the DFA technology manual, Frequently Asked Questions about DFA, and DFA tutorials.[64] In addition, I communicated with one of the creators of DFA, Dr. Carl L. Benner, who expressed an interest in participating in a Michigan pilot.

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[63] *Id.* at p 6.

[64] See also *Mid-South DFA presentation at 2019 Annual Membership Meeting* (July 8, 2019), available at https://www.youtube.com/watch?v=nrb42Hmvh0g, last checked June 22, 2021; KETK, *Tool Developed in Texas to predict power failures now being tasted in California to prevent wildfire* (Dec. 17, 2019), available at https://www.youtube.com/watch?v=7nG1vjuWdps, last checked June 22, 2021.

Q. **Are proactive replacements or repairs advantageous to waiting for an actual failure?**

A. Absolutely. The Company acknowledges that proactive replacements are more economical, safer, and can save customer outage minutes compared to waiting for an actual failure. (Blumenstock Direct, p. 188).

Q. **Is there a connection between distribution system monitoring/assessment and the level of distribution asset replacement and rehabilitation programs**?

A. Yes. The Company acknowledges that system monitoring, and replacement and rehabilitation programs are intrinsically connected. For example, witness Blumenstock states: "The LVD Lines Rehabilitation sub-program includes capital repair or replacement of LVD lines equipment that has not actually failed, but that has been assessed to be at risk of failure in the near term."[65] By assessment, the Company has in mind monitoring programs such as six-year cycle overhead line assessments: "The overhead line inspection category evaluates all equipment on a structure, including the pole, through a visual inspection process. The circuits are assessed by completing driving inspections to identify public safety hazards along with failed, end-of-life, defective, and obsolete equipment."[66] In addition, the Company made clear again in this case, as it did in its prior rate case, U-20697, that replacement and rehabilitation programs are substantially driven by lifecycle data.[67] What the Company is missing, in my opinion, is the refinement in replacement or

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[65] Blumenstock Direct, p. 203.

[66] *Id.,* p. 204.

[67] *Id.* at 22-23. As shown in Concept Approvals supporting the Company's specific reliability distribution projects in this case, the Company uniformly captures the date equipment was installed, though Concept Approvals rarely capture details regarding outage causes and duration. See Ex MEC-26 (Attachment 126); Ex MEC-32 (MEC-CE-880, Attachment 2 - Concept Approvals).

rehabilitation programs, and thus potential cost reductions in those programs, and the mitigation of outages made available by implementation of continuous distribution asset monitoring technologies.

Q. **What are your recommendations with respect to continuous distribution system monitoring?**

A. State-of-the-art continuous distribution monitoring technologies have potential to enhance the Company's ability to make proactive replacements or repairs, to improve reliability, improve safety, reduce costs, and to improve distribution asset replacement strategies. The Company proposes significant investments in distribution Reliability projects in particular, both in recent rate cases and in this case, and that trend is likely be repeated in future rate case distribution system capital spending requests. As a result, it befits the Company and its ratepayers to integrate a concerted fault investigation into its repertoire of technology investments, and to fully investigate their potential application to the Company's distribution system.

I recommend that the Commission direct the Company to undertake a comprehensive investigation into available continuous distribution monitoring technologies and file a report on such investigations, within six months in this docket. This report should include, among others the Company may identify, the DFA technology, provide a thorough cost and benefit analysis, and include at least one pilot project proposal to test integration of this technology. It is critically important to begin immediately to investment and implement continuous monitoring to identify incipient conditions, particularly considering the magnitude of year-over-year increases the Company is requesting for asset replacements and the potential to further improve asset replacement strategies and thus control escalating costs.

E. HVD Line Rebuild for Non-Standard Construction Lines

Q. Do you have any recommendations regarding the Company's proposed HVD Line Rebuild subprogram?

A. Yes. The Company is requesting approximately $46 million in HVD line rebuilds in the 2020. Ex A-48, p. 5, lines 30-60 and p. 6, lines 1-8. I reviewed the Concept Approval for each of these projects, and I have several recommendations related to test-year HVD Line Rebuilds, particularly for "non-standard construction" lines, as well as for future rate cases.

Q. Why did you review each HVD Line Rebuilds project Concept Approval?

A. This is a notably costly spending category, so careful scrutiny of the proposed projects is warranted. HVD Line Rebuild is part of HVD Line Reliability, the single largest category of Reliability spending in the test year. (Ex A-35). After New Business LVD Lines, HVD Lines Reliability is the Company's single most costly subprogram for test year distribution system capital spending, consistent with the bridge year. Moreover, HVD Lines Reliability accounts for the single largest increase in 2022 distribution system spending over historic 5-year spending. HVD Line Rebuilds comprise $46 million of the $78 million for HVD Lines Reliability in 2022. (Ex A-48, pp. 5-6). HVD Line Rebuilds comprise 12 of the 25 most expensive distribution projects in 2022.[68]

[68] Ex MEC-26 (Attachment 126).

Q. Did you observe any patterns in the Concept Approvals for the Company's proposed 2022 HVD Lines Rebuilds projects?

A. Yes. I observed that, of the 29 HVD Line Rebuild projects proposed for 2022, many involved rebuilding line segments that are "non-standard construction."[69] Seventeen of these projects, and information from their corresponding Concept Approvals and Company-provided outage data, are identified in Exhibit MEC-38. The Company justified many of these "non-standard construction" rebuild projects with the following near-identical language in each:

> HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages.[70]

The Company further justified many of these rebuild projects by replicating a table purportedly showing that line rebuilds reduce outages to zero.[71] Mr. Blumenstock discusses the same table in his testimony. He asserts that HVD line rebuilds "substantially improve the performance of the line," and his testimony refers to the table, which is labeled "Impacts of Line Rebuilds on Outages."[72] According to Mr. Blumenstock, Figure 42 shows that "after completing a rebuild for which line outages were a factor driving the need for the

[69] *Id.*; Ex MEC-32 (MEC-CE-880, Attachment 2 – Concept Approvals).

[70] Ex MEC-26, p. 308 (Shelby Concept Approval, p. 308 of 312); see also *id.* at pp. 76 (Remus), 84 (Wirtz), 101 (Big Rapids), 139 (Nashville), 154 (Hodenpyl), 167 (Wayland), 213 (Morrice); see also Ex MEC-32, pp. 13 (Union City), 17 (Union City 2), 27 (Hammond), 42 (Cooper).

[71] See, e.g., Ex MEC-26, pp. 74 (Remus), 82 (Wirtz), 99 (Big Rapids).

[72] Blumenstock Direct, p. 141, Fig. 42.

rebuild, a line section typically experiences zero or minimal line equipment-related outages."[73] Figure 42 shows there were some outages before and no outages for 3 to 8 years after line rebuilds.[74] Figure 42 does not identify the duration, frequency or cause of outages, number of customers benefited, nor the project cost. Nor did the Company provide this information in discovery.[75]

Q. Do you disagree that HVD line rebuilds reduce outages?

I have no doubt that rebuilding lines – whether HVD or LVD, standard or non-standard – may reduce or eliminate most outages for at least 3 to 8 years, as shown in Figure 42. There are many causes of HVD line outages, and line rebuilding is likely to eliminate many causes for some period of time after the rebuild. But it does not necessarily follow that line rebuilding is cost effective. Tree trimming, pole replacement, or line rehabilitation may achieve similar outage reductions for substantially lower costs. It should be noted that HVD line reliability projects include line clearing forestry as part of the capital investment.[76] The Company incurred over $1.5 million in capital line clearing for HVD projects in 2019 and nearly $1.8 million in 2018.[77] Evaluating outages before and after selected tree trimming projects may demonstrate similar outage reduction statistics during a 3-8 year period.

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[73] *Id.* at p. 140.

[74] *Id.*

[75] Ex MEC-33 (MEC-CE-882).

[76] Blumenstock Direct, p. 130; Ex MEC-36 (MEC-CE-881).

[77] Ex MEC-36 (MEC-CE-881, Attachment 1). It is unclear if 2018 and 2019 HVD line clearing capital costs include costs for Company employees. See *id*, at MEC-CE-881(c).

Q. Has the Company provided sufficient project-specific justification for each of the 17 HVD Line Rebuild non-standard construction identified in Exhibit MEC-38?

A. No. The Concept Approvals for these 17 projects do not provide enough project-specific information about the line to assess the reasonableness of the decision to rebuild.[78] These Concept Approvals identify the year the line was constructed, the number of outage incidents (events) during a historic period, and repeat the generic assertion that rebuilding the line will reduce outages. They do not provide the frequency or duration of outages, nor number of customers affected, which impact the potential SAIDI, CAIDI, and SAIFI benefits of the project. Nor do the Concept Approvals identify the cause of outages.

The Company provided additional information about the number of customers, and outage duration and causes for these line segments in discovery.[79] This information, which is captured in Exhibit MEC-38, shows that the cause of many outages is apparently unrelated to non-standard construction: trees, third-party damages (*e.g.*, car accident), poles, cross-arms, substation equipment, transmission. It should be noted that the outage data provided in discovery does not correlate the location on the line that experienced the outage events with the section of line proposed for rebuild.[80]

For outages identified as caused by conductors and insulators, there is no basis to ascertain whether "non-standard construction" contributed to the outage, or whether there was some other underlying cause. Nor is there any indication that conductor and insulator outages

[78] Ex MEC-26, 32 (Concept Approvals).

[79] Ex MEC-32 (MEC-CE-880, Attachment 1).

[80] *Id.*

were more frequent or longer than outages with other causes. In sum, there is no information to support the conclusion that rebuilding the line will reduce the number of outages.

Several projects identify no outage caused by issues potentially connected to the non-standard line construction – *i.e.*, conductor, insulator or lightning.[81] Wirtz Road is a proposed $3.9 million line rebuild. The Company identified that there are poles in need of replacement, with a projected repair cost of $311,000. Of the 4 outages on the Wirtz Road line, each was caused by an issue *other than* line equipment: substation equipment, trees, and third-party damages. The Hammond line rebuild comes in at a cost of $3.1 million. The Company rejected an alternative $568,000 pole top rehabilitation project for this line segment because "Rebuild of this line is needed to improve overall system reliability and for the approximately 4,400 customers served from the Hammond Rd 46 kV line." Yet for the 8 outages on this line segment since 2011, *all* were caused by third party damage or trees. Rebuilding this line does not appear to address the historic causes of historic outages for customers on this line. For the Cooper line rebuild, the Company justified the $279,000 rebuild over the $127,000 pole replacements because "outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages." Yet this is a line that has *no* history of outages.

For other projects, the available information indicates that tree trimming improvements should be implemented ahead of line rebuilding. The Goodale line, which the Company proposes to rebuild for $1.3 million, is among the worst performing HVD lines by SAIDI.

[81] Blumenstock Direct, p. 136. See Ex MEC-38 for citations for each project.

However, the outage data for this line, which serves 10,152 customers, shows trees are the major outage cause, contributing 1,181 outage minutes, followed by pole (550 outage minutes), then third-party damage (388 minutes), and finally insulator (253 minutes). There is no indication of consideration of a forestry fix instead of a line rebuild.

The record further suggests there is not an urgency to rebuild these "non-standard" line segments. The Wayland line, projected to cost $4.5 million, is justified on the basis it will "improve overall system reliability and for approximately 8000 customers served from the Wayland 46 kV line." The Company record identifies 2 historic outages, in 2013 and 2016, caused by an insulator and trees. This line has apparently operated without an outage for 5 years. The Union City rebuild has a similar narrative. The Company proposes to rebuild 2 segments of the Union City line, with a combined cost of $6.7 million, both justified on the identical basis as Wayland. Yet the Company identified no outage on these line segments since a 36-minute outage in 2013, and one prior in 2011. The Company rejected a $1.1 million pole replacement alternative for one of the 2 Union City segments.

Q. Did the Company fully consider alternatives to line rebuilding for the non-standard construction projects identified in Exhibit MEC-38?

Not according to the project Concept Approvals. For some sections of lines, the Company identified poles in need of replacement through inspection programs, and identified pole rehabilitation as an alternative to line rebuild, with substantial cost savings.[82] Yet in each case, the Company decided to rebuild rather than rehabilitate the line segment. While the Company identifies non-standard construction lines as "candidates" for rebuild rather than

[82] Ex MEC-38, *e.g.*, Wirtz Road, Shelby, Union City 2.

rehabilitation, in practice, none of the non-standard lines were successful candidates for lower-cost rehabilitation.[83] It appears the Company is reflexing pursuing the higher-cost rebuild alternative for each segment.

This approach, where the Company inspects a line and identifies poles rehabilitation remedies but automatically adopts the line rebuild alternative, illustrates inefficiencies and waste in the Company's line inspection approach, and further raises the question as to the efficacity and value of the Company's current system monitoring approach, as discussed above.

In addition, none of the Concept Approvals discuss line clearing activities – historic and proposed – along the line segments proposed to be rebuilt in 2022. Line clearing can be effective at improving performance (reducing outages) at a fraction of the cost of line rebuilding. Given the evidence that trees caused a disproportionate number of the historic outages at these line segments, the Concept Approvals should identify recent line clearing to ascertain whether the line clearing is effective to address outages.

Q. Has the Company supported the reasonableness of each of the proposed HVD Line Rebuild projects shown in Exhibit MEC-38?

A. No. The Company has failed to demonstrate that it undertook a reasonable line-specific assessment of the actual causes and potential benefits of rebuilding each of these projects. The Company has apparently made a policy choice to rebuild rather than rehabilitate HVD lines as part of the HVD Lines Reliability subprogram whenever the Company identifies

[83] Ex MEC-33 (MEC-CE-1058(c)).

"non-standard construction." Line rebuilding is exponentially more costly than rehabilitation.[84] The Company has done even less to assess line clearing as a potential remedy to improve reliability along these lines. Although the Company claims these lines have higher outage rates, their data does not bear this out. The Company has disregarded or failed to integrate into its decision-making reasonable consideration of inspection data, line-clearing historic activities and potential alternative remedies, assessment of the underlying causes of outages along these line segments. Instead, the Company has relied on the generic conclusion that non-standard lines must be reconstructed.

More particularly, the Company proposed "rebuild instead of rehabilitation" projects for 4 line segments with 1 or fewer outages in the past five years: Shelby, Union City, Hodenpyl, and Cooper. These rebuild projects should be disallowed and replaced by much less expensive rehabilitation projects that the Company rejected. This is an example of gold plating with respect to distribution investments. The cost of a rebuild versus rehabilitation for each is as follows:

1. Shelby: $3,942,000 (rebuild) versus $507.000 (rehabilitate)

2. Union City: $ 6,705,000 (rebuild) versus $1,100,000 (pole replacement)

3. Hodenpyl: $3,005,000 (rebuild) versus $432,000 (rehabilitation)

4. Cooper: $279,000 (rebuild) versus $127,000 (pole top replacement)

[84] Blumenstock Direct, p. 137, Fig. 41.

Absent further project-specific justification supporting the conclusion that it is necessary and cost-effective to rebuild each line, the Company has not met its burden to support the reasonableness of these proposed test year investments.

The Company did not identify an alternative for the Wayland rebuild, which has similarly experienced a single outage in the last 5 years. This $4.5 million rebuild project should be deferred until the Company has evaluated lower-cost alternatives for this line.

The Company also has not supported its rebuild decision for projects where there is no evidence that non-standard construction has caused or contributed to an outage on the line segment, as discussed above. These include Wirtz ($3.9 million); Hammond ($3.1 million); and Cooper ($279,000). These are total project costs; 2022 spending for each project is identified in Exhibit MEC-38 and Exhibit A-48, pages 5-6.

Q. Do you have any additional recommendations related to HVD Line Rebuild projects?

A. Yes. Based upon the Shelby and other 16 projects discussed above, and upon the Company's strategic objective to expand investment opportunities in its distribution system (as illustrated in my policy comments at the beginning of my direct testimony), the Commission should be concerned that the Company may have a bias toward high-cost line rebuilds in place of lower-cost line rehabilitation. I am recommending that the Commission order the Company to provide project-specific justification for each HVD line rebuild project in the next rate case, including: (1) line-specific justification for "rebuild instead of rehabilitate"; (2) the number of customers on each line; (3) the outage history for the past five years; (4) the projected improvements in reliability indices for the rebuild and rehabilitate options; (5) the cost differential for each approach; and (6) bids from alternative suppliers for capital and labor.

In addition, and as further discussed above, there is a potential to integrate DFA technology (or similar tools) into existing monitoring and technology capabilities, to identify faults and the underlying causes of events along these lines. As discussed above, the Commission should require Consumers to institute a pilot program to ascertain the opportunity to further improve reliability outcomes at lower costs for ratepayers by capitalizing on technology opportunities rather than automatically defaulting to rebuilding non-standard lines.

III. SERVICE RESTORATION O&M

Q. What is your recommendation regarding the appropriate level of service restoration costs to include in the 2022 projected test-year?

A. I recommend that the Commission reject the Company's proposed service restoration cost of $74,358,592 based on a 3-year average (of 2018 through 2020 actual costs) escalated for 2021 and 2022 inflation, and approve a level of $64,400,000 based on a 5-year arithmetic average of storm restoration costs, with 2016 through 2019 costs adjusted for inflation through 2020[85] and inflation through 2022 offset by cost reductions associated with line clearing and reliability improvements.

[85] Ex MEC-35 (AG-CE-867).

I am also recommending that the Commission reject the Company's request for a 10-year amortization at the Company's overall rate of return, and instead approve a 3-year amortization, at the Company's short-term borrowing rate.

Lastly, because the recommended level of expenses is intended to be a reasonable estimate, that is neither deliberately high (nor low), I recommend that the Commission not approve the Company's requested non-symmetrical deferred recovery mechanism. Instead, to the extent the Commission finds unacceptable risk that test year spending will result in unexpected, excessive and unavoidable costs, then the Commission may authorize a simple symmetrical, regulatory-liability/regulatory-asset deferral mechanism. The overall recommendation puts both the Company and its customers on a level playing field.

Q. What is the basis for your recommended five-year average of historical storm restoration costs?

A. The five-year average better recognizes the significant variability in year-to-year data than a three-year average, particularly considering the 2019 outlier. This is the approach that the Commission approved in the Company's prior rate case, Case No. U-20697, with two differences. In the prior case, the Commission approved an unadjusted historical average, as that was proposed by multiple intervenors to the proceeding, including myself (representing MNSC). I improved the accuracy of the methodology by including an inflation adjustment within the five-year historical time span. Additionally, I agree with the Company that it is appropriate to make an inflation adjustment for 2021 and 2022. However, that adjustment must be offset by cost reductions associated with line clearing and capex reliability improvements to service restoration costs.

Q. **What inflation rate did you use?**

A. For the years 2016 through 2019, and 2021 and 2022, I used a fixed annual inflation rate of 3.2% for Exempt Labor, Non-exempt Labor and Other Labor; and 3% for OM&C Labor. These fixed rates are the same as were applied by the Company to escalate its proposed 3-year average of these cost categories from 2020 to 2022.[86] With respect to Contractor Costs, Material, and Other Expense, I used the annual Consumer Price Index (CPI) for each year. I applied such rates on a compound annual basis to escalate the actual costs within the five-year period. In this way, I obtained a obtained a more consistent average, since all costs were scaled to a 2020 cost basis. The resulting 2020 cost components (5-year average cost basis) were escalated by the appropriate inflation rate for 2021, whereupon estimated 2021 service restoration savings associated with line-clearing[87] and reliability improvements were subtracted from the aggregate cost. The resulting 2021 cost components were escalated by 2022 inflation rates and again estimated 2022 service restoration savings associated with line-clearing and reliability improvements were subtracted from the aggregate cost.[88]

Q. **Why are service restoration savings associated with the Company's expanded line clearing efforts and reliability investments included as an offset to inflation related cost increases?**

A. A clear offset to inflation that must be recognized is related to the likely improvements in both SAIDI and SAIFI that should be occurring considering the substantial expenditures

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[86] Ex MEC-35 (AG-CE-867).

[87] Bolden Direct, p. 27.

[88] Ex MEC-39 (Storm Restoration Cost Calculation).

in distribution reliability assets, and grid modernization, and the especially the increasing levels of forestry work that the Commission has approved in the prior rate case (2021 test-year) and that the Company is requesting in this rate case (2022 test-year). These improvements are not embedded in the historical service restoration costs and must be recognized in calculating the 2021 bridge year and 2022 test-year service restoration costs.

Q. How did you estimate the 2021 and 2022 service restoration savings associated with line clearing and reliability capital improvements?

A. The Company quantified the service restoration savings associated with the requested level of line clearing in 2021 ($380,000) and 2022 ($1,000,000)[89] and I incorporated these estimates in my calculations. The Company did not provide an estimated service restoration saving related to its expenditures in distribution reliability assets or grid modernization. Since forestry expenditures normally result in the majority of improvements in the Company's reliability indices, but in light of the level of spending in capital related reliability programs during 2021 and projected for 2022, I assumed that the resulting reliability improvements yield service restoration savings at one-half of the level of service restoration cost savings that the Company estimated for line clearing.

Q. Will the Company be fully compensated for actual 2022 service restoration costs under the MNSC's proposal; and if so where is the incentive for the utility to control cost increases?

A. The Company will be fully compensated to the extent deferred actual costs are deemed reasonable and prudent in subsequent rate cases. However, evaluating the reasonableness

[89] Bolden Direct, pp. 26-27.

and prudence of incurred service restoration costs is an extremely difficult endeavor on the part of the Commission, its Staff, or intervenors. For, example, in the prior Consumers Energy electric rate case, the Commission approved a five-year average of service restoration costs without any evaluation or adjustment for unreasonable or imprudent expenses. I am not aware of the Commission disallowing recovery of any portion of the Company's deferred service restoration costs in past years. This is an area that needs further investigation and analysis, and where a Performance Based Ratemaking (PBR) mechanism may have value. and for this reason, I recommend that the Commission require the Company to file a service restoration PBR proposal in its next rate case.

Q. Why should the Commission approve a three-year amortization period at the Company's short-term borrowing rate, rather than a ten-year period at the Company's overall rate of return?

A. A ten-year amortization period is too long. Service restoration is an O&M expense like maintenance on a company vehicle *e.g.*, fixing a tire or a battery repair. The proposed ten-year amortization at the authorized rate of return essentially makes this O&M expense a profit center for the Company. It is inappropriate for the Company to be earning profits on service restoration costs, considering that no performance standards have been established (as would occur in a PBR mechanism). The excessive amortization period also creates issues of customer inter-generational inequity as new customers many years out into the future would be required to bear the deferred cost of outage restorations from the distant past. In addition, by choosing a short amortization period, the Company's short-term borrowing rate becomes the appropriate recovery rate, thus saving customers in the financing costs of deferrals.

IV. RESIDENTIAL BATTERY BACK-UP PILOT

Q. Please summarize the Company's proposed residential battery back-up pilot?

A. The Company is proposing a new residential battery back-up pilot, with an estimated participation of 2,000 customers.[90] The Company's proposal would follow on the heels of its 50-customer pilot, whereby batteries were provided to participants at no cost. In my view, the Company had limited learnings with the 50-participant pilot, which is closed to new customers but runs to completion. The learnings were limited in large part by the size and design of the pilot, which gave batteries to customers for free. Despite the limited learnings, CE wants to implement a major expansion in a new pilot. The limited learnings of the prior pilot are a critical issue that is not supportive of an immediate move to a major expansion. The proposed expanded new pilot takes participation to 2,000 customers, a 40-fold increase. The new pilot will not be free to participants (as was the 50-customer pilot) but will require participants bear a portion of the costs for both customer-owned and Company-owned segments.

It is acknowledged that the concept of using a single battery installation to provide benefits to two entities, a customer and the utility, and to share the costs of such installation between those two entities, is novel and may be worthy of piloting. In addition, the idea of linking geographically dispersed batteries to create generation capacity resources across the company's service territory appears to have merit, albeit premature at this stage of piloting efforts.

[90] Machi Direct, pp. 7-25.

Q. What are your observations and recommendations regarding the size and cost of the proposed new battery back-up pilot?

A. The Company is requesting approval of a funding level of $14.3 million dollars.[91] This is a large and unreasonably expensive expansion from the preceding 50 customer pilot. In my opinion, the limited learnings from the 50-customer pilot do not justify such a large and expensive expansion. Critically, the Company's support for the proposal was only qualitative in nature. The Company did not provide a quantitative cost benefit analysis.[92] Giving the Company the benefit of the doubt, this deficiency is reasonably linked to the very early stage of exploration of the concepts being investigated through the pilot. Because of this limitation, in my view, the Commission cannot adequately evaluate the merits of the pilot. As I explained with respect to the proposed Standish pilot, full recovery of pilot expenses from ratepayers is only appropriate: (1) if the pilot has a reasonable possibility of being cost effective; and (2) if it is determined that expected learnings have sufficient value to offset any potential deficiency in net benefits. Such a determination cannot be made absent a rigorous cost benefit analysis. For this reason, I do not believe that the Commission can actually make a determination of the public interest of the proposed new and expanded pilot, at this time.

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[91] *Id.* at 2.

[92] *Id.* at pp. 1-25.

Q. What is your recommendation regarding an appropriate program size if the Commission wanted to approve a substantially revised pilot?

A. I am recommending that should the Commission approve a revised pilot, it should limit pilot funding to 500 customers (10 times the original pilot). This should be large enough to obtain additional learnings related to feeder upgrade deferral, generation capacity and energy avoided costs, system losses, ancillary services value, and the merits of utility ownership – that last issue being a core issue CE wants to address[93] ,- while still accounting for the near-term high relative costs of the battery project to ratepayers. The potential learnings with respect to benefits of distribution asset deferral, in particular demands a smaller pilot than what the Company proposed, one that is compatible with geotargeting participating customers at a limited number of specific substations and its feeders. The focusing of scaled-back pilot on a geotargeted customer base will ensure that that distribution benefits have a reasonable opportunity to be realized. Marketing the pilot across the Company's service territory, as proposed by the Company[94] will likely result in feeders with few participating customers and illusionary distribution benefits. MNSC witness Chris Villarreal discusses the potential to modify the proposed pilot to provide non-wires alternative (NWA) benefits. Based on the results of a 500-customer pilot, future expansions could explore expanding availability throughout the Company's service territory to answer the question of how a dispersed fleet of batteries can be used across the Company's service territory. Should the Commission approve a revised pilot, I recommend that an annual report be filed with the Commission on the results and learnings of the pilot.

[93] *Id.* at 8.

[94] *Id.* at 10.

From there, a determination can be made if and how to expand the pilot in future years as project costs decline.

Q. Aside from the proposed pilot size, what other deficiencies in the proposed pilot have you elicited?

A. In examining the merits of the pilot, the Commission should be aware that there are deficiencies relating to pilot structure that impact the value proposition gained by participating customers. Those deficiencies are: (1) the provision of free maintenance if the customer chooses the company-owned option; (2) the poorly framed solution to compensating customers for power inflows and outflows used to charge and discharge the battery; and (3) poorly framed interface with customers on the Company's DG and Net Metering tariffs.

In my opinion, these issues are significant and also require resolution before the Commission approves ratepayer funding for this pilot project.

Q. What issues are created by offering free maintenance to customers choosing the company-owned option?

A. The Company has created a selection bias in their pilot. As I understand, credits and fees for both available options (Bring Your Own Device, and Company Owned) were calculated to create an equivalency between the two options for each enrollment tier. For example, the Company projected a given battery cost of approximately 25-30kWh capacity.[95] The fees for the Company owned option are equal to this assumed battery cost less assumed

[95] *Id.* at 8.

benefits. On the other hand, the credits for a BYOD participant are set equal to the same assumed benefits. If the customer-owned battery costs the same as used to set the Company-owned battery fees, then the net cost to the BYOD customer (installed cost of the batteries less cumulative compensation) is equal to the cumulative fees paid by the customer choosing the Company owned option. The bottom line is that there is an equivalency in the net cost to all participants. The fly in the ointment is that only customers who choose the Company-owned option get free maintenance. The provision of free maintenance is obviously a compelling benefit. This inherent bias in the pilot incents higher participation in the Company-owned option, in direct conflict with the core goal of the pilot, which is to determine customer interest in having Company-owned batteries for back-up service.

Q. What issues do you see with respect to establishing compensation for power inflows and outflows?

A. The Company addresses the issue of adverse impacts on the customer's bill related to power inflows and outflows asserting that any bill impact will be minimal.[96] Under the terms of the pilot, the Company will be controlling the charge and discharge modes. Apparently, irrespective of which tariff to which a customer is enrolled, energy used to charge the battery (power inflows) will be billed as a retail sale to the customer and included in the customer's monthly bill. With respect the battery discharge, the Company identified a design objective of having the ability to dispatch the battery beyond the home's load during peak system conditions. During these times, outflows will exist, and the issue

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[96] *Id.* at 14.

of outflow compensation becomes relevant. If a customer is on a standard tariff, and there are differences between retail rates and outflow credits, then the potential for adverse economic impacts exists. The Company is proposing that if a participating customer is on a standard rate, power outflows will not be credited through the customer bill but addressed in the customer contract. If on a DG tariff, the customer will be credited at the specified outflow rate (power supply less transmission).

Q. Are there any defects with the proposed compensation approaches for power outflows?

A. Yes. For participating customers on a standard residential tariff, the Company has not actually specified how it will set compensation for outflows, only that the level of compensation with be determined via a contract. This is a critical issue and it would be unconscionable to approve a pilot where the outflow rate is not established in the case. As with any other utility rate, the method of setting compensation for power outflows needs to be clearly defined and approved by the Commission. The Company cannot unilaterally set its electric rates, including outflow credits. In addition, not using the customer bill to accommodate the rate impact of battery discharge cycles resulting in power outflows is a missed opportunity.

Q. With respect to the proposed Home Battery Pilot, do you have a recommendation regarding the setting of outflow rates for customers on a standard residential tariff?

A. Yes. I recommend that customers on a standard residential tariff, and who enroll in the reliability as a service pilot, be billed as a true net metering customer. The reason for this recommendation is that it is a simple solution, easily understandable by customers, and will yield reasonable and equitable results. If power outflows are simply netted against power inflows on a kWh basis during a monthly billing cycle, then the compensation issue disappears. The Company expressed a desire to minimize adverse impacts on participating customers, and in my opinion, this is the best approach. If the terms or conditions of any tariff need to be modified to accommodate such billing, then the Company should file an appropriate amendment.

Q. Are there any policy issues that should be addressed by the Commission regarding the proposed Home Battery Pilot?

A. Yes. In addressing this pilot, the Commission should make clear that connecting standby batteries to customer service panels is not an alternative solution to distribution reliability/resilience issues being experienced by the utility's customers, as it masks the core issue of service quality at high cost to participants. It is reasonable to assume that customers most likely to enroll in the Company's "resiliency as a service" offering are those customers experiencing the worst reliability service. In essence, rate-basing utility-owned batteries connected behind the meter rewards the Company for bad service and does not address the root cause of customers enrolling due to their outage history.

Secondly, with respect to the utility ownership, the Commission should also address issues created by the fact that the Company is a monopoly subject to economic regulation, and its move into a competitive market may have adverse impacts disrupting such competition. The Company's plan to contract with Michigan vendors/installers does not sufficiently address these issues, in that such contracts intrinsically distort the competitive dynamics of the market. Unless the Company revises the pilot to demonstrate additional non-wires alternative benefits associated with its utility-owned behind-the-meter batteries (as recommended by MNSC witness Villarreal), then this issue may be sufficient a basis for the Commission to outright prohibit Company-owned batteries behind the meter, and require Consumers to revise then refile the proposal accordingly.

Q. Do you anticipate environmental or energy justice issues with the proposed pilot?

A. Yes. The pilot fails to address environmental/energy justice issues related to poverty and the ability of low-income customers to afford this utility-sponsored battery back-up program. In particular, there may be medical necessities of some customers, especially those on fixed or limited incomes, who may benefit from a utility sponsored back-up service. The Company has not addressed these critical policy issues in its proposal, nor developed pilot objectives to test solutions. I recommend that the Commission require clearly framed pilot objectives related to environmental and energy justice as a condition of approval.

Q. Do you have any other recommendations with respect to the proposed pilot?

A. Yes. I would be hard pressed to support the pilot as currently structured. It is recommended that the Company continue its engagement with stakeholders and depending on the outcome of those discussions refile a substantially revised and improved pilot.

V. RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations to the Commission.

A. As discussed above, I recommend that the Commission:

(1) The Commission should address and make clear the goal of cost effectiveness, particularly in distribution related pilots and technology investments. As discussed

above, I specifically recommend that the Commission adopt a standard that requires the utility to satisfactorily demonstrate, before it may recover the full cost of distribution system pilot projects from ratepayers, that (a) the pilot has a reasonable possibility of being cost effective (*i.e.* a positive NPV); or (b) the learnings have sufficient value to offset a potential deficiency in net benefits.

(2) The Commission should disallow full recovery through rate base of the costs associated with the Standish portable battery pilot project. Instead, the Commission should cap cost recovery for this project at $3,942,500. Should the Company realize revenue streams as a result of this project, the Commission should allow the Company to retain 30% of the cash benefits as a PBR mechanism.

(3) The Commission should disallow recovery of the proposed grid automation battery pilot project connecting the Neeley/Hooper and Gun Lake/Trails End feeders. The Commission may reject cost recovery on the basis the project is not sufficient ripe for consideration in this case, considering the Company's recent project revision. The Commission may instead authorize the Company to advance capacity upgrades and ATS installation from 2027 to 2022.

(4) The Commission should reject or defer to a future case the Company's proposed investment in the Distributed Energy Resource Management System.

(5) The Commission should require Consumers Energy to undertake a comprehensive investigation into available continuous distribution monitoring technologies, including Distribution Fault Anticipation (DFA) technology, to be filed in this proceeding docket within six months of the final order in this case. The report should

also include at least one pilot project proposal to integrate this technology into the Company's existing distribution system monitoring toolbox.

(6) The Commission should find that the Company has not supported the reasonableness and prudence of 17 of its proposed HVD Line Rebuild projects for "non-standard construction" line segments, considering its generic and unsupported justifications for these projects. In addition, the Commission should require the Company to include line-specific justification for line rebuild projects, outage history data for the project, cost differentials and outage benefits of alternatives, and bids from suppliers for these projects.

(7) The Commission should again reject the Company's proposed Service Restoration cost projection for 2022 based on the 3-year average, and instead approve a reduced amount based on the 5-year arithmetic average of costs adjusted for inflation as described above. The Commission should further reject the Company's request to amortize this expense over 10 years and instead approve a 3-year amortization at the Company's short-term borrowing rate. Finally, the Commission should reject the Company's proposed deferred recovery mechanism.

(8) The Commission should not approve full cost recovery through rate base of the Home Battery Pilot as proposed by Consumers Energy. Instead, this pilot should be rejected entirely or modified substantially. The project should not be approved absent improvements that include (among others) reducing the number of participants, eliminating the bias towards utility-owned batteries – or even eliminating the utility-owned behind-the-meter battery option entirely, providing net metering for

customers enrolled in this pilot, and ensuring equity in access to participation in such a pilot project.

Q. Does that complete your testimony?

A. Yes.

Robert G. Ozar P.E.

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- 5Lakes Energy, Senior Consultant: Energy Analysis, Energy/Regulatory Policy, Electric/Gas Utility Engineering
- MPSC: Natural Gas Engineering Specialist • Manager, Electric Operations Section • Manager, Energy Efficiency Section • Assistant Director, Electric Reliability Division

WORK EXPERIENCE

Michigan Public Service Commission **Nov 1979 – Dec 2019**

Natural Gas Regulatory Accomplishments

- Created Quartile Exponential Smoothing Strategy for gas distribution utility hedging during periods of high market volatility
- Created Contingency Factor regulatory process for setting Gas Cost Recovery Factors
- Performed energy market analysis and projections of natural gas supply/demand/prices
- Analysis of basis differentials in regional natural gas markets
- Review of gas transmission infrastructure projects requested by regulated gas utilities
- Developed residential, commercial and industrial sales forecasts and weather normalization methods for use in gas utility general rate-case proceedings
- Testified in numerous contested case proceedings on issues related to natural gas engineering, economics, and regulatory theory, policy and practice

Energy Efficiency Accomplishments

- Chair of the Energy Efficiency Workgroup in the Capacity Needs Forum for development of a statewide Integrated Resource Plan
- Created, led and managed the Michigan Energy Efficiency Workgroup
- Created the first Energy Optimization Program Incentive-Mechanism for meeting and exceeding performance targets set by Michigan statute

- Led the development of the Michigan Deemed Savings Database, used to set uniform achieved savings levels for Michigan utilities
- Led the regulatory review of Energy Optimization Plans and annual financial reconciliations for Michigan utilities
- Wrote the Request for Proposal (RFP) for the creation of *Michigan Saves*, a statewide program for financing energy efficiency improvements by Michigan utility customers

Electric Industry Accomplishments

- Chief lead for MPSC staff in the Michigan Electric Vehicle Preparedness Taskforce
- Created and led the Michigan Smart Grid Collaborative facilitating the introduction of electric utility infrastructure and regulatory structure for review and approval of capital expenditures
- Led Staff review of utility requests for rate approval of advanced metering infrastructure (AMI)
- Created the request for proposal (RFP) for a $5 million electric vehicle study of the potential impact of market growth of plug-in EV's on electric utility distribution systems and electric generation systems in Michigan, and the need for active management by utilities of EV charging by utility customers
- Created the concept of using a twenty-year levelized cost of renewable energy programs which was codified in PA 295
- Author of the Inflow/Outflow pricing model adopted by the MPSC as a cost based regulatory structure to replace Net Energy Metering (NEM) in Michigan

Depreciation Engineering

- Wrote a MATLAB model for review of life curves and remaining life of utility assets for use by the MPSC Depreciation Staff

EDUCATION

Michigan State University, East Lansing, MI **2001**
Master's in Chemical Engineering

Michigan State University, East Lansing, MI **1979**
BS in Chemical Engineering

- With Honors
- Recipient of the Schlumberger Scholarship in Chemical Engineering
- Inducted into the national engineering honor societies Tau Beta Pi, and Omega Chi Epsilon

TEACHING AND MENTORSHIP

Mr. Ozar has taught/spoken as an energy expert at energy industry conferences having both national and international audiences. He has regularly taught at the Michigan State University Institute of Public Utilities (IPU) Fundamentals, Intermediate and Advanced Regulatory Studies Program. Mr. Ozar has invested significant time in mentorship of young professionals at the Michigan Public Service Commission.

Question:

56. Please amend Exhibit A-48 (RTB-15) so that it shows 2021 information. Please use the following columns: line number; sub-program; project description, line, substation, or location; projected 2021 bridge year spending; units; unit type; and investment category.

Response:

> **Objection of Counsel:** Consumers Energy Company objects to this discovery request on the basis that it is unduly burdensome. Without waiving this objection, the Company responds as follows:

The Company provided a comprehensive 2021 project list in a similar manner to Exhibit A-48 (RTB-15) in its prior electric rate case, which used 2021 as the projected test year. Refer to Exhibit A-42 (RTB-15) in Case No. U-20697. The Company's 2021 bridge year spending in this case is based on what was provided in Case No. U-20697. Please see the following references in my direct testimony, relevant to the Reliability and Capacity programs:

- Page 119, lines 1 through 11
- Page 220, lines 10 through 12

In two areas, the Company is spending on projects in 2021 that were specifically disallowed by the Commission in Case No. U-20697. One of these is the portable battery project, as discussed on page 216, line 17, through page 218, line 10, of my direct testimony. The other area is DERMS, as discussed on page 160, line 9, through page 162, line 14, of my direct testimony.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 23, 2021

Electric Planning

Question:

6. On Page 216-217, lines 21 – 2, of Mr. Blumenstock's testimony, and in reference to the Commission's disallowance of the Standish battery project, Mr. Blumenstock states: "However, in the 2021 bridge year and the 2022 test year in this case, the Company is still proposing to make investments in the portable battery, on a scaled down basis, because it is in the best interests of customers to do so.

   a. When was the decision to scale down the project?

   b. What was the basis for scaling down the project?

   c. How was the project "scaled down"?

   d. What is the Company's current estimate of the cost per kWh of battery capacity of the project as implemented by the Company and what is the cost per kWh that would make the full cost of the portable-battery deferral project equivalent to the cost of the Standish substation upgrade?

   e. What is the Company's current estimate of the cost of a traditional upgrade of the Standish substation?

Response:

a. This decision was made in January 2021.

b. The project was scaled down following the Commission's disallowance of project costs in its Order in Case No. U-20697. As discussed on page 217, line 3, through page 218, line 10, of my direct testimony, the Company decided not to cancel the project, but did seek to reduce the spending amount.

c. Project scope was reduced to limit expenditures to those related to critical tasks. Less critical tasks, like a dispatch optimization analysis and a third-party analysis on the battery's performance one year after commissioning, were eliminated from the project scope.

d. The current cost estimate for this project for battery capacity is $580/kW. With an estimated substation upgrade cost of $1.5 million, the equivalent cost per kW of the battery would need to be $140/kW. However, that only counts the Standish substation, and this battery is intended to defer two additional substation upgrade projects. Factoring those two additional projects in as well, the battery cost would need to be $472/kW to be equivalent to the upgrade costs of all three substations.

e. The current estimate for a traditional capacity upgrade at Standish substation is $1.5 million, which would involve building a new substation and removing the existing substation.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

Question:

8. On page 217 lines 15-16, Mr. Blumenstock states: "The Company executed its contract with the chosen integrator on September 8, 2020, well before the Commission ruled in Case No. U-20697. Had the Company delayed beyond this date, the battery would not have been available in time to alleviate load on the Standish substation, obviating the potential to test the battery as an NWS."

   a. Prior to committing to a contract for battery equipment on September 8, 2020, did the Company re-evaluate its substations for possible overloads, including its finding that the Standish substation could be overloaded in the summer of 2021? If so, what were the findings of such re-evaluation?

   b. As a result of such re-evaluation, were any other substations projected to have possible overloads during the 5-year period 2021 through 2026? Which of those could meet all other screening criteria?

   c. Prior to executing its contract on Sept 8, 2020, were the management personal responsible for the decision to go forward with a contract aware that briefs to the proceeding were filed which opposed the project on grounds that the proposed pilot cost were excessive, and that a PFD was to be forthcoming the next month? If so, did the Company have contingency plans, should the Commission, in its final order, agree that the Standish pilot costs were excessive?

Response:

a. Prior to September 8, 2020, the company reevaluated the loading conditions resulting from the 2020 summer peak at Standish substation. This reevaluation found that there was an average demand increase of 3.5% between the 2018 and the 2020 peaks. This increase kept Standish substation on the list of substations expected to reach overload in 2021. The other substations that had been part of the original pool of deferral candidates (refer to response 20963-MEC-CE-482) were not reevaluated prior to September 8, 2020.

b. There was no reevaluation of other substations prior to September 8, 2020, aside from what is stated in subpart a.

c. Notwithstanding the then-current briefs in Case No. U-20697, the Company had and has a commitment to developing its Grid Storage capabilities and was and is committed to this project. Furthermore, given the projected overload on the Standish substation, as stated in subpart a, the Company needed to move forward with the project on that date in order to remain on schedule to meet the projected overload.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

Question:

9. On page 217, lines 1-4, Mr. Blumenstock states: "If the Company cancels the project outright … the Company will still be contending with a substation overload on the Standish substation."

   a. What is the latest date that equipment purchase commitments would need to be made for upgrading the Standish substation (as opposed to implementing a portable battery) in time to alleviate re-evaluated projections of station overload?

   b. Please explain why such date is critical?

   c. Would a substation upgrade allow for continued load growth (i.e. would the upgrade allow for additional load growth for a reasonable future period beyond the commencement of overload conditions)? If so, what is that projected future period?

   d. Would the portable battery allow for continued load growth (i.e. would the portable battery pilot allow for additional load growth for a reasonable future period beyond the commencement of overload conditions)? If so, what is that projected future period?

   e. When the Company upgrades a substation, does it have a standard-design expansion capability for all substation upgrades, or is the expansion capability unique to each substation? Please explain.

Response:

a. The Standish substation is projected to be overloaded in 2021. As stated in response 20963-MEC-CE-482, this would normally lead to an LVD Substations Capacity project scheduled for 2022. On that timeline, purchase commitments would need to have been made in February and March 2021.

b. The transformer bank, a key component of the substation, has an estimated lead time of 52 weeks. To avoid a repeat overload in 2022, following a projected one in 2021, the upgrade would need to be complete by May 15, 2022, requiring delivery by April 1, 2022 to allow for construction.

c. Building a new substation at Standish and removing the existing substation would allow continued load growth for a period of 20 years.

d. The power rating and the energy rating of the battery were determined to allow for continued demand growth. The battery was designed to support load growth in the Standish area for a period of three to five years after the commencement of overload conditions, after which the battery will be moved to the next location. Similar periods are also estimated for the second and third deferral locations.

e. Although many of the Company's substations conform to the same standards and have similar upgrading requirements, each upgrade is approached initially as a unique situation. The scope of an upgrade for an overloaded substation is determined by several factors besides the distribution demand. These factors include, but are not limited to, capacity and loading conditions on the HVD side, short circuit availability at the location of the substation, protection options available on the HVD and the distribution sides, circuit loading, distribution reliability, substation configuration and footprint, space availability on site, accessibility, and others.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

Question:

Blumenstock:

In summarizing the Company's long-term electric strategy, Mr. Blumenstock notes on page 5, lines 20-22, of his testimony that: "Building for the future" consists of enabling the transition to cleaner energy resources, including integration of distributed energy resources ("DERs")…" Mr. Blumenstock states on page 7, lines 9-11: "The new IRP will continue to involve increasing reliance on solar generation, particularly on a distributed basis, which will continue to drive the "build for the future" component of the Company's distribution strategy."

On page 8, lines 3-7, Mr. Blumenstock notes the "need for … more investments in grid modernization and other technologies to facilitate the Company's IRP through interconnection of distributed solar generation and other future DER integration."

On page 15 lines 8-10: Mr. Blumenstock states: "The Company's 2018 IRP included a plan to heavily invest in distributed solar generation to help meet generation capacity needs while significantly reducing the use of fossil fuels…." and on page 15, lines 14-15: "The Company is also planning, in general, for greater expansion of DERs, including third-party owned generation and utility and third-party owned storage. All of these factors are accounted for in the Company's Grid Modernization Roadmap, which drives the Company's strategy surrounding new technologies and analytics, as discussed in more detail in the section of my direct testimony covering Grid Modernization."

On page 160, lines 18-22, in response to the question of what benefits will be provided by DERMS, Mr. Blumenstock states: "The Company is confident that DER penetration will accelerate in the relatively near-term future, with continued commitments to distributed solar generation, as well as the potential for customer-sited storage similar to what Company witness Priya D. Machi discusses in her testimony. This accelerating DER penetration will introduce various technical questions, primarily related to control and optimization of DERs, that must be addressed."

a. Regarding the Company's stated commitment to DER's, what role will customer-sited solar generation (associated with the Company's DG program) play in enabling the transition to cleaner energy resources?

b. How expansive a role would the Company like to see with respect to customersited solar generation? Please quantify and provide timelines if possible.

c. How long into the future does the Company plan to self-impose a participation cap for its DG program? What is necessary, in the Company's opinion, remove such cap, or significantly increase it?

d. What does Mr. Blumenstock mean by referring to "customer sited storage similar to what Company witness Priya D. Machi discusses in her testimony."?

e. In noting the potential for customer-sited storage, does the Company have any plans to remove its current prohibition against battery-only systems that implement energy arbitrage strategies that rely at times on discharge cycles that export power outflows to the grid as opposed to strictly using battery discharge to meet onsite load? Does the Company view the issue of setting compensation for outflows the reason for its prohibition? What would be a fair approach to set compensation in the Company's opinion? What tariff or operational requirements would be necessary to accommodate such customer arbitrage strategies?

f. As an alternative to its current proposed residential battery backup pilot, or as a complimentary pilot to accelerate distributed energy resources, has the company considered locating company-owned batteries at distribution transformers (primary to secondary), as a more economically and operationally efficient means of balancing the distribution grid, as opposed to batteries connected to residential-customer service-panels (and operated to balance the distribution grid) as in the Company's proposed back-up pilot?

Response:

Objection of Counsel: Consumers Energy objects to subparts (a), (b), (c), and (e) of this discovery request on the basis that they do not seek to discover any fact or document, but instead seek speculation, opinion and/or legal analysis. Without waiving this objection, Consumers Energy responds as follows:

a. The referenced statements were not intended to assign contributions to the proliferation of DERs to any specific Company program such as the Distribution Generation program. They are meant to state the Company's view that realization of DERs will accelerate in the relatively near-term future and, thus, investment in preparation to integrate those resources is necessary and prudent.

b. See subpart a above. The Company is not able to quantify and provide timelines for customer-sited solar generation, since, by definition, any such decision is at the discretion of the customer, not the Company. To the extent that customer-sited solar generation provides value to customers in excess of other energy and capacity supply options, and customers are interested in providing such supply, it will play a role in the transition to cleaner energy resources.

c. The Company does not have a participation cap on the number of customers that can install distributed generation. As noted in the Company's initial brief in Case No. U-20697, in addition to utilizing the Company's DG Tariff, customers are able to install solar generation facilities for or the purpose of (1) self- generation without selling the surplus energy to the Company, (2) selling surplus or all of the output under a PURPA PPA or (3) selling the surplus or all of the output under an energy-only contract, all of which are already in existence in the Company's electric rate book.

d. This statement refers to residential batteries.

e. No. The Company is not proposing any modifications to any battery-only operational provisions.

f. The Company has not considered such an option at this time.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

<u>Question:</u>

2. On page 161, lines 2-4 Mr. Blumenstock asserts: "If the Company delays its DERMS schedule beyond the 2021 bridge year or the 2022 test year in this case, there would be an increased risk that DER penetration gets too high to reliably manage and control before the Company's DERMS is ready." Further on page 161, lines 17-21 Mr. Blumenstock states: "Studies by the PJM Interconnection, the North American Electric Reliability Corporation, and the Electric Power Research Institute ("EPRI") have shown that operational challenges begin to manifest themselves when DER penetration reaches between 20% and 30% of the electric demand being served. At this point, DERMS is necessary to reliably manage DERs at peak conditions, and to generally coordinate DERs so as not to introduce voltage issues or other issues that threaten reliability. In short, while DERMS is not addressing a specific reliability threat that exists in 2021, it will prevent a reliability threat that is likely to exist by the time the project is complete if no action is taken."

   a. Does Mr. Blumenstock's use of the term "DER penetration" refer to Company owned grid scale DER deployed via the Company's anticipated schedule for deployment, plus third-party grid-scale generation contracted by the Company, plus customer sited DER such as that associated with the Company's DG program? Has the Company made a forecast of DER penetration, for each category, in setting its anticipated DERMS schedule?

   b. If DERMS schedule is essentially complete by the end of the 2022 test-year, as proposed by the Company, what year will DERMS be ready for managing and controlling DER?

   c. Referring to question (b) above, what level of DER is anticipated by the Company in the year that DERMS is ready? Please break out the level by (1) company owned DER, (2) third-party grid-scale DER contracted by the Company, and (3) customer sited DER.

   d. In the Company's opinion, for every year the DERMS schedule is delayed beyond the 2022 test-year, is the year in which DERMS will be ready for managing and controlling DER delayed by one-year?

   e. Please provide customer power inflow and outflow data integrated on an hourly basis for 200 randomly selected residential DG customers along with their associated nameplate PV capacity (as indicated on the customer's interconnection agreement)? Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer.

   f. Please provide customer power inflow and outflow data integrated on an hourly basis for 200 randomly selected commercial solar PV customers. If the Company has less than 200 but at least 15 of such customers include all customers. For each customer, include the associated nameplate PV capacity (as indicated on the customer's interconnection agreement. Include the building type (e.g. small office, grocery store, warehouse etc.). Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer.

g. Please provide customer inflow data integrated on an hourly basis for 200 randomly selected residential full-requirements customers? Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer.

h. Please provide customer inflow data integrated on an hourly basis for 200 randomly selected commercial full-requirements customers? Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer. Include the building type (e.g. small office, grocery store, warehouse etc.).

i. Any developments since the prior rate case U-20697, that the Commission should take into account in re-evaluating the proposed DERMS deployment?

j. Has the Company evaluated, or developed any plans to own and rate-base customer-sited solar generation, similar to its desire to own and rate-base customer-sited battery back-up? If so, please summarize such evaluation or plan, and provide a copy of the analysis or plan.

k. Is DERMS intended to be the core tool for scheduling and operating the proposed residential battery back-up pilot?

<u>Response:</u>

a. Yes, the reference to “DER penetration” includes any of these types of DERs, regardless of ownership. As stated in discovery response 20963-MEC-CE-476, the Company does not have a forecast of DER penetration by type of ownership.

b. DERMS deployment will not be essentially complete by the end of 2022. As stated on page 161, line 1, of my direct testimony, the Company will have developed its DERMS capabilities by the end of 2023. Given the need for testing, DERMS will not be fully functional until 2024. However, DERMS capabilities are not a binary function, with no capabilities one day and full capabilities the next day. As discussed on page 160, lines 1 through 8, and again on page 162, lines 1 through 14, of my direct testimony, the Company is phasing in DERMS by first using it at a specific location, meaning some capabilities are already being developed in 2021. To prepare for management and control of larger numbers of DERs, the Company must develop its understanding of the practical operation of DERMS through hands-on exercises. Even in early stages of this phase-in, DERMS can deliver benefits. Even when DER penetration is relatively low, DERMS allows for dynamic discovery and coordination of DERs on the system. Without DERMS, the Company does not have this ability. By 2024, DERMS capabilities will be much more developed and more ready to handle an influx of DER penetration.

c. As discussed in discovery response 20963-MEC-CE-476, the Company does not have such a forecast. As stated on page 160, lines 17 through 22, of my direct testimony, the Company is confident that DER penetration will accelerate in the relatively near-term future, regardless of the specific resource mix determined through integrated resource planning.

d. Yes.

i. Yes. Recent developments in DERMS deployment include finalization of technical requirements. Work has started on the development of a conceptual architecture design for communications as well as defining use cases and developing a test strategy. This work will help the Company validate possible functions of DERMS. The first use cases will include core capabilities such as DER registration in the DERMS and Solar Smoothing using battery controls.

j. The Company proposed a “Bring Your Own Bright Field” pilot in case No. U-20649 that would have allowed the Company to own solar energy systems installed at a customer’s facility. Outside of this proposal, the Company has not developed any other plans to own and/or rate-base customer sited solar.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

Question:

2. On page 161, lines 2-4 Mr. Blumenstock asserts: "If the Company delays its DERMS schedule beyond the 2021 bridge year or the 2022 test year in this case, there would be an increased risk that DER penetration gets too high to reliably manage and control before the Company's DERMS is ready." Further on page 161, lines 17-21 Mr. Blumenstock states: "Studies by the PJM Interconnection, the North American Electric Reliability Corporation, and the Electric Power Research Institute ("EPRI") have shown that operational challenges begin to manifest themselves when DER penetration reaches between 20% and 30% of the electric demand being served. At this point, DERMS is necessary to reliably manage DERs at peak conditions, and to generally coordinate DERs so as not to introduce voltage issues or other issues that threaten reliability. In short, while DERMS is not addressing a specific reliability threat that exists in 2021, it will prevent a reliability threat that is likely to exist by the time the project is complete if no action is taken."

a. Does Mr. Blumenstock's use of the term "DER penetration" refer to Company owned grid scale DER deployed via the Company's anticipated schedule for deployment, plus third-party grid-scale generation contracted by the Company, plus customer sited DER such as that associated with the Company's DG program? Has the Company made a forecast of DER penetration, for each category, in setting its anticipated DERMS schedule?

b. If DERMS schedule is essentially complete by the end of the 2022 test-year, as proposed by the Company, what year will DERMS be ready for managing and controlling DER?

c. Referring to question (b) above, what level of DER is anticipated by the Company in the year that DERMS is ready? Please break out the level by (1) company owned DER, (2) third-party grid-scale DER contracted by the Company, and (3) customer sited DER.

d. In the Company's opinion, for every year the DERMS schedule is delayed beyond the 2022 test-year, is the year in which DERMS will be ready for managing and controlling DER delayed by one-year?

e. Please provide customer power inflow and outflow data integrated on an hourly basis for 200 randomly selected residential DG customers along with their associated nameplate PV capacity (as indicated on the customer's interconnection agreement)? Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer.

f. Please provide customer power inflow and outflow data integrated on an hourly basis for 200 randomly selected commercial solar PV customers. If the Company has less than 200 but at least 15 of such customers include all customers. For each customer, include the associated nameplate PV capacity (as indicated on the customer's interconnection agreement. Include the building type (e.g. small office, grocery store, warehouse etc.). Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer.

g. Please provide customer inflow data integrated on an hourly basis for 200 randomly selected residential full-requirements customers? Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer.

h. Please provide customer inflow data integrated on an hourly basis for 200 randomly selected commercial full-requirements customers? Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer. Include the building type (e.g. small office, grocery store, warehouse etc.).

i. Any developments since the prior rate case U-20697, that the Commission should take into account in re-evaluating the proposed DERMS deployment?

j. Has the Company evaluated, or developed any plans to own and rate-base customer-sited solar generation, similar to its desire to own and rate-base customer-sited battery back-up? If so, please summarize such evaluation or plan, and provide a copy of the analysis or plan.

k. Is DERMS intended to be the core tool for scheduling and operating the proposed residential battery back-up pilot?

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request because it seeks information that is irrelevant and not proportional to the needs of this case. The Company also objects to this discovery request to the extent it calls for the creation of documents, data, and analyses which currently do not exist. Subject to this objection, and without waiving it, the Company provides the following response:

Please see the response to the subparts below. The data provided is for calendar year 2020. Note that the Company does not track the customer's building type.

For the Attachments provided, please note the following:

- Unit of Measure: kWh
- Time Intervals: Time provided in EST. INT01 captures 00:00:00 - 00:59:59. Intervals are not cumulative. If an interval is missing, the energy is not captured in the following period.
- The identifier is a unique 9-letter code that's consistent for each customer across files. This code is used to protect customer privacy.

e. Please see Attachment 1 for inflow and Attachment 2 for outflow. Please see Attachment 3 for the DC and AC Rating (kW).

f. Please see Attachment 4 for inflow and Attachment 5 for outflow. Please see Attachment 6 for the DC and AC Rating (kW).

g. Please see Attachment 7.

h. Please see Attachment 8.

Emily Davis

Emily A. Davis
May 6, 2021

Rates and Regulation

Question:

2. On page 161, lines 2-4 Mr. Blumenstock asserts: "If the Company delays its DERMS schedule beyond the 2021 bridge year or the 2022 test year in this case, there would be an increased risk that DER penetration gets too high to reliably manage and control before the Company's DERMS is ready." Further on page 161, lines 17-21 Mr. Blumenstock states: "Studies by the PJM Interconnection, the North American Electric Reliability Corporation, and the Electric Power Research Institute ("EPRI") have shown that operational challenges begin to manifest themselves when DER penetration reaches between 20% and 30% of the electric demand being served. At this point, DERMS is necessary to reliably manage DERs at peak conditions, and to generally coordinate DERs so as not to introduce voltage issues or other issues that threaten reliability. In short, while DERMS is not addressing a specific reliability threat that exists in 2021, it will prevent a reliability threat that is likely to exist by the time the project is complete if no action is taken."

   a. Does Mr. Blumenstock's use of the term "DER penetration" refer to Company owned grid scale DER deployed via the Company's anticipated schedule for deployment, plus third-party grid-scale generation contracted by the Company, plus customer sited DER such as that associated with the Company's DG program? Has the Company made a forecast of DER penetration, for each category, in setting its anticipated DERMS schedule?

   b. If DERMS schedule is essentially complete by the end of the 2022 test-year, as proposed by the Company, what year will DERMS be ready for managing and controlling DER?

   c. Referring to question (b) above, what level of DER is anticipated by the Company in the year that DERMS is ready? Please break out the level by (1) company owned DER, (2) third-party grid-scale DER contracted by the Company, and (3) customer sited DER.

   d. In the Company's opinion, for every year the DERMS schedule is delayed beyond the 2022 test-year, is the year in which DERMS will be ready for managing and controlling DER delayed by one-year?

   e. Please provide customer power inflow and outflow data integrated on an hourly basis for 200 randomly selected residential DG customers along with their associated nameplate PV capacity (as indicated on the customer's interconnection agreement)? Please provide the data for each month of the most currently available calendar year, and with the 8,760 hour data grouped by individual customer.

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i. Any developments since the prior rate case U-20697, that the Commission should take into account in re-evaluating the proposed DERMS deployment?

j. Has the Company evaluated, or developed any plans to own and rate-base customer-sited solar generation, similar to its desire to own and rate-base customer-sited battery back-up? If so, please summarize such evaluation or plan, and provide a copy of the analysis or plan.

k. Is DERMS intended to be the core tool for scheduling and operating the proposed residential battery back-up pilot?

<u>Response:</u>

k. The Company will conduct a Request for Proposals ("RFP") to solicit the Home Battery Pilot hardware, software, installation, and maintenance vendors. If DERMS software providers choose to participate in the Home Battery Pilot RFP, we will consider their products alongside others. In the future, if the Company moves forward with a scaled, customer-sited storage offering, the Company will consider using DERMS to operate such a program.

Priya D. Machi
May 6, 2021

Question:

13. Refer to Mr. Blumenstock's direct testimony, pages 216 to 218, and to the Company's responses to MEC-CE-481 to -484, discussing the Company's proposed portable battery Grid Storage project.

a. Has the Company identified any additional value streams (e.g., ancillary service) for this battery project? If so, please describe them and provide any estimate or projection that the Company has developed for additional value streams associated with this battery project.
b. For this project, please provide each Concept Approval, including a revised Concept Approval following the decision to "scale down" the project.
c. Has the Company updated the benefit cost analysis for comparing alternatives for this project in this case? If so, please provide it.
d. Did the Company seek bids or issue a Request for Proposal (RFP) for an alternative ownership approach, other than utility-ownership, for this battery storage project? If so, please provide all supporting documents. If not, please explain why not.

Response:

a. The Company is considering registering the Airpark Battery in MISO's Fast First Frequency Regulation Market for an additional value stream. A projection of the revenue attainable by the Company from participating in this MISO market appears in the table below. These projections are informed by data obtained from the Company's Parkview battery, and are based on Airpark's rating of 2.0 MW and assumes that the battery will be fully operational for 96% of the year, with 17% of this time being reserved for other uses like peak shaving. This projection also assumes that Airpark is selected by MISO to perform fast frequency regulation during 50% of the remaining time.

Year	Value
2021	$ 153,600
2022	$ 149,592
2023	$ 145,460
2024	$ 146,684
2025	$ 148,177
2026	$ 152,301
2027	$ 156,298
2028	$ 159,783
2029	$ 163,216
2030	$ 166,837
2031	$ 170,383
2032	$ 173,798
2033	$ 177,873
2034	$ 181,844
2035	$ 185,403
2036	$ 189,242
2037	$ 193,139
2038	$ 197,520
2039	$ 201,617
2040	$ 205,600

b. Please see Attachment 1 to this discovery response, which is the original approved Concept Approval for this project. The Concept Approval was not revised to reflect the scaled-down scope.

c. The Company has not updated the benefit cost analysis for this project. The scaled-back scope of this project still delivers the same benefits, so the original Concept Approval and benefit cost analysis are still valid.

d. The Company did not seek bids or issue a Request for Proposal for an alternative ownership approach for this project. The purpose of this project is to develop the Company's capabilities in using a transportable battery system to defer substation upgrades, so it is essential that the Company retains ownership of this storage system.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 15, 2021

Electric Planning

Consumers Energy
Customer & Service Infrastructure
CONCEPT APPROVAL

Concept Number: 21-0027

Project: **Portable Battery System - Defer Standish Substation Upgrade** **County:** Arenac

Date: March 25, 2020 **Need System Changes By:** 6/30/2021

Problem Description:

Background

More than ever before, the electric grid is rapidly changing. Some of the factors that are changing the grid include:

- High penetration of intermittent generation
- Retirement of base load generation
- Potential of high penetration of electric vehicles
- Microgrid and islanding technology
- Demand response technology

While these developments bring many benefits to electric customers, they also introduce challenges to keeping the grid stable and reliable. More sophisticated tools are required to address these challenges, as these new technologies introduce conditions that have not been experienced before on the grid.

Battery energy storage (BESS) is a technology with great potential to revolutionize how we operate and control electric networks. It can address power quality issues as well as provide flexibility and bring stability to the grid. Presently, battery prices are high compared to traditional solutions; however, for the last few years, the price gap has steadily declined.

Consumers Energy's current strategy calls for deploying small demonstration battery projects over the next few years, to gain technical and operational knowledge while prices continue to decline. By following this strategy, the Company will be prepared to deploy batteries at a larger scale when prices become competitive.

Project Specifics

The Standish Substation 416kVA group regulators were loaded to 91% in 2018 and are projected to reach overload in 2020. Upgrading these group regulators to the next available size is not possible without rebuilding the low-side of the substation due to the physical size of the 576kVA replacement units. The substation transformer is projected to reach overload in 2026.

A properly sized battery storage system, coupled to one of the Standish distribution circuits, can defer the station upgrade for at least three years by providing supplemental capacity during demand peaks. In addition to relieving the substation during high demand, the battery system will be able to provide Volt-

VAR control and power factor correction on the distribution circuit. By providing voltage control, the battery can also help reduce the number of required tap changes by the voltage regulators at the substation, thus expanding their operational life and cutting down on maintenance.

Installing a portable battery at Standish Substation will allow for this same system to be used at a different location once the Standish load grows past what the battery can provide. Based on the demand growth observed at Standish Substation over the last five years, the plan is to procure a battery with enough capacity to defer the substation upgrade for 3-5 years.

Once the Standish Substation load excess meets the battery capacity, the substation will be rebuilt, and the battery relocated to another project for further investment deferral. Current candidates for the battery's next locations include:

- Beadle Substation (projected overload year: 2024)
- Pickerel Substation (projected overload year: 2027)

Beadle Substation has been chosen for the second location. It is recommended, however, that as the load nears battery capacity at Standish, additional studies are completed to determine the next most optimal location for the battery.

The goals for this project are to:

1. Use a battery to defer a substation upgrade.
2. Procure a "Portable Battery" that can be moved to different locations as needed.
3. Provide voltage support to the substation when operating during outages on the HVD Line from Almeda.
4. Understand how to use a battery that is primarily intended for peak shaving, for:
    a. Circuit power quality
    b. Market interaction

The knowledge gained through this project will allow CE to deploy batteries strategically across the grid to extend the life of our assets.

<u>Alternatives Considered:</u>

1. Increase capacity at Standish Substation in 2021, Beadle Substation in 2024 and Pickerel Substation in 2027 with traditional solutions. These substation upgrades will include:
    - Replacement of the existing 10/12.5MVA transformer with a 12/16/20MVA unit at each substation.
    - Convert each substation from group regulation to circuit regulation.
    - Each substation upgrade estimated at $1,500,000.

Total Cost = $4,500,000

2. Complete the Standish Substation portable battery project in 2021, transfer the battery to Beadle Substation in 2024, and then transfer the battery to Pickerel Substation in 2027. These projects will include:
    - 2020 - Property acquisition at Standish Sub (additional space is needed to build the battery), and BESS engineering and contract milestone payments.
    - 2021 - Initial portable BESS acquisition and install at Standish Sub.
    - 2024 – Relocate portable BESS to Beadle Sub and increase capacity at Standish Sub by replacing the transformer and converting to circuit regulation. Relocation is $100,000.
    - 2027 - Relocate portable BESS to Pickerel Sub and increase capacity at Beadle Sub by replacing the transformer and converting to circuit regulation. Relocation is $100,000.
    - 3030 –Increase capacity at Pickerel Sub by replacing the transformer and converting to circuit regulation.
    - Each substation upgrade estimated at $1,500,000.

    Total Cost = $15,722,000

Recommended Alternative:

The recommended option is Alternative 2 – Complete the portable battery project.

This option will allow the Company to gain critical technical and operational knowledge on how to effectively use a BESS for substation upgrade deferrals. It will also provide us with first-hand experience on the installation and portability requirements of battery systems designed for multiple relocations. In addition, the knowledge acquired from this project will increase the Company's flexibility to choose critical system upgrades that require immediate investments over deferrable ones.

The economic comparison of the two alternatives, considering multiple battery relocations and capacity increase deferrals in coming years, is provided in the following table. For this analysis, two battery relocations were considered, and a cost of $100,000 was assumed for each battery relocation.

Yearly Activities per Alternative	Sum of Present Worth of Revenue Requirements	Total Capital (2020 – 2031)	First Year Capital (2020)
Alternative 1 2021: Increase capacity at Standish Substation. 2024: Increase capacity at Beadle Substation. 2027: Increase capacity at Pickerel Substation.	$5,052,000	$4,500,00	$0
Alternative 2 2020: Acquire additional property at Standish. 2021: Install BESS at Standish Sub. 2024: Relocate BESS to Beadle Sub, increase capacity at Standish Sub. 2027: Relocate BESS to Pickerel, increase capacity at Beadle Sub. 2030: Remove BESS from Pickerel Substation, increase capacity at Pickerel Sub.	$19,176,000	$15,722,000*	$2,842,500

*Total cost of battery project not including substation deferrals = $11,022,000 NPV = $14,714,000.

Despite the higher cost of Alternative 2, due to the cost associated with the battery, the economic analysis shows that deferring the three substation upgrades involves $589,000 in NPV savings. The NPV tables showing this economic analysis are provided at the end of this document.

Preliminary engineering is in progress. Target size of the battery is 2MW with a 4-hour duration (8MWh).

The estimated loaded Capex for the Portable BESS to complete the first project, defer capacity the increase at Standish Substation, is $11,022,000.

WBS Element	2020 Direct Cost	2020 Cost with Overheads	Description
ED-98219-1-19-02-01	$180,000	$270,000	Property expenditures
ED-98219-1-19-02-01	$1,009,800	$1,514,700	BESS contract execution & engineering milestone (15% BESS integrator price)
ED-98219-1-19-02-01	$32,400	$48,000	Dispatch optimization consulting
ED-98219-1-19-02-01	$673,000	$1,009,800	BESS contract execution & engineering milestone (10% BESS integrator price)
WBS Element	**2021 Direct Cost**	**2021 Cost with Overheads**	**Description**
ED-98219-1-19-02-01	$180,000	$270,000	BOP Equipment (transformer, switches, relays, etc.)
ED-98219-1-19-02-01	$12,000	$18,000	Factory Acceptance Test visit
ED-98219-1-19-02-01	$3,029,400	$4,544,100	BESS delivery (45% BESS integrator price)
ED-98219-1-19-02-01	$180,000	$270,000	Construction and installation
ED-98219-1-19-02-01	$2,019,600	$3,029,400	BESS commissioning (30% BESS integrator price)
WBS Element	**2022 Direct Cost**	**2022 Cost with Overheads**	**Description**
ED-98219-1-19-02-01.	$32,400	$48,000	White paper on findings from review of real data
Customer Contribution	$0	$0	
Project Total CapEx	**$7,348,800**	**$11,022,000**	

All costs related to the BESS project will be funded by the Grid Storage budget.

Present Need: On approval, this document authorizes the DER/I&C Design group to proceed with the work order design and the acquisition of property and material.

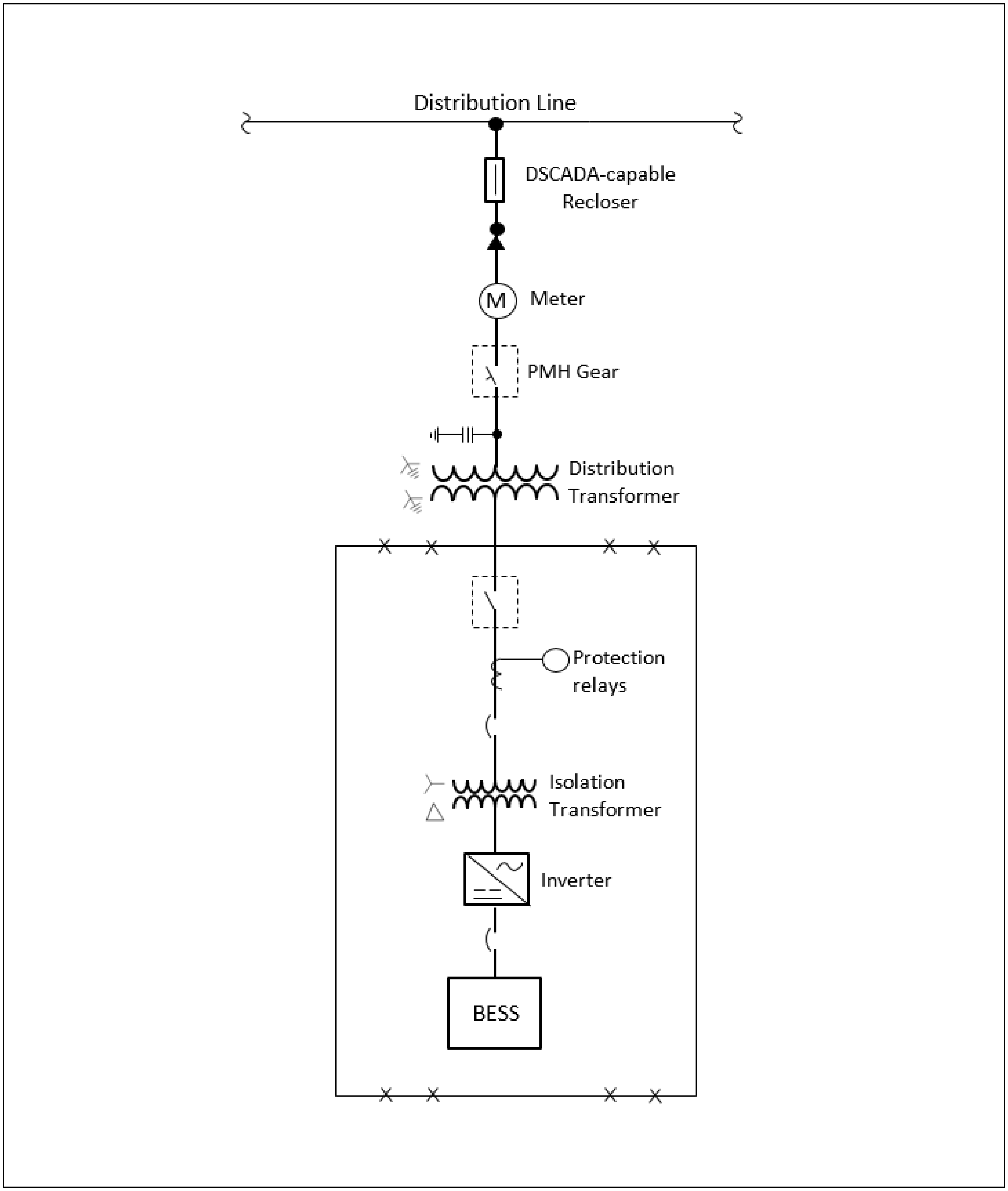
Prepared By: Nate Washburn/Demeury Naranjo **Date** 3.25.2020

APPROVALS

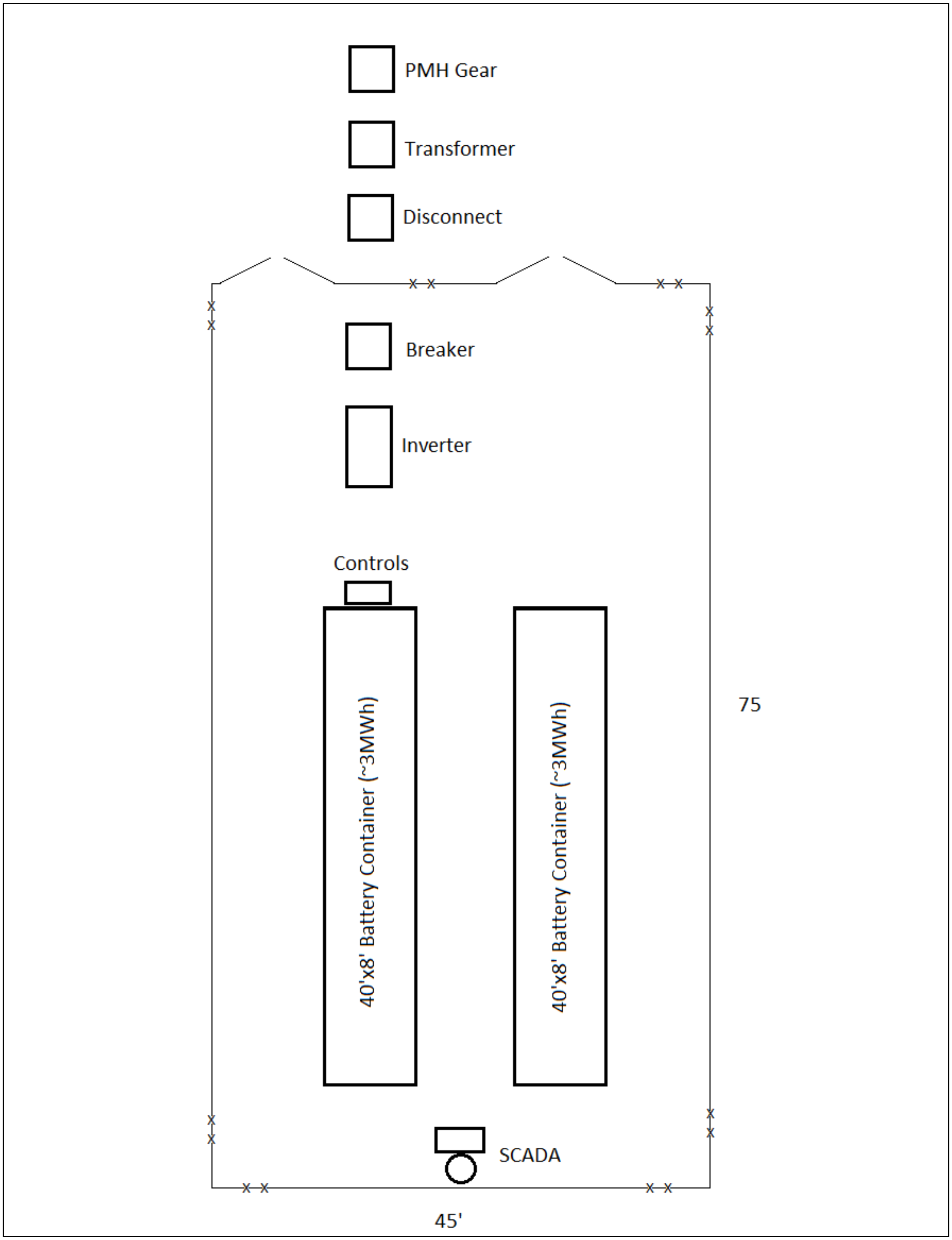
Director of LVD System Planning:	(DAL) *electronic routing*	Date:_____________
Director of HVD System Planning:	(DCP) *electronic routing*	Date:_____________
Executive Director of Electric Planning:	(RTB) *electronic routing*	Date:_____________
VP of Electric Grid Integration:	(TJS) *electronic routing*	Date:_____________
Senior VP of Transformation, Engineering & Operations Support:	(JFB) *electronic routing*	Date:_____________

Location Map

Basic One-line



Preliminary Equipment Layout



Tables Supporting NPV Analysis: Summary Page

ECONOMIC ANALYSIS OF ALTERNATIVE PLANS

Standish Battery

DESCRIPTION of ALTERNATIVES	Sum of Present Worth of Revenue Requirements	Total Capital
Subs Only	$5,051.679	$4,500
Battery Only	$14,713.549	$11,022
Battery + Subs Deferral	$19,175.956	$15,722
Deferral Value =	$589.271	

Tables Supporting NPV Analysis: NPV Calculation for Alternative 1

Alternative 1 Description	Substation Upgrades Without Deferral											
								Total Annual Costs			Sum of	Present Worth
	Capital	O&M	Losses in MW			Escalatec	Cummula	Fixed	Escalated	Loss	Total	of Total
	Capital	O&M				Capital	Capital	Charges	O&M	Costs	Annual	Annual
	Costs	Costs	CE Cu	METC Cu	Core	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	Costs	Costs
Year	($1,000)	($1,000)	Copper		Core	Costs	Costs	Charges	O&M	Losses	TOTAL	
2020						0	0	0	0	0	0	0
2021	1500					1,533	1,533	169	0	0	169	146
2022						0	1,533	169	0	0	169	136
2023						0	1,533	169	0	0	169	127
2024	1500					1,636	3,169	350	0	0	350	244
2025						0	3,169	350	0	0	350	227
2026						0	3,169	350	0	0	350	211
2027	1500					1,747	4,916	543	0	0	543	304
2028						0	4,916	543	0	0	543	283
2029						0	4,916	543	0	0	543	263
2030						0	4,916	543	0	0	543	245
2031						0	4,916	543	0	0	543	228
2032						0	4,916	543	0	0	543	212
2033						0	4,916	543	0	0	543	197
2034						0	4,916	543	0	0	543	183
2035						0	4,916	543	0	0	543	171
2036						0	4,916	543	0	0	543	159
2037						0	4,916	543	0	0	543	148
2038						0	4,916	543	0	0	543	137
2039						0	4,916	543	0	0	543	128
2040						0	4,916	543	0	0	543	119
2041						0	4,916	543	0	0	543	111
2042						0	4,916	543	0	0	543	103
2043						0	4,916	543	0	0	543	96
2044						0	4,916	543	0	0	543	89
2045						0	4,916	543	0	0	543	83
2046						0	4,916	543	0	0	543	77
2047						0	4,916	543	0	0	543	72
2048						0	4,916	543	0	0	543	67
2049						0	4,916	543	0	0	543	62
2050						0	4,916	543	0	0	543	58
2051						0	4,916	543	0	0	543	54
2052						0	4,916	543	0	0	543	50
2053						0	4,916	543	0	0	543	46
2054						0	4,916	543	0	0	543	43
2055						0	4,916	543	0	0	543	40
2056						0	4,916	543	0	0	543	37
2057						0	4,916	543	0	0	543	35
2058						0	4,916	543	0	0	543	32
2059						0	4,916	543	0	0	543	30
TOTALS	4,500	0	0.00	0.00	0	4,916	176,343	19,468	0	0	19,468	5,052

Tables Supporting NPV Analysis: NPV Calculation for Battery Investment

	Description:	Battery Only										
								Total Annual Costs			Sum of	Present Worth
						Escalatec	Cummula	Fixed	Escalated	Loss	Total	of Total
	Capital	O&M	Losses in MW			Capital	Capital	Charges	O&M	Costs	Annual	Annual
	Costs	Costs	CE Cu	METC Cu	Core	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	Costs	Costs
Year	($1,000)	($1,000)	Copper		Core	Costs	Costs	Charges	O&M	Losses	TOTAL	
2020	2,842.5					2,843	2,843	314	0	0	314	292
2021	8,131.5					8,310	11,153	1,231	0	0	1,231	1,065
2022	48					50	11,203	1,237	0	0	1,237	996
2023						0	11,203	1,237	0	0	1,237	926
2024						0	11,203	1,237	0	0	1,237	862
2025						0	11,203	1,237	0	0	1,237	801
2026						0	11,203	1,237	0	0	1,237	745
2027						0	11,203	1,237	0	0	1,237	693
2028						0	11,203	1,237	0	0	1,237	645
2029						0	11,203	1,237	0	0	1,237	600
2030						0	11,203	1,237	0	0	1,237	558
2031						0	11,203	1,237	0	0	1,237	519
2032						0	11,203	1,237	0	0	1,237	483
2033						0	11,203	1,237	0	0	1,237	449
2034						0	11,203	1,237	0	0	1,237	418
2035						0	11,203	1,237	0	0	1,237	389
2036						0	11,203	1,237	0	0	1,237	362
2037						0	11,203	1,237	0	0	1,237	336
2038						0	11,203	1,237	0	0	1,237	313
2039						0	11,203	1,237	0	0	1,237	291
2040						0	11,203	1,237	0	0	1,237	271
2041						0	11,203	1,237	0	0	1,237	252
2042						0	11,203	1,237	0	0	1,237	234
2043						0	11,203	1,237	0	0	1,237	218
2044						0	11,203	1,237	0	0	1,237	203
2045						0	11,203	1,237	0	0	1,237	189
2046						0	11,203	1,237	0	0	1,237	175
2047						0	11,203	1,237	0	0	1,237	163
2048						0	11,203	1,237	0	0	1,237	152
2049						0	11,203	1,237	0	0	1,237	141
2050						0	11,203	1,237	0	0	1,237	131
2051						0	11,203	1,237	0	0	1,237	122
2052						0	11,203	1,237	0	0	1,237	114
2053						0	11,203	1,237	0	0	1,237	106
2054						0	11,203	1,237	0	0	1,237	98
2055						0	11,203	1,237	0	0	1,237	92
2056						0	11,203	1,237	0	0	1,237	85
2057						0	11,203	1,237	0	0	1,237	79
2058						0	11,203	1,237	0	0	1,237	74
2059						0	11,203	1,237	0	0	1,237	69
TOTALS	11,022	0	0	0	0	11,203	439,710	48,544	0	0	48,544	14,714

Tables Supporting NPV Analysis: NPV Calculation for Battery and Deferred Sub Upgrades

Alternative 2 Description			Battery Installation + Deferred Substation Upgrades									Present Worth of Total Annual Costs
								Total Annual Costs			Sum of Total Annual Costs	
			Losses in MW									
Year	Capital Costs ($1,000)	O&M Costs ($1,000)	CE Cu Copper	METC Cu	Core Core	Escalatec Capital ($1,000) Costs	Cummula Capital ($1,000) Costs	Fixed Charges ($1,000) Charges	Escalated O&M ($1,000) O&M	Loss Costs ($1,000) Losses	TOTAL	
2020	2,842.5					2,843	2,843	314	0	0	314	292
2021	8,131.5					8,310	11,153	1,231	0	0	1,231	1,065
2022	48					50	11,203	1,237	0	0	1,237	996
2023						0	11,203	1,237	0	0	1,237	926
2024	1600					1,746	12,949	1,430	0	0	1,430	996
2025						0	12,949	1,430	0	0	1,430	926
2026						0	12,949	1,430	0	0	1,430	862
2027	1600					1,863	14,812	1,635	0	0	1,635	917
2028						0	14,812	1,635	0	0	1,635	853
2029						0	14,812	1,635	0	0	1,635	793
2030	1500					1,865	16,676	1,841	0	0	1,841	831
2031						0	16,676	1,841	0	0	1,841	773
2032						0	16,676	1,841	0	0	1,841	719
2033						0	16,676	1,841	0	0	1,841	669
2034						0	16,676	1,841	0	0	1,841	622
2035						0	16,676	1,841	0	0	1,841	579
2036						0	16,676	1,841	0	0	1,841	538
2037						0	16,676	1,841	0	0	1,841	501
2038						0	16,676	1,841	0	0	1,841	466
2039						0	16,676	1,841	0	0	1,841	433
2040						0	16,676	1,841	0	0	1,841	403
2041						0	16,676	1,841	0	0	1,841	375
2042						0	16,676	1,841	0	0	1,841	349
2043						0	16,676	1,841	0	0	1,841	325
2044						0	16,676	1,841	0	0	1,841	302
2045						0	16,676	1,841	0	0	1,841	281
2046						0	16,676	1,841	0	0	1,841	261
2047						0	16,676	1,841	0	0	1,841	243
2048						0	16,676	1,841	0	0	1,841	226
2049						0	16,676	1,841	0	0	1,841	210
2050						0	16,676	1,841	0	0	1,841	196
2051						0	16,676	1,841	0	0	1,841	182
2052						0	16,676	1,841	0	0	1,841	169
2053						0	16,676	1,841	0	0	1,841	157
2054						0	16,676	1,841	0	0	1,841	146
2055						0	16,676	1,841	0	0	1,841	136
2056						0	16,676	1,841	0	0	1,841	127
2057						0	16,676	1,841	0	0	1,841	118
2058						0	16,676	1,841	0	0	1,841	110
2059						0	16,676	1,841	0	0	1,841	102
TOTALS	15,722	0	0	0	0	16,676	619,977	68,445	0	0	68,445	19,176

Question:

2) Refer to Attachment 126 filed under Part III – Public of the Company's Application. For each of the Top 25 Projects in 2022 Test Year, please provide the following:

a. The number of customers serviced by the line, substation, or component;
b. The number of outages on the line, substation, or component since 2011;
c. The length of each outage on the line, substation, or component since 2011; and
d. The cause of each outage on the line, substation, or component since 2011.
e. For each capacity-related project, the present load and projected overload data (year) for the component.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request to that it seeks information as far back as 2011, which is irrelevant, overly broad, unduly burdensome, and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:

1. Distribution Automation Battery

a. Number of customers serviced by each circuit to which the battery will attach:
   i. Gun Lake Substation, Trails End Circuit services approximately 1,191 customers.
   ii. Neeley Substation, Hooper Circuit services approximately 341 customers.
b. The Company relies on the information provided in Concept 22-0053 to substantiate this project. As stated in Concept 22-0053, number of customer interruptions for primary devices between 2015 – 2019:
   i. Gun Lake Substation, Trails End Circuit 18,139 customer interruptions.
   ii. Neeley Substation, Hooper Circuit 4,975 customer interruptions.
c. As stated in Concept 22-0053, average outage duration between 2015 – 2019;
   i. Gun Lake Substation, Trails End Circuit 478 minutes (CAIDI).
   ii. Neeley Substation, Hooper Circuit 634 minutes (CAIDI).
d. Outage causes for answer (b) above was not part of the Concept 22-0053 evaluation and is not readily accessible.
e. Substation capacity data:
   i. Gun Lake Substation 2020 load was 12.26 MVA, projected overload in 2056 at 20.95 MVA.
   ii. Neeley Substation 2020 load was 2.94 MVA, projected overload in 2041 at 4.02 MVA.

2. Higgins Substation Rebuild - Completion

a. Approximately 35,000. Note that all customers are also fed by a second HVD substation.
b. One since 2011
c. 84 minutes
d. Relay issue. System was in non-standard configuration.
e. Not Applicable. Reliability project.

3. Wayland Substation Rebuild – Part 1

a. Approximately 13,100. Note that all customers are also fed by a second HVD substation.
b. One since 2011
c. 130 minutes
d. Recloser failed due to bird nest causing main station fuses to blow. System was in non-standard configuration
e. Not Applicable. Reliability project.

4. North Belding Substation Rebuild – Part 1

a. Approximately 20,900. Note that all customers are also fed by a second HVD substation
b. None since 2011.
c. N/A
d. N/A
e. Not Applicable. Reliability project

5. Santiago 138kV Tap and Line

a. N/A – new line, not in service yet.
b. N/A – new line, not in service yet.
c. N/A – new line, not in service yet.
d. N/A – new line, not in service yet.
e. N/A – new line, not in service yet.

8. Morrow (new sub to be named Celery) Substation Rebuild – Completion

a. Approximately 37,200. Note that 33,500l customers are also fed by a second HVD substation.
b. Three since 2011.
c. The length of each extended outage of the substation since 2011:
   i. 178 minutes
   ii. 469 minutes
   iii. 464 minutes
d. The cause of each extended outage of the substation since 2011:
   i. Failed circuit breaker initiated by a lightning strike. Activated breaker failure relaying.
   ii. Violently failed circuit breaker activated breaker failure relaying.
   iii. Failed bus insulator. System was in non-standard configuration.
e. Not Applicable. Reliability project.

10. Mobile #24

a. N/A – new component, not in service yet.
b. N/A – new component, not in service yet.
c. N/A – new component, not in service yet.
d. N/A – new component, not in service yet.
e. N/A – new component, not in service yet. The component will not be operated outside of its electrical ratings.

14. Rebuild Coopersville 46 kV Line Cleveland – Rochester Products

a. Approximately 1,600.
b. Four since 2011.
c. The length of each extended outage on the line since 2011:

   i. 72 minutes
   ii. 82 minutes
   iii. 42 minutes
   iv. 120 minutes

d. The cause of each extended outage on the line since 2011:
   i. Pole
   ii. Distribution Underbuild
   iii. Insulator
   iv. Insulator

e. Not Applicable, as stated in the previously provided Concept Approval 23-0010, this project is being done to address clearance violations and needed pole replacements on this line.

18. MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD

a. The number of customers served by this project is 210, as noted in Part III, Attachment 126, p. 174.
b. There have been 7 outages since 2011 attributed to the facilities covered by this project.
c. The outage lengths were: 649, 364, 256, 166, 76, 44, and 88 minutes.
d. The causes of these outages were: Equipment failure, Equipment failure, Planned/Scheduled, Planned/Scheduled, Planned/Scheduled, Planned/Scheduled, and Planned/Scheduled.
e. This is not a capacity-related project.

19. ELEANOR STREET UPGRADES

a. The number of customers served by this project is 76 (43 + 33), as noted in Part III, Attachment 126, p. 197.
b. There have been 2 outages since 2011 attributed to the facilities covered by this project.
c. The outage lengths were: 120 and 118 minutes.
d. The causes of these outages were: Forced Outage/Emergency and Forced Outage/Emergency.
e. This is not a capacity-related project.

20. Metro Mobile Vaults

a. This question does not apply because the component has not yet been acquired.
b. This question does not apply because the component has not yet been acquired.
c. This question does not apply because the component has not yet been acquired.
d. This question does not apply because the component has not yet been acquired.
e. This is not a capacity-related project.

22. Broadmoor #1 Transformer Replacement

a. Approximately 9,500. Note that 4,500 customers are also fed by a second HVD substation.
b. None since 2011.
c. N/A
d. N/A
e. Not Applicable. Reliability project.

23. Beecher #5 Transformer Replacement

a. Approximately 17,300. Note that all customers are also fed by the Beecher #6 transformer which is in parallel. Note that 10,600 are also fed by a second HVD substation.
b. None since 2011.

c. N/A
d. N/A
e. Not Applicable. Reliability project.

24. DARE-SUB LINCOLN/LOST LAKE

a. There are 1536 customers that will be impacted by the 2022 project.
b. There have been 22 outages since 2011 attributed to the facilities covered by this project.
c. The outage lengths were: 816, 181, 739, 182, 1006, 2299, 87, 79, 20, 152, 429, 59, 163, 337, 516, 100, 486, 290, 828, 2917, 268, 73 minutes.
d. The causes of these outages were: Unique Incident, Equipment failure, Equipment failure, Equipment failure, Trees, Weather, Trees, HVD Equipment failure, HVD Equipment failure, Equipment failure, Equipment failure, No Specific Cause Found, Equipment failure, HVD Line/Lightning, Trees, Trees, Planned/Scheduled, Trees, HVD line/Weather, Trees, Weather, and HVD line/Equipment failure.
e. The present load on the substation transformer component is 7.1 MVA and is currently overloaded at 108%

Information related to projects 6, 7, 9, 11, 12, 13, 15, 16, 17, 21, and 25, as listed in Part III Requirement #126, is provided in Attachment 1 to this discovery response.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 1, 2021

Electric Planning

<u>Question:</u>
14. Refer to Mr. Blumenstock's direct testimony, page 216, lines 9, and to Concept Approval 22-0053 for the "Distribution Automation BESS – Neely and Gun Lake Substations" in Part III Attachment 126 provided with the Company's Application.

a. Did the Company perform a Reliability Improvement Estimate for Alternative 1 or Alternative 2? If so, please provide them. If not, please explain why not.
b. Please provide a copy of the technology evaluation for this project.
c. Please describe and itemize the $1,499,533 annual O&M cost that is a "reliability penalty" addressed in the Concept Approval and the NPVs.
d. Please provide an excel version of the NPV Tables 1 to 5.
e. Alternative 1 would wait for capacity overload in 2025 to upgrade the Neeley substation. Did the Company consider any alternatives that would address the identified causes of outages and reliability issues discussed on page 2 of the Concept Approval? If so, please describe such alternative(s). If not, please explain why not.
f. Did the Company seek bids or issue a Request for Proposal (RFP) for an alternative ownership approach, other than utility-ownership, for this battery storage project? If so, please provide all supporting documents. If not, please explain why not.

<u>Response:</u>

a. The reliability improvement estimation that was presented with Alternative 3 is the same across all alternatives. For Alternative 1, the reliability improvement is realized through distribution automation once capacity is increased at Neeley Substation, and the backbones of the two neighboring circuits are reconductored to support the load transfers. In the case of Alternative 2, the lithium-ion battery would also allow transfers of the same size and scope as in Alternative 3.
b. The technology evaluation is not being performed. The technology evaluation would have assessed a long duration battery. However, since the original Concept Approval was developed, the Company has instead opted to use a lithium-ion battery instead, and a technology evaluation is not necessary for this, as lithium-ion battery technology is well-understood by the Company. Attachment 1 to this discovery is a revised Concept Approval showing that a lithium-ion battery is now being used.
c. The reliability penalty is a monetized measure of the reliability improvement based on customer minute savings. In the Concept Approval, the reliability penalty is used to assess the relative advantage of each alternative over the others according to when the system changes are performed. An annual cost equivalent to the reliability penalty is applied to all three alternatives for each year the system changes are deferred. This is the cost of "neglecting" the reliability benefit that can be attained by the proposed system improvements. Earlier system changes result in fewer years incurring the penalty.

   The reliability penalty is based on the annual average customer-minute savings that the system changes can yield, valued at a flat cost of $3 for every minute a customer is out. In the Concept Approval, the average savings were estimated to be 499,533 customer minutes per year. These two components yield a total of $1,498,599—the $1,499,533 stated in the concept is an error.

The customer-minute savings are based on the historical outage data of the two circuits and were obtained by subtracting the outage contributions of customers between the circuit tie and the sectionalizing devices to be deployed with the automation loop.

d. Please refer to Attachment 2 to this discovery response. Note that in this attachment, the reliability penalty referenced in subpart c is rounded to $1,499,000.

e. The Company has already completed several reliability projects to improve the performance of the Gun Lake and Neeley substation circuits since 2017. These include a rebuild of the Gun Lake 46kV line, a full forestry line clearing of the Gun Lake/Trails End circuit in 2018, reliability projects in 2017, 2018, and 2020, and repetitive outage projects in 2019 and 2021. For the Neeley/Hooper circuit, the Company completed repetitive outage projects in 2017 and 2019, with a third project being executed in 2021. Additionally, a protection project in 2019 corrected several miscoordination issues on the Neeley/Hooper circuit. However, power restoration on the two circuits targeted by this battery project is particularly challenging because they serve areas that are far away from their respective headquarters and go across heavily wooded and swampy terrain. Ultimately, the Company decided to address the lingering reliability issues by installing distribution automation between these two circuits to reduce the number of customers affected by outages on the first protection zones. But for distribution automation to make a significant reliability improvement on these two circuits, substation and line capacity upgrades are required.

f. The Company is not seeking an alternative ownership approach for this project. Ownership of this project will give the Company experience with design, construction, operation, and maintenance of battery technology deployed for outage mitigation purposes. The experience gained from this battery project, and others like it, will allow for better assessment of battery technology and its application to the Company's electric grid.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 15, 2021

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Consumers Energy
Distribution Substation Planning & Reliability
CONCEPT APPROVAL

Concept Number: 22-0053 County: Allegan

Project: Distribution Automation Battery Application - Neeley & Gun Lake Substations

Date: 12/16/2020 Need System Changes By: 12/31/2022

Problem Description

The ability to transfer customers between adjacent feeders to mitigate outages has proven essential to improving the reliability of the electric service. Distribution automation spares CE's customers from hundreds of thousands of outage minutes annually. However, as this program expands with new automatic transfer scheme (ATS) implementations each year, a pool of unviable feeders also grows.

Currently, 228 ATS proposals are deemed unviable for field implementation. Of these proposals, 83 have been rejected due to inadequate distribution infrastructure to support the load transfers and 53 are due to having the proposed feeders already involved in other active or scheduled loops. The main problem with these two groups is that capacity limitations at the substation, or on the lines, put these feeders at much higher risk of failure when accepting automatic transfers.

The annual selection of ATS proposals is based on a cost-benefit evaluation, which favors proposals with the highest cost-benefit ratios. Proposals with capacity limitations normally require extensive work and cost to build adequate system capacity for automatic transfers; therefore, their cost is usually too high to justify selection, even when some of the feeders in them may have had consistently poor reliability performance over the years. Choosing proposals with high cost-benefit ratios results in a better return-on-investment, and with feeders needing little work, more of these can be accommodated within in the same budget. But, some of the proposals deemed unviable, could also show attractive cost- benefit ratios if the resulting reliability benefit is considered over a long period of time.

Unviable proposals, however, are unlikely to be reevaluated as long as viable feeders remain in the selection pool, or capacity upgrades remove the limitations from the feeders, both of which could take a while. Until then, opportunities for the company and our customers to capitalize on the benefits of an earlier ATS deployment may be missed.

The purpose of this concept is to introduce a new pilot project involving a battery energy storage system (BESS) connected to the distribution system to support automatic load transfers between feeders with poor reliability and capacity limitations. With this project CE will explore and develop the interconnection requirements needed to provide a BESS with the ability to automatically switch between two circuits, as a component of an automation scheme. This use case will also allow the company to assess how the revenue-generating value of a BESS can be increased through direct reliability gains.

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An alternative under consideration for the battery technology is a long-duration storage system. Long-duration batteries have the advantage over li-ion batteries of relatively long lifetimes, more flexible depth-of-discharge and state-of-charge controls, and less demands for constant temperature monitoring for safe operation. Selecting a long-duration battery for this project will allow the company to gain technical and operational knowledge on long-duration systems, ahead of the anticipated growth of renewable generation in our state.

Project Specific:

A BESS installed at the tie point between two distribution feeders has the unique advantage of providing additional capacity at the end of both circuits. From this location, a properly sized battery could allow automatic transfers between feeders with insufficient capacity to accept load, even during peak demand periods. By placing the point of interconnection for the BESS between two ties, as shown in Attachment 1, the BESS will have a normal connection to one preferred feeder but will be able to switch to the alternate feeder if required. When a transfer is needed, the BESS site controller can reconfigure the interconnection so that the BESS can support the transfer while connected to the energized source. In normal configuration, the BESS can perform other services like peak shaving, frequency regulation, volt-var control, and market interaction.

In this application, the BESS is not intended for islanding and will always have a connection to one energized feeder. This guarantees proper grounding and eliminates the issue of inverters producing low fault currents that wouldn't operate traditional protection devices.

An ATS proposal between the Neeley\Hooper and Gun Lake\Trails End feeders offers an opportunity to deploy a BESS for this use case. These two feeders have small conductors (#2ACSR) on their entire backbone (approximately 5.7 miles combined), and Neeley Substation is currently loaded at 90%, with about 800kVA of remaining capacity. Based on these conditions, these feeders are not suitable for automatic transfers. At the observed growth rate of 1.56% per year, the transformer at Neeley Substation is projected to reach overload in 2025, which means that a capacity upgrade may not be needed until then. Neeley and Gun Lake Substations have only one three-phase tie in common, with no other ties to neighboring substations. Both substations are remote, with their circuits winding through heavily wooded and swampy areas. As proposed, this ATS could potentially impact up to 278 customers. The proposed location for installing the BESS is provided on Attachment 2.

Outage data from the past five years (2015-2019) indicates that customers on the Gun Lake/Trails End feeder experienced an average of 1,734,911 outage minutes annually, with 62% of these minutes caused by the operation of the reclosers at the substation. The average customer on this circuit was out for 478 minutes (7.97 hours) per year. Gun Lake/Trails End had the tenth highest interruption rate (3.22) among feeders of similar lengths and number of customers. Primary outages on the Neeley/Hooper feeder caused 631,241 outage minutes per year for the same period, of which 61% were due to faults on the first protection zone. The average customer on the Neeley/Hooper circuit was out for 634 minutes (10.57 hours) per year. Neely/ Hooper had the third highest interruption rate (2.92) from the group of feeders with comparable lengths and customer counts.

A CYME model of the two circuits and a BESS was used to simulate the transfers associated with the proposed ATS. This simulation indicated that a BESS with a minimum power rating of 0.9 MW

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and an energy rating of 3.6 MWh (4-hour duration) would enable the two feeders to accept automatic load transfers from each other for ten years after a tentative installation in 2022. To retain the same functionality 15 years after installation, the BESS would require power and energy rating of 1.2 MW and 7.2 MWh (6-hour duration). Assessment of the potential reliability benefit that can be attained with this application showed that installing the BESS and associated ATS could potentially save 499,533 customer minutes per year, which would yield a combined CAIDI improvement of 10.3% (Attachment 3). Because of the bank capacity limitation at Neeley Substation, the recommended feeder for the normal BESS interconnection is Neeley/Hooper, so the BESS can also perform peak shaving to relieve the substation when not needed for transfers. A desirable location identified for the BESS is shown in Attachment 2.

This concept approval considers all types of batteries, including long-duration storage. One long-duration technology of particular interest is flow batteries. In general, flow batteries offer durations above six hours at peak power output, which aligns with outages mitigation needs, and have operational lifetimes between 15 and 20 years. Flow batteries have low chemistry degradation and do not require strict temperature controls for proper operation due to their low fire risk. They are also capable of fast response and can adjust their output to quickly mitigate transient conditions on the grid. However, one major drawback of long-duration technology, in comparison with lithium-based energy storage, is low round-trip efficiency (~70% compared to ~86% for li-ion batteries).

Due to the wide variability in cost and operational lifespans attributed to long-duration technologies in the published literature, a power and energy rating of 1.2 MW and 7.2 MWh and a service life of 15 years have been established as the minimum requirements for the long-duration system to be procured. These minimum requirements will guarantee a minimum cost for a system that will be able to perform as expected for the majority of its lifetime.

The risks associated with this project include:

1. Unknowns of investing in a relatively new technology, particularly if long-duration batteries are selected.
2. Finding a reliable vendor of a commercially mature long-duration battery system (if selected) that can accommodate the required specifications.
3. The communications interfacing and programming needed for the BESS and ATS to operate as intended may fall outside CE’s expertise and standard equipment options.
4. The two feeders involved in the ATS may experience faster growth that has been anticipated, rendering the battery unable to support the transfers at an earlier time.
5. Potential of customer loads increasing past the battery capabilities, preventing the load transfers.
6. Potential of load imbalances on the circuits that could prevent proper inverter operation.

Project Goals:

The goals for this demonstration project are:

1. Use a BESS to support automatic load transfers between distribution circuits with insufficient transfer capabilities.

2. Develop and install a communications-based interconnection design to allow a BESS to switch between two adjacent circuits according to power flow conditions.
3. Develop safety and operational procedures for battery-supported distribution automation with battery transfer between the feeders. The proposed ATS will be in an area where no distribution automation currently exists; the addition of the storage system along with the ATR devices will require developing a more comprehensive set of procedures and training for the line crews. The Neeley/Hooper and the Gun Lake\Trails End feeders are also managed from different headquarters, which will require additional awareness and coordination during normal operations and restoration work.
4. Explore the operational capabilities of commercially available long-duration storage systems and explore their feasibility for deployment within CE's distribution system.
5. Understand how to use a BESS that is primarily intended for load transfer support, for:
    a. Circuit peak shaving
    b. Circuit power quality
    c. Market interaction
6. Explore and understand how to implement weather-based predictive algorithms to establish BESS charging and discharging patterns.

Alternatives:

1. **Don't explore using a storage system to support load transfers between circuits.** Wait for the Neeley Substation transformer to reach overload in 2025 and perform a capacity upgrade at the substation and the backbones of Neeley/Hooper and Gun Lake/Trails End. This option avoids additional up-front costs by implementing traditional substation and line capacity upgrades after the substation capacity has been exceeded.

    2026

    - Upgrade the Neeley Substation transformer with a 5.6/6.25 MVA bank. ($400,000)
    - Reconductor 5.7 miles (with 100% pole replacement) of 2ACSR overhead line on the backbone of Neeley/Hooper and Gun Lake/Trails End with 336ACSR conductor ($1,707,000).

    2027

    - Install a regular ATS between the two circuits without any additional logic or communication features ($380,000).
    - LVD Protection reconfiguration ($20,000).

    Total Cost = $2,507,000 (NPV: $10,482,000. This NPV includes a reliability penalty)

2. **Complete the installation of a li-ion BESS between the Neeley/Hooper and Gun Lake/Trails End feeders to enable load transfers between the two circuits**. With the deployment of two li-ion batteries in recent years and the ongoing effort to install three more, the company has already accumulated significant experience on procurement, engineering and construction of lithium-based storage systems. This acquired experience will limit risks and

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minimize the impact of unknowns associated with the storage technology. Using a li-ion BESS will limit the operational lifetime of this application to 10 years.

2021-2023

- Install li-ion BESS by the three-phase tie between the Neeley/Hooper and Gun Lake/Trails End feeders to enable load transfers between the two circuits ($4,209,000).
- Install the proposed ATS with four communication-enabled devices and required interfaces to interact with the BESS controller ($1,617,000).

2031

- Reconductor 2.84 miles (with 100% pole replacement) of 2ACSR overhead line on the Neeley/Hooper backbone with 336ACSR conductor ($852,000).

2032

- Reconductor 2.85 miles (with 100% pole replacement) of 2ACSR overhead line on the and Gun Lake/Trails End with 336ACSR conductor ($855,000).

2033

- Upgrade the Neeley Substation transformer with a 5.6/6.25 MVA bank ($400,000).
- Remove battery storage system ($100,000).

Total Cost = $8,033,000 (NPV: $11,454,000. This NPV includes a reliability penalty, annual BESS maintenance, and BESS retirement at end of life)

3. **Complete the installation of a long-duration battery storage system to enable load transfers between the feeders Neeley/Hooper and Gun Lake/Trails End**. This alternative would allow CE to develop a knowledge base on long-duration technologies by deploying a small long-duration system on the distribution network. As CE expands its renewable generation fleet, long-duration energy storage will be an essential piece in the company's portfolio for attaining 40% of renewable energy by 2040. As of today, long-duration systems have higher up-front costs than lithium-based storage, however, these costs have also been declining in recent years and are projected to continue falling as these systems gain more visibility in the market. A long duration system will generally be operational for five additional years compared to lithium-based battery storage.

2021-2023

- Install a long-duration battery system between the Neeley/Hooper and Gun Lake/Trails End feeders to enable load transfers between the two circuits ($8,302,000)
- Install the proposed ATS with four communication-enabled ATR devices and the required interfaces for the two substations and line ATRs to interact with the battery controller ($1,617,000).

2036

- Reconductor 2.84 miles (with 100% pole replacement) of 2ACSR overhead line on the Neeley/Hooper backbone with 336ACSR conductor ($852,000).

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<u>2037</u>

- Reconductor 2.85 miles (with 100% pole replacement) of 2ACSR overhead line on the and Gun Lake/Trails End with 336ACSR conductor ($855,000).

<u>2038</u>

- Upgrade the Neeley Substation transformer with a 5.6/6.25 MVA bank ($400,000).
- Remove battery storage system ($100,000).

Total Cost = $12,126,000 (NPV: $16,115,000. This NPV includes a reliability penalty, annual BESS maintenance, and BESS retirement at end of life)

<u>Recommended Alternative:</u>

The recommended solution is Alternative 2 – Complete the installation of a lithium-based storage system to enable load transfers between the feeders Neeley/Hooper and Gun Lake/Trails End in 2022**.**

Alternative 1. Implementing a traditional capacity upgrade at Neeley Substation and on the backbones of the two feeders will prevent CE from learning how to deploy a battery system capable of boosting reliability on two neighboring distribution circuits. Choosing not to deploy the BESS for this application will also deprive the Company from the opportunity to develop a novel non-wires alternative that captures additional value from the BESS.

Alternative 2. The shorter service life of the li-ion BESS allows for smaller power and energy ratings, which in turn provide a significant reduction in up-front costs for this system. With 0.9 MW and 3.6MWh, the BESS will be capable of supporting automatic transfers on either circuit for a minimum of eight hours ten years after installation. Li-ion batteries are used extensively in grid applications and have a verifiable operational track record. CE has deployed a few of these systems and continues to work on additional deployments, further expanding our experience on li-ion storage. As the company's renewables portfolio continues to grow, however, the need to explore storage options capable of durations beyond four hours of continuous operation becomes more apparent. While using a li-ion BESS is the lowest-cost storage option for this case, it would delay CE from developing the skillset necessary to deploy larger long-duration systems.

Alternative 3. Completing the installation of a long-duration storage system to enable load transfers between the feeders Neeley/Hooper and Gun Lake/Trails End is not recommended because of the higher up-front costs and NPV, as well as the associated risk of employing a relatively immature technology. To be able to support the projected demand for a minimum of 15 years after 2022, the system to be procured would require power and energy ratings of 1.2 MW and 7.2 MWh, which will come at the indicated much higher cost. Additionally, this alternative involves higher engineering and operational risks due to the general lack of field experience with these technologies in distribution environments.

A lithium-based BESS will allow CE to address the existing reliability and capacity concerns on the identified circuits in an innovative way, while minimizing the cost and risk associated with the type of storage technology employed.

The economic comparison of the three alternatives, considering an annual reliability penalty, continued battery maintenance, and battery removal at the end of life, is provided in the following table. This analysis used a flat rate of $3 per customer-minute to penalize the annual deferral of the reliability improvement. This is the average cost to CE for each outage minute. Annual battery maintenance costs were estimated at a rate of $10/kW-year. A cost of $100,000 was assumed for battery removal at the end of life.

Yearly Activities per Alternative	Sum of Present Worth of Revenue Requirements	Total Capital (2021 – 2038)	First Year Capital (2021)
Alternative 1 2026: - Increase capacity at Neeley Substation - Reconductor Neeley/Hooper and Gun Lake/Trails End. 2027: - Install the proposed ATS to allow load transfers between Neeley/Hooper and Gun Lake/Trails End	$10,482,000	$2,507,000	$0
Alternative 2 2022: - Install li-ion BESS and the proposed ATS to allow load transfers between Neeley/Hooper and Gun Lake/Trails End. 2031: - Reconductor the Neeley/Hooper feeder. 2032: - Reconductor the Gun Lake/Trails End feeder. 2033: - Increase capacity at Neeley Substation. - Remove BESS.	$11,454,000	$8,033,000	$67,000
Alternative 3 2022: - Install long-duration battery storage system and the proposed ATS to allow load transfers between Neeley/Hooper and Gun Lake/Trails End. 2036: - Reconductor the Neeley/Hooper feeder. 2037: - Reconductor the Gun Lake/Trails End feeder. 2038: - Increase capacity at Neeley Substation. - Remove long-duration storage system.	$16,115,000	$12,126,000	$85,000

The estimated cost of installing the BESS and the associated ATS (not including the Neeley Substation upgrade and the line reconductors) is: $5,826,000 NPV= $7,253,000.

The economic analysis also indicates that, at the rate of $3 per customer-minute, installing the proposed ATS in 2022—as opposed to 2027 in Alternative 1—could yield up to $5,365,000 (NPV) in savings from outage reduction. The estimated NPV savings resulting from deferring the system capacity upgrades until 2032 is $981,000. The NPV tables showing this economic analysis are provided at the end of this document.

The estimated loaded CapEx for installing the li-ion BESS and the proposed ATS is $5,826,000.

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WBS Element	2021 Direct Cost	2021 Loaded Cost	Description
ED-98219-1-19-02-01	$15,000	$21,000	Property option secured
ED-98219-1-19-02-01	$33,000	$46,000	Technology evaluation study
WBS Element	**2022 Direct Cost**	**2022 Loaded Cost**	**Description**
ED-98219-1-19-02-01	$99,000	$139,000	Property acquisition completion
ED-98219-1-19-02-01	$447,000	$625,000	BESS contract execution & engineering milestone (20% BESS integrator price)
ED-98219-1-19-02-01	$97,000	$136,000	BOP Equipment (transformer, switches, relays, etc.)
ED-98219-1-19-02-01	$11,000	$15,000	Factory acceptance test visit
ED-98219-1-19-02-01	$28,000	$39,000	Dispatch Optimization Report (SGP)
ED-98219-1-19-02-01	$335,000	$469,000	Engineering drawings approval (15% BESS integrator price)
ED-98219-1-19-02-01	$1,228,000	$1,718,000	BESS delivery (55% BESS integrator price)
ED-98219-1-19-02-01	$374,000	$523,000	Site construction and BESS installation
ED-98219-1-19-02-01	$179,000	$250,000	BESS substantial completion (8% BESS integrator price)
ED-98219-1-19-02-01	$1,147,000	$1,605,000	Installation of tie devices, line ATRs, fiber, and related communications infrastructure
ED-98219-1-19-02-01	$94,000	$132,000	Project management and coordination
WBS Element	**2023 Direct Cost**	**2023 Loaded Cost**	**Description**
ED-98219-1-19-02-01	$44,000	$62,000	BESS commissioning (2% BESS integrator price)
ED-98219-1-19-02-01	$5,000	$7,000	Project management and coordination
ED-98219-1-19-02-01	$28,000	$39,000	White paper on findings from review of real data
Subtotal	$4,161,000	$5,826,000	
Customer Contribution	$0	$0	
Project Total CapEx	**$4,161,000**	**$5,826,000**	

All costs related to the BESS project will be funded by the 2.18 Grid Storage budget.

Present Need:

On approval, this document authorizes the DER/I&C Design group to proceed with the work order design and the acquisition of property and material pending receipt of appropriate budget authorization.

Prepared By: Demeury Naranjo Date: 06/14/2021

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Approvals:

HVD Planning Engineer, HVD System Planning	Benjamin T. Scott	Required
Director, LVD System Planning	Donald A. Lynd	Required
Director, HVD System Planning	Edward R. Mathews	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation/Eng & Ops Support	Jean-Francois Brossoit	Required

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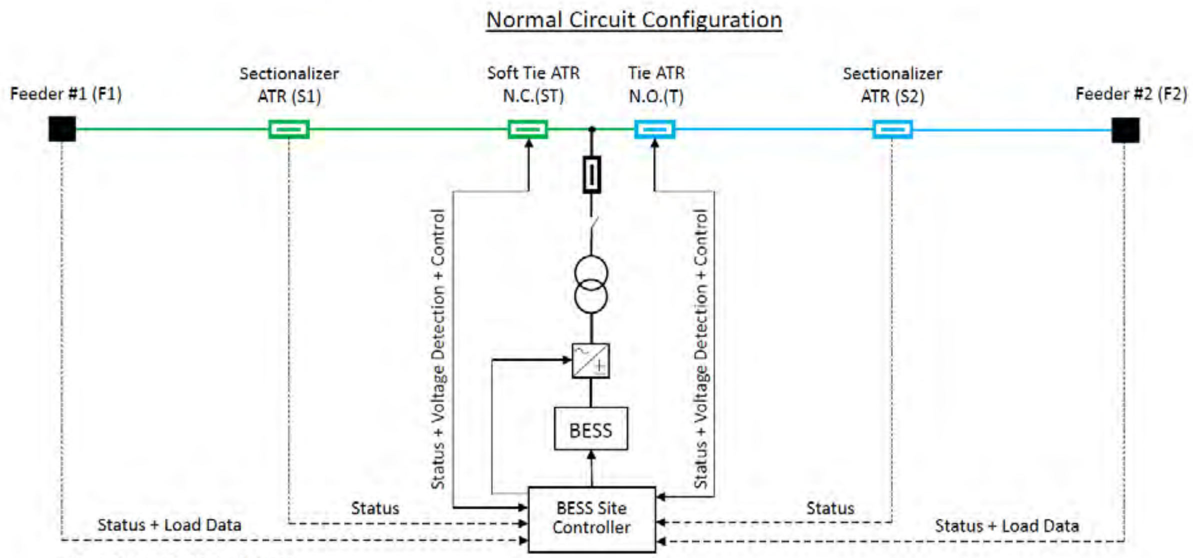
Attachment 1. BESS-Supported ATS Interconnection Diagram



General Operation Guidelines

1. BESS not to island. BESS is required to be attached to one energized feeder to operate.
2. Feeder #1 (F1) is the preferred feeder.
3. BESS not to parallel the feeders.
4. The Soft Tie and Tie devices will have protection settings enabled only when the power flow is reversed through them.
5. One transfer to be allowed before needing to reset the ATS.
6. Under certain conditions the BESS can be transferred alone.
7. The Status and Load data signals from the sectionalizer devices and the substation reclosers will be sent to the BESS Site Controller via cellular data transfer.
8. The BESS Site Controller will collect status and voltage detection information from the Soft Tie and Tie devices and will send commands to them via fiber interconnection.

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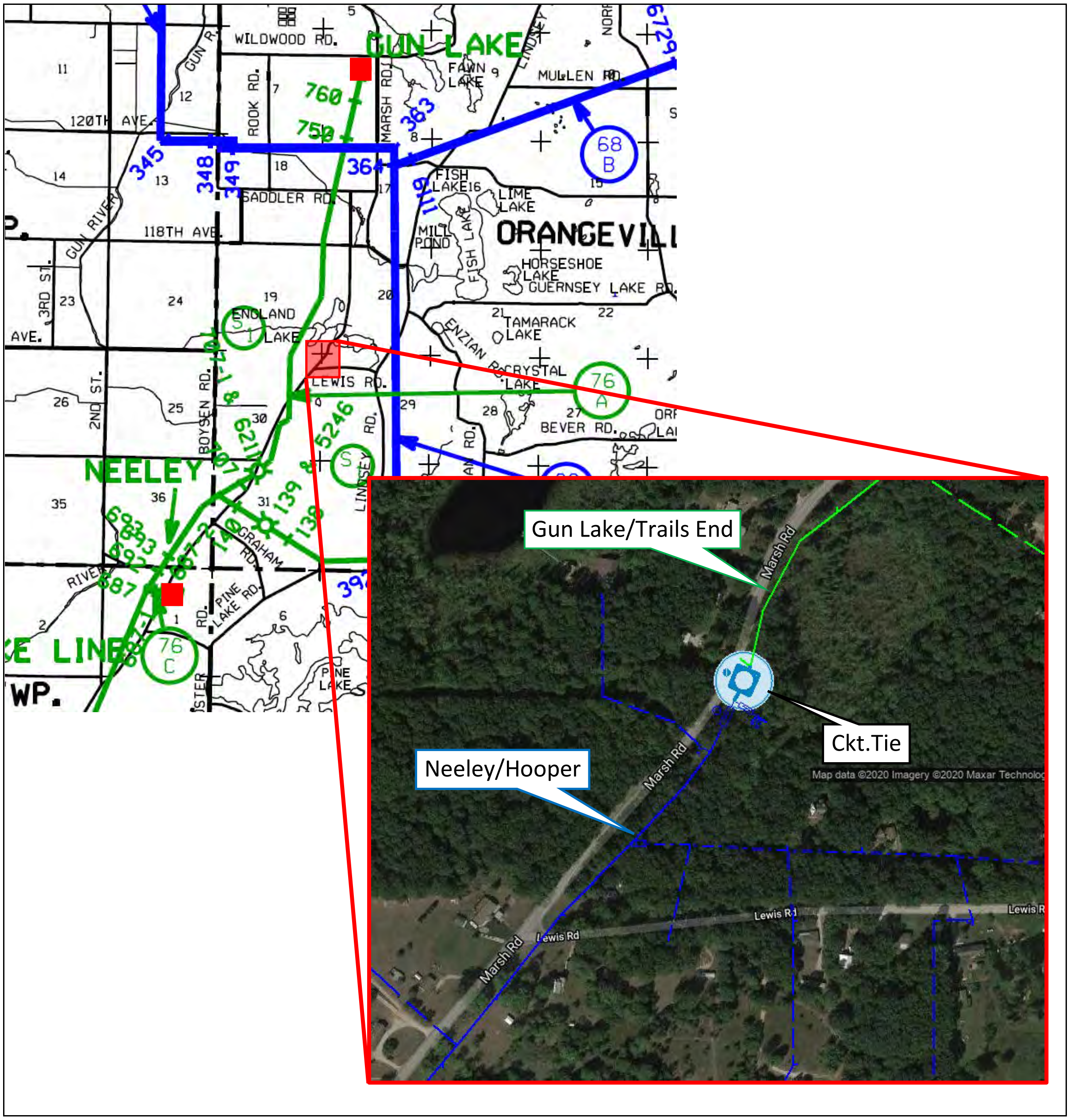
Attachment 2. Proposed Location for BESS Site



The preferred location for the BESS site is as close as possible to the circuit tie.
This area is in Orangeville Twp., Allegan County.

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Attachment 3. Reliability Improvement Estimate

Reliability Performance by Feeder During the Last Five Years (2015-2019)

Substation	Circuit	Customers Served	Customer Minutes	Customer Interruptions	Average Cust. Minutes
Gun Lake	Trails End (2-6)	1,127	8,674,553	18,139	1,734,911
Neeley	Hooper (1-6)	340	3,156,207	4,975	631,241

Substation	Circuit	Average Cust. Minutes	CAIDI	SAIDI	SAIFI
Gun Lake WD 0265	Trails End (2-6)	1,734,911	478	1539	3.22
Neeley WD 0368	Hooper (1-6)	631,241	634	1856	2.92
Both Feeders Combined		2,366,152	512	1612	3.15

Estimated Reliability Performance after the installation of the BESS and proposed ATS

Served Customers	Customer Minutes	Customer Interruptions	Average Cust. Minutes
1,127	6,715,609	16,059	1,343,122
340	2,617,487	4,275	523,497

Substation	Circuit	Average Cust. Minutes	CAIDI	SAIDI	SAIFI
Gun Lake WD 0265	Trails End (1-6)	1,343,122	418	1191	2.85
Neeley WD 0368	Hooper (1-6)	523,497	612	1539	2.51
Both Feeders Combined		1,866,619	459	1272	2.77

Estimated Reliability Improvement

Substation	Circuit	Average Cust. Minutes	CAIDI	SAIDI	SAIFI
Gun Lake WD 0265	Trails End (1-6)	391,789	60	348	0.37
Neeley WD 0368	Hooper (1-6)	107,744	22	317	0.41
All Feeders Combined Percent Improvement		499,533 21.1%	53 10.3%	340 21.1%	0.38 12.0%

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Attachment 4. Key Project Milestone Dates

Task	Date
Internal Concept Approval signed	05.15.21
RFP Issued	10.01.21
Property acquisition complete	01.15.22
Battery Integrator contract executed	01.15.22
Construction start	09.15.22
BESS equipment delivery	11.01.22
BESS substantial completion	12.15.22
ATS installation and commissioning Complete	12.31.22
BESS – ATS communications testing complete (final completion)	02.15.23

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NPV Table 1. Economic Analysis Summary

ECONOMIC ANALYSIS OF ALTERNATIVE PLANS

STUDY TITLE : CA 22-0053 Distribution Automation BESS - Neeley and Gun Lake Substations

	DESCRIPTION of ALTERNATIVES	Sum of Present Worth of Revenue Requirements	Total Capital	First Year Capital
ALTERNATIVE 1 :	Repl. TB at Neeley Sub with 5/6.25MVA Bank. Reconductor 5.7 miles of 2CSR feeder backbone	$10,482	$2,507	$0
ALTERNATIVE 2 :	Install li-ion BESS in 2022. Repl. Neeley Sub. TB and reconductor 5.7 miles of feeder backbone.	$11,454	$8,033	$67
ALTERNATIVE 3:	Repl. TB at Neeley Sub with 5/6.25MVA Bank. Reconductor 5.7 miles of 2CSR feeder backbone	$16,115	$12,126	$85
	NPV based on the CAPEX due to the installation of the li-ion BESS and the ATS	$7,253	$5,826	
	Estimated savings due to system capacity upgrade deferral by the li-ion BESS	$981		
	NPV based on the CAPEX due to the installation of the long-duration BESS and the ATS	$12,294	$9,919	
	Estimated savings due to system capacity upgrade deferral by the long-duration BESS	$1,342		
	Estimated savings due to the earlier reliability improvement resulting from installing a BESS	$5,365		

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NPV Table 2. Alternative #1 Cost Schedule Detail

Alternative 1 Description	Repl. TB at Neeley Sub with 5/6.25MVA Bank. Reconductor 5.7 miles of 2CSR feeder backbone											Present
								Total Annual Costs			Sum of	Worth
					Escalated	Cummulative	Fixed	Escalated	Loss	Total	of Total
	Capital	O&M	Losses in MW			Capital	Capital	Charges	O&M	Costs	Annual	Annual
	Costs	Costs	CE Cu	METC Cu	Core	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	Costs	Costs
Year	($1,000)	($1,000)	Copper		Core	Costs	Costs	Charges	O&M	Losses	TOTAL	
2020						0	0	0	0	0	0	0
2021		1499				0	0	0	1,532	0	1,532	1,325
2022		1499				0	0	0	1,565	0	1,565	1,260
2023		1499				0	0	0	1,600	0	1,600	1,198
2024		1499				0	0	0	1,635	0	1,635	1,139
2025		1499				0	0	0	1,671	0	1,671	1,083
2026	2107	1499				2,401	2,401	265	1,708	0	1,973	1,189
2027	400	1499				466	2,867	316	1,745	0	2,062	1,156
2028						0	2,867	316	0	0	316	165
2029						0	2,867	316	0	0	316	154
2030						0	2,867	316	0	0	316	143
2031						0	2,867	316	0	0	316	133
2032						0	2,867	316	0	0	316	124
2033						0	2,867	316	0	0	316	115
2034						0	2,867	316	0	0	316	107
2035						0	2,867	316	0	0	316	99
2036						0	2,867	316	0	0	316	93
2037						0	2,867	316	0	0	316	86
2038						0	2,867	316	0	0	316	80
2039						0	2,867	316	0	0	316	75
2040						0	2,867	316	0	0	316	69
2041						0	2,867	316	0	0	316	64
2042						0	2,867	316	0	0	316	60
2043						0	2,867	316	0	0	316	56
2044						0	2,867	316	0	0	316	52
2045						0	2,867	316	0	0	316	48
2046						0	2,867	316	0	0	316	45
2047						0	2,867	316	0	0	316	42
2048						0	2,867	316	0	0	316	39
2049						0	2,867	316	0	0	316	36
2050						0	2,867	316	0	0	316	34
2051						0	2,867	316	0	0	316	31
2052						0	2,867	316	0	0	316	29
2053						0	2,867	316	0	0	316	27
2054						0	2,867	316	0	0	316	25
2055						0	2,867	316	0	0	316	23
2056						0	2,867	316	0	0	316	22
2057						0	2,867	316	0	0	316	20
2058						0	2,867	316	0	0	316	19
2059						0	2,867	316	0	0	316	18
TOTALS	2,507	10,490	0.00	0.00	0	2,867	97,002	10,709	11,455	0	22,164	10,482

-$1,499,533 in annual O&M cost is used as a penalty for the deferral of reliability improvement

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NPV Table 3. Alternative #2 Cost Schedule Detail

Alternative 2 Description			Install li-ion BESS in 2022. Repl. Neeley Sub. TB and reconductor 5.7 miles of feeder backbone.									Present
								Total Annual Costs			Sum of	Worth
						Escalated	Cummulative	Fixed	Escalated	Loss	Total	of Total
	Capital	O&M	Losses in MW			Capital	Capital	Charges	O&M	Costs	Annual	Annual
	Costs	Costs	CE Cu	METC Cu	Core	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	Costs	Costs
Year	($1,000)	($1,000)	Copper		Core	Costs	Costs	Charges	O&M	Losses	TOTAL	
2020						0	0	0	0	0	0	0
2021	67	1499				68	68	8	1,532	0	1,539	1,332
2022	5652	1499				5,903	5,972	659	1,565	0	2,225	1,791
2023	108	9				115	6,087	672	10	0	682	510
2024		9				0	6,087	672	10	0	682	475
2025		9				0	6,087	672	10	0	682	442
2026		9				0	6,087	672	10	0	682	411
2027		9				0	6,087	672	10	0	682	383
2028		9				0	6,087	672	11	0	683	356
2029		9				0	6,087	672	11	0	683	331
2030		9				0	6,087	672	11	0	683	308
2031	852	9				1,082	7,169	791	11	0	803	337
2032	855	9				1,110	8,279	914	12	0	926	362
2033	500	9				663	8,943	987	12	0	999	363
2034						0	8,943	987	0	0	987	334
2035						0	8,943	987	0	0	987	310
2036						0	8,943	987	0	0	987	289
2037						0	8,943	987	0	0	987	269
2038						0	8,943	987	0	0	987	250
2039						0	8,943	987	0	0	987	232
2040						0	8,943	987	0	0	987	216
2041						0	8,943	987	0	0	987	201
2042						0	8,943	987	0	0	987	187
2043						0	8,943	987	0	0	987	174
2044						0	8,943	987	0	0	987	162
2045						0	8,943	987	0	0	987	151
2046						0	8,943	987	0	0	987	140
2047						0	8,943	987	0	0	987	130
2048						0	8,943	987	0	0	987	121
2049						0	8,943	987	0	0	987	113
2050						0	8,943	987	0	0	987	105
2051						0	8,943	987	0	0	987	98
2052						0	8,943	987	0	0	987	91
2053						0	8,943	987	0	0	987	84
2054						0	8,943	987	0	0	987	79
2055						0	8,943	987	0	0	987	73
2056						0	8,943	987	0	0	987	68
2057						0	8,943	987	0	0	987	63
2058						0	8,943	987	0	0	987	59
2059						0	8,943	987	0	0	987	55
TOTALS	8,033	3,096	0.00	0.00	0	8,943	311,630	34,404	3,215	0	37,619	11,454

- $1,499,533 in annual O&M cost is used as a penalty for the deferral of reliability improvement
- $100,000 cost was assumed for removal of battery components
- $9,000 is the annual cost of battery maintenance

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NPV Table 4. Alternative #3 Cost Schedule Detail

Alternative 3 Description	Repl. TB at Neeley Sub with 5/6.25MVA Bank. Reconductor 5.7 miles of 2CSR feeder backbone											
								Total Annual Costs			Sum of	Present
			Losses in MW			Escalated	Cummulat	Fixed	Escalated	Loss	Total	Worth of Total
	Capital Costs	O&M Costs	CE Cu	METC Cu	Core	Capital ($1,000)	Capital ($1,000)	Charges ($1,000)	O&M ($1,000)	Costs ($1,000)	Annual Costs	Annual Costs
Year	($1,000)	($1,000)	Copper		Core	Costs	Costs	Charges	O&M	Losses	TOTAL	
2020						0	0	0	0	0	0	0
2021	85	1499				87	87	10	1,532	0	1,541	1,334
2022	8893	1499				9,288	9,376	1,035	1,565	0	2,600	2,093
2023	941	12				1,005	10,380	1,146	13	0	1,159	868
2024		12				0	10,380	1,146	13	0	1,159	807
2025		12				0	10,380	1,146	13	0	1,159	751
2026		12				0	10,380	1,146	14	0	1,160	699
2027		12				0	10,380	1,146	14	0	1,160	650
2028		12				0	10,380	1,146	14	0	1,160	605
2029		12				0	10,380	1,146	15	0	1,161	563
2030		12				0	10,380	1,146	15	0	1,161	524
2031		12				0	10,380	1,146	15	0	1,161	488
2032		12				0	10,380	1,146	16	0	1,162	454
2033		12				0	10,380	1,146	16	0	1,162	422
2034		12				0	10,380	1,146	16	0	1,162	393
2035		12				0	10,380	1,146	17	0	1,163	366
2036	852	12				1,207	11,587	1,279	17	0	1,296	379
2037	855	12				1,238	12,825	1,416	17	0	1,433	390
2038	500	12				740	13,564	1,498	18	0	1,515	383
2039						0	13,564	1,498	0	0	1,498	353
2040						0	13,564	1,498	0	0	1,498	328
2041						0	13,564	1,498	0	0	1,498	305
2042						0	13,564	1,498	0	0	1,498	284
2043						0	13,564	1,498	0	0	1,498	264
2044						0	13,564	1,498	0	0	1,498	246
2045						0	13,564	1,498	0	0	1,498	228
2046						0	13,564	1,498	0	0	1,498	212
2047						0	13,564	1,498	0	0	1,498	198
2048						0	13,564	1,498	0	0	1,498	184
2049						0	13,564	1,498	0	0	1,498	171
2050						0	13,564	1,498	0	0	1,498	159
2051						0	13,564	1,498	0	0	1,498	148
2052						0	13,564	1,498	0	0	1,498	138
2053						0	13,564	1,498	0	0	1,498	128
2054						0	13,564	1,498	0	0	1,498	119
2055						0	13,564	1,498	0	0	1,498	111
2056						0	13,564	1,498	0	0	1,498	103
2057						0	13,564	1,498	0	0	1,498	96
2058						0	13,564	1,498	0	0	1,498	89
2059						0	13,564	1,498	0	0	1,498	83
TOTALS	12,126	3,189	0	0	0	13,564	467,233	51,583	3,339	0	54,922	16,115

- $1,499,533 in annual O&M cost is used as a penalty for the deferral of reliability improvement
- $100,000 cost was assumed for removal of battery components
-$12,000 is the annual cost of battery maintenance

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NPV Table 5. Capital and NPV Cost of Installing li-ion BESS and ATS in 2022

Description	NPV based on the CAPEX due to the installation of the li-ion BESS and the ATS											Present
							Total Annual Costs				Sum of	Worth
					Escalated	Cummulat	Fixed	Escalated	Loss		Total	of Total
	Capital	O&M		Losses in MW		Capital	Capital	Charges	O&M	Costs	Annual	Annual
	Costs	Costs	CE Cu	METC Cu	Core	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	Costs	Costs
Year	($1,000)	($1,000)	Copper		Core	Costs	Costs	Charges	O&M	Losses	TOTAL	
2020						0	0	0	0	0	0	0
2021	67					68	68	8	0	0	8	7
2022	5652					5,903	5,972	659	0	0	659	531
2023	108					115	6,087	672	0	0	672	503
2024						0	6,087	672	0	0	672	468
2025						0	6,087	672	0	0	672	435
2026						0	6,087	672	0	0	672	405
2027						0	6,087	672	0	0	672	377
2028						0	6,087	672	0	0	672	350
2029						0	6,087	672	0	0	672	326
2030						0	6,087	672	0	0	672	303
2031						0	6,087	672	0	0	672	282
2032						0	6,087	672	0	0	672	262
2033						0	6,087	672	0	0	672	244
2034						0	6,087	672	0	0	672	227
2035						0	6,087	672	0	0	672	211
2036						0	6,087	672	0	0	672	197
2037						0	6,087	672	0	0	672	183
2038						0	6,087	672	0	0	672	170
2039						0	6,087	672	0	0	672	158
2040						0	6,087	672	0	0	672	147
2041						0	6,087	672	0	0	672	137
2042						0	6,087	672	0	0	672	127
2043						0	6,087	672	0	0	672	118
2044						0	6,087	672	0	0	672	110
2045						0	6,087	672	0	0	672	102
2046						0	6,087	672	0	0	672	95
2047						0	6,087	672	0	0	672	89
2048						0	6,087	672	0	0	672	83
2049						0	6,087	672	0	0	672	77
2050						0	6,087	672	0	0	672	71
2051						0	6,087	672	0	0	672	66
2052						0	6,087	672	0	0	672	62
2053						0	6,087	672	0	0	672	57
2054						0	6,087	672	0	0	672	53
2055						0	6,087	672	0	0	672	50
2056						0	6,087	672	0	0	672	46
2057						0	6,087	672	0	0	672	43
2058						0	6,087	672	0	0	672	40
2059						0	6,087	672	0	0	672	37
TOTALS	5,826	0	0	0	0	6,087	231,241	25,529	0	0	25,529	7,253

Part III Requirement #126

2022 Test Year - Top 25 Projects

Rank	Project	Cost ($000)	Investment Category	Concept Approval Number
1	Distribution Automation Battery - 2022 Work	8,698	Battery	22-0053
2	WD0036 HIGGINS RBLD SUB - Completion	8,200	HVD Substation Failure Projects	22-0003
3	Wayland Sub Rebuild Part 1	5,500	HVD Substation Failure Projects	23-0011
4	North Belding Sub Rebuild Part 1	4,600	HVD Substation Failure Projects	23-0012
5	SANTIAGO 138KV TAP AND LINE	4,300	New Interconnections (HVD Capacity)	20-0059
6	Remus	3,720	HVD Line Rebuilds	21-0019
7	Wirtz Rd 2	3,720	HVD Line Rebuilds	22-0054
8	WD1696 CELERY NEW 138/46KV SUB - Completion	3,500	HVD Substation Failure Projects	22-0002
9	Big Rapids	3,441	HVD Line Rebuilds	22-0051
10	MOBILE #24	3,360	New Mobile Substation	21-0015
11	Maple City	3,348	HVD Line Rebuilds	22-0049
12	Rosebush	3,255	HVD Line Rebuilds	17-0019A
13	Nashville	3,013	HVD Line Rebuilds	21-0041
14	Rebuild Coopersville 46 kV Line Cleveland - Rochester Products	2,559	Load Carrying Capability/Voltage Support	23-0010
15	Hodenpyl	2,139	HVD Line Rebuilds	22-0052
16	Merrill 108A	2,139	HVD Line Rebuilds	22-0008
17	Wayland	2,108	HVD Line Rebuilds	21-0023
18	MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	2,085	Metro - Vault or Manhole Rehabilitation	1050165426
19	ELEANOR ST UPGRADES	2,000	Metro - Obsolete or Needed Civil Assets	METRORLBY21 KZO ELEANOR ST UPGRADES
20	MOBILE VAULTS	2,000	New Technologies	METRORLBY 2021 XXX MOBILE VAULT
21	Morrice 2	1,969	HVD Line Rebuilds	22-0055
22	Broadmoor #1 Transformer Replacement	1,950	HVD Substation Failure Projects	22-0044
23	Beecher #5 Transformer Replacement	1,950	HVD Substation Failure Projects	22-0043
24	DARE-SUB LINCOLN/LOST LAKE	1,900	Sub Capacity-associated Line Work	1041345703/18-0025
25	Shelby	1,880	HVD Line Rebuilds	22-0050

PROJECT: Distribution Automation BESS – Neeley and Gun Lake Substations

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this project is to install a battery energy storage system (BESS) by the tie point between two adjacent circuits to support automatic load transfers. The circuits Hooper, out of Neeley substation, and Trails End, out of Gun Lake substation are deemed unviable for distribution automation due to low substation and line capacity. The interconnection for this proposed battery system will be designed to allow bidirectional transfers between the circuits, so the BESS will be able to support automatic transfers with minimum risk of overloading the substation or the lines supporting the circuits. When transfers are not needed, the BESS will perform peak shaving for Neeley substation to defer capacity upgrade upgrades. A long-duration energy storage system will be procured for this use case. In addition to making the two circuits eligible for distribution automation, this project will be the first opportunity for Consumer's personnel to gain experience with long-duration storage technology.

Concept Approval 22-0053 provides additional project details.

ii. Line Design, size material used.

Not applicable, BESS project.

iii. Line Length and ROW requirements.

Not applicable, BESS construction project on Consumers Energy easement or owned property.

iv. Approximate Construction Schedule.

Construction Start: September 15, 2022
Construction Complete: December 15, 2022

v. Project effect on cost of operation and reliability of service.

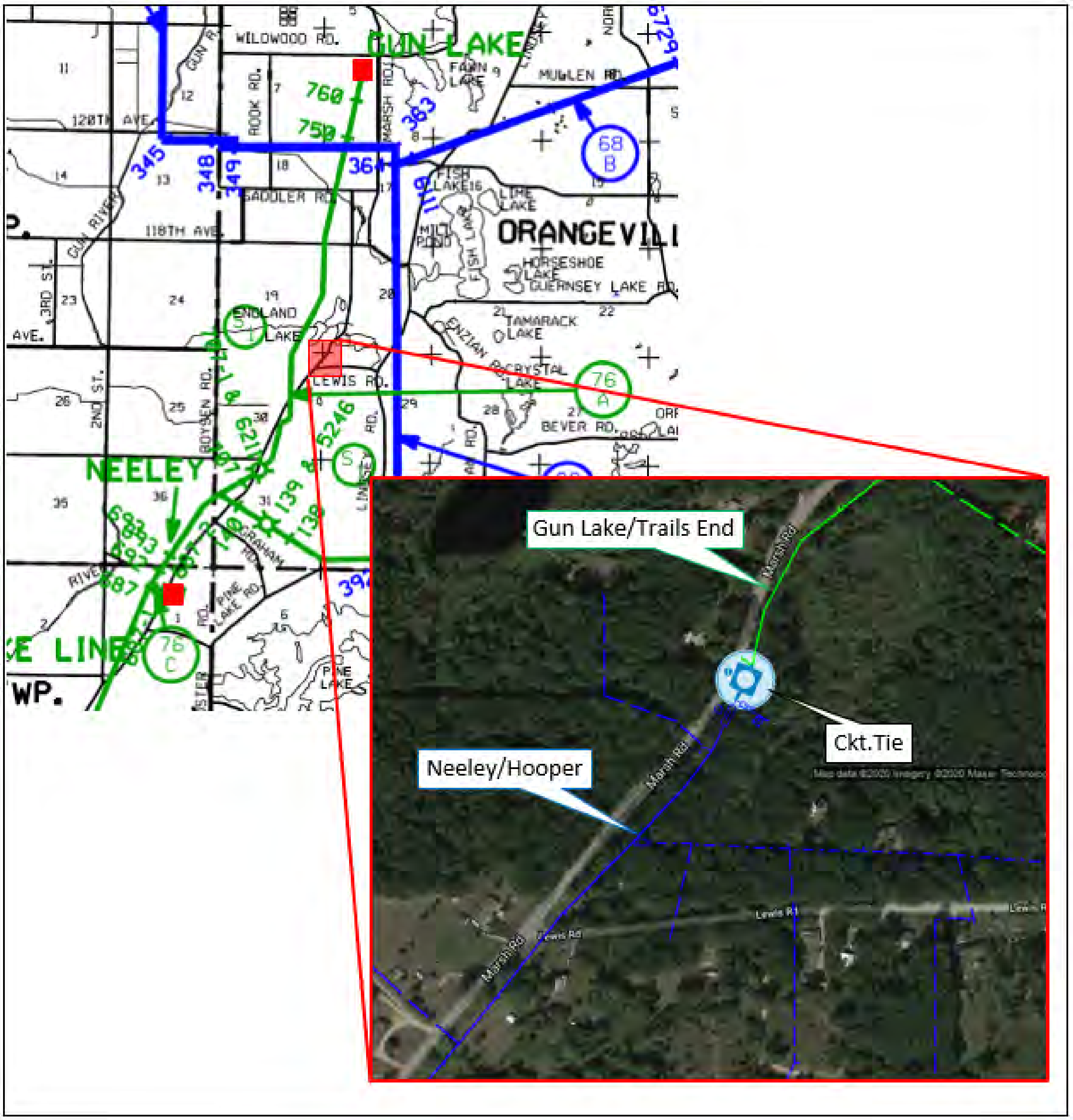
The reliability of the two circuits involved in the proposed transfer scheme will increase with the battery installation. Both circuits serve remote areas and have no connection to any other distribution lines, so when outages occur CE customers must wait for our crews to correct problems on the line. The BESS will enable automatic transfers between the circuits to benefit a total of 278 customers. This project is estimated to save 499,533 outage minutes annually. The BESS will also allow to defer a capacity upgrade at Neeley Substation.

vi. A description of the property being replaced and salvage value.

Not applicable, new BESS to be installed on new site.

vii. Map of site and location of facilities.

Property for the BESS will be procured as close as possible to the tie device between the two shown circuits. This location is in Orangeville Twp., Allegan County.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See the attached Concept Approval 22-0053

x. Date of board approval.

N/A

DISTRIBUTION AUTOMATION BESS — Neeley and Gun Lake Substations – Attachment 1

CONCEPT APPROVAL No. 22-0053*
Battery Storage System - Distribution Automation BESS — Neeley and Gun Lake Substations

*Concept Approval is currently being routed for developed management approval

Concept Document To Be Attached Here.

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Consumers Energy
Distribution Substation Planning & Reliability
CONCEPT APPROVAL

Concept Number: 22-0053 County: Allegan

Project: Distribution Automation BESS - Neeley & Gun Lake Substations

Date: 12/16/2020 Need System Changes By: 12/31/2022

<u>Problem Description</u>

The ability to transfer customers between adjacent feeders to mitigate outages is essential to improving the reliability of the electric service in the communities served by Consumers Energy. Distribution automation spares CE's customers from hundreds of thousands of outage minutes annually. However, as this program expands with new automatic transfer scheme (ATS) implementations each year, a pool of unviable feeders also grows.

Currently, 228 ATS proposals are deemed unviable for field implementation. Of these proposals, 83 have been rejected due to inadequate distribution infrastructure to support the load transfers and 53 are due to having the proposed feeders already involved in other active or scheduled loops. The main problem with these two groups is that capacity limitations at the substation, or on the lines, put these feeders at much higher risk of failure when accepting automatic transfers.

The annual selection of ATS proposals is based on a cost-benefit evaluation, which favors proposals with the highest cost-benefit ratios. Proposals with capacity limitations normally require extensive work and cost to build adequate system capacity for automatic transfers; therefore, their cost is usually too high to justify selection, even when some of the feeders in them may have had consistently poor reliability performance over the years. Choosing proposals with high cost-benefit ratios results in better return-on-investment, and with feeders needing little work, more of these can be accommodated within in the same budget. But, some of the proposals deemed unviable, could also show attractive cost- benefit ratios if the resulting reliability benefit is considered over a long period of time.

Unviable proposals, however, are unlikely to be reevaluated as long as viable feeders remain in the selection pool, or capacity upgrades remove the limitations from the feeders, both of which could take a while. Until then, opportunities for the company and our customers to capitalize on the benefits of an earlier ATS deployment may be squandered.

The purpose of this concept is to introduce a new pilot project involving a battery energy storage system (BESS) connected to the distribution system to support automatic load transfers between feeders with poor reliability and capacity limitations. With this project CE will explore and develop the interconnection requirements needed to provide a BESS with the ability to automatically switch between two circuits, as a component of an automation scheme. This use case will also allow the company to assess how the revenue-generating value of a BESS can be increased through direct reliability gains.

Another objective of this project is to explore the feasibility of deploying a long-duration storage system for this use case. Considering that li-ion batteries have relatively short lifetimes, require strict depth-of-discharge and state-of-charge controls to suppress degradation, and need constant temperature monitoring for safe operation, a long-duration BESS appears to be a much better fit for this application. Completing this project will allow the company to gain technical and operational knowledge on long-duration systems, ahead of the anticipated growth of renewable generation in our state.

Project Specific:

A battery storage system (BESS) installed at the tie point between two distribution feeders has the unique advantage of providing additional capacity at the end of both circuits. From this location, a properly sized battery could allow automatic transfers between feeders with insufficient capacity to accept load, even during peak demand periods. By placing the point of interconnection for the BESS between two ties, as shown in Attachment 1, the BESS will have a normal connection to one preferred feeder but will be able to switch to the alternate feeder if required. When a transfer is needed, the BESS site controller can reconfigure the interconnection so that the BESS can support the transfer while connected to the energized source. In normal configuration, the BESS can perform other services like peak shaving, frequency regulation, volt-var control, and market interaction.

In this application, the BESS is not intended for islanding and will always have a connection to one energized feeder. This guarantees proper grounding and fault currents on the circuits for the protection devices to operate.

An ATS proposal between the Neeley\Hooper and Gun Lake\Trails End feeders offers an opportunity to deploy a BESS for this use case. These two feeders have small conductors (#2ACSR) on their entire backbone (approximately 5.7 miles combined), and Neeley Substation is currently loaded at 90%, with about 800kVA of remaining capacity. Based on these conditions, these feeders are not suitable for automatic transfers. At the observed growth rate of 1.56% per year, the transformer at Neeley Substation is projected to reach overload in 2025, which means that a capacity upgrade may not be needed until then. Neeley and Gun Lake substations have only one three-phase tie in common, with no other ties to neighboring substations. Both substations are remote, with their circuits winding through heavily wooded and swampy areas. As proposed, this ATS could potentially impact up to 278 customers. The proposed location for installing the BESS is provided on Attachment 2.

Outage data from the past five years (2015-2019) indicates that customers on the Gun Lake/Trails End feeder experienced an average of 1,734,911 outage minutes annually, with 62% of these minutes caused by the operation of the reclosers at the substation. The average customer on this circuit was out for 478 minutes (7.97 hours) per year. Primary outages on the Neeley/Hooper feeder caused 631,241 outage minutes per year for the same period, of which 61% were due to faults on the first protection zone. The average customer on the Neeley/Hooper circuit was out for 634 minutes (10.57 hours) per year.

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A CYME model of the two circuits and a BESS was used to simulate the transfers associated with the proposed ATS. This simulation indicated that a power rating of 1.2 MW and an energy rating of 9.6 MWh (8-hour duration) would enable automatic transfer capability between the two feeders for at least 15 years, after a tentative installation in 2022. Assessment of the potential reliability benefit that can be attained with this application showed that installing the BESS and associated ATS could potentially save 499,533 customer minutes per year, which would yield a combined CAIDI improvement of 10.3% (Attachment 2). Because of the bank capacity limitation at Neeley Substation, the recommended feeder for the normal BESS interconnection is Neeley/Hooper, so the BESS can also perform peak shaving to relieve the substation when not needed for transfers. A desirable location identified for the BESS is shown in Attachment 3.

A long-duration battery energy storage system is recommended for this application. One long duration technology of particular interest are flow batteries. In general, flow batteries offer durations above six hours—which is desirable in this case, considering the average outage durations obtained from the historical outage data of the two circuits— and have operational lifetimes between 15 and 20 years. Flow batteries have low chemistry degradation, which allows for more charge-discharge cycles, have a low fire risk, and require less stringent temperature control. They are also capable of fast response and can adjust their output to quickly mitigate transient conditions on the grid. However, when soliciting bids for this project, other long-duration technologies will be welcome in the proposals.

Due to the wide cost variability of long-duration technologies reported in published literature, power and energy ratings of 1.2 MW and 7.2 MWh (6-hour duration) have been established as the minimum requirement for the system to be procured. These minimum ratings will guarantee a minimum cost for a system that will be able to perform as expected for the majority of its service life. These ratings will be used as the basis for the estimates provided in this concept. The selection of the optimum long-duration technology will include evaluating if an 8-hour duration can be realized at a cost comparable to the one presented herein.

The risks associated with this project include:

1. Unknowns of investing in a relatively new technology, without a lot of verifiable field exposure.
2. Finding a reliable vendor of a commercially mature long-duration battery system that can accommodate the required specifications.
3. The communications interfacing and programming needed for the BESS and ATS to operate as intended may fall outside CE’s expertise and standard equipment options.
4. The two feeders involved in the ATS may experience faster growth that has been anticipated, rendering the battery unable to support the transfers at an earlier time.
5. Potential of customer loads increasing past the battery capabilities, preventing the load transfers.
6. Potential of load imbalances on the circuits that could prevent proper inverter operation.

Because of these risks, additional time and budget will be allocated to cover supplementary consulting and research.

Project Goals:

The goals for this demonstration project are:

1. Use a long-duration storage system to support automatic load transfers between distribution circuits with insufficient transfer capabilities.
2. Develop and install a communications-based interconnection design to allow a BESS to switch between two adjacent circuits according to power flow conditions.
3. Develop safety and operational procedures for battery-supported distribution automation with battery transfer between the feeders. The proposed ATS will be in an area where no distribution automation currently exists; the addition of the storage system along with the ATR devices will require developing a more comprehensive set of procedures and training for the line crews. The Neeley/Hooper and the Gun Lake\Trails End feeders are also managed from different headquarters, which will require additional awareness and coordination during normal operations and restoration work.
4. Determine the operational capabilities of long-duration storage systems.
5. Understand how to use a long-duration BESS that is primarily intended for transfer support, for:
    a. Circuit peak shaving
    b. Circuit power quality
    c. Market interaction
6. Explore and understand how to implement weather-based predictive algorithms to establish BESS charging and discharging patterns.

Alternatives:

1. **Don't explore using a storage system to support load transfers between circuits.** Wait for the Neeley Substation transformer to reach overload in 2025 and perform a capacity upgrade at the substation and the backbones of Neeley/Hooper and Gun Lake/Trails End. This option avoids additional up-front costs by implementing traditional substation and line capacity upgrades after the substation capacity has been exceeded.

    2026

    - Upgrade the Neeley Substation transformer with a 5.6/6.25 MVA bank. ($400,000)
    - Reconductor 5.7 miles (with 100% pole replacement) of 2ACSR overhead line on the backbone of Neeley/Hooper and Gun Lake/Trails End with 336ACSR conductor ($1,707,000).

    2027

    - Install a regular ATS between the two circuits without any additional logic or

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communication features ($380,000).

- LVD Protection reconfiguration ($20,000).

Total Cost = $2,507,000 (NPV: $10,482,000. This NPV includes a reliability penalty)

2. **Complete the installation of a li-ion BESS between the Neeley/Hooper and Gun Lake/Trails End feeders to enable load transfers between the two circuits**. With the deployment of two li-ion batteries in recent years and the ongoing effort to install three more of these systems, the company has already accrued significant experience on procurement, engineering and construction of lithium-based storage systems. This acquired experience will limit risks and minimize the impact of unknowns associated with the storage technology.

   2022

   - Install li-ion BESS by the three-phase tie between the Neeley/Hooper and Gun Lake/Trails End feeders to enable load transfers between the two circuits ($6,301,000).
   - Install the proposed ATS with four communication-enabled devices and required interfaces to interact with the BESS controller ($1,515,000).

   2031

   - Reconductor 2.84 miles (with 100% pole replacement) of 2ACSR overhead line on the Neeley/Hooper backbone with 336ACSR conductor ($852,000).

   2032

   - Reconductor 2.85 miles (with 100% pole replacement) of 2ACSR overhead line on the and Gun Lake/Trails End with 336ACSR conductor ($855,000).

   2033

   - Upgrade the Neeley Substation transformer with a 5.6/6.25 MVA bank ($400,000).
   - Remove battery storage system ($100,000).

   Total Cost = $10,090,000 (NPV: $14,037,000. This NPV includes a reliability penalty, annual BESS maintenance, and BESS retirement at end of life)

3. **Complete the installation of a long-duration battery storage system to enable load transfers between the feeders Neeley/Hooper and Gun Lake/Trails End**. This alternative would allow CE to develop a knowledge base on long-duration technologies by deploying a small long-duration system on the distribution network. As CE expands its renewable generation fleet, long-duration energy storage will be an essential piece in the company's portfolio for attaining 40% of renewable energy by 2040. As of today, long-duration systems have higher up-front costs than lithium-based storage, however, these costs have also been declining in recent years and are projected to continue falling as these systems gain more visibility in the market. A long duration system will generally be operational for five additional years compared to a lithium-based battery.

   2022

   - Install a long-duration battery system between the Neeley/Hooper and Gun Lake/Trails End feeders to enable load transfers between the two circuits ($8,473,000)

- Install the proposed ATS with four communication-enabled ATR devices and the required interfaces for the two substations and line ATRs to interact with the battery controller ($1,515,000).

2036

- Reconductor 2.84 miles (with 100% pole replacement) of 2ACSR overhead line on the Neeley/Hooper backbone with 336ACSR conductor ($852,000).

2037

- Reconductor 2.85 miles (with 100% pole replacement) of 2ACSR overhead line on the and Gun Lake/Trails End with 336ACSR conductor ($855,000).

2038

- Upgrade the Neeley Substation transformer with a 5.6/6.25 MVA bank ($400,000).
- Remove battery storage system ($100,000).

Total Cost = $12,195,000 (NPV: $16,184,000. This NPV includes a reliability penalty, annual BESS maintenance, and BESS retirement at end of life)

Recommended Alternative:

The recommended solution is Alternative 3 – Complete the installation of a long-duration storage system to enable load transfers between the feeders Neeley/Hooper and Gun Lake/Trails End in 2022**.**

Alternative 1. Implementing a traditional capacity upgrade at Neeley Substation and on the backbones of the two feeders will leave CE without the experience to develop future long-duration battery projects. Long-duration systems offer a much better match than lithium-based storage for large output renewables, and it is in CE's best interest to begin assessing the long-duration technologies that are commercially available today.

Alternative 2. The minimum power and energy ratings (1.2MW and 7.2MWh) required for this application can be satisfied with li-ion batteries at a lower cost and NPV than the recommended alternative. Li-ion batteries are used extensively in grid applications and have a verifiable operational track record. CE has deployed a few of these systems and continues to work on additional deployments, further expanding our experience on li-ion storage. As the company's renewables portfolio continues to grow, however, the need to explore storage options lasting beyond four hours becomes more apparent. While using a li-ion BESS to complete this project is a practical solution to the address the existing reliability concern, it would prevent CE from taking a first small step towards developing the skillset necessary to deploy larger long-duration systems in the near future.

Alternative 3. Completing the installation of a long-duration storage system to enable load transfers between the feeders Neeley/Hooper and Gun Lake/Trails End is recommended because it will allow CE to begin developing a knowledge base on long-duration systems, in addition to addressing reliability performance on the identified circuits. A first-time experience on two fronts, this project will set the basis for the integration of distribution storage and automation and will guide the company's first steps towards deploying long-duration storage technology.

In this setting, the storage system will allow load transfers and will defer system upgrades for several years more than a li-ion BESS of the same rating. Long-duration technologies have projected lifetimes of 15 to 20 years, compared to 10 years with a standard li-ion BESS. The extended lifetime also means that the selected system will be expected to recover a larger portion of its up-front cost through the value streams available to it (capacity credit, frequency regulation, market arbitrage). The capital cost and NPV provided for this alternative were calculated based on projected costs for redox flow batteries for the year 2021.

The economic comparison of the three alternatives, considering an annual reliability penalty, continued battery maintenance, and battery removal at the end of life, is provided in the following table. This analysis used a flat rate of $3 per customer-minute to penalize the annual deferral of the reliability improvement. Annual battery maintenance costs were estimated at a rate of $10/kW-year. A cost of $100,000 was assumed for battery removal at the end of life.

Yearly Activities per Alternative	**Sum of Present Worth of Revenue Requirements**	**Total Capital (2021 – 2038)**	**First Year Capital (2021)**
<u>Alternative 1</u> 2026: - Increase capacity at Neeley Substation - Reconductor Neeley/Hooper and Gun Lake/Trails End. 2027: - Install the proposed ATS to allow load transfers between Neeley/Hooper and Gun Lake/Trails End	$10,482,000	$2,507,000	$0
<u>Alternative 2</u> 2022: - Install li-ion BESS and the proposed ATS to allow load transfers between Neeley/Hooper and Gun Lake/Trails End. 2031: - Reconductor the Neeley/Hooper feeder. 2032: - Reconductor the Gun Lake/Trails End feeder. 2033: - Increase capacity at Neeley Substation. - Remove BESS.	$14,037,000	$10,090,000	$25,000
<u>Alternative 3</u> 2022: - Install long-duration battery storage system and the proposed ATS to allow load transfers between Neeley/Hooper and Gun Lake/Trails End. 2036: - Reconductor the Neeley/Hooper feeder. 2037: - Reconductor the Gun Lake/Trails End feeder. 2038: - Increase capacity at Neeley Substation. - Remove long-duration storage system.	$16,184,000	$12,195,000	$94,000

The estimated cost of installing the long-duration battery system and the associated ATS (not including the Neeley Substation upgrade and the line reconductors) is: $9,988,000 NPV= $12,363,000.

The economic analysis also indicates that, at the rate of $3 per customer-minute, installing the proposed ATS in 2022—as opposed to 2027 in Alternative 1—could yield up to $5,320,000 (NPV) in savings. The estimated NPV savings resulting from deferring the system capacity upgrades until 2036 is $1,389,000. The NPV tables showing this economic analysis are provided at the end of this document.

The estimated loaded CapEx for installing the long-duration BESS and the proposed ATS is $9,988,000.

WBS Element	2021 Direct Cost	2021 Loaded Cost	Description
ED-98219-1-19-02-01	$18,000	$26,000	Property option secured
ED-98219-1-19-02-01	$48,000	$68,000	Technology evaluation study
WBS Element	**2022 Direct Cost**	**2022 Loaded Cost**	**Description**
ED-98219-1-19-02-01	$161,000	$225,000	Property acquisition completion
ED-98219-1-19-02-01	$35,000	$48,000	RFP for long-duration BESS completed
ED-98219-1-19-02-01	$1,743,000	$2,441,000	BESS contract execution & engineering milestone (40% BESS integrator price)
ED-98219-1-19-02-01	$151,000	$211,000	BOP Equipment (transformer, switches, relays, etc.)
ED-98219-1-19-02-01	$12,000	$16,000	Factory Acceptance Test visit
ED-98219-1-19-02-01	$29,000	$40,000	Dispatch Optimization Report (SGP)
ED-98219-1-19-02-01	$654,000	$915,000	Engineering drawings approval (15% BESS integrator price)
ED-98219-1-19-02-01	$1,090,000	$1,525,000	BESS delivery (35% BESS integrator price)
ED-98219-1-19-02-01	$1,610,000	$2,254,000	Site construction and BESS installation
ED-98219-1-19-02-01	$473,000	$662,000	BESS commissioning (10% BESS integrator price plus testing and IT work)
ED-98219-1-19-02-01	$255,000	$357,000	Substation DTT and data transfer work
WBS Element	**2023 Direct Cost**	**2023 Loaded Cost**	**Description**
ED-98219-1-19-02-01	$827,000	$1,158,000	Install ATS, fiber, and comm. infrastructure
ED-98219-1-19-02-01	$30,000	$42,000	White paper on findings from review of real data
Subtotal	$7,120,000	$9,988,000	

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Customer Contribution	$0	$0	
Project Total CapEx	**$7,120,000**	**$9,988,000**	

All costs related to the BESS project will be funded by the 2.18 Grid Storage budget.

Present Need:

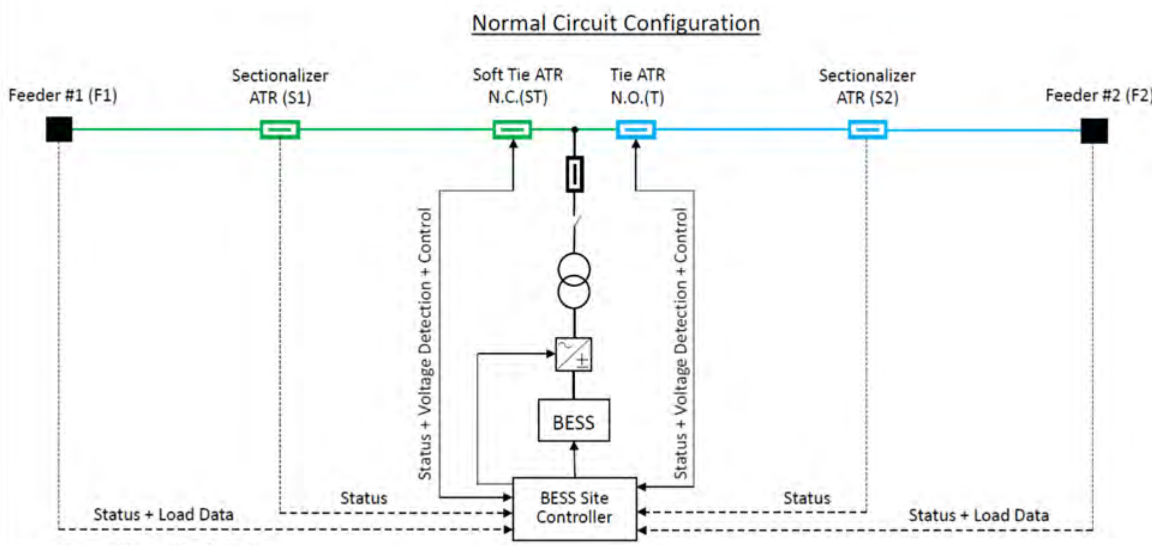
On approval, this document authorizes the DER/I&C Design group to proceed with the work order design and the acquisition of property and material pending receipt of appropriate budget authorization.

Prepared By: Demeury Naranjo Date: 1/12/2021

Approvals:

HVD Planning Engineer, HVD System Planning	Benjamin T. Scott	Required
Director, LVD System Planning	Donald A. Lynd	Required
Director, HVD System Planning	Edward R. Mathews	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation/Eng & Ops Support	Jean-Francois Brossoit	Required

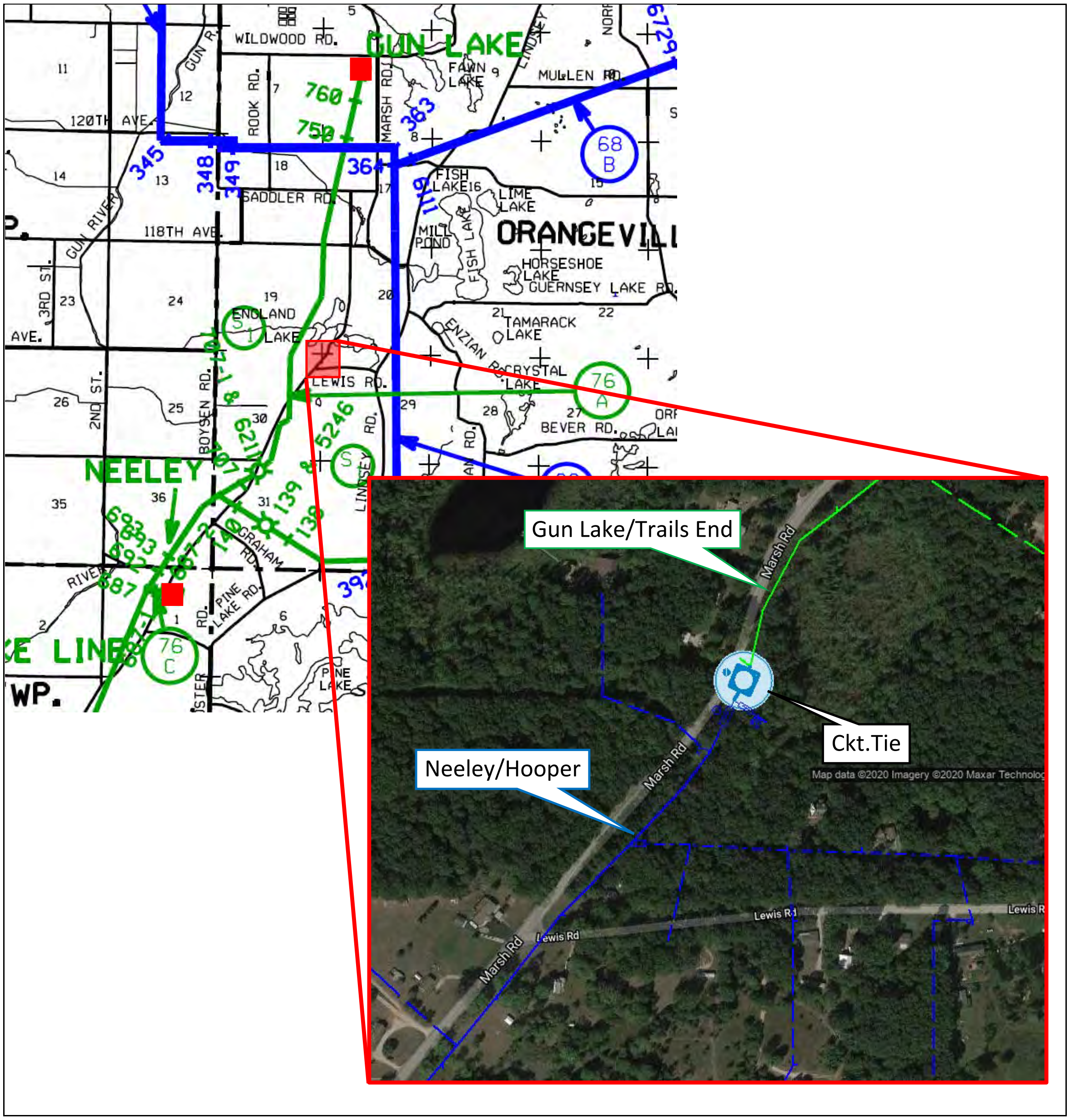
Attachment 1. BESS-Supported ATS Interconnection Diagram



General Operation Guidelines

1. BESS not to island. BESS is required to be attached to one energized feeder to operate.
2. Feeder #1 (F1) is the preferred feeder.
3. BESS not to parallel the feeders.
4. The Soft Tie and Tie devices will have protection settings enabled only when the power flow is reversed through them.
5. One transfer to be allowed before needing to reset the ATS.
6. Under certain conditions the BESS can be transferred alone.
7. The Status and Load data signals from the sectionalizer devices and the substation reclosers will be sent to the BESS Site Controller via cellular data transfer.
8. The BESS Site Controller will collect status and voltage detection information from the Soft Tie and Tie devices and will send commands to them via fiber interconnection.

Attachment 2. Proposed Location for BESS Site



The preferred location for the BESS site is as close as possible to the circuit tie.
This area is in Orangeville Twp., Allegan County.

Attachment 3. Reliability Improvement Estimate

Reliability Performance by Feeder During the Last Five Years (2015-2019)

Customers Served	Customer Minutes	Customer Interruptions	Average Cust. Minutes
1,127	8,674,553	18,139	1,734,911
340	3,156,207	4,975	631,241

Substation	Circuit	Average Cust. Minutes	CAIDI	SAIDI	SAIFI
Gun Lake WD 0265	Trails End (2-6)	1,734,911	478	1539	3.22
Neeley WD 0368	Hooper (1-6)	631,241	634	1856	2.92
Both Feeders Combined		2,366,152	512	1612	3.15

Estimated Reliability Performance after the installation of the BESS and proposed ATS

Served Customers	Customer Minutes	Customer Interruptions	Average Cust. Minutes
1,127	6,715,609	16,059	1,343,122
340	2,617,487	4,275	523,497

Substation	Circuit	Average Cust. Minutes	CAIDI	SAIDI	SAIFI
Gun Lake WD 0265	Trails End (1-6)	1,343,122	418	1191	2.85
Neeley WD 0368	Hooper (1-6)	523,497	612	1539	2.51
Both Feeders Combined		1,866,619	459	1272	2.77

Estimated Reliability Improvement

Substation	Circuit	Average Cust. Minutes	CAIDI	SAIDI	SAIFI
Gun Lake WD 0265	Trails End (1-6)	391,789	60	348	0.37
Neeley WD 0368	Hooper (1-6)	107,744	22	317	0.41
All Feeders Combined		499,533	53	340	0.38
Percent Improvement		21.1%	10.3%	21.1%	12.0%

Page 17 of 312

Attachment 4. Key Project Milestone Dates

Task	Date
Internal Concept Approval signed	02.15.21
Long-duration technology evaluation	04.15.21
RFP Issued	07.01.21
Property acquisition complete	01.15.21
Battery Integrator contract executed	01.15.22
Construction start	09.15.22
BESS equipment delivery	11.01.22
BESS construction and installation complete	12.15.22
ATS installation and commissioning Complete	01.31.23
BESS – ATS communications testing complete	03.01.23

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NPV Table 1. Economic Analysis Summary

ECONOMIC ANALYSIS OF ALTERNATIVE PLANS

STUDY TITLE : CA 21-00## Distribution Automation Support Long-Duration Battery Storage

	DESCRIPTION of ALTERNATIVES	Sum of Present Worth of Revenue Requirements	Total Capital	First Year Capital
ALTERNATIVE 1 :	Repl. TB at Neeley Sub with 5/6.25MVA Bank. Reconductor 5.7 miles of 2CSR feeder backbone	$10,482	$2,507	$0
ALTERNATIVE 2 :	Install li-ion BESS in 2022. Repl. Neeley Sub. TB and reconductor 5.7 miles of feeder backbone.	$14,037	$10,090	$25
ALTERNATIVE 3:	Repl. TB at Neeley Sub with 5/6.25MVA Bank. Reconductor 5.7 miles of 2CSR feeder backbone	$16,184	$12,195	$94
	NPV based on the CAPEX due to the installation of the long-duration battery system and the ATS	$12,363	$9,988	
	Estimated savings due to earlier reliability improvement resulting from installing BESS	$5,320		
	Estimated savings due to system capacity upgrade deferrals	$1,389		

NPV Table 2. Alternative #1 Cost Schedule Detail

Alternative 1 Description: Repl. TB at Neeley Sub with 5/6.25MVA Bank. Reconductor 5.7 miles of 2CSR feeder backbone

Year	Capital Costs ($1,000)	O&M Costs ($1,000)	Losses in MW: CE Cu Copper	Losses in MW: METC Cu	Core Core	Escalated Capital ($1,000) Costs	Cummulative Capital ($1,000) Costs	Total Annual Costs: Fixed Charges ($1,000) Charges	Total Annual Costs: Escalated O&M ($1,000) O&M	Total Annual Costs: Loss Costs ($1,000) Losses	Sum of Total Annual Costs TOTAL	Present Worth of Total Annual Costs
2020						0	0	0	0	0	0	0
2021		1499				0	0	0	1,532	0	1,532	1,325
2022		1499				0	0	0	1,565	0	1,565	1,260
2023		1499				0	0	0	1,600	0	1,600	1,198
2024		1499				0	0	0	1,635	0	1,635	1,139
2025		1499				0	0	0	1,671	0	1,671	1,083
2026	2107	1499				2,401	2,401	265	1,708	0	1,973	1,189
2027	400	1499				466	2,867	316	1,745	0	2,062	1,156
2028						0	2,867	316	0	0	316	165
2029						0	2,867	316	0	0	316	154
2030						0	2,867	316	0	0	316	143
2031						0	2,867	316	0	0	316	133
2032						0	2,867	316	0	0	316	124
2033						0	2,867	316	0	0	316	115
2034						0	2,867	316	0	0	316	107
2035						0	2,867	316	0	0	316	99
2036						0	2,867	316	0	0	316	93
2037						0	2,867	316	0	0	316	86
2038						0	2,867	316	0	0	316	80
2039						0	2,867	316	0	0	316	75
2040						0	2,867	316	0	0	316	69
2041						0	2,867	316	0	0	316	64
2042						0	2,867	316	0	0	316	60
2043						0	2,867	316	0	0	316	56
2044						0	2,867	316	0	0	316	52
2045						0	2,867	316	0	0	316	48
2046						0	2,867	316	0	0	316	45
2047						0	2,867	316	0	0	316	42
2048						0	2,867	316	0	0	316	39
2049						0	2,867	316	0	0	316	36
2050						0	2,867	316	0	0	316	34
2051						0	2,867	316	0	0	316	31
2052						0	2,867	316	0	0	316	29
2053						0	2,867	316	0	0	316	27
2054						0	2,867	316	0	0	316	25
2055						0	2,867	316	0	0	316	23
2056						0	2,867	316	0	0	316	22
2057						0	2,867	316	0	0	316	20
2058						0	2,867	316	0	0	316	19
2059						0	2,867	316	0	0	316	18
TOTALS	2,507	10,490	0.00	0.00	0	2,867	97,002	10,709	11,455	0	22,164	10,482

-$1,499,533 in annual O&M cost is used as a penalty for the deferral of reliability improvement

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NPV Table 3. Alternative #2 Cost Schedule Detail

Alternative 2 Description	Install li-ion BESS in 2022. Repl. Neeley Sub. TB and reconductor 5.7 miles of feeder backbone.											
								Total Annual Costs			Sum of Total Annual Costs	Present Worth of Total Annual Costs
	Capital Costs ($1,000)	O&M Costs ($1,000)	Losses in MW			Escalated Capital ($1,000)	Cummulative Capital ($1,000)	Fixed Charges ($1,000)	Escalated O&M ($1,000)	Loss Costs ($1,000)		
Year			CE Cu Copper	METC Cu	Core Core	Costs	Costs	Charges	O&M	Losses	TOTAL	
2020						0	0	0	0	0	0	0
2021	25	1499				26	26	3	1,532	0	1,534	1,328
2022	7816	1499				8,164	8,189	904	1,565	0	2,469	1,988
2023	42	12				45	8,234	909	13	0	922	690
2024		12				0	8,234	909	13	0	922	642
2025		12				0	8,234	909	13	0	922	598
2026		12				0	8,234	909	14	0	923	556
2027		12				0	8,234	909	14	0	923	518
2028		12				0	8,234	909	14	0	923	482
2029		12				0	8,234	909	15	0	924	448
2030		12				0	8,234	909	15	0	924	417
2031	855	12				1,086	9,320	1,029	15	0	1,044	438
2032	852	12				1,106	10,427	1,151	16	0	1,167	456
2033	500	12				663	11,090	1,224	16	0	1,240	451
2034						0	11,090	1,224	0	0	1,224	414
2035						0	11,090	1,224	0	0	1,224	385
2036						0	11,090	1,224	0	0	1,224	358
2037						0	11,090	1,224	0	0	1,224	333
2038						0	11,090	1,224	0	0	1,224	310
2039						0	11,090	1,224	0	0	1,224	288
2040						0	11,090	1,224	0	0	1,224	268
2041						0	11,090	1,224	0	0	1,224	249
2042						0	11,090	1,224	0	0	1,224	232
2043						0	11,090	1,224	0	0	1,224	216
2044						0	11,090	1,224	0	0	1,224	201
2045						0	11,090	1,224	0	0	1,224	187
2046						0	11,090	1,224	0	0	1,224	174
2047						0	11,090	1,224	0	0	1,224	162
2048						0	11,090	1,224	0	0	1,224	150
2049						0	11,090	1,224	0	0	1,224	140
2050						0	11,090	1,224	0	0	1,224	130
2051						0	11,090	1,224	0	0	1,224	121
2052						0	11,090	1,224	0	0	1,224	113
2053						0	11,090	1,224	0	0	1,224	105
2054						0	11,090	1,224	0	0	1,224	97
2055						0	11,090	1,224	0	0	1,224	91
2056						0	11,090	1,224	0	0	1,224	84
2057						0	11,090	1,224	0	0	1,224	78
2058						0	11,090	1,224	0	0	1,224	73
2059						0	11,090	1,224	0	0	1,224	68
TOTALS	10,090	3,129	0.00	0.00	0	11,090	393,272	43,417	3,254	0	46,672	14,037

- $1,499,533 in annual O&M cost is used as a penalty for the deferral of reliability improvement
- $100,000 cost was assumed for removal of battery components
- $12,000 is the annual cost of battery maintenance

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NPV Table 4. Alternative #3 Cost Schedule Detail

Alternative 3 Description			Repl. TB at Neeley Sub with 5/6.25MVA Bank. Reconductor 5.7 miles of 2CSR feeder backbone									
								Total Annual Costs			Sum of	Present Worth
Year	Capital Costs ($1,000)	O&M Costs ($1,000)	Losses in MW CE Cu Copper	METC Cu	Core Core	Escalated Capital ($1,000) Costs	Cummulat Capital ($1,000) Costs	Fixed Charges ($1,000) Charges	Escalated O&M ($1,000) O&M	Loss Costs ($1,000) Losses	Total Annual Costs TOTAL	of Total Annual Costs
2020						0	0	0	0	0	0	0
2021	94	1499				96	96	11	1,532	0	1,542	1,334
2022	8694	1499				9,081	9,177	1,013	1,565	0	2,578	2,075
2023	1200	12				1,281	10,458	1,155	13	0	1,167	874
2024		12				0	10,458	1,155	13	0	1,168	813
2025		12				0	10,458	1,155	13	0	1,168	757
2026		12				0	10,458	1,155	14	0	1,168	704
2027		12				0	10,458	1,155	14	0	1,169	655
2028		12				0	10,458	1,155	14	0	1,169	610
2029		12				0	10,458	1,155	15	0	1,169	567
2030		12				0	10,458	1,155	15	0	1,169	528
2031		12				0	10,458	1,155	15	0	1,170	491
2032		12				0	10,458	1,155	16	0	1,170	457
2033		12				0	10,458	1,155	16	0	1,170	425
2034		12				0	10,458	1,155	16	0	1,171	396
2035		12				0	10,458	1,155	17	0	1,171	368
2036	855	12				1,211	11,669	1,288	17	0	1,305	382
2037	852	12				1,233	12,902	1,424	17	0	1,442	392
2038	500	12				740	13,642	1,506	18	0	1,524	386
2039						0	13,642	1,506	0	0	1,506	355
2040						0	13,642	1,506	0	0	1,506	330
2041						0	13,642	1,506	0	0	1,506	307
2042						0	13,642	1,506	0	0	1,506	285
2043						0	13,642	1,506	0	0	1,506	265
2044						0	13,642	1,506	0	0	1,506	247
2045						0	13,642	1,506	0	0	1,506	230
2046						0	13,642	1,506	0	0	1,506	214
2047						0	13,642	1,506	0	0	1,506	199
2048						0	13,642	1,506	0	0	1,506	185
2049						0	13,642	1,506	0	0	1,506	172
2050						0	13,642	1,506	0	0	1,506	160
2051						0	13,642	1,506	0	0	1,506	149
2052						0	13,642	1,506	0	0	1,506	138
2053						0	13,642	1,506	0	0	1,506	129
2054						0	13,642	1,506	0	0	1,506	120
2055						0	13,642	1,506	0	0	1,506	111
2056						0	13,642	1,506	0	0	1,506	104
2057						0	13,642	1,506	0	0	1,506	96
2058						0	13,642	1,506	0	0	1,506	90
2059						0	13,642	1,506	0	0	1,506	83
TOTALS	12,195	3,189	0	0	0	13,642	469,919	51,879	3,339	0	55,218	16,184

- $1,499,533 in annual O&M cost is used as a penalty for the deferral of reliability improvement
- $100,000 cost was assumed for removal of battery components
-$12,000 is the annual cost of battery maintenance

BCMazur
DALynd
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

NPV Table 5. Capital and NPV Cost of Installing Long-Duration BESS and ATS in 2022

Description	NPV based on the CAPEX due to the installation of the long-duration battery system and the ATS											Present Worth of Total Annual Costs
								Total Annual Costs			Sum of Total Annual Costs	
Year	Capital Costs ($1,000)	O&M Costs ($1,000)	CE Cu Copper	Losses in MW METC Cu	Core Core	Escalated Capital ($1,000) Costs	Cummulat Capital ($1,000) Costs	Fixed Charges ($1,000) Charges	Escalated O&M ($1,000) O&M	Loss Costs ($1,000) Losses	TOTAL	
2020						0	0	0	0	0	0	0
2021	94					96	96	11	0	0	11	9
2022	8694					9,081	9,177	1,013	0	0	1,013	816
2023	1200					1,281	10,458	1,155	0	0	1,155	865
2024						0	10,458	1,155	0	0	1,155	804
2025						0	10,458	1,155	0	0	1,155	748
2026						0	10,458	1,155	0	0	1,155	696
2027						0	10,458	1,155	0	0	1,155	647
2028						0	10,458	1,155	0	0	1,155	602
2029						0	10,458	1,155	0	0	1,155	560
2030						0	10,458	1,155	0	0	1,155	521
2031						0	10,458	1,155	0	0	1,155	485
2032						0	10,458	1,155	0	0	1,155	451
2033						0	10,458	1,155	0	0	1,155	419
2034						0	10,458	1,155	0	0	1,155	390
2035						0	10,458	1,155	0	0	1,155	363
2036						0	10,458	1,155	0	0	1,155	338
2037						0	10,458	1,155	0	0	1,155	314
2038						0	10,458	1,155	0	0	1,155	292
2039						0	10,458	1,155	0	0	1,155	272
2040						0	10,458	1,155	0	0	1,155	253
2041						0	10,458	1,155	0	0	1,155	235
2042						0	10,458	1,155	0	0	1,155	219
2043						0	10,458	1,155	0	0	1,155	204
2044						0	10,458	1,155	0	0	1,155	189
2045						0	10,458	1,155	0	0	1,155	176
2046						0	10,458	1,155	0	0	1,155	164
2047						0	10,458	1,155	0	0	1,155	152
2048						0	10,458	1,155	0	0	1,155	142
2049						0	10,458	1,155	0	0	1,155	132
2050						0	10,458	1,155	0	0	1,155	123
2051						0	10,458	1,155	0	0	1,155	114
2052						0	10,458	1,155	0	0	1,155	106
2053						0	10,458	1,155	0	0	1,155	99
2054						0	10,458	1,155	0	0	1,155	92
2055						0	10,458	1,155	0	0	1,155	85
2056						0	10,458	1,155	0	0	1,155	79
2057						0	10,458	1,155	0	0	1,155	74
2058						0	10,458	1,155	0	0	1,155	69
2059						0	10,458	1,155	0	0	1,155	64
TOTALS	9,988	0	0	0	0	10,458	396,210	43,742	0	0	43,742	12,363

PROJECT: WD0940 – Rebuild Higgins Substation (WO #36897793)

i. Purpose and Necessity of the Project with Supporting Data.

Higgins Substation is a 138 to 46 kV bulk power substation located near Higgins Lake that provides a bulk power source to the Gerrish, West Branch and Markey 46 kV lines. It has two, 15/20 MVA 138/46 kV transformer circuits. It was originally constructed in approximately 1940.

Four unit control houses at Higgins substation have been identified as violating working space clearances as described in the National Electric Safety Code (NESC). There is a 10-year program to resolve working space violations across the HVD system by 2026.

The System Protection department has identified Higgins as one of their top candidates for transformer replacement. Transformer bank #2 consists of three 1951 vintage Allis Chalmers 5/6.7MVA single phase units connected in a delta-delta configuration, which limits the available short circuit to the area and reduces coordination. This subsequently limits capacity in the area by restricting the acceptable fuse sizes at 46 kV distribution substations connected to the 46 kV lines served from Higgins Substation.

Transformer bank #4 is also a 1950 vintage Allis Chalmers 15/20 MVA 3-phase unit and has tested for elevated levels of ethane. This is a unit that is reaching end of life and must be replaced. Transformer bank #3 is a 1947 vintage Westinghouse transformer and is the only grounding transformer on the HVD system. It has elevated gas levels and is reaching end of life and must be either replaced or eliminated by replacing transformer bank #2 and transformer bank #4 with a standard connected auto transformer with a delta tertiary.

The Concept Approval 22-0003 (Attachment 1) which identified the need for the replacement described above.

ii. Line Design, size material used.

Not applicable, substation construction project.

iii. Line Length and ROW requirements.

Easements are being obtained to construct a new access driveway at the northwest part of the substation.

iv. Approximate Construction Schedule.

Construction Start: March 30, 2022
Construction Complete: January 4, 2023
Equipment Checkout Complete: January 18, 2023

v. Project effect on cost of operation and reliability of service.

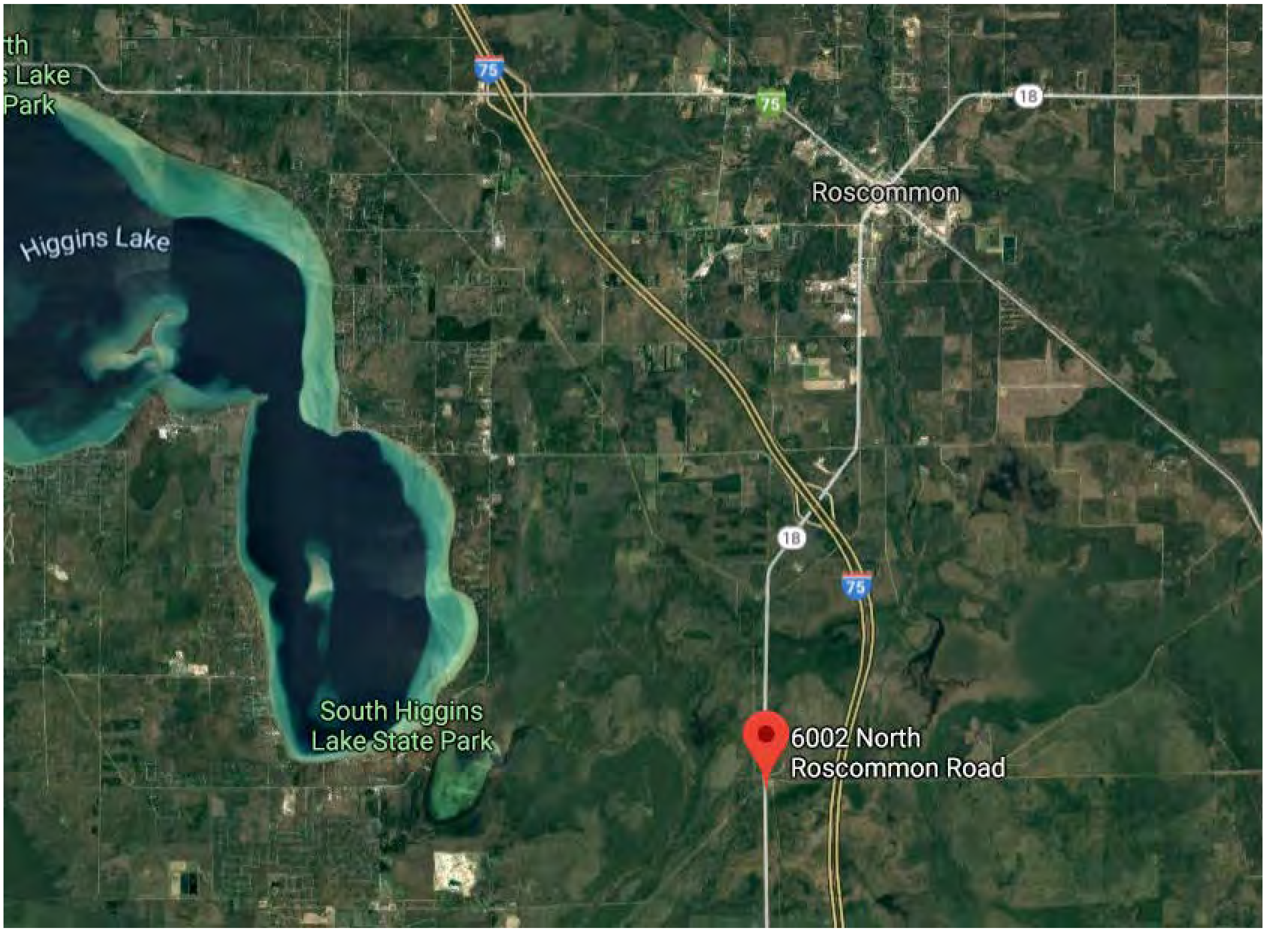
Core business function of providing adequate electrical capacity to serve existing and new customer electrical load.

vi. A description of the property being replaced and salvage value.

The current transformers were manufactured in 1947, 1950 and 1951. Transformers may have a salvage value of $15,000. The balance of the substation has no salvage value.

vii. Map of site and location of facilities.

6002 N Roscommon Road, Roscommon, MI



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See Attachment 1, Concept Approval 22-0003.

x. Date of board approval.

N/A

BCMazur
ALRoot
DCParker
RTBlumenstock
TJSparks
JFBrossoit

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0003

Project: **WD0036 – Higgins Substation Rebuild** **County:** Roscommon

Date: July 13, 2020 **Need System Changes By:** 6/1/2022

Problem Description:

Higgins Substation is a 138 to 46 kV bulk power substation located near Higgins Lake that provides a bulk power source to the Gerrish, West Branch and Markey 46 kV lines. It has two, 15/20 MVA 138/46 kV transformer circuits. It was originally constructed in approximately 1940.

Four unit control houses at Higgins substation have been identified as violating working space clearances as described in the National Electric Safety Code (NESC). There is a 10-year program to resolve working space violations across the HVD system by 2026.

The System Protection and Substation Reliability departments have identified Higgins as one of their top candidates for transformer replacement. Transformer bank #2 consists of three 1951 vintage Allis Chalmers 5/6.7MVA single phase units connected in a delta-delta configuration, which limits the available short circuit to the area and reduces coordination. This subsequently limits capacity in the area by restricting the acceptable fuse sizes at 46 kV distribution substations connected to the 46 kV lines served from Higgins Substation. Transformer bank #4 is a 1950 vintage Allis Chalmers 15/20 MVA 3-phase unit and has a TOA (Transformer Oil Analysis) code of 3 (code 4 being highest). This is a unit that is reaching end of life and must be replaced.

Transformer bank #3 is a 1947 vintage Westinghouse transformer and is the only grounding transformer on the HVD system. It has a TOA code of 4 and is reaching end of life and must be either replaced or eliminated by replacing transformer bank #2 and transformer bank #4 with standard connected auto transformers with delta tertiaries. Also, here is no 46 kV bus protection at Higgins, which is a reliability concern as the remote ends all 46 kV lines must trip to clear a bus fault, impacting 26,400 customers.

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Consumers relies on METC's 138 kV breakers at Higgins substation to clear transformer faults in either transformer bank #2 or transformer bank #4. Consumers' preference is to have a primary interrupting device such as a breaker or circuit switcher that would not rely on METC-owned equipment for transformer protection.

The current bus work at Higgins is copper supported on obsolete brown insulators. There are 6 Delta-Star MK40 46 kV switches, Maclean arresters on the low side of transformer bank #4, and a 156 Joslyn VMB capacitor switch that are all reliability concerns, as indicated by the Substation Reliability group. Higgins also has a 3-phase 46 kV regulator on the Gerrish line. This regulator has a TOA code of 3.

Alternative Solutions:

1. Eliminate working space violations by removing the following control houses: H10A-11A, H12-13, H14-15, H16-17. Panels in these houses will be relocated into a new control house.
   Conceptual cost: $350,000
2. Eliminate working space violations (Alternative 1) and replace failing transformer bank #4. This would be replaced with a 30/40/50 MVA bank. Install a circuit switcher.
   Conceptual cost: $2,850,000
3. Eliminate working space violations (Alternative 1) and replace and relocate transformer banks #4 (failing) and #2. Replace each with a 30/40/50 MVA transformer. Install a circuit switcher with each bank.
   Conceptual cost: $ 5,350,000
4. Replace transformers and rebuild entire 46 kV station. Replace and relocate transformer banks #4 and #2 with separate 30/40/50 MVA transformers. Install a circuit switcher with each bank. Retire and remove the obsolete grounding transformer bank #3. Relocate as necessary and rebuild the 46 kV structure. A new central control house will be required to accommodate additional relaying for bus protection and to complete working space violations. New transformer structures, including 138 kV circuit switchers, will be required. Replace and relocate the 3-phase 46 kV voltage regulator as necessary.

Conceptual cost: $13,000,000

Recommended Alternative:

Alternative #4 is recommended. Higgins is an older substation, built approximately in 1940 and violates working space clearances as described by the NESC. Two of the transformers have a TOA code of 3 or higher, and one of them is the only grounding transformer on our entire system. By replacing transformer bank #4 and #2, it would increase the available short circuit, which would allow for more capacity increases in the area.

As both transformer #2 and #4 have a higher than average risk for failure, Substation Reliability has planned to replace these deteriorated assets as soon as possible. If these banks were not removed and replaced as one unit, it could leave the substation with undesirable, and potentially non-standard, configurations. If transformer #2 or transformer #4 is replaced independently, it could cost more in the long run. If neither of these transformers were replaced, and either or both failed, there would be a higher cost associated to replace under emergency conditions and the failure(s) would disrupt the mobile schedule, which would result in negative impacts on other projects in terms of time, cost, and resources. Also, by rebuilding the station in one project, rather than just fixing the immediate concerns, we greatly reduce the risk of additional failures and additional patch work fixes after a failure happens.

Currently, we do not proactively replace buses and insulators. Replacement only happens once there have been a handful of failures in a substation. As a standalone project, which would consist of replacing the 46kV bus work, at minimum 6 obsolete switches, and fuses cutouts or disconnects that have brown insulators, the estimated cost is $500,000, loaded. Replacing bus work would require an outage, and if the intent is to minimize the number of outages taken, replacing the bus work and obsolete equipment associated during this project would be the best course of action. Also, there are two gas breakers (the 466 and 1288) that are 1996 and 1998 vintage, respectfully. While these do not have any indications of poor health currently, that could suddenly change. Completing this work during the substation rebuild would also reduce the necessity for patch work fixes.

Furthermore, adding 138 kV circuit switchers as high side protective devices to each transformer eliminates the need to rely on METC-owned equipment for transformer protection. Finally, this alternative addresses the working space violations at Higgins substation which must be remedied by 2024.

While alternatives one, two, and three are cheaper alternatives, they are not as desirable as the fourth alternative. The bare minimum that we *must do* at Higgins rectify the working space issues. But, given the state of the transformers and the age of the substation, only doing alternative one will temporarily fix a small portion of Higgins, but there is still the potential for drastic failures of equipment. Therefore, selecting alternative one is not desirable.

Alternative two does address the working space and replaces a failing transformer. But, in doing only this, we would be creating another non-standard connection. It would be very difficult to parallel a new autotransformer with three single phase units as well as a high chance of overloading the new bank before the three single phase units took much load. The other downside to this alternative is that there is an extremely high probability that there could not be a temporary outage to either transformer bank. Therefore, to avoid adding another non-stand connection onto the system, alternative two is not desirable.

Unlike alternative two, alternative three would eliminate the non-standard connection by replacing both transformer banks #2 and #4. Removing the existing transformers and installing the new transformers would be a substantial amount of work. And this would be adding to the patch work of Higgins substation. Higgins was built in approximately 1940 and is roughly 80 years old, one of the oldest on the system. By only fixing some parts of the substation now, we would end up spending more money in the future to replace everything than what we would spend now. Or, we wait until something fails and only replace it then. We need to be more proactive and leave it better than we found it, and this alternative doesn’t lend itself to that. Therefore, alternative three is not desirable.

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Alternative #4 Recommended Scope:
Acquire property, as needed.

Replace and relocate transformer banks #2 and #4 with separate 30/40/50 MVA transformers. Retire and remove the obsolete grounding transformer bank #3. Relocate as necessary and rebuild the 46 kV structure. A new central control house will be required to accommodate additional relaying for bus protection and to complete working space violations. New transformer structures, including 138 kV circuit switchers, will be required. Replace and relocate the 3-phase 46kV voltage regulator as necessary.

METC facilities are required for this project.

Conceptual Estimate by WBS:

WBS Element	2020 Direct Cost	2020 Cost with Over-heads	2021 Direct Cost	2021 Cost with Over-heads	2022 Direct Cost	2022 Cost with Over-heads	Description
EH-95208	$10,000	$0	$0	$0	$0	$0	Acquire new right of way for rebuild
EH-95408	$0	$0	$4,800,000	$4,800,000	$4,920,000	$8,200,000	Alternative 3: Working space & station rebuild
Total	$10,000	$0	$2,880,000	$4,800,000	$4,920,000	$8,200,000	Grand Total Cost with Overheads: **$13,000,000**

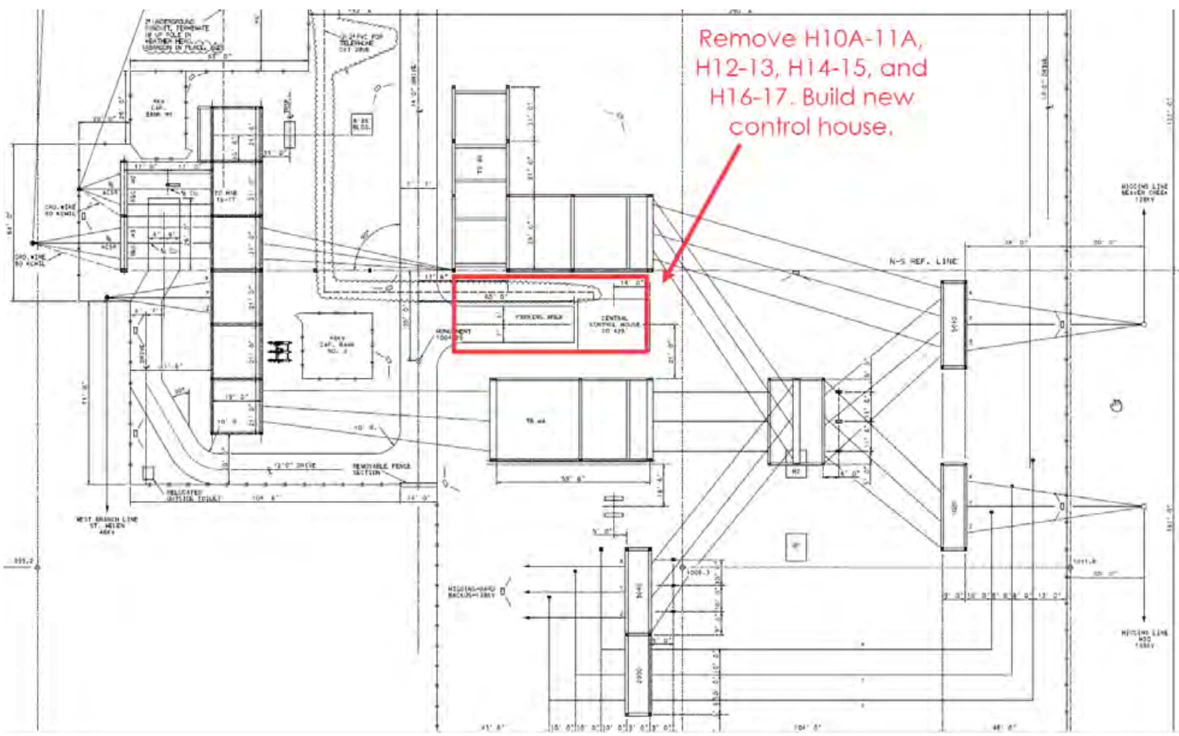
Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: BLAnderson/ALRoot **Team Leader:** DRMeyers

BCMazur
ALRoot
DCParker
RTBlumenstock
TJSparks
JFBrossoit

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required



Alternative 1

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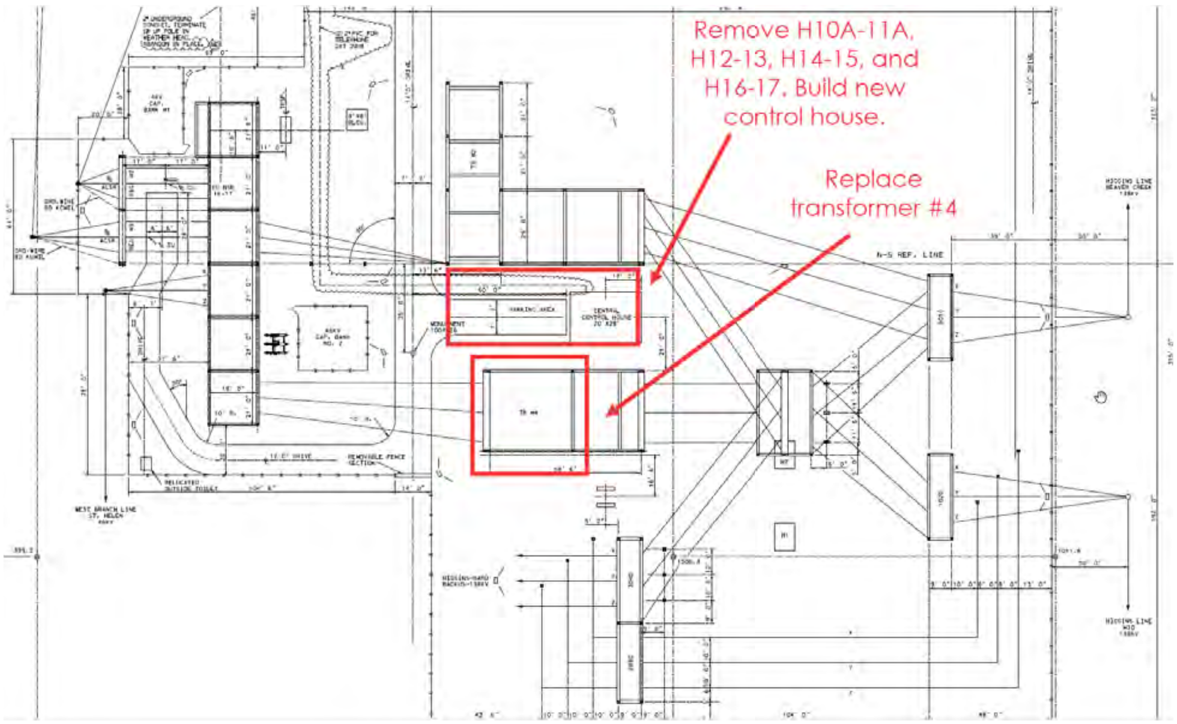

Alternative 2

BCMazur
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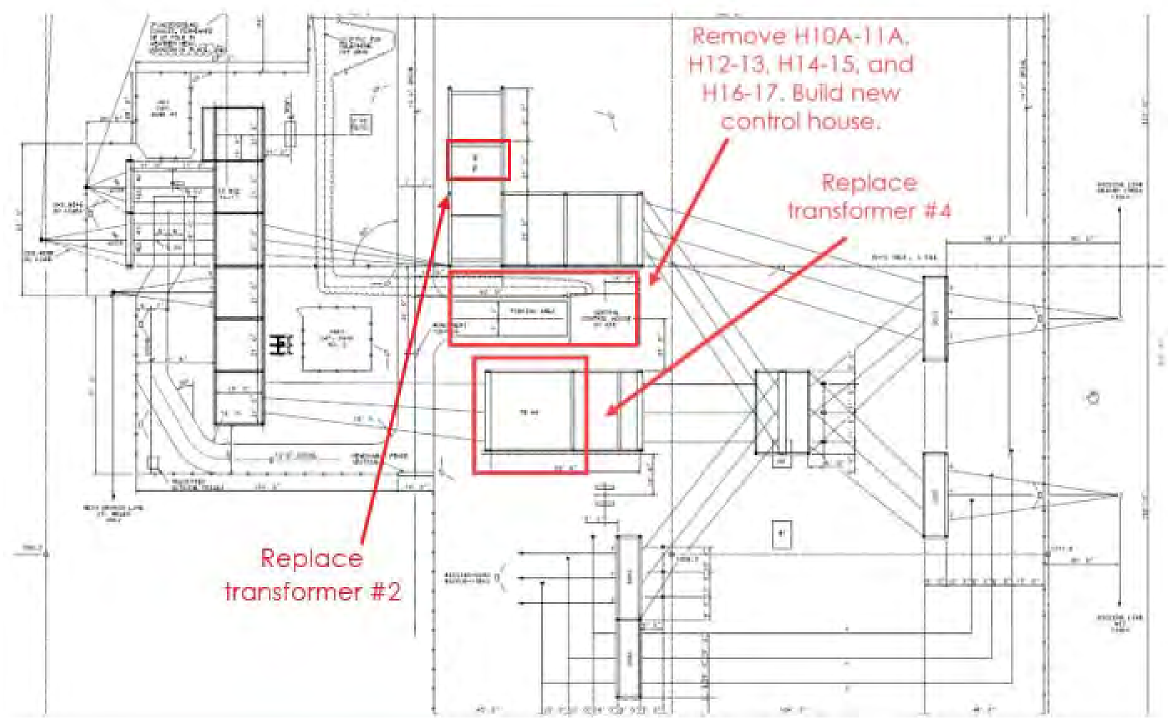
JFBrossoit



Alternative 3

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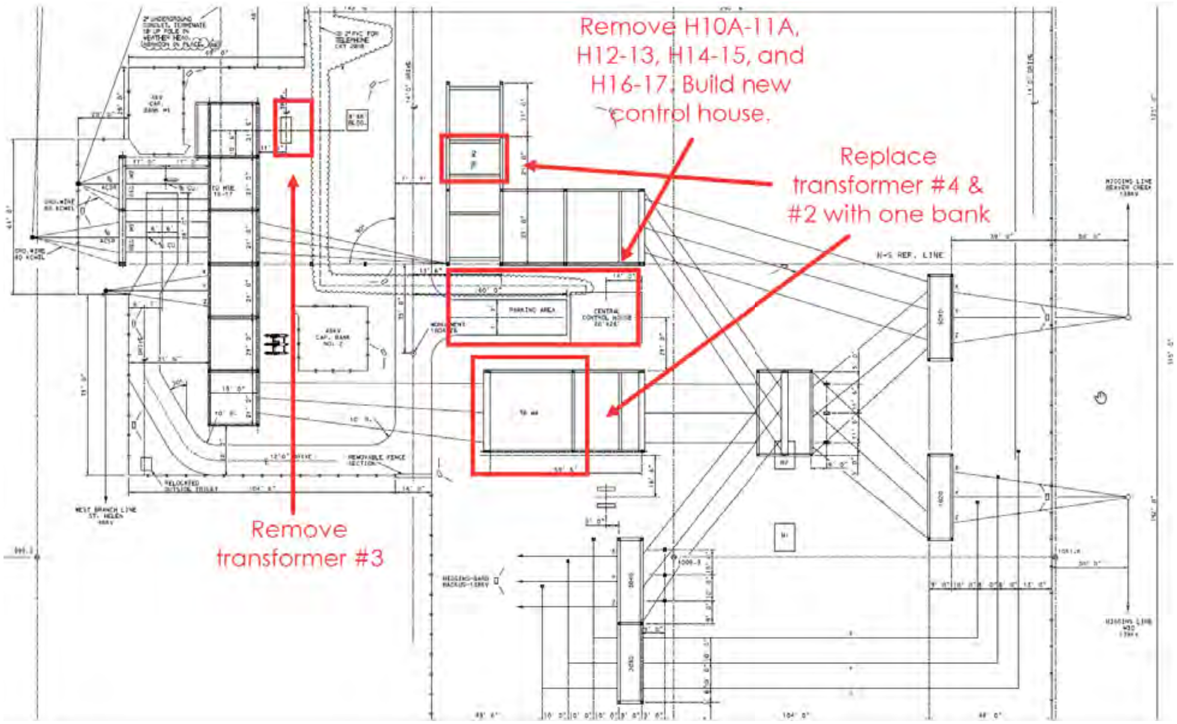
JFBrossoit



Alternative 4

BRIAN C. MAZUR

From: SPAdvisor
Sent: Friday, August 14, 2020 10:21 AM
To: BRIAN C. MAZUR
Cc: BRIAN C. MAZUR; Ivan E. Principe; DWAYNE.PARKER@cmsenergy.com; ARIC L. ROOT; Edward R. Mathews; Jacob D. Roberson; Britta Anderson
Subject: Approval has completed on 22-0003 Higgins Substation Rebuild.

Approval has completed on 22-0003 Higgins Substation Rebuild.

Approval on 22-0003 Higgins Substation Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 7/13/2020 3:19 PM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 7/14/2020 9:10 AM
Comment:

Approved by DWAYNE C. PARKER on 7/27/2020 12:08 PM
Comment: Approve ~DCParker. Rick Blumenstock and I approved previously, it is now going through the workflow again as it needs to go to Tim Sparks and JF Brossoit.

Approved by RICHARD T. BLUMENSTOCK on 7/27/2020 12:33 PM
Comment: This project and the concept approval are straight forward. However, should you like us to develop a presentation to walk through the details of this project and to answer any questions you or JF might have, we can do so. Just let us know.

Approved by Timothy J. Sparks on 7/31/2020 1:34 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 8/14/2020 10:21 AM
Comment:

View the workflow history.

PROJECT: Wayland Substation Rebuild

i. Purpose and Necessity of the Project with Supporting Data.

Wayland substation is a 138 to 46 kV bulk power substation located in the city of Wayland that provides a bulk power source to the Wayland 46 kV line. It has a single, 15/20 MVA 138/46 kV transformer bank. It was originally constructed in approximately 1953.

The Wayland transformer bank has been identified as a transformer replacement candidate due to the presence of acetylene in recent dissolved gas analysis trends. Also, the transformer bank is expected to be loaded to 103.9% of normal ratings in the for a Buck Creek 46 kV bus outage contingency at 80% of peak system load conditions at times when Clyde Generation is offline.

The layout of Wayland Substation is non-standard. There is not enough room on the existing parcel to replace the existing 15/20 MVA transformer bank with a standard size 30/40/50 MVA transformer and rebuild the substation to meet present standards. There is not available property adjacent to the existing parcel to expand the site.

A new bulk power substation will be built to replace Wayland Substation on previously acquired property new Titus Lake Substation.

The Concept Approval 23-0011 (Attachment 1) which initially identified the need for the Wayland Substation rebuild describes the above.

ii. Line Design, size material used.

Not applicable, substation construction project.

iii. Line Length and ROW requirements.

Not applicable, substation construction project on Consumers Energy owned property.

iv. Approximate Construction Schedule.

Construction Start: July 31, 2022
Construction Complete: April 9, 2023
Equipment Checkout Complete: May 21, 2023

v. Project effect on cost of operation and reliability of service.

In the process of relocating the substation, all new equipment is planned for the new substation. This is expected to increase reliability and reduce maintenance costs on the old 1950's vintage substation.

vi. A description of the property being replaced and salvage value.

This new substation would replace one (1) 138/46 kV transformer, two (2) 46kV breakers, one (1) capacitor switcher, one (1) capacitor bank, and other associated relaying, structure, PT's & CT's. The estimated salvage value is unknown at this time.

vii. Map of site and location of facilities.

viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See Attachment 1, Concept Approval 23-0011.

x. Date of board approval.

N/A

Wayland Substation Rebuild – Attachment 1

CONCEPT APPROVAL No. 23-0011
Wayland Substation – Replace with New 138-46 kV Bulk Power Substation

BCMazur
BTScott
DRMeyers
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 23-0011

Project: **Wayland Substation – Replace with New 138/46 kV Bulk Power Substation** **County:** Allegan

Date: December 21, 2020 **Need System Changes By:** 6/1/2023

Problem Description:

Wayland substation is a 138 to 46 kV bulk power substation located in the city of Wayland that provides a bulk power source to the Wayland 46 kV line. It has a single, 15/20 MVA 138/46 kV transformer bank. It was originally constructed in approximately 1953.

Wayland Substation has been identified as one of the top 25 HVD bulk power substations to rebuild after a comprehensive look at all HVD bulk power substations. This comprehensive look involved first sorting the substations by age then a cross-functional review was performed by Operations Engineering, System Protection, Substation Reliability, Substation Engineering, Substation Operations, Substation Maintenance, Electric Field Lab, Substation Construction, and HVD Planning.

The Wayland transformer bank has been identified as a transformer replacement candidate due to the presence of acetylene in recent dissolved gas analysis trends. The transformer bank has lock-type “L” bushings that do not have test caps, which means there is no way to accurately test them. The risk of the bushings violently failing cannot be measured without the ability to test the bushings. Also, the transformer bank is expected to be loaded to 103.9% of normal ratings in the Series 2019 basecase for a Buck Creek 46 kV bus outage contingency at 80% of peak system load conditions at times when Clyde Generation is offline.

BCMazur
BTScott
DRMeyers
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

The layout of Wayland Substation is non-standard. There is not enough room on the existing parcel to replace the existing 15/20 MVA transformer bank with a standard size 30/40/50 MVA transformer and rebuild the substation to meet present standards. There is not available property adjacent to the existing parcel to expand the site.

In 2006-2008, HVD Planning had completed a long-range plan for this area that recommended a new bulk power substation (named “Buskirk Creek”) near what is now the 138 kV Titus Lake distribution substation located near the Wayland 46 kV line and the Hazelwood – Beals Rd. 138 kV Line. Property adjacent to Titus Lake Substation was purchased at that time for the future Buskirk Creek 138/46 kV Substation.

Alternative Solutions:

1. **Do nothing.** *Conceptual cost: $0*
2. **Replace Wayland Transformer Bank Like-for-Like:** Replace the existing 15/20 MVA transformer with a new 15/20 MVA transformer. *Conceptual cost: $1,200,000*
3. **New 138/46 kV Bulk Power Substation near Titus Lake:** Build a 30/40/50 MVA 138/46 kV Bulk Power Substation (Buskirk Creek Substation) on previously acquired property near Titus Lake Substation. Split the existing Wayland 46 kV Line to create a Buskirk Creek – Buck Creek 46 kV Line and a Buskirk Creek – Hopkins 46 kV Line. Retire & remove the existing Wayland Substation after Buskirk Creek is energized. *Conceptual cost: $8,600,00*

Recommended Alternative:

Alternative #3 is recommended. This alternative addresses the existing issues at Wayland Substation and increases the available 46 kV system capacity in the area. The property at this location was purchased over 10 years ago for a future bulk power substation and already has both 46 kV & 138 kV on site.

Future Potential Loop with Radial Gun Lake (Martin Spur) 46kV Line:

Alternative #3 provides the opportunity, in the future, to install another 46 kV breaker at the new Bulk Power Substation and build 6 miles of new 46 kV line to loop in the radial Gun Lake (Martin Spur) 46 kV line, this work would be covered by a separate concept approval.

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Alternative #2 is not recommended because it does not adequately address the excessive loadings on the transformer bank. Wayland Substation would continue to be a non-standard configuration with no space available to expand the substation.

Alternative #1 is not recommended because it does not adequately address the condition of the existing transformer bank or the excessive loadings. Wayland Substation would continue to be a non-standard configuration with no space available to expand the substation.

Alternative #3 Recommended Scope:

Build a 30/40/50 MVA 138/46 kV Bulk Power Substation (Buskirk Creek Substation) on previously acquired property near Titus Lake Substation. The new substation will include one (1) 30/40/50 MVA, 138/46 kV Auto-Transformer, a dedicated sparing 100 tie breaker, one (1) 46 kV 7.2 MVAR capacitor bank, two (2) 46 kV line exits, and space for future 46 kV line exits.

Split the existing Wayland 46 kV Line by building four (4) new spans of 46 kV line to create a Buskirk Creek – Buck Creek 46 kV Line and a Buskirk Creek – Hopkins 46 kV Line.

Retire & remove the existing Wayland Substation after Buskirk Creek is energized.

METC facilities are required for this project.

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DRMeyers
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	2023 Direct Cost	2023 Cost with Overheads	2024 Direct Cost	2024 Cost with Overheads	Description
EH-98320	$3,700,000	$5,500,00	$1,800,000	$2,650,000	$0	$0	Build a new 30/40/50 MVA 138/46 kV Bulk Power Substation
EH-95120-1-19-02-01 - HVD Lines - Improved Functionality Projects	$0	$0	$100,000	$150,000	$0	$0	Build four (4) new spans of 46 kV line
Cost of Removal	$0	$0	$0	$0	$200,000	$300,000	Remove Wayland 138/46 kV Bulk Power Substation
Project Total	**$3,700,000**	**$5,500,000**	**$1,900,000**	**$2,800,000**	**$200,000**	**$300,000**	**Grand Total with Overheads: $8,600,000**

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

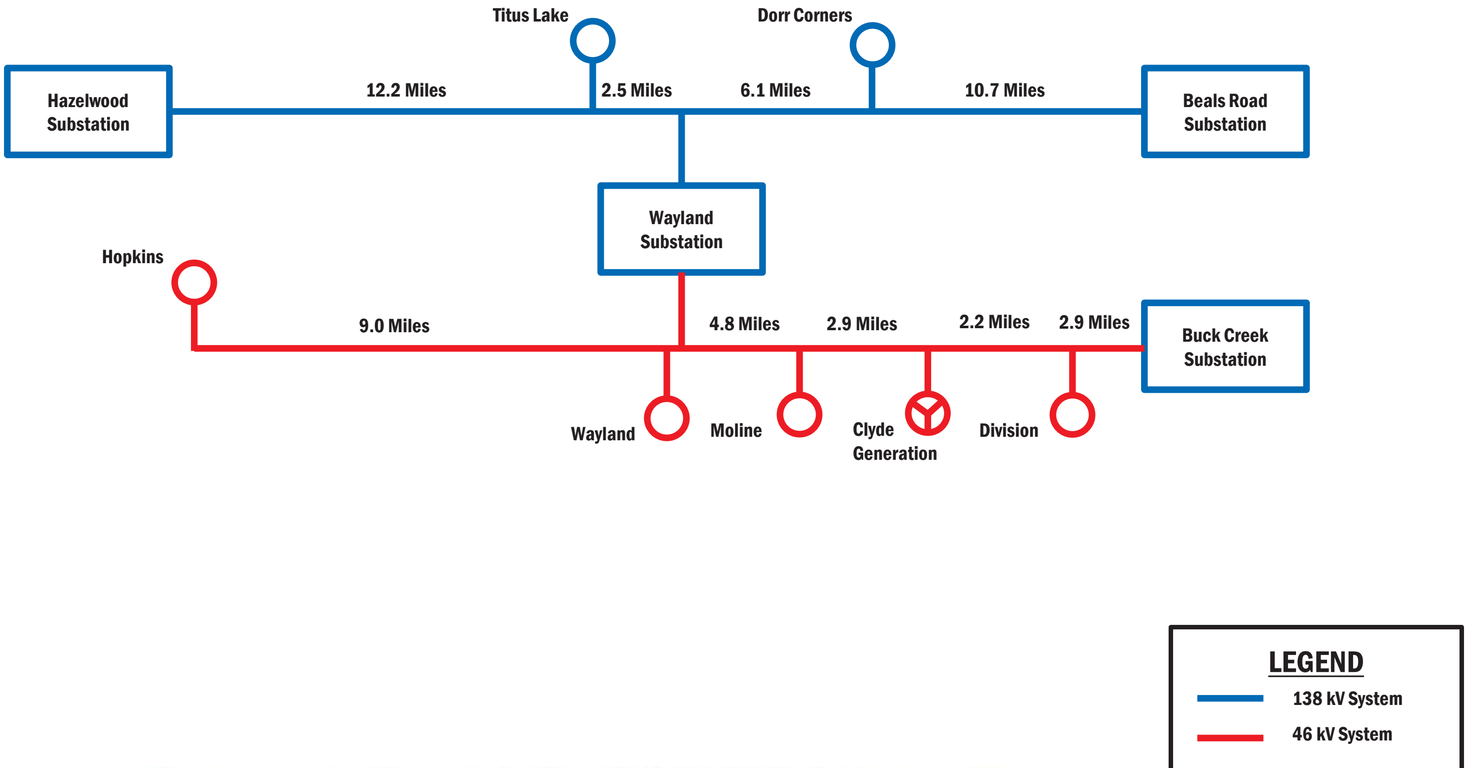
Prepared By: BTScott

BCMazur
BTScott
DRMeyers
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

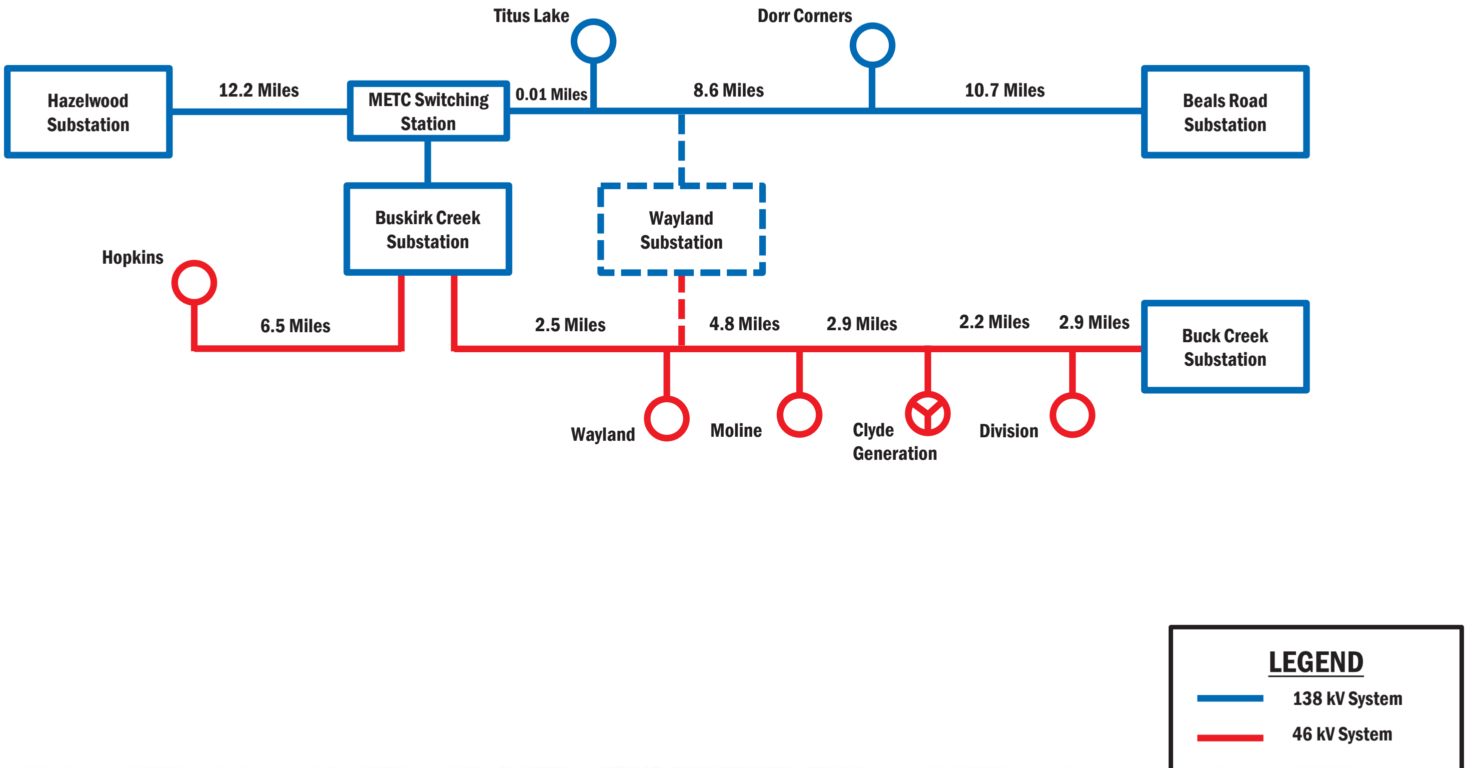
Approvals:

Senior Engineer Lead, HVD Planning West & Transmission	BTScott	Required
Senior Engineer Lead, Reliability & Support	Douglas R. Meyers	Required
Director, HVD System Planning	Edward R. Mathews	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required

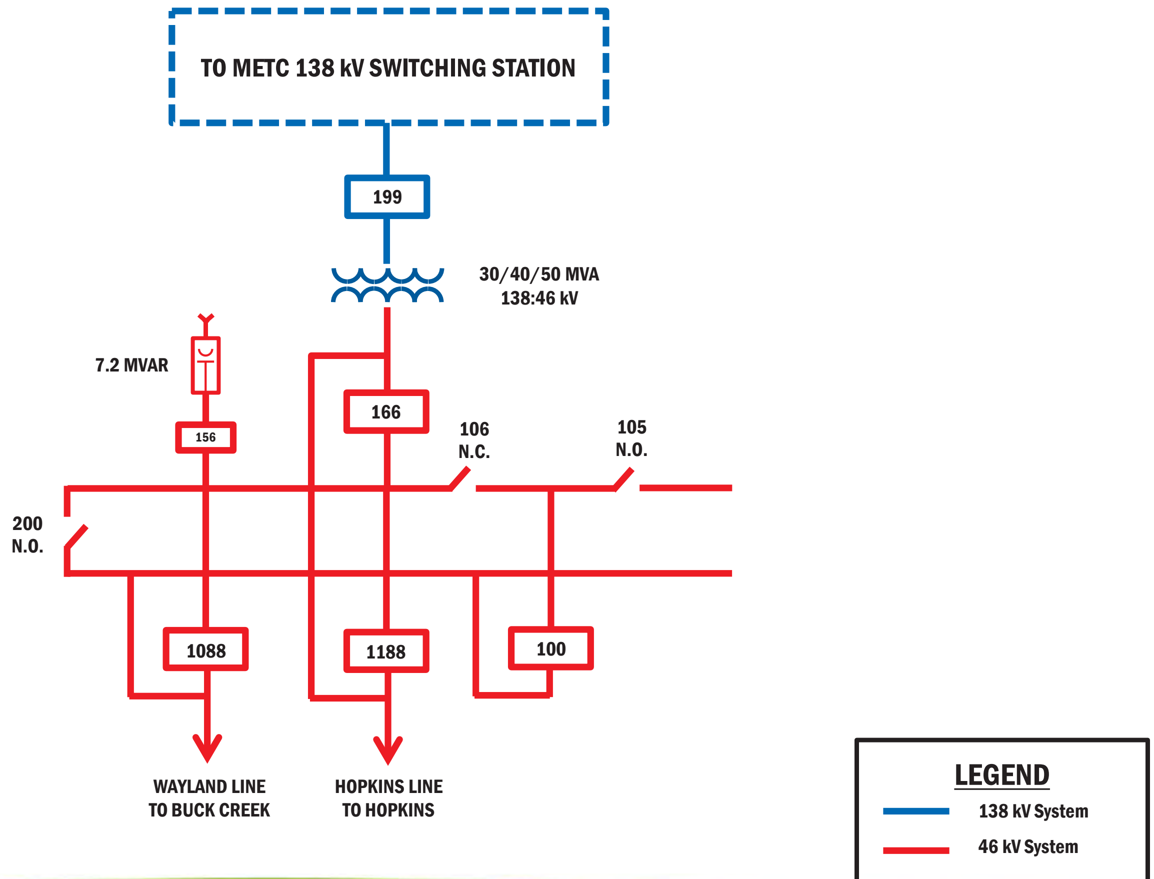
Existing System Configuration

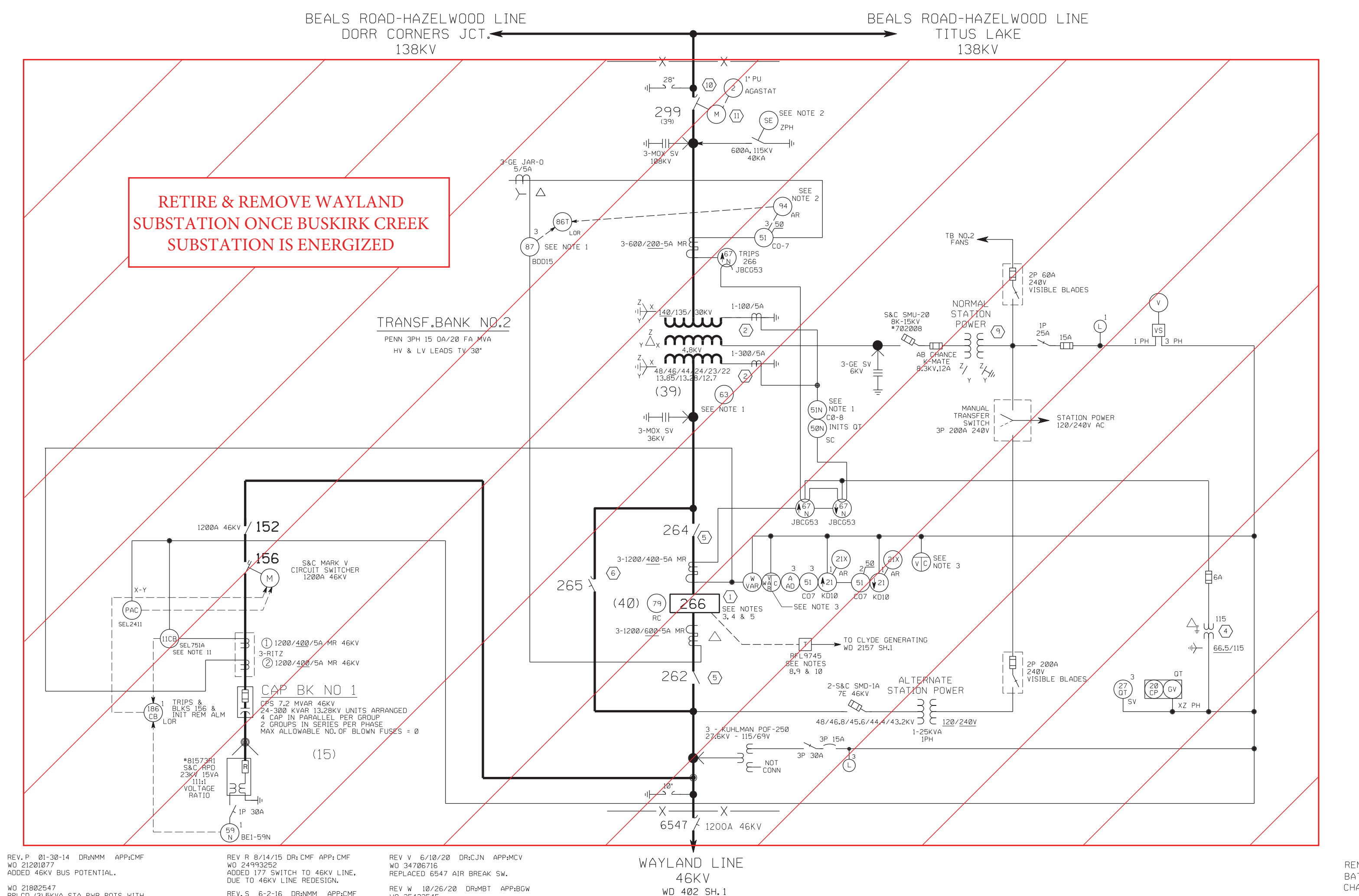


New System Configuration



Proposed New Buskirk Creek Substation Configuration





NOTES:

1. TRANSF. BANK DIFF. (87), SUDDEN PRESS. (63) AND TOTAL. NEUT. GRD (51N) RELAYS WILL OPERATE A DIFF. AUX. (86T) RELAY. THE (86T) WILL TRIP AND BLOCK CLOSING OF THE 266 OCB, TRIP THE SOGS AND INITIATE OPENING OF 299 MOAB AFTER A ONE SEC. TIME DELAY.
2. SOGS IS TRIPPED BY (86T) OF TB #2 AND THE HIGH-SIDE (51) RELAYS. THESE (51) RELAYS ALSO OPERATE A (94) AR RELAY WHICH WILL INITIATE THE TB #2 (86T).
3. THE FOLLOWING INFORMATION IS SENT TO SYSTEM CONTROL VIA RTU:
   A - SWITCH POSITION FOR 299
   B - BREAKER POSITION FOR 266
   C - WATT / VAR FLOW TB2
   D - BUS VOLTAGE 46 KV REGULATED BUS
4. BREAKER 266 MAY BE TRIPPED OR CLOSED FROM SYSTEM CONTROL
5.
6.
7.
8. DIRECT TRANSFER TRIP (DTT) TO CLYDE GENERATING IS INITIATED BY OPENING OF THE 266 OCB.
9. THE DTT TRANSMITTER IS TO BE CUT OUT OF SERVICE DURING 266 OCB BREAKER MAINTENANCE.
10. OPERATION OF DTT SCHEME WILL TRIP THE MAIN BREAKER AND EACH GENERATOR BREAKER AT CLYDE GENERATING.
11. SEL751A DEVICE (11CB) FUNCTIONS AS: 50/51 & 50N/51N

1 McGRAW EDISON TYPE CG-38 1200A 46KV OA-3 MECH
2 GE TYPE JKW-6 CURRENT TRANSF
4 JEFFERSON AUX PT 66.5/115-115V
5 STOCK SW 1200A 46KV
6 SOUTHERN STATES TYPE EV 1200A 46KV
9 1 PH 25KVA 4800/8320 120/240V
10 SOUTHERN STATES TYPE EV 600A 115KV
11 SOUTHERN STATES MOAB TYPE VM-1104

REV. P 01-30-14 DR:NMM APP:CMF
WO 21201077
ADDED 46KV BUS POTENTIAL.

WO 21802547
RPLCD (3) 5KVA STA PWR POTS WITH (1) 25KVA ALTERNATE STA PWR. RMVD (2) 10KVA STA PWR POTS & ASSOC BKRS. ADDED MANUAL TRANSFER SWITCH & (1) 60A DISC SW FOR TB2 FANS & (1) 200A DISC SW.

REV. Q 4-10-14 DR:NMM APP:CMF
WO 22009051
REMOVED AUTO SYSTEM SECURITY RELAYS (81) & (86F). REMOVED NOTE 5.

REV R 8/14/15 DR: CMF APP: CMF
WO 24993252
ADDED 177 SWITCH TO 46KV LINE, DUE TO 46KV LINE REDESIGN.

REV. S 6-2-16 DR:NMM APP:CMF
FOR RECORD
CORRECTED NOTE 2. ADDED (86T) RELAY.

REV. T 8-18-16 DR:MBT APP: ASL
FOR RECORD
RMVD CLYDE GENERATING DISCONN IN NOTE 9 PER SYS PROT.

REV U 3/06/19 DR:MBT APP:BGW
FOR RECORD WO 33716464
RENUMBERED 177 ABS TO 6547.

REV V 6/10/20 DR:CJN APP:MCV
WO 34706716
REPLACED 6547 AIR BREAK SW.

REV W 10/26/20 DR:MBT APP:BGW
WO 35423545
REPLACED 156 CAP BANK NO.1 CONTROLS. ADDED NOTE 11. REMOVED NOTES 6 & 7. REMOVED 156 GROUND SWITCH AND CAPACITOR GROUND SWITCH.

REMOTE ALARM - WESTERN REGION POWER CONTROL
BATTERY - EXIDE CA-5 100 AH 125V DC 60 CELLS
CHARGER - PCP MODEL FD-130-12 130V DC 12A

DR M W SMELL	06/26/86
APP T L KRUMMREY	06/26/86
APP J C RACEY	06/26/86
APP D C TARSI	06/26/86

Consumers Energy
JACKSON, MICHIGAN
CORRECTED TO 10/26/20
REV W

WAYLAND
SUBSTATION
T
WAYLAND, SW
NW REGION
WD 402
SHEET 2

BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Friday, January 1, 2021 4:56 PM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Jacob D. Roberson; Benjamin T. Scott
Subject:	Approval has completed on 23-0011 Wayland Substation - Replace with New 138-46 kV Bulk Power Substation.

Approval has completed on 23-0011 Wayland Substation - Replace with New 138-46 kV Bulk Power Substation.

Approval on 23-0011 Wayland Substation - Replace with New 138-46 kV Bulk Power Substation has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 12/21/2020 3:42 PM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by Benjamin T. Scott on 12/21/2020 3:43 PM
Comment:

Approved by DOUGLAS R. MEYERS on 12/21/2020 3:56 PM
Comment:

Approved by Edward R. Mathews on 12/21/2020 4:01 PM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 12/22/2020 9:02 AM
Comment: Approved.

Approved by Timothy J. Sparks on 12/22/2020 9:21 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 1/1/2021 4:56 PM
Comment:

View the workflow history.

PROJECT: North Belding Substation Rebuild (WO# 38051801)

i. Purpose and Necessity of the Project with Supporting Data.

North Belding is a 1947's vintage substation. Multiple pieces of major equipment have been identified as obsolete including the transformer, bus switches, capacitor switcher, copper bus and brown insulators. Copper bus is also known to crack and split under extreme weather changes and brown bus support insulators have a higher than normal failure rate.

The Concept Approval 23-0012 (Attachment 1) which initially identified the need for the North Belding Substation rebuild describes the above.

ii. Line Design, size material used.

Not applicable, substation construction project.

iii. Line Length and ROW requirements.

Not applicable, substation construction project on Consumers Energy owned property.

iv. Approximate Construction Schedule.

Construction Start: September 9, 2022
Construction Complete: April 17, 2023
Equipment Checkout Complete: May 15, 2023

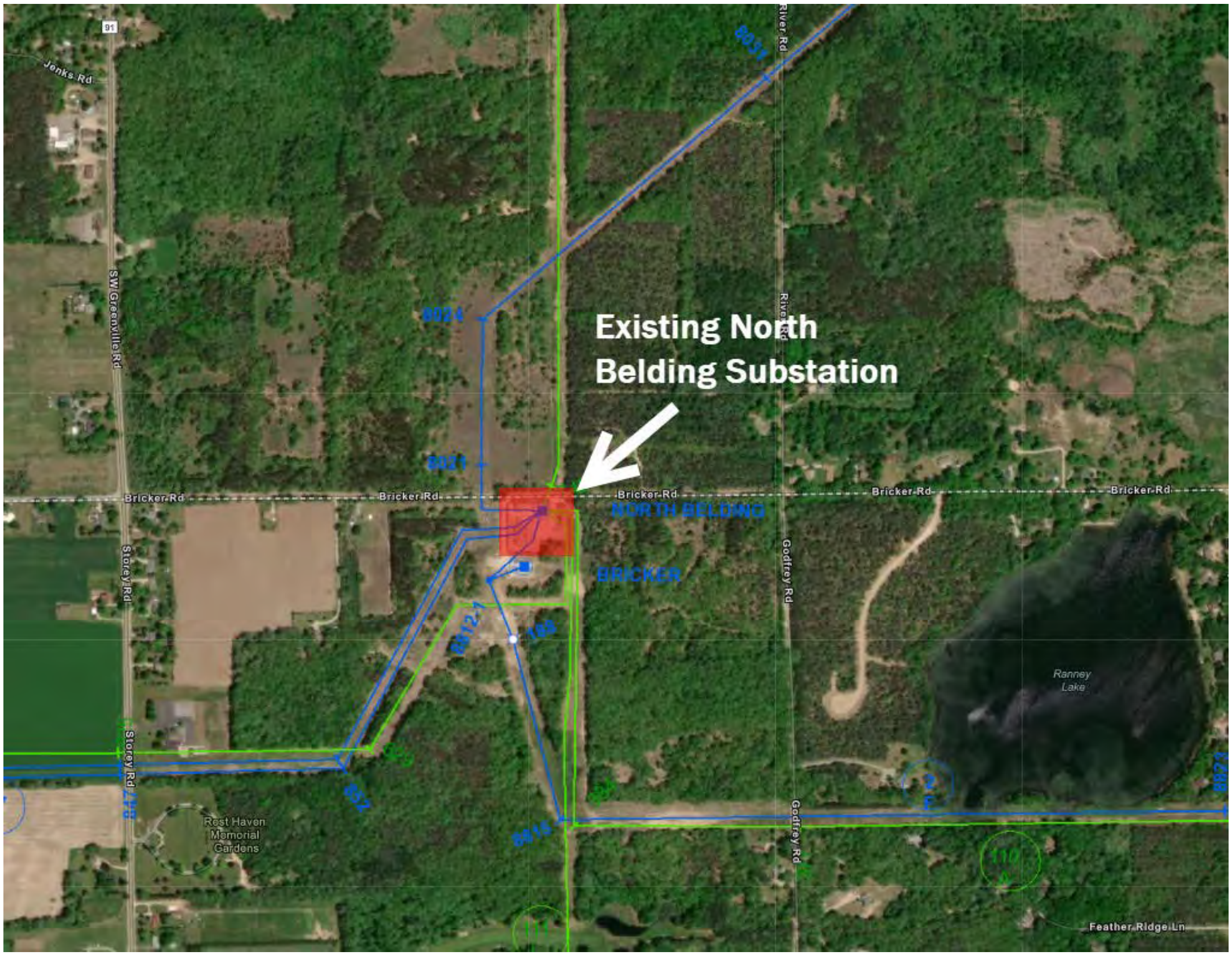
v. Project effect on cost of operation and reliability of service.

In the process of rebuilding the substation, new equipment is planned for the new substation for any piece of equipment not replaced in the last year or two. This is expected to increase reliability and reduce maintenance costs on the old 1947's vintage substation.

vi. A description of the property being replaced and salvage value.

This new substation would replace one (1) 138/46 kV transformers, two (2) 46kV breakers, two (2) capacitor switchers, two (2) capacitor banks, and other associated relaying, structure, PT's & CT's. The estimated salvage value is unknown at this time.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See Attachment 1, Concept Approval 23-0012.

x. Date of board approval.

N/A

North Belding Substation Rebuild – Attachment 1

CONCEPT APPROVAL No. 23-0012
North Belding Substation Rebuild

BCMazur
BTScott
DRMeyers
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 23-0012

Project: **North Belding – Rebuild Substation** **County:** Ionia

Date: December 17, 2020 **Need System Changes By:** 5/15/2023

Problem Description:

North Belding Substation is a 138 to 46 kV bulk power substation located near Belding, Michigan that provides a bulk power source to the Cannonsburg, York, Orleans and Greenville 46 kV lines. It has one, 30/40/50 MVA 138/46 kV transformer and was originally constructed in approximately 1947.

North Belding Substation has been identified as one of the top 25 HVD bulk power substations to rebuild after a comprehensive look at all HVD bulk power substations. This comprehensive look involved first sorting the substations by age then a cross-functional review was performed by Operations Engineering, System Protection, Substation Reliability, Substation Engineering, Substation Operations, Substation Maintenance, Electric Field Lab, Substation Construction, and HVD Planning.

Substation Reliability has identified the transformer (1972 Allis Chalmers), two circuit breakers, obsolete bus switches, Joslyn Varmaster capacitor switcher, S&C Mark V cap switcher, 46 kV copper bus, and brown 46 kV bus support insulators as candidates for replacement. Copper bus is known to crack and split under extreme weather changes and brown bus support insulators have a higher-than-normal failure rate. The control house and fence have also been identified as needing to be replaced.

The layout of North Belding Substation is non-standard. The Transformer is situated so that the high side of the transformer is facing the 46 kV bus and the low side of the transformer is facing the 138 kV bus. The Cannonsburg 46 kV line does not have a dedicated line exit circuit breaker. The relaying for the Cannonsburg 46 kV Line connected to the “200” bus tie breaker relaying, which limits the use of the 200 breaker

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for sparing capability. Also, capacitor bank #2 has capacitor cans stacked four high compared to the current standard of single high, which has the potential for ergonomic risks when replacing.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild the HVD portion of North Belding Substation on the existing site. *Conceptual cost: $6,900,000*

Recommended Alternative:

Alternative #2 is recommended. This alternative addresses the obsolete equipment and non-standard layout at North Belding. Replacing 46 kV bus, insulators, switches, and rebuilding the station to a standard layout with full sparing capability will improve the reliability and operational flexibility of this station. By performing all the work under one construction contract, efficiencies in bid pricing can be realized while limiting the number of outages.

Alternative #1 is not recommended because this alternative does not address the obsolete equipment and non-standard substation layout.

Alternative #2 Recommended Scope:

Replace the existing 30/40/50 MVA 138/46 kV transformer with a new 30/40/50 MVA transformer. In the Series 2019 cases, the maximum expected loading on the new transformer bank is 33.8 MVA. Based on this information, a new 30/40/50 MVA transformer bank is expected to be loaded to 53.1% of its expected maximum rating (67.8 MVA). Build a new 46 kV Central Control House (CCH) large enough to accommodate all existing CE panels and room for potential future panels. Replace the 166 and 1477 gas breakers and install a new line exit breaker for the Cannonsburg 46 kV Line. Rebuild the 46 kV structure and replace the 46 kV copper bus and brown 46 kV bus support insulators. Replace the 156 and 256 capacitor switcher and rebuild the 256 cap bank. Replace the station power transformer and install an alternate station power. Replace the 205 and 206 bus disconnect switches. Replace fence as needed.

METC facilities are not required for this project.

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Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2023 Direct Cost	2022 Cost with Overheads	2023 Cost with Overheads	Description
EH-98320 – HVD Substation Failure Projects	$3,000,000	$1,400,000	$4,400,000	$2,200,000	Rebuild the HVD portion of North Belding Substation on the existing site
Cost of Removal	$130,000	$70,000	$200,000	$100,000	Remove existing equipment at North Belding
Total	**$3,130,000**	**$1,470,000**	**$4,600,000**	**$2,300,000**	**Grand Total: $6,900,000**

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: CMFranklin

Approvals:

Senior Engineer Lead, HVD Planning West	BTScott	Required
Senior Engineer Lead, Reliability & Support	Douglas R. Meyers	Required
Director, HVD System Planning	Edward R. Mathews	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required

BCMazur
BTScott
DRMeyers
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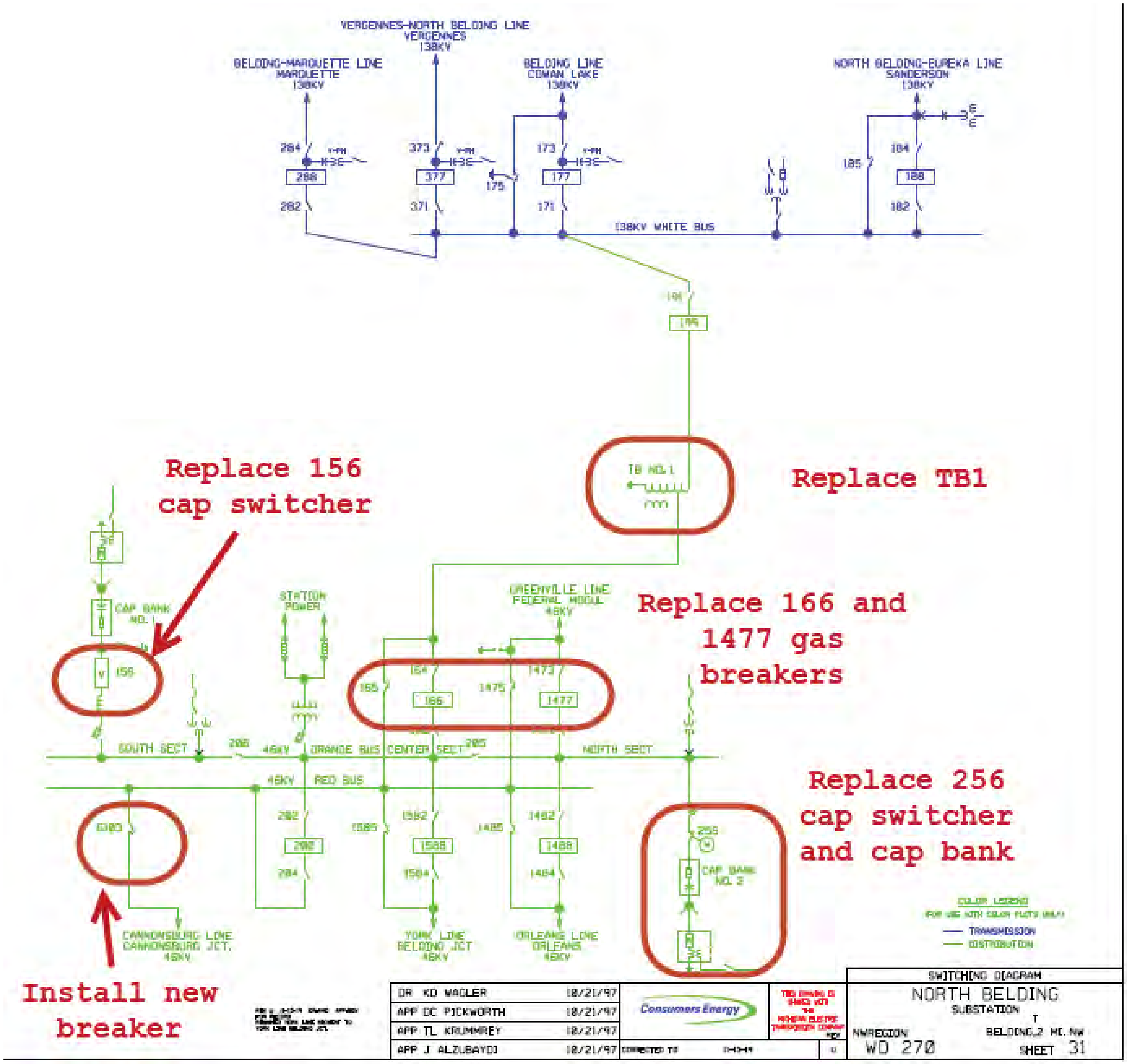
RTBlumenstock
TJSparks
JFBrossoit



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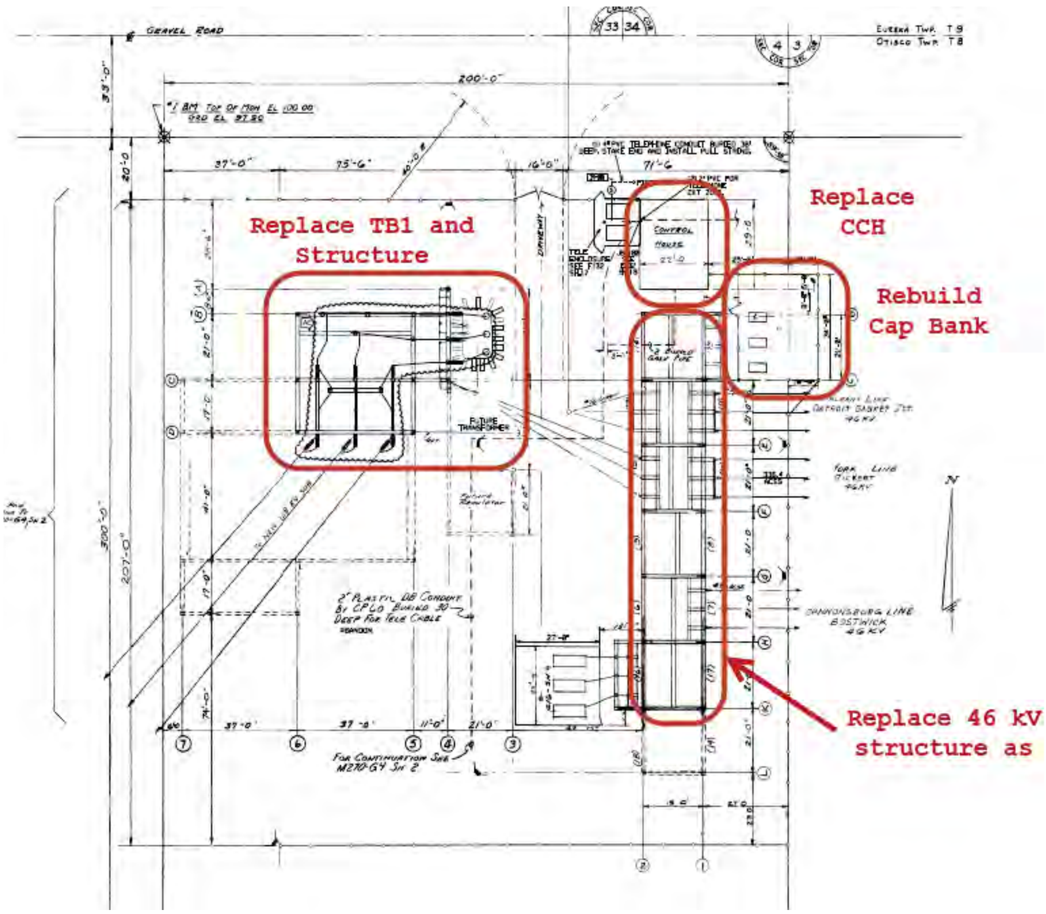

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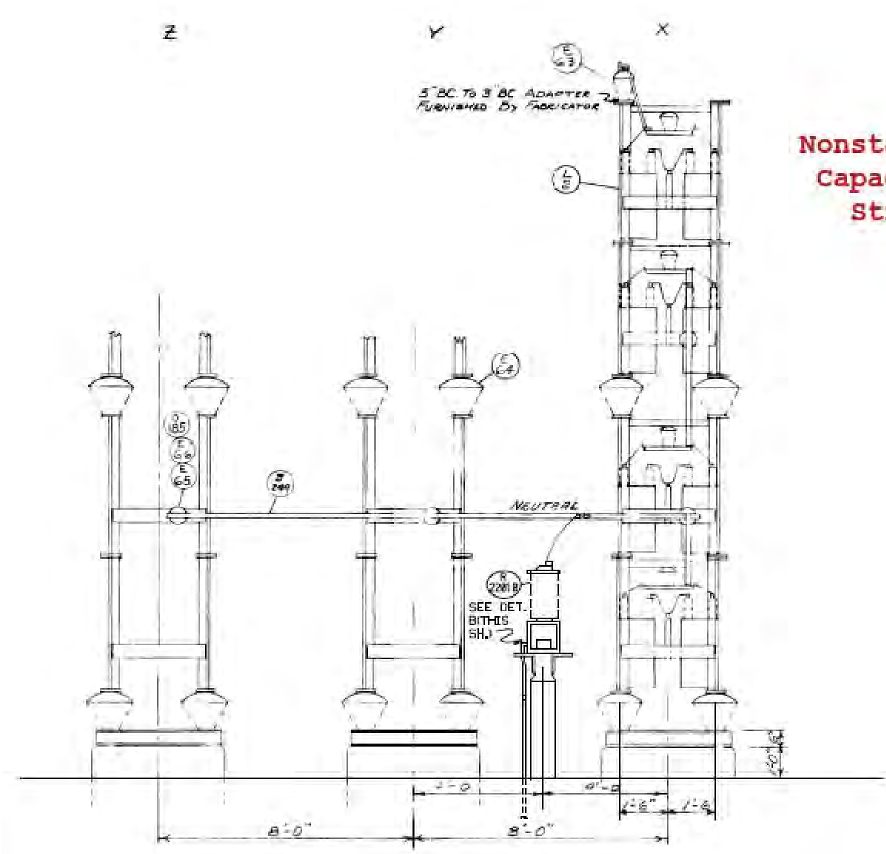

Nonstandard 256 Capacitor Can Structure

BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Friday, January 1, 2021 4:56 PM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Jacob D. Roberson; Catherine M. Franklin
Subject:	Approval has completed on 23-0012 North Belding - Rebuild Substation.

Approval has completed on 23-0012 North Belding - Rebuild Substation.

Approval on 23-0012 North Belding - Rebuild Substation has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 12/21/2020 9:43 AM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by Benjamin T. Scott on 12/21/2020 10:03 AM
Comment:

Approved by DOUGLAS R. MEYERS on 12/21/2020 2:46 PM
Comment:

Approved by Edward R. Mathews on 12/21/2020 2:55 PM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 12/22/2020 8:39 AM
Comment: Approved.

Approved by Timothy J. Sparks on 12/22/2020 8:49 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 1/1/2021 4:55 PM
Comment:

View the workflow history.

PROJECT: SANTIAGO 138KV TAP AND LINE LN005AG (SAP #37900695)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this new 138kV line is to connect the new Santiago distribution substation to the system. The substation's incoming 138kV line is necessary to energize the substation and serve the growing customer load in Au Gres township. This will address the current load capacity issues, along with addressing future substation reliability concerns of the area. The new substation will alleviate the HVD system capacity limits which will free up 8 MVA on the surrounding 46kV substations.

Concept Approval 20-0059 provides additional project details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336.4 ACSR conductor.

iii. Line Length and ROW requirements.

The new line is 7 miles long and new right-of-way is required for the entire length.

iv. Approximate Construction Schedule.

Construction Start: January 15, 2022
Construction Complete: July 31, 2022

v. Project effect on cost of operation and reliability of service.

Core business function of providing adequate electrical capacity to serve existing and new customer electrical load.

vi. A description of the property being replaced and salvage value.

Not applicable, new 138kV line to supplement existing HVD lines.

vii. Map of site and location of facilities.

viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See the attached Concept Approval 20-0059.

x. Date of board approval.

N/A.

MDGood
Ermathews
JRFox
DALynd
RTBlumenstock
TJSparks
JFBroissoit

Consumers Energy
Customer & Service Infrastructure - HVD
CONCEPT APPROVAL

Concept Number: 20-0059 County: Arenac

Project: Santiago Substation – Au Gres Commercial Marijuana Facilities

Date: 06/16/2020 Need System Changes By: 06/31/2021

Problem Description:
Au Gres township passed a medical marijuana facilities ordinance in 2018. Electric Planning completed the necessary LVD line upgrades to provide the final 1.3MW of available 46kV HVD capacity at Au Gres substation (6 MW total). Substation OCR's are being replaced in order to meet the additional capacity. Due to the insufficient footprint of the Au Gres substation, the new reclosers are being installed in a non-conventional configuration outside the substation fence mounted on a pole. The final 900kVA of 46kV HVD capacity (Standish line) at Bessinger substation has been allocated to marijuana facilities (3 MW total). This leaves no capacity left on the Standish 46kV line in the Omer area, with the current system configuration. In addition, Turner and Noble substations have less than 1MVA of available 46kV HVD capacity each.

There are additional facilities in Au Gres and Omer area that have contacted Consumers Energy to determine what electrical capacity is available. With the electrical capacity depleted in the area, we are informing customers to seek alternative methods to meet their electrical needs including natural gas and diesel generators until we can construct a new substation.

Both Au Gres and Bessinger substations need upgrades due to their age and delta supply voltage. Additionally, these substations do not meet the standard safety or design specifications we follow today due to limited clearances between equipment.

Future Growth:
With the recent passage of the marijuana ordinance in Au Gres the load growth has exceeded our capacity on the LVD system, Substation, and HVD system. There are 5 customers requesting a total of 2.8 MVA that would connect to the electric utility if there was capacity. Currently, the total capacity needed for the Au Gres and Bessinger area is 11.8 MVA. Au Gres township has approved all the allowable grow licenses they have available. Most of these license holders are in the process of working through the requirements set by the state to obtain the approvals to grow. Based on our communication with the township we estimate 35% of the indoor license holders are currently operational. Once these facilities work through the approvals, there will be additional load that cannot be supported by the existing electrical system. Figure 1 (page 6) indicates the parcels which have purchased licenses.

MDGood
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TJSparks
JFBroissoit

Alternatives Considered:

Alternative 1: Rebuild Au Gres & Bessinger substation

Alternative 1 rebuilds the Au Gres substation with a larger (single) transformer at the current location and converts the circuits from 11kV delta to 24.9/14.4 kV wye. Bessinger substation would also be removed from the 46 kV Standish line and rebuilt in a new location tapped of off the 138kV line.

Based on the contingency results, loading Au Gres to 12MW is not feasible. Both the peak and shoulder cases presented issues, namely that multiple sections of lines were loaded above 100% and numerous buses were below the minimum allowable voltages to operate the system safely and to properly supply our customers. Lower loads were selected to find what the limit on the Au Gres substation was for there to be no contingency problems during the peak case study. This process was stopped at 2.5MW as this would provide very little increase to the current capacity of Au Gres.

The question remained if line rebuilds could help increase the available capacity, and reduce some contingency issues, but it would be a costly expenditure. Given all the issues with the contingencies, it is likely that full, or near to full, rebuilds would need to occur to alleviate these issues. To fully rebuild the Whitestone Point line, it would cost $12,000,000; to fully rebuild the Alabaster line, it would cost $18,000,000; and to fully rebuild the Standish line, it would be $25,000,000. These costs are for the line rebuilds alone, and not for any other potentially needed upgrades for this alternative. Therefore, this alternative was not pursued further.

Alternative 2: Install a new substation near Omer on the 138kV system

This alternative builds a new 20MVA 138-14.4/24.9kV substation on the east side of Omer under the existing 138kV line. Unfortunately, most of the new and existing load is located near the city of Au Gres and it would require LVD to serve 7MVA of load seven and a half miles away from the substation. This limits the new load growth capacity of Au Gres area to 2MVA. At this point the voltage drops below the MPSC mandated limit and Consumers does not stock line regulators large enough to handle the load. This alternative also brings up some reliability concerns. The circuit feeding Au Gres would have a total of 1,530 customers but only 60 customers would be in in the first 7 miles. The first two and a half miles of the first zone will be double circuit construction, an outage on this line will cause the entire substation to lock out affecting 1,961 customers. Therefore, this alternative was not pursued further.

Alternative 3: Install a new substation near M-65 & Noggle Rd on the 138kV system

Alternative 3 builds a new 20MVA 138-14.4/24.9kV substation (see figure 3, shown on page 8) near the intersection of M-65 and Noggle Rd. This will require a two-mile 138kV line extension off Iosco-Karn line (5O), which will include a load break switch and easements. A load break switch is a requirement from METC for lines of 2 miles or longer. METC will need to install a 138kV tap pole and switches on each side of the tap. The substation will allow us to serve all the new additional load along with providing the area with load growth potential. The proposed load for the new substation would be 10.8 MVA based on existing loads. The three new LVD circuits will be 67 miles, 18 miles, and 13 miles in length. See Table 1 on page 9 for circuit characteristics.

The estimated project costs for Alternative 3 are as follows:

- 138kV general distribution substation cost estimate: $1,800,000
- Substation property acquisition estimate: $80,000
- Two-mile 138kV line extension, load break switch, and easements: $1,564,000
- LVD line work required to reach new loads: $2,080,000
- **Total: $5,524,000**

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JFBroissoit

Alternative 4: Install a new substation on the west side of Au Gres on the 138kV system

Alternative 4 builds a new 20MVA 138-14.4/24.9kV substation (see figure 3, shown on page 8) on Santiago Rd on the northeast corner of the 2497 Huron Rd marijuana facility. Lower property cost is expected at this location due to the property being owned by a marijuana facility with a vested interest in a new substation. The new substation will require a seven-mile 138kV line extension off the Iosco-Karn line (5O), a load break switch, and five miles of LVD underbuild. A load break switch is a requirement from METC for lines of 2 miles or longer. METC will need to install a 138 kV tap pole and switches on each side of the tap. This substation will allow us to serve the new load along with providing the area with potential for load growth. The proposed load for the new substation would be 10.8 MVA based on existing loads. Figure 2 depicts the scout map for the HVD right of way acquisition. The three new LVD circuits will be 32 miles, 46 miles, and 25 miles in length. See Table 1 on page 9 for circuit characteristics.

The estimated project costs for Alternative 4 are as follows:

- 138kV general distribution substation cost estimate: $1,800,000
- Substation property acquisition estimate: $20,000
- Seven-mile 138kV line extension, load break switch, and easements: $5,000,000
- Five miles of LVD underbuild: $555,000
- **Total: $7,375,000**

Recommended Alternative

Alternative 4 is a path forward that will address current load capacity issues, along with addressing future substation reliability concerns of the area. The new substation will alleviate the HVD system capacity limits which will free up 8 MVA on the surrounding 46kV substations.

Alternative 4 will provide increased reliability compared with Alternative 3 due to the substation being closer to the city of Au Gres where the largest loads and customer counts are located. The 5 mile stretch between Au Gres and M-65 is heavily wooded and swampy. Alternative 3 locates the substation at M-65 which requires the first zone of the circuit feeding the city of Au Gres to be constructed through this area. This would cause additional LVD circuit lockouts along with long restoration times resulting in poor reliability to 78% (circuit 1) of the customers in the area. With the substation located in Au Gres, the circuit feeding Omer (through the wooded and swampy zone) would have much less exposure to these risks due to underbuilt construction. Along with limited exposure, only 25% (circuit 2) of customers would be fed through this territory. Using current reliability data for the lines we do have in this area we expect a 297,000 ($891,000 savings based on $3/min) yearly outage minute reduction with Alternative 4. Using the circuit characteristics shown in Table 1 (shown on page 9), it can be concluded that Alternative 4 provides more balanced circuits for loading, customer-count, and customer miles.

This concept covers the first 2 of 8 years of the Santiago long range plan. The long range plan includes retiring Au Gres and Bessinger substations by voltage converting all the LVD backbone from delta to wye and transferring to Santiago substation. The work covered in this concept is necessary to start the voltage conversion process and to meet immediate substation and HVD capacity needs. The LVD voltage conversions, to be completed on future concepts, can utilize the new business process to complete the appropriate work as needed. These future concepts bring the total cost to $17.2 million as discussed in the long range plan. Please review the attached long range plan for in depth details about the economic analysis, LVD system losses, and future LVD voltage conversion plans.

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Conceptual Estimates by WBS

	WBS Element	Direct Cost	Cost with Overheads	Description	Year(s)
HVD	EH-95208	$700,000	$700,000	7 Miles 138kV ROW	2020
HVD	EH-95208	$20,000	$20,000	Substation Property	2020
HVD	ED-95720	$1,200,000	$1,800,000	New 138kV General Distribution Sub	2021
HVD	EH-95008	$2,900,000	$4,300,000	7 Miles New 138kV Line	2021
HVD			**$6,720,000**	**Total HVD Costs**	
LVD	ED-10000		$555,000	5 Miles 138kV Underbuild	2021
			$555,000	**Total LVD Costs**	
TOTAL COSTS			**$7,375,000**	**Total HVD + LVD Costs**	

Present Need: On approval, this document authorizes the C&SI, LVD, and HVD Engineering groups to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: Blake Dycewicz & Matt Koepke

MDGood
Ermathews
JRFox
DALynd
RTBlumenstock
TJSparks
JFBroissoit

Approvals:

Substation Planning & Reliability East	Matthew Good	Required
Interim Director HVD System Planning	Ed Matthews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Engineering and Transformation	Jean-Francois Brossoit	Required

MDGood
Ermathews
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DALynd
RTBlumenstock
TJSparks
JFBroissoit

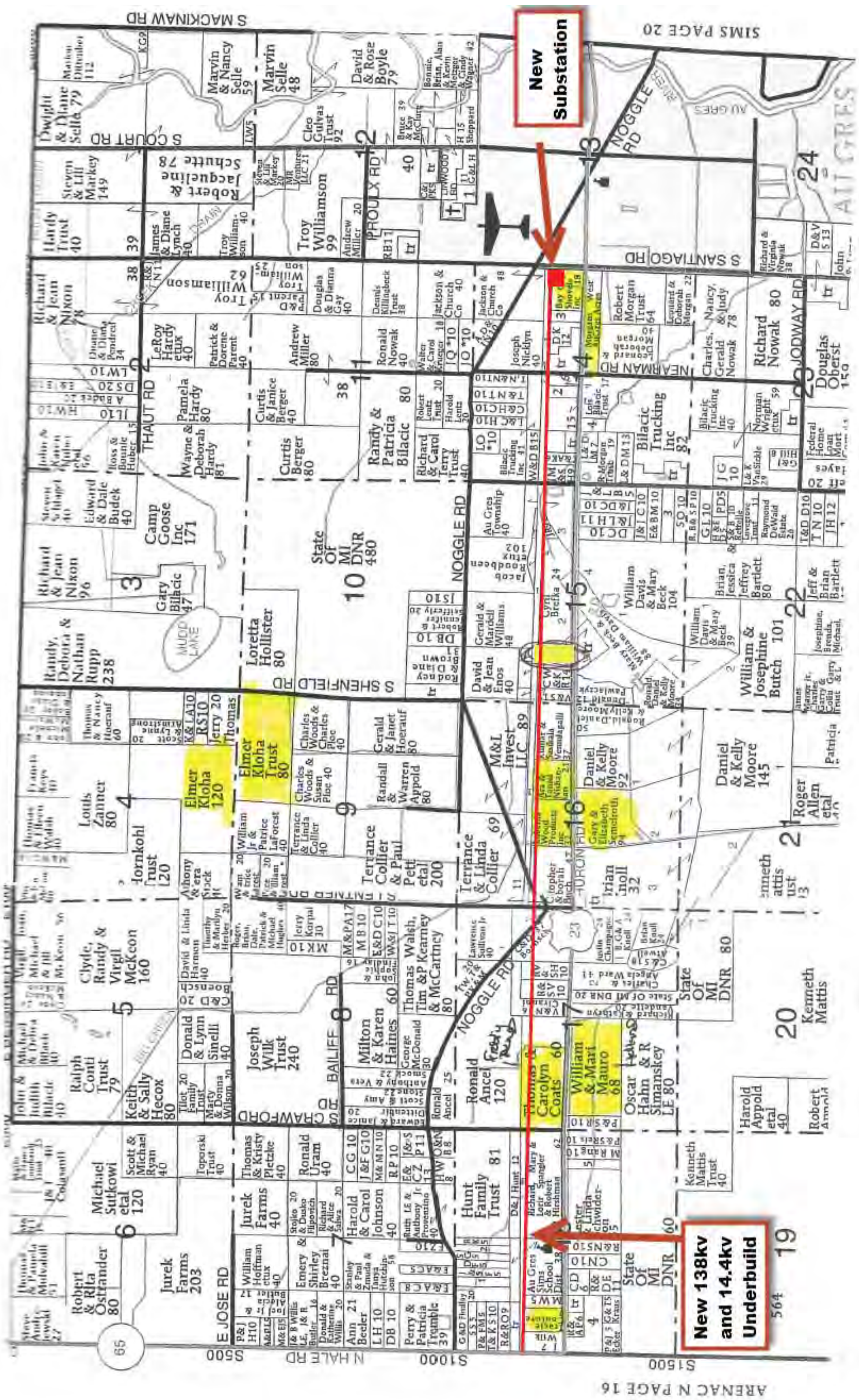

Figure 1: Properties in Au Gres that have Purchased Marijuana Licenses

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TJSparks
JFBroissoit

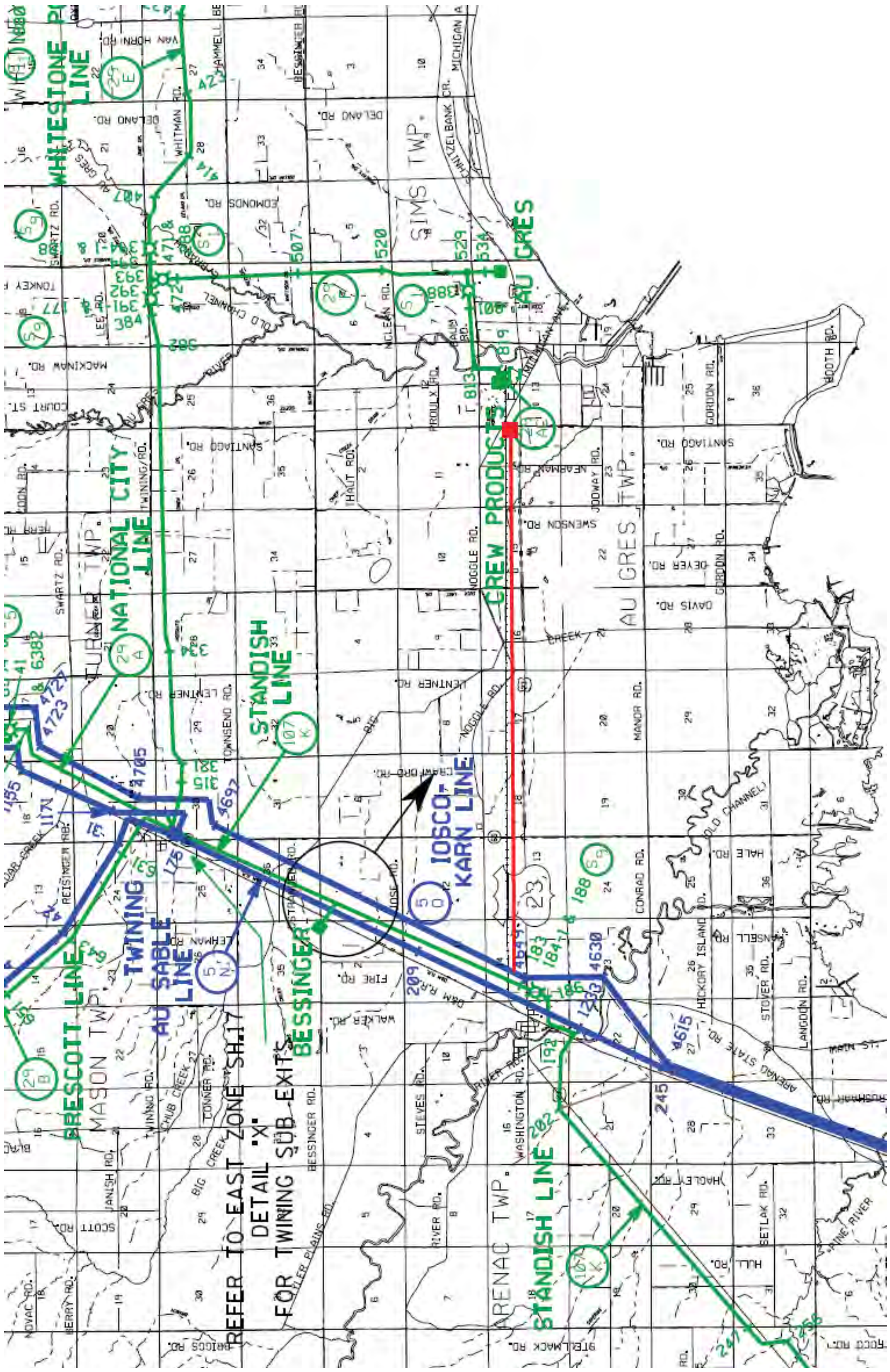

Figure 2: Alternative 4 Scout Map Area Showing Proposed 138kV Line and Substation

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JRFox
DALynd
RTBlumenstock
TJSparks
JFBroissoit

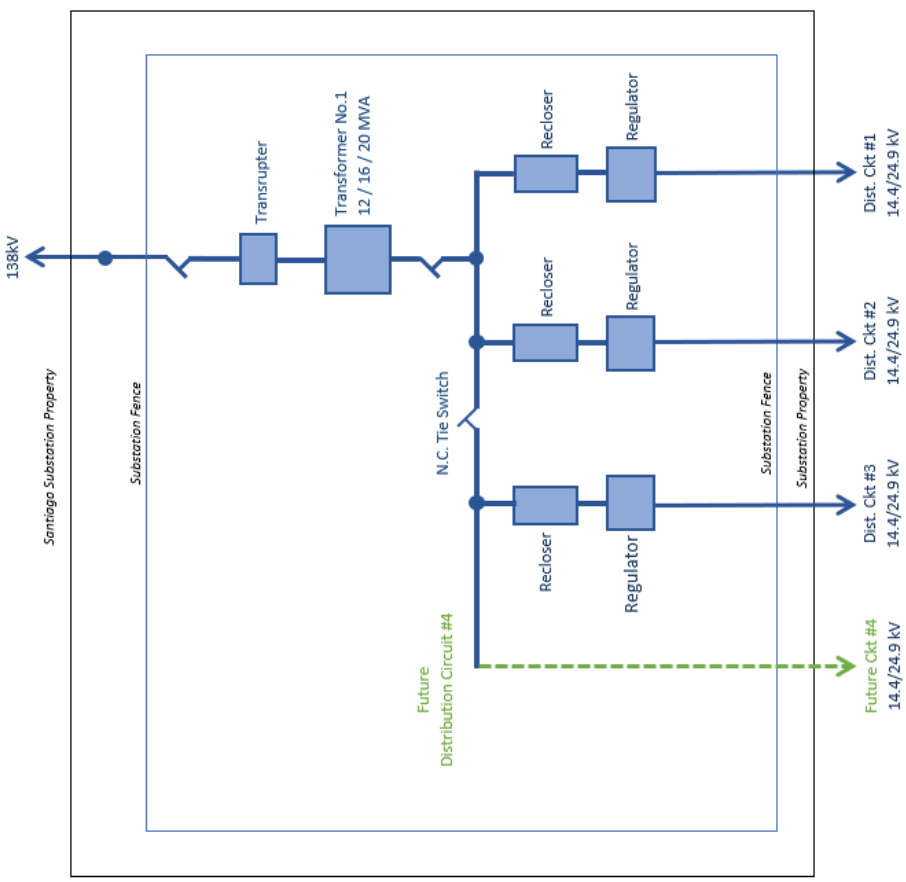

Figure 3: Substation Configuration

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JRFox
DALynd
RTBlumenstock
TJSparks
JFBroissoit

Table 1: Circuit Data Breakdown

Alternative 3									
Circuit		**Load (MVA)**	**% Total Load**		**Miles**	**% Total Ckt Miles**		**Customers**	**% Customer Count**
	1	8.2	75.9		67	68.37		1530	78.02
	2	2.3	21.3		18	18.37		347	17.70
	3	0.3	2.8		13	13.27		84	4.28
Total		**10.8**			**98**			**1961**	

Alternative 4									
Circuit		**Load (MVA)**	**% Total Load**		**Miles**	**% Total Ckt Miles**		**Customers**	**% Customer Count**
	1	5	46.3		31.5	30.73		596	30.39
	2	3.5	32.4		46	44.88		491	25.04
	3	2.3	21.3		25	24.39		874	44.57
Total		**10.8**			**102.5**			**1961**	

BRIAN C. MAZUR

From: SPAdvisor
Sent: Tuesday, October 6, 2020 8:19 AM
To: BRIAN C. MAZUR
Cc: BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; Gregory E. Kral; Jacob D. Roberson; Blake A. Dycewicz; Matthew R. Koepke
Subject: Approval has completed on 20-0059_LVD Substations - Santiago Substation - Au Gres Commercial Marijuana Facilities.

Approval has completed on 20-0059_LVD Substations - Santiago Substation - Au Gres Commercial Marijuana Facilities.

Approval on 20-0059_LVD Substations - Santiago Substation - Au Gres Commercial Marijuana Facilities has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 9/11/2020 3:36 PM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by Matthew D. Good on 9/11/2020 3:37 PM
Comment:

Approved by Edward R. Mathews on 9/14/2020 1:51 PM
Comment:

Approved by JULIA R. FOX on 9/15/2020 7:03 AM
Comment: Approved. The LVD Lines (Underbuild) will be charging to 3.06 New Business Capacity. ED-10000 is a retired WBS.

Approved by DONALD A. LYND on 9/15/2020 7:21 AM
Comment: Approved.

Approved by RICHARD T. BLUMENSTOCK on 9/18/2020 11:59 AM
Comment: Approved. Tim - I will send you the long range plan for this area to supplement this concept approval.

Approved by Timothy J. Sparks on 10/5/2020 9:35 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 10/6/2020 8:19 AM
Comment:

View the workflow history.

PROJECT: LN112C REMUS REBUILD (SAP WO#37776880)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve overall reliability and in particular for customers served from the Remus 46 kV Line. There are 27 out of 98 poles (28%) that were identified as replacement candidates by the pole inspector for the 112C, 8.0 mile section covered under this rebuild. Actual line performance over the past five years has shown the Remus 46 kV Line to be underperforming (see plot under Section ix). HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild vs. further investment in pole replacements or pole top rehabilitation on a non-standard line. The Remus 112C line section is presently non-standard small single layer #2 ACSR conductor.

Concept Approval 21-0019 provides additional project details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336 ACSR conductor and steel shield wire.

iii. Line Length and ROW requirements.

The line is 8 miles long and will be built 20' offset of the existing centerline on a combination of existing Consumers Energy and newly obtained easements.

iv. Approximate Construction Schedule.

Construction Start: January 1, 2022
Construction Complete: August 31, 2022

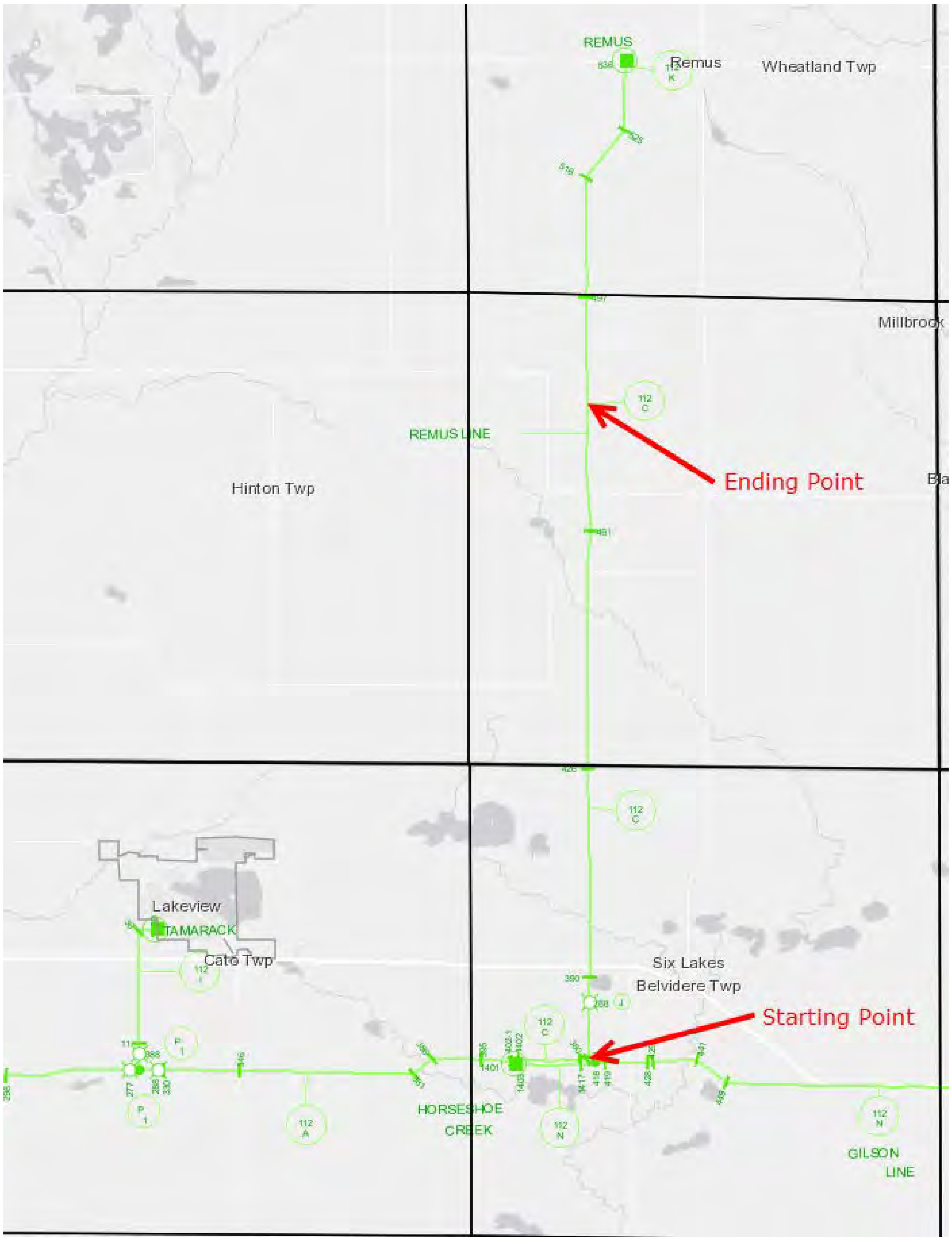
v. Project effect on cost of operation and reliability of service.

The reliability of electric service will increase with the new configuration. The Remus 46 kV line experienced 3 outage incidents between years 2015 through 2019. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor and etc. that were constructed in 1948 are being removed starting at structure #380 to structure #477. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.

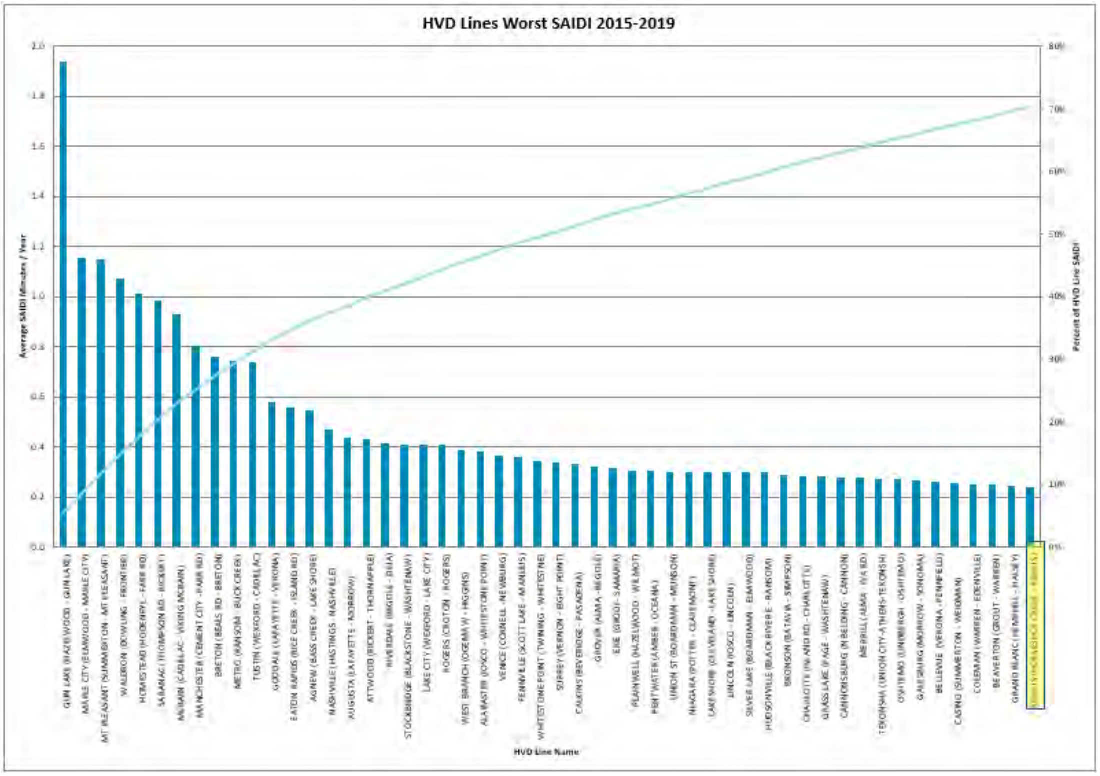


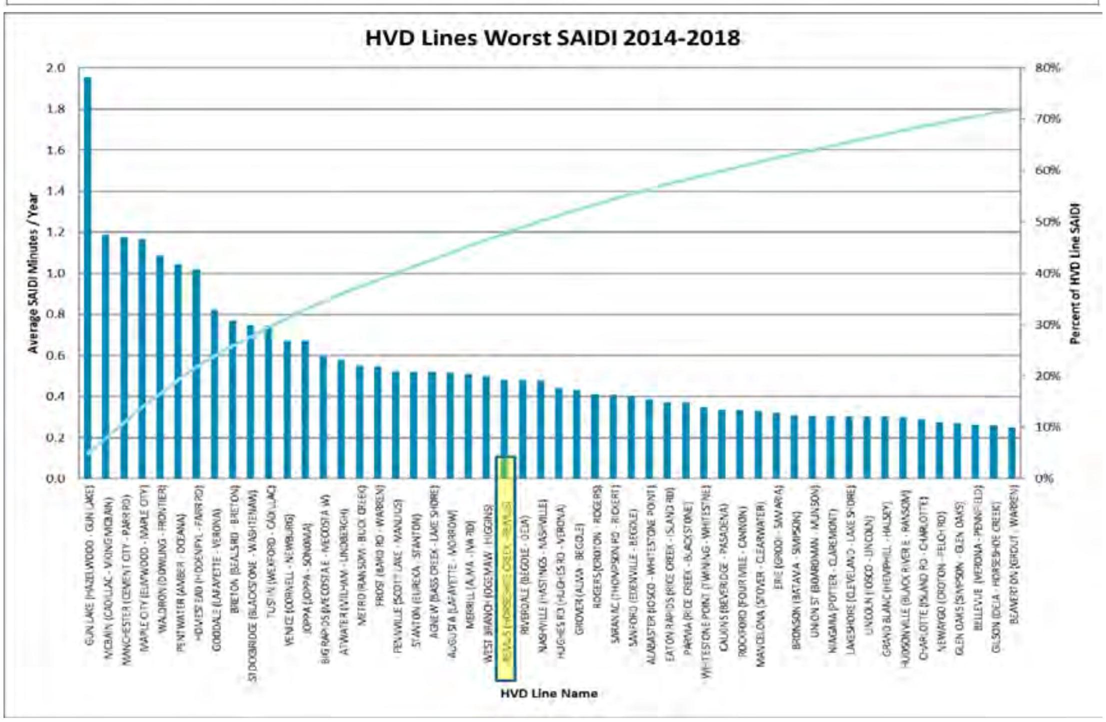
viii. Funding from other entities.

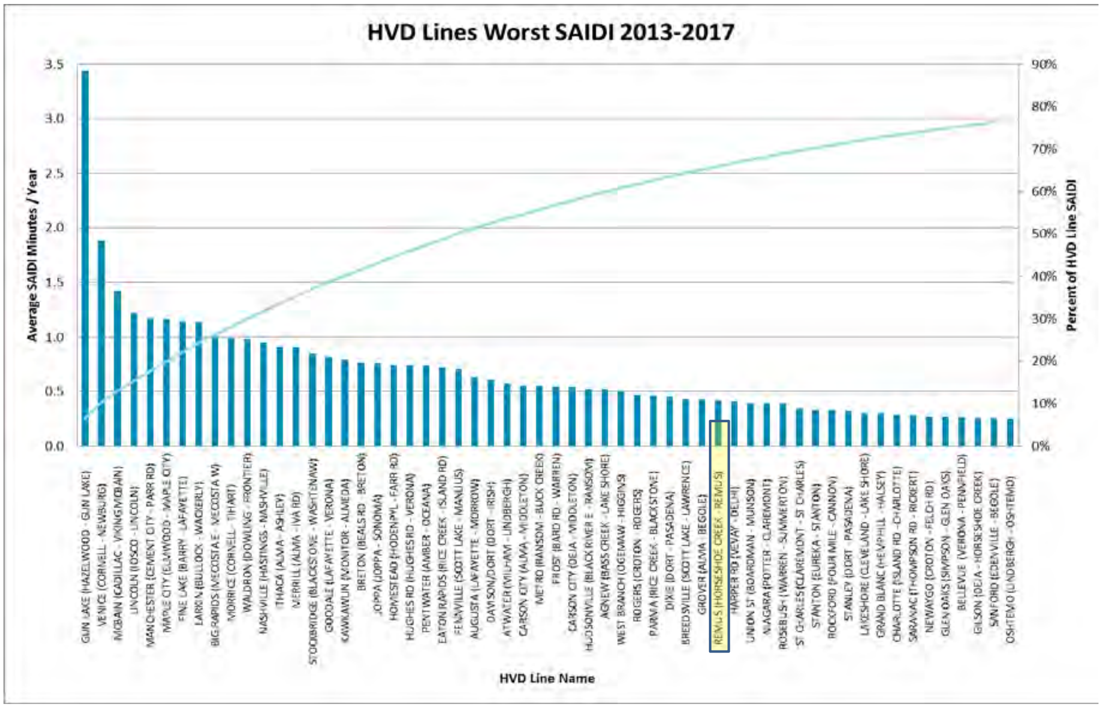
None.

ix. All studies performed by the Company or 3rd party regarding the project.

The 2018 pole inspection identified 40 out of 157 poles (25%) on this line segment as needing to be replaced.







Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0

Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 21-0019
Remus 46 kV HVD Lines Reliability Rebuild

BCMazur
DRMeyers
DCParker
RTBlumenstock
TJSparks
JFBrossoit
PKPoppe

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0019

Project: **Remus 46 kV Line – HVD Lines Reliability Rebuild** **County:** Montcalm/Mecosta

Date: January 7, 2020 **Need System Changes By:** 12/31/2021

Problem Description:

The 12.9 mile 46 kV Remus line constructed in 1948 has experienced 4 outage incidents between 2014 and 2018. See attached HVD Lines Worst SAIDI 2014-2018. There were 40 out of 157 (~25%) poles identified as replacement candidates on the 12.9 mile Remus Line. Presently this line is non-standard small single layer #2 ACSR conductor. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild the 12.9 mile Remus 46 kV line. This alternative saves an estimated 0.48 SAIDI minutes per year. *Conceptual cost: $5,905,000*

Recommended Alternative:

Alternative #2 is recommended. Rebuild of this line is needed to improve overall system reliability and for approximately 1700 customers served from the Remus 46 kV line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Thus, this alternative is estimated to save 0.48 SAIDI minutes per year. Rebuild also replaces the older non-standard conductor with modern standards and design.

Alternative #1 does not address the poles that need replacement or the reliability of the system on this line and would result in a continual decrease in reliability.

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TJSparks
JFBrossoit
PKPoppe

Alternative #2 Recommended Scope:

Rebuild the 12.9 mile Remus 46 kV line from Remus Substation to pole #380 Remus junction with single circuit 3/0 ACSR conductor 20 feet offset of existing centerline on a combination of existing easements and newly obtained easements as needed. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2021 Cost with Overheads	Description
EH-95308	$3,940,000	$5,905,000	Rebuild Remus 46 kV line
Project Total	$3,940,000	$5,905,000	
Customer Contribution	$0	$0	
Total	$3,940,000	$5,905,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka/ERMathews **Team Leader:** Doug Meyers

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required
President & CEO, Consumers Energy	Patricia K. Poppe	Required

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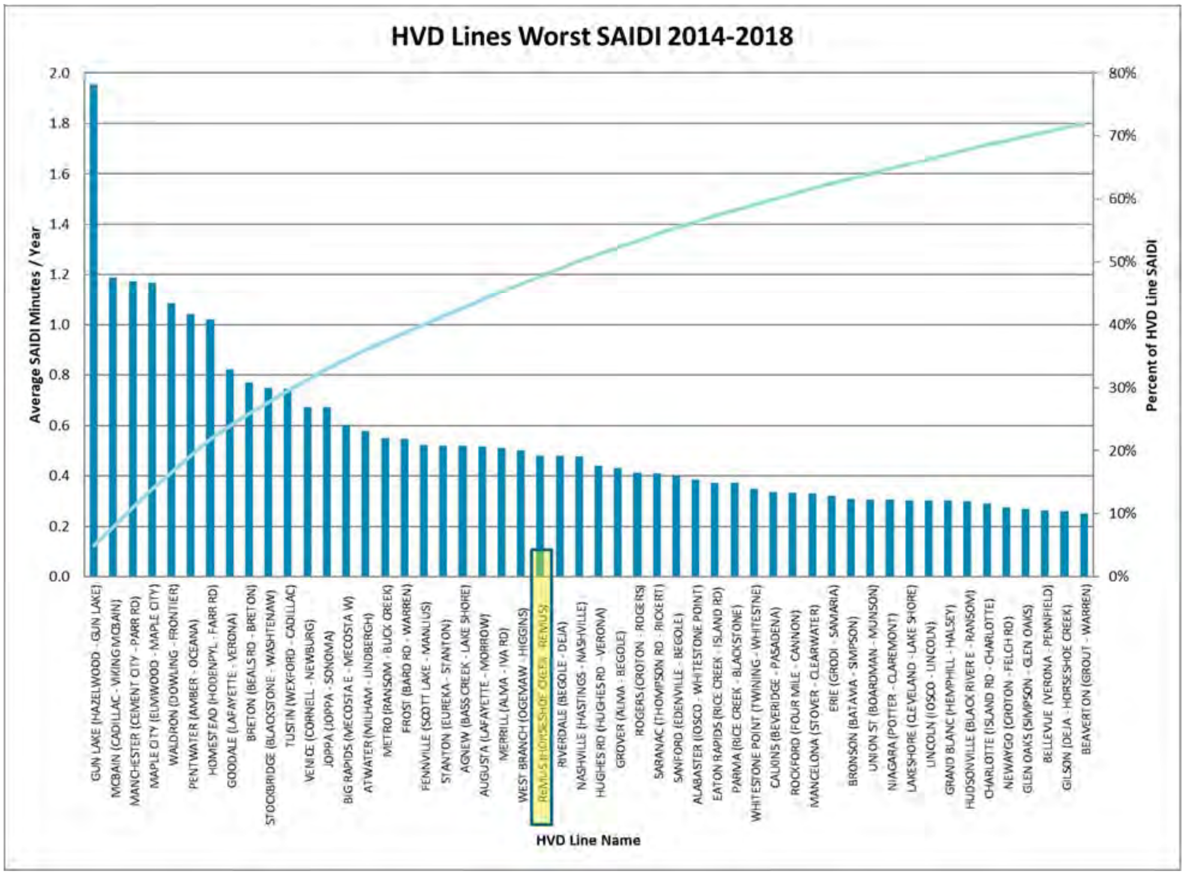
DRMeyers
DCParker
RTBlumenstock
TJSparks
JFBrossoit
PKPoppe



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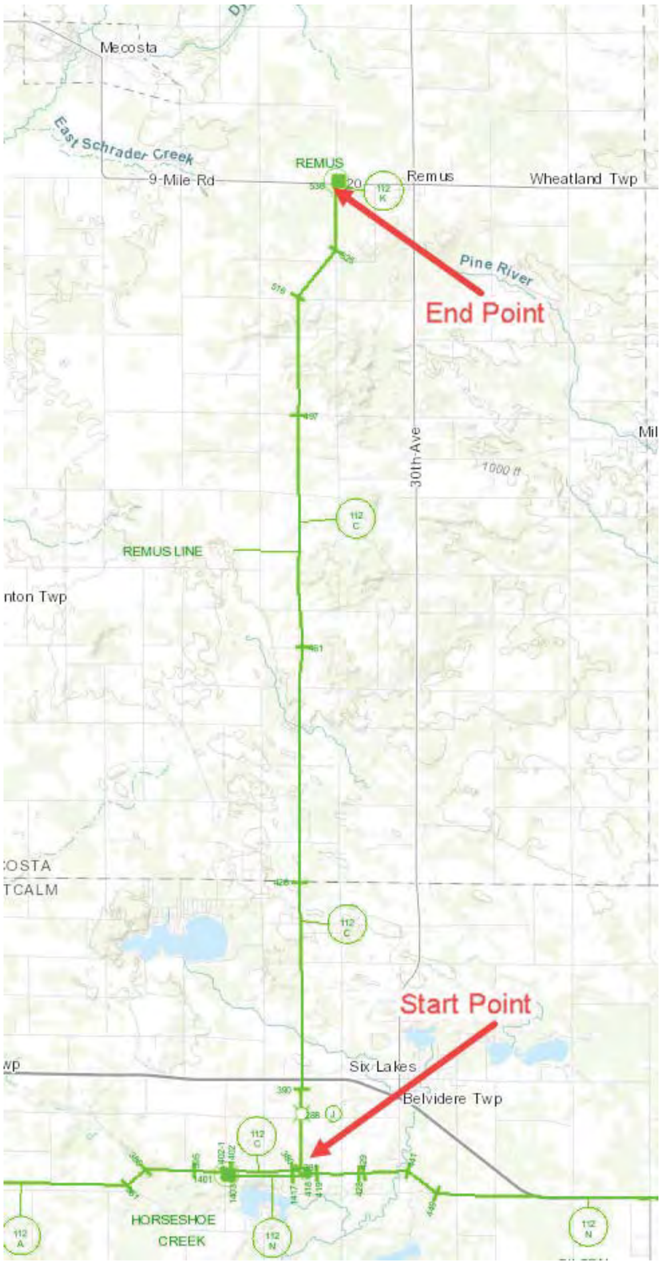
JFBrossoit
PKPoppe



From: SPAdvisor
To: BRIAN C. MAZUR
Cc: BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; LOUIS B. HINCKA; DOUGLAS R. MEYERS
Subject: Approval has completed on 21-0019 Remus 46 kV HVD Lines Reliability Rebuild.
Date: Friday, January 17, 2020 2:29:56 PM

Approval has completed on 21-0019 Remus 46 kV HVD Lines Reliability Rebuild.

Approval on 21-0019 Remus 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 1/7/2020 2:20 PM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/8/2020 8:26 AM
Comment:

Approved by DWAYNE C. PARKER on 1/8/2020 3:41 PM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 1/8/2020 3:45 PM
Comment: Approved.

Approved by Timothy J. Sparks on 1/8/2020 3:51 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 1/14/2020 2:21 PM
Comment:

Approved by Patricia K. Poppe on 1/17/2020 2:29 PM
Comment:

View the workflow history.

PROJECT: LN033AE WIRTZ RD WEST RBLD 8.04 MILES (SAP #36169756)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve the overall reliability, in particular for the customers served from the Wirtz Rd 46 kV Line. There have been 1 outage incident on the line between 2016 and 2020. 16 poles were recommended as a “Planned replacement” by the 2018 pole inspection program. Structure #537 was not tested by the pole inspector because of excessive vegetation being around the pole. Currently this section of line is non-standard #2 ACSR conductor construction. HVD lines that are non-standard construction (unshielded or non-standard conductor), like this section of line, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation.

Attached Concept Approval #22-0054 provides additional details.

ii. Line Design, size material used.

Single circuit, wood pole design with 3/0 ACSR conductor and OPGW fiber optic cable shield wire.

iii. Line Length and ROW requirements.

The rebuild is 8.04 miles long and will be built approximately 20 feet from the existing centerline utilizing existing easements or new and existing easements.

iv. Approximate Construction Schedule.

Construction Start: January 1, 2022
Construction Complete: October 1, 2022

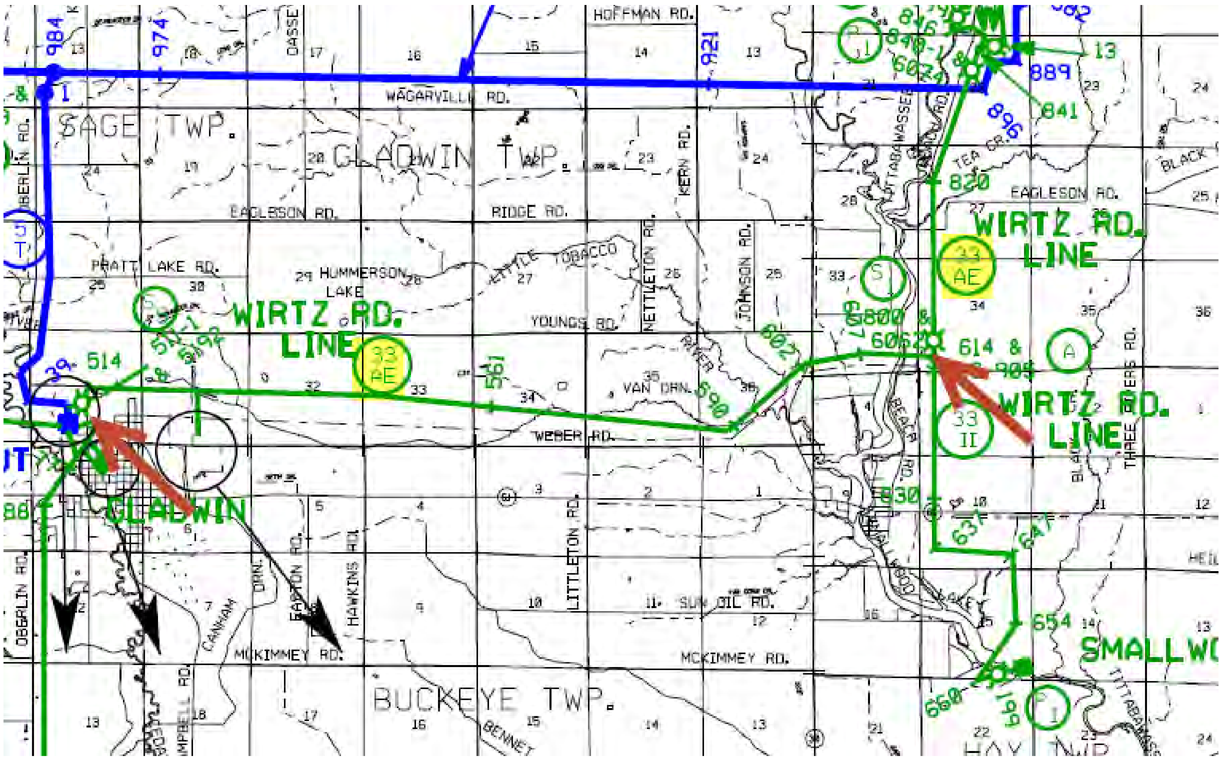
v. Project effect on cost of operation and reliability of service.

The reliability of service will increase with the new configuration. The Wirtz Rd 46 kV line experienced 1 outage incident in this section of line between 2016 and 2020. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor, etc. that were constructed in approximately 1954 are being removed starting at structure #510 to #800. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

LVD will be funding the replacement of the underbuild on the structures.

ix. All studies performed by the Company or 3rd party regarding the project.

The 2018 pole inspection program identified 16 out of 107 poles (15%) in this line segment as needing to be replaced.

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0

Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 22-0054
Wirtz Rd 46 kV HVD Lines Reliability Rebuild

BCMazur
DRMeyers
JLBirchmeier
JRFox
ERMathews
DALynd
RTBlumenstock
TJSparks
JFBrossoit

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0054

Project: **Wirtz Rd 46 kV Line – HVD Lines Reliability Rebuild** **County:** Gladwin

Date: January 14, 2021 **Need System Changes By:** 10/31/2022

Problem Description:

The Wirtz Rd (033AE) 46 kV line from structure #510 to #800 were installed around 1954. There have been 1 outage incidents on the line between 2016 and 2020. 16 out of 107 poles (15%) in the 8.04-mile section of line requires replacement. 16 poles were recommended as a “Planned replacement” by the 2018 pole inspection program. Structure #537 was not tested by the pole inspector because of excessive vegetation being around the pole. Currently this section of line is non-standard #2 ACSR conductor construction. HVD lines that are non-standard construction (unshielded or non-standard conductor), like this section of line, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Replace only the recommended pole replacements on the 8.04-mile section of line. HVD *Conceptual cost: $297,600 and* LVD *Conceptual cost: $14,400*
3. Rebuild 8.07 miles of 033AE line. HVD *Conceptual cost: $3,738,600 and* LVD *Conceptual cost: $181,000*

Recommended Alternative:

Alternative #3 recommended. Rebuilding the 8.04 miles of 033AE line is needed to improve the overall system reliability. Outage data has shown that after completing a rebuild, a line typically has zero or minimal line equipment related outages. A rebuild will also replace the older non-standard conductor with modern standards and design.

Alternative #1 does not address the poles, crossarms and insulators on the line that needs to be replaced or the reliability of the system on the line and would result in a continual decrease in reliability.

Alternative #2 does not address some of the poles, crossarms and insulators on the 8.04--mile section of line 033AE that needs to be replaced or the reliability of the system on the section of line and would result in a continual decrease in reliability.

<u>Alternative #3 Recommended Scope:</u>
Alternative #3 recommended. Rebuild 8.04-miles of the Wirtz Rd 46 kV 033AE line, including the associated LVD underbuild from structure #510 to #800. Utilize single circuit 3/0 ACRS conductor and OPGW shield wire on the existing or a combination of existing easements and newly obtained easements as needed.

METC facilities are not required for this project.

<u>Conceptual Estimate by WBS:</u>

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$2,412,000	$3,738,600	Rebuild 8.04 miles of the Wirtz Rd 46 kV 033AE line
ED-95719	$116,774	$181,000	LVD Underbuild (033AE)
Project Total	$2,528,774	$3,919,600	
Customer Contribution	$0	$0	
Total	$2,528,774	$3,919,600	

<u>Present Need:</u> On approval, this document authorizes the High Voltage Distribution Engineering group and the Low Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

BCMazur
DRMeyers
JLBirchmeier
JRFox
ERMathews
DALynd
RTBlumenstock
TJSparks
JFBrossoit

Prepared By: KPBoynton **Team Leader:** Doug Meyers

Approvals:

Electric Reliability & Support Lead	Douglas R Meyers	Required
LVD System Engineer	Joshua L Birchmeier	Required
Director, LVD Circuit Planning	Julia A Fox	Required
Director, HVD System Planning	Edward R Mathews	Required
Director, LVD System Planning	Donald A Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required

BCMazur
DRMeyers
JLBirchmeier
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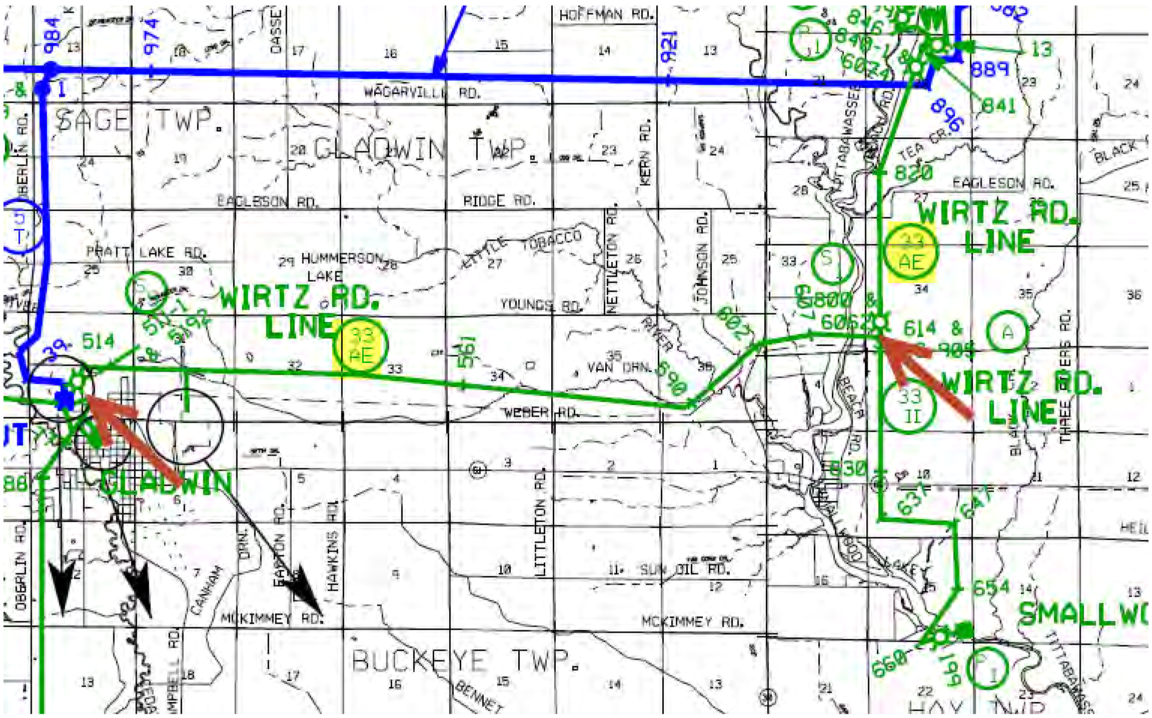


PROJECT: Morrow Substation Rebuild (Celery Substation) (WO# 36096428)

i. Purpose and Necessity of the Project with Supporting Data.

Morrow Substation is a 1920's vintage substation with over $7.5 Million dollars of work identified over the next 3 years. There are also site concerns based on a building in disrepair and an earthen dam that has some integrity concerns, both owned by a third party, being in very close proximity to the substation at Morrow. Catastrophic failue becomes more probable with each passing year. Relocating and rebuilding the substation was identified as the most efficient solution to alleviate the issues with the present site but would also provide new concrete and steel structure used in our modern standards to mitigate potential substation structural issues.

The Concept Approval 22-0002 (Attachment 1) which initially identified the need for Morrow Substation relocation describes the above.

ii. Line Design, size material used.

Not applicable, substation construction project.

iii. Line Length and ROW requirements.

Not applicable, substation construction project on Consumers Energy owned property.

iv. Approximate Construction Schedule.

Construction Start: December 22, 2021
Construction Complete: October 17, 2022
Equipment Checkout Complete: January 26, 2023

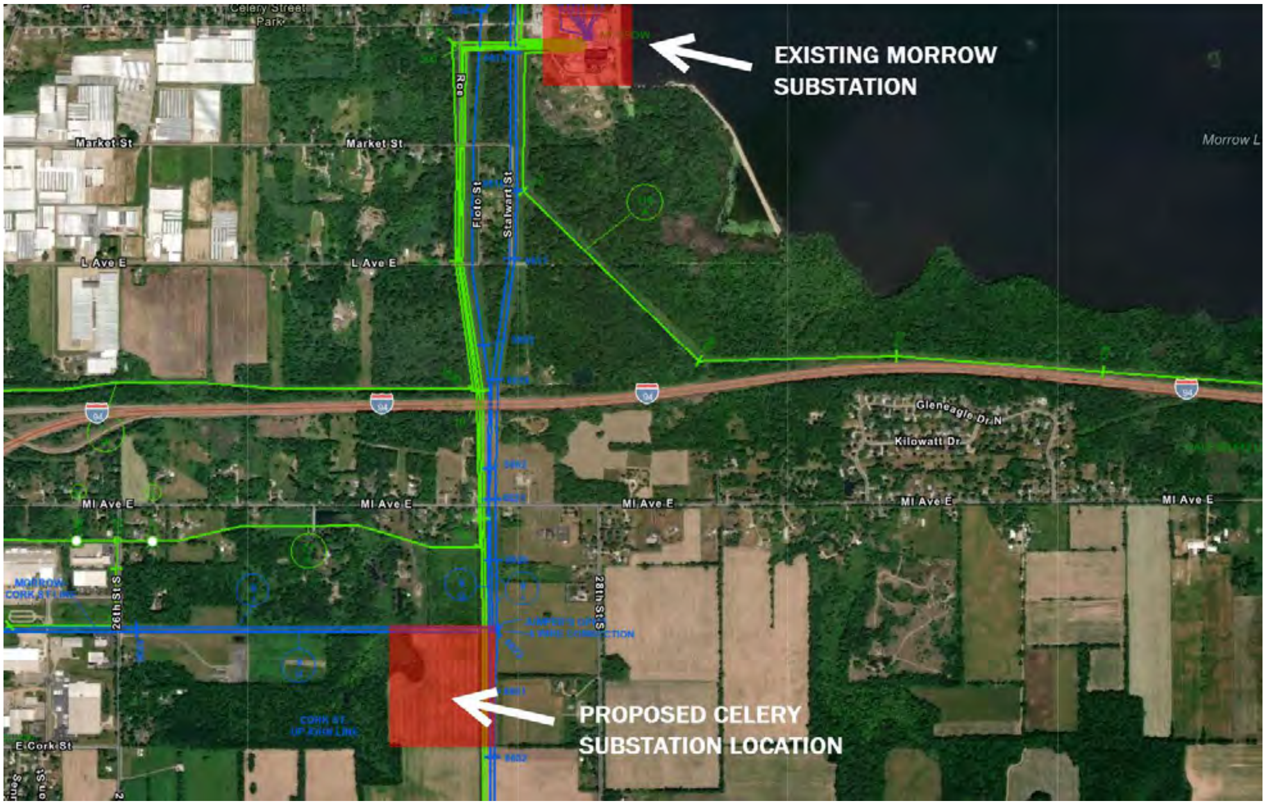
v. Project effect on cost of operation and reliability of service.

In the process of relocating the substation, all new equipment is planned for the new substation. This is expected to increase reliability and reduce maintenance costs on the old 1920's vintage substation.

vi. A description of the property being replaced and salvage value.

This new substation would replace three (3) 138/46 kV transformers, eleven (11) 46kV breakers, two (2) capacitor switchers, two (2) capacitor banks, and other associated relaying, structure, PT's & CT's. The estimated salvage value is unknown at this time.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See Attachment 1, Concept Approval 22-0002.

x. Date of board approval.

N/A

Morrow Substation Rebuild – Attachment 1

CONCEPT APPROVAL No. 22-0002
Morrow Substation Rebuild

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0002

Project: **Morrow – Relocate Morrow Substation** **County:** Kalamazoo

Date: January 15, 2020 **Need System Changes By:** 7/1/2022

Problem Description:

Morrow Substation is a vintage bulk power substation dating from the 1920's with (3) 138 /46 kV transformers, (11) 46 kV breakers, and (2) 46 kV capacitors providing a source of high voltage distribution power to the greater Kalamazoo area. As of today, there is over $10 Million of work identified to be completed at the existing Morrow Substation over the next 3 years. The known work at Morrow substation includes yard and security work, capacitor switch replacement, both METC and CE relay work, breaker replacements, retaining wall repair, Plant/Substation physical separation (new central control house), and 46kV copper bus and brown bus insulator replacement. In addition to the specific problems mentioned in this concept approval that have generated the planned work thus far, it is believed that the general site conditions and location combined with the age of the core infrastructure will result in continued future problems above and beyond the $10 Million of identified work to date.

The existing HVD relays and controls are located inside a control house building adjacent and connected to the retired Morrow generating plant building. The Morrow generating plant building was sold to a third party many years ago and is now in disrepair. Scrapping activity inside the plant building has removed drainage systems that has led to groundwater seepage and flooding in the basement of the control house building. This has created a hazardous work environment for field personnel and a risk of nuisance tripping of electrical equipment. There are also structural concerns with the brick wall shared by the control house building and generating plant building. Physical separation of HVD Substation assets from the generating plant building is required to ensure reliability of the substation and resolve the work environment and environmental concerns by eliminating the dependency on the third party's plant building and retaining wall maintenance.

Additionally, there are concerns with groundwater seepage relative to the substation's proximity to the Kalamazoo River. The existing retaining wall located to the east of the substation between the substation and Morrow Lake is showing signs of deterioration. There is concern that the retaining wall may fail over time based on ever changing lake water head pressure behind the wall and Michigan's weather cycles.

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There is a history of bus support insulators failing at Morrow substation two of which occurred in 2019. On January 13, 2019 an insulator failure caused the 46kV bus, TB No. 1 and TB No. 2 to trip, which affected over 20,000 customers. When a bus insulator fails at Morrow Substation typically the entire 46 kV bus trips off rather than a single line exit or a section of the 46 kV bus. A contributing factor to this phenomenon is the antiquated catwalk design, which condenses the 46 kV bus equipment into a smaller, more vertical area. This has contributed to a larger reliability impact for a bus insulator failure compared to a typical substation design.

Alternative Solutions:

1. Complete the currently identified work at Morrow Substation and continue to schedule projects in the future as work is identified at the substation. Continue to rehab the retaining wall as needed. *Conceptual Cost = $10,000,000, Retaining wall rehab Conceptual Cost = $350,000 each time*

   This is only the cost amount known at this time, future cost of potential continued problems not included/known but could include relocating the entire substation at an additional approximately $17.3 Million

2. Build a new 138/46kV bulk power substation to replace the existing Morrow Substation. Retire and remove Morrow substation once the new substation is completed and the existing 46kV lines are connected to the new substation. *Concept Cost = $17,300,000*

Recommended Alternative:

Alternative #2 is recommended: This alternative provides the most efficient long term solution. It allows the company to control siting and environmental factors of the area surrounding the substation. The new substation would be built to present design standards eliminating the known issues at Morrow Substation and fixes the future issues that are expected to arise with the 1920's vintage substation with the existing site conditions and location. The new substation design will reduce the installation of unnecessary equipment and simplifies future operation and maintenance activities. This alternative also eliminates the hazardous and potentially unsafe work environment and risk of the adjacent 3rd party building falling on the substation and potentially causing a catastrophic long term complete substation outage.

Alternative #1 is not feasible as it only addresses some of the known issues at the existing Morrow substation at this time. It would require replacement of and/or continual maintaining/repairing of the retaining wall between the substation and Morrow Lake. It does not immediately address concerns such as the 3rd party building that is in disrepair falling onto the substation, and water infiltration at the existing site from the neighboring building which creates a hazardous and potentially unsafe work environment for employees. It is believed the only feasible mitigation for these concerns is relocation of the substation. These conditions not being addressed by Alternative #1 could conceivably force a complete relocation such as Alternative #2 in the future potentially stranding much of the $10 Million of investment that would be completed in the near future and in the end costing the company the costs of both alternatives approximately $27.3 Million or more.

Recommended Alternative #2 Scope:

Acquire property and required line rights south of the existing Morrow substation. Build a new substation approximately 1.5 miles south of the existing Morrow Substation. The new substation will include two 60/80/100 MVA, 138/46kV Auto-Transformers, a normally closed 100 tie breaker, two 46kV 18 MVAR capacitor banks and seven 46kV line exits.

Build 0.02 miles new 46kV line from new sub rack to existing Mendon 46kV Line #070A. Build 0.02 miles new 46kV line from new sub rack to existing Burdett 46kV Line #070D. Build 0.15 miles new 46kV line from new sub rack to existing Phillips #1 46kV Line #071A. Build 0.5 miles new 46kV line from new sub rack to existing Phillips #2 46kV Line #071W. Build 1.5 miles new double circuit 46kV line with Eastwood 46kV Line #071L and Augusta 46kV Line #116G from new sub rack to existing Eastwood and Augusta 46kV Lines. Build 0.95 miles new 46kV line from new sub rack to existing Galesburg 46kV Line #116A.

METC facilities are required for this project.

Conceptual Estimate by WBS:

WBS Element	2020 Direct Cost	2021 Direct Cost	2022 Direct Cost	2020 Cost with Overheads	2021 Cost with Overheads	2022 Cost with Overheads	Description
EH-95408	$0	$4,100,000	$5,200,000	$0	$6,100,000	$7,700,000	Build a new two 60/80/100 MVA bank Bulk Power Substation
EH-95008	$0	$0	$2,000,000	$0	$0	$3,000,000	Build approximately 4.6 Miles of 46 kV line to connect with the existing 46 kV lines out of Morrow
EH-95208	$400,000	$0	$0	$400,000	$0	$0	Right of Way for new Substation

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EH-95208	$100,000	$0	$0	$100,000	$0	$0	Right of way for approximately 4.6 Miles of 46 kV Line
Project Total	**$500,000**	**$4,100,000**	**$7,200,000**	**$500,000**	**$6,100,000**	**$10,700,000**	Grand Total with Overheads: **$17,300,000**

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: CMFranklin/BTScott **Team Leader:** DRMeyers

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required

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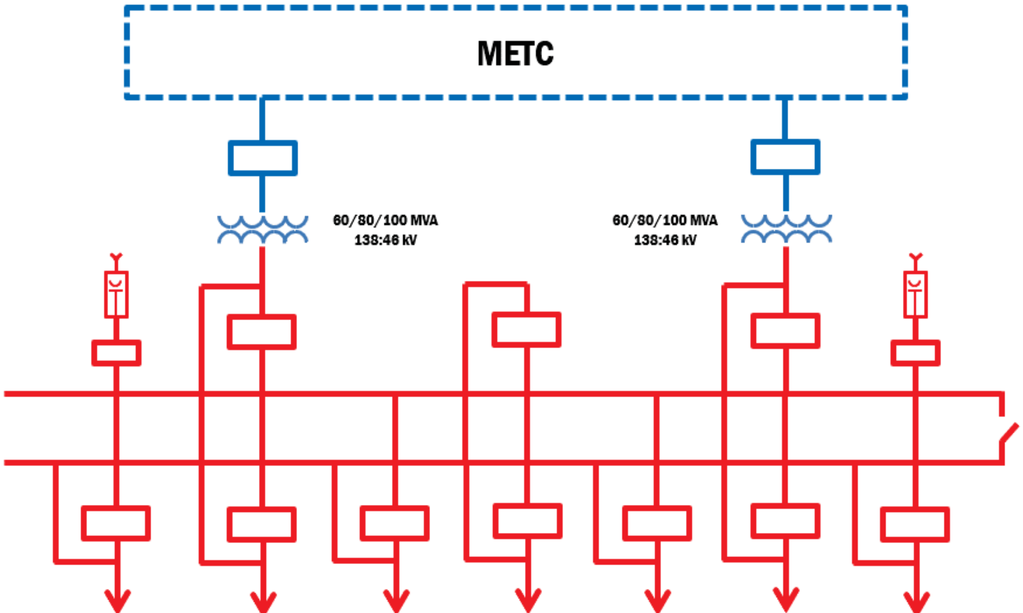
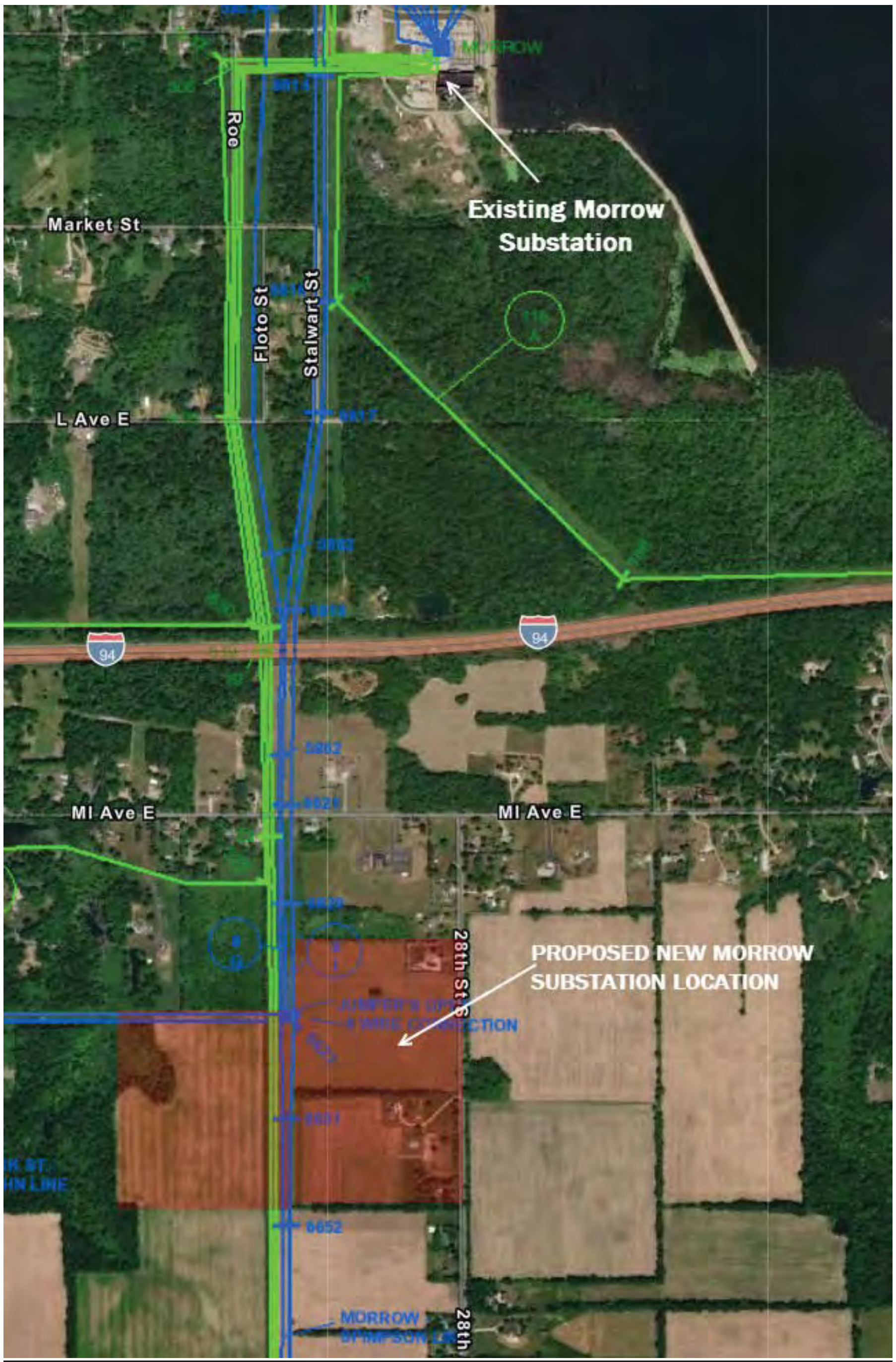
TJSparks
JFBrossoit

Proposed New Morrow Substation Configuration



*Substation configuration subject to change.

Proposed New Substation Location



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Existing Substation Satellite View

From: SPAdvisor
To: BRIAN C. MAZUR
Cc: BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; Catherine M. Franklin; Benjamin T. Scott
Subject: Approval has completed on 22-0002 Morrow Substation Relocation.
Date: Wednesday, January 29, 2020 11:38:31 AM

Approval has completed on 22-0002 Morrow Substation Relocation.

Approval on 22-0002 Morrow Substation Relocation has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 1/15/2020 2:18 PM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/15/2020 3:04 PM
Comment:

Approved by DWAYNE C. PARKER on 1/16/2020 9:29 AM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 1/22/2020 8:11 AM
Comment: Approved. Tim - Detail has been added on the remediation scope and cost necessary for alternative #1 (repair existing substation). The cost difference between repair and rebuild is less than the original concept approval. A good point is made concerning stranded investment if we repair at $10 million and then eventually are forced to rebuild in the future at $17 million if conditions markedly deteriorate.

Approved by Timothy J. Sparks on 1/26/2020 4:50 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 1/29/2020 11:38 AM
Comment:

View the workflow history.

PROJECT: LN019M BIG RAPIDS REBUILD

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve overall reliability and in particular for the approximately 5,300 customers served from the Big Rapids 46 kV Line. Actual line performance over the past five years has shown the Big Rapids 46 kV Line to be underperforming. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild vs. further investment in pole top rehabilitation on a non-standard line. The Big Rapids 32D line section is presently non-standard small single layer #2 ACSR conductor.

Concept Approval 22-0051 provides additional project details.

ii. Line Design, size material used.

Single circuit, wood pole design with 3/0 ACSR conductor and steel shield wire.

iii. Line Length and ROW requirements.

The line is 7.4 miles long and will be built 20' offset of the existing centerline on a combination of existing Consumers Energy and newly obtained easements.

iv. Approximate Construction Schedule.

Construction Start: June 1, 2022
Construction Complete: December 31, 2022

v. Project effect on cost of operation and reliability of service.

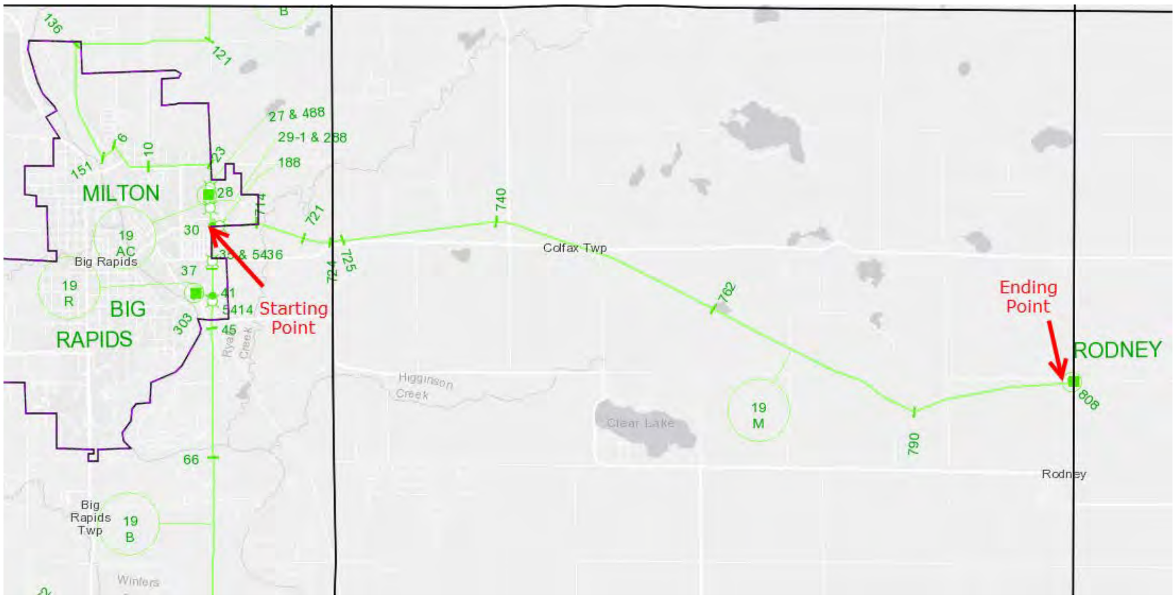
The reliability of electric service will increase with the new configuration. This section of the Big Rapids line has experienced 1 of the 2 overall outages on this line between 2015 and 2019. In 2014, the Rodney Spur failed from service twice by conductor hot tie failures and once again in 2017 causing extended outages. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor and etc. that were constructed in 1952 are being removed starting at structure #30 to the Rodney Substation. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

Case No. U-20963
Attachment No. 126
Page 99 of 312

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0

Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 22-0051
Big Rapids 46 kV HVD Lines Reliability Rebuild

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TJSparks

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0051

Project: **Big Rapids 46 kV Line – HVD Lines Reliability Rebuild** **County:** Mecosta

Date: January 14, 2021 **Need System Changes By:** 12/31/2022

Problem Description:

Line performance data over the past five years has shown the Big Rapids 46 kV line to be underperforming. The Rodney Spur of the Big Rapids 46 kV line is a 7.4 mile radial line section that feeds the Rodney Substation and was originally installed in 1951. This section of the Big Rapids line has experienced 1 of the 2 overall outages on this line between 2015 and 2019. In 2014, the Rodney Spur failed from service twice by conductor hot tie failures and once again in 2017 causing extended outages. The line is constructed with non-standard #2 ACSR conductor in a shielded configuration.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Top Rehabilitation of the line. *Conceptual cost: $688,000*
3. Rebuild 7.4 miles of the Big Rapids 46 kV line. *HVD Conceptual cost: $3,441,000 and LVD Conceptual cost: $300,000*

Recommended Alternative:

Alternative #3 is recommended. Rebuild of this line is needed to improve overall system reliability and for the approximately 5,300 customers served from the Big Rapids 46 kV line. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages.

Alternative #1 does not address the reliability of the system on this line and would result

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in a continual decrease in reliability.

Alternative #2 does address the deteriorating conductor tie wires but does not address the aged non-standard #2 ACSR conductor.

Alternative #3 Recommended Scope:

Rebuild the 7.4 mile section of the Big Rapids 46 kV line from structure #30 to the Rodney Substation with a single circuit 3/0 ACSR conductor built on a 20' offset of the existing centerline. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$2,220,000	$3,441,000	Rebuild the Big Rapids 46 kV line
ED-95719	$193,500	$300,000	LVD Underbuild Line Relocation
Customer Contribution	$0	$0	
Total	$2,413,500	$3,741,000	Grand Total Cost with Overheads: **$3,741,000**

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka **Team Leader:** Doug Meyers

Approvals:

Senior Engineer Lead, LVD Circuit Planning	Jennifer M. Partlan	Required
Director, HVD System Planning	Edward R. Mathews	Required

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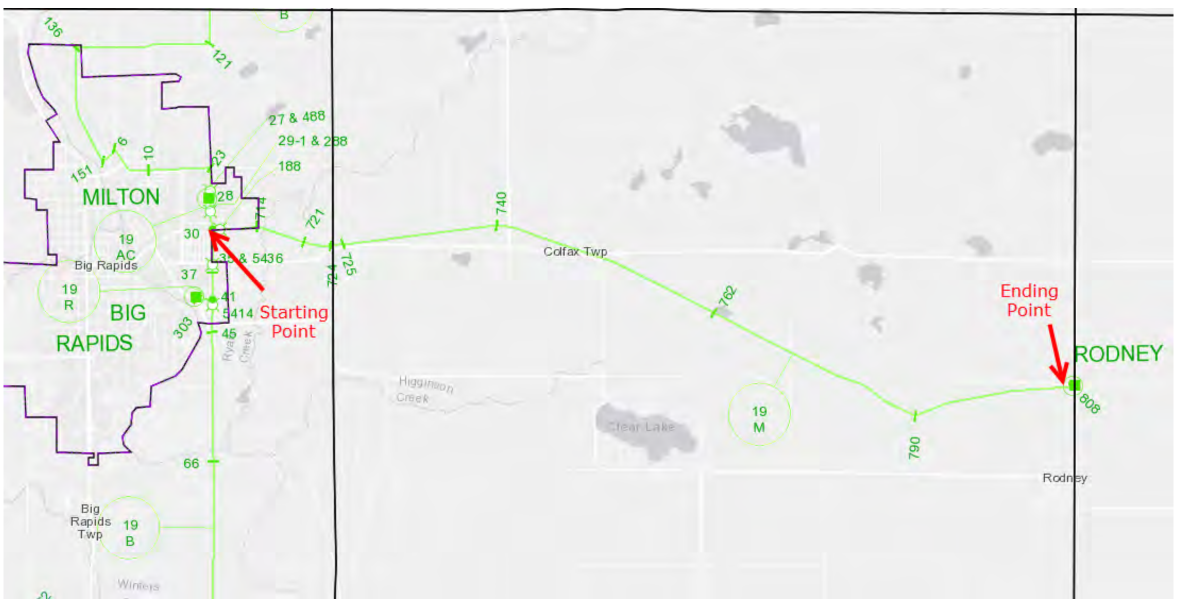
TJSparks

Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required



From:	SPAdvisor
To:	Amanda J. Rueff
Cc:	BRIAN C. MAZUR; Brian M. Bushey; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Gregory E. Kral; Jacob D. Roberson; LOUIS B. HINCKA; DOUGLAS R. MEYERS
Subject:	Approval has completed on 22-0051 Big Rapids 46 kV HVD Lines Reliability Rebuild.
Date:	Thursday, January 14, 2021 10:04:46 AM

Approval has completed on 22-0051 Big Rapids 46 kV HVD Lines Reliability Rebuild.

Approval on 22-0051 Big Rapids 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by Amanda J. Rueff on 1/13/2021 2:47 PM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by Jennifer M Partlan on 1/13/2021 2:53 PM
Comment: Milan Greenman provided the LVD underbuilt costs which is included in this concept.

Approved by Edward R. Mathews on 1/13/2021 3:53 PM
Comment:

Approved by JULIA R. FOX on 1/13/2021 3:55 PM
Comment:

Approved by DONALD A. LYND on 1/14/2021 9:20 AM
Comment: Approved.

Approved by RICHARD T. BLUMENSTOCK on 1/14/2021 9:28 AM
Comment: Approved.

Approved by Timothy J. Sparks on 1/14/2021 10:04 AM
Comment: Approved.

View the workflow history.

PROJECT: MOBILE SUBSTATION 24

i. Purpose and Necessity of the Project with Supporting Data.

The number of substation projects requiring temporary mobile substations are increasing.

1. More project types are being scheduled that require mobile substations. Projects are being scheduled to proactively replace degrading transformers. These replacements were historically responded to with the emergency mobile substation on an expedited schedule.

2. More project types need mobile substations than in the past. Our legacy substations were not built to meet today's minimum approach distances. Equipment replacements, such as regulators and reclosers, can no longer be accomplished without a complete outage to the substation.

3. HVD line projects need mobile stations. HVD line rebuild projects are utilizing mobile substations when working around the substation taps to avoid the outages that had been acceptable in the past.

4. Customers are requesting mobiles for their short-term power needs. Mobile substations are being used at customer locations to provide quicker service while the long-term solution is being built, or to provide an onsite contingency when part of a redundant substation facility is de-energized for construction and the customer is uncomfortable with the operating on a single source (i.e. municipal water pumping substations, municipal water treatment substations, substations serving industrial customers).

Attached Concept Approval 21-0015 provides additional details.

ii. Line Design, size material used.

Not applicable, the mobile substation is a self contained unit.

iii. Line Length and ROW requirements.

Not applicable, the mobile substation is a self contained unit.

iv. Approximate Construction Schedule.

The purchase order will be submitted to the chosen manufacturer in 2021, and Mobile 24 would be received in 2022.

Page 106 of 312

v. Project effect on cost of operation and reliability of service.

Core business function of providing adequate electrical capacity to serve customer electrical load during substation construction projects, and to restore electrical service during extended substation outages.

vi. A description of the property being replaced and salvage value.

Not applicable, the mobile substation is a new unit.

vii. Map of site and location of facilities.

Not applicable, the mobile substation will be utilized statewide.

viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See the attached Concept Approval 21-0015.

x. Date of board approval.

N/A

MOBILE SUBSTATION 24 – Attachment 1

CONCEPT APPROVAL No. Approval 21-0015
Mobile Substation 24 - New 46kV Mobile Substation

Concept Document To Be Attached Here

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JFBrossoit

Consumers Energy
Customer & Service Infrastructure - HVD
CONCEPT APPROVAL

Concept Number: 21-0015 County: Gratiot

Project: Mobile Substation 24 – New 46kV Mobile Substation

Date: 11/19/2019 Need System Changes By: 12/31/2021

Problem Description:
The 138kV mobile fleet has been expanded by recent acquisitions, but the recent 46kV mobile purchases have been to simply position us for the inevitable retirement of the aging mobiles.

Existing Mobile	Replacement Mobile	Year Replacement Acquired	High-Side (kv)
-	Mobile 16	2010	69x138
Mobile 7 (retired, 2012)	Mobile 17	2012	46
Mobile 8	Mobile 18	2013	46
Mobile 6	Mobile 19	2017	46
Mobile 4	Mobile 20	2020	46
Mobile 5	Mobile 21	2020	46
-	Mobile 22	2020	138
-	Mobile 23	2020	138

The number of projects requiring a mobile are increasing:

1. More project types are being scheduled with mobile needs. Projects are being scheduled to actively replace aging, unhealthy transformers. These replacements were historically responded to with the emergency mobile on an expedited schedule.

2. More project types need mobiles than have in the past. Our legacy substations were not built to meet today's minimum approach distances (MAD). Equipment replacements, such as regulators or reclosers, can no longer be accomplished using the bypasses within the substation.

3. HVD line projects need mobiles. HVD line rebuild projects are utilizing mobiles when working around substation taps to forgo the outages (~8hrs) that we have subjected customers to in the past.

4. Customers are requesting mobiles for their short-term power needs. We are scheduling mobiles for use at customer locations to quickly provide service while a long-term solution (traditional substation) is built.

A larger fleet is available while Mobiles 6, 8, 4, and 5 remain in-service, but this increased fleet size will not last and it has become the operating norm. Losing legacy mobile resources, as originally planned as part of the Mobile 17, 18, 19, 20, and 21 procurements, will be a devasting blow to the mobile schedule and meeting the annual spend plans.

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Recommended Solution:
Purchase a new 46kV mobile. A new mobile will be a step towards positioning CE to have an increased mobile fleet even after the inevitable retirement of our aging assets. A new mobile will provide coverage to the same distribution voltages (8.32kV, 12.47kV, and 24.9kV) and more locations through its higher rating (25MVA) and on-board voltage regulation (LTC).

Conceptual Cost Estimate by WBS

WBS Element	Direct Cost	Cost with Overheads	Description	Year
EH-96508	2,000,000	3,200,000	Mobile Substation 24	2021
EH-96508	100,000	160,000	CE Check-out costs	2021
		3,360,000	**Total Project Costs**	

Present Need: On approval, this document authorizes the C&SI, LVD, and HVD Engineering groups to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: MDGood

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required

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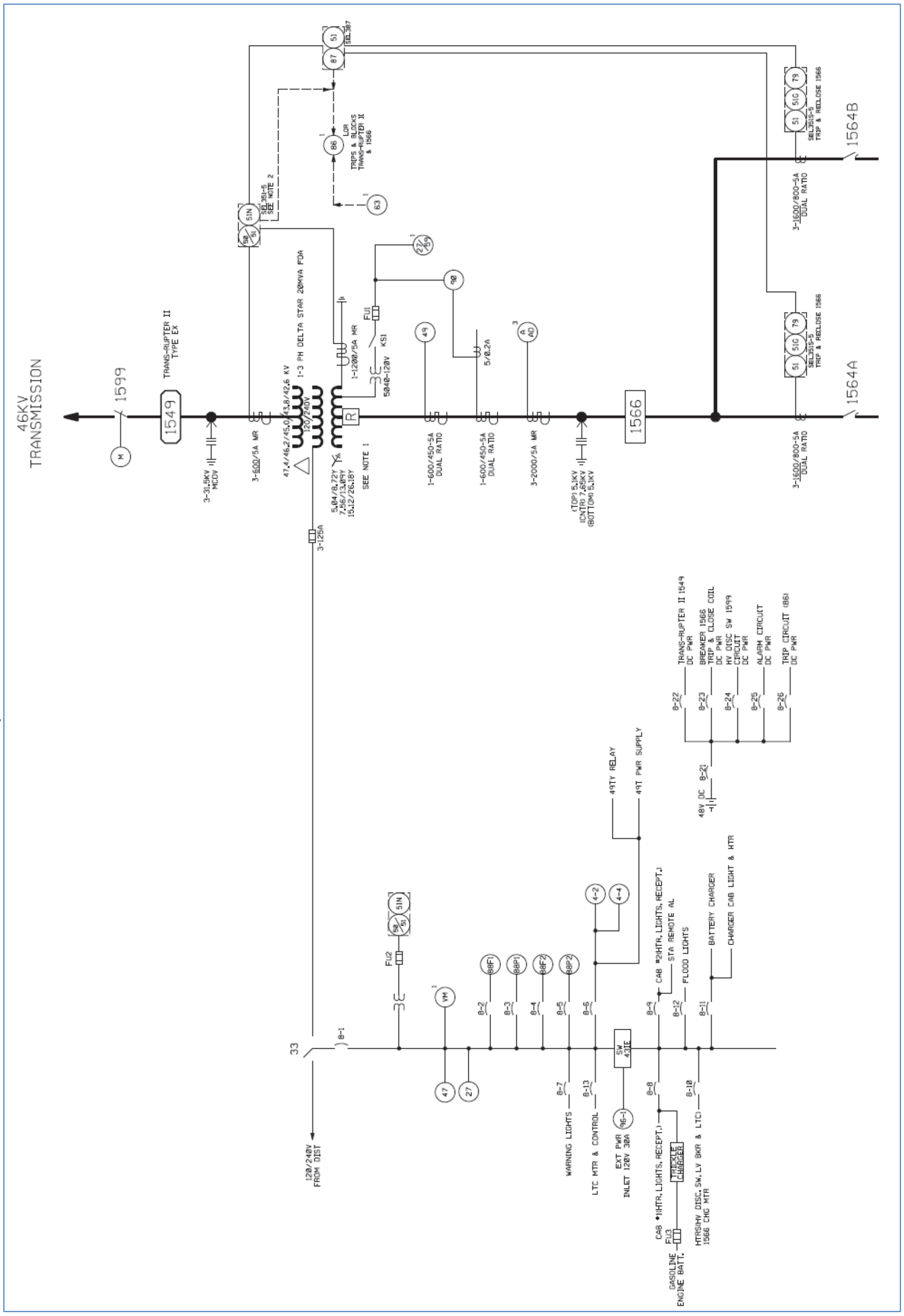
Conceptual WD for Mobile 24



BRIAN C. MAZUR

From: SPAdvisor
Sent: Wednesday, December 11, 2019 8:23 PM
To: BRIAN C. MAZUR
Cc: BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; Matthew D. Good
Subject: Approval has completed on 21-0015 Mobile Substation 24.

Approval has completed on 21-0015 Mobile Substation 24.

Approval on 21-0015 Mobile Substation 24 has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 11/20/2019 8:57 AM
Comment: A new document has been added to the C&SI HVD Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by Matthew D. Good on 11/20/2019 8:59 AM
Comment:

Approved by DWAYNE C. PARKER on 12/7/2019 1:59 PM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 12/9/2019 12:42 PM
Comment: Approved.

Approved by Timothy J. Sparks on 12/10/2019 9:13 AM
Comment: Approved. Mobile substations are one advantage we have over other utilities when it comes to attracting new customers. We can show customers we have backup facilities that can be installed quickly if permanent facilities should fail.

Approved by Jean-Francois Brossoit on 12/11/2019 8:23 PM
Comment:

View the workflow history.

PROJECT: LN032D MAPLE CITY REBUILD

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve overall reliability and in particular for the approximately 5,100 customers served from the Maple City 46 kV Line. Actual line performance over the past five years has shown the Maple City 46 kV Line to be underperforming (see plot under Section ix). HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild vs. further investment in pole top rehabilitation on a non-standard line. The Maple City 32D line section is presently non-standard small single layer #2 ACSR conductor.

Concept Approval 22-0049 provides additional project details.

ii. Line Design, size material used.

Single circuit, wood pole design with 3/0 ACSR conductor and steel shield wire.

iii. Line Length and ROW requirements.

The line is 7.2 miles long and will be built 20’ offset of the existing centerline on a combination of existing Consumers Energy and newly obtained easements.

iv. Approximate Construction Schedule.

Construction Start: June 1, 2022
Construction Complete: December 31, 2022

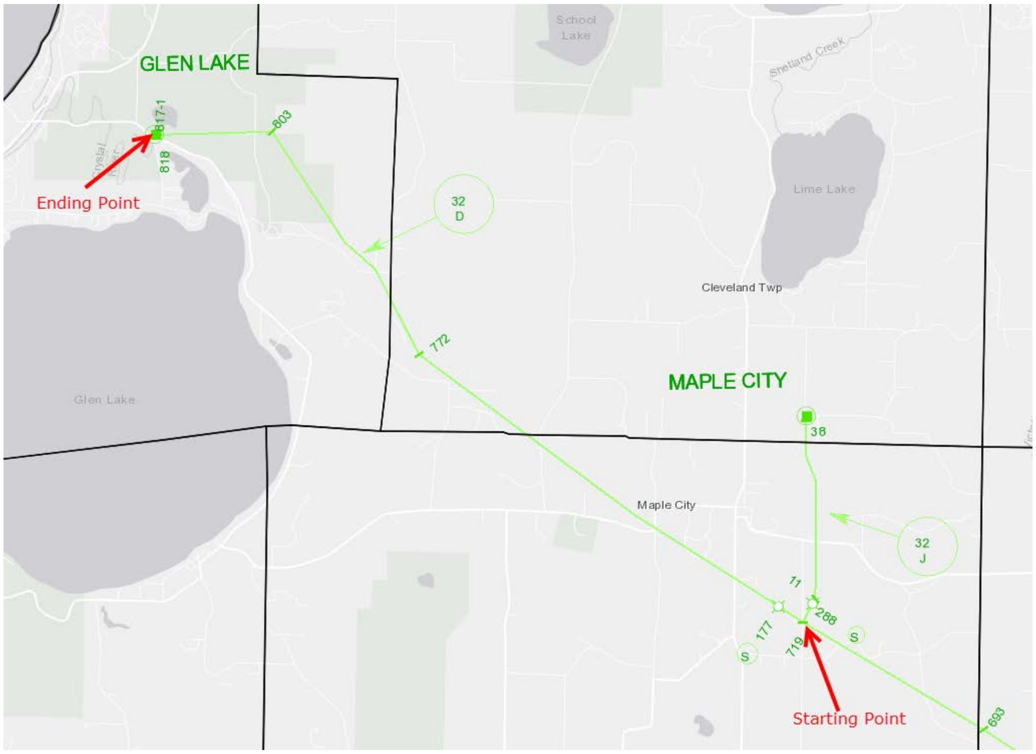
v. Project effect on cost of operation and reliability of service.

The reliability of electric service will increase with the new configuration. The Maple City 46 kV Line has the second highest SAIDI of all HVD lines between 2015 and 2019. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor and etc. that were constructed in 1952 are being removed starting at structure #719 to the Glen Lake Substation. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

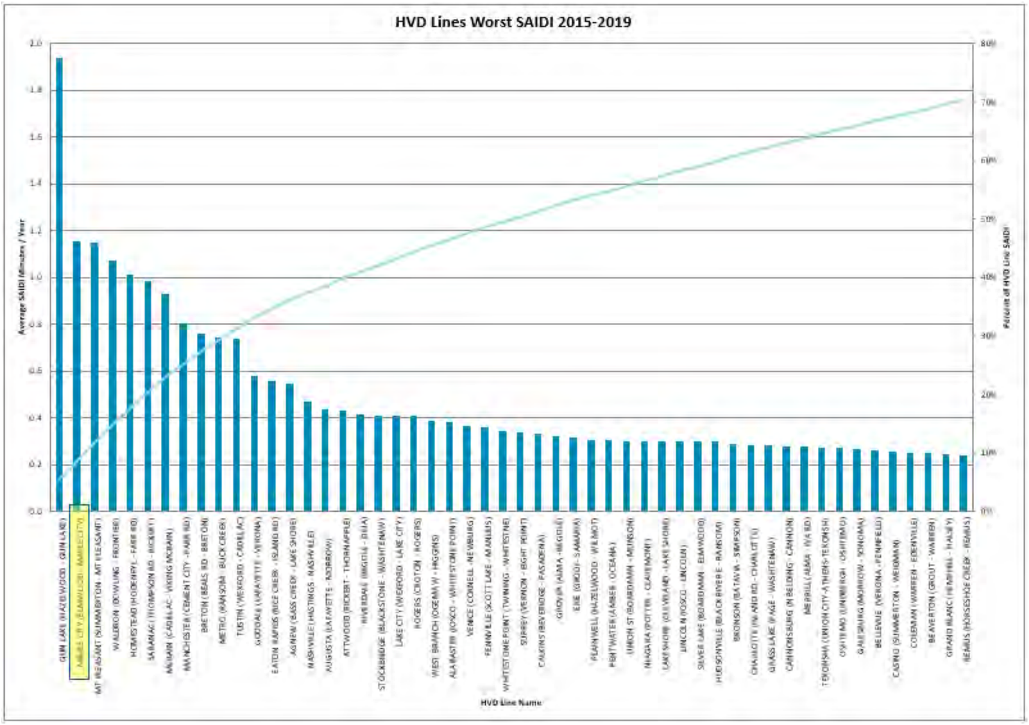
vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.



Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0

Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 22-0049
Maple City 46 kV HVD Lines Reliability Rebuild

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0049

Project: **Maple City 46 kV Line – HVD Lines Reliability Rebuild** **County:** Leelanau

Date: January 14, 2021 **Need System Changes By:** 12/31/2022

Problem Description:

Line performance data over the past five years has shown the Maple City 46 kV line to be underperforming. The Maple City 46 kV line, a radial line originally installed in 1952, has the second highest SAIDI of all 46kV lines between 2015 and 2019. The line has also experienced multiple momentary interruptions over the past several years due to insulator, conductor tie wires and conductor galloping issues. The line is constructed with non-standard #2 ACSR conductor in a shielded configuration. Recent aerial inspections of the line have shown advanced deterioration of the pole top assemblies. The most recent failure of the line on December 30, 2020 has shown the steel core of the conductor to be corroded, rusted and deformed. The current state of the of the conductor and pole top assemblies will lead to an increased outage frequency.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Top Rehabilitation of the line. *Conceptual cost: $670,000*
3. Rebuild 7.2 miles of the Maple City 46 kV line. *HVD Conceptual cost: $3,348,000 and LVD Conceptual cost: $1,764,000*

Recommended Alternative:

Alternative #3 is recommended. Rebuild of this line is needed to improve overall system reliability and for the approximately 5,100 customers served from the Maple City 46 kV line. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

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DALynd
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages.

Alternative #1 does not address the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 does not address the deteriorating #2 ACSR conductor.

Alternative #3 Recommended Scope:
Rebuild the 7.2 mile section of the Maple City 46 kV line from structure #719 to the Glen Lake Substation with a single circuit 3/0 ACSR conductor built on a 20' offset of the existing centerline. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$2,160,000	$3,348,000	Rebuild the Maple City 46 kV line
ED-95719	$1,138,100	$1,764,000	LVD Underbuild Line Relocation
Customer Contribution	$0	$0	
Total	$3,298,100	$5,112,000	Grand Total Cost with Overheads: **$5,112,000**

Present Need: On approval, this document authorizes the Electric Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka **Team Leader:** Doug Meyers

Approvals:

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Senior Engineer Lead, LVD Circuit Planning	John P. Brack	Required
Director, HVD System Planning	Edward R. Mathews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required

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JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

BCMazur
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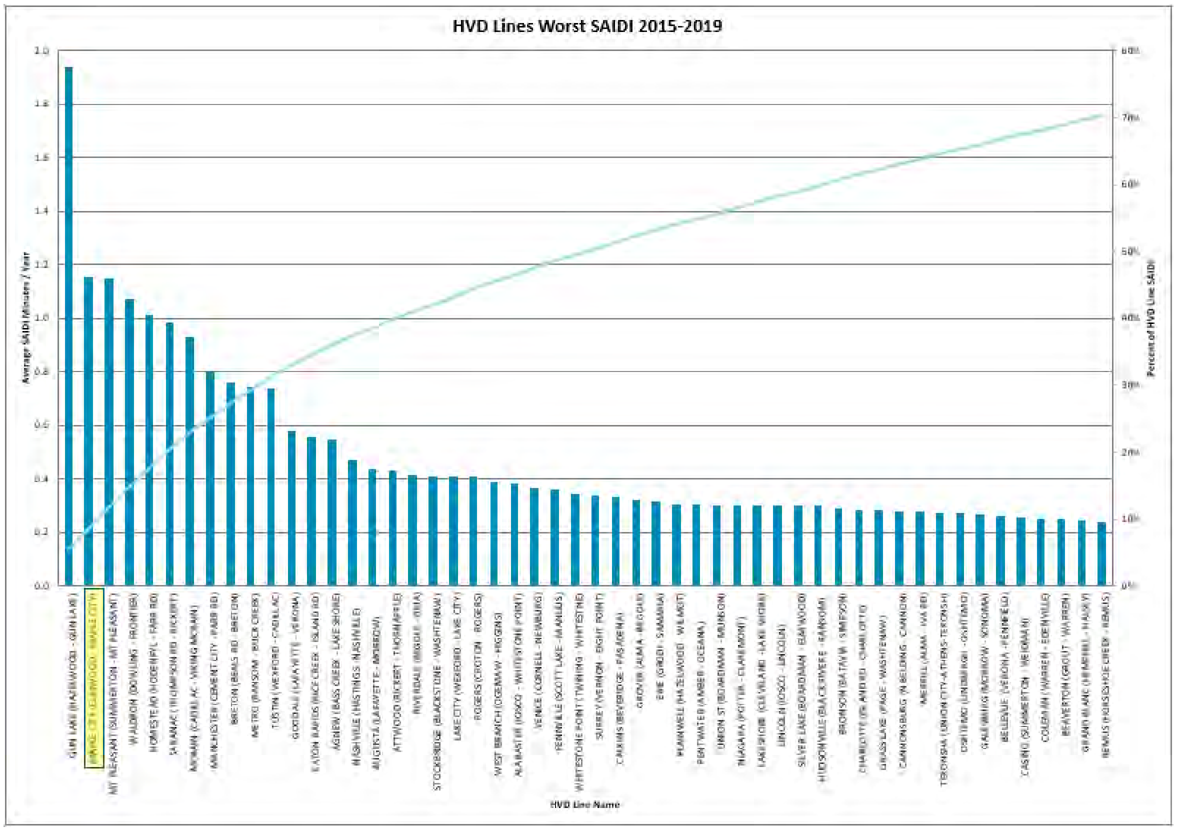
JFBrossoit



PROJECT: LN033CA Rosebush New 46kV 8.0 MI (SAP WO# 29334854)

i. Purpose and Necessity of the Project with Supporting Data.

The Rosebush 46 kV Line had 31 structures identified for replacement by the 2012 pole inspection. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild vs. further investment in significant pole replacements on a non-standard line. The line cannot be rebuilt along the same route nor can the poles be easily replaced due to inadequate easement rights. Additionally, Consumers Energy does not have adequate tree rights or right of entry to perform normal maintenance on this line. This project is part of a broader initiative to reroute the entire Rosebush 46 kV Line to reduce line length and improve access to the line. The present Rosebush 46 kV line is non-standard unshielded construction.

Concept Approval 17-0019A Phase 3 provides additional project details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336.4 ACSR conductor and steel shield wire.

iii. Line Length and ROW requirements.

The new line route is 8.0 miles long. New easement rights are required for 40 feet of no-build. 80 feet of clear-cut, and 160 feet of danger trees for the entire route.

iv. Approximate Construction Schedule.

Construction Start: October 1, 2021
Construction Complete: July 31, 2022

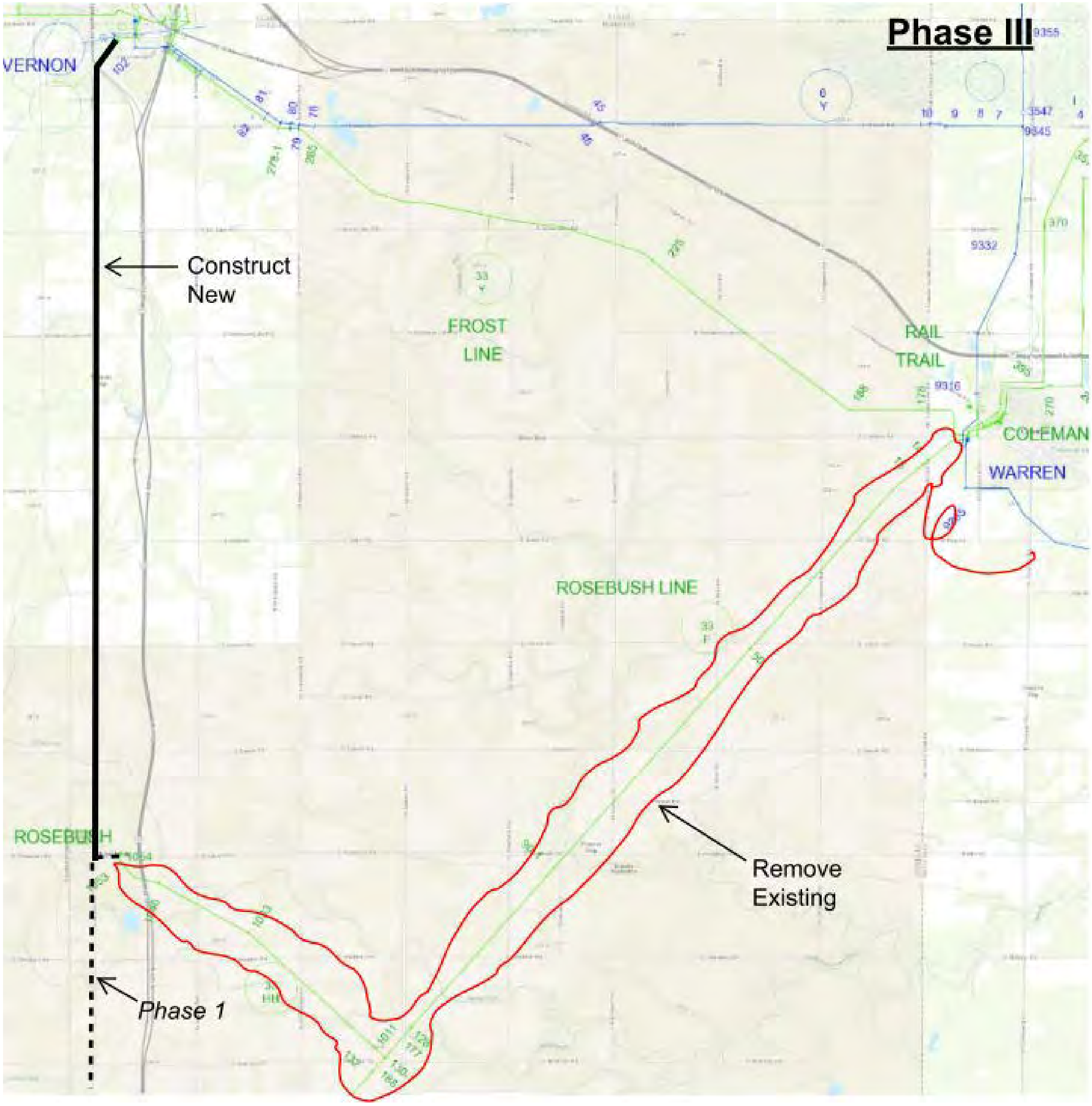
v. Project effect on cost of operation and reliability of service.

The reliability of electric service will increase with the new configuration. The Rosebush 46 kV line experienced 1 outage incident between years 2014 through 2018 and averaged 0.2 SAIDI minutes/year (including MEDs, excluding trees) over the five year period. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table). Normal maintenance and forestry will be improved, and costs reduced, due to the shorter line length and easier access with the improved easement rights. Line losses will also be decreased as a result of the larger conductor.

vi. A description of the property being replaced and salvage value.
Wood poles, crossarms, insulators, conductor, and etc. along the present route are being removed (see attached Concept Approval 17-0019A Phase 3). The wood poles and crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.

Included in Concept Approval 17-0019A Phase 3

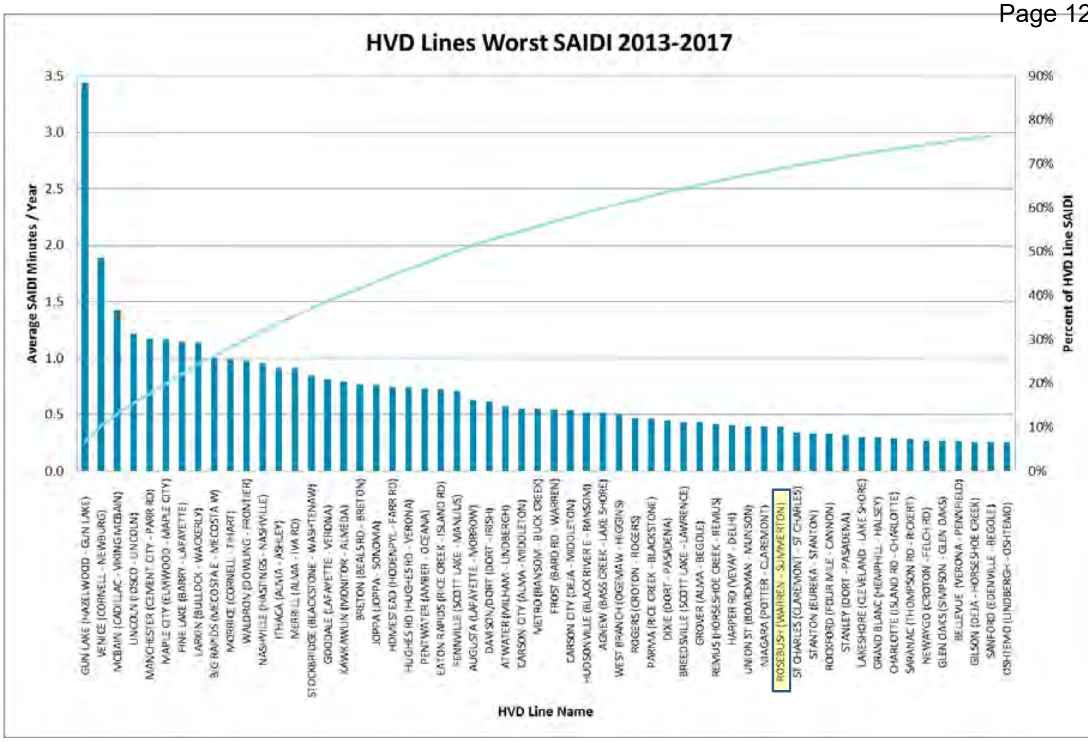


viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See Concept Approval 17-0019A Phase 3


HVD Lines Worst SAIDI 2013-2017
Average SAIDI Minutes / Year
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Percent of HVD Line SAIDI
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
GUN LAKE (HAZELWOOD - GUN LAKE)
VENICE (CORNELL - NEWBURG)
MCBAIN (CADILLAC - VIKING MCBAIN)
LINCOLN (OSCO - LINCOLN)
MANCHESTER (CEMENT CITY - PARR RD)
MAPLE CITY (ELMWOOD - MAPLE CITY)
FINE LAKE (BARRY - LAFAYETTE)
LARKIN (BULLOCK - WACKERLY)
BIG RAPIDS (MECOSTA E - MECOSTA W)
MORRICE (CORNELL - THART)
WALDRON (DOWLING - FRONTIER)
NASHVILLE (HASTINGS - NASHVILLE)
ITHACA (ALMA - ASHLEY)
MERRILL (ALMA - IVA RD)
STOCKBRIDGE (BLACKSTONE - WASHTENAW)
GOODALE (LAFAYETTE - VERONA)
KAWKAWLIN (MONITOR - ALMEDA)
BRETON (BEALS RD - BRETON)
JOPPA (JOPPA - SONOMA)
HOMESTEAD (HODENPYL - FARR RD)
HUGHES RD (HUGHES RD - VERONA)
PENTWATER (AMBER - OCEANA)
EATON RAPIDS (RICE CREEK - ISLAND RD)
FENNVILLE (SCOTT LAKE - MANLIUS)
AUGUSTA (LAFAYETTE - MORROW)
DAWSON/DORT (DORT - IRISH)
ATWATER (MILHAM - LINDBERGH)
CARSON CITY (ALMA - MIDDLETON)
METRO (RANSOM - BUCK CREEK)
FROST (BARD RD - WARREN)
CARSON CITY (DEJA - MIDDLETON)
HUDSONVILLE (BLACK RIVER E - RANSOM)
AGNEW (BASS CREEK - LAKE SHORE)
WEST BRANCH (OGEMAW - HIGGINS)
ROGERS (CROTON - ROGERS)
PARMA (RICE CREEK - BLACKSTONE)
DIXIE (DORT - PASADENA)
BREEDSVILLE (SCOTT LAKE - LAWRENCE)
GROVER (ALMA - BEGOLE)
REMUS (HORSESHOE CREEK - REMUS)
HARPER RD (VEVAY - DELHI)
UNION ST (BOARDMAN - MUNSON)
NIAGARA (POTTER - CLAREMONT)
ROSEBUSH (WARREN - SUMMERTON)
ST CHARLES (CLAREMONT - ST CHARLES)
STANTON (EUREKA - STANTON)
ROCKFORD (FOUR MILE - CANNON)
STANLEY (DORT - PASADENA)
LAKESHORE (CLEVELAND - LAKE SHORE)
GRAND BLANC (HEMPHILL - HALSEY)
CHARLOTTE (ISLAND RD - CHARLOTTE)
SARANAC (THOMPSON RD - RICKERT)
NEWAYGO (CROTON - FELCH RD)
GLEN OAKS (SIMPSON - GLEN OAKS)
BELLEVUE (VERONA - PENNFIELD)
GILSON (DEJA - HORSESHOE CREEK)
SANFORD (EDENVILLE - BEGOLE)
OSHTEMO (LINDBERGH - OSHTEMO)
HVD Line Name

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
	Totals	**64**	**1**

x. Date of board approval.

N/A

SLWatters
ALRoot
DCParker
JRAnderson
TJSparks
JFBrossoit
PKPoppe
SLWatters

Consumers Energy
Customer & Service Infrastructure
CONCEPT APPROVAL

Concept Number: 17-0019A

Project: **Rosebush Line – Rebuild line in new location Rev A** **County:** Isabella

Date: February 6, 2018 **Need System Changes By:** 4/1/2021

Problem Description:

The Rosebush 46 kV line, LN033F, connecting Summerton and Warren substations, is 13 miles long and in a condition of deterioration. Consumers' existing property rights along the line, based on a previous court case, are not sufficient to reconstruct the line along the same route. Some parts of the line are difficult to access, hindering line maintenance. Along portions of the line tree clearing rights are only 17.5' from centerline, whereas the norm for a 46 kV line is 40'. Thus, the line has an increased danger of failure resulting from a falling tree or branch. An HVD lines reliability project to rebuild the line is approved through the economic model at this time, but rebuilding along the same route is not recommended due to the property issues already mentioned nor is it conducive to future plans for the area.

The Frost 46 kV line has been shown in planning and operations studies to have low voltages in the event of an outage to the 46 kV bus at Bard Rd. substation. In such cases the customer-owned Larch generating station is relied upon to maintain acceptable voltage levels. The Frost 46 kV line connects Bard Rd. and Warren substations and is 36 miles long (with 52 miles of total exposure). The Vernon 138 kV/46 kV substation presently feeds only the radial Surrey line. Vernon is located near the Frost 46 kV line route and was constructed with the intent of looping into the Frost 46 kV line to alleviate this problem.

Alternative Solutions:

Alternative #1 (Recommended)

Reconstruct the Rosebush 46 kV line along a new 14 mile route, starting from existing structure #214 or #215 to a new line exit at Vernon substation. A new ¼ mile tap off of the line would be constructed to feed Rosebush substation. Loop Vernon substation into the Frost 46 kV line by creating two new lines and line exits to tap the Frost line, then open the Frost line between the two taps. Looping Vernon into the Frost line will provide better voltage support to the northern Frost line than Warren substation does as well as improve reliability and reduce line losses. Operationally, to maintain the present level of system flexibility, looping Vernon into the Frost line will be necessary in order to replace the 46 kV source into Warren substation that would be eliminated by the removal of the existing Rosebush line.

This project would proceed in three phases:

SLWatters
ALRoot
DCParker
JRAnderson
TJSparks
JFBrossoit
PKPoppe
SLWatters

1) Acquire property rights and construct 5.5 miles of new 46 kV line from structure #214/215 north approximately to E. Rosebush Rd. Construct a new ¼ mile tap from Mission Rd. east to Rosebush substation. Install a 46 kV switch on the 5.5 mile line segment south of the ¼ mile tap. Upon completion of this phase the old Rosebush line can be operated normally open and Rosebush substation can be normally fed from the new line.
2) Expand Vernon substation to add four circuit breakers, making one a sparing breaker, and three new 46 kV line exits. Move the existing Surrey line exit from the existing 166 breaker to a new breaker. Construct new 46 kV line taps from the new line exits to tap the Frost line north of the 188 switch and the Surrey line west of the 488 switch; then make the Frost 188 switch normally open and the Surrey 488 switch normally closed. The fourth breaker will be designated for the new Rosebush line to be constructed as phase 3.
3) From the new ¼ mile Rosebush tap construct a new 8 mile 46 kV line to Vernon substation. Install a new 46 kV switch to the north of the new Rosebush tap. Upon completion, the new Rosebush line can be operated as a looped line between Summerton and Vernon and the old Rosebush line can be retired.

The three project phases can be executed in parallel, wherever possible. However, phase 1 is needed to feed Rosebush substation ASAP, in case of a failure of the existing Rosebush line. The conceptual cost for this project is $8,803,000.
Rev A: After detailed Engineering and Field reviews of the project, it was determined that the R/W cost estimates and lead times originally quoted in this concept were incorrect due to increased number of parcels required for construction. The details of the increased costs can be found in the table below. The new conceptual cost for this project is $9,746,000

Project Phase	**Original Estimate**	**New Estimate**	**Reason for increased costs**
Phase I (5.7 miles from Weidman Jct to Rosebush)	$480,000	$843,000	Increased number of parcels
Phase 2 (1.3 miles for taps to Vernon)	$146,000	$326,000	Route travels through city/industrial areas
Phase 3 (8 miles from Vernon to Rosebush)	$641,000	$1,041,000	Increased number of parcels
Total	**$1,267,000**	**$2,210,000**	

Alternative #2
Rebuild the Rosebush 46 kV line on the existing route and centerline. Acquire additional easements where existing property rights are inadequate. If the standard HVD right of way were attainable the loaded cost estimate for construction and right of way would be $4,722,000. However, after much prior effort on the part of CE's Real Estate Acquisition department, the proper easements for this construction project are regarded as unattainable. In addition, the project to loop Vernon substation into the Frost 46 kV line would still be scheduled separately, at a cost of $2,415,000 loaded, totaling $7,415,000 for the two projects. Furthermore, Rosebush substation would remain served by a 3.3 mile radial spur. While

alternative #2 is lower in cost than alternative #1 it is not a viable alternative because the Rosebush line cannot be rebuilt on the same centerline.

Recommended Alternative:

Alternative #1 is recommended – This is the best viable alternative. This alternative is preferred by the HVD Lines Construction, Real Estate Acquisition, Forestry, Operations, and HVD Planning departments. Overall, there would be approximately 12 miles less total line exposure than for alternative #2 and annual customer-minute savings (121,000 customer-minutes) and line loss savings ($31,000) as compared to the present system configuration. Relocating the Rosebush 46 kV line along the US-127 corridor will facilitate system expansions necessary to serve future load growth in the area and would be more easily accessible for construction and maintenance.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2018 Direct Cost	2018 Cost with Overheads	Description
EH-95208	$806,000	$843,000	Acquire R/W for 5.7 miles 46 kV from Weidman Jct to Rosebush.
	$684,000	$716,000	Acquire R/W for 8 miles 46 kV from Rosebush to Vernon (part 1)
WBS Element	**2019 Direct Cost**	**2019 Cost with Overheads**	**Description**
EH-95208	$314,000	$326,000	Acquire R/W for 1.3 miles 46 kV from Vernon substation
	$312,000	$325,000	Acquire R/W for 8 miles 46 kV from Rosebush to Vernon (part 2)
EH-95308	$1,509,000	$2,265,000	Construct 5.7 miles new 46 kV line from near Weidman Jct to Rosebush + 1 46 kV ABS.
WBS Element	**2020 Direct Cost**	**2020 Cost with Overheads**	**Description**
EH-95008	$1,204,000	$1,792,000	Expand Vernon substation to add 4 breakers and 46 kV line exits.
	$321,000	$477,000	Construct two 46 kV taps from Vernon to Frost & Surrey lines totaling 1.3 miles.
EH-95308	$1,505,000	$2,253,000	Construct 8 miles new 46 kV line from Rosebush to Vernon + 1 46 kV ABS (part 1)
WBS Element	**2021 Direct Cost**	**2021 Cost with Overheads**	**Description**
EH-95308	$500,000	$749,000	Construct 8 miles new 46 kV line from Rosebush to Vernon + 1 46 kV ABS (part 2)
Project Total	$7,155,000	$9,746,000	

SLWatters
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JRAnderson
TJSparks
JFBrossoit
PKPoppe
SLWatters

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: ~~BDStyes~~ JRMcCormick **Team Leader:** ALRoot

Approvals:

Director, Customer & Service Infrastructure HVD	Dwayne C. Parker	Required
Director, Elec Transmission & HVD Eng	James R. Anderson	Required
Vice President, Electric Grid Integration	Timothy J Sparks	Required
Senior Vice President, Transformation/Eng & Ops Sprt	Jean-Francois Brossoit	Required
President	Patricia K. Poppe	Required

From:	Electric Asset Management
To:	SUSAN L. WATTERS
Cc:	SUSAN L. WATTERS; CINDY L. KEZELE; Brian M. Bushey; DONALD A. LYND; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews
Subject:	Approval has completed on 17-0019A Rosebush_Line-Rebuild_Line_in_New_Location - Rev.A.
Date:	Tuesday, February 27, 2018 6:40:54 PM

Approval has completed on 17-0019A Rosebush_Line-Rebuild_Line_in_New_Location - Rev.A.

Approval on 17-0019A Rosebush_Line-Rebuild_Line_in_New_Location - Rev.A has successfully completed. All participants have completed their tasks.

Approval started by SUSAN L. WATTERS on 2/6/2018 3:55 PM
Comment: A new document has been added to the C&SI HVD Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by ARIC L. ROOT on 2/8/2018 9:29 AM
Comment:

Approved by DWAYNE C. PARKER on 2/21/2018 3:41 PM
Comment:

Approved by James R. Anderson on 2/21/2018 8:39 PM
Comment: I approve. An ~ $940k increase in the project cost associated with real estate costs being higher than what was originally projected, moving the project cost from ~ $8.8M to ~ $9.7M. Does not change the selected alternative. Original and revised cost required approvals through and including Patti. Thx. JRAnderson

Approved by Timothy J. Sparks on 2/25/2018 8:33 PM
Comment: Approved. The Rosebush 46 kV line has been near impossible to maintain for decades due to inadequate right of way and uncooperative property owners along its route. This project will reroute this line out of the problem area and connect the 46 kV system in a more resilient configuration.

Approved by Jean-Francois Brossoit on 2/26/2018 3:43 PM
Comment:

Approved by Patricia K. Poppe on 2/27/2018 6:40 PM
Comment:

View the workflow history.

SLWatters
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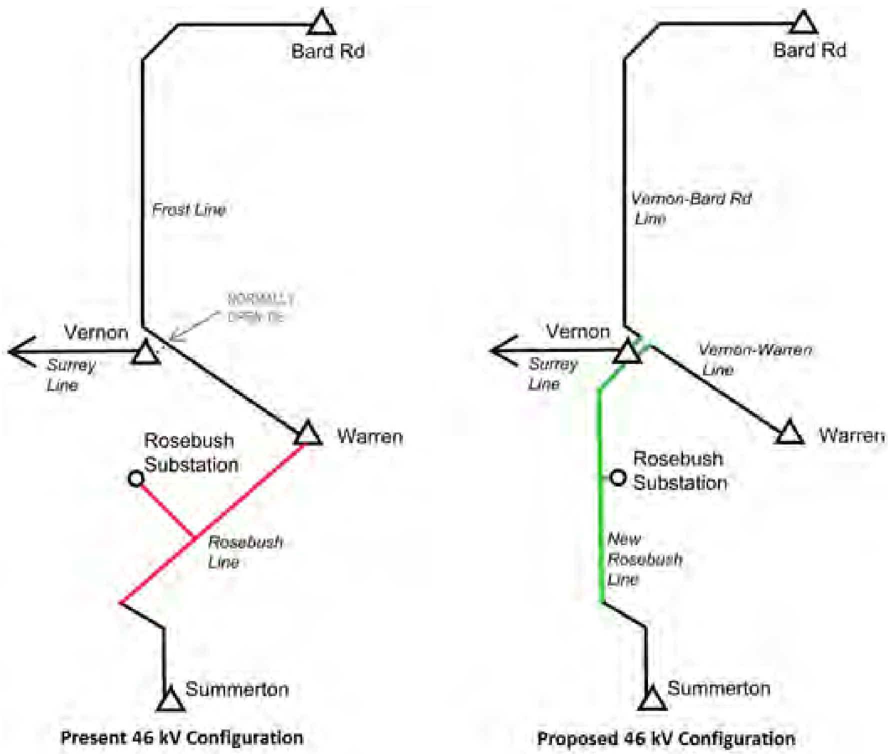
JRAnderson
TJSparks
JFBrossoit
PKPoppe
SLWatters



SLWatters
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TJSparks
JFBrossoit
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JRAnderson
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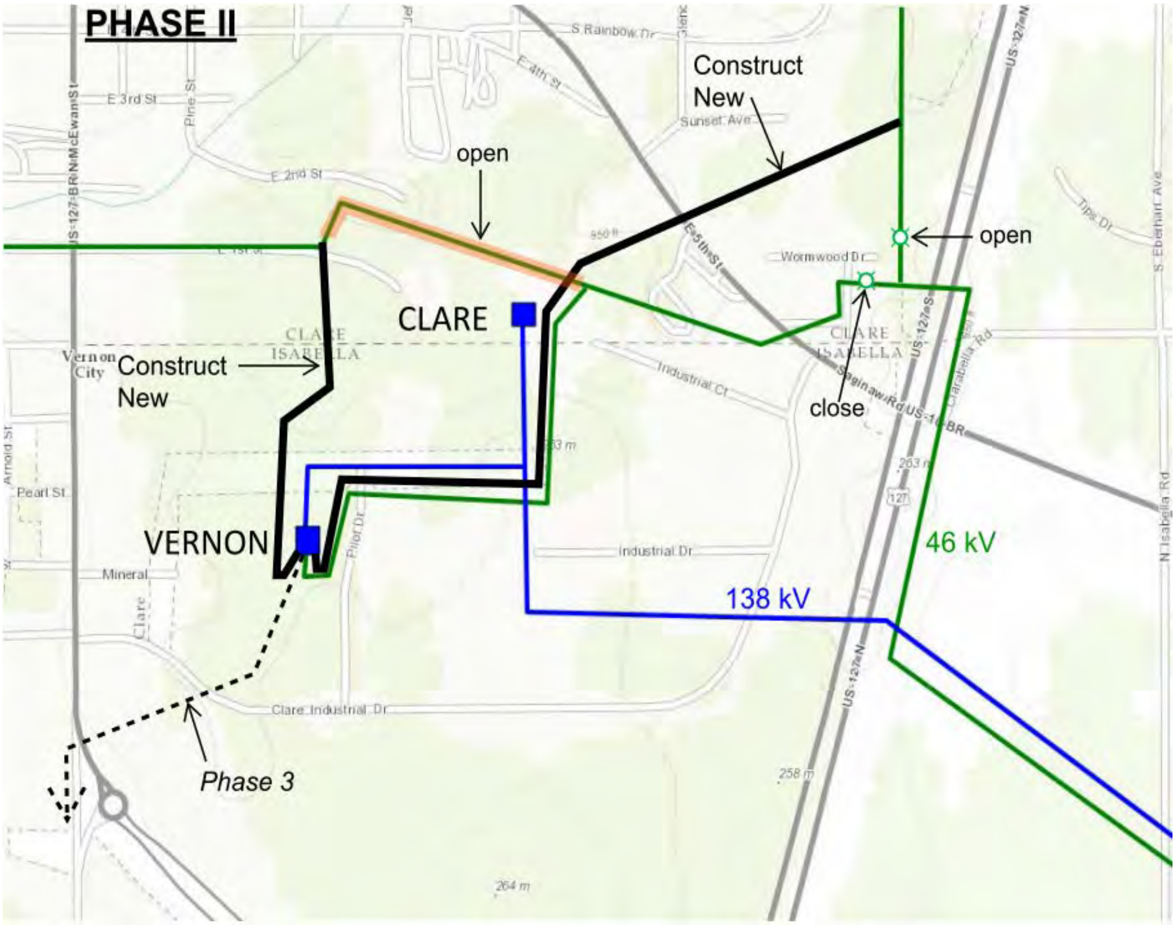

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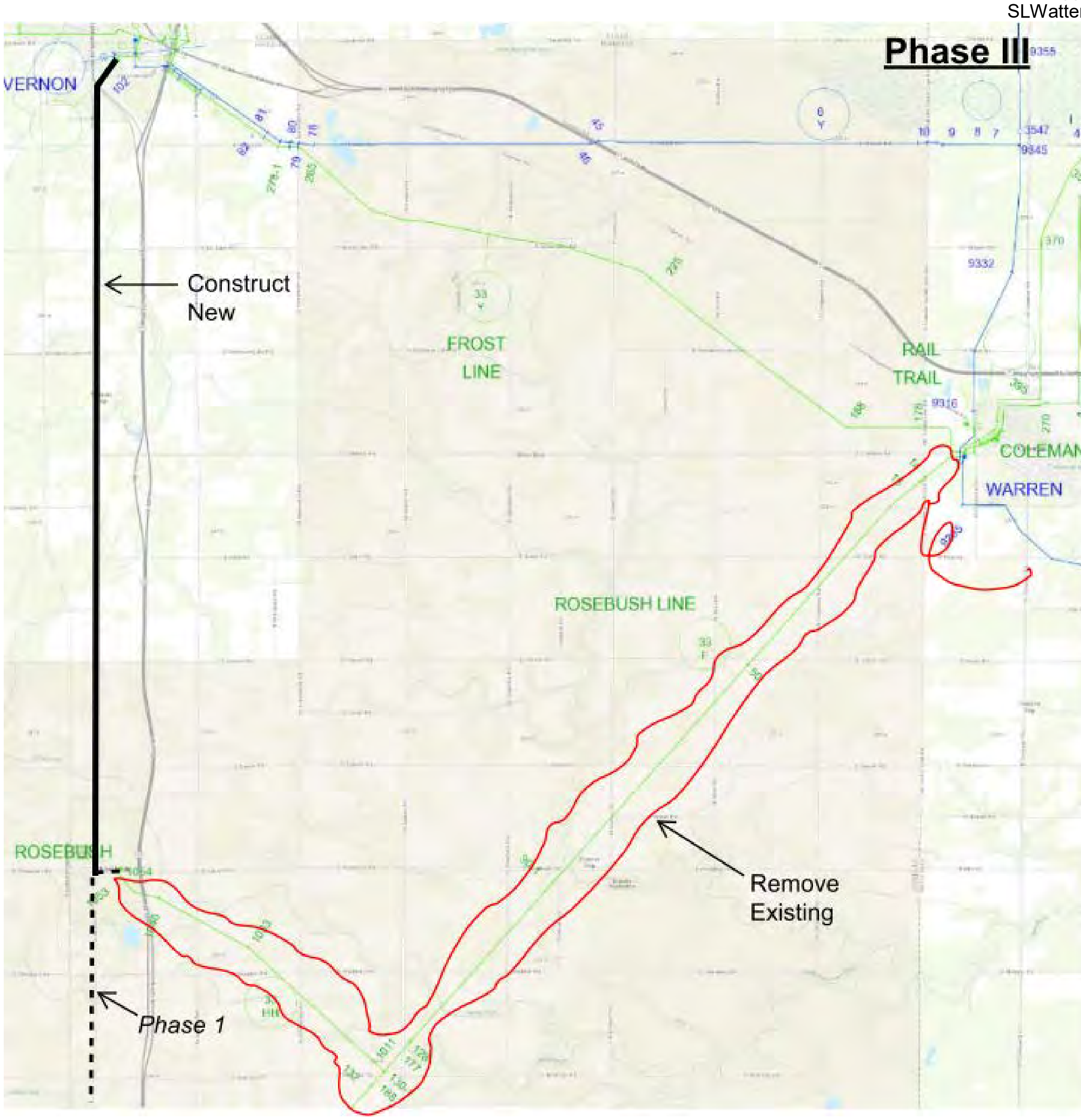

17-0019A_Rosebush_Line-Rebuild_Line_in_New_Location

SLWatters
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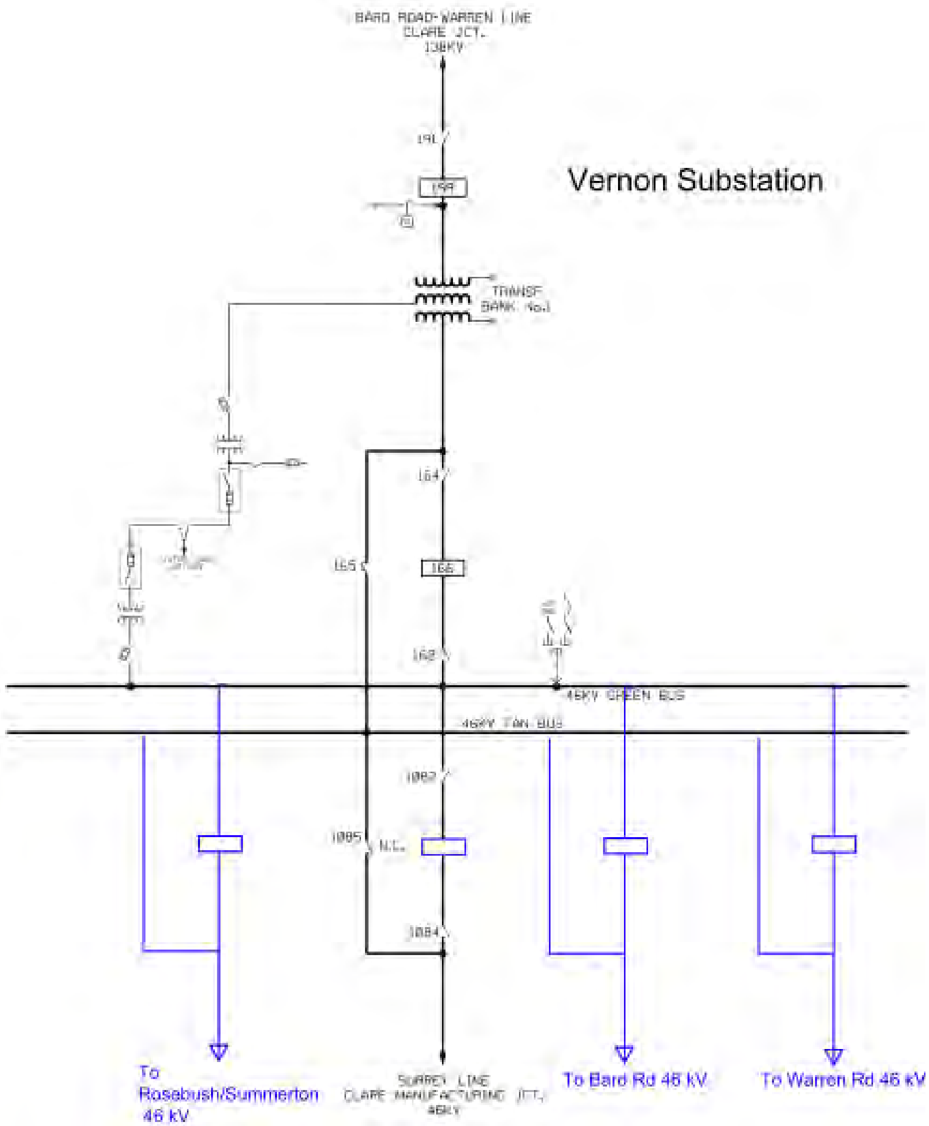


PROJECT: LN042A NASHVILLE FAR WEST RBLD 11.85 MI% (SAP WO# 34710819)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve the overall reliability, in particular for the customers served from the Nashville 46 kV Line. There have been 1 outage incident and 2 forced outages on the section of line between 2016 and 2020. There were 36 out of 241 (14.9%) structures identified in 2018 by the pole inspector as needing to be replaced. Currently this section of line is non-standard 1/0 copper conductor with #2 ACSR shield wire construction. HVD lines that are non-standard construction (unshielded or non-standard conductor), like this section of line, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation.

Attached Concept Approval #21-0041 provides additional details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336.4 KCMil conductor and OPGW fiber optic cable shield wire.

iii. Line Length and ROW requirements.

The rebuild is 11.85 miles long and will be built on the existing centerline utilizing existing easements.

iv. Approximate Construction Schedule.

Construction Start: September 15, 2021
Construction Complete: May 15, 2022

v. Project effect on cost of operation and reliability of service.

The reliability of service will increase with the new configuration. The Nashville 46 kV line experienced 1 outage incident and 2 forced outages on this section of line between 2016 and 2020 due to failed equipment. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor, etc. that were constructed in approximately 1957 are being removed starting at the Hastings substation to structure #249. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.

A9Rbhojbm_1gzh6sq_3ro.pdf

viii. Funding from other entities.

LVD will be funding the replacement of the underbuild on the structures.

ix. All studies performed by the Company or 3rd party regarding the project.

The 2018 pole inspection program identified 36 out of 241 (14.9%) in this line segment as needing to be replaced.

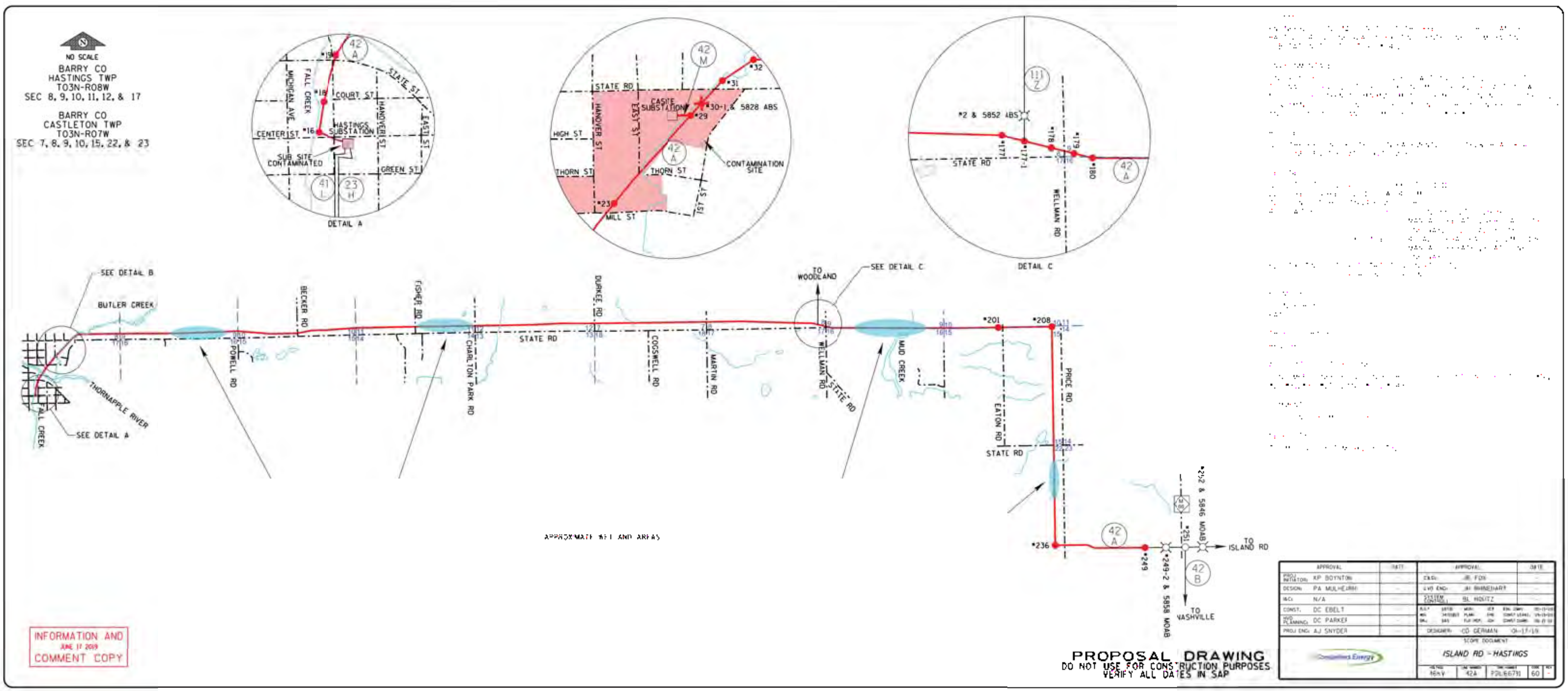
Impact of Line Rebuilds on Outages			
Line Description	Completion Date	Prior Outages	Post Outages
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0

Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

1/11/20

CONCEPT APPROVAL No. 21-0041
Nashville 46 kV HVD Lines Reliability Rebuild


NO SCALE
BARRY CO
HASTINGS TWP
T03N-R08W
SEC 8, 9, 10, 11, 12, & 17
BARRY CO
CASTLETON TWP
T03N-R07W
SEC 7, 8, 9, 10, 15, 22, & 23
DETAIL A
HASTINGS SUBSTATION
SUB SITE CONTAMINATED
CENTER ST
COURT ST
GREEN ST
STATE ST
STATE RD
HIGH ST
THORN ST
MILL ST
CASITE SUBSTATION
5828 ABS
CONTAMINATION SITE
2 & 5852 ABS
DETAIL C
WELLMAN RD
SEE DETAIL B
BUTLER CREEK
THORNAPPLE RIVER
SEE DETAIL A
POWELL RD
BECKER RD
FISHER RD
CHARLTON PARK RD
STATE RD
DURKEE RD
COSGWELL RD
MARTIN RD
TO WOODLAND
SEE DETAIL C
MUD CREEK
EATON RD
PRICE RD
TO ISLAND RD
TO NASHVILLE
APPROXIMATE WETLAND AREAS
INFORMATION AND COMMENT COPY
PROPOSAL DRAWING
DO NOT USE FOR CONSTRUCTION PURPOSES
VERIFY ALL DATES IN SAP
ISLAND RD - HASTINGS

BCMazur
DRMeyers
DCParker
RTBlumenstock
TJSparks
JFBrossoit
PKPoppe

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0041

Project: **Nashville 46 kV Line – HVD Lines Reliability Rebuild** **County:** Barry

Date: January 3, 2020 **Need System Changes By:** 6/1/2022

Problem Description:

The Nashville 46 kV line (42A) has experienced 7 outage incidents between 2014 and 2018. See attached HVD Lines Worst SAIDI 2014-2018. There were 36 out of 244 (14.8%) poles identified as replacement candidates in this 11.9-mile section of the line. Three of the seven outage incidents between 2014 and 2018 occurred in this 11.9 mile section of the Nashville line. The line was constructed in 1957 and is non-standard 1/0 copper conductor with a #2 ACSR shield wire. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like these line sections, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild 11.9 miles of the Nashville 46 kV line. *Conceptual cost: $5,480,000*

Recommended Alternative:

Alternative #2 is recommended. Rebuild of this line is needed to improve overall system reliability and for approximately 4500 customers served from the Nashville 46 kV line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Rebuild also replaces the older non-standard conductor with modern standards and design.

Alternative #1 does not address the poles that need replacement or the reliability of the system on this line and would result in a continual decrease in reliability.

BCMazur
DRMeyers
DCParker
RTBlumenstock
TJSparks
JFBrossoit
PKPoppe

Alternative #2 Recommended Scope:

Rebuild the 11.9-mile section of the Nashville 46 kV line (42A) from Hastings Substation to pole #249 with single circuit 336.4 ACSR conductor on existing centerline on existing easements. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2022 Direct Cost	2021 Cost with Overheads	2022 Cost with Overheads	Description
EH-95308	$1,800,000	$1,800,000	$2,740,000	$2,740,000	Rebuild Nashville 46 kV line
Project Total	$1,800,000	$1,800,000	$2,740,000	$2,740,000	
Customer Contribution	$0	$0	$0	$0	
Total	$1,800,000	$1,800,000	$2,740,000	$2,740,000	Grand Total Cost with Overheads: **$5,480,000**

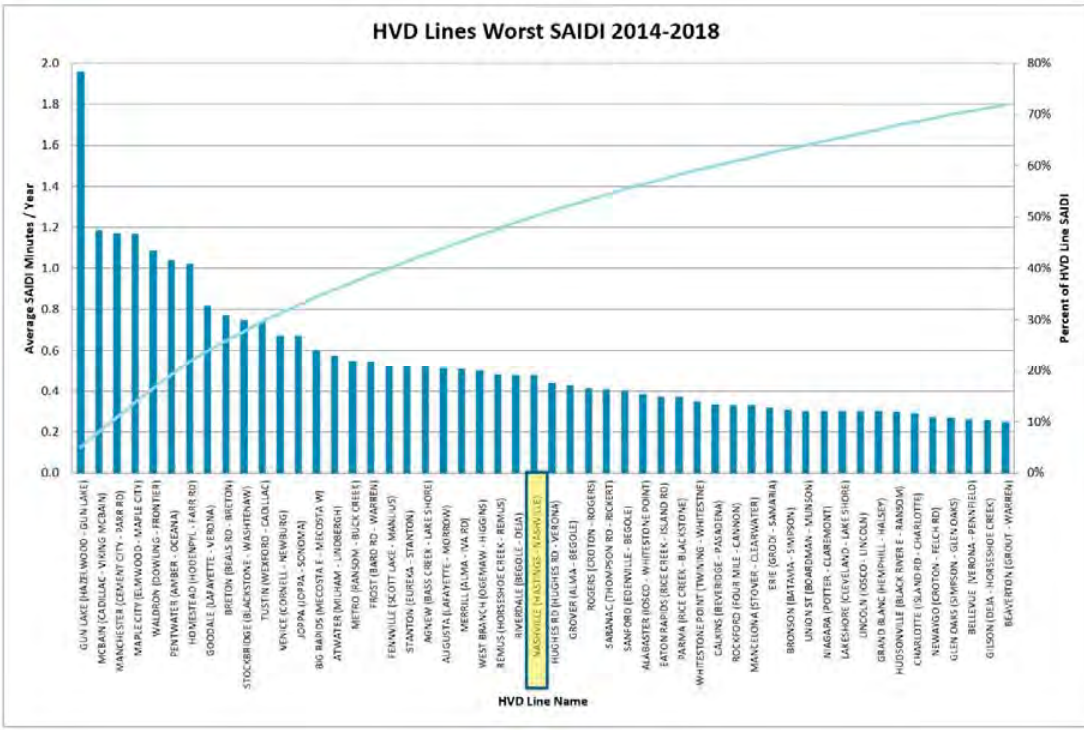
Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

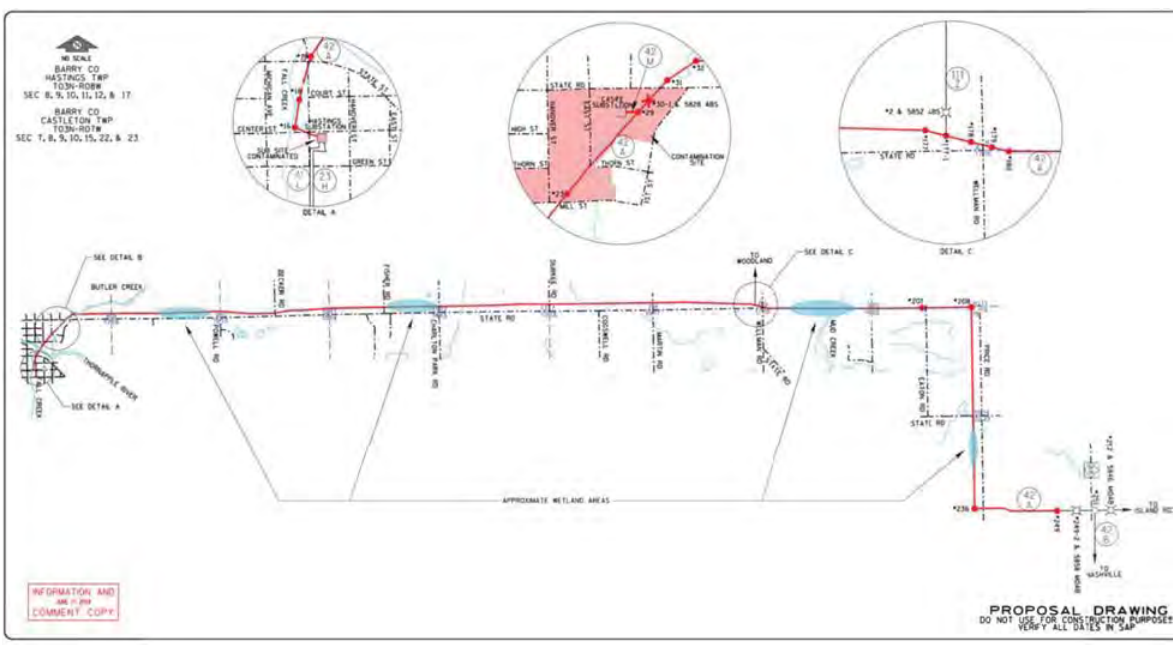
Prepared By: KPBoynton/ALRoot **Team Leader:** Doug Meyers

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required
President & CEO, Consumers Energy	Patricia K. Poppe	Required

BCMazur
DRMeyers
DCParker
RTBlumenstock
TJSparks
JFBrossoit
PKPoppe





Nashville 46 kV Line – 11.9-mile Section

From:	SPAdvisor
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; KIMBERLY P. BOYNTON
Subject:	Approval has completed on 21-0041 Nashville 46 kV HVD Lines Reliability Rebuild.
Date:	Saturday, January 11, 2020 7:35:56 AM

Approval has completed on 21-0041 Nashville 46 kV HVD Lines Reliability Rebuild.

Approval on 21-0041 Nashville 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 1/6/2020 10:34 AM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/6/2020 10:40 AM
Comment:

Approved by DWAYNE C. PARKER on 1/6/2020 11:00 AM
Comment: Approve. The CA has been updated to include the breakdown of outages that occurred on the line section being rebuilt.

Approved by RICHARD T. BLUMENSTOCK on 1/6/2020 11:20 AM
Comment: Approved.

Approved by Timothy J. Sparks on 1/7/2020 8:42 AM
Comment: Approved.

Approved by Jean-Francois Brossoit on 1/8/2020 6:24 PM
Comment:

Approved by Patricia K. Poppe on 1/11/2020 7:35 AM
Comment:

View the workflow history.

PROJECT: Rebuild Coopersville 46 kV Line Cleveland – Rochester Products (WO# 37985001)

i. Purpose and Necessity of the Project with Supporting Data.

During pole testing on the Coopersville 46 kV line (Cleveland – Rochester Products) 19 structures were identified as needing to be replaced. During engineering it was determined that the existing line design did not meet today's standard clearances. Commonwealth was hired to review the entire line and it was found 67% of the line to not meet today's standards accounting for approximately 154 HVD structures.

The Concept Approval 23-0010 (Attachment 1) which initially identified the need for the Coopersville 46 kV line rebuild describes the above.

ii. Line Design, size material used.

Single circuit, wood pole design with 336.4 ACSR conductor and OPGW fiber optic cable shield wire.

iii. Line Length and ROW requirements.

The rebuild is 10.7 miles long and will be built on existing center line. The rebuild will be on the Consumers Energy owned fee strip with real estate trying to acquire danger tree rights outside of the existing fee strip.

iv. Approximate Construction Schedule.

Construction Start: October 17, 2022
Construction Complete: August 12, 2023
Equipment Checkout Complete: August 26, 2023

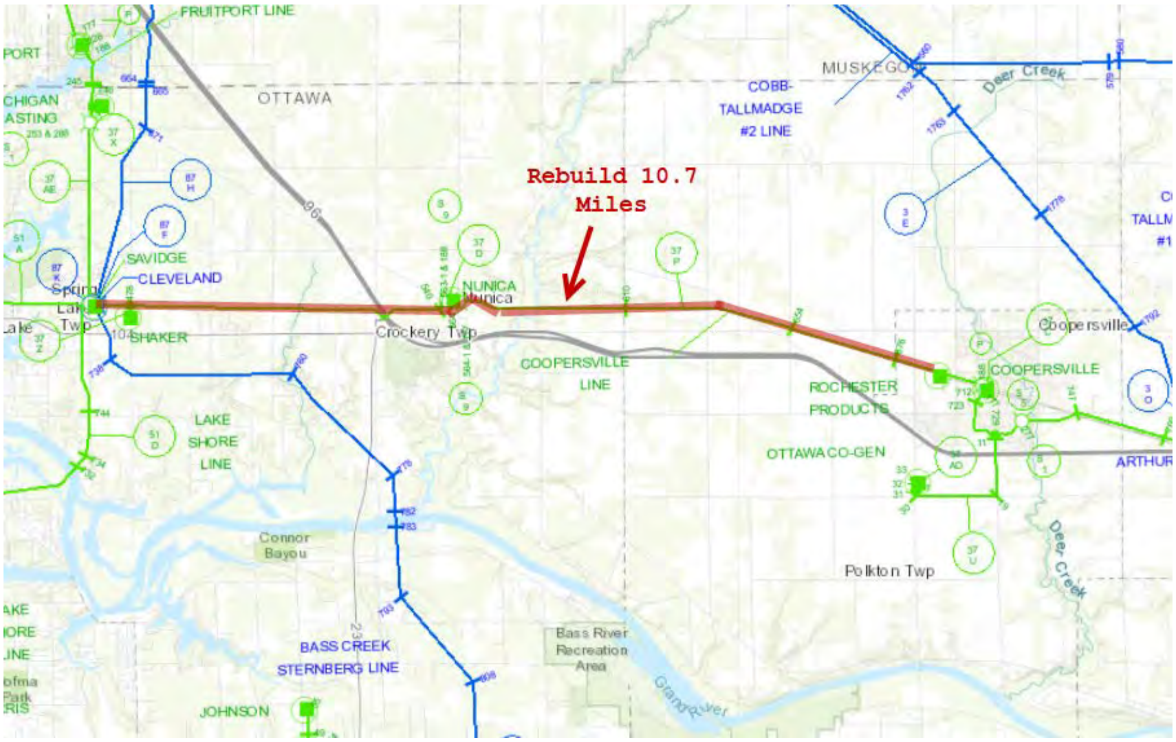
v. Project effect on cost of operation and reliability of service.

Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table). Line losses will also be decreased as a result of the larger conductor.

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor, etc. starting at Cleveland Substation to Rochester Products Substation. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

Coopersville 46 kV Line Rebuild – Attachment 1

CONCEPT APPROVAL No. 23-0010
Coopersville 46 kV Line – Rebuild 10.7 miles

BCMazur
JPBrock
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 23-0010

Project: **Coopersville 46 kV Line – Rebuild 10.7 miles** **County:** Ottawa

Date: December 1, 2020 **Need System Changes By:** 5/15/2023

Problem Description:

HVD Lines reliability had scheduled a pole replacement project to replace 19 structures in 2018 on the Coopersville 46 kV line between Cleveland and Rochester Products. During engineering it was found that there were many clearance violations between the 46 kV line, underbuilt LVD and the ground. Commonwealth was hired to review the entire line and 67% of the line was found to have clearance violations accounting for approximately 154 HVD structures. Forestry has also brought up concerns about the tree rights outside of the existing fee strip on this section of 46 kV line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Derate the 46 kV line to mitigate the clearance violations. *Conceptual cost: $0*
3. Rebuild 10.7 miles of the Coopersville 46 kV Line between Cleveland and Rochester Products. *Conceptual cost: $7,135,000*

Recommended Alternative:

Alternative #3 is recommended. Alternative #1 ignores the issue and leaves the system and customers at risk. Alternative #2 was investigated but the existing 46 kV line could not be derated enough to mitigate the clearance violations, even with the addition of Polkton (a planned new bulk power substation that provides for additional capacity in the general Coopersville area), as the clearance violations are present all the way down to wire temps 20-35 degrees F. Alternative #3 corrects the clearance violations bringing the line up to present standards, allows the line to be used to its full capacity in an area that is continuing to grow, and takes care of the needed pole replacements .

BCMazur
JPBrock
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Alternative #3 Recommended Scope:

Acquire tree rights out side of the existing fee strip bringing the existing clearing rights up to current standards. Rebuild 10.7 miles of the Coopersville 46 kV Line between Cleveland and Rochester Products on existing center line with 336 ACSR. Replace the existing LVD underbuild on approximately 92 locations. Reconductor approximately 2 miles, Nunica Substation, Leonard Circuit #2, of the LVD underbuild from 1/0 ACSR to 336 ACSR.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2022 Direct Cost	2023 Direct Cost	2021 Cost with Overheads	2022 Cost with Overheads	2023 Cost with Overheads	Description
EH-95220-1-19-02-01 - HVD Lines - Load Carrying / Voltage	$0	$2,100,000	$2,100,000	$0	$3,200,000	$3,200,000	Rebuild 10.7 miles of the Coopersville 46 kV line.
EH-95208 - R/W - HVD Capacity	$145,000	$0	$0	$145,000	$0	$0	Tree rights outside of existing fee strip
ED-95719	$0	$148,000	$148,000	$0	$295,000	$295,000	LVD Underbuild
Total	$145,000	$2,248,000	$2,248,000	$145,000	$3,495,000	$3,495,000	**Grand Total: $7,135,000**

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

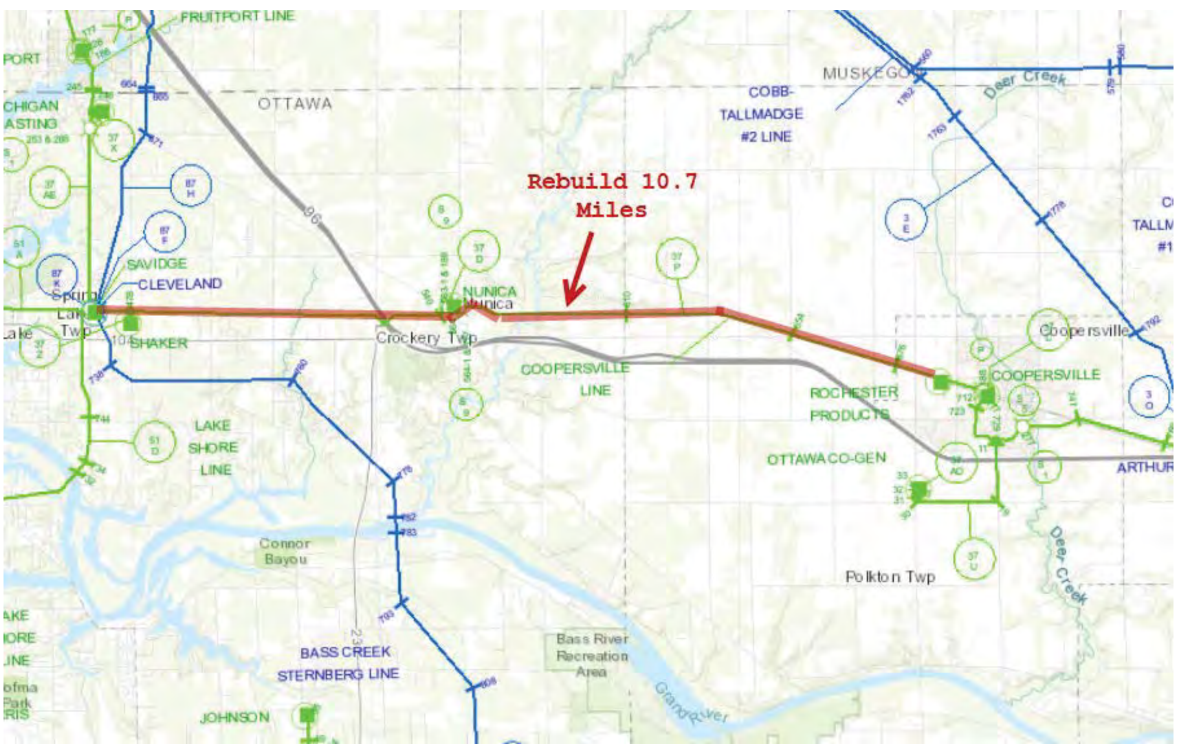
Prepared By: CMFranklin

Approvals:

Senior Engineer Lead, LVD Planning	John P. Brack	Approved 12/1/2020

BCMazur
JPBrock
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks
JFBrossoit

Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Director, HVD System Planning	Edward R. Mathews	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required



BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Sunday, December 13, 2020 9:17 PM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Gregory E. Kral; Jacob D. Roberson; JOHN P. BRACK; Catherine M. Franklin
Subject:	Approval has completed on 23-0010 Coopersville 46 kV Line - Rebuild Cleveland - Rochester Products.

Approval has completed on 23-0010 Coopersville 46 kV Line - Rebuild Cleveland - Rochester Products.

Approval on 23-0010 Coopersville 46 kV Line - Rebuild Cleveland - Rochester Products has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 12/1/2020 4:12 PM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by JULIA R. FOX on 12/1/2020 4:13 PM
Comment:

Approved by DONALD A. LYND on 12/1/2020 4:34 PM
Comment: LVD Approved.

Approved by Edward R. Mathews on 12/2/2020 7:55 AM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 12/9/2020 8:27 AM
Comment: Approved. Tim - This is a 3-year project (2021-2023) to rebuild 10.7 miles of the Coopersville Line. Should you need additional information or a presentation for JF, please let us know.

Approved by Timothy J. Sparks on 12/9/2020 10:22 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 12/13/2020 9:17 PM
Comment:

View the workflow history.

PROJECT: LN013J HODENPYL REBUILD

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve overall reliability and in particular for the approximately 5,300 customers served from the Hodenpyl 46 kV Line. Actual line performance over the past five years has shown the Hodenpyl 46 kV Line to be underperforming. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild vs. further investment in pole top rehabilitation on a non-standard line. The Hodenpyl 13J line section is presently non-standard 1/0 copper conductor in an unshielded configuration.

Concept Approval 22-0052 provides additional project details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336 ACSR conductor and fiber optic shield wire.

iii. Line Length and ROW requirements.

The line is 4.6 miles long and will be built on the existing centerline utilizing existing Consumers Energy easements.

iv. Approximate Construction Schedule.

Construction Start: January 1, 2022
Construction Complete: May 31, 2022

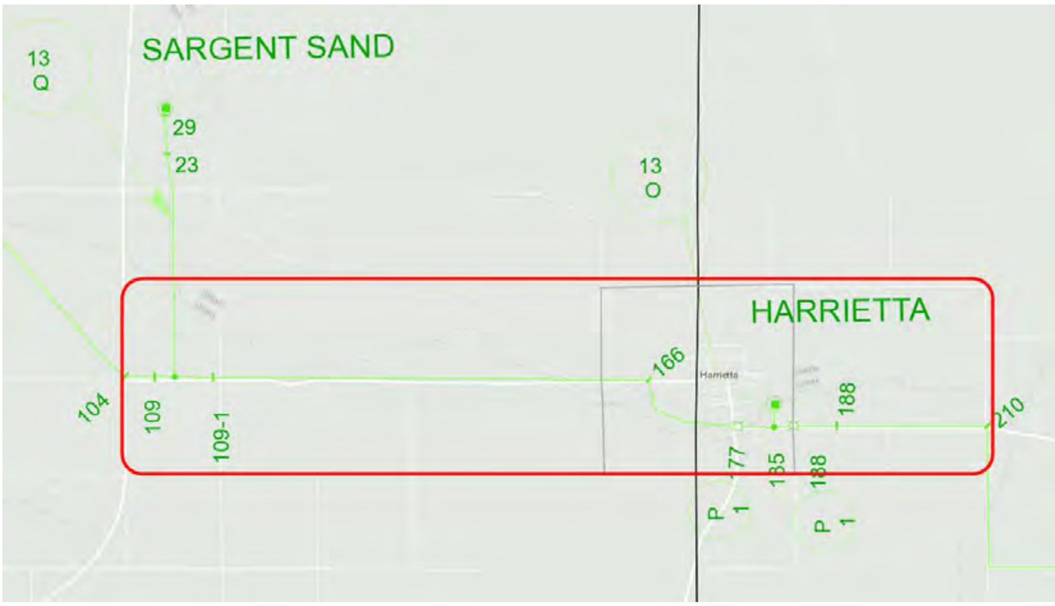
v. Project effect on cost of operation and reliability of service.

The reliability of electric service will increase with the new configuration. The Hodenpyl 46 kV line has experienced 2 outage incidents between 2015 and 2019. The line has also been removed from service 3 times during that span due to crossarm and insulator failures. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor and etc. that were constructed in 1931 are being removed starting at structure #104 to structure #210. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0

Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 22-0052
Hodenpyl 46 kV HVD Lines Reliability Rebuild

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0052

Project: **Hodenpyl 46 kV Line – HVD Lines Reliability Rebuild** **County:** Wexford

Date: January 14, 2021 **Need System Changes By:** 5/31/2022

Problem Description:

Line performance data over the past five years has shown the Hodenpyl 46 kV line to be underperforming. The Hodenpyl 46 kV line, originally installed in 1931, has experienced 2 outage incidents between 2015 and 2019. The line has also been removed from service 3 times during that span due to crossarm and insulator failures. The line is constructed with non-standard 1/0 copper conductor in an unshielded configuration. Recent aerial inspections of the line have shown advanced deterioration of the crossarms and pole tops. The Harrietta Substation will undergo a rebuild in 2022 and will be adding a 3rd circuit at that time. As part of that rebuild, LVD Planning has requested to attach a 2nd underbuild circuit between HVD structures 186 and 104 and the present line configuration cannot accommodate that request.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Top Rehabilitation of the line. *Conceptual cost: $428,000*
3. Rebuild 4.6 miles of the Hodenpyl 46 kV line. *HVD Conceptual cost: $2,139,000 and LVD Conceptual cost: $1,770,000*

Recommended Alternative:

Alternative #3 is recommended. Rebuild of this line is needed to improve overall system reliability and for the approximately 5,300 customers served from the Hodenpyl 46 kV line. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line. Outage data has shown that after completing a rebuild a line typically has zero or

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minimal line equipment related outages.

Alternative #1 does not address the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 does not address the aged copper conductor, poles or the unshielded configuration of the line. LVD Planning will also not be allowed to add the 2nd underbuild circuit to the line.

Alternative #3 Recommended Scope:
Rebuild the 4.6 mile section of the Hodenpyl 46 kV line from structure #104 to structure #210 with single circuit 336.4 ACSR conductor built on the existing centerline with poles that will accommodate two underbuild circuits between structures 104-186. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$1,380,000	$2,139,000	Rebuild the Hodenpyl 46 kV line
ED-95719	$1,141,900	$1,770,000	LVD Underbuild Line Relocation
Customer Contribution	$0	$0	
Total	$2,521,900	$3,909,000	Grand Total Cost with Overheads: **$3,909,000**

Present Need: On approval, this document authorizes the Electric Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka **Team Leader:** Doug Meyers

BCMazur
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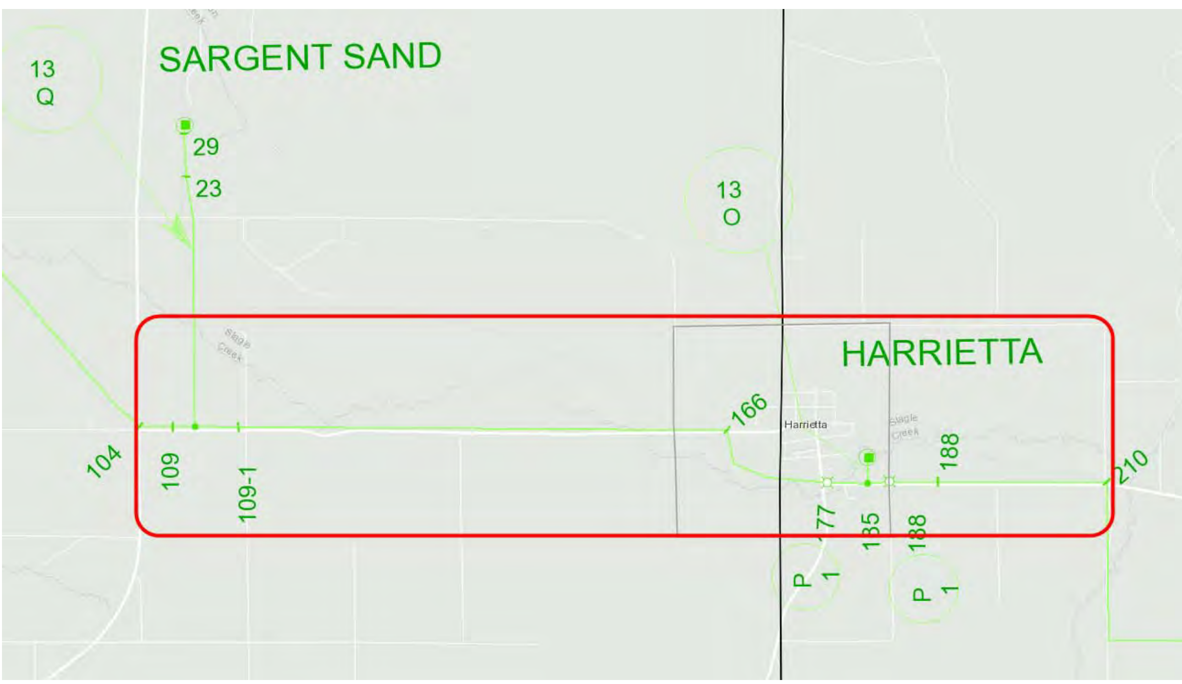
DALynd
ERMathews
RTBlumenstock
TJSparks

Approvals:

Senior Engineer Lead, LVD Circuit Planning	John P. Brack	Required
Director, HVD System Planning	Edward R. Mathews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required



PROJECT: LN108A MERRILL CENTER REBUILD 4.62 MILES (SAP #36608998)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve the overall reliability, in particular for the customers served from the Merrill 46 kV Line. There have been 3 outage incidents on the line between 2016 and 2020. There are 25 out of 65 (38.5%) poles that were identified as replacement candidates by the pole inspector for the Merrill 108A line section covered under this rebuild. There are brown and gray pin type insulators in this section of the line that have been known to cause issues that were identified by the helicopter patrol.

Attached Concept Approval #22-0008 provides additional details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336.4 ACSR conductor and OPGW fiber optic cable shield wire.

iii. Line Length and ROW requirements.

The rebuild is 4.62 miles long and will be built on the existing centerline utilizing existing easements.

iv. Approximate Construction Schedule.

Construction Start: January 3, 2022
Construction Complete: May 15, 2022

v. Project effect on cost of operation and reliability of service.

The reliability of service will increase with the new configuration. The Merrill 46 kV line experienced 3 outage incidents on the line between 2016 and 2020. 38.5% of the poles in this section of line were recommended for replacement by the pole inspector and needs to be replaced. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

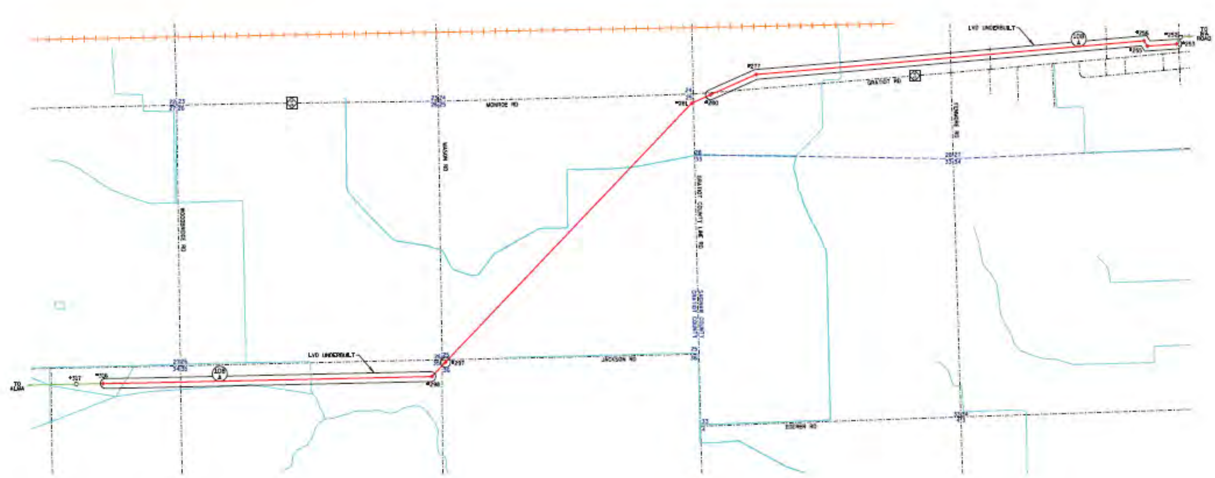
vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor, etc. that were constructed in approximately 1948 are being removed starting at structure #253 to #316. The wood poles, crossarms and porcelain

Case No. U-20963
Attachment No. 126
Page 158 of 312

insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

LVD will fund part of the project.

ix. All studies performed by the Company or 3rd party regarding the project.

The 2019 pole inspection program identified 25 out of 65 (38.5%) on this line segment as needing to be replaced.

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0

Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 22-0008
Merrill 46 kV HVD Lines Reliability Rebuild

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DALynd
RTBlumenstock
TJSparks
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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0008

Project: **Merrill 46 kV Line – HVD Lines Reliability Rebuild** **County:** Saginaw and Gratiot

Date: January 14, 2021 **Need System Changes By:** 5/15/2022

Problem Description:

The Merrill (108A) 46 kV line from structure #253 to #316 were installed around 1948. There have been 3 outage incidents on the line between 2016 and 2020. 25 out of 65 poles (38.5%) in the 4.62-mile section of line requires replacement. 9 of the poles were recommended as a "Rush" replacement and 16 were recommended as a "Planned replacement" by the 2019 pole inspection program. Structure #266 is located in deep water and was not tested by the pole inspector. There are brown and gray pin type insulators in this section of the line that have been known to cause issues that were identified by the helicopter patrol.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Replace only the recommended pole replacements on the 4.62-mile section of line. HVD *Conceptual cost: $506,850 and* LVD *Conceptual cost: $71,000*
3. Rebuild 4.62 miles of 108A line. HVD *Conceptual cost: $2,148,300 and* LVD *Conceptual cost: $300,747*

Recommended Alternative:

Alternative #3 recommended. Rebuilding the 4.62 miles of 108A line is needed to improve the overall system reliability. Outage data has shown that after completing a rebuild, a line typically has zero or minimal line equipment related outages. A rebuild will also replace the older conductor with modern standards and design.

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Alternative #1 does not address the poles, crossarms and insulators on the line that needs to be replaced or the reliability of the system on the line and would result in a continual decrease in reliability.

Alternative #2 does not address some of the poles, crossarms and insulators on the 4.62--mile section of line 108A that needs to be replaced or the reliability of the system on the section of line and would result in a continual decrease in reliability.

Alternative #3 Recommended Scope:
Alternative #3 recommended. Rebuild 4.62-miles of the Merrill 46 kV 108A line, including the associated LVD underbuild from structure #253 to 316. Utilize single circuit 336.4 ACRS conductor and OPGW shield wire on the existing or a combination of existing easements and newly obtained easements as needed.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$1,386,000	$2,148,300	Rebuild 4.62 miles of the Merrill 46 kV 108A line
ED-95719	$194,030	$300,747	LVD Underbuild (108A)
Project Total	$1,580,030	$2,449,047	
Customer Contribution	$0	$0	
Total	$1,580,030	$2,449,047	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group and the Low Voltage Distribution Engineering group to proceed with

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the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: KPBoynton **Team Leader:** Doug Meyers

Approvals:

Electric Reliability & Support Lead	Douglas R Meyers	Required
LVD System Engineer	Joshua L Birchmeier	Required
Director, LVD Circuit Planning	Julia A Fox	Required
Director, HVD System Planning	Edward R Mathews	Required
Director, LVD System Planning	Donald A Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required

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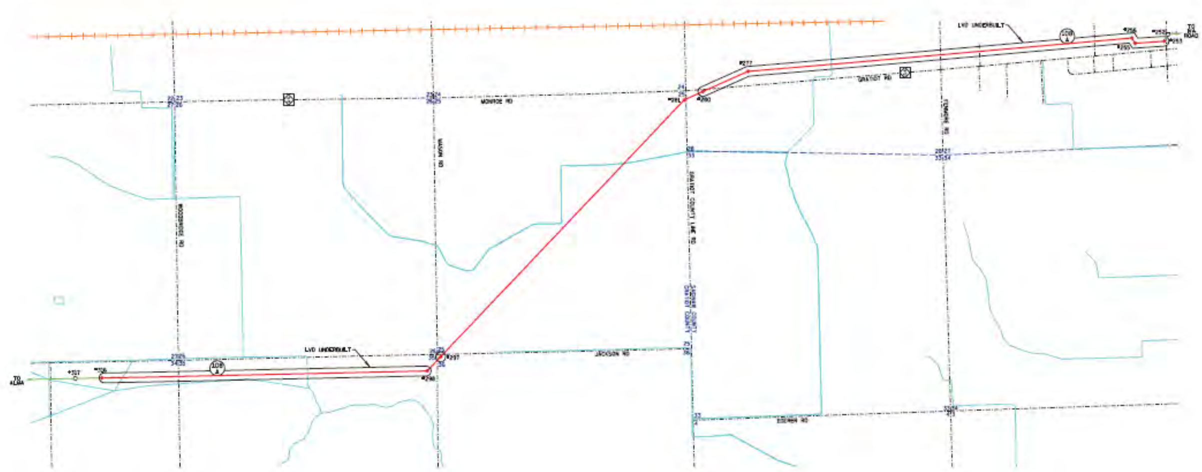


PROJECT: LN082H WAYLAND REBUILD (SAP WO#34706716)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve overall reliability and in particular for the approximately 8,000 customers served from the Wayland 46 kV Line. There are 52 out of 134 poles (39%) that were identified as replacement candidates by the pole inspector for the 82H, 9.9 mile section covered under this rebuild. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild vs. further investment in pole replacements or pole top rehabilitation on a non-standard line. The Wayland 82H line section is presently non-standard unshielded construction.

Concept Approval 21-0023 provides additional project details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336 ACSR conductor and fiber optic shield wire.

iii. Line Length and ROW requirements.

The line is 9.9 miles long and will be built on the existing centerline utilizing existing Consumers Energy-owned fee strip. Additional tree easements are being acquired to increase the clearance of the line to danger trees.

iv. Approximate Construction Schedule.

Construction Start: September 1, 2021
Construction Complete: May 31, 2022

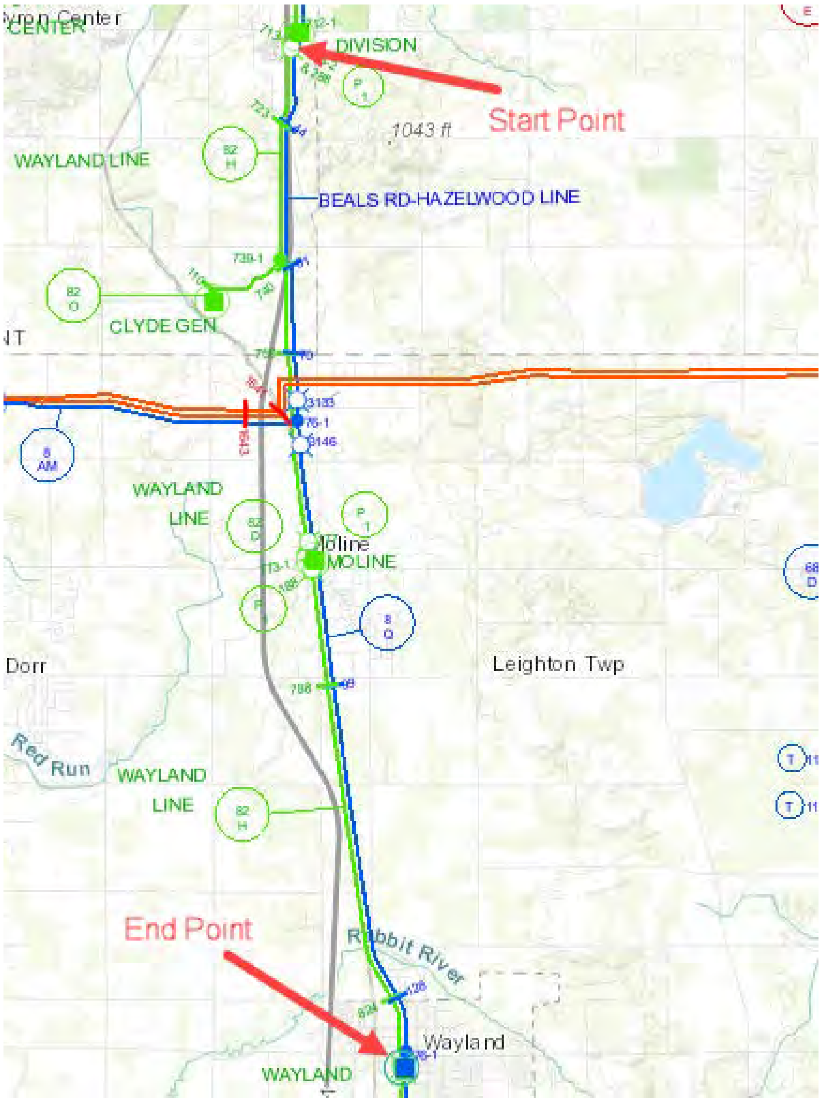
v. Project effect on cost of operation and reliability of service.

The reliability of electric service will increase with the new configuration. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor, etc. that were originally installed pre-WW2 are being removed starting near Division Substation to Wayland Substation. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

The 2018 pole inspection identified 52 out of 134 poles (39%) on this line segment as needing to be replaced.

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 21-0023

Wayland 46 kV HVD Lines Reliability Rebuild

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JFBrossoit

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0023

Project: **Wayland 46 kV Line – HVD Lines Reliability Rebuild** **County:** Kent

Date: January 8, 2020 **Need System Changes By:** 5/31/2022

Problem Description:

Pole inspections have identified that 52 out of 134 poles (~39%) in a 9.9 miles section of the Wayland 46 kV line need replacement. Presently this line section is non-standard unshielded construction. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild the 9.9 mile section of the Wayland 46 kV line. *Conceptual cost: $2,250,000*

Recommended Alternative:

Alternative #2 is recommended. Rebuild of this line is needed to improve overall system reliability and for approximately 8000 customers served from the Wayland 46 kV line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Rebuild also replaces the older non-standard conductor with modern standards and design.

Alternative #1 does not address the poles that need replacement or the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 Recommended Scope:

Rebuild the 9.9 mile Wayland 46 kV line from pole # 711 near Division Substation to Wayland Substation with single circuit 336.4 ACSR conductor on existing centerline on

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existing easements. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2022 Direct Cost	2021 Cost with Overheads	2022 Cost with Overheads	Description
EH-95308	$1,500,000	$1,500,000	$2,250,000	$2,250,000	Rebuild Wayland 46 kV line
Project Total	$1,500,000	$1,500,000	$2,250,000	$2,250,000	
Customer Contribution	$0	$0	$0	$0	
Total	$1,500,000	$1,500,000	$2,250,000	$2,250,000	Grand Total with Overheads: **$4,500,000**

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka/ERMathews **Team Leader:** Doug Meyers

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required

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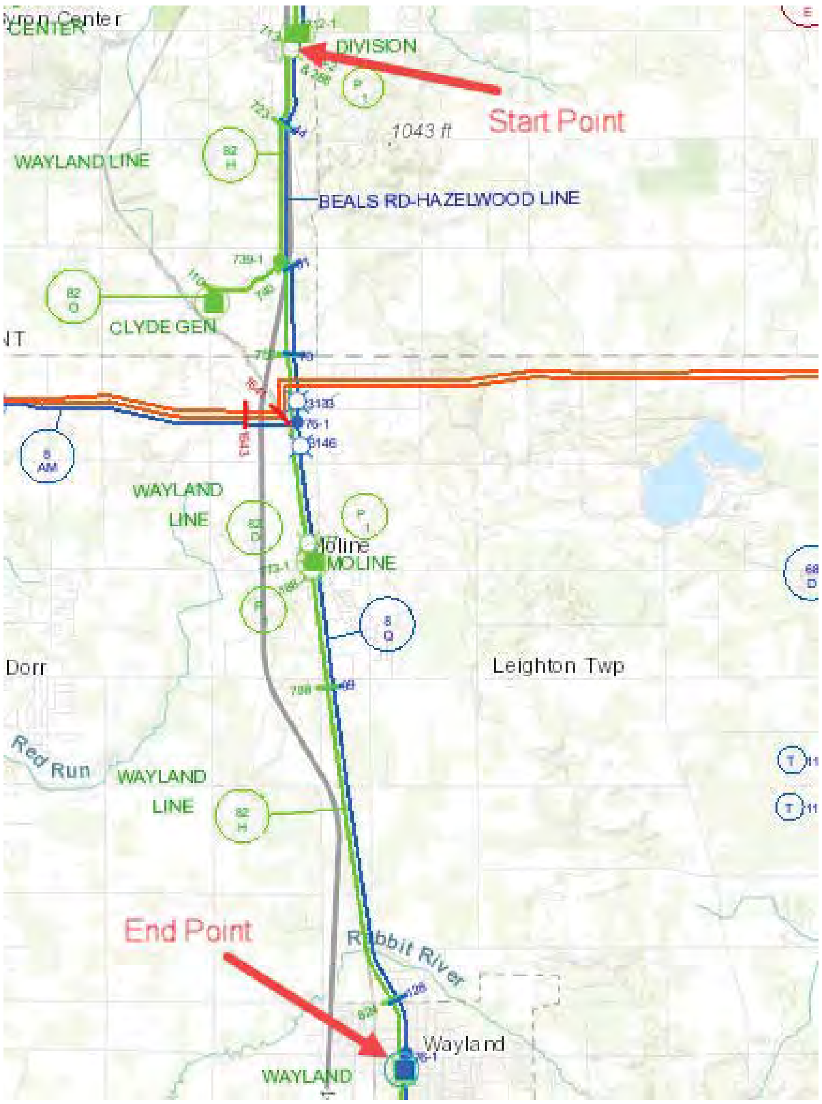
TJSparks
JFBrossoit



From:	SPAdvisor
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; LOUIS B. HINCKA
Subject:	Approval has completed on 21-0023 Wayland 46 kV HVD Lines Reliability Rebuild.
Date:	Tuesday, January 14, 2020 8:35:02 AM

Approval has completed on 21-0023 Wayland 46 kV HVD Lines Reliability Rebuild.

Approval on 21-0023 Wayland 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 1/8/2020 11:07 AM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/8/2020 3:45 PM
Comment:

Approved by DWAYNE C. PARKER on 1/8/2020 3:50 PM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 1/9/2020 12:00 PM
Comment: Approved.

Approved by Timothy J. Sparks on 1/9/2020 1:34 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 1/14/2020 8:34 AM
Comment:

View the workflow history.

PROJECT: MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD (SAP # 1050165426)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this project is to rehabilitate the metro underground electric system along Cortland Street in downtown Jackson. The vaults are in need of repairs due to failing concrete and exposed and deteriorated electrical equipment. The duct system in this street is inadequate for present standard metro cables. Further, there have been safety concerns raised regarding safe working conditions in this part of the system.

Concept Approval 1050165426 provides additional project details.

ii. Line Design, size material used.

Underground duct bank utilizing standard six inch polyvinyl chloride (PVC) conduits encased in concrete.

iii. Line Length and ROW requirements.

The duct bank replaced will be 800 feet long and constructed in the city street right-of-way via permit.

iv. Approximate Construction Schedule.

Construction Start: March 2022
Construction Complete: October 2022

v. Project effect on cost of operation and reliability of service.

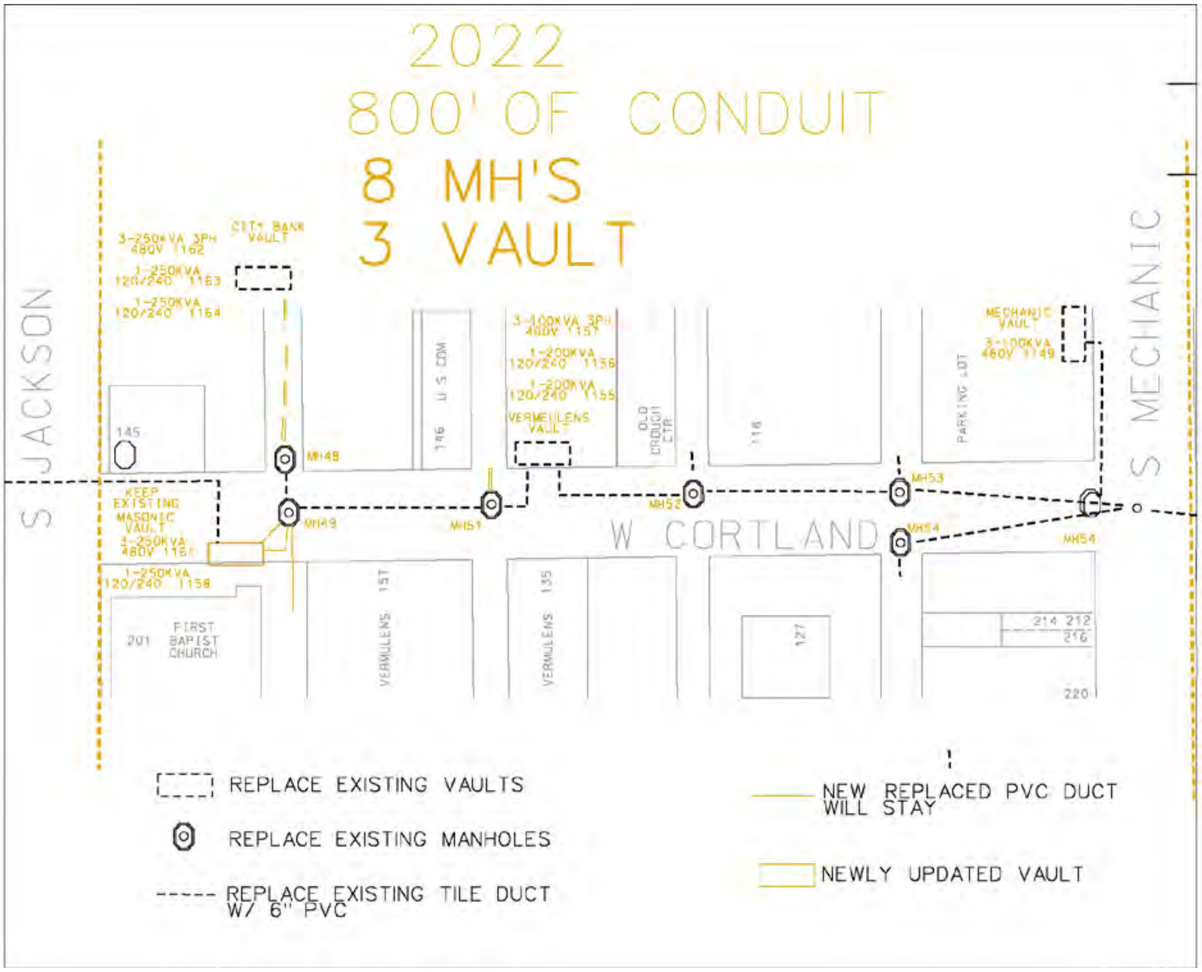
The reliability of service will increase with the new equipment. The working conditions will be brought to present standards to the benefit of crews.

Additionally, the 4.8 kV delta voltage is non-standard. Delta systems require two phase-ground faults to be present before the phase protective device operates or trips, which means a faulted delta cable will not trip a primary protective device until a second phase fault develops. This project will facilitate future conversation to a standard grounded-wye voltage.

vi. A description of the property being replaced and salvage value.

Metro vaults, duct banks, transformers, switches, cables, and associated equipment are being replaced on Cortland Street between Jackson and Mechanic Streets. The vaults and duct banks have zero salvage value. Other equipment and cable will be sent to Investment Recovery to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See the attached Concept Approval 1050165426.

x. Date of board approval.

N/A

MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD – Attachment 1

CONCEPT APPROVAL No. 1050165426
MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD

Concept Document To Be Attached Here

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Notification Concept Number: 1050165426

Project Title: MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD **Work HQ:** Jackson

Date: 12/6/2019 **Proposed Year of System Changes:** 2021-2023

Problem Description:

Over the last ten years two-thirds of the Jackson Civil Metro system has been rebuilt, the last one-third is the metro system on Cortland Street between Blackstone and MLK (Francis) streets. In this area there are nine vaults of which six vaults are in need of repairs. All of the duct bank in the corridor is 3 ½ inch fiber which is inadequate for present standard metro cables. The vault roofs double as a sidewalk and are showing signs of spalling, cracking, and exposed rebar. In some instances, walls are starting to crumble and pieces are falling off onto the floor. This leaves the company exposed to a public safety risk.

The recent Jackson Sub Metro crews' Stop the Job was due to their main concern of working in live front vaults. Many of these live front vaults are in the Cortland Street corridor. Present issues include live secondary connection bus hanging from crumbling ceilings and secondary wires freely hanging from the ceiling. Non-load break live front switches and fuses do not provide proper minimal approach distances required. Live front facing bushing transformers and deteriorated transformer stands also pose stability and minimum approach distance safety concerns.

The Cortland Street cooridor consists of ductbank, manholes, and nine vaults serving 210 customers and 1,262 kVA of load as shown in the table below.

Vault	Transformer	Customers	Load (kVA)
Methodist	#1254	5	40
	#1256	4	45
Jacobson	#1248	1	230
Fields	#1241	7	44
	#1244	8	44
	#1242	3	27
Masonic	#1158	4	22
	#1161	10	130
City Bank	#1163	13	31
	#1164	4	31
Vermeulens	#1155	7	66
	#1156	9	30
Mechanic	#1149	3	64
	#1147	6	160
Cortland	#1146	5	26
	#1145	30	130
Otsego	#1143	1	12
	#1141	90	130
Cortland Street Total		210	1,262

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Specific deficiencies of the six vaults are as follows. See attached pictures showing many of these deficiencies.

- Methodist Vault has live-front non-load-break fuses, exposed bus bars, and deteriorated transformer stands.
- City Bank Vault has live-front transformers, live-front non-load-break fuses, and exposed live bus bars on the ceiling.
- Vermeulens Vault has live-front transformers, live-front non-load-break fuses, and exposed live bus bars on ceiling.
- Mechanic Vault has live front transformers, live-front non-load-break fuses, exposed live bus bars on the ceiling, no load centers, and wires and cables running in every direction.
- Cortland Vault has live front transformers, live-front non-load-break fuses, exposed live bus bars hanging from the ceiling, no load centers, foam filling cracks in the ceiling, and wires and cables running in every direction.
- Otsego Vault has live-front transformers, live-front non-load-break fuses, exposed live bus bars hanging from the ceiling, no load centers, foam filling cracks in the ceiling, and wires and cables running in every direction.

__Alternative Solutions:__

1. Do nothing. Make civil structure repairs as needed until a major outage occurs from pieces of concrete from the vault roof or walls falling onto energized equipment. This will result in a longer outage time for making any repairs. Given the 2 year metro average outage duration, we estimate outages in this area of the Jackson metro to take 331 minutes (+5 hours) to restore service; compared to current Consumers Energy base line of 210 minutes. Vault outages will also have to occur for new electrical connections to serve new load, since approach distances will not be able to be met. This will result in more expenses for overtime work since most customers will not take an outage during business hours. There is no partial solution to this project because new cables cannot be pulled through a duct system that is failing.
   Estimated Loaded Cost = $0
   Estimated Labor Hours = 0

2. Replace civil infrastructure including new five new precast vaults and seventeen manhole structures in alternative locations and new duct bank with standard 6 inch PVC conduits. This new civil infrastructure will be paired with new electrical infrastructure that would include new metro cables, dead fronting of six vaults. Once the vaults are dead fronted, they can prepped for subsequent primary voltage conversation (4800 Delta to 4800/8320 Wye). This voltage conversation would be necessary to allow additional distributed energy resources (DER) within the downtown district. The new civil system will need to be built while the old systems remain in service to minimize outages and transfer times from the old system to the new system. See picture on last page for an example of a newer vault. Due to the amount of civil and electrical rebuild needed, this work would need to be staged over three years. Below is the year to year conceptual plan of work for this alternative.

   In **2021** civil infrastructure in the street between Blackstone and Jackson Streets would be rebuilt, including six new manholes and removal of old crumbling ducts. In the Methodist Vault, minor electrical components would be installed to gain proper approach distances for the crews and

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

secondary load centers would be installed to make new customer hookups easier, safer, and completed without an outage. Minor electrical work may need to occur in the Fields Vault. No major work is planned for the Jacobson Vault other than connection of new ducts and cables.

In **2022** more civil and electrical infrastructure would be replaced with new in the street between Jackson and Mechanic Streets. The duct banks going north and south from this cooridor are newer and will not need to be replaced, just tied into with new duct. In addition to the duct replacement, eight new manholes and two new vaults would be installed, The City Bank Vault electrical equipment will be largely removed; customers will be reconnected into nearby vaults. The Vermeulens and Mechanic vaults will be replaced entirely with new electrical deadfronting vaults. The new vaults will provide crews the proper clearances needed to perform their work.

In **2023** the final part of this project would consist of replacing old duct within the street between Mechanic and MLK (Francis) Streets, including three new manholes and two new vaults. Installation of new electrical deadfronting vaults to replace Otsego and Cortland, will provide our crews the proper clearances needed to perform their work.
Estimated Loaded Cost =$5,000,000
Estimated Labor Hours = 12,130

Recommended Alternative:
Alternative # 2 is recommended replace our old deteriorating vaults and install equipment to make safe working conditions for our crews. Outage probability will be reduced with the new equipment. This project is also a prerequisite to future conversion of the delta voltage to grounded-wye, which will facilitate DER interconnections, once completed. Finally, this project would also ensure that Consumers Energy gets the civil infrastructure installed before the City of Jackson decides to repave Cortland Street. If this work was completed after the city repaved, Consumers Energy would be responsible for complete restoration of the street which would increase the cost of the project.

Conceptual Estimate:

Program	Notification #	Loaded Cost	Labor Hours	Year	Description
Metro Rehabilitation	1050165426	$1,500,000	3360	2021	Civil and Electrical, Blackstone-Jackson
Metro Rehabilitation	TBD	$2,000,000	4612	2022	Civil and Electrical, Jackson-Mechanic
Metro Rehabilitation	TBD	$1,500,000	4158	2023	Civil and Electrical, Mechanic-Francis
Project Total		$5,000,000	12,130		

Present Need: On approval, this document authorizes the Low Voltage Distribution Metro Planning group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

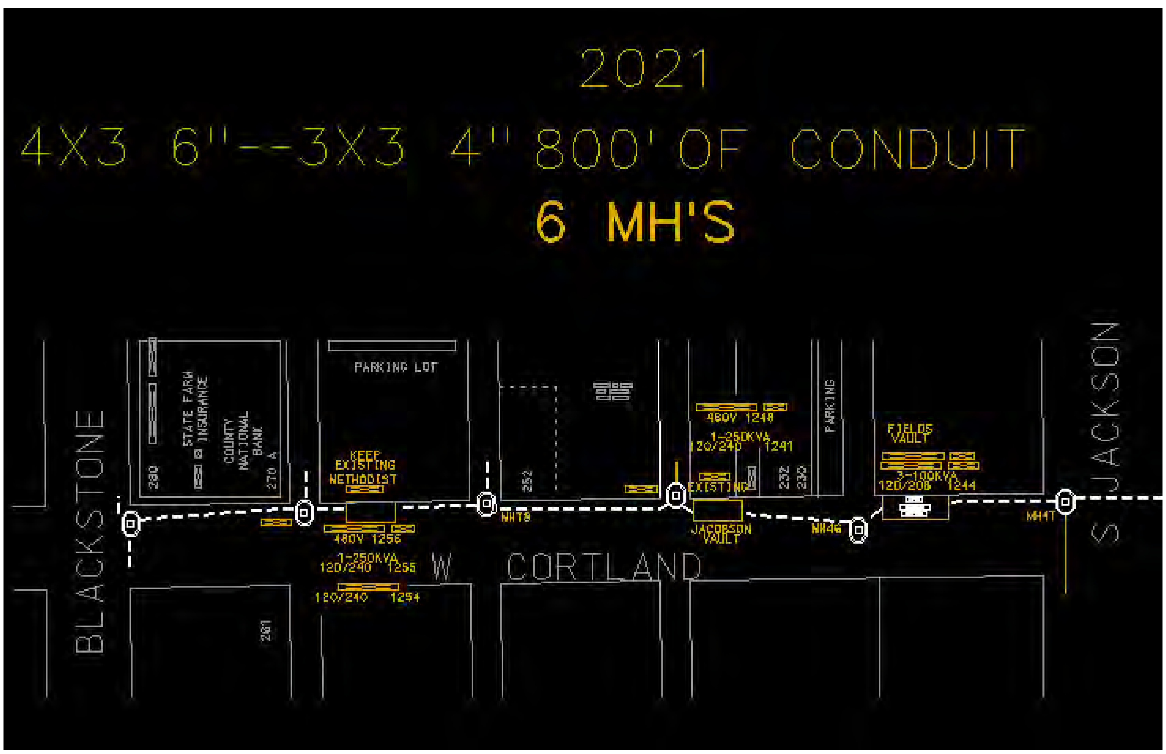
Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Circuit Owner: Phillip P. Ziemba **System Engineer:** JJFloyd

Approvals:

Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required

Attachments



2021 plan for Cortland Street, between Blackstone and Jackson streets. Replacing 6 manholes and duct system, new facilities shown in white lines.

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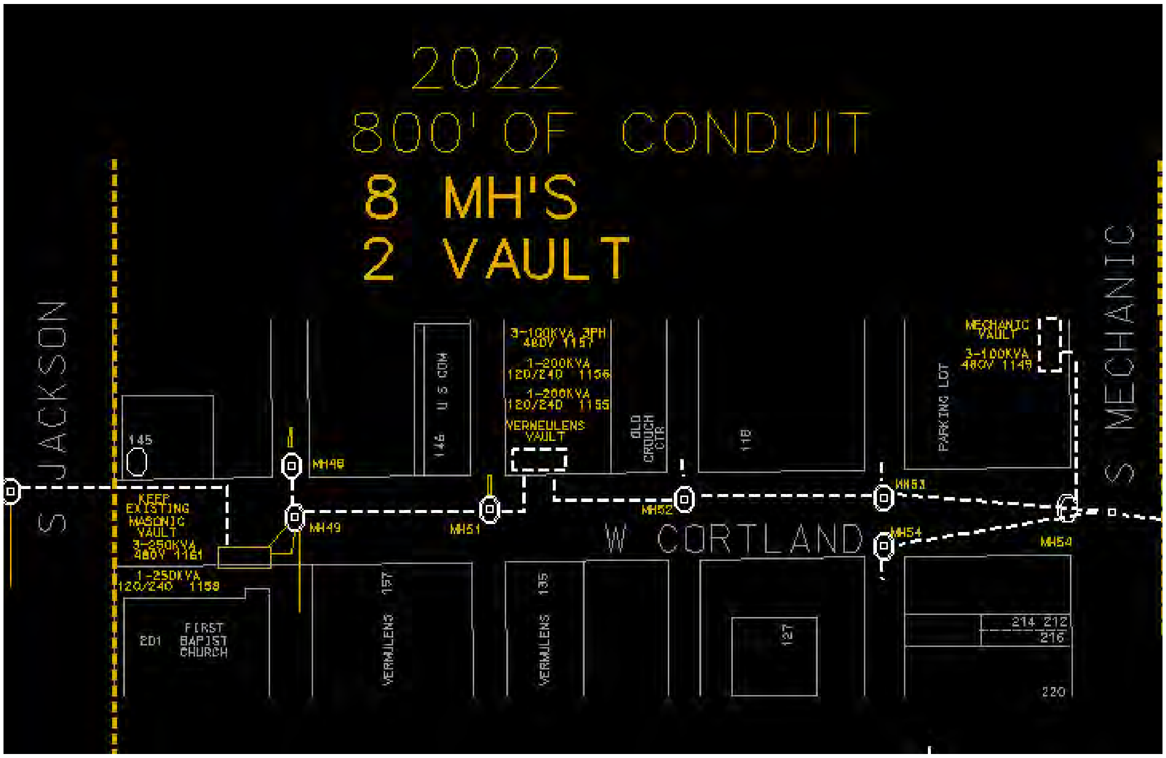
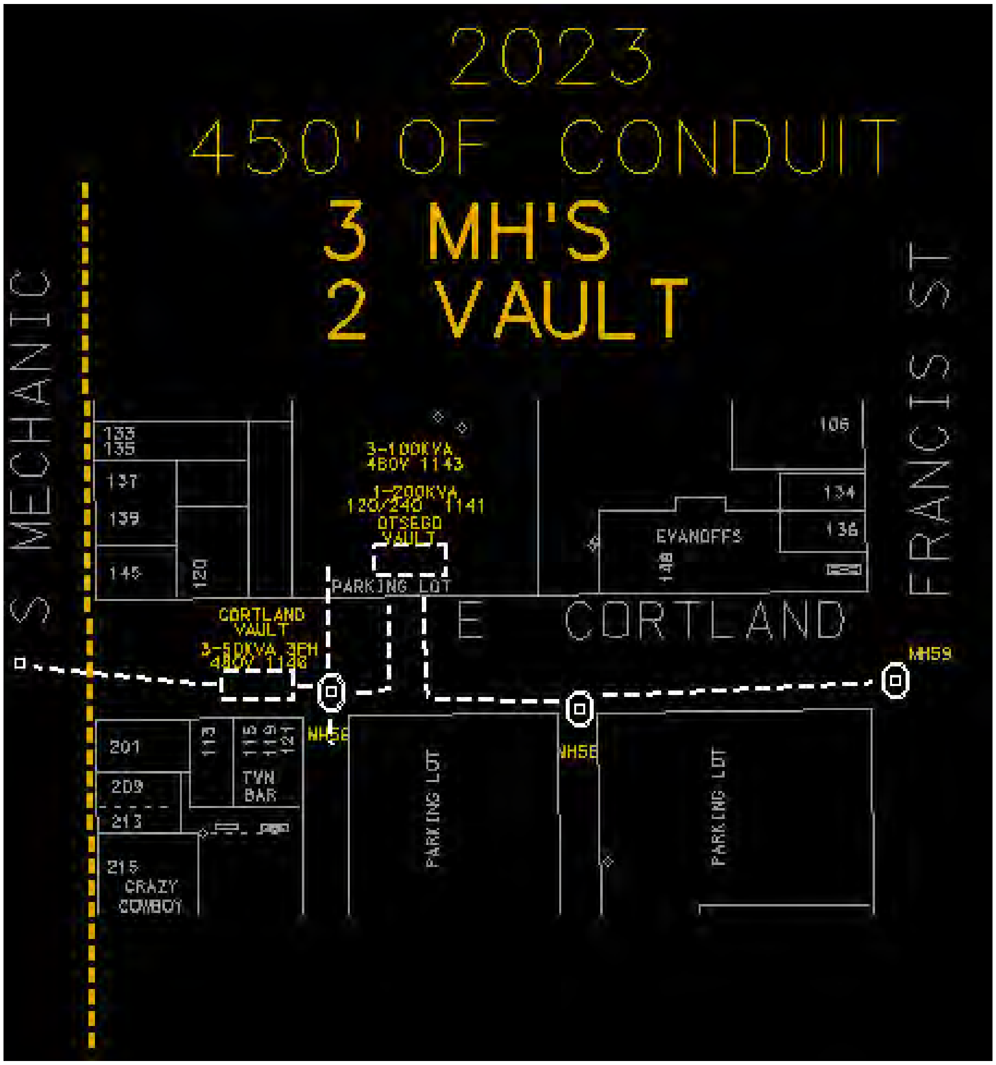
CONCEPT APPROVAL



2022 plan for Cortland Street between Jackson and Mechanic streets. Replacing duct bank, 8 manholes, and 2 vaults, Vermeulens and Mechanic.

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL



2023 plan for Cortland Street between Mechanic and MLK (Francis) streets. Replacing duct bank, 3 manholes, and 2 vaults, Otsego and Cortland.

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Vermeulens Vault with live front transformers and live front facing fuses

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Live front transformers and fuses in Vermeulens vault

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CONCEPT APPROVAL

Mechanic Vault live front lighter transformer

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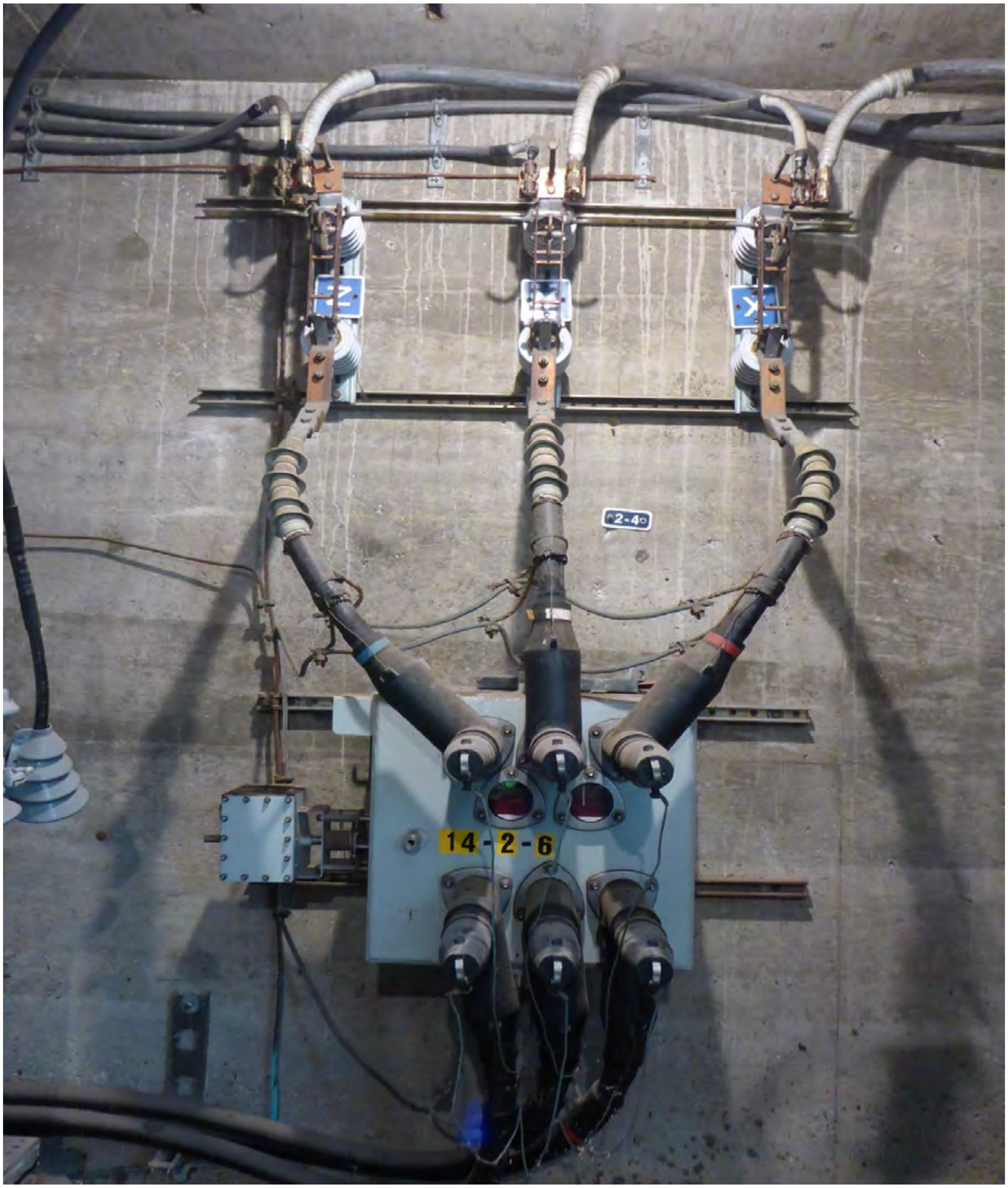
LVD Metro Planning
CONCEPT APPROVAL



Mechanic Vault primary switches with live front primary disconnect switches (labeled X, Y, & Z)

Consumers Energy
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CONCEPT APPROVAL

Cortland Live Secondary Bus Bar hanging from vault ceiling

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Cortland vault leaking transformer

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Cortland Vault with live front transformers and fusing

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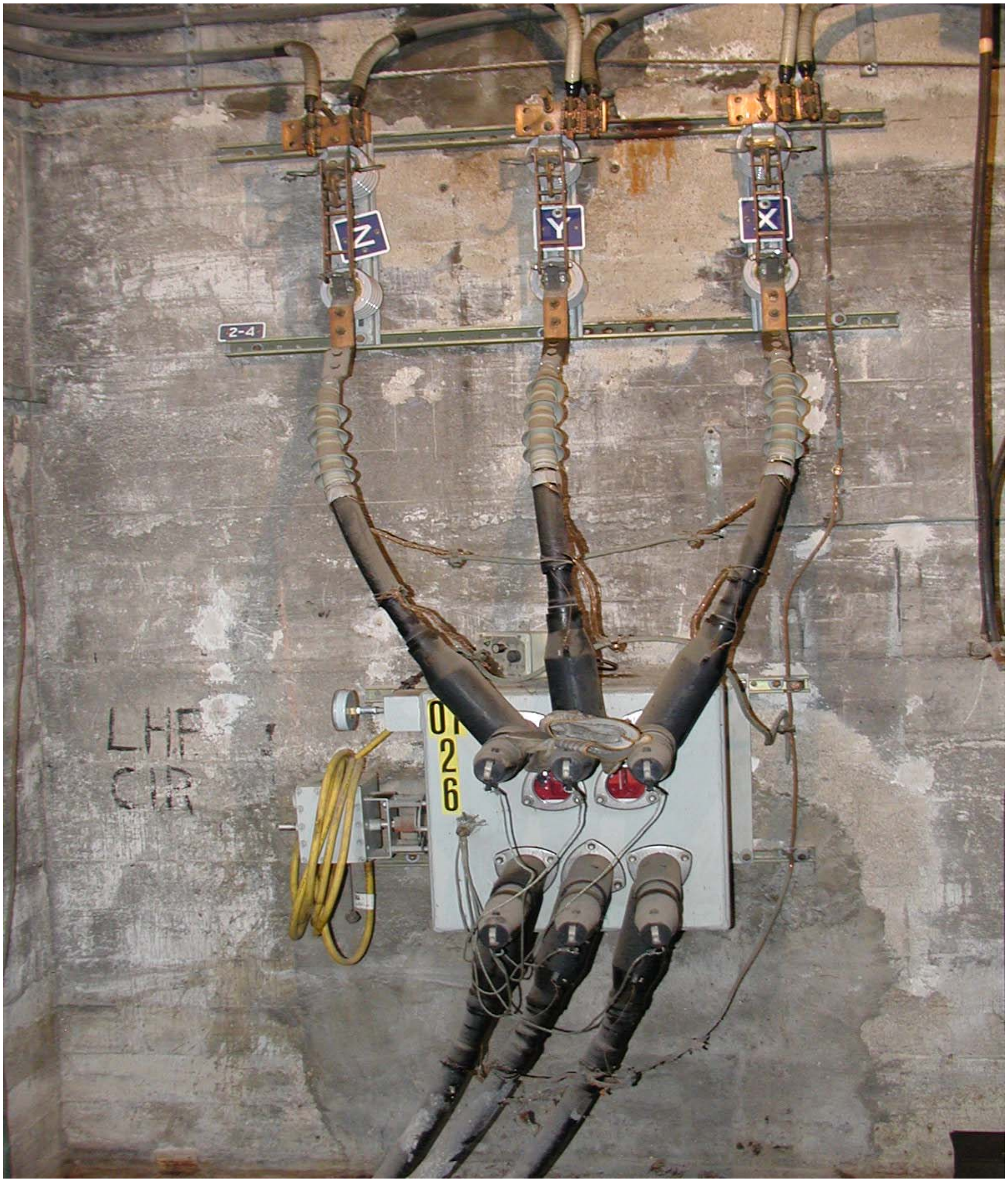
LVD Metro Planning
CONCEPT APPROVAL



Cortland Vault live front primary disconnects for switches (labeled X, Y, & Z)

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Cortland Vault entrance from sidewalk with exposed rebar

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Otsego Vault livefront power and lighter transformers

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Otsego Vault secondary connection bus bar hanging from ceiling next to hole in sidewalk patched by wood and expanding foam

Consumers Energy
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CONCEPT APPROVAL


Otsego Vault showing debris which fell from ceiling

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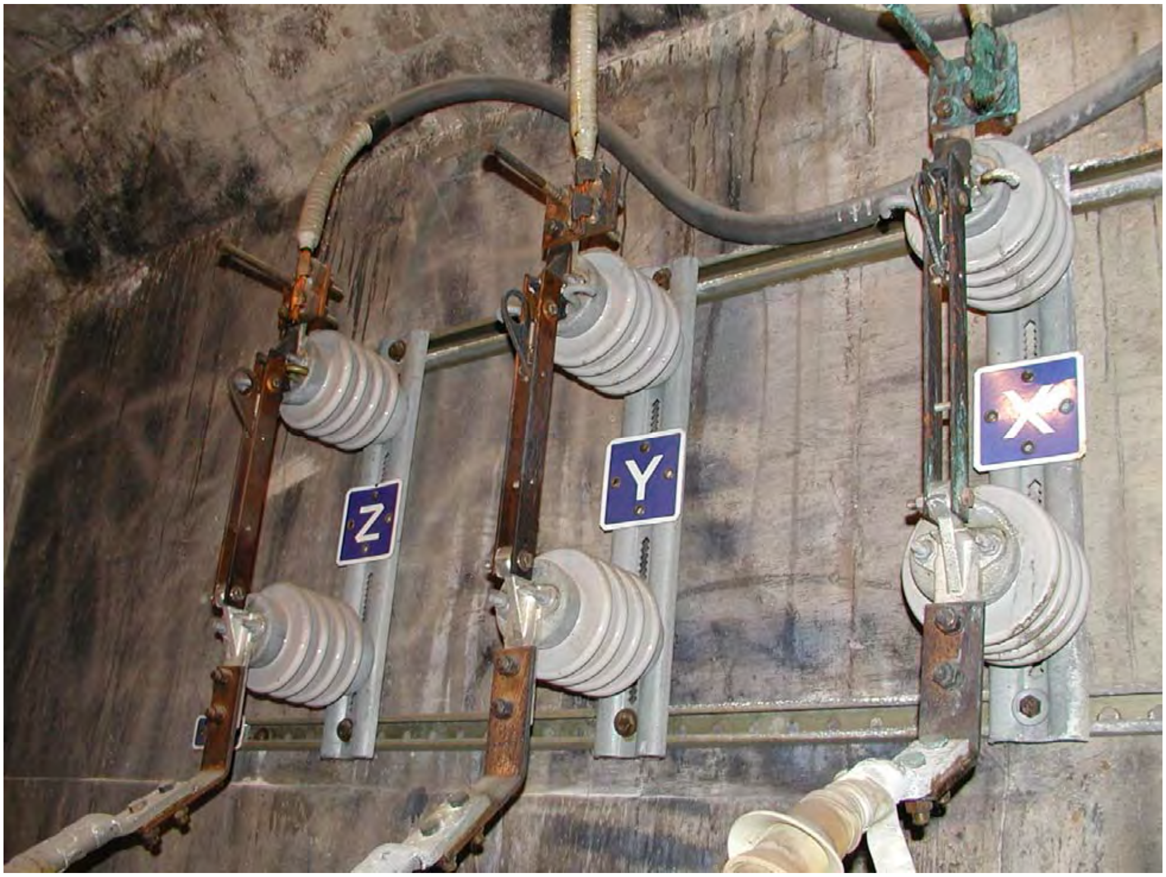
LVD Metro Planning
CONCEPT APPROVAL



Otsego Vault livefront primary disconnects

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

An example of new standard metro electrical equipment, including dead-front transofrmers, dead-front disconnect switches, and SF6 switches, in the Masonic Vault

Metro ▸ Workflow Status: LVD Planning Metro Concept Approval: $5,000,000

Workflow Information

Initiator: Jeffrey J. Floyd
Started: 12/6/2019 1:31 PM
Last run: 12/31/2019 11:44 AM
Item: MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD
Status: Approved

Tasks

The following tasks have been assigned to the participants in this workflow. Click a task to edit it. You can also view these tasks in the list Metro Concept Approval Tasks.

Assigned To	Title	Due Date	Status	Related Content	Outcome
Jeffrey J. Floyd	Please approve MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	12/11/2019	Completed	MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	Approved
DONALD A. LYND	Please approve MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	12/11/2019	Completed	MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	
PHILLIP P. ZIEMBA	A change has been requested on MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	12/11/2019	Completed	MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	Finished by PHILLIP P. ZIEMBA
DONALD A. LYND	Please approve MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	12/11/2019	Completed	MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	Approved
RICHARD T. BLUMENSTOCK	Please approve MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	12/17/2019	Completed	MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	Approved
Timothy J. Sparks	Please approve MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	12/25/2019	Completed	MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	Approved
Jean-Francois Brossoit	Please approve MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	12/27/2019	Completed	MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD	Approved

Workflow History

View workflow reports

The following events have occurred in this workflow.

Date Occurred	Event Type	User ID	Description	Outcome
12/6/2019 1:31 PM	Workflow Initiated	Jeffrey J. Floyd	Approval was started. Participants: Jeffrey J. Floyd;DONALD A. LYND;RICHARD T. BLUMENSTOCK;Timothy J. Sparks;Jean-Francois Brossoit	
12/6/2019 1:31 PM	Task Created	Jeffrey J. Floyd	Task created for Jeffrey J. Floyd. Due by: None	
12/6/2019 1:37 PM	Task Completed	Jeffrey J. Floyd	Task assigned to Jeffrey J. Floyd was approved by Jeffrey J. Floyd. Comments: Approved. This will be a multi-year project/process to rebuild the last 1/3rd of the Jackson metro system. Upon completion we can pursue the long range plans of primary voltag	Approved by Jeffrey J. Floyd
12/6/2019 1:37 PM	Task Created	Jeffrey J. Floyd	Task created for DONALD A. LYND. Due by: None	
12/11/2019 3:28 PM	Task Completed	DONALD A. LYND	DONALD A. LYND has requested a change to the task assigned to DONALD A. LYND. Comments: I made some changes, please review to ensure you agree these. Thanks.	Change Requested of PHILLIP P. ZIEMBA by DONALD A. LYND
12/11/2019 3:28 PM	Task Created	Jeffrey J. Floyd	Task created for PHILLIP P. ZIEMBA. Due by: None	
12/12/2019 9:00 AM	Task Completed	PHILLIP P. ZIEMBA	Task assigned to PHILLIP P. ZIEMBA for a requested change was completed by PHILLIP P. ZIEMBA. Comments: Reviews applied PZ	Finished by PHILLIP P. ZIEMBA
12/12/2019 9:00 AM	Task Created	Jeffrey J. Floyd	Task created for DONALD A. LYND. Due by: None	
12/12/2019 9:25 AM	Task Completed	DONALD A. LYND	Task assigned to DONALD A. LYND was approved by DONALD A. LYND. Comments: Approved. This work will address metro system deficiencies and enable future voltage conversion from delta.	Approved by DONALD A. LYND
12/12/2019 9:25 AM	Task Created	Jeffrey J. Floyd	Task created for RICHARD T. BLUMENSTOCK. Due by: None	
12/20/2019 8:03 AM	Task Completed	RICHARD T. BLUMENSTOCK	Task assigned to RICHARD T. BLUMENSTOCK was approved by RICHARD T. BLUMENSTOCK. Comments: Approved. The concept approval file name is MRELBY20 CORTLAND REBUILD.docx	Approved by RICHARD T. BLUMENSTOCK
12/20/2019 8:03 AM	Task Created	Jeffrey J. Floyd	Task created for Timothy J. Sparks. Due by: None	
12/22/2019 10:32 PM	Task Completed	Timothy J. Sparks	Task assigned to Timothy J. Sparks was approved by Timothy J. Sparks. Comments: Approved.	Approved by Timothy J. Sparks
12/22/2019 10:32 PM	Task Created	Jeffrey J. Floyd	Task created for Jean-Francois Brossoit. Due by: None	
12/31/2019 11:44 AM	Task Completed	Jean-Francois Brossoit	Task assigned to Jean-Francois Brossoit was approved by Jean-Francois Brossoit. Comments:	Approved by Jean-Francois Brossoit
12/31/2019 11:44 AM	Workflow Completed	Jeffrey J. Floyd	Approval was completed.	Approval on MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD has successfully completed. All participants have completed their tasks.

PROJECT: ELEANOR STREET UPGRADES (SAP # TBD)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this project is to improve the underground electric system along Eleanor Street, between Rose Street and Kalamazoo Mall, in downtown Kalamazoo. This area contains a radial direct-bury system amongst other metro circuits and equipment. One of the padmount transformers is also leaking. The project will provide metro underground facilities to replace the direct-bury system, replace the transformers, and provide an alternate feed to the customers in this area to improve reliability.

Concept Approval titled “METRORLBY21 KZO ELEANOR ST UPGRADES” provides additional project details.

ii. Line Design, size material used.

Underground duct bank utilizing standard six inch polyvinyl chloride (PVC) conduits encased in concrete.

iii. Line Length and ROW requirements.

The duct bank replaced will be 800 feet long and constructed in the city street right-of-way via permit.

iv. Approximate Construction Schedule.

Construction Start: March 2022
Construction Complete: October 2022

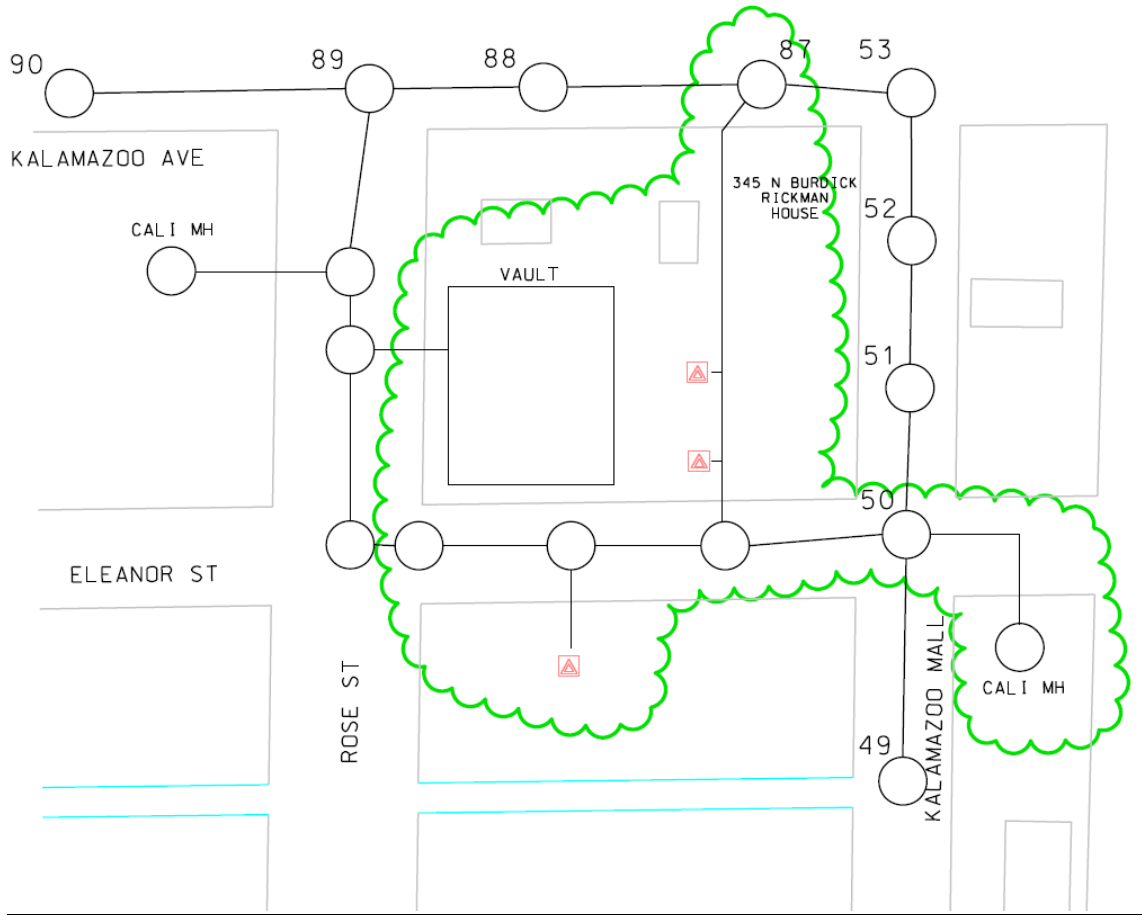
v. Project effect on cost of operation and reliability of service.

The reliability of service will increase with the new equipment. The working conditions will be brought to present metro standards to the benefit of crews.

vi. A description of the property being replaced and salvage value.

Direct bury cable, transformers, switches, cables, and associated equipment are being replaced on along Eleanor Street between Rose Street and Kalamazoo Mall. The vaults and duct banks have zero salvage value. The equipment and cable removed will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See the attached Concept Approval titled "METRORLBY21 KZO ELEANOR ST UPGRADES".

x. Date of board approval.

N/A

MREHAB CORTLAND ST CIVIL & ELECTRIC REBUILD – Attachment 1

CONCEPT APPROVAL No. TBD

METRORLBY21 KZO ELEANOR ST UPGRADES

Concept Document To Be Attached Here

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Notification Concept Number: TBD

Project Title: METRORLBY21 KZO ELEANOR ST UPGRADES **Work HQ:** Kalamazoo

Capital Program: Metro Reliability **EDIIP Investment Category**: Reliability - Other

Date: 1/15/2021 **Proposed Year of System Changes:** 2022

Problem Description:

Eleanor Street between Rose Street and Kalamazoo Mall contains a direct-buried system housing primary voltage in the midst of the metro underground system. The direct-buried system also stretches through an alley from Eleanor Street to Kalamazoo Avenue. Operational responsibilities between Sub-metro Operations and LVD Lines has created confusion in the past as far as which department is responsible for troubleshooting the direct-buried system. We had a problem in 2018 with one of the customers fed out of a three-phase pad-mount transformer TLM 4160 fed out the direct-buried system. Metro Operations was called out to fix the problem because it was determined that LVD Lines wasn't responsible for going into the building where the service point was located. Metro Operations ended up fixing the problem even though service was part of the direct-buried system. This poses a safety risk due to Metro Operations not being familiar with the direct-buried system and the associated electrical equipment, such as the Hybrid PMH-9 gear being used as a junction point that connects to five different pad-mounted transformers.

The Ampersee Substation, Welder Circuit, and the Cooley Substation, Exchange Circuit, are a radial feed to pad-mount transformers which provide power to multiple businesses along the Kalamazoo Mall and Eleanor Street. There are currently 43 customers fed out of the Ampersee Welder Circuit (overhead direct-buried) and 33 customers on the Cooley Exchange circuit (overhead direct-buried). A dig-in poses the highest risk of an outage affecting multiple costumers, with durations depending on the fault location and severity. Given the metro average of 176 CAIDI minutes in Kalamazoo, a dig-in would result in 13,376 customer-outage-minutes.

Due to the exponential growth of the city and new development taking place, dig-ins have been happening more frequently in the past few years. Repairs can take several weeks, depending on how much cable re-conductoring and/or what equipment needs to be replaced, causing a costly extended use of generation to keep the customers' power energized. In order to prevent a long sustained outage, an alternative feed would be needed. Additionally, a leaking pad-mount transformer exists under the parking ramp at 320 North Rose Street.

Alternative Solutions:

1. **ELEANOR ST CIVIL SYSTEM:** Extend the metro system by installing 800 feet of metro conduit including five manholes along Eleanor Street between Rose Street and Kalamazoo Mall including the alley east and parallel to Rose Street from Kalamazoo Avenue to Eleanor Street.
   Estimated Loaded Cost Civil = $2,000,000
   Estimated Labor Hours Civil = 1600

2. **ARCADIA VAULT:** Convert from a storefront transformer enclosure to a fully enclosed ground level metro vault at 320 North Rose Street (Arcadia Vault). The leaking pad-mount transformer (TLM 3150) will be replaced with Metro T-Spec transformers and the PMH switchgear will be removed and converted to standard metro SF6 gas switches. This will give the oportunity to bring three different metro circuits into the new vault, increasing the reliability of the electric system and capability by

being able to transfer between three different circuits, and decreasing the time of restoration.
Estimated Loaded Cost = $250,000
Estimated Labor Hours = 1000

3. **ELEANOR ST ELECTRICAL SYSTEM:** Extend the Cooley Substation Exchange Circuit through the new metro system proposed in Alternative 1, to replace existing direct-buried system along Eleanor Street providing power to all existing transformers fed by the direct-buried Exchange Circuit. This circuit extension will also branch from manhole 50 east in order to provide an alternative feed to the Ampersee Substation, Welder Circuit at existing live-front hybrid PMH-9 Switchgear (LCP 989J). In addition to the reliability benefit of having the conductors in a concrete encased ductbank safe from possible dig-ins, the conversion to metro equipment will clear any operations confusion.
Estimated Loaded Cost = $200,000
Estimated Labor Hours = 1200

4. **Deadfront Equipment Replacement:** Replace existing live-front hybrid PMH-9 switchgear (LCP 989J) with a dead-front PSE-9 switchgear and replace transformer transclosure (TLM 3147) fed from PMH-9 switchgear with dead-front pad-mount transformer.
Estimated Loaded Cost = $50,000
Estimated Labor Hours = 600

5. **Do nothing**. Make repairs as failures occur, accepting the longer restoration times and the higher cost of responding to these failures.
Estimated Loaded Cost = $0
Estimated Labor Hours = 0

<u>Recommended Alternative:</u>

Alternatives #1, 2, 3, and 4 are recommended in order to properly provide reliable power to customers and prevent long sustained outages. These alternatives together address the problems identified. Providing an alternate feed and reducing operations confusion will both contribute to quicker restoration times and increase the safety of the employees. These alternatives are scalable, single scoped, yet interconnected with the long term reliability of this area in mind. It is possible to select the alternatives in a multi-year approach

Consumers Energy
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CONCEPT APPROVAL

Conceptual Estimate:

Program	Investment Category	Notification #	Loaded Cost	Description
Metro Reliability	Obsolete or Needed Civil Assets	TBD	$ 2,000,000	METRORLBY22 KZO ELEANOR ST UPGRADES CIVIL
Metro Reliability	Deadfronting	TBD	$250,000	METRORLBY21 KZO ELEANOR ST UPGRADES ARCADIA VAULT
Metro Reliability	Obsolete or Needed Electrical Assets	TBD	$200,000	METRORLBY21 KZO ELEANOR ST UPGRADES ELECTRICAL
Metro Reliability	Deadfronting	TBD	$50,000	METRORLBY21 KZO ELEANOR ST UPGRADES EQUIPMENT REPLACEMENT
Project Total			$ 2,500,000	

Present Need: On approval, this document authorizes the Low Voltage Distribution Planning group to proceed with the work order design and material acquisition pending receipt of appropriate conceptual budget authorization.

Circuit Owner: Emmanuel J. Cabrejo **System Engineer:** JJFloyd

Approvals:

Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	N/A

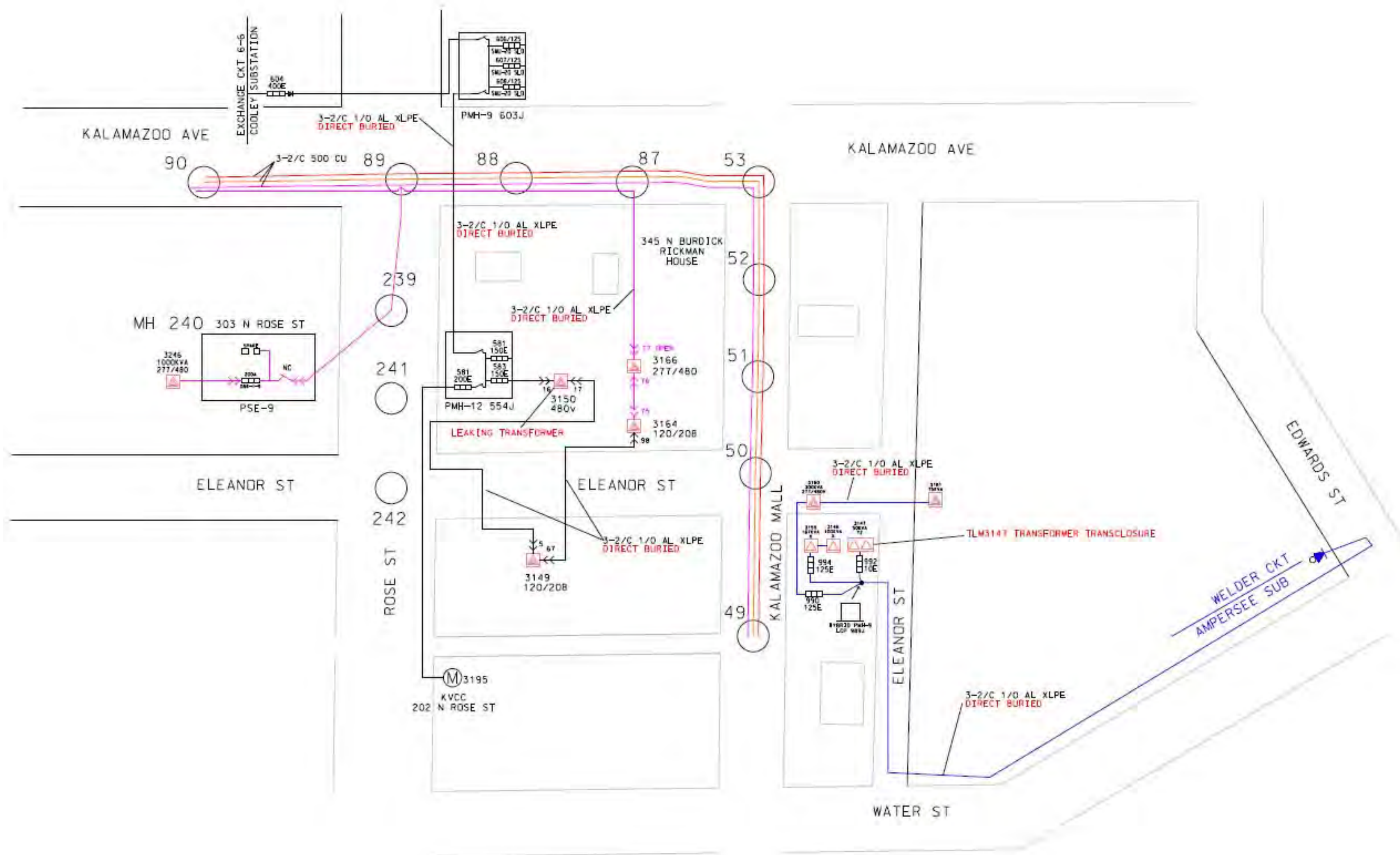
Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

<u>Attachments</u>

Proposed Civil Plan:

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Existing Electrical System:



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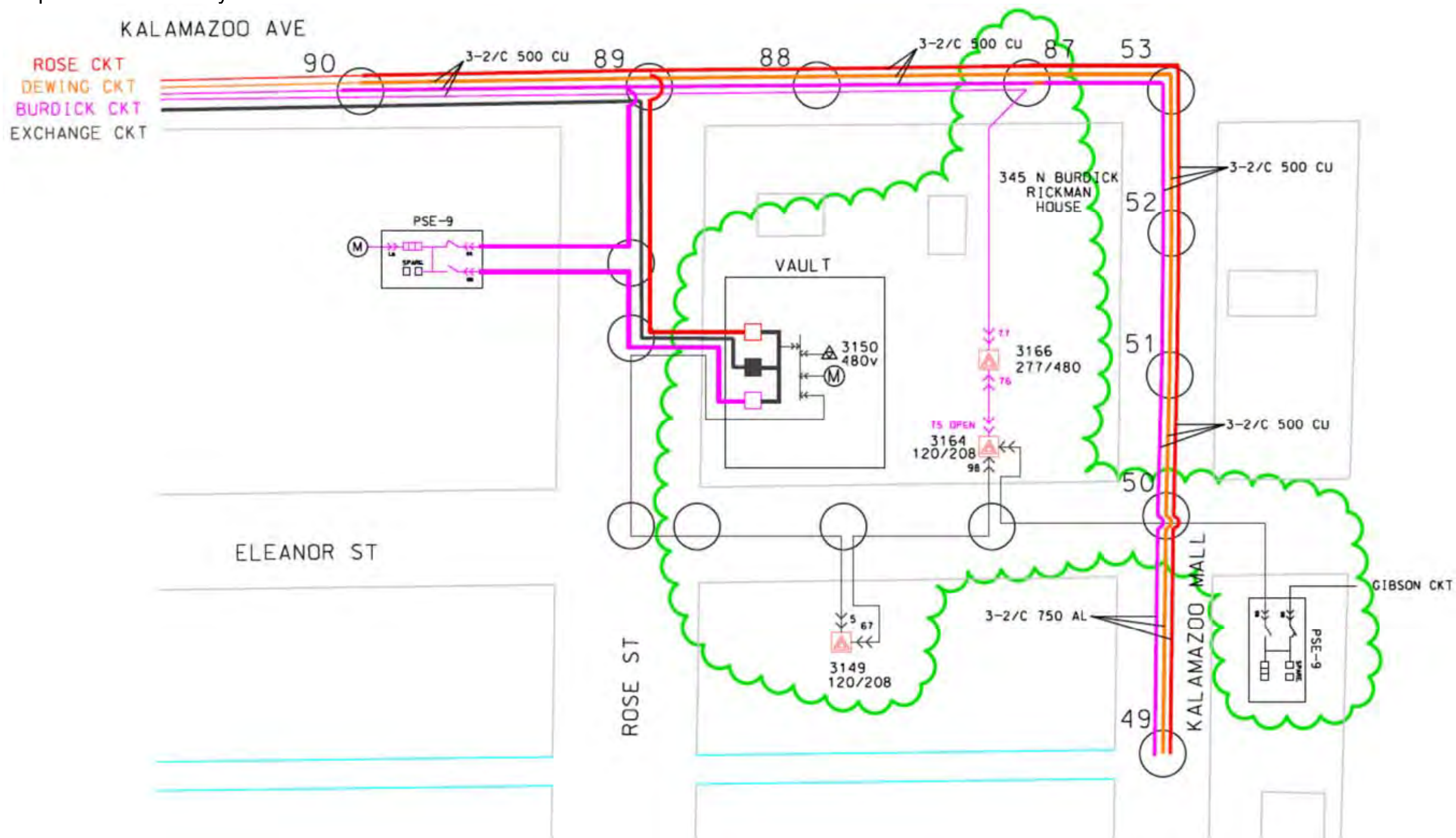
CONCEPT APPROVAL

Proposed Electrical System:



PROJECT: Metro Mobile Vaults

i. Purpose and Necessity of the Project with Supporting Data.

Procure two new "mobile vaults" to facilitate increasing metro vault rebuilds. A mobile vault, much like a mobile substation, will alleviate the need to use temporary generation or other temporary ad-hoc solutions to maintain service to customers during construction projects. Most vault rebuild projects will not have transfer options for all customers. Further, these mobile vaults can also be utilized for emergency restoration or repairs to support quicker restoration following a failure.

Concept Approval titled "METRORLBY 2021 XXX MOBILE VAULT" provides additional project details.

ii. Line Design, size material used.

Not applicable, the mobile vaults will be self-contained units.

iii. Line Length and ROW requirements.

Not applicable, the mobile vaults will be self-contained units.

iv. Approximate Construction Schedule.

The purchase order is anticipated to be submitted to the chosen manufacturer in 2021, with delivery in 2022.

v. Project effect on cost of operation and reliability of service.

Core business function of providing adequate electrical capacity to serve customer electrical load during metro vault rebuild projects, and to restore electrical service following extended vault outages. O&M savings of up to $400,000 per event.

vi. A description of the property being replaced and salvage value.

Not applicable, the mobile vaults will be new units.

vii. Map of site and location of facilities.

Not applicable, the mobile substation will be utilized across all six of the metro underground distribution systems.

viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See the attached Concept Approval titled “METRORLBY 2021 XXX MOBILE VAULT”.

x. Date of board approval.

N/A

Metro Mobile Vaults – Attachment 1

CONCEPT APPROVAL
METRORLBY 2021 XXX MOBILE VAULT

Concept Document To Be Attached Here

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Notification Concept Number: TBD

Project Title: METRORLBY 2021 XXX MOBILE VAULT **Work HQ:** Statewide

Capital Program: Metro Reliability **EDIIP Investment Category**: Reliability - Other

Date: 11/9/2020 **Proposed Year of System Changes:** 2021

Problem Description:

Equipment failures in transformer vaults and planned vault upgrades require extended outages up to several weeks. For example, in August 2019 the Cherry-Sheldon Vault in Grand Rapids experienced a catastrophic failure. There were no transfer options and the vault space had contamination concerns. As a result, temporary generation from an electrical contractor was deployed for several months. The generation required maintenance one hour for every 250 hours of operation. The operations and maintenance expenditure for rental, diesel fuel, and maintenance was approximately $400,000. Furthermore, we received several complaints regarding the noise and required maintenance. Work on Cortland Street in Jackson in 2017 required a temporary installation of above-ground transformers and equipment to accommodate a vault rebuild project. This temporary installation required several days of setup and teardown. Use of these mobile vaults to accommodate construction and unplanned failures is estimated to be three uses per unit per year.

Alternative Solutions:

1. Procure a single “mobile vault” that would be utilized during failures and planned vault upgrades. The unit would have taps for all secondary voltages in use on the metro system. The unit would have the following primary voltages:
    a. 7200V delta
    b. 7200/12470V grounded wye
    c. 4800V delta
    d. 4800/8320V grounded wye

   Estimated Loaded Cost = $1,500,000 (capital)
   Estimated Labor Hours = 0

2. Procure two (2) “mobile vaults” that would be utilized during failures and planned vault upgrades. The units would have taps for all secondary voltages in use on the metro system. Each unit would have the following primary voltages:
    a. Unit #1 (Grand Rapids): 7200V delta & 7200/12470 V grounded-wye
    b. Unit #2 (kept in Marshall/Battle Creek): 4800 V delta & 4800/8320 V grounded-wye

   Estimated Loaded Cost = $2,000,000 (capital)
   Estimated Labor Hours = 0

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

3. Procure three (3) "mobile vaults" that would be utilized during failures and planned vault upgrades. The units would have taps for all secondary voltages in use on the metro system. The units would be deployed to three areas across the state to reduce travel times. Each unit would have the following primary voltages:
    a. Unit #1 (Grand Rapids): 7200V delta & 7200/12470 V grounded-wye
    b. Unit #2 (Marshall/Battle Creek): 4800 V delta & 4800/8320 V grounded-wye
    c. Unit #3 (Flint): 4800 V delta & 4800/8320 V grounded-wye.

    Estimated Loaded Cost = $3,000,000 (capital)
    Estimated Labor Hours = 0

4. Continue to rent temporary generators as needed.

    Estimated Loaded Cost = $12,800/week/vault (O&M), or approximately $500,000/year (O&M)
    Estimated Labor Hours = 0

Recommended Alternative:

Alternative # 2 is recommended over Alternative #4 in that it aligns with our long-term strategy to reduce operations and maintenance expenses. The simple payback is estimated at four years based on current assumptions. Alternative #2 is recommended over alternative #1 in that it allows flexibility to utilize the units in different areas simultaneously. The 2021/2022 workplan for deadfronting vaults include Kalamazoo: Rave Theatre Vault; Battle Creek: Wolverine Vault, Carlyle Vault; Grand Rapids: Square Center Vault; and Flint: E First St Vault. Avoiding the use of diesel-powered temporary generators aligns with the company goal of reducing carbon emissions. Two potential vendors would be Eaton Corporation (MITS Solution), and ABB (Skid Solution).

Conceptual Estimate:

Program	Notification #	Loaded Cost	Description
Metro Reliability	TBD	$ 1,000,000	Procure Mobile Vault #1
Metro Reliability	TBD	$ 1,000,000	Procure Mobile Vault #2
Project Total		$ 2,000,000	

Present Need: On approval, this document authorizes the Low Voltage Distribution Metro Planning group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Circuit Owner: Mark A. Lyons, P.E. **System Engineer:** JJFloyd

Consumers Energy
LVD Metro Planning
CONCEPT APPROVAL

Approvals:

Director, LVD Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	N/A

Attachments

Generator setup at the Cherry-Sheldon Vault

Metro ▸ Workflow Status: LVD Planning Metro Concept Approval: <= $2,000,000

Workflow Information

Initiator: MARK A. LYONS
Started: 11/19/2020 12:17 PM
Last run: 11/23/2020 1:26 PM

Item: METRORLBY 2021 XX MOBILE VAULT
Status: Approved

Tasks

The following tasks have been assigned to the participants in this workflow. Click a task to edit it. You can also view these tasks in the list Metro Concept Approval Tasks.

Assigned To	Title	Due Date	Status	Related Content	Outcome
Jeffrey J. Floyd	Please approve METRORLBY 2021 XX MOBILE VAULT	11/24/2020	Completed	METRORLBY 2021 XX MOBILE VAULT	Approved
DONALD A. LYND	Please approve METRORLBY 2021 XX MOBILE VAULT	11/24/2020	Completed	METRORLBY 2021 XX MOBILE VAULT	Approved
RICHARD T. BLUMENSTOCK	Please approve METRORLBY 2021 XX MOBILE VAULT	11/25/2020	Completed	METRORLBY 2021 XX MOBILE VAULT	Approved

Workflow History

View workflow reports

The following events have occurred in this workflow.

Date Occurred	Event Type	User ID	Description	Outcome
11/19/2020 12:17 PM	Workflow Initiated	MARK A. LYONS	Approval was started. Participants: Jeffrey J. Floyd;DONALD A. LYND;RICHARD T. BLUMENSTOCK	
11/19/2020 12:17 PM	Task Created	MARK A. LYONS	Task created for Jeffrey J. Floyd. Due by: None	
11/19/2020 12:21 PM	Task Completed	Jeffrey J. Floyd	Task assigned to Jeffrey J. Floyd was approved by Jeffrey J. Floyd. Comments: Updated document to reflect changes asked for in 11/3 meeting	Approved by Jeffrey J. Floyd
11/19/2020 12:21 PM	Task Created	MARK A. LYONS	Task created for DONALD A. LYND. Due by: None	
11/20/2020 3:49 PM	Task Completed	DONALD A. LYND	Task assigned to DONALD A. LYND was approved by DONALD A. LYND. Comments: Approved.	Approved by DONALD A. LYND
11/20/2020 3:49 PM	Task Created	MARK A. LYONS	Task created for RICHARD T. BLUMENSTOCK. Due by: None	
11/23/2020 1:25 PM	Task Completed	RICHARD T. BLUMENSTOCK	Task assigned to RICHARD T. BLUMENSTOCK was approved by RICHARD T. BLUMENSTOCK. Comments: Approved.	Approved by RICHARD T. BLUMENSTOCK
11/23/2020 1:26 PM	Workflow Completed	MARK A. LYONS	Approval was completed.	Approval on METRORLBY 2021 XX MOBILE VAULT has successfully completed. All participants have completed their tasks.

PROJECT: LN028C MORRICE CENTER RBLD 5.49 MILES

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve the overall reliability, in particular for the customers served from the Morrice 46 kV Line. There have been 3 outage incidents on the line between 2016 and 2020. Currently this line is non-standard unshielded 115 KCMil copper and 1/0 copper conductor construction. HVD lines that are non-standard construction (unshielded or non-standard conductor), like this section of line, are candidates for a rebuild versus further investment in pole replacements or pole top rehabilitation.

Attached Concept Approval #22-0055 provides additional details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336.4 ACSR conductor and OPGW fiber optic cable shield wire.

iii. Line Length and ROW requirements.

The rebuild is 5.49 miles long and will be built on the existing centerline utilizing existing easements.

iv. Approximate Construction Schedule.

Construction Start: September 15, 2022
Construction Complete: February 28, 2023

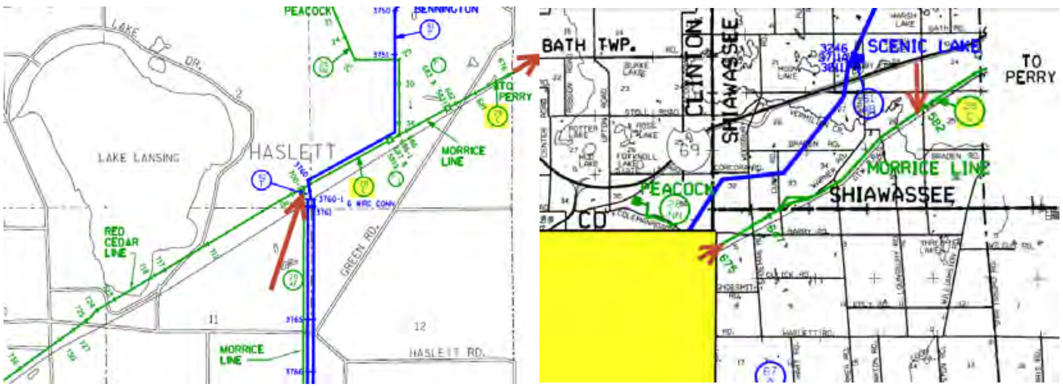
v. Project effect on cost of operation and reliability of service.

The reliability of service will increase with the new configuration. The Morrice 46 kV line experienced 3 outage incidents in this section of line between 2016 and 2020. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor, etc. that were constructed in approximately 1963 are being removed starting at structure #584 to #700-1. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

LVD will fund a small part of the project. There is a small number of structures with LVD on the pole in this section of line.

ix. All studies performed by the Company or 3rd party regarding the project.

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0

Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 22-0055
Morrice 46 kV HVD Lines Reliability Rebuild

Case No. U-20963
Attachment No. 126
Page 213 of 312

BCMazur
DRMeyers
MALabrie
JRFox
ERMathews
DALynd
RTBlumenstock
TJSparks
JFBrossoit

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0055

Project: **Morrice 46 kV Line – HVD Lines Reliability Rebuild** **County:** Shiawassee and Ingham

Date: January 14, 2021 **Need System Changes By:** 2/28/2023

Problem Description:

The Morrice (028C) 46 kV line from structure #584 to #700-1 were installed around 1963. There have been 3 outage incidents in the 5.49-mile section of line between 2016 and 2020. Currently this line is non-standard unshielded 115 KCMil copper and 1/0 copper conductor construction. HVD lines that are non-standard construction (unshielded or non-standard conductor), like this section of line, are candidates for a rebuild versus further investment in pole replacements or pole top rehabilitation.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild 5.49 miles of 028C line. HVD *Conceptual cost: $2,552,850*

Recommended Alternative:

Alternative #2 recommended. Rebuilding the 5.49 miles of 028C line is needed to improve the overall system reliability. Outage data has shown that after completing a rebuild, a line typically has zero or minimal line equipment related outages. A rebuild will also replace the older conductor with modern standards and design.

Alternative #1 does not address the poles, crossarms and insulators on the line that needs to be replaced or the reliability of the system on the line and would result in a continual decrease in reliability.

BCMazur
DRMeyers
MALabrie
JRFox
ERMathews
DALynd
RTBlumenstock
TJSparks
JFBrossoit

Alternative #2 Recommended Scope:

Alternative #2 recommended. Rebuild 5.49-miles of the Morrice 46 kV 028C line from structure #584 to #700-1. Utilize single circuit 336.4 ACRS conductor and OPGW shield wire on the existing or a combination of existing easements and newly obtained easements as needed.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	2023 Direct Cost	2023 Cost with Overheads	Description
EH-95308	$1,098,000	$1,701,900	$549,000	$*850,950*	Rebuild 5.49 miles of the Morrice 46 kV 028C line
Project Total	$1,098,000	$1,701,900	$549,000	$*850,950*	
Customer Contribution	$0	$0	$0	$0	
Total	$1,098,000	$1,701,900	$549,000	$*850,950*	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group and the Low Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: KPBoynton **Team Leader:** Doug Meyers

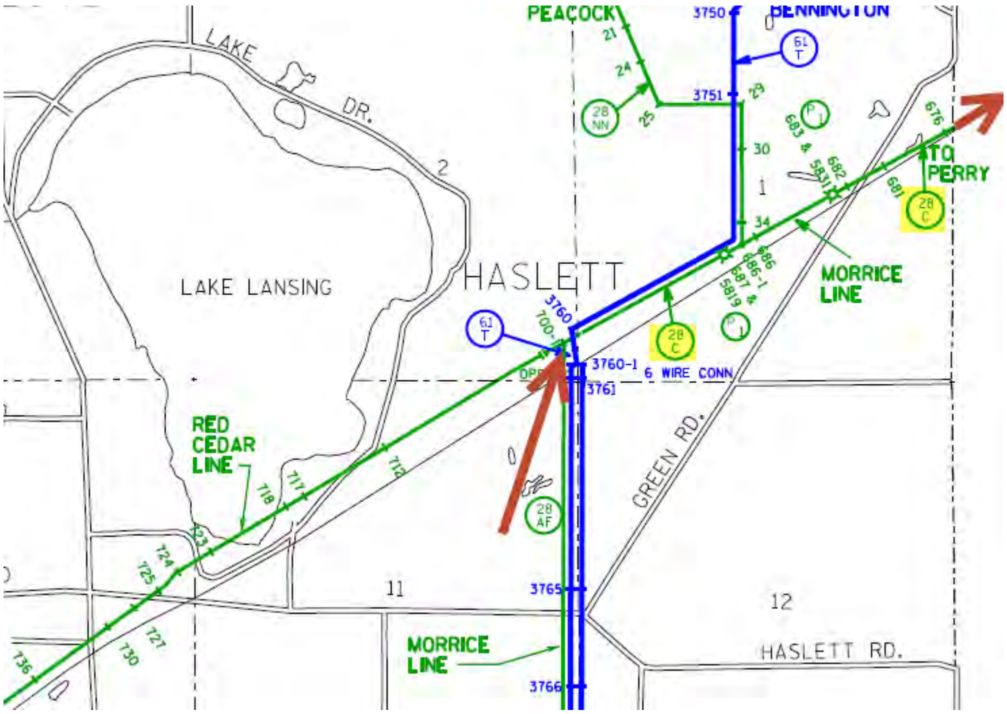
Page 215 of 312

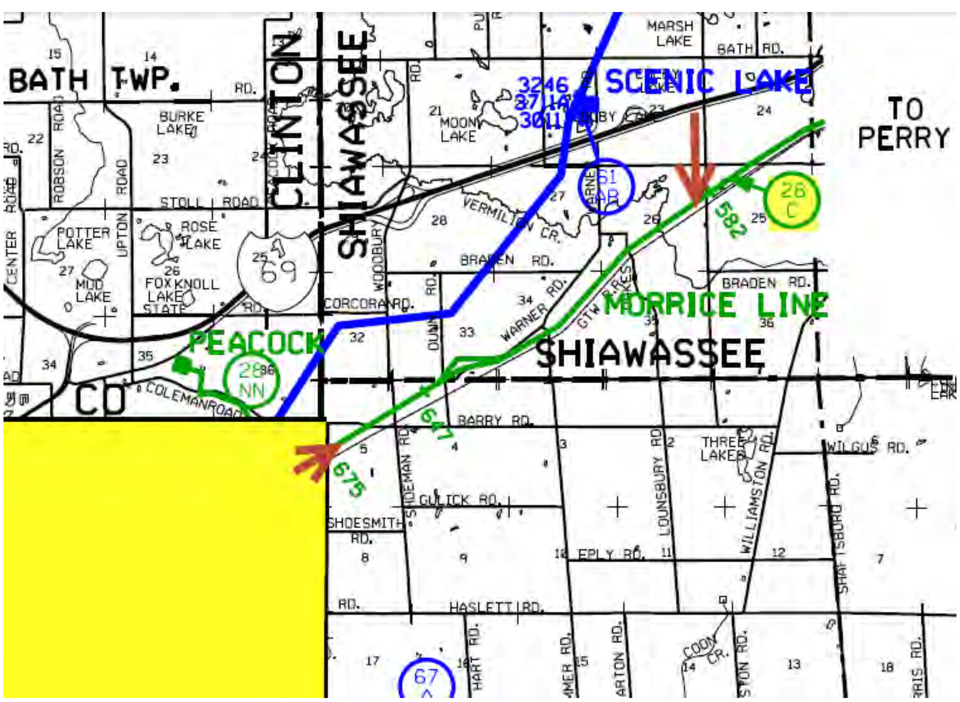
BCMazur
DRMeyers
MALabrie
JRFox
ERMathews
DALynd
RTBlumenstock
TJSparks
JFBrossoit

Approvals:

Electric Reliability & Support Lead	Douglas R Meyers	Required
LVD System Engineer	Michael A Labrie	N/A
Director, LVD Circuit Planning	Julia A Fox	N/A
Director, HVD System Planning	Edward R Mathews	Required
Director, LVD System Planning	Donald A Lynd	N/A
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required

BCMazur
DRMeyers
MALabrie
JRFox
ERMathews
DALynd
RTBlumenstock
TJSparks
JFBrossoit





Page 217 of 312

PROJECT: WD1368 – Replace Broadmoor 138/46 kV Transformer #1 (WO#37974201)

i. Purpose and Necessity of the Project with Supporting Data.

The 60/80/100 MVA #1 transformer at Broadmoor substation is reaching end of life. The transformer has a history of ethane gas production noted in annual dissolved gas analysis tests, suggesting internal heating. The unit has also been a chronic oil and nitrogen leaker, requiring consistent maintenance. The transformer was manufactured by Allis Chalmers in 1973.

The Concept Approval 22-0044 (Attachment 1) which initially identified the need for the Broadmoor Transformer Replacement describes the above.

ii. Line Design, size material used.

Not applicable, substation construction project.

iii. Line Length and ROW requirements.

Not applicable, substation construction project on Consumers Energy owned property.

iv. Approximate Construction Schedule.

Construction Start: February 1, 2022
Construction Complete: May 1, 2022
Equipment Checkout Complete: May 15, 2022

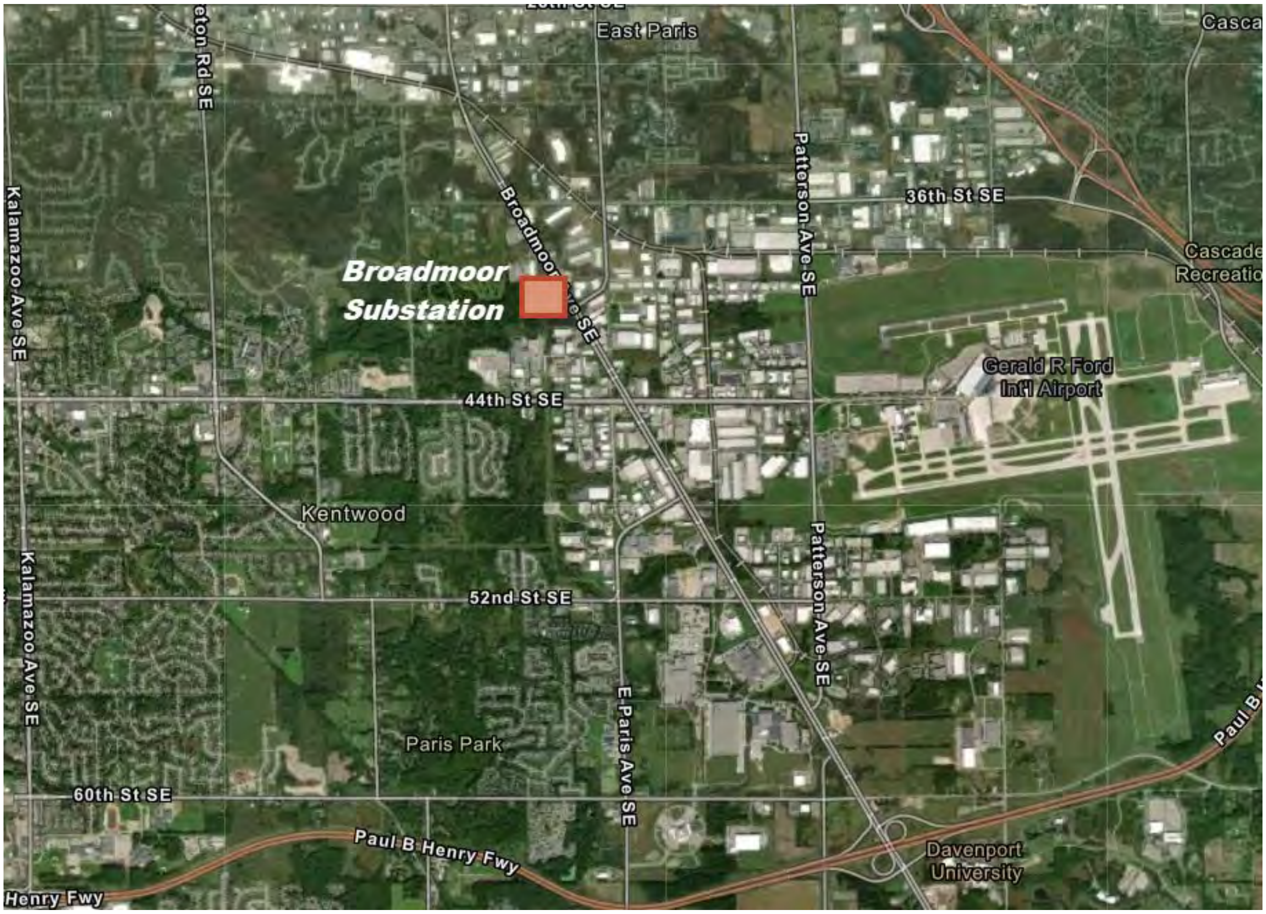
v. Project effect on cost of operation and reliability of service.

Replacing the transformer with new is expected to increase reliability and reduce maintenance costs.

vi. A description of the property being replaced and salvage value.

This project would replace one (1) 138/46 kV transformer. The estimated salvage value is unknown at this time.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See Attachment 1, Concept Approval 22-0044.

x. Date of board approval.

N/A

WD1368 – Replace Broadmoor 138/46 kV Transformer #1 – Attachment 1

CONCEPT APPROVAL No. 22-0044
WD1368 – Replace Broadmoor 138/46 kV Transformer #1

BCMazur
DRMeyers
ERMathews
RTBlumenstock

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0044

Project: **WD1368 – Replace Broadmoor 138/46kV Transformer #1** **County:** Kent

Date: November 30, 2020 **Need System Changes By:** 12/31/2022

Problem Description:

The 60/80/100 MVA #1 transformer at Broadmoor substation is reaching end of life. The transformer has a history of ethane gas production noted in annual dissolved gas analysis tests, suggesting internal heating. The unit has also been a chronic oil and nitrogen leaker, requiring consistent maintenance. The transformer was manufactured by Allis Chalmers in 1973.

Alternative Solutions:

1. Do nothing. Allow transformer to reach end of life and fail resulting in radial feed to multiple substations until bank can be replaced as a demand order. Estimated additional cost to replace unit on an emergency basis: $150K.

2. Replace the Broadmoor #1 transformer bank to ensure reliable service for 50+ years. *Conceptual cost: $1.95M* SAIDI Savings: 0 SAIDI minutes due to looped configuration.

Recommended Alternative:

Alternative #2 is recommended as a long-term solution. Replacing the Broadmoor #5 transformer on a planned basis minimizes the cost and disruption to the system. Alternative 1 is not selected as it could subject the area to significantly reduced reliability for 1-6 months until the transformer can be replaced.

BCMazur
DRMeyers
ERMathews
RTBlumenstock

Conceptual Estimate by WBS:

WBS Element	2022 **Direct Cost**	2022 **Cost with Overheads**	**Description**
EH-95408-1	$1,300,000	$1,950,000	
Choose a WBS	$0	$0	
Choose a WBS	$0	$0	
Project Total	$1,300,000	$1,950,000	
Customer Contribution	$0	$0	
Total	$1,300,000	$1,950,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: Matthew T Wykstra

Approvals:

Sr. Engineer Lead, Electric Reliability & Support	Douglas R. Meyers	
Director, HVD System Planning	Edward R. Mathews	(≤ $100,000)
Executive Director, Electric Planning	Richard T. Blumenstock	(> $100,000 & ≤ $2,000,000)

BRIAN C. MAZUR

From: SPAdvisor
Sent: Saturday, November 28, 2020 11:36 AM
To: BRIAN C. MAZUR
Cc: BRIAN C. MAZUR; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Jacob D. Roberson; Matthew T. Wykstra
Subject: Approval has completed on 22-0044 Broadmoor 138-46kV Transformer 1.

Approval has completed on 22-0044 Broadmoor 138-46kV Transformer 1.

Approval on 22-0044 Broadmoor 138-46kV Transformer 1 has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 11/25/2020 9:04 AM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 11/25/2020 11:35 AM
Comment:

Approved by Edward R. Mathews on 11/27/2020 2:01 PM
Comment: Approved, there

Approved by RICHARD T. BLUMENSTOCK on 11/28/2020 11:36 AM
Comment: Approved.

View the workflow history.

PROJECT: WD0064 – Replace Beecher 138/46 kV Transformer #5 (WO#37974207)

i. Purpose and Necessity of the Project with Supporting Data.

The 60/80/100 MVA #5 transformer at Beecher substation is reaching end of life. The transformer was found with an abnormal heating pattern in an infrared inspection, suggesting that the unit is potentially unstable. It has Westinghouse type O and type OS bushings, which have a high probability of being PCB contaminated. The unit has also been a chronic oil and nitrogen leaker, requiring consistent maintenance. The transformer was manufactured by Westinghouse in 1963, failed in service and was rewound in 1977.

The Concept Approval 22-0043 (Attachment 1) which initially identified the need for the Beecher Transformer Replacement describes the above.

ii. Line Design, size material used.

Not applicable, substation construction project.

iii. Line Length and ROW requirements.

Not applicable, substation construction project on Consumers Energy owned property.

iv. Approximate Construction Schedule.

Construction Start: February 1, 2022
Construction Complete: May 1, 2022
Equipment Checkout Complete: May 15, 2022

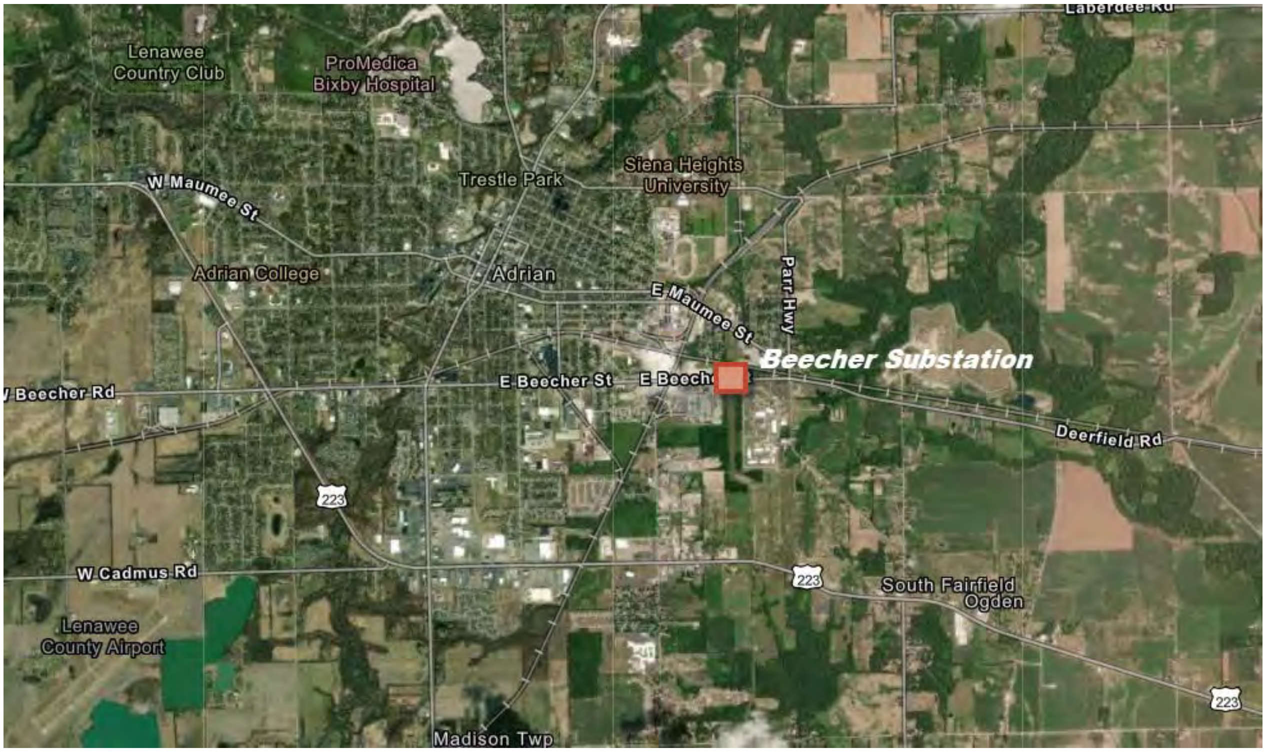
v. Project effect on cost of operation and reliability of service.

Replacing the transformer with new is expected to increase reliability and reduce maintenance costs.

vi. A description of the property being replaced and salvage value.

This project would replace one (1) 138/46 kV transformer. The estimated salvage value is unknown at this time.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

See Attachment 1, Concept Approval 22-0043.

x. Date of board approval.

N/A

WD0064 – Replace Beecher 138/46 kV Transformer #5 – Attachment 1

CONCEPT APPROVAL No. 22-0043
WD0064 – Replace Beecher 138/46 kV Transformer #5

BCMazur
DRMeyers
ERMathews
RTBlumenstock

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0043

Project: **WD0064 – Replace Beecher 138/46kV Transformer #5** **County:** Lenawee

Date: November 30, 2020 **Need System Changes By:** 12/31/2022

Problem Description:

The 60/80/100 MVA #5 transformer at Beecher substation is reaching end of life. The transformer was found with an abnormal heating pattern in an infrared inspection, suggesting that the unit is potentially unstable. It has Westinghouse type O and type OS bushings, which have a high probability of being PCB contaminated. The unit has also been a chronic oil and nitrogen leaker, requiring consistent maintenance. The transformer was manufactured by Westinghouse in 1963, failed in service and was rewound in 1977.

Alternative Solutions:

1. Do nothing. Allow transformer to reach end of life and fail resulting in radial feed to multiple substations until bank can be replaced as a demand order. Estimated additional cost to replace unit on an emergency basis: $150K, or more if PCB cleanup is required.

2. Replace the Beecher #5 transformer bank to ensure reliable service for 50+ years. *Conceptual cost: $1.95M* SAIDI Savings: 0 SAIDI minutes due to looped configuration.

Recommended Alternative:

Alternative #2 is recommended as a long-term solution. Replacing the Beecher #5 transformer on a planned basis minimizes the cost and disruption to the system. Alternative 1 is not selected as it could subject the area to significantly reduced reliability for 1-6 months until the transformer can be replaced.

BCMazur
DRMeyers
ERMathews
RTBlumenstock

Conceptual Estimate by WBS:

WBS Element	2022 **Direct Cost**	2022 **Cost with Overheads**	**Description**
EH-95408-1	$1,300,000	$1,950,000	
Choose a WBS	$0	$0	
Choose a WBS	$0	$0	
Project Total	$1,300,000	$1,950,000	
Customer Contribution	$0	$0	
Total	$1,300,000	$1,950,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: Matthew T Wykstra

Approvals:

Sr. Engineer Lead, Electric Reliability & Support	Douglas R. Meyers	
Director, HVD System Planning	Edward R. Mathews	(≤ $100,000)
Executive Director, Electric Planning	Richard T. Blumenstock	(> $100,000 & ≤ $2,000,000)

BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Saturday, November 28, 2020 11:35 AM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Jacob D. Roberson; Matthew T. Wykstra
Subject:	Approval has completed on 22-0043 Beecher 138-46kV Transformer 5.

Approval has completed on 22-0043 Beecher 138-46kV Transformer 5.

Approval on 22-0043 Beecher 138-46kV Transformer 5 has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 11/24/2020 4:51 PM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 11/25/2020 8:25 AM
Comment:

Approved by Edward R. Mathews on 11/27/2020 2:09 PM
Comment: approved, sent to minor corrections to Matt to fix before posting as final

Approved by RICHARD T. BLUMENSTOCK on 11/28/2020 11:35 AM
Comment: Approved.

View the workflow history.

PROJECT: DARE - SUB LINCOLN/LOST LAKE (#1041345703)

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this LVD project is to transfer the LVD circuits from the existing Lincoln Substation to the new Lincoln Substation.

Lincoln Substation is planned to be replaced as described and approved in concept approval 18-0025. The existing Lincoln Substation is 11 kV delta surrounded by 14.4/24.9 kV wye grounded. The proposed substation will be 14.4/24.9 kV, which requires the LVD circuits to be converted from an 11 kV delta supply to 14.4/24.9 kV.

ii. Line Design, size material used.

This project is primarily single circuit wood pole design with conductor sizes ranging from 4 ACSR to 3/0 ACSR, in accordance with the projected load to be served. The project includes a section of double circuit 3/0 ACSR wood pole design.

iii. Line Length and ROW requirements.

The project includes a 3 mile section of double circuit and a total of 5 miles of voltage conversion from 11 kV Delta to 14.4/24.9 kV wye. Easements have been reviewed and additional rights are not anticipated.

iv. Approximate Construction Schedule.

Construction Start: July 1st, 2022
Construction Complete: September 30, 2022

v. Project effect on cost of operation and reliability of service.

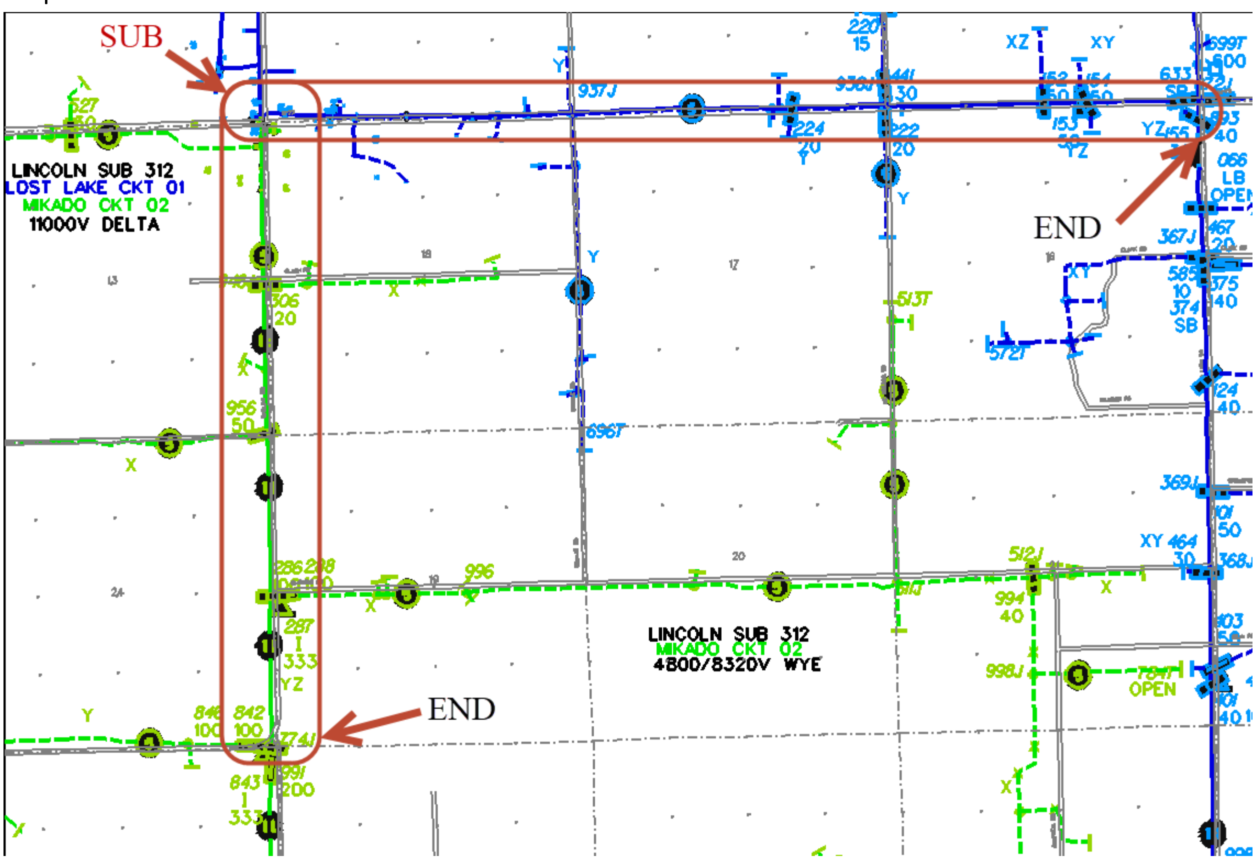
The reliability of the distribution system will increase due to the equipment replacement associated with the double circuit build and the voltage conversion. Equipment replacements will include poles, crossarms, pins, insulator, and transformers.

Additionally, the 11 kV delta voltage is non-standard and poses a wiredown safety risk. Delta systems require two phase-ground faults to be present before the phase protective device operates/trips, which means a downed delta wire will not trip a primary protective device until a second phase fault develops. This project will reduce the amount of system operated at a non-standard delta voltage.

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, pins, insulators, and transformers are being replaced. The wood poles, crossarms and porcelain insulators have zero salvage value. The conductor will be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

Case No. U-20963
Attachment No. 126
Page 229 of 312

ix. All studies performed by the Company or 3rd party regarding the project.

Table IX: Initial Circuit Miles

Column1	Circuit Name	Circuit Miles
Initial Configuration	Lincoln - Lost Lake	91.23
	Lincoln - Mikado	105.43
	Greenbush - Harrisville	26.71
	Greenbush - Greenbush	35.85
	Cedar Lake - Kings Corner	60.29
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	104.1
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Table X: Alternative 3 2026 Configuration Circuit Miles

Column1	Circuit Name	Circuit Miles
Alternative 3	Lincoln - Circuit 1	41.99
	Lincoln - Circuit 2	67.38
	Lincoln - Circuit 3	46.04
	Lincoln - Circuit 4	87.99
	Cedar Lake - Kings Corner	77.80
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	104.1
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Transformer Loading

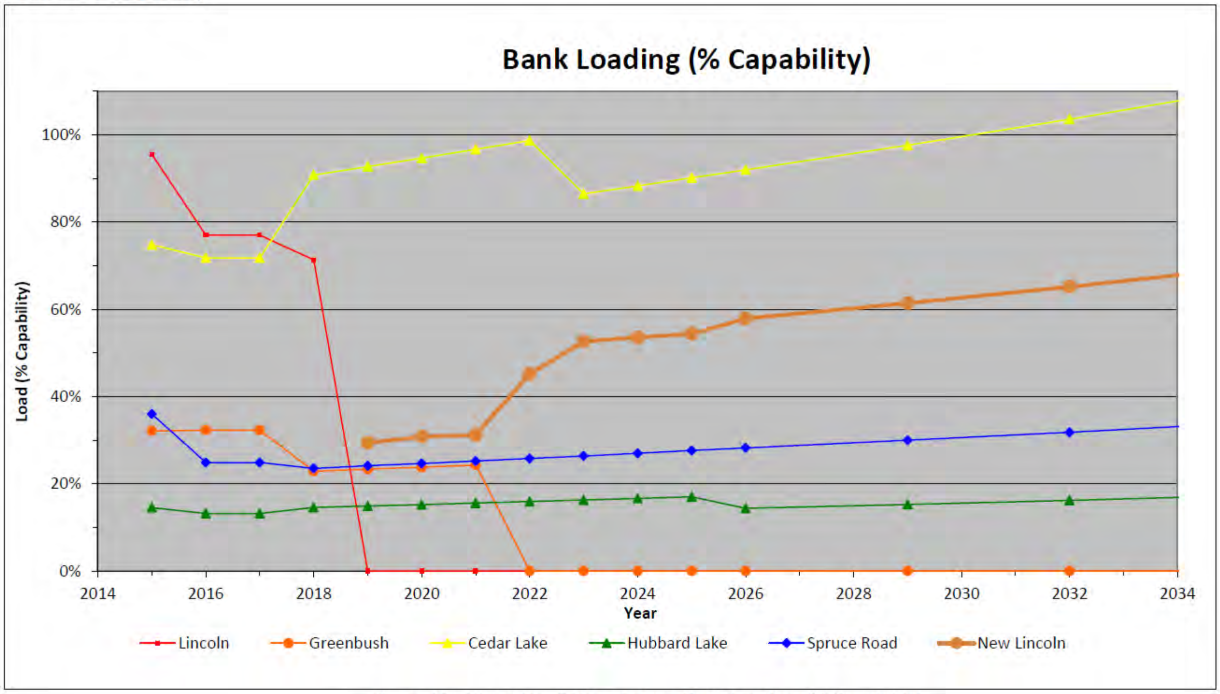


Figure 15: Alternative 3 Transformer Bank Loading (% Capability)

The company completed the Lincoln-Greenbush Long Range Plan which guided selection of this project.
The company previously completed Concept Approval No. 18-0025, Lincoln Greenbush Long Range Plan: Lincoln Rebuild.

x. Date of board approval.
N/A

Concept Approval No. 1041345703 DARE-SUB LINCOLN/LOST LAKE

Concept Approval No. 18-0025, Lincoln Greenbush Long Range Plan: Lincoln Rebuild.

Consumers Energy
LVD Planning
CONCEPT APPROVAL

Notification Concept Number: 1041345703

Project Title: DARE Lincoln Greenbush Long Range Plan: LVD **Work HQ:** Tawas

Date: December 7, 2020 **Proposed Year of System Changes:** 2021

Problem Description:

Lincoln Substation is planned to be replaced as described and approved in concept approval 18-0025 Lincoln Greenbush Long Range Plan: Lincoln Rebuild. This plan is further described, including alternatives not selected, in the Lincoln-Greenbush Long Range Plan. The existing Lincoln Substation is 11 kV delta surrounded by 14.4/24.9 kV wye grounded. The proposed substation will be 14.4/24.9 kV. In order to transfer the LVD circuits from the existing Lincoln Substation to the new Lincoln Substation, work is required on the LVD circuits to convert from an 11 kV delta supply to 14.4/24.9 kV.

Additionally, both Lincoln and Greenbush are served by approximately 11.2 miles of a poor performing, aged, and non-standard construction radial 46kV line, negatively impacting their reliability. The 46 kV outages and distribution outages continually place Greenbush Substation in the bottom 10% of circuits based on reliability performance.

Finally, the 11 kV delta voltage is non-standard and poses a wiredown safety risk. Delta systems require two phase-ground faults to be present before the phase protective device operates/trips, which means a downed delta wire will not trip a primary protective device until a second phase fault develops.

Alternative Solutions:

1. Lincoln Substation is being rebuilt in place with a 10 MVA 138 kV-14.4/24.9 kV transformer with four LVD circuits. This new substation can also retire Greenbush Substation. Below are the details of the work required to convert the voltage from 11 kV delta to 14.4/24.9 kV wye.

    - Lincoln Substation, Mikado Circuit: Convert the voltage 5 miles downstream south of the substation to LCP 790 from 11 kV delta to 14.4/24.9 kV wye. Change all isolators from 11 kV delta/4.8 kV wye to 14.4 kV wye/4.8 kV wye. Transfer downstream of LCP 959 to Cedar Lake Substation, Kings Corner Circuit. The voltage in this area is the same therefore no voltage conversion is necessary. Transfer the converted circuit to the new circuit exit #4.

Consumers Energy
LVD Planning
CONCEPT APPROVAL

- Lincoln Substation, Lost Lake Circuit: Convert the voltage for 9 miles downstream of LCP 639 and transfer to Hubbard Lake Substation, Miller Road Circuit. Install isolators north of the Lincoln Substation at LCP 633. This will be circuit #3 of the new substation. Build a double circuit 3/0 ACSR line east of the Lincoln Substation for 3 miles. Convert the voltage along the three miles from 11 kV delta to 14.4/24.9 kV wye and from 4.8/8.32 kV wye to 14.4/24.9 kV wye. This will be circuits #1 and #2 of the new substation. Circuit #1 will be the top gain and circuit #2 will be bottom gain.

- Greenbush Substation, Harrisville Circuit: Convert 5 miles from Greenbush Substation to LCP 066 from 11 kV delta to 14.4/24.9 kV wye. Install a 14.4 kV wye/11 kV delta isolator east of LCP 375. Once voltage is converted, transfer Greenbush Substation, Harrisville Circuit, to the new substation, Circuit #2.

- Greenbush Substation, Greenbush Circuit: Convert the voltage of all 14 miles of 11 kV delta sections on Greenbush Substation, Greenbush Circuit, from 11 kV delta to 14.4/24.9 kV wye. Replace all 11 kV delta/4.8 kV wye isolators with 14.4 kV wye/4.8 kV wye isolators. Once voltage is converted, transfer Greenbush Substation, Greenbush Circuit, to the new substation, circuit #2. The Greenbush Substation can then be decommissioned. By converting to 14.4/24.9 kV, automation loops with surrounding 14.4/24.9 kV substations will now be possible.

Estimated Design Hours = 11,160
Estimated Loaded Cost = $5,729,800

2. This is the same as Alternative #1 except there will be only three LVD circuits fed by the new substation. This would eliminate the need for double circuit construction east of Lincoln Substation. However, this alternative will have longer circuits due to having only three LVD circuits instead of four.
   Estimated Design Hours = 9,688
   Estimated Loaded Cost = $4,973,800

Recommended Alternative:
Alternative # 1 is recommended. Alternative #1 is preferable to Alternative #2 because the distribution area would be divided between four circuits instead of three. Alternative #2 in the final configuration has a circuit that is about 130 miles long. This is a high circuit length that would have a negative impact on reliability due to the increased line exposure in heavily wooded areas. It will also create longer service restoration times due to the length of the circuit that would need be investigated. Another major benefit of Alternative #1 is the possibility for automation loops once all the voltage is converted at the end of the approved Lincoln – Greenbush Long Range Plan. Three automation loops are possible and would keep the towns of Greenbush, Lincoln, and Harrisville online in the event of a circuit lockout. This would reduce outage times, especially considering the remote location of the study area. Alternative #2 only has the possibility of two automation loops. In addition, Alternative #1 provides increased load capacity for future growth in the area and achieves a company objective of reducing the amount of circuit miles operating delta and replaces it with a standard voltage. The City of Harrisville has recently approved growing

recreational and medical marijuana. Alternative #1 will put Consumers Energy in a better position to provide capacity to this new industry.

Conceptual Estimate:

Program	Loaded Cost	Plan year	Description
LVD Capacity	$1,190,700	2021	• Convert the voltage at Lincoln/Lost Lake LCP 639, transfer to Hubbard Lake/Miller Rd. • Convert Greenbush/Greenbush LCP 503J; transfer to Cedar Lake/Kings Corner. • Transfer Lincoln/Mikado LCP 959 to Cedar Lake/Kings Corner
LVD Capacity	$1,895,900	2022	• Build 3 miles of three phase double circuit east of Lincoln Substation. • Convert the voltage 3 miles east of the substation along path of double circuit • Install isolators just north of Lincoln Substation. • Transfer circuit 2 (formerly Lost Lake) downstream of LCP 902 on to Spruce Road Substation Black River Circuit • Convert the voltage on the Mikado Circuit from Lincoln Substation 2 miles south to LCP 991
LVD Capacity	$928,300	2023	• Convert circuit #4 (formerly Mikado) from LCP 991 to LCP 790
LVD Capacity	$524,100	2024	• Convert the voltage on Greenbush/Greenbush from Greenbush Substation to LCP 544, transfer to new circuit #4, and decommission Greenbush/Greenbush • Transfer Greenbush/Harrisonville on to circuit #2. Install isolators at LCP 374 and LCP 375, and decommission Greenbush/Harrisville circuit
LVD Capacity	$1,190,800	2025	• Convert the voltage at new circuit #2 from LCP 374 to Greenbush Substation • Transfer new circuit #4 from LCP 544 on to circuit #2 • Transfer Cedar lake downstream of LCP 522 back to Circuit #2
Project Total	$5,729,800		

Present Need: On approval, this document authorizes the Low Voltage Distribution Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Circuit Owner: Amy P Merrick **System Engineer:** JLBirchmeier

Consumers Energy
LVD Planning
CONCEPT APPROVAL

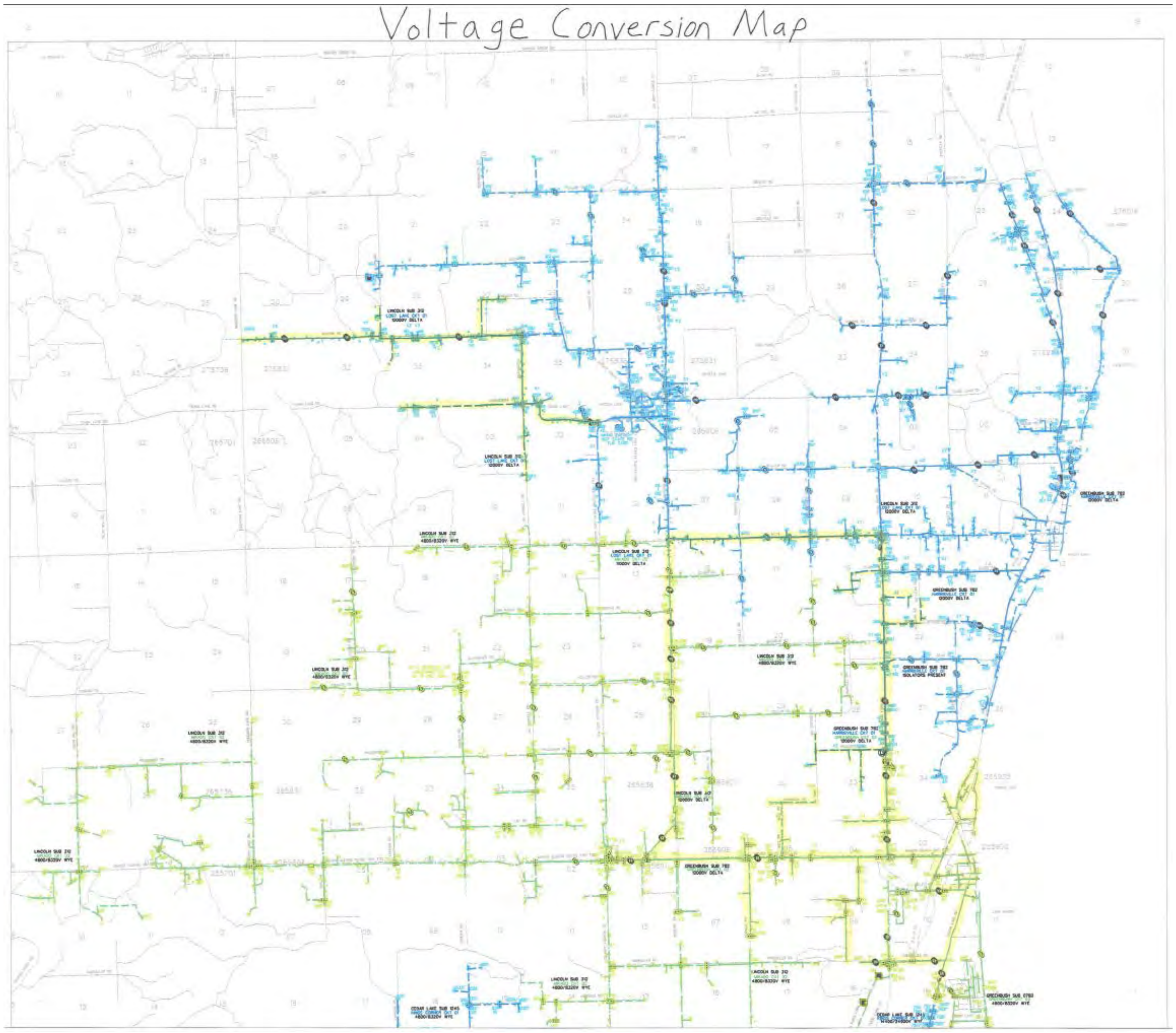
Approvals:

Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required
President and Chief Executive Office – CMS Energy	Patricia K. Poppe	Required

Consumers Energy
LVD Planning
CONCEPT APPROVAL

Scope Map:

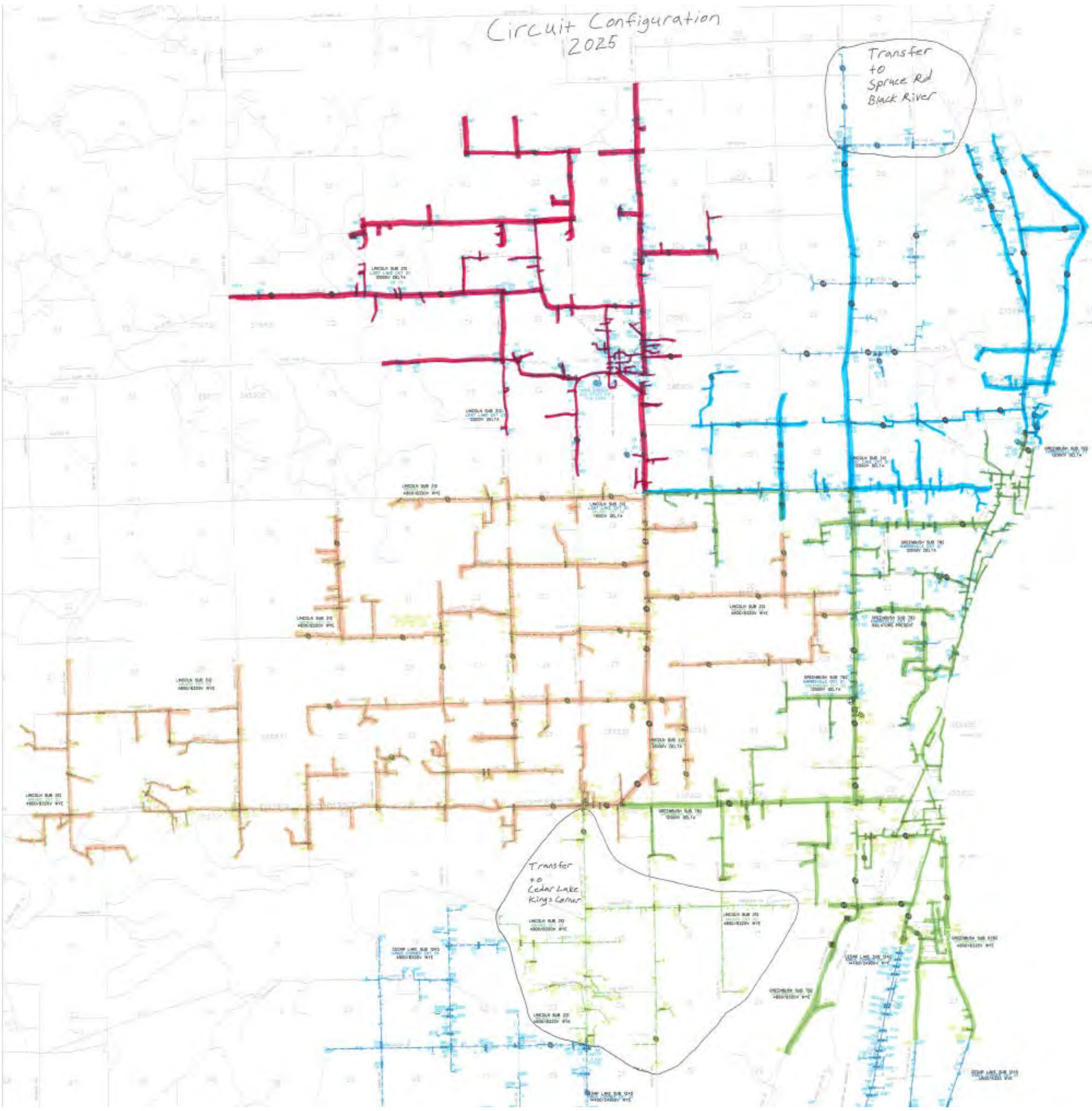
Areas the voltage will be converted on Lincoln and Greenbush Substations are highlighted:



Consumers Energy
LVD Planning
CONCEPT APPROVAL

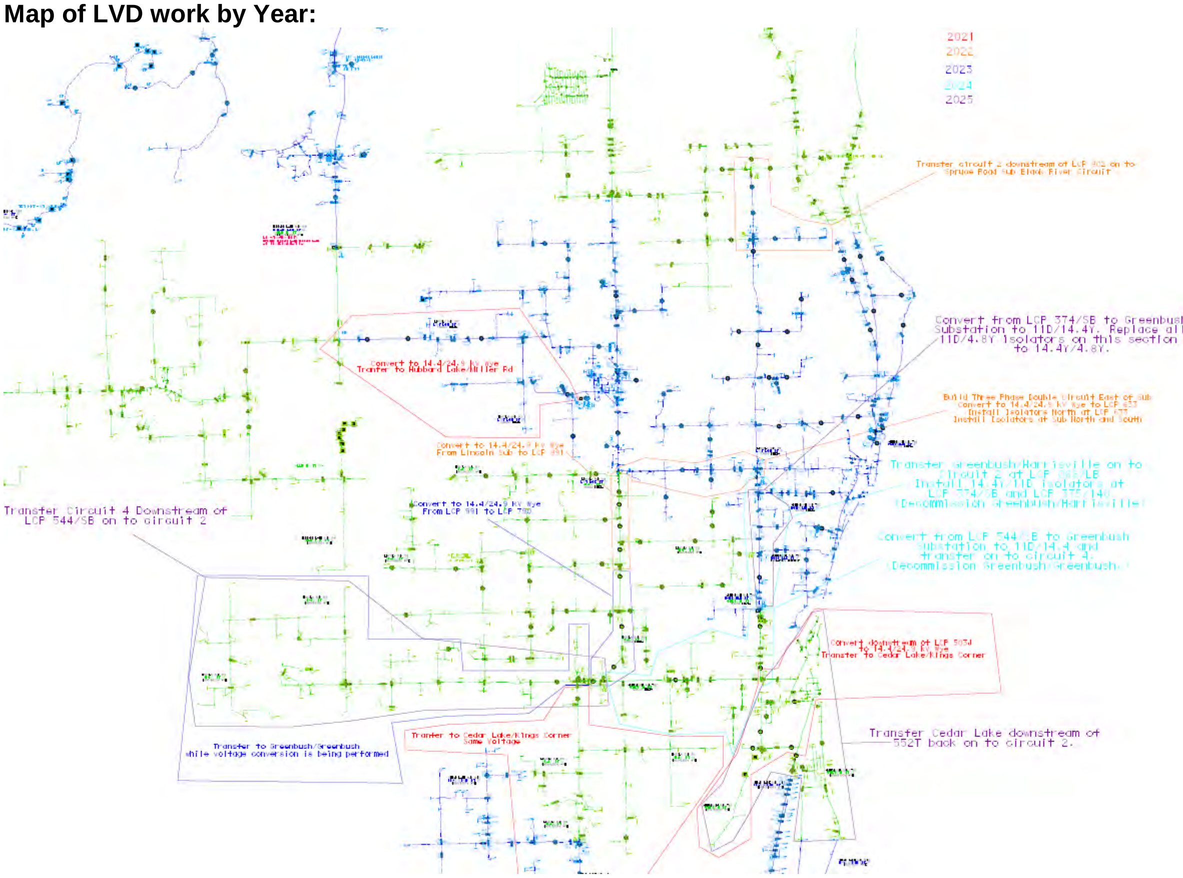
Configuration in 2025:

Circuit 1 = Blue
Circuit 2 = Green
Circuit 3 = Red
Circuit 4 = Orange



Consumers Energy
LVD Planning
CONCEPT APPROVAL

Map of LVD work by Year:



PDF for map above:

Lincoln By Year.pdf

DCParker, P14-109
CLKezele, P14-206
JRAnderson, P14-601
TJSparks P13-415A
JFBrossoit, EP12-230
SLWatters, P14-703

Consumers Energy
Distribution Planning and Performance
CONCEPT APPROVAL

Concept Number: 18-0025 County: Alcona

Project: Lincoln Greenbush Long Range Plan: Lincoln Rebuild

Date: 01/28/2018 Need System Changes By: 12/31/2019

Problem Description:
Lincoln substation is an 11kV delta non-standard low side voltage. The Lincoln substation transformer is at 95% capability during peak load and is projected to be above 100% by 2018 during peak loads at current growth rate. One of Lincoln's LVD circuits is also in the bottom 10% in terms of statewide reliability each year also.

Greenbush substation is also an 11kV delta non-standard low side voltage. The reliability of Greenbush substation due to 46kV outages and distribution outages continually place this substation in the bottom 10% reliability performance.

Additionally, both Lincoln and Greenbush are served by approximately 11.2 miles of a poor performing, aged, and non-standard construction radial 46kV line, negatively impacting their reliability.

Alternatives Considered: (Refer to Approved Long Range Plan for Complete Details)
This concept approval is for the ROW and easements, 138kV line build, and substation rebuild at the Lincoln site and supports the Long Range Plan for this area. LVD voltage conversion work assumed throughout this Long Range Plan is not included in the figures below. The estimated cost of a full LVD line voltage conversion is $9.2 million as described in the Long Range Plan. This voltage conversion will be approved in phases through the LVD Planning project approval process and coordinated with the work on this concept. HVD reliability and pole replacements are included in the cost figures below.

1. Replace the Lincoln 5MVA/11kV with a three circuit 10MVA/24.9kV; serve Greenbush's customers from the new Lincoln substation and retire Greenbush. Dividing the area into three circuits causes one circuit to be approximately 126 miles in length, which will increase response time and impacts SAIDI customer minutes negatively. Construct two miles of 138kV line to feed new Lincoln substation at the current Lincoln substation location.

2. Build a new substation with a four circuit under-build 10MVA/24.9kV; serve Greenbush and Lincoln's customers from the new substation and retire Greenbush and Lincoln. An additional two miles of 138kV line needs to be built in this alternative.

3. Replace the Lincoln 5MVA/11kV with a four circuit 10MVA/24.9kV; serve Greenbush's customers from the new Lincoln substation and retire Greenbush. Construct two miles of 138kV line to feed new Lincoln substation at the current Lincoln substation location.

4. Replace the Lincoln 5MVA/11kV with 10MVA/24.9kV and replace the Greenbush 5MVA/11kV with 10MVA/24.9kV; keep both substations on the 46kV system.

5. Replace the Lincoln 5MVA/11kV with 10MVA/24.9kV and replace the Greenbush 5MVA/11kV with 10MVA/24.9kV; the Lincoln substation would be fed off of the 138kV system, while Greenbush would still be fed off the 46kV.

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JRAnderson, P14-601
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JFBrossoit, EP12-230
SLWatters, P14-703

	Capital Cost of Substation and Unique LVD Projects	Projected LVD Cust-Min	HVD Cust-Min	Total Projected Cust-Min	Total Cust-Min Saved from Base	$X Per Cust-Min Saved
Base Cust-Min	-	3,204,887	1,928,202	5,133,089	-	-
Alternative 1	$3,180,995	3,028,936	111,000	3,139,936	1,993,153	$1.60
Alternative 2	$5,193,271	2,895,445	111,000	3,006,445	2,126,644	$2.44
Alternative 3	$4,071,045	2,973,661	111,000	3,084,661	2,048,428	$1.99
Alternative 4	$3,166,266	2,847,203	1,928,202	4,775,405	357,684	$8.85
Alternative 5	$3,532,845	2,966,793	968,202	3,934,995	1,198,094	$2.95

Notes:

- HVD Base customer minutes represent the 46kV impact and do not include the existing 138kV system area total customer minute numbers.
- Cost of decommissioning substations is not included in each alternatives cost above.
- Alternative 2 has $556,000 in Unique LVD Project costs due to the double circuit work with this alternative.
- Alternative 3 has $556,000 in Unique LVD Project costs due to the double circuit work with this alternative.

DCParker, P14-109
CLKezele, P14-206
JRAnderson, P14-601
TJSparks P13-415A
JFBrossoit, EP12-230
SLWatters, P14-703

Recommended Alternative: Alternative 3

The additional cost of alternative 3 ($4,071,045) over alternative 1 ($3,180,995), of approximately $890,050 is justified through the reliability benefits that CYME calculated and those that CYME cannot quantify. Alternative 3 is preferable compared to alternative 1 because alternative 1 has a three circuit design, with one circuit being approximately 126 miles long. Through experience, Consumers Energy has learned that LVD circuits of excessive length (i.e over 100 miles in length) generally perform poorly. System protection due to coordination challenges can easily become compromised and excessive length increases damage assessment/outage restoration ride out times, which negatively impact SAIDI customer minutes. The chart below represents the length of LVD circuits associated with Alternative 3, all four of which will be less than 100 miles in length.

Substation – Circuit	Existing Miles	Proposed Miles	Existing Customers	Proposed Customers	Proposed MVA
Lincoln – Lost Lake (Circuit 1)	91	42	1410	560	0.96
Lincoln – Mikado (Circuit 2)	106	68	935	1868	3.73
Lincoln – Circuit 3		46		820	2.56
Lincoln – Circuit 4		88		773	2.57
Greenbush - Harrisville	27		838		
Greenbush - Greenbush	36		1005		
Cedar Lake – Kings Corner	60	78		167	0.26
Total	**320**	**322**	**4,188**	**4,188**	10.08

Conceptual Estimate by WBS:

WBS Element	Direct Cost	Cost with Overheads	Description	Year
EH - 95208	$225,000	$250,000	Easement & ROW Purchase	2018
EH - 95008	$710,000	$1,030,000	Two Mile Tap to Iosco-Alpena 138kV Line	2019
EH - 96608	$1,300,000	$2,340,000	Lincoln – Substation Rebuild to 138kV adding 3rd and 4th LVD Circuit Exits	2019
Project Total	$2,235,000	$3,620,000		

Note:

- Cost figures in the Conceptual Estimate by WBS table above exclude Unique LVD Project costs.

DCParker, P14-109
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JFBrossoit, EP12-230
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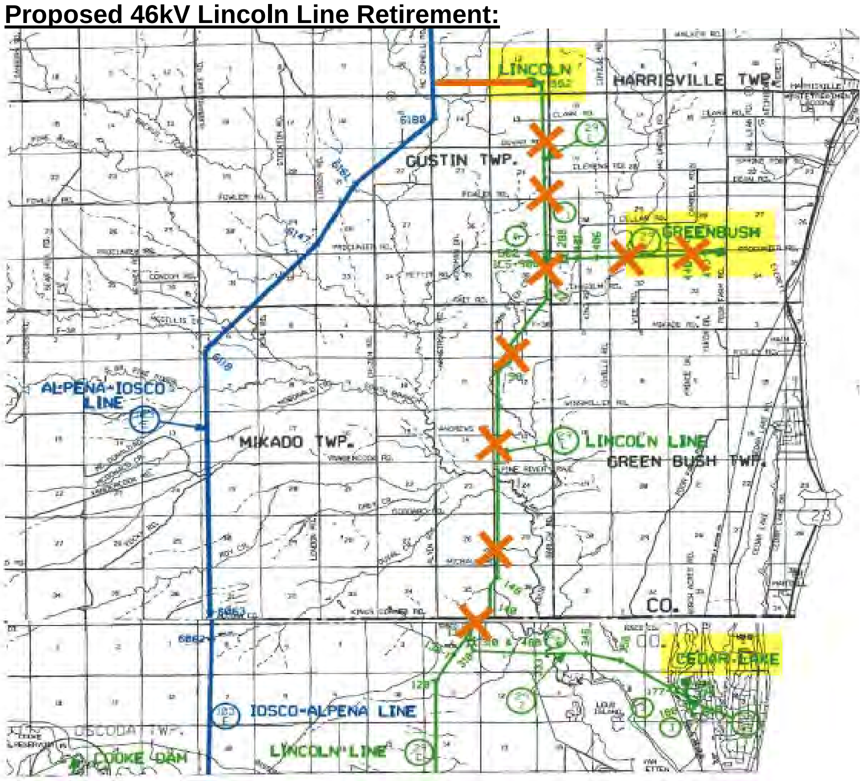
Proposed 138kV Line Route:

Proposed 46kV Lincoln Line Retirement:



DCParker, P14-109
CLKezele, P14-206
JRAnderson, P14-601
TJSparks P13-415A
JFBrossoit, EP12-230
SLWatters, P14-703

Present Need: On approval, this document authorizes the C&SI, LVD, and HVD Engineering groups to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By:	JJHolbrook / SFMarkey	Date:	01/29/18
Team Leader:	DCParker	Date:	

Approvals:

Executive Director, Transmission	(JRA)	Date:	
Vice President, Electric Grid Integration	(TJS)	Date:	
Senior Vice President, Engineering	(JFB)	Date:	

From: Electric Asset Management
To: SUSAN L. WATTERS
Cc: SUSAN L. WATTERS; CINDY L. KEZELE; Brian M. Bushey; DONALD A. LYND; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews
Subject: Approval has completed on 18-0025 Lincoln Greenbush LRP - Lincoln Rebuild - Update.2.
Date: Monday, February 26, 2018 3:43:20 PM

Approval has completed on 18-0025 Lincoln Greenbush LRP - Lincoln Rebuild - Update.2.

Approval on 18-0025 Lincoln Greenbush LRP - Lincoln Rebuild - Update.2 has successfully completed. All participants have completed their tasks.

Approval started by SUSAN L. WATTERS on 2/16/2018 9:01 AM
Comment: A new document has been added to the C&SI HVD Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by DWAYNE C. PARKER on 2/16/2018 9:15 AM
Comment:

Approved by James R. Anderson on 2/17/2018 5:53 AM
Comment: I approve. This Concept is in coordination with LVD long range plan for the West Branch area. Requires JF approval.

Approved by Timothy J. Sparks on 2/18/2018 1:22 PM
Comment: JF, this project will eliminate non-standard voltages in the West Branch area, retire to non-standard voltage substations fed from 46 kV, retire many miles of underperforming 46 kV line, and create shorter standard voltage circuits serving customers.

Approved by Jean-Francois Brossoit on 2/26/2018 3:43 PM
Comment:

View the workflow history.

Lincoln - Greenbush Long Range Plan

October 2016

Prepared by Matthew Koepke and Jordan Holbrook

Case No. U-20963
Attachment No. 126
Page 245 of 312

Table of Contents

Problem Statement

The area of Greenbush and Lincoln are being looked at as a voltage conversion project to standardize our voltage portfolio. Both Greenbush and Lincoln are 11 kV delta substations, surrounded by 14.4/24.9kV wye grounded substations. Lincoln's transformer is currently loaded to approximately 95%. Using a 2% growth rate, that was calculated using Maxloads, throughout this study Lincoln substation is projected to be overloaded by 2018. With such a high potential of an overloaded transformer bank we are looking at possibly upgrading the substation equipment.

Additionally, the LVD circuits of Greenbush/Harrisville and Lincoln/Lost Lake are in the bottom 10% statewide in terms of reliability. A major goal of this study is to improve the reliability of the LVD system in the study area.

Current State of the System

The following substations were included in the ten year study. The peak load shown was used as the basis for load projections. If no Projected Overload is shown, the substation transformer does not overload until 2036 or beyond.

Lincoln – WD #0312

- Voltage: 11 kV
- Rating: 5.0/6.25 OA/FA MVA
- Capability: 6.6 MVA
- 2015 Peak Load: 6.3 MVA (95.45%)
- Projected Overload 2018
- Circuits: #1 Lost Lake, #2 Mikado

Greenbush – WD #0782

- Voltage: 11 kV
- Rating: 5.0/6.25 OA/FA MVA
- Capability: 9.3 MVA
- 2015 Peak Load: 3.0 MVA (32.25%)
- Circuits: #1 Harrisville, #2 Greenbush

Cedar Lake – WD #1245

- Voltage: 14.4/24.9 kV
- Rating: 5.0/6.25 OA/FA MVA
- Capability: 8.2 MVA
- 2015 Peak Load: 6.14 MVA (74.85%)
- Circuits: #1 Kings Corner, #2 Van Etten

Spruce Road – WD #1263

- Voltage: 14.4/24.9 kV
- Rating: 10.0/12.5 OA/FA MVA
- Capability: 17 MVA
- 2015 Peak Load: 6.15 MVA (36.02%)
- Circuits: #1 East Bay, #2 Black River

Hubbard Lake – WD #1516

- Voltage: 14.4/24.9 kV
- Rating: 10.0/12.5 OA/FA MVA
- Capability: 17 MVA
- 2015 Peak Load: 2.47 MVA (14.53%)
- Circuits: #1 Hubbard Lake, #2 Miller

HVD Concerns

The proposed substation projects within the alternatives are acceptable to both the HVD Protection and HVD Planning groups. Lincoln and Greenbush subs are both fed off of the 46kV Lincoln line, which in recent years has been experiencing many outages. To alleviate this problem it is proposed that the 46kV Lincoln Line be decommissioned back to Cedar Lake junction, and the study area of Lincoln and Greenbush be fed by the 138kV Iosco-Alpena Line. The biggest transformer that system protection is able to coordinate with if the study area is fed off of the 46kV line still, would be 10 MVA's.

Figure 1: Current Distribution Configuration

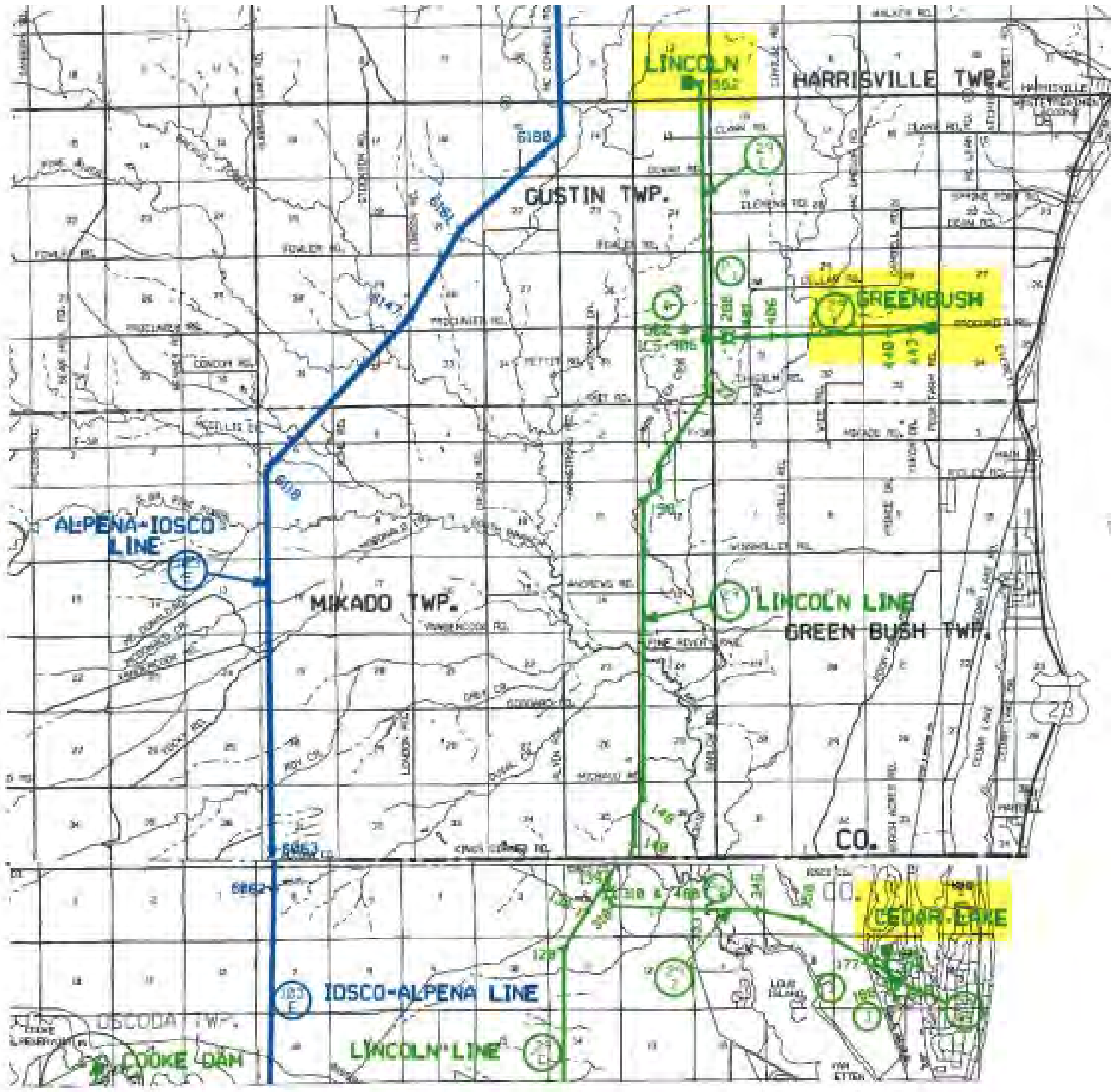


Figure 2: Current HVD and Transmission Configuration

System History

Historical Loading

The following table, Table I: Past Transformer MaxLoads provides historical information on the study area. Figure 3 provides a graphical representation of the load growth in the study area.

Table I: Past Transformer Max Loads

Substation	WD	kVLL	Nameplate (MVA)	TLC (MVA)	Cooling Type	LOADS IN MVA 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Lincoln	0312	11	5.0	6.6	FC	7.1	6.9	4.2	4.3	4.8	6.0	4.5	7.4	5.9	6.3	6.2
Greenbush	0782	11	5.0	9.3	FC	3.8	3.6	3.2	3.5	3.5	3.0	3.5	3.7	2.6	3.0	3.3
TOTAL						10.9	10.5	7.4	7.8	8.3	9.0	8.0	11.1	8.5	9.3	9.5
Average Yearly Growth:								2.0%								

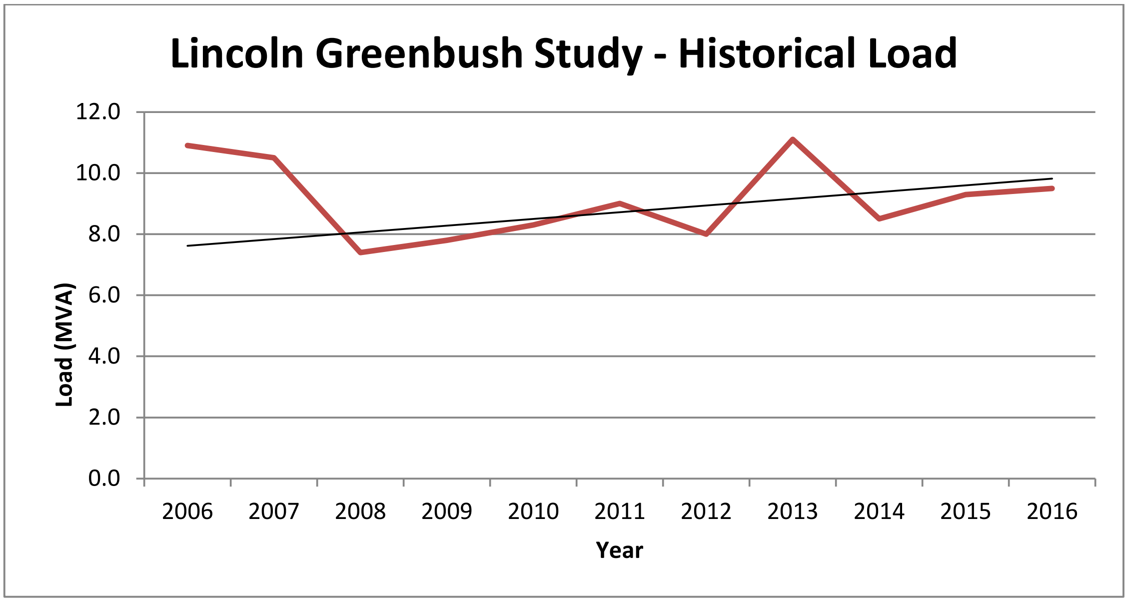


Figure 3: Historical Load Growth for Lincoln Greenbush Study Area

The line above trends the historical load from 2008 to 2016. The line was extrapolated back from 2006 to 2008.

<u>Historical Outage Rates</u>

The outage rates used in the study were calculated using three years of historical outage data from 2011 to 2013. The outage data used included storms, but did not include outages coded as either HVD/transmission or secondary. The outage rate, when ran on the CYME base-case study, returned the historical SAIFI and CAIDI values. The calculated outage rates were assigned to their respective circuits. When load transfers were performed between circuits, the original outage rate assigned to that section of line stayed with it.

Even though we did not include outage rates coded as either HVD/transmission or secondary, we found out that decommissioning the 46kV line back to Cedar Lake results in a net savings of 1.58 million customer outage minutes. These customers would then be fed by the 138kV Iosco-Alpena line.

Future System Projections

Growth Rates

A constant growth rate of 2.0% per year was used throughout the study.

The customer counts used were obtained from the CYME studies. The total number of customers in the study was held constant at 11,944. Table II shows the number of customers served from each substation.

Table II: Number of customers by substation

Substation	WD#	Customers
Lincoln	0312	2,345
Greenbush	0782	1,843
Cedar Lake	1245	3,702
Spruce Road	1263	3,057
Hubbard Lake	1516	1,047
Total Customers		11,994

Assumptions

- A new 10MVA transformer bank has a capability of 17MVA.
- Most of the load is residential, so the diversification factor stayed at 1.0 throughout the study.
- After conversion work, zones were applied in CYME analysis to accommodate for reliability work being done during voltage conversion work. According to the 2013 Reliability Improvement Report after conversion work is done, a 32.2% and a 16.2% increase in reliability is seen in SAIFI and CAIDI annual minutes respectively. This improvement was applied to the original outage history data, which is how the zones throughout the study were calculated.
- Costs of decommissioning substations were not included in the economic analysis for this study.
- Costs of decommissioning the 46kV line were not included in the economic analysis.
- Throughout the study it was assumed that for every minute that customers experience an outage it will cost the company three dollars.

Alternative 1: Build a 138kV Substation at existing Lincoln location 2019

Alternative 1 addresses the projected overload at Lincoln in 2018 by rebuilding the existing location with a 10 MVA 138kV-14.4/24.9kV transformer that is forced air cooled. The new substation would have three circuits which would feed Lincoln/Lost Lake, Lincoln/Mikado, Greenbush/Harrisville, and Greenbush/Greenbush. This alternative would retire Greenbush substation.

Alternative 1 requires two miles of 138kV line to be constructed to service the new Lincoln substation. The 46kV line feeding Lincoln and Greenbush would be retired back to the Cedar Lake junction.

Description

The same load transfers and voltage conversions as Alternative 3 were followed to complete Alternative 1's complete voltage conversion.

Table III: Initial Circuit Miles

Column1	Circuit Name	Circuit Miles
Initial Configuration	Lincoln - Lost Lake	91.23
	Lincoln - Mikado	105.43
	Greenbush - Harrisville	26.71
	Greenbush - Greenbush	35.85
	Cedar Lake - Kings Corner	60.29
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	104.1
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Table IV: Alternative 1 2026 Configuration Circuit Miles

Column1	Circuit Name	Circuit Miles
Alternative 1	Lincoln - Lost Lake	46.06
	Lincoln - Harrisville	72.31
	Lincoln - Mikado	123.87
	Cedar Lake - Kings Corner	77.8
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	107.64
	Hubbard Lake - Hubbard lake	13.49
	Hubbard Lake - Miller	59.97

Distribution Automation

The loops between Lincoln – Circuit 2 and Lincoln – Circuit 4, plus the loop between Lincoln – Circuit 3 and Hubbard Lake – Miller from Alternative 3 could be implemented in Alternative 1. However, the trip settings of each OCR will be different. The trip settings should be calculated and verified using CYME before any loops are implemented for this alternative if it is chose.

Case No. U-20963
Attachment No. 126
Page 256 of 312

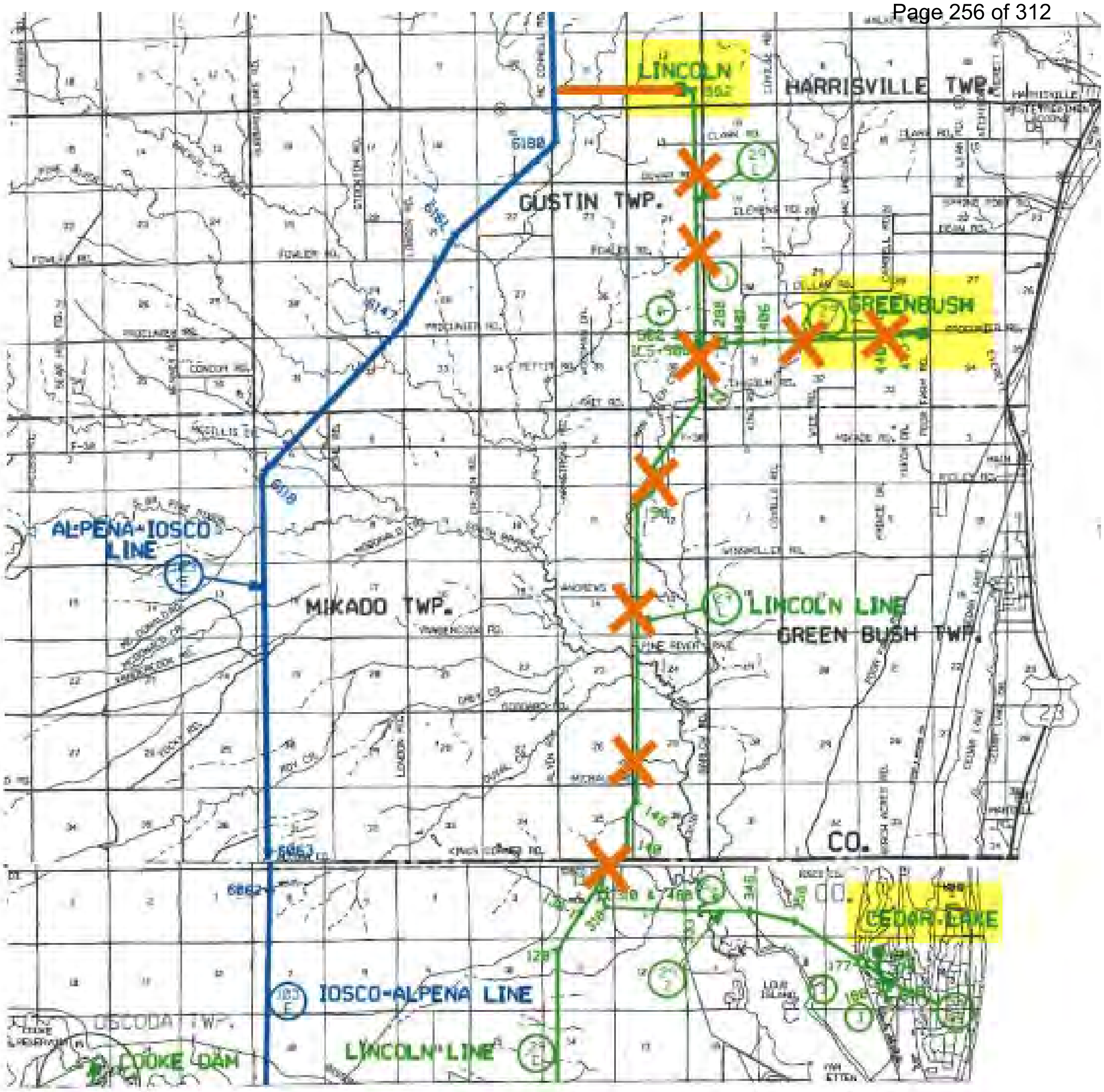


Figure 4: HVD and Transmission Proposed for Alternative 1

Case No. U-20963
Attachment No. 126
Page 257 of 312

Figure 5: Distribution Configuration Alternative 1 in 2015

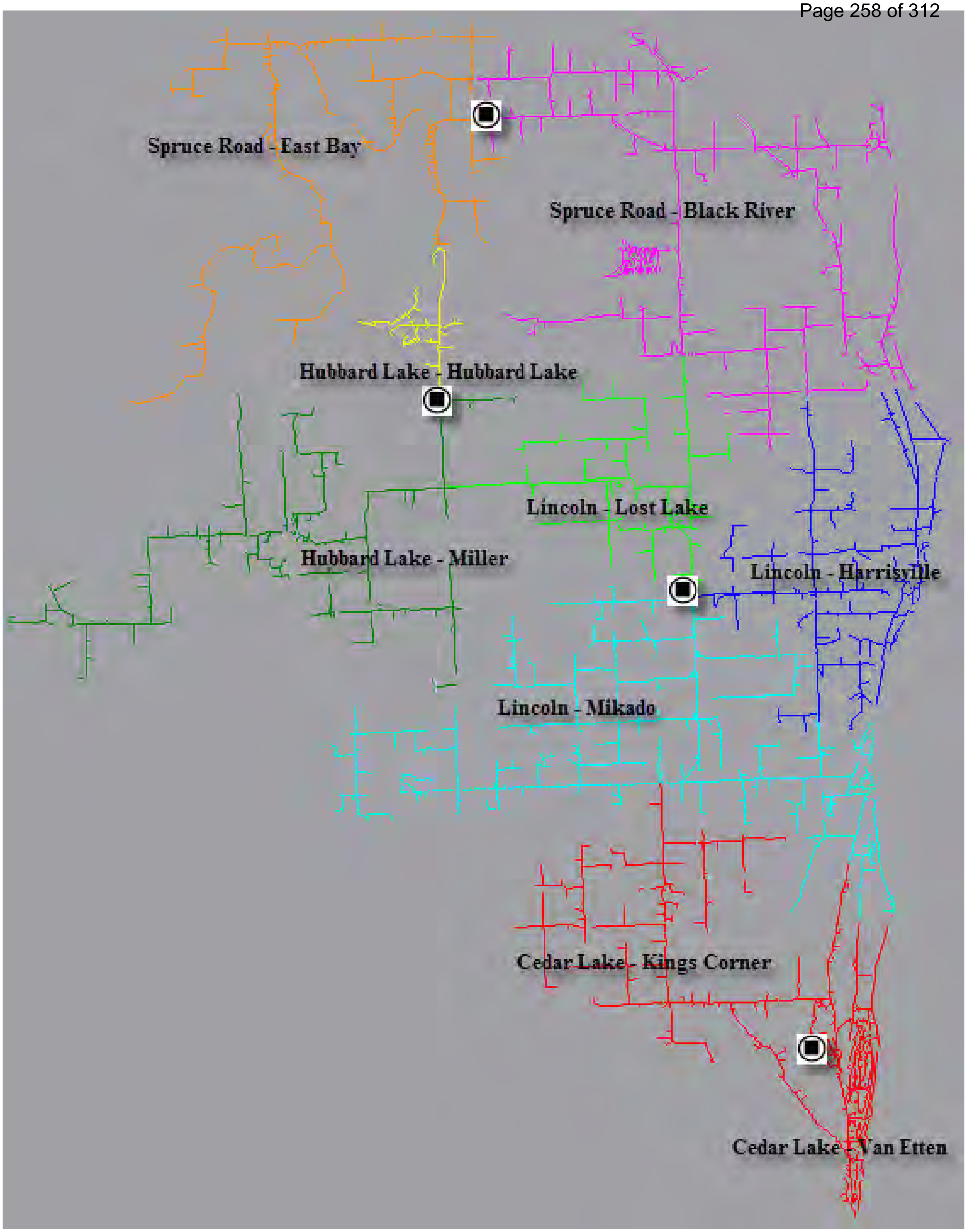


Figure 6: Distribution Configuration Alternative 1 in 2026

Transformer Loading

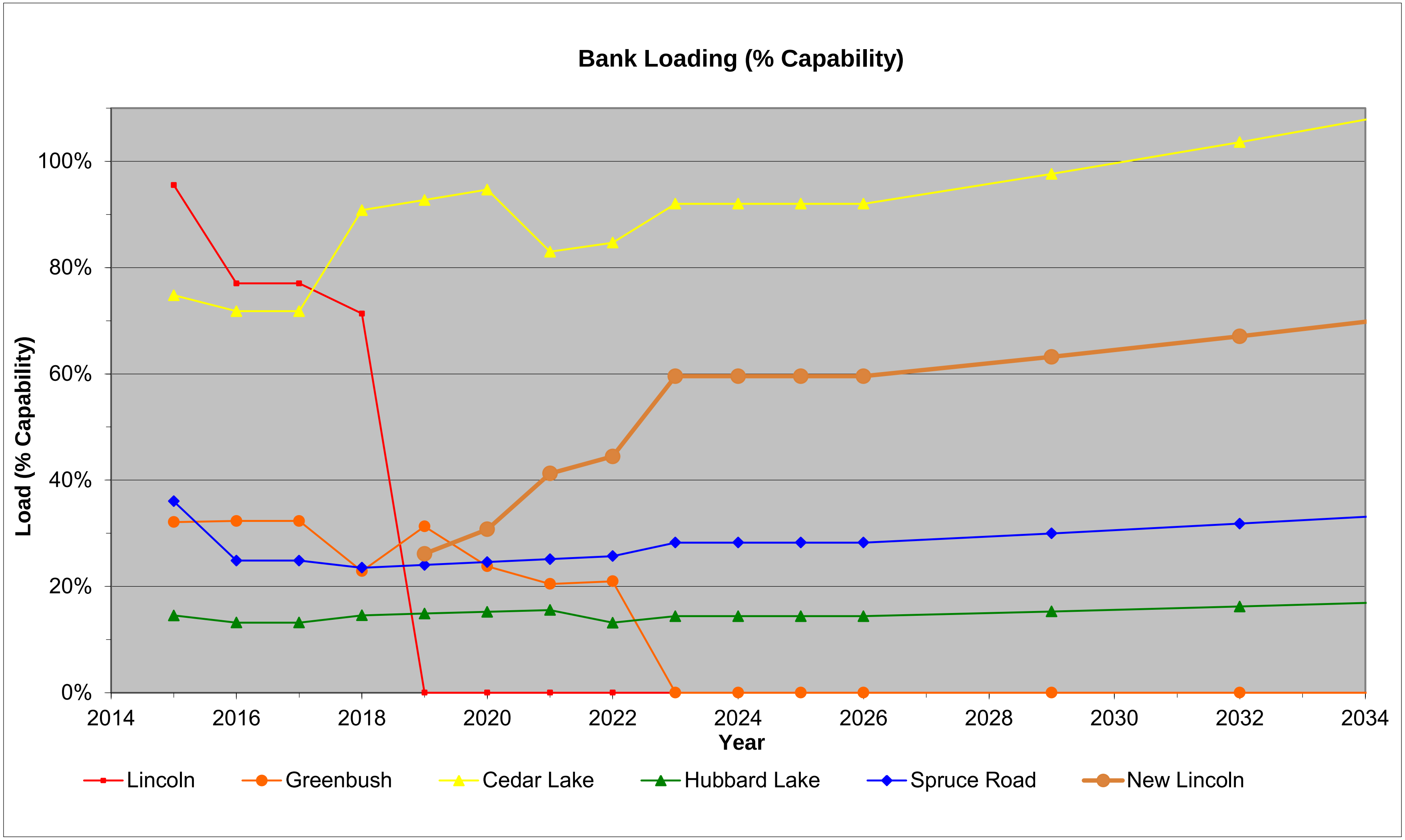


Figure 7: Alternative 1 Transformer Bank Loading (% Capability)

Yearly Cost Estimates

Table V: Alternative 1 Yearly Cost Estimates

Costs							
Year	**Transmission**	**ROW & Site**	**Substation**	**LVD Work**	**Regulators**	**Total Cost**	**Capacity Projects**
2016				$217,416			
2017				$217,416			
2018		$134,000		$1,665,004			ROW easements and purchase
2019	$513,000		$1,100,000	$721,000	$30,000		Rebuild of Lincoln Sub 5MVA to 10 MVA
2020				$1,547,155	$28,000		
2021				$524,100			
2022				$1,190,778	$112,000		
2023				$77,000			
2024				$265,166			
2025				$1,673,066			
2026				$618,000	$153,000		
Total:	**$513,000**	**$134,000**	**$1,100,000**	**$8,393,101**	**$323,000**	**$10,463,101**	

Alternative 2: Build a 138kV substation at M-72 and Poor Farm Road

Alternative 2 addresses the projected overload at Lincoln in 2018 by building a new substation at M-72 and Poor Farm Road. The new substation would have a 10 MVA 138kV-14.4/24.9kV transformer that is forced air cooled. The new substation would have four circuits which would feed Lincoln/Lost Lake, Lincoln/Mikado, Greenbush/Harrisville, and Greenbush/Greenbush. This alternative would retire Lincoln and Greenbush substation.

Alternative 2 requires five miles of 138kV line to be constructed to service the new substation. The 46kV line feeding Lincoln and Greenbush would be retired back to the Cedar Lake junction.

Description

The same load transfers and voltage conversions as Alternative 3 were followed to complete Alternative 2's complete voltage conversion.

Table VI: Initial Circuit Miles

Column1	Circuit Name	Circuit Miles
Initial Configuration	Lincoln - Lost Lake	91.23
	Lincoln - Mikado	105.43
	Greenbush - Harrisville	26.71
	Greenbush - Greenbush	35.85
	Cedar Lake - Kings Corner	60.29
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	104.1
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Table VII: Alternative 2 2026 Configuration Circuit Miles

Column1	Circuit Name	Circuit Miles
Alternative 2	Lincoln - Poor Farm	34.33
	Lincoln - Harrisville	62.91
	Lincoln - Lost Lake	27.29
	Lincoln - Mikado	92.46
	Cedar Lake - Kings Corner	77.8
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	107.64
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	86.43

Distribution Automation

All loops used in Alternative 3 could be implemented in Alternative 2; however the trip settings and number of OCR's will be different. The trip settings should be calculated and verified using CYME before any loops are implemented for this alternative if it is chose.

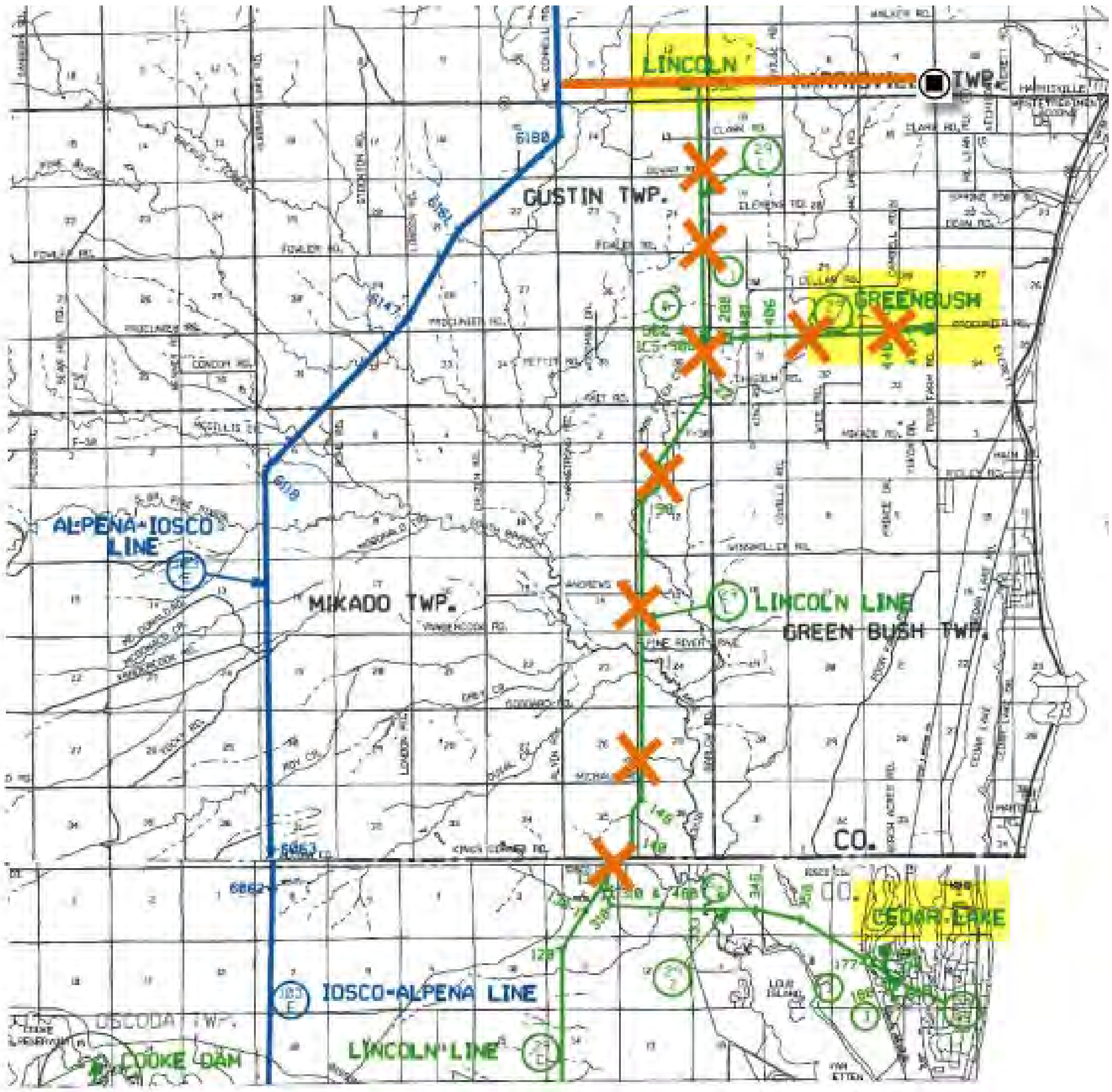


Figure 8: HVD and Transmission Proposed for Alternative 2

Figure 9: Distribution Configuration Alternative 2 in 2015

Figure 10: Alternative 2 Distribution Configuration in 2026

Transformer Loading

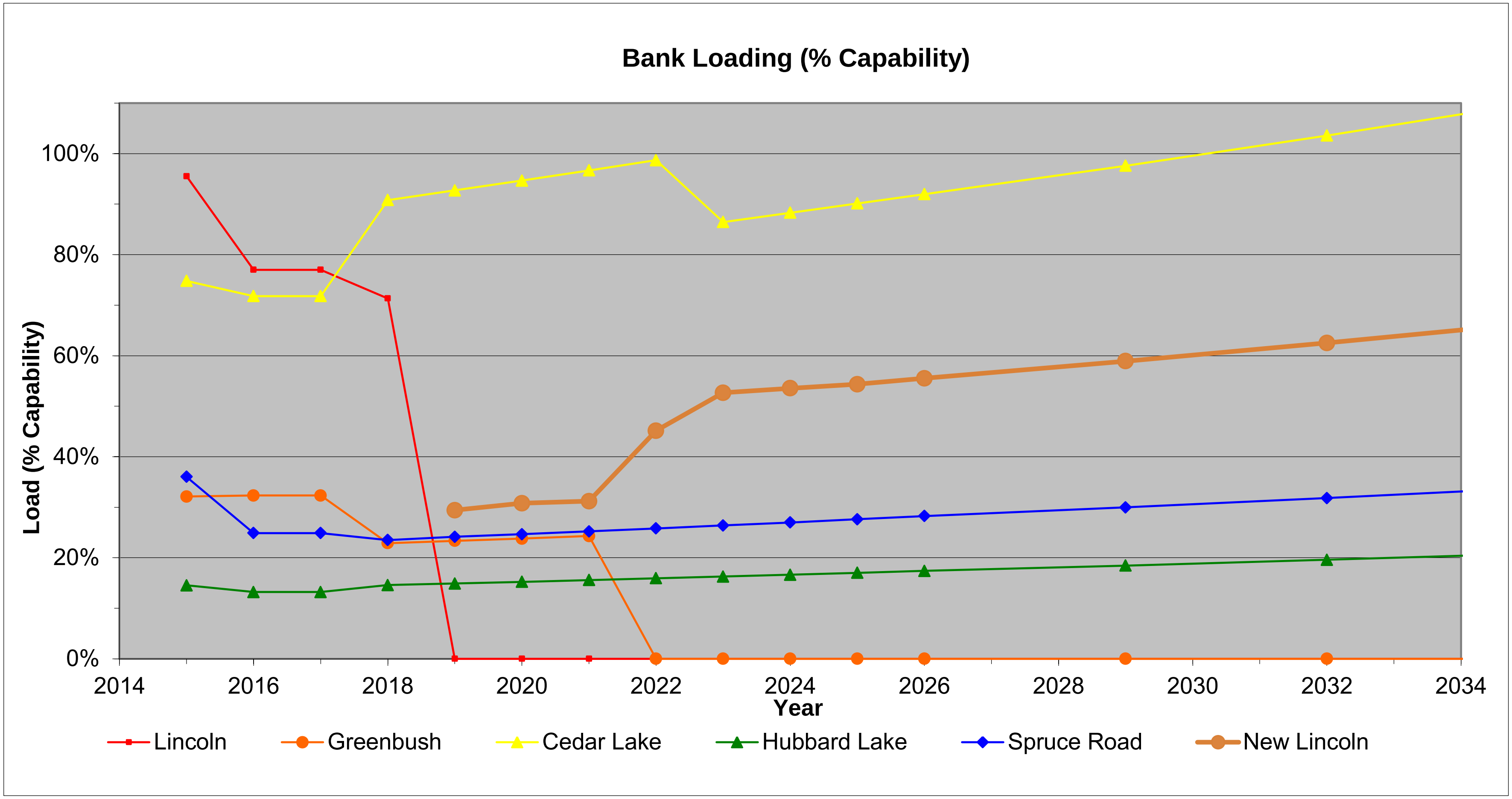


Figure 11: Alternative 2 Transformer Bank Loading (% Capability)

Yearly Cost Estimates

Table VIII: Alternative 2 Yearly Cost Estimates

Costs							
Year	**Transmission**	**ROW & Site**	**Substation**	**LVD Work**	**Regulators**	**Total Cost**	**Capacity Projects**
2016				$217,416			
2017				$217,416			
2018		$448,000		$1,665,004			ROW easements and purchase
2019	$1,113,000		$1,400,000	$1,277,000	$30,000		Build new sub and double circuit under-build work
2020				$1,547,155	$28,000		
2021				$524,100			
2022				$1,190,778	$112,000		
2023				$77,000			
2024				$265,166			
2025				$1,673,066			
2026				$618,000	$153,000		
Total:	**$1,113,000**	**$448,000**	**$1,400,000**	**$8,949,103**	**$323,000**	**$12,233,103**	

Alternative 3: Build a 138kV Substation at existing Lincoln location 2019

Alternative 3 addresses the projected overload at Lincoln in 2018 by rebuilding the existing location with a 10 MVA 138kV-14.4/24.9kV transformer that is forced air cooled. The new substation would have four circuits which would feed Lincoln/Lost Lake, Lincoln/Mikado, Greenbush/Harrisville, and Greenbush/Greenbush. This alternative would retire Greenbush substation.

Alternative 3 requires two miles of 138kV line to be constructed to service the new Lincoln substation. In order to have a four circuit configuration, three miles of double circuit needs to be constructed heading east out of Lincoln substation. The 46kV line feeding Lincoln and Greenbush would be retired back to the Cedar Lake junction. In this alternative there are three automation loops possible.

Description

The following steps show the work required each year to complete Alternative 3.

- 2016 - 2017
  - Fixed Protection and Coordination issues on all LVD circuits in study area
- 2018
  - Perform an 11D/14.4Y voltage conversion on Lincoln/Lost Lake downstream of LCP 639/65. Replace all 11D distribution transformers to 14.4Y. Replace the 11D/4.8Y Isolators on this section of line to 14.4Y/4.8Y.
  - Transfer Lincoln/Lost Lake downstream of LCP 639/65 to Hubbard Lake/Miller Rd by creating a tie point at LCP 457/SB.
  - Perform an 11D/14.4Y voltage conversion on Greenbush/Greenbush downstream (East) of 503J. Replace all 11D secondary transformers to 14.4Y. Replace the 11D/4.8Y isolators on this section to 14.4Y/4.8Y.
  - Transfer Greenbush/Greenbush downstream (East) of 503J to Cedar Lake/Kings Corner by creating a tie point at 552T.
  - Transfer Lincoln/Mikado downstream of LCP 959/70 to Cedar Lake/Kings Corner at LCP 071/SB.
    - No voltage conversion is required for this load transfer because both circuits are isolated down to 4.8Y at this point.
  - Obtain two miles of ROW for 138kV line to existing Lincoln substation location
- 2019
  - Construct two miles of 138kV line to existing Lincoln substation location
  - Construct new substation at Lincoln site
  - Construct three miles of three-phase 14.4Y double circuit (circuit 1 and 2) to the East of Lincoln Substation. Install 14.4Y/11D isolators looking north on circuit 1 at LCP 633 SB. Perform a voltage conversion on circuit 2 up to LCP 066/LB on Greenbush/Harrisville.
  - Install 14.4Y/11D isolators outside Lincoln substation looking North (circuit 3) and South (circuit 4)
  - Transfer circuit 2 downstream of isolator LCP 902/167 on to Spruce Road/Black River at LCP 705/SB.

- 2020
    - Transfer circuit 4 downstream of LCP 999/SB on to Greenbush/Greenbush.
    - Perform an 11D/14.4Y voltage conversion on circuit 4 from Lincoln substation to isolator LCP 790/333 (5 miles). Replace all 11D secondary transformers to 14.4Y. Replace the11D/4.8Y isolators on this section to 14.4Y/4.8Y.
    - Transfer the line section downstream of LCP 999/SB back on to circuit 4.
- 2021
    - Perform an 11D/14.4Y voltage conversion on Greenbush/Greenbush from LCP 544/SB to Greenbush Substation and transfer on to circuit 4 (decommission Greenbush/Greenbush).
    - Transfer Greenbush/Harrisville on to circuit 2 at LCP 066/LB (decommission Greenbush/Harrisville). Install 14.4Y/11D isolators at LCP 374/SB and LCP 375/140.
- 2022
    - Perform an 11D/14.4Y voltage conversion on circuit 2 from LCP 374/SB to Greenbush substation. Replace all 11D distribution transformers to 14.4Y. Replace the11D/4.8Y isolators on this section to 14.4Y/4.8Y.
    - Transfer circuit 4 downstream from LCP 544/SB on to circuit 2.
    - Transfer Cedar Lake downstream of 552T back on to circuit 2.
- 2023
    - Perform an 11D/14.4Y voltage conversion on circuit 2 downstream of LCP 375/140. Replace all 11D distribution transformers to 14.4Y. Replace the11D/4.8Y isolators on this section to 14.4Y/4.8Y.
- 2024
    - Perform an 11D/14.4Y voltage conversion on circuit 3 from Lincoln substation to regulator LCP 399/100. Replace all 11D distribution transformers to 14.4Y. Replace the11D/4.8Y isolators on this section to 14.4Y/4.8Y.
    - Transfer the section downstream of the tie point between Hubbard Lake/ Miller Rd and Lincoln back on to circuit 3.
- 2025
    - Perform an 11D/14.4Y voltage conversion on circuit 3 downstream of regulator 399/100. Replace all 11D distribution transformers to 14.4Y. Replace the11D/4.8Y isolators on this section to 14.4Y/4.8Y.
    - Perform an 11D/14.4Y voltage conversion on circuit 1 from LCP 663/SB to junction 876J. Replace all 11D distribution transformers to 14.4Y. Replace the11D/4.8Y isolators on this section to 14.4Y/4.8Y.
- 2026
    - Perform an 11D/14.4Y voltage conversion on circuit 3 downstream of junction 876J. Replace all 11D distribution transformers to 14.4Y. Replace the11D/4.8Y isolators on this section to 14.4Y/4.8Y.

Table IX: Initial Circuit Miles

Column1	Circuit Name	Circuit Miles
Initial Configuration	Lincoln - Lost Lake	91.23
	Lincoln - Mikado	105.43
	Greenbush - Harrisville	26.71
	Greenbush - Greenbush	35.85
	Cedar Lake - Kings Corner	60.29
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	104.1
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Table X: Alternative 3 2026 Configuration Circuit Miles

Column1	Circuit Name	Circuit Miles
Alternative 3	Lincoln - Circuit 1	41.99
	Lincoln - Circuit 2	67.38
	Lincoln - Circuit 3	46.04
	Lincoln - Circuit 4	87.99
	Cedar Lake - Kings Corner	77.80
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	104.1
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Case No. U-20963
Attachment No. 126
Page 271 of 312

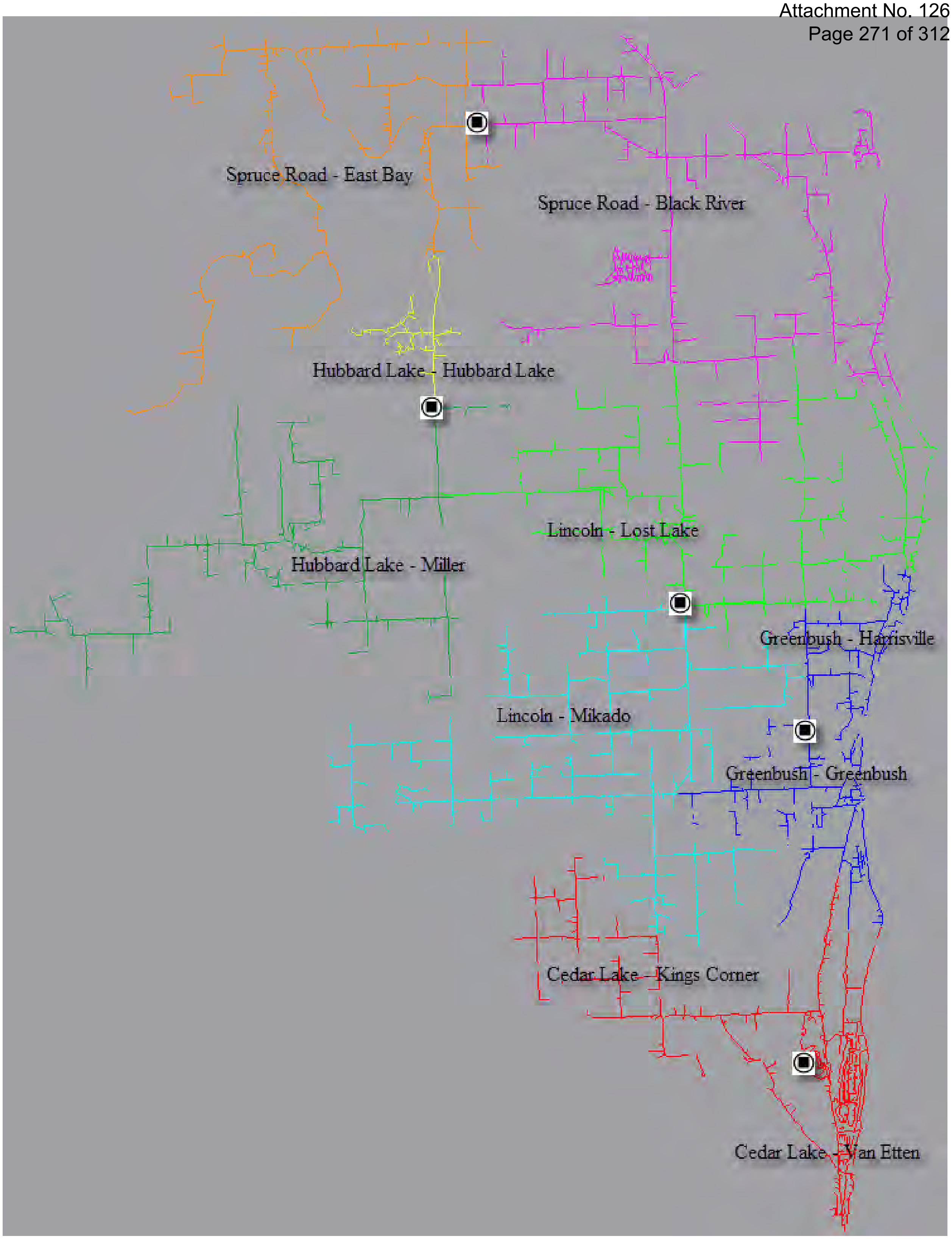


Figure 12: Distribution Configuration Alternative 3 in 2015

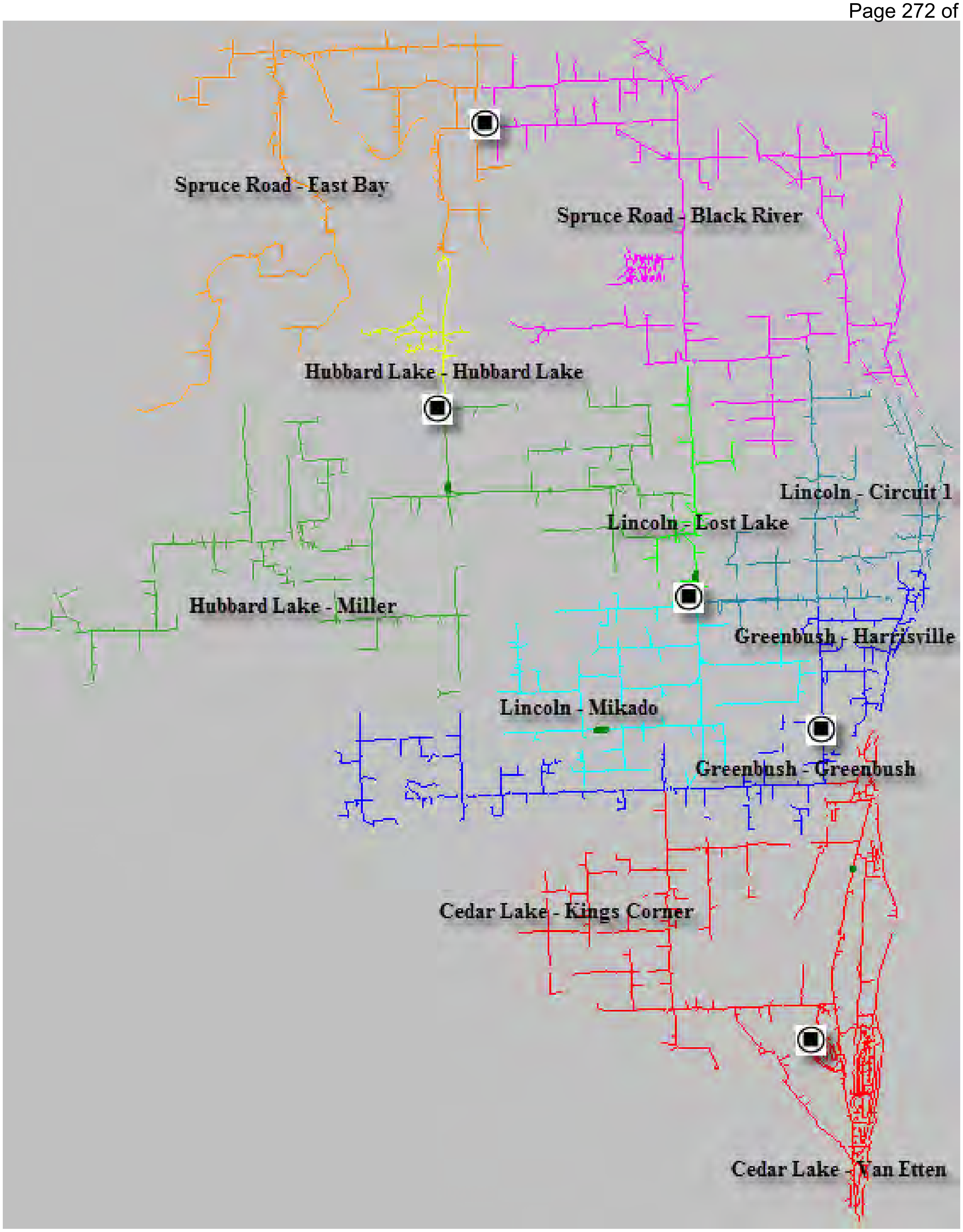


Figure 13: Distribution Configuration Alternative 3 in 2020

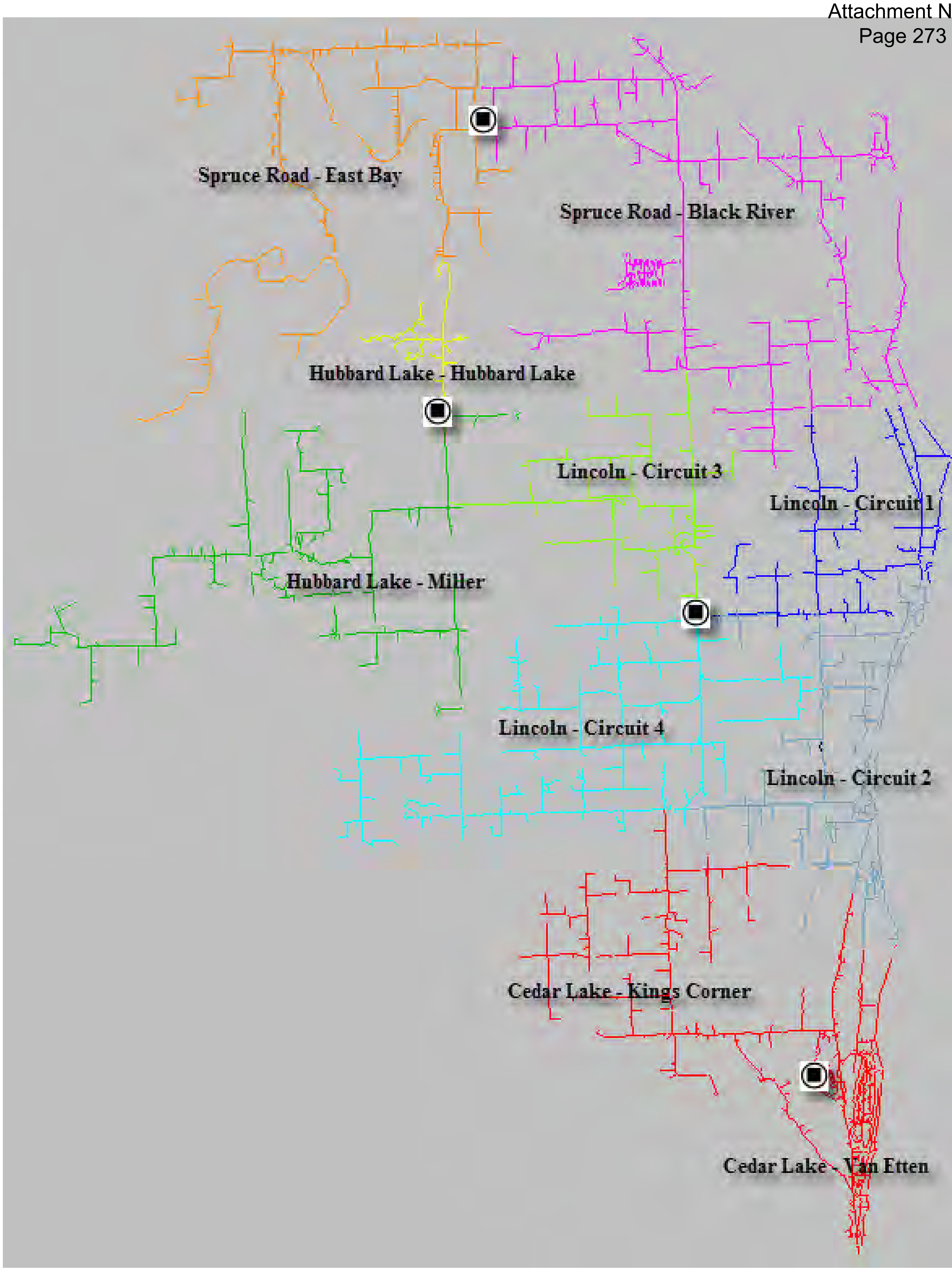


Figure 14: Distribution Configuration Alternative 3 in 2026

Transformer Loading

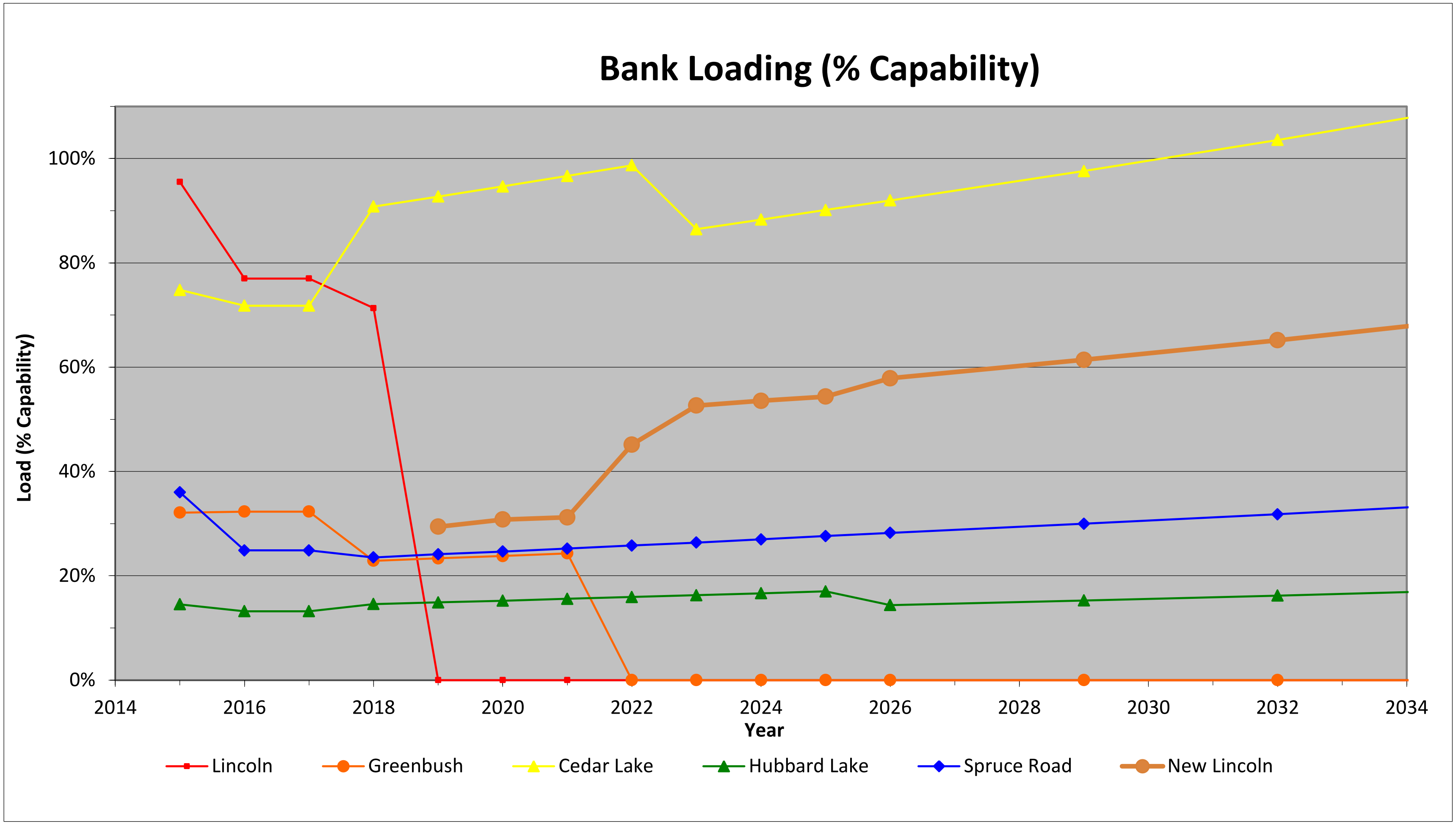


Figure 15: Alternative 3 Transformer Bank Loading (% Capability)

Yearly Cost Estimates

Table XI: Alternative 3 Yearly Cost Estimates

Costs							
Year	**Transmission**	**ROW & Site**	**Substation**	**LVD Work**	**Regulators**	**Total Cost**	**Capacity Projects**
2016				$217,416			
2017				$217,416			
2018		$134,000		$1,665,004			ROW easements and purchase
2019	$513,000		$1,300,000	$1,277,000	$30,000		Rebuild Lincoln and Double circuit work
2020				$1,547,155	$28,000		
2021				$524,100			
2022				$1,190,778	$112,000		
2023				$77,000			
2024				$265,166			
2025				$1,673,066			
2026				$618,000	$153,000		
Total:	**$513,000**	**$134,000**	**$1,300,000**	**$8,949,103**	**$323,000**	**$11,219,103**	

Distribution Automation

Table XII: Automation Loop Locations

OCR #	Location	
1	Greenbush/Harrisville LCP 374/SB	Loop 1
7	Greenbush/Greenbush Junction 503J (Looking South)	
8	Greenbush/Greenbush LCP 555/65	
9	Open point between Lincoln/Mikado and Greenbush/Greenbush (LCP 544/SB)	
10	Lincoln/Mikado Junction 861J Looking South	
2	Greenbush/Harrisville LCP 375/140	Loop 2
3	Lincoln/Lost Lake LCP 633/SB (Looking North)	
4	Lincoln/Lost Lake East of Spur LCP 892/40	
5	Open point between Lincoln/Lost Lake and Greenbush/Harrisville (AB 711T)	
6	Greenbush/Harrisville LCP 412/100	
11	Lincoln/Lost Lake Junction 722J Looking West	Loop 3
12	Lincoln/Lost Lake Junction 642J Looking West	
13	Open point between Lincoln/Lost Lake and Hubbard Lake/Miller Rd (646T)	

Automation Loop 1 is between Lincoln – Circuit 2 and Lincoln – Circuit 4.
Automation Loop 2 is between Lincoln – Circuit 1 and Lincoln – Circuit 2.
Automation Loop 3 is between Lincoln – Circuit 3 and Hubbard Lake – Miller.

All reclosers for the automation loops are NovaTS using the “116” - curve. The trip settings for each loop and their operation are labeled accordingly in Table XIII. A regulator was installed at OCR number five to prevent low voltage during operation.

Case No. U-20963
Attachment No. 126
Page 277 of 312

Table XIII: Automation Loop Settings

OCR #	Status/Trip Setting	Fault Location
1	455	No Fault
7	380	
8	290	
9	Open	
10	400	
2	460	
3	460	
4	380	
5	Open	
6	380	
11	350	
12	250	
13	Open	

OCR #	Status/Trip Setting	Fault Location
1	440	Circuit 1 & 4 Lockout
7	380	
8	290	
9	350	
10	Open	
2	460	
3	Open	
4	280	
5	320	
6	380	
11	N/A	
12	N/A	
13	N/A	

OCR #	Status/Trip Setting	Fault Location
1	Open	Circuit 2 & 3 Lockout
7	230	
8	290	
9	350	
10	460	
2	Open	
3	460	
4	380	
5	290	
6	250	
11	Open	
12	250	
13	350	

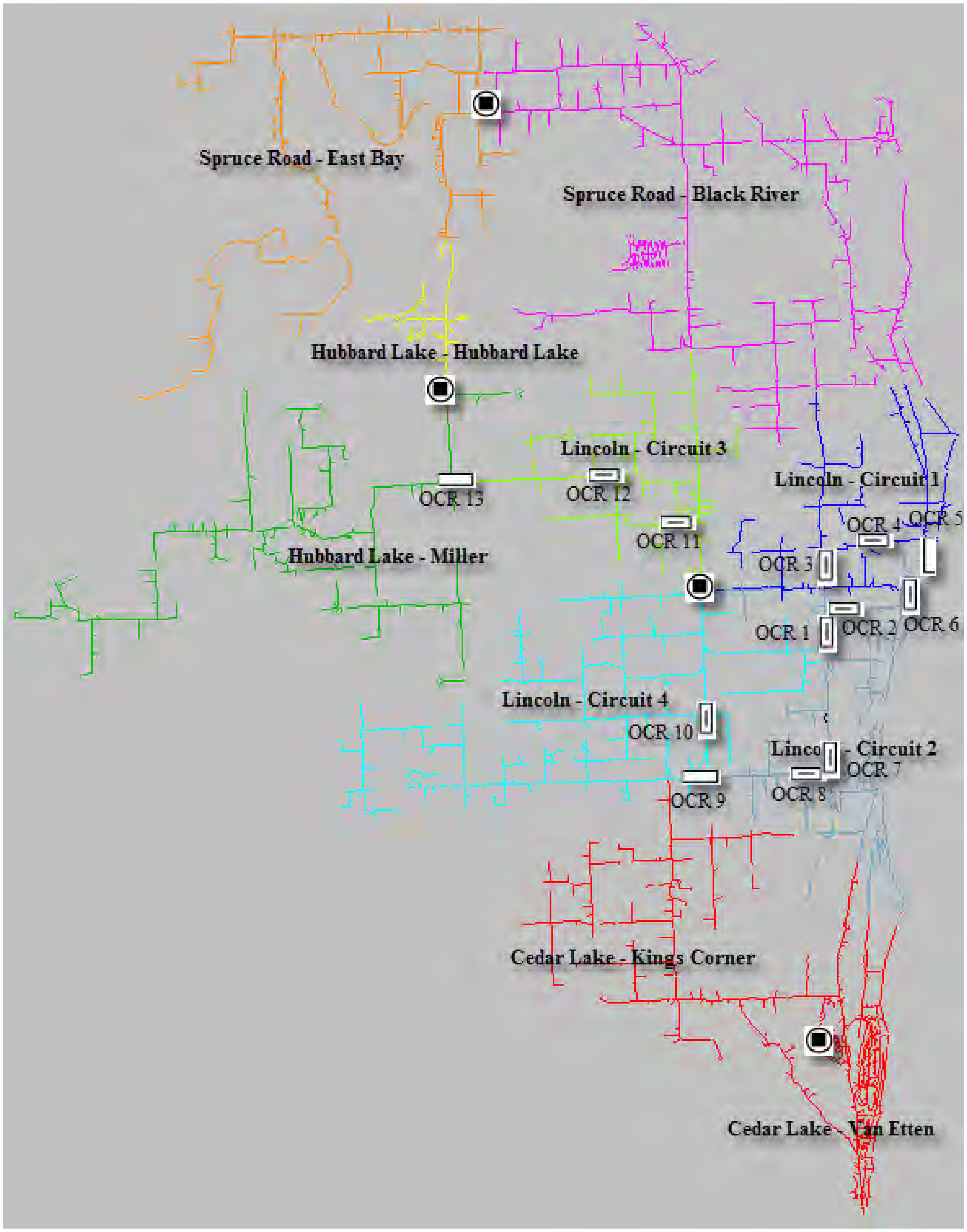


Figure 16: Normal Automation Loop Configuration

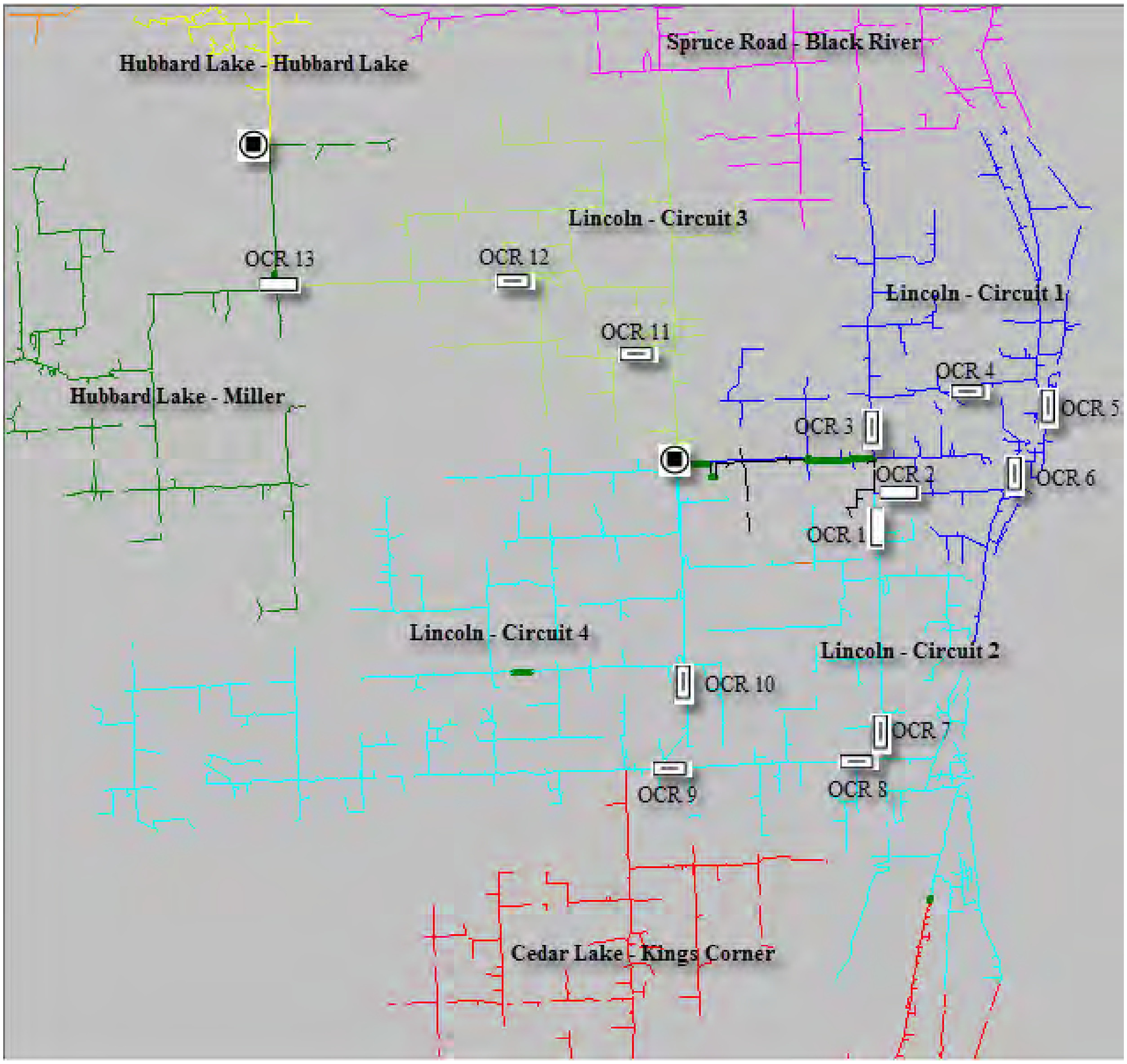


Figure 17: Lincoln – Circuit 2 Lockout

Figure 18: Lincoln – Circuit 3 Lockout

Case No. U-20963
Attachment No. 126
Page 281 of 312

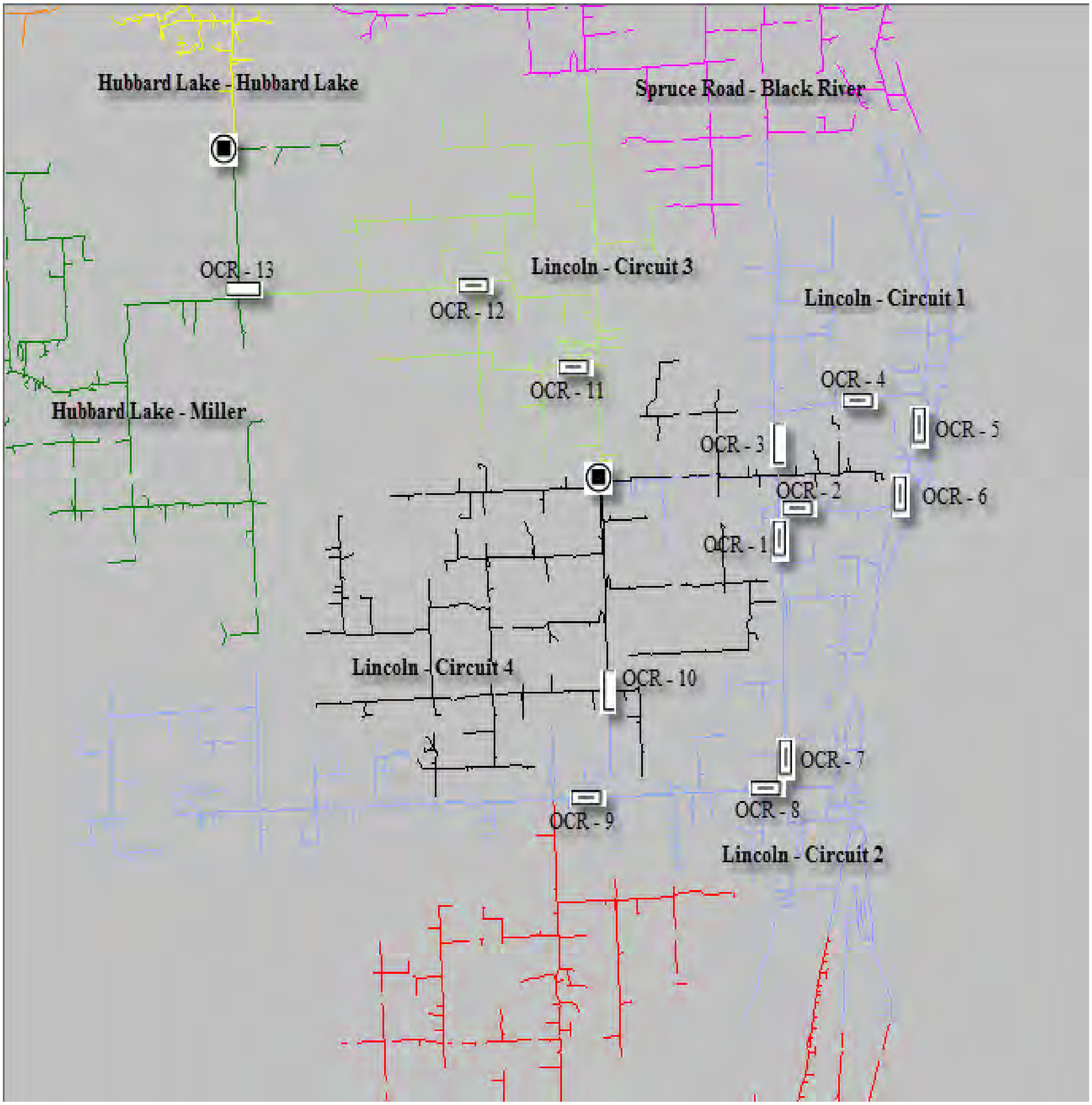


Figure 19: Lincoln – Circuit 1 & 4 Lockout

Table XIV: Number of Customers Saved by Automation

Number of Customers Saved by Automaiton				
Circuit Lockout	Saved Customer Count	Cyme SADI Numbers	Projected Cust-Min Savings	Cost Savings
1	387	187.8	72680	$218,039.28
2	1,817	102.8	186870	$560,610.28
3	456	134.3	61261	$183,782.04
4	390	111.6	43507	$130,522.16

Table XV: Automation Cost Estimate

Loop	Cost to Implement
Lincoln-Circuit 3 & Hubbard Lake-Miller Rd	$222,000.00
Lincoln-Circuit 2 & Lincoln Circuit 1	$415,000.00
Lincoln-Circuit 2 & Lincoln Circuit 4	$370,000.00

Alternative 4: Rebuild Lincoln and Greenbush substations

Alternative 4 addresses the projected overload at Lincoln in 2018 by rebuilding the existing location with a 10 MVA 46kV-14.4/24.9kV transformer that is forced air cooled. In this alternative Greenbush substation is also being rebuilt as a 10 MVA 46kV-14.4/24.9kV transformer, three circuit design that is forced air cooled. The substations will still service the same area they are servicing currently.

Alternative 4 requires no additional transmission or ROW to be purchased. The HVD and transmission would remain in its current state.

Description

The same pattern of voltage conversion was used in Alternative 4 as in Alternative 3 to completely voltage convert the whole study area. Load transfers were not an issue in Alternative 4 because the same substations still serve the same area as before.

Table XVI: Initial Circuit Miles

Column1	Circuit Name	Circuit Miles
Initial Configuration	Lincoln - Lost Lake	91.23
	Lincoln - Mikado	105.43
	Greenbush - Harrisville	26.71
	Greenbush - Greenbush	35.85
	Cedar Lake - Kings Corner	60.29
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	104.1
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Table XVII: Alternative 4 2026 Configuration Circuit Miles

Column1	Circuit Name	Circuit Miles
Alternative 4	Lincoln - Lost Lake	41.65
	Lincoln - Mikado	88.02
	Lincoln - Circuit 3	45.49
	Greenbush - Harrisville	26.71
	Greenbush - Greenbush	35.85
	Cedar Lake - Kings Corner	77.80
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	107.64
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Page 284 of 312

Distribution Automation

Automation cannot be implemented on Alternative 4 because of the trip setting of each substation. There is not enough fault current is present to change the substation NovaTS trip settings. This is a direct result of looking at the bus fault report and using a Thevenin equivalent impedance of the substation transformer in CYME to calculate the fault current.

Figure 20: Distribution Configuration Alternative 4 in 2016

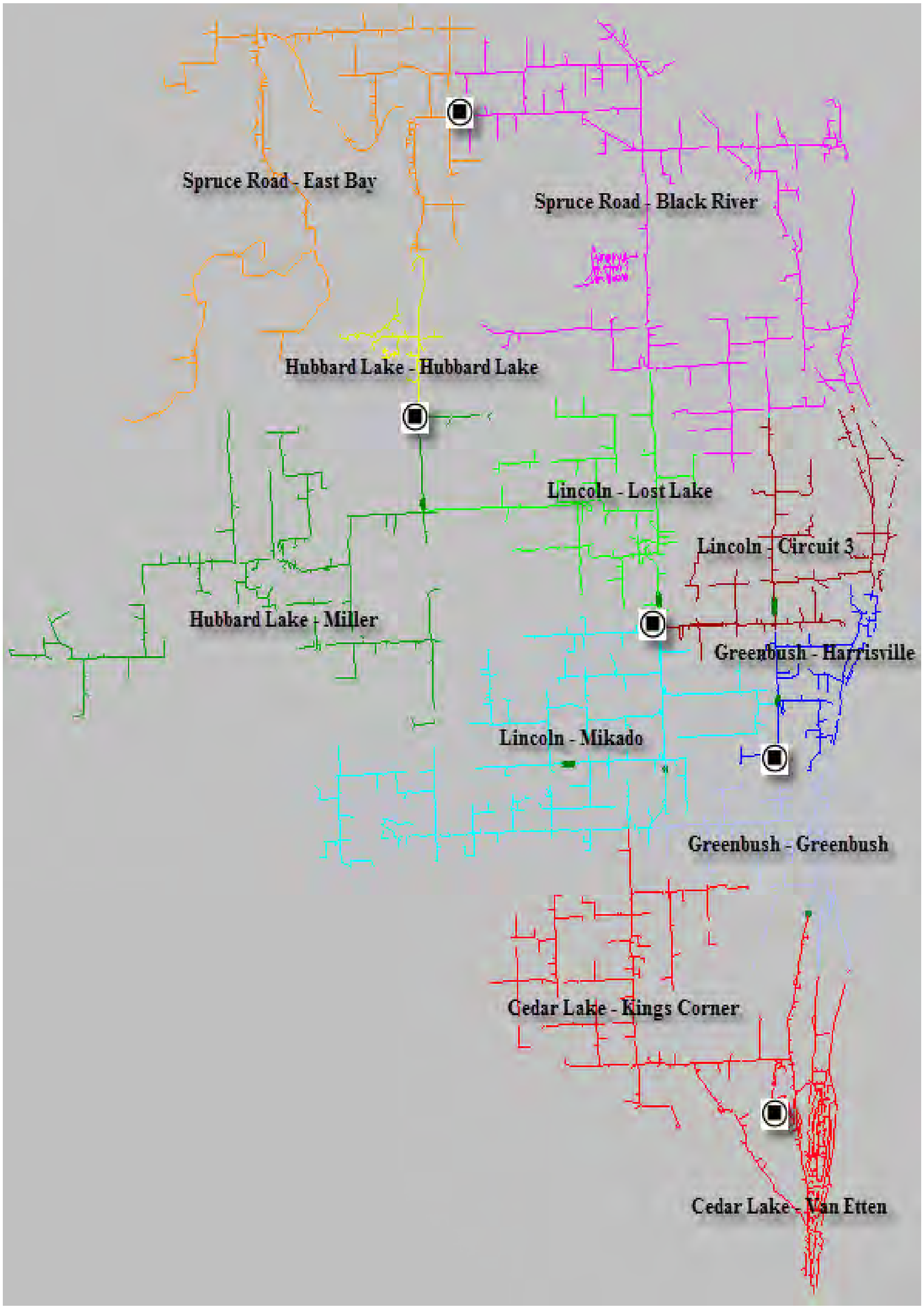


Figure 21: Distribution Configuration Alternative 4 2026

Yearly Cost Estimates

Table XVIII: Alternative 4 Yearly Cost Estimates

Costs							
Year	**Transmission**	**ROW & Site**	**Substation**	**LVD Work**	**Regulators**	**Total Cost**	**Capacity Projects**
2016				$217,416			
2017				$217,416			
2018				$1,665,004			
2019			$700,000	$721,000	$30,000		Rebuild Greenbush Sub
2020				$1,547,155	$28,000		
2021				$524,100			
2022			$800,000	$1,190,778	$112,000		Rebuild Lincoln Sub
2023				$77,000			
2024				$265,166			
2025				$1,673,066			
2026				$618,000	$153,000		
Total:			**$1,500,000**	**$8,393,101**	**$323,000**	**$10,216,101**	

Alternative 4B: Rebuild Lincoln and Greenbush Substations:

Alternative 4b addresses the issue of not being able to obtain an easement for the 138kV line necessary for alternatives 1, 2, and 3. In this alternative the configuration of Greenbush substation does not change. However, the location of Lincoln Substation is moved to a 4 acre lot owned by Consumers Energy shown in Figure 22 along the 138kV line. The new substation would be a 10MVA 138-24.9/14.4 transformer that is forced air cooled. This substation would feed two circuits and service the entire area of Lincoln substation.

Description

Alternative 4b will cost an additional $670,000, compared to the regular Alternative 4 proposed. This is due to the 138kV substation, the single-phase to three-phase line extension, and the 4.8kV to 14.4kV voltage conversion on Lincoln-Mikado. The phase extension/voltage conversion refers to a new 3-phase 14.4kV line that must be constructed 1.5 miles south of the substation to junction 349J, then East 2 miles to the original Lincoln site. Alternative 4b had 3,117,357 customer minutes according to the CYME reliability report. This alternative will retire 3.2 miles of 46kV line from Lincoln substation to the Greenbush junction resulting in a savings 956,793 customer minutes. This would result in a savings of $2,870,379.

Table XIX: Initial Circuit Miles

Column1	Circuit Name	Circuit Miles
Initial Configuration	Lincoln - Lost Lake	91.23
	Lincoln - Mikado	105.43
	Greenbush - Harrisville	26.71
	Greenbush - Greenbush	35.85
	Cedar Lake - Kings Corner	60.29
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	104.1
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	59.97

Table XX: Alternative 4B 2026 Configuration Circuit Miles

Column1	Circuit Name	Circuit Miles
Alternative 4B	Lincoln - Lost Lake	63.17
	Lincoln - Mikado	90.17
	Greenbush - Harrisville	26.71
	Greenbush - Greenbush	35.85
	Cedar Lake - Kings Corner	77.80
	Cedar Lake - Van Etten	30.32
	Spruce Road - East Bay	63.11
	Spruce Road - Black River	107.64
	Hubbard Lake - Hubbard Lake	13.49
	Hubbard Lake - Miller	86.43

Page 289 of 312

<u>Distribution Automation:</u>

Two automation loops are possible for Alternative 4b. The first automation loop possible is between Hubbard Lake-Miller Rd and Lincoln-Lost Lake. The second automation loop is between Lincoln-Lost Lake and Lincoln-Mikado. The exact location and trip settings for the NOVATS should be verified using CYME.

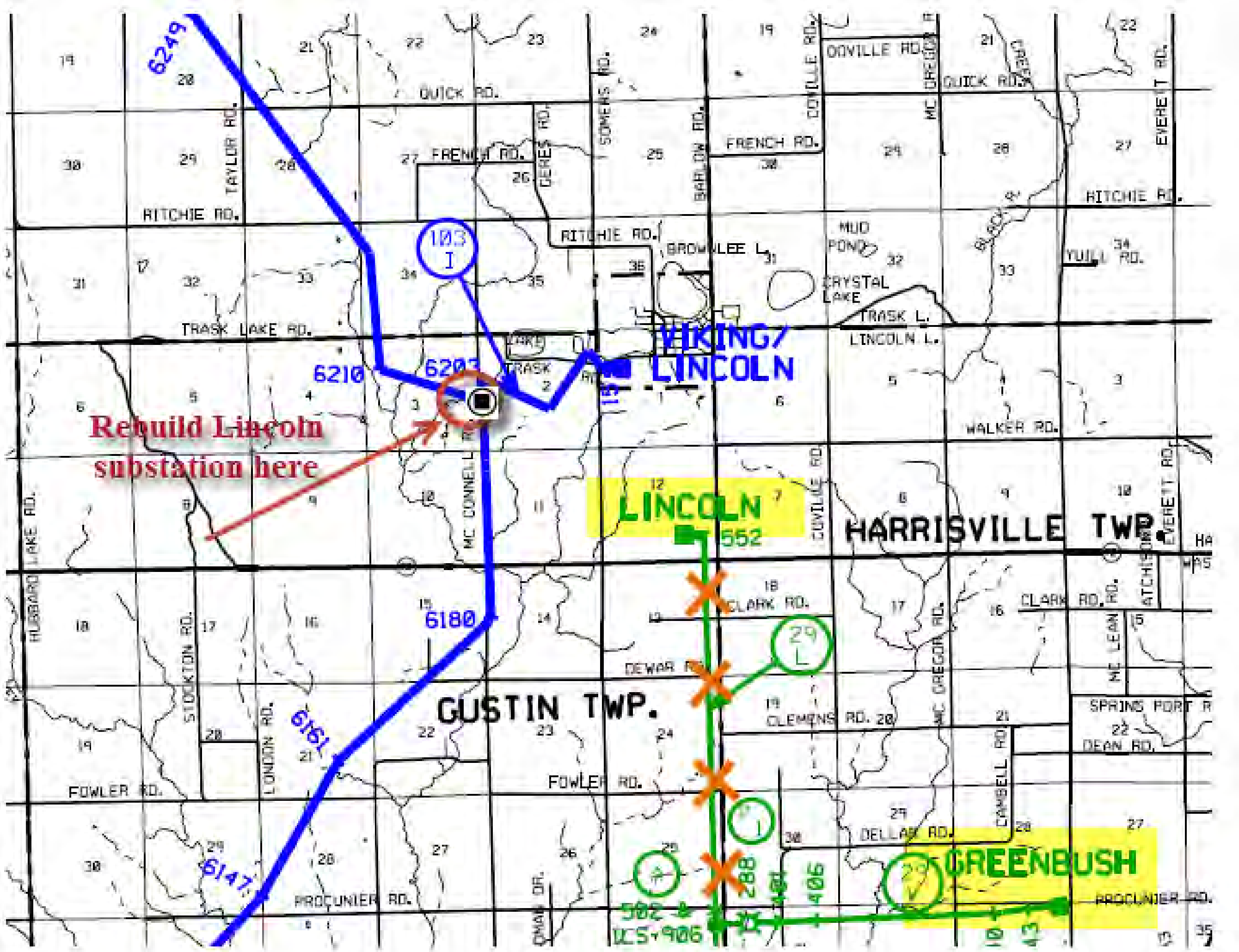


Figure 22: HVD and Transmission Proposed for Alternative 4B

Figure 23: Distribution Configuration Alternative 4B in 2015

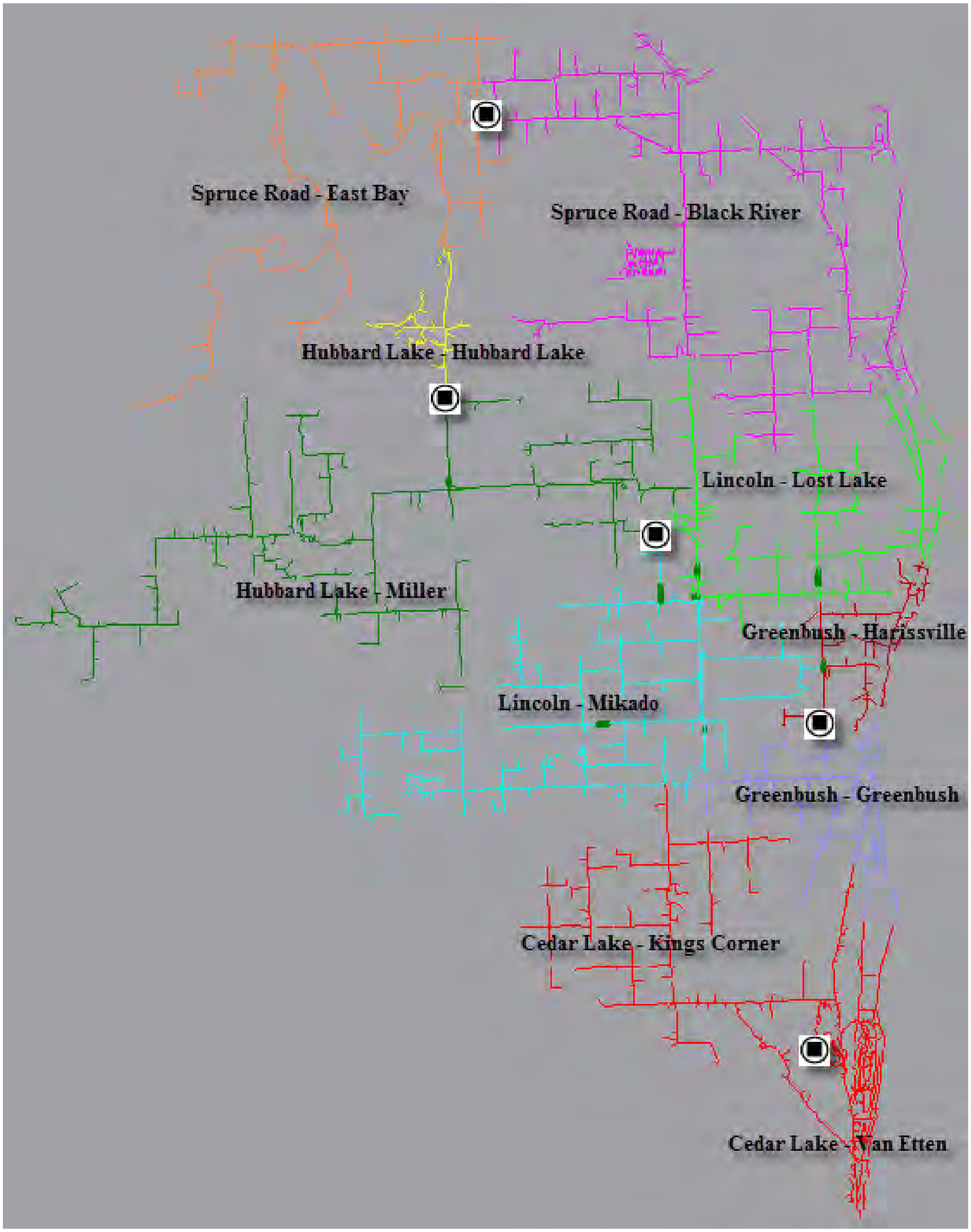


Figure 24: Distribution Configuration Alternative 4B in 2026

Table XXI: Alternative 4B Yearly Cost Estimates

Costs							
Year	**Transmission**	**ROW & Site**	**Substation**	**LVD Work**	**Regulators**	**Total Cost**	**Capacity Projects**
2016				$217,416			
2017				$217,416			
2018	$113,000			$1,665,004			
2019			$900,000	$1,176,500	$30,000		Rebuild Lincoln Sub and Phase Extensions
2020				$1,547,155	$28,000		
2021				$524,100			
2022			$700,000	$1,190,778	$112,000		Rebuild Greenbush Sub
2023				$77,000			
2024				$265,166			
2025				$1,673,066			
2026				$618,000	$153,000		
Total:	**$113,000**		**$1,600,000**	**$9,171,601**	**$323,000**	**$10,884,601**	

Analysis of Proposed Alternatives

Losses Analysis

Shown below, in Figure 25, are the losses for the proposed alternatives. These numbers take into account transformer core, transformer copper and circuit copper losses. Losses from the HVD and transmission systems are not included.

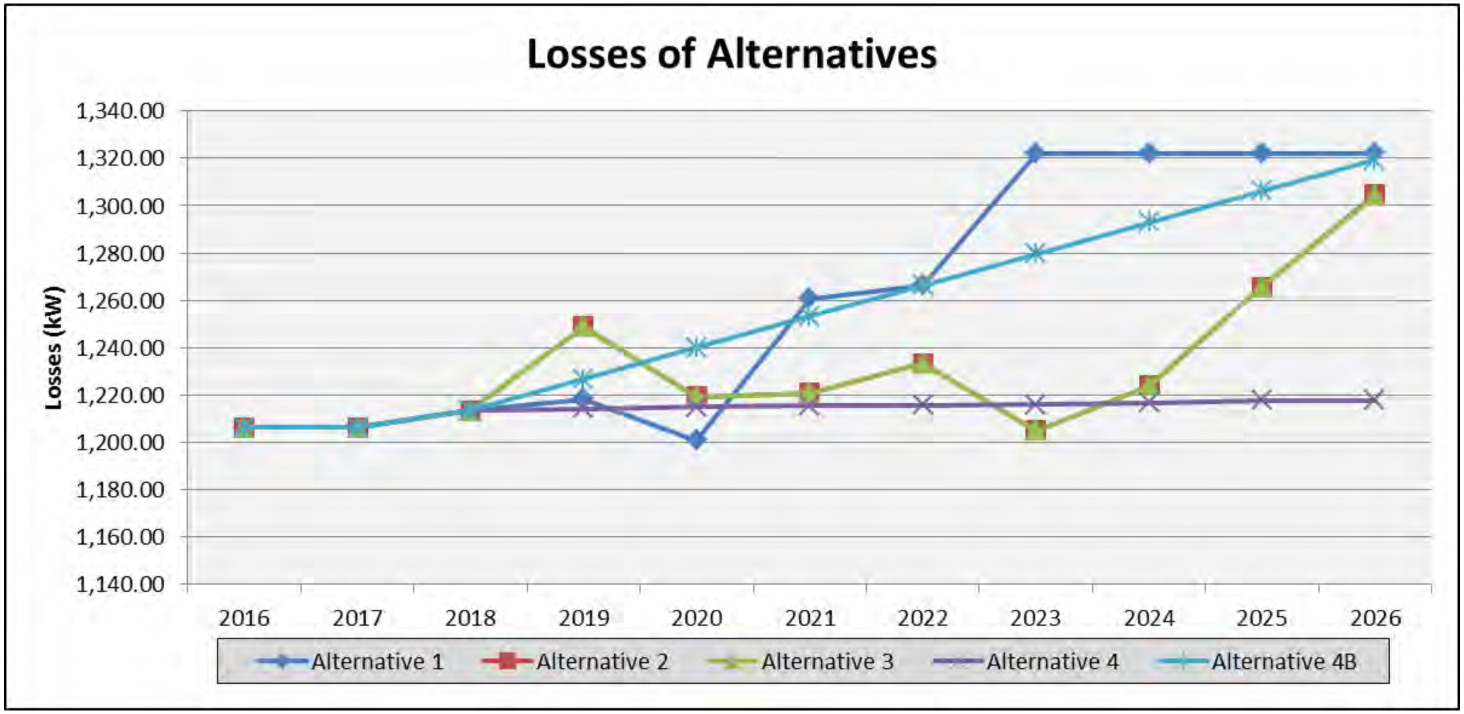


Figure 25: Losses Analysis of Alternatives

The data of Alternative 4 and Alternative 4B for 2019-2025 was interpolated and the results are shown above.

Reliability Analysis

The projected reliability numbers for the proposed alternatives are shown below in Figure 26. Each circuit had a different outage rate that was calculated from historical outage data.

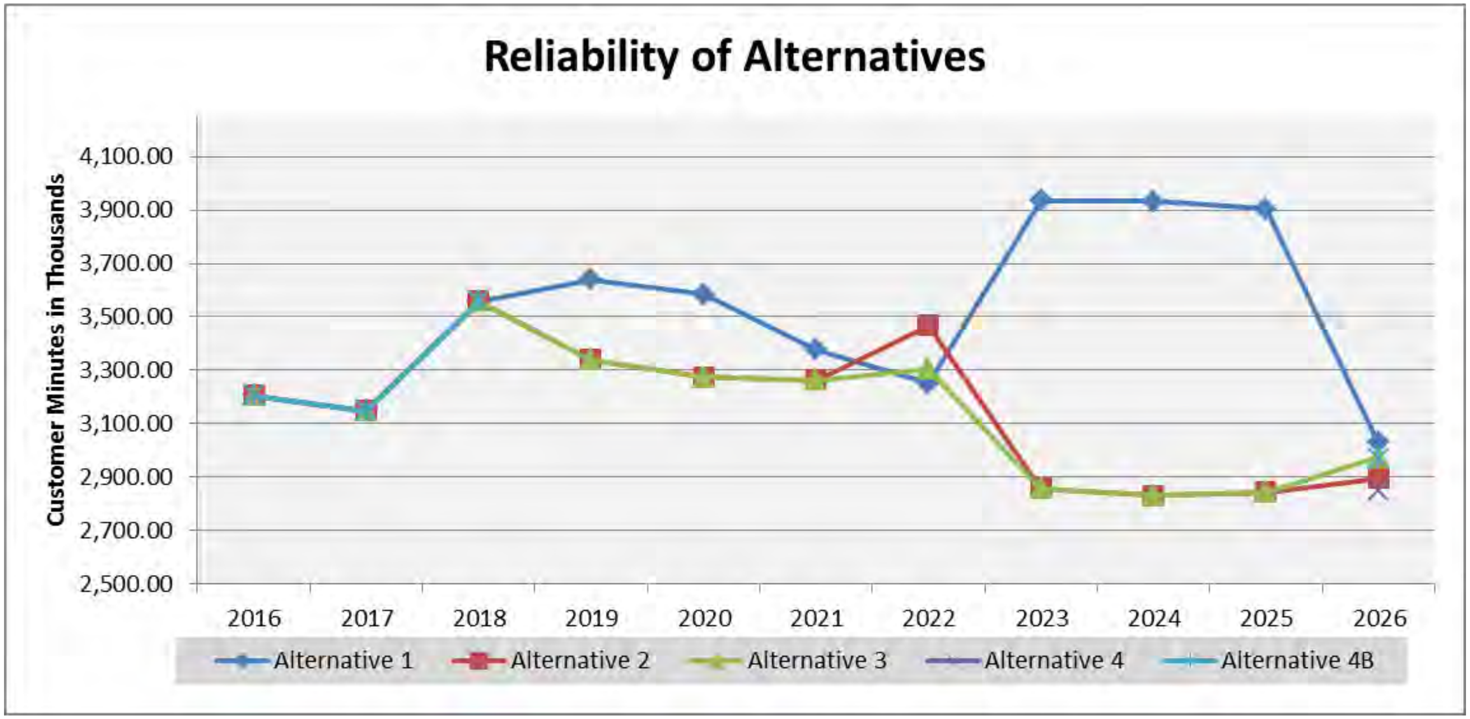


Figure 26: Reliability Analysis of Alternatives

For Alternative 4 the reliability of the “base case” years (2016-2018) and the final year (2026) were calculated and displayed above.

- Alternative 1 was 181,760 customer minutes less reliable than Alternative 4, resulting in a penalty of $545,280 being applied in 2022.
- Alternative 2 was 48,242 customer minutes less reliable than Alternative 4, resulting in a penalty of $144,726 being applied in 2022.
- Alternative 3 was 126,458 customer minutes less reliable than Alternative 4, resulting in a penalty of $379,374 being applied in 2022.
- Alternative 4B was 119,590 customer minutes less reliable than Alternative 4, resulting in a penalty of $358,770 being applied in 2022.

Economic Analysis with Reliability Adjustment

The economic analysis, shown below in Table XXII, is adjusted for reliability savings on a basis of $3 per 1 customer-minute. Circuit and transformer core losses are included in the analysis.

Table XXII: Economic Analysis of Proposed Alternatives with Reliability Adjustment

DESCRIPTION of ALTERNATIVES		Sum of Present Worth of Revenue Requirements	Relative Present Worth
Alternative 1	2018: ROW and easement purchases 2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation with a 3 circuit design	$12,744,111	1.21
Alternative 2	2018: ROW and easement purchases 2019: Build new 10 MVA substation as a 4 circuit design with double circuit under-build work	$14,282,966	1.36
Alternative 3	2018: ROW and easement purchases 2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 4 circuit design with double circuit work	$13,344,417	1.27
Alternative 4	2019: Rebuild Greenbush from a 5MVA to a 10 MVA substation as a 2 circuit design 2022: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 3 circuit design	$10,510,400	1.00
Alternative 4B	2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 2 circuit design with phase extension work 2022: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 2 circuit design	$11,333,371	1.08

- This economic analysis takes into account all work to be done to do a complete voltage conversion of the area that Lincoln and Greenbush substations serve.

Economic Analysis of ROW and Substations with Reliability Adjustment

The economic analysis, shown below in Table XXIII, is adjusted for reliability savings on a basis of $3 per 1 customer-minute. Circuit and transformer core losses are included in the analysis. Voltage conversion work for all of the alternatives is the same and can be considered a constant cost. Presented below are the LVD substation, ROW, transmission, and major LVD project work that is different between alternatives. The table below also only includes the LVD reliability benefits to the system. The HVD system and reliability adjustments are taken in to account in Table XXIV on page 54.

Table XXIII: Economic Analysis of Proposed Alternatives with Reliability Adjustment

DESCRIPTION of ALTERNATIVES		Sum of Present Worth of Revenue Requirements	Relative Present Worth
Alternative 1	2018: ROW and easement purchases 2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation with a 3 circuit design	$3,724,923	1.08
Alternative 2	2018: ROW and easement purchases 2019: Build new 10 MVA substation as a 4 circuit design with double circuit under-build work	$5,337,638	1.55
Alternative 3	2018: ROW and easement purchases 2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 4 circuit design with double circuit work	$4,449,478	1.29
Alternative 4	2019: Rebuild Greenbush from a 5MVA to a 10 MVA substation as a 2 circuit design 2022: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 3 circuit design	$3,451,267	1.00
Alternative 4B	2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 2 circuit design with phase extension work 2022: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 2 circuit design	$3,532,845	1.02

- This economic analysis takes into account the difference in substation and ROW cost.

Economic Analysis of ROW and Substations with Penalty for 46kV HVD

The economic analysis, shown below in
Table XXIV, is adjusted for reliability savings on a basis of $3 per 1 customer-minute. In addition to the previously mentioned penalties, Alternative 4 also includes HVD pole replacement costs and a reliability adjustment for serving customers from HVD instead of the 138kV line.

Table XXIV: Economic Analysis of Proposed Alternatives with Alternative 4 Penalty of 46kV Line

DESCRIPTION of ALTERNATIVES		Sum of Present Worth of Revenue Requirements	Relative Present Worth
Alternative 1	2018: ROW and easement purchases 2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation with a 3 circuit design	$3,724,923	1.00
Alternative 2	2018: ROW and easement purchases 2019: Build new 10 MVA substation as a 4 circuit design with double circuit under-build work	$5,337,638	1.43
Alternative 3	2018: ROW and easement purchases 2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 4 circuit design with double circuit work	$4,449,478	1.19
Alternative 4	2019: Rebuild Greenbush from a 5MVA to a 10 MVA substation as a 2 circuit design 2022: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 3 circuit design 2024: Pole replacements resulting in a penalty of $390,000. 2026: Reliability penalty was applied resulting in $5,451,606. 2036: Pole replacements resulting in a penalty of $390,000.	$7,583,054	2.04
Alternative 4B	2019: Rebuild Lincoln from a 5MVA to a 10 MVA substation as a 2 circuit design with phase extension work 2022: Rebuild Greenbush from a 5MVA to a 10 MVA substation as a 2 circuit design 2024: Pole replacements resulting in a penalty of $276,545. 2026: Reliability penalty was applied resulting in a penalty of $2,870,379. 2036: Pole replacements resulting in a penalty of $276,545.	$6,594,506	1.77

- This economic analysis takes into account the 2.28 million net customer-minute savings by decommissioning 11.2 miles of 46kV line for Alternative 4. This would lead to a projected $6.84 million dollars if we assume each customer outage minute costs the company $3.
- This economic analysis also takes into account the 0.96 million net customer-minute savings by decommissioning 3.2 miles of 46 kV line for Alternative 4B. This would lead to a projected $2.87 million dollars if we assume each customer outage minute cost the company $3.
    - Instead of assuming that each customer outage minute costs the company $3 and assume a price of $0.95, Alternative 4 would then match Alternative 3’s cost. If we do the same with Alternative 4B and instead of assuming $3 per customer minute, however assume a price of $0.70 per minute, Alternative 4B would then match Alternative 3’s cost.
- Pole replacement costs for the 46kV line were also factored into the analysis.

Alternative Costs

The costs of each alternative are shown compiled below in Table XXV: Comparison of Alternative Costs.

Table XXV: Comparison of Alternative Costs

Alternative 3

Year	Transmission	ROW & Site	Substation	LVD Work	Regulators	Total Cost	Capacity Projects
2016				$217,416			
2017				$217,416			
2018		$134,000		$1,665,004			ROW easements and purchase
2019	$513,000		$1,300,000	$1,277,000	$30,000		Rebuild Lincoln and Double circuit work
2020				$1,547,155	$28,000		
2021				$524,100			
2022				$1,190,778	$112,000		
2023				$77,000			
2024				$265,166			
2025				$1,673,066			
2026				$618,000	$153,000		
Total:	**$513,000**	**$134,000**	**$1,300,000**	**$8,949,103**	**$323,000**	**$11,219,103**	

Alternative 4

Year	Transmission	ROW & Site	Substation	LVD Work	Regulators	Total Cost	Capacity Projects
2016				$217,416			
2017				$217,416			
2018				$1,665,004			
2019			$700,000	$721,000	$30,000		Rebuild Greenbush Sub
2020				$1,547,155	$28,000		
2021				$524,100			
2022			$800,000	$1,190,778	$112,000		Rebuild Lincoln Sub
2023				$77,000			
2024				$265,166			
2025				$1,673,066			
2026				$618,000	$153,000		
Total:			**$1,500,000**	**$8,393,101**	**$323,000**	**$10,216,101**	

Alternative 4B

Year	Transmission	ROW & Site	Substation	LVD Work	Regulators	Total Cost	Capacity Projects
2016				$217,416			
2017				$217,416			
2018	$113,000			$1,665,004			
2019			$900,000	$1,176,500	$30,000		Rebuild Lincoln Sub and Phase Extensions
2020				$1,547,155	$28,000		
2021				$524,100			
2022			$700,000	$1,190,778	$112,000		Rebuild Greenbush Sub
2023				$77,000			
2024				$265,166			
2025				$1,673,066			
2026				$618,000	$153,000		
Total:	**$113,000**		**$1,600,000**	**$9,171,601**	**$323,000**	**$10,884,601**	

Conclusions

Summary

Greenbush and Lincoln substations are under consideration for a voltage conversion. Currently both substations are 11kV Delta and, in order to match the voltage of the surrounding substations, it is being proposed that Greenbush and Lincoln's systems be converted to 14.4/24.9kV Wye grounded.

The Lincoln transformer is also currently loaded to approximately 95% and is projected to reach capacity by 2018. This potential overload should bring upgrades to Lincoln substation into consideration.

Additionally, Greenbush/Harrisville and Lincoln/Lost Lake circuits are in the bottom 10% statewide in terms of reliability. Upgrades to the system are recommended to improve the SAIDI and SAIFI minutes of this area.

Alternative 1 proposes to rebuild Lincoln substation with a 10 MVA 138kV/14.4kV transformer three circuit design. The transformer would also be forced air cooled to enable the capability of the substation to reach 17 MVA. This alternative requires construction of two miles of 138kV line and ROW to be purchased. The 11kV Delta LVD on Greenbush and Lincoln would be converted to 14.4kV Wye. The three circuits from the rebuilt Lincoln substation would feed the entire LVD area that both Greenbush and Lincoln currently provide. Ultimately, Greenbush substation would be retired along with 10.6 miles of 46kV line back to the Cedar Lake junction.

Alternative 2 constructs a new substation with a 10 MVA 138kV/14.4kV transformer that is forced air cooled located three miles East of Lincoln substation. This requires construction of 5 miles of 138kV line and ROW to be purchased. The substation would have four circuits that would feed the entire LVD area of both Greenbush and Lincoln. The11kV Delta LVD on Greenbush and Lincoln would be converted to 14.4kV Wye. Greenbush and Lincoln substation would be retired along with 10.6 miles of 46kV line back to the Cedar Lake junction.

Alternative 3 is the same as Alternative 1, except that the Lincoln substation is rebuilt with four LVD circuits. This reduces the circuit miles per circuit and makes the area more reliable.

Alternative 4 rebuilds both Greenbush and Lincoln substations with 10 MVA 46kV/14.4kV forced air cooled transformers. Lincoln substation would be rebuilt with three circuits and Greenbush substation would be rebuilt with a two circuit design. No changes are made to the HVD system in this alternative.

Alternative 4b is a variation of Alternative 4. In this alternative Lincoln substation is decommissioned and a new 138-24.9/14.4kV substation is constructed on Consumers Energy owned property along the 138kV line. This new substation would have a forced air cooled 10MVA transformer two circuit design and would service Lincoln/Mikado and Lincoln/Lost Lake. This alternative will retire 3.2 miles of 46kV line from Lincoln substation to the Greenbush junction.

Automation was also considered due to the remote location of the study area and the travel time required for crews to restore power. Three automation loops are possible for Alternative 2 and Alternative 3. These loops would keep the towns of Lincoln, Greenbush, and Harrisville online due to a circuit lockout. Two automation loops are possible for Alternative 1. No automation scheme is possible for Alternative 4 due to coordination issues with the high side fuses on the 46kV line. One automation loop is possible for Alternative 4b between Hubbard Lake and Lincoln/Lost Lake. Two one-way automation loops may be possible between Lincoln and Greenbush substations.

Recommendation Summary and Approvals

The recommendation for this long range plan is Alternative 3 – Rebuilding Lincoln substation with a four circuit design being fed from the 138kV Alpena-Iosco Line.

Alternative 4 has drawbacks compared to Alternative 3. In Alternative 4 there is no change to the HVD configuration, meaning that the 46kV radial line cannot be retired. Without retiring this line, Consumers Energy still has to maintain it replacing poles each year, refer to Table XXI. As shown in Table XVII, there is a savings of 2.17 million net customer-minutes by retiring the HVD line. Another drawback Alternative 4 presents is that no automation is possible. The possibility of automation is gone because of coordination issues with the fuses on the 46kV line. One of the goals of this plan was to increase the reliability of the study area, making Alternative 4 a less desirable solution.

Alternative 3 is preferable compared to Alternative 1 because the distribution area would be divided between four circuits, instead of three. Alternative 1 in its final configuration has a circuit that is about 130 miles long. This circuit causes issues with reliability, as well as issues with damage assessment ride out times. With this circuit being so large, CYME cannot factor in all of these extra issues, therefore the reliability of this alternative still looks acceptable. Alternative 2 is not as desirable due to the increased cost of constructing 3 extra miles of 138kV line with little improvement to customer outage minutes.
In the event that the easement for the 138kV line cannot be obtained for Alternatives 1, 2 and 3, we recommend implementing Alternative 4b. Alternative 4b is preferable to Alternative 4 because all of the customers on Lincoln substation would be serviced off of the 138kV line. This alternative also presents one automation loop possibility between Hubbard Lake and Lincoln/Lost Lake.

One of the major benefits of Alternative 3 is the possibility for automation loops once all the voltage conversion is completed. Three automation loops are possible which would keep the towns of Greenbush, Lincoln, and Harrisville online in the event of a circuit lockout. This would reduce outage time, especially considering the remote location of the study area.

Jordan Holbrook, Cooperative Assistant	Date
Matthew Koepke, Cooperative Assistant	Date

Approvals:

Matt Good, Long Range Planning Engineer	Date
Brad Styes, HVD Planning	Date
Amy Merrick, System Owner	Date
Katrina Casarez, System Engineer	Date
Steve Markey, Substation Planning, East	Date
Dwayne Parker, Director C&SI & HVD	Date

From: SPAdvisor
To: Joshua L. Birchmeier
Subject: Approval has completed on DARE Lincoln Greenbush Long Range Plan: LVD.
Date: Thursday, December 19, 2019 1:05:21 PM

Approval has completed on DARE Lincoln Greenbush Long Range Plan: LVD.

Approval on DARE Lincoln Greenbush Long Range Plan: LVD has successfully completed. All participants have completed their tasks.

Approval started by Joshua L. Birchmeier on 12/6/2019 4:12 PM
Comment: Please review and approve/reject the proposed LVD concept.

Approved by Joshua L. Birchmeier on 12/6/2019 4:13 PM
Comment:

Approved by JULIA R. FOX on 12/9/2019 6:41 PM
Comment: Approved

Approved by DONALD A. LYND on 12/12/2019 8:03 PM
Comment: Approved. This multi-year project fulfills a voltage conversion objective and permits retirement of a substation and miles of radial 46 kV line.

Approved by RICHARD T. BLUMENSTOCK on 12/17/2019 12:20 PM
Comment: Approved. Links to a related concept approval and a supporting long range plan report are included. So, too, are maps of the area before and after substation and circuit conversions.

Approved by Timothy J. Sparks on 12/18/2019 12:37 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 12/19/2019 1:05 PM
Comment:

View the workflow history.

From: SPAdvisor
To: Joshua L. Birchmeier
Subject: Approval has completed on DARE Lincoln Greenbush Long Range Plan: LVD.
Date: Friday, December 27, 2019 12:11:39 PM

Approval has completed on DARE Lincoln Greenbush Long Range Plan: LVD.

Approval on DARE Lincoln Greenbush Long Range Plan: LVD has successfully completed. All participants have completed their tasks.

Approval started by Joshua L. Birchmeier on 12/19/2019 2:52 PM
Comment: Please review and approve/reject the proposed LVD concept. Approval through JF was completed under a separate workflow. Approval sheet is attached to the concept.

Approved by Patricia K. Poppe on 12/27/2019 12:11 PM
Comment:

View the workflow history.

PROJECT: LN086E SHELBY REBUILD

i. Purpose and Necessity of the Project with Supporting Data.

The purpose of this HVD line rebuild is to improve overall reliability and in particular for the approximately 2,500 customers served from the Shelby 46 kV Line. There are 24 out of 102 poles (24%) that were identified as replacement candidates by the pole inspector for the 86E, 5.25 mile section covered under this rebuild. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild vs. further investment in pole replacements or pole top rehabilitation on a non-standard line. The Shelby 86E line section is presently non-standard 2/0 copper conductor in an unshielded configuration.

Concept Approval 22-0050 provides additional project details.

ii. Line Design, size material used.

Single circuit, wood pole design with 336 ACSR conductor and fiber optic shield wire.

iii. Line Length and ROW requirements.

The rebuild is 5.25 miles long and will be rebuilt on the existing centerline utilizing existing easements.

iv. Approximate Construction Schedule.

Construction Start: September 1, 2022
Construction Complete: February 28, 2023

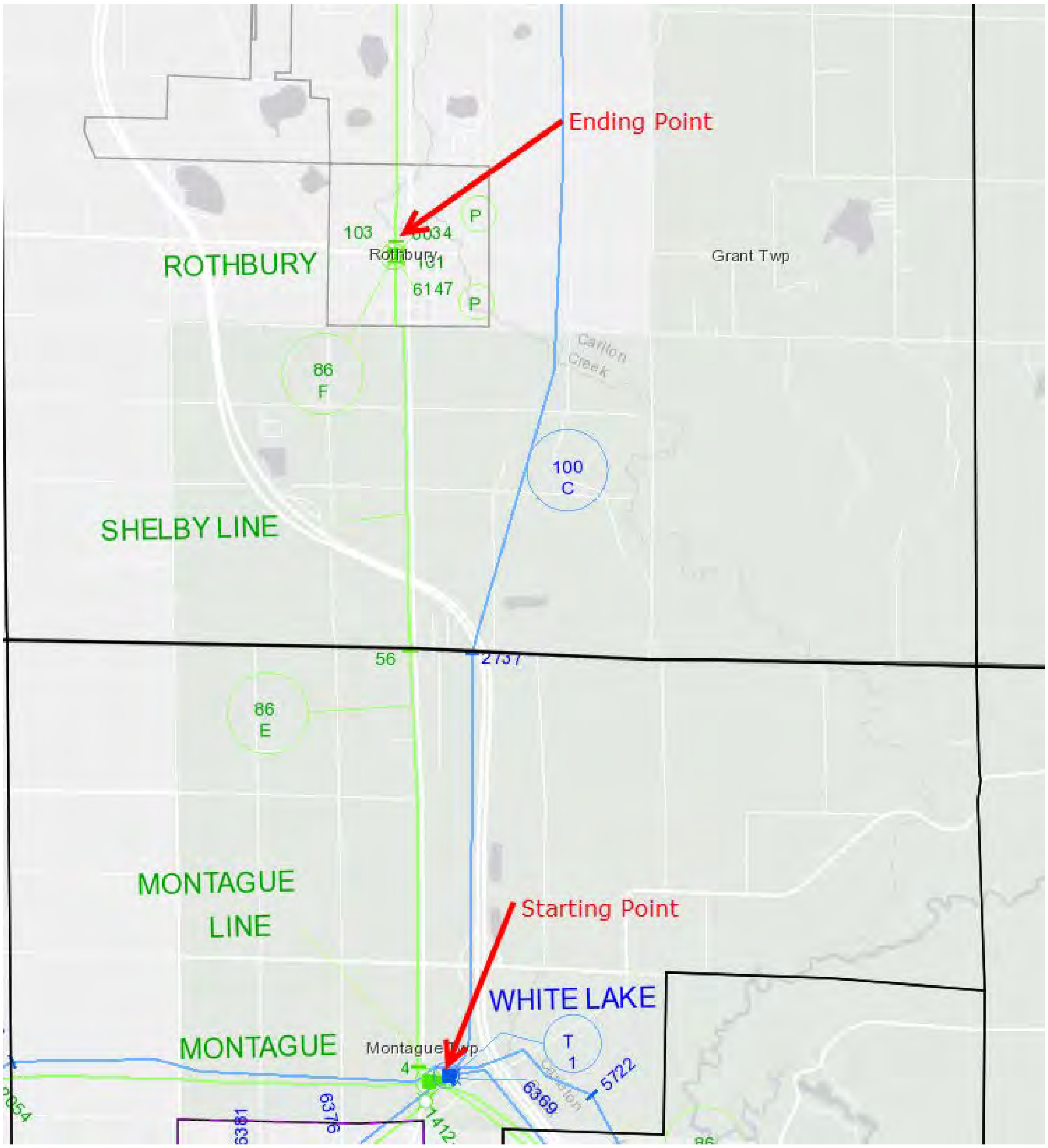
v. Project effect on cost of operation and reliability of service.

The reliability of electric service will increase with the new configuration. The Shelby 46 kV line experienced 1 outage incident between years 2015 through 2019. Consumers Energy has been rebuilding HVD lines for many years. Outage data clearly show that after completing a rebuild a line typically experiences zero or minimal line equipment related outages (see Section ix. Impact of Line Rebuilds on Outages table).

vi. A description of the property being replaced and salvage value.

Wood poles, crossarms, insulators, conductor and etc. that were constructed pre-WWII are being removed starting at White Lake Substation to structure #104. The wood poles and crossarms and porcelain insulators have zero salvage value. The conductor will be sent to Central Reclamation to be sold at scrap value.

vii. Map of site and location of facilities.



viii. Funding from other entities.

None.

ix. All studies performed by the Company or 3rd party regarding the project.

The 2019 pole inspection identified 24 out of 102 poles (24%) on this line segment as needing to be replaced.

Impact of Line Rebuilds on Outages			
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**
Barry – Broadmoor	2/17/2009	5	0
Dowling – Beecher	2/24/2009	4	0
Warren – Grout	3/4/2009	2	0
Monitor – Almeda	4/8/2010	1	1
Whitestone Point	6/30/2010	10	0
Parma – West	4/11/2011	2	0
Standish	7/6/2011	1	0
North Adams – North	10/10/2011	2	0
Mancelona	10/21/2011	1	0
Parma – East	11/1/2011	3	0
Nashville East	2/24/2012	3	0
Bridgeport	6/15/2012	1	0
Suttons Bay – South	10/9/2012	2	0
North Adams – Center	1/14/2013	1	0
Fremont – West	2/28/2014	2	0
Fremont – East	7/15/2014	4	0
Sanford	11/3/2014	3	0
Carson City – South	12/3/2014	7	0
Union Street	2/12/2015	2	0
Nashville Center	5/29/2015	1	0
Markey – North	5/29/2015	2	0
Carson City – North	12/1/2015	1	0
North Adams – South	12/29/2015	1	0
Peach Ridge	6/20/2016	1	0
Nashville – West	8/29/2016	2	0
Pierson – Trufant West	1/24/2017	1	0
Textron	1/27/2017	1	0
Bridgeport	1/27/2017	1	0
Manitou Beach	3/29/2017	1	0
Augusta	5/1/2017	2	0
Pierson - Trufant East	5/30/2017	3	0
	Totals	**73**	**1**

x. Date of board approval.

N/A

CONCEPT APPROVAL No. 22-0050
Shelby 46 kV HVD Lines Reliability Rebuild

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0050

Project: **Shelby 46 kV Line – HVD Lines Reliability Rebuild** **County:** Muskegon and Oceana Counties

Date: January 14, 2021 **Need System Changes By:** 2/28/2023

Problem Description:

The Shelby 46 kV line was constructed pre-1940 by a local REA company and purchased by Consumers Energy in the early 1940s. The line is constructed with non-standard 2/0 copper conductor in an unshielded configuration. The Shelby 46 kV line has experienced 1 outage incident between 2015 and 2019. Pole inspections have recently identified that 24 out of 102 (23.5%) poles are replacement candidates in the section of the Shelby 46 kV line from the White Lake Substation to structure #104.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Replacements. *Conceptual cost: $507,000*
3. Rebuild 5.25 miles of the Shelby 46 kV line. *HVD Conceptual cost: $2,442,000 and LVD Conceptual cost: $1,500,000*

Recommended Alternative:

Alternative #3 is recommended. Rebuild of this line is needed to improve overall system reliability and for the approximately 2,500 customers served from the Shelby 46 kV line. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages.

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks

Alternative #1 does not address the poles that need replacement or the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 addresses the poles that need replacement but does not address the aged copper conductor or the unshielded configuration of the line.

Alternative #3 Recommended Scope:
Rebuild the 5.25 mile section of the Shelby 46 kV line from the White Lake Substation to structure #104 with a single circuit 336.4 ACSR conductor built on the existing centerline. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2023 Direct Cost	2022 Cost with Overheads	2023 Cost with Overheads	Description
EH-95308	$1,213,000	$363,000	$1,880,000	$562,000	Rebuild Shelby 46 kV line
ED-95719	$745,200	$222,600	$1,155,000	$345,000	LVD Underbuild Line Relocation
Customer Contribution	$0	$0	$0	$0	
Total	$1,958,200	$585,600	$3,035,000	$907,000	Grand Total Cost with Overheads: **$3,942,000**

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

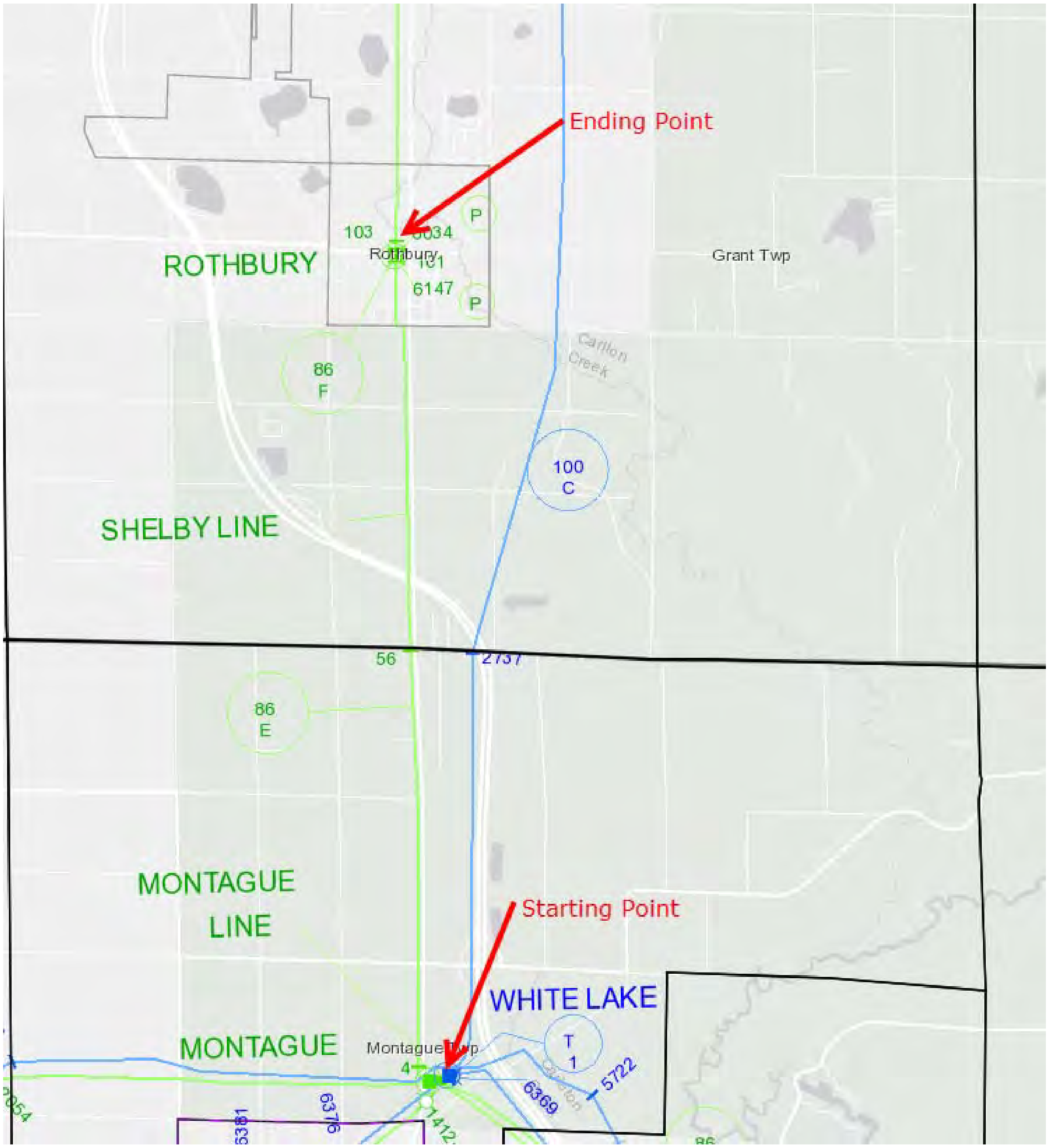
Prepared By: LBHincka **Team Leader:** Doug Meyers

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks

Approvals:

Senior Engineer Lead, LVD Circuit Planning	John P. Brack	Required
Director, HVD System Planning	Edward R. Mathews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks



Case No. U-20963
Attachment No. 126
Page 312 of 312

From:	SPAdvisor
To:	Amanda J. Rueff
Cc:	BRIAN C. MAZUR; Brian M. Bushey; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Gregory E. Kral; Jacob D. Roberson; LOUIS B. HINCKA; DOUGLAS R. MEYERS
Subject:	Approval has completed on 22-0050 Shelby 46 kV HVD Lines Reliability Rebuild.
Date:	Thursday, January 14, 2021 10:01:56 AM

Approval has completed on 22-0050 Shelby 46 kV HVD Lines Reliability Rebuild.

Approval on 22-0050 Shelby 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by Amanda J. Rueff on 1/13/2021 2:45 PM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by JOHN P. BRACK on 1/13/2021 2:51 PM
Comment:

Approved by Edward R. Mathews on 1/13/2021 3:39 PM
Comment:

Approved by JULIA R. FOX on 1/13/2021 3:49 PM
Comment:

Approved by DONALD A. LYND on 1/13/2021 4:40 PM
Comment: Approved.

Approved by RICHARD T. BLUMENSTOCK on 1/13/2021 4:44 PM
Comment: Approved.

Approved by Timothy J. Sparks on 1/14/2021 10:01 AM
Comment: Approved.

View the workflow history.

Question:

3. On page 188, Lines 8-11 of Mr. Blumenstock's testimony, he explains the Company's HVD inspection programs: "The four key HVD lines inspection programs informing the HVD Lines and Substations Rehabilitation sub-program are: (i) pole inspections; (ii) helicopter inspections; (iii) biannual ground patrols; and (iv) MOABS testing."

   a. How often does the Company have failures of HVD lines or substation equipment during the interim period between 12-year pole inspections, annual helicopter inspections, biannual ground inspections, annual Motor Operated Air Brake Switch (MOABS) inspections, or monthly substation visual inspections? Please provide details for each category?

   b. How often do inspections with infrared or corona cameras (either aerial or ground inspections) miss equipment failures in which a corona is in existence?

   c. How often do corona induced faults occur in the interim between camera inspections?

   d. How often do monthly HVD substation patrols miss identifying equipment in a state of imminent failure?

   e. On page 190, lines 16-19, Mr. Blumenstock in reference to HVD substations notes that: "Some equipment (power transformers, station batteries, gas circuit breakers, and transformer bushings) are monitored by Field Technical Services and Substation Reliability Engineers and are replaced prior to failure through this subprogram." Does the HVD substation inspection program contain the same elements and frequency as the LVD substation inspection program, as detailed in Figure 513 (LVD Inspection Cadence) of Mr. Blumenstock's testimony? If not, please explain in detail the nature of the inspection, and the frequency of inspection?

   f. What is the frequency of HVD and LVD substation transformer failures over the past 5 years that have occurred despite substation inspection-programs?

Response:

a. The referenced inspections apply only to HVD lines, not to any substations. From 2016 through the first quarter of 2021, the Company had 127 Priority 1 HVD pole replacement orders, indicating a failure between inspections. From 2016 through 2020, the Company had 196 Priority 1 orders for HVD pole-top equipment on both flyable and non-flyable lines. The Company did not have any MOABS that failed to operate when called upon between 2016 and 2020, indicating no failures in between inspections.

b. By definition, it is impossible to count the number of occurrences of something that was missed.

c. From 2018 through 2020, the Company identified 296 corona signatures requiring insulator replacement using the corona camera, indicating a fault in between inspections. During that same time period, the Company experienced 52 Victor-type insulator failures on the HVD system.

d. By definition, it is impossible to count the number of occurrences of something that was missed. The nature of equipment failures at HVD substations does not lend itself to discovery through routine substation inspections. Imminent failures are most often detected by equipment inspections per procedures specific to the equipment being inspected.

e. Yes. Equipment that is common to both HVD and LVD substations is inspected using the same cadence. Some equipment types are rare in LVD substations but very common in HVD substations. Breakers are visually inspected monthly as part of the monthly substation inspection. They are typically test operated at least annually and will be scheduled for an equipment inspection on anywhere from a 5 to 20-year cycle (based on type, model and manufacturer). Gas breakers will have a gas purity test performed every three years. Oil breakers will have a periodic oil test.

f.

CE Power Transformer Failures			
	LVD	HVD	Single Customer
2016	4	0	0
2017	2	1	0
2018	4	0	1
2019	0	0	1
2020	3	0	0

It should be noted that in many cases, there was an event that preceded/caused/accelerated the failure. These would not be detected by transformer oil analysis:

- 2016
  - Transformer 1 (1956): Two through faults probably accelerated failure
  - Transformer 2 (1951): Initiated by animal contact
  - Transformer 4 (1954): Bushing failure
- 2017
  - Transformer 2 (1950): Bushing failure
  - Transformer 3 (1969): LVD fault caused bushing failure
- 2018
  - Transformer 1 (1952): Car/pole accident resulting in fault current
  - Transformer 2 (1960): Car/pole accident resulting in fault current
- 2020
  - Transformer 2 (1962): Bird contact

With over 1,440 transformers on the system, this represents a failure rate of about 0.22% per year.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

Question:

4. Referring to Figure 513 (LVD Inspection Cadence):

   a. How often to failures occur (for each category) during the interim period between inspections?

   b. Does the Company perform aerial or ground inspection of its LVD system using infrared or corona cameras? If so, how often do inspections miss equipment failures in which a corona is in existence?

Response:

a. Unless a failure occurs by chance while an inspection is taking place, every failure happens in between inspections. As stated on page 92, lines 5 through 7, of my direct testimony, the Company experiences an average of six transformer failures, 26 recloser failures, and 78 regulator failures in LVD substations each year.

b. The Company does perform infrared inspections of LVD substations on a biennial basis. The Company does not perform regular corona camera inspection of LVD substations. By definition, it would not be possible to know how often any inspection misses any existing issue.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

<u>Question:</u>

1) Refer to Mr. Blumenstock's direct testimony, pages 131, 139, 188, and 271, where he describes the Company's HVD lines, poles, and substation inspection programs. In addition, refer to pages 122-23, Figure 513 on page 197, and pages 203-204 of Mr. Blumenstock's testimony, which describes LVD inspections for lines, poles, and substations.

For the following questions, an "incipient condition" is defined as anything likely to cause a fault, additional fault, sustained outage, interruption, intermittent power quality event, customer complaint, catastrophic equipment failure, equipment stress, or other negative events in the future.

Examples of incipient conditions may include but are not limited to: (a) fault-induced conductor slap, (b) cracked bushings, broken insulators, (3) hot spots in clamps or switches, (4) incipient failure of vacuum or oil switches in capacitor banks, such as internal arcing or partial loss of vacuum, internal arcing of capacitors, blown fuses, (5) early-stage failures of HVD lines or associated equipment, recurrent fault clusters, progressive conductor damage, catastrophically failed lightning arresters.

a. Regarding the Company's inspections and monitoring of its HVD lines, poles, substations, and associated equipment:
    i. Please quantify (e.g., number of customers affected, length of outage) and provide detail by year, for the years 2016 – 2020, every negative event (e.g., fault, additional fault, sustained outage, etc. as listed above) that was preceded by or likely preceded by incipient conditions.
    ii. Please identify the incipient condition(s);
    iii. Please identify the date and type of the most current inspection preceding the incipient condition(s) – whether (1) pole inspection, (2) helicopter inspection, (3) ground patrol, infrared or corona camera inspection or (4) other inspections;
    iv. Please identify whether such incipient condition(s) were likely in existence (and identified or were failed to be identified while in an incipient condition) at the time of the most current inspection; whether the incipient condition likely developed in the interim between or after the inspection(s); and whether the incipient condition(s) were identified or failed to be identified while in an incipient condition by the Company's continuous HVD monitoring programs.
b. Please provide the same information as requested is subpart (a) above, with respect to the Company's LVD lines, poles, substations, and associated equipment.
c. Do the Company's HVD and LVD continuous monitoring programs enable both detection and determination of location of incipient conditions? Please explain the technologies and capabilities of the Company's continuous monitoring systems with respect to incipient conditions?

Response:

Objection of Counsel: Consumers Energy Company objects to subparts a. and b. of this discovery request on the basis that it requests the Company to provide data on "incipient conditions," which is not a term that the Company uses, nor does it track information based on such term. Further objecting, the request calls for speculation to the extent that it asks for things that were "likely" to cause a fault, events that were "likely" preceded by incipient conditions, and conditions that were "likely" in existence during or between inspections. The request is also unduly burdensome and not proportional to the needs of this case. Without waiving this objection, the Company responds as follows:

a and b: The Company does not have the analysis requested in subparts a and b, because the Company has not used the concept of "incipient condition" in its electric planning and does not track information in this manner.

c. The Company's inspection programs do allow the Company to identify areas of potential future outages on the HVD and LVD systems. However, the Company's inspection programs are generally periodic, not "continuous" in the sense of around-the-clock monitoring of all distribution assets.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 1, 2021

Electric Planning

Question:

52. How does Consumers determine where to locate VVO/ATR loops/line sensors/voltage regulators and controllers/capacitor upgrades and replacements?

Response:

The Company deploys VVO on every circuit that has both DSCADA-enabled and upgraded capacitors.

For deploying ATR loops, the entire system is evaluated on an annual basis to determine which circuit tie points to automate. Planning engineers consider locations in their regions of responsibility and craft detailed proposals with the scope of upgrades to install ATRs as well as the projected benefits based on outage history of the affected circuits. These are then ranked by cost/benefit ratio, with the highest-ranking selected for the next workplan.

The selection process for lines sensors is performed using a circuit-by-circuit analysis of such factors as CAIDI, 10-Year fault history (weighted by recency), circuit length, and circuit loading are evaluated. Once a circuit is selected, additional analysis is performed to choose specific sensor locations. Sensor locations are placed to divide the circuit into zones of approximately 1 to 2 miles to optimize fault location benefits. Line sensors are often placed near non-communicating line reclosers to provided better insight for protection coordination or placed near potentially overloaded equipment to verify loadings. Locations are also analyzed to ensure adequate physical properties such as conductor size, type, and length to ensure structural integrity.

Voltage regulator controller upgrades are prioritized based on circuits that have DSCADA enabled, and areas that allow for efficient contractor construction and mobility. For example, northern, rural regions are targeted for summer months.

The Company deploys capacitor upgrades to locations that have not already received a neutral current sensor ("NCS"). Of the locations that have not already been upgraded with an NCS, they are prioritized based on circuits that are not DSCADA-enabled, and those capacitors that are identified as needing additional repairs such as a blown fuse.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

Incipient Conditions on Electric Power Circuits

A White Paper – April 2017

Carl L. Benner and Dr. B. Don Russell

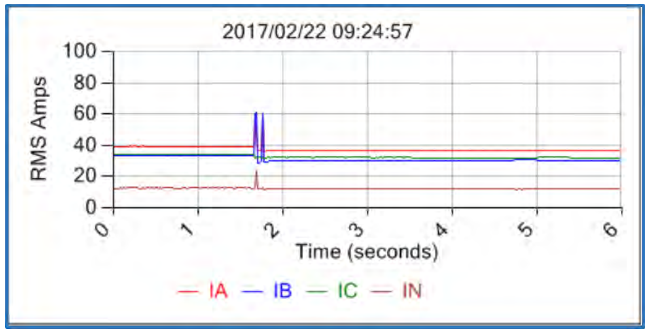
Incipient*: adjective; beginning to develop or exist; beginning to come into being or to become apparent.*
(source: Merriam-Webster online)

A practical definition of an incipient condition on an electric power circuit is anything likely to cause a fault, outage, or other negative event in the future. A common misconception holds that incipient conditions manifest themselves only as low-amplitude electrical events, and conversely that high-amplitude electrical events do not represent incipient conditions. More than a decade of Distribution Fault Anticipation (DFA) field investigations demonstrates that this often is not true. Incipient conditions can manifest themselves as high-amplitude electrical events, although often in ways that conventional systems and processes fail to recognize as predictors of future events. Field experience demonstrates that an incipient condition may have any combination of the following characteristics:

- It may or may not have caused past customer complaint(s).
- It may or may not have caused past high-amplitude electrical event(s).
- It may or may not have caused past conventional protection operation(s).
- It may or may not have caused past outage(s).

It is the potential to cause negative future events, not the amplitude of past events, that makes a condition incipient. Incipient conditions are predictive of consequential events that may occur in the future. Documented examples of incipient conditions include the following:

- Fault-induced conductor slap (FICS) – FICS events draw substantial current and often cause circuit-level momentary interruptions or sustained outages. FICS events represent incipient conditions, because a span that has experienced FICS once is prone to experiencing it again. FICS conditions are difficult to diagnose with conventional tools and practices, and therefore often are not diagnosed properly or corrected. FICS events tend to occur repeatedly in a given location. Future consequences of this type of incipient condition can include additional faults, interruptions, outages, equipment stress, progressive conductor damage, and possibly broken conductors.
- Cracked bushings – A cracked bushing may result in a high-amplitude flashover fault, often when rain or dew wets the surface of the bushing. Momentary trip/close operations can clear individual flashover incidents but leave the underlying incipient failure condition undiagnosed. Future high-moisture events can result in additional flashover faults and trip/closes. Potential consequences of this type of incipient condition include additional faults, system stresses, damaged conductors, catastrophic equipment failures, outages, and possibly broken conductors.
- "Hot spots" in clamps and switches – A failing in-line clamp or switch can develop a "hot spot," which can cause progressive erosion both of the clamp and of the conductor. Over time such a condition can cause intermittent power quality issues, mysterious fuse operations, eroded conductors, and possibly broken conductors.



- Failing capacitor switches – Switched capacitor banks experience a high incidence of failures, including failures of their switches. Vacuum and oil switches can develop incipient failures that produce electrical transients that are not detected by conventional systems, including sophisticated capacitor controls. These incipient failures can evolve and cause substantial power quality problems and catastrophic switch failures.

The foregoing list is not intended to be exhaustive but rather to demonstrate that incipient conditions take many forms and cause both high-amplitude and low-amplitude electrical events. Of the examples listed, early-stage "hot spots" and capacitor failures may cause only low-amplitude electrical activity, but FICS and cracked bushings can cause high-amplitude events and interruptions. Personnel often are unaware of incipient conditions, even those that cause intermittent, high-amplitude events, and their lack of awareness limits their ability to diagnose the problems and take appropriate corrective action.

Distribution Fault Anticipation (DFA) Technology and Incipient Faults

DFA technology, developed collaboratively by Texas A&M Engineering and the Electric Power Research Institute, Inc. (EPRI), is a multi-function, data-driven technology that provides utility companies with awareness of circuit conditions that conventional monitoring and protection systems do not provide. DFA technology detects and helps locate existing problems. DFA technology also detects and helps locate incipient conditions. It does this by continuously monitoring circuit current and voltage waveforms, in high fidelity, from substation CTs and PTs, and applying sophisticated digital signal processing, pattern matching, and other software techniques that report ongoing and developing circuit events and conditions.

- DFA technology can detect the unique electrical signature caused by FICS and provide information to target a search for its location.
- DFA reports intermittent flashover faults, caused by such things as cracked bushings, and provides information to help locate the underlying, incipient problem. It does this even when fault episodes are separated in time by weeks of inactivity.
- DFA reports in-line clamp and switch "hot spots" as they evolve, often intermittently over periods of days to weeks, so that a utility company can make informed responses to vague, hard-to-diagnose symptoms such as mysterious fuse operations and intermittently flickering lights.
- DFA reports multiple specific types of capacitor bank failures and incipient failures, including those not detected by advanced capacitor controls, so that the utility company can take corrective action.

With conventional systems and processes, utilities often remain unaware of such conditions and therefore unable to correct them. A DFA incipient fault report can be the first or only notice they receive. It is this awareness that enables them to act upon these incipient conditions.

DFA technology does not purport to detect all negative circuit conditions or prevent all problems, incipient or otherwise, but it has demonstrated the ability to alert utility companies to numerous existing and incipient conditions that are not found by conventional means. Improved awareness enables the utility to be more proactive in addressing some incipient conditions, thereby preventing some negative future events and outages, and to respond with faster, more targeted responses to outages and other trouble.

DFA Technology Detects Circuit Device Failures – Experience of Mid-South Synergy

Presented by Carl L. Benner

72nd Annual Conference for Protective Relay Engineers
Texas A&M University, College Station, Texas
March 25-28, 2019

Accompanying paper authored by
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Paper in substantially similar form was first presented to CIGRE Grid of the Future Conference, Reston, Virginia, October 2018.

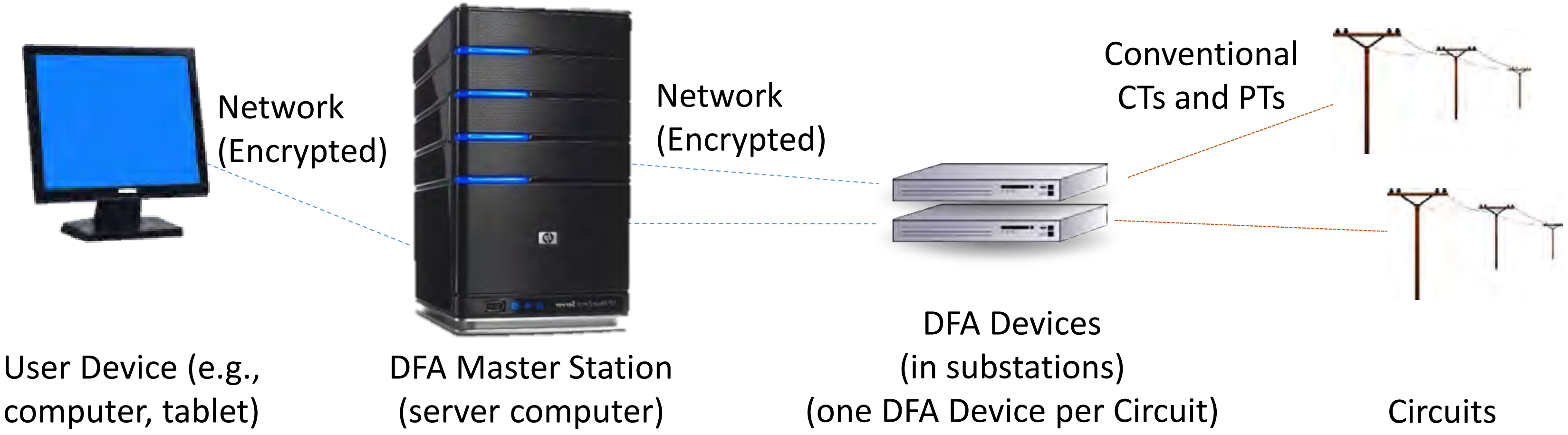
Takeaways

- Electrical signals contain much information about line health.
- But conventional technologies waste most of it.
- Proper use enables:
  - Improved Reliability – fewer interruptions, outages, …
  - Improved Safety – fewer hazards to personnel and public, reduced fire risk, …
- Three examples in this presentation:
  - Each affected reliability. Each affected safety.
  - None were actionable from conventional technologies, AMI, smart grid, etc.
  - All data comes from conventional CTs and PTs at the substation. Communications with line devices (e.g., reclosers) is not required.

Data System for Examples in This Presentation

- Texas A&M Engineering, working with EPRI and industry for two decades, has implemented a real-time monitoring system to detect line issues.
- The technology, known as Distribution Fault Anticipation (DFA), is installed on more than 100 distribution circuits.
- Substation-based DFA devices analyze waveform events and send reports to a central master station server in real-time. Circuit owners and Texas A&M access those reports via secure, browser-based login.
- Mid-South initially installed DFA on 10 circuits, added 10 more in 2018, and is adding 10 more in 2019.
- Important: Sensing data comes from conventional, substation-installed CTs and PTs, without distributed sensing or communications with reclosers or other line devices.

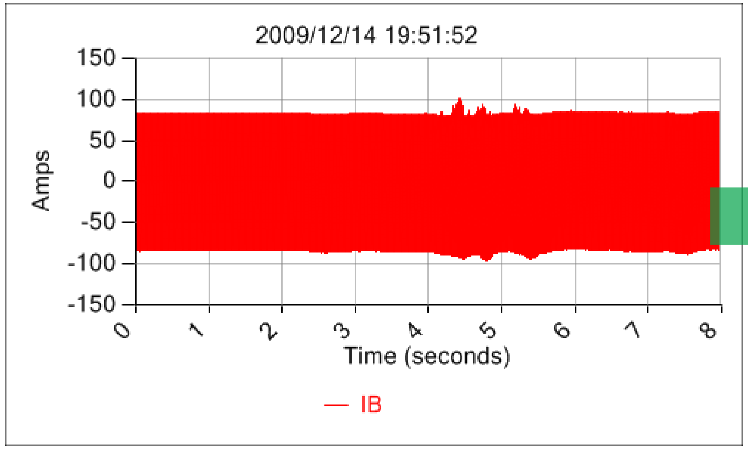
Data System for Examples



Waveform analysis software runs automatically in each substation-installed DFA device, which then sends reports to the DFA Master Station for access by personnel. The Master Station deploys improved waveform analysis software as it becomes available.

Basic Concept – Waveforms Reveal Problems

- Graph shows line current during “normal” operations.
- Conventional technologies waste (ignore) this information entirely.
- Software embedded in the DFA system reports this event as a failing clamp (which can persist for weeks, degrade service, even burn down a line).



Specialized, Automated Classification Software

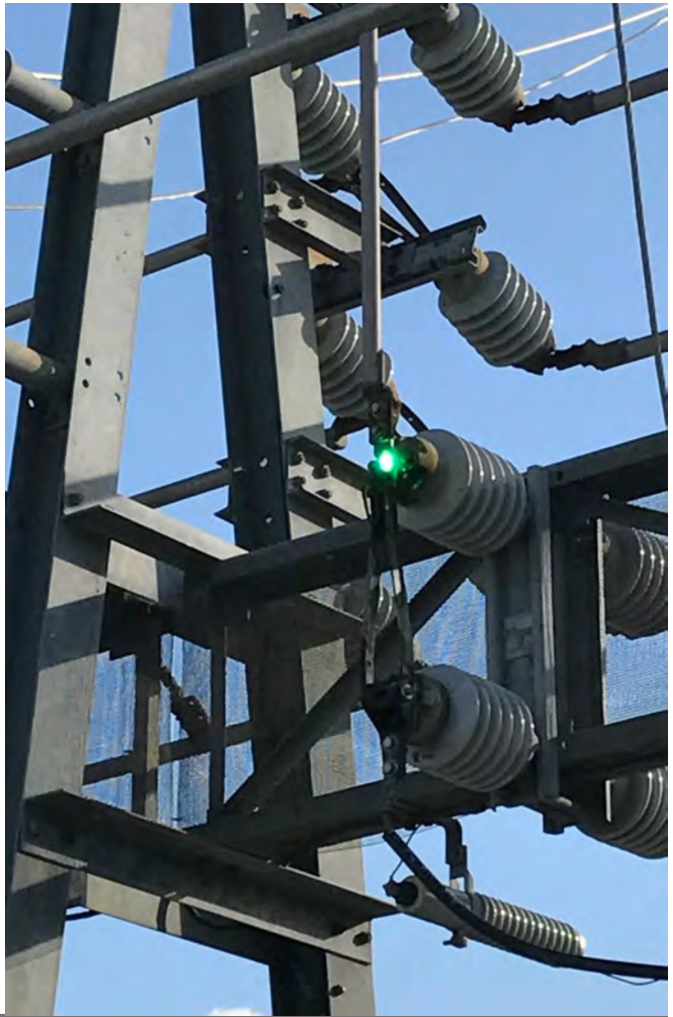
Texas Powerline-Caused Wildfire Mitigation Project

- DFA was the basis for the Texas Powerline-Caused Wildfire Mitigation project, 2014-2017.
- Mid-South and five other Texas utilities installed DFA on 50+ circuits and worked with Texas A&M to document how DFA enabled them to correct many issues. A partial list:
  - Detect and repair a substantial number of routine outages, without customer calls.
  - Detect and locate tree branch hanging on line and causing intermittent faults.
  - Detect and locate intact tree intermittently pushing conductors together.
  - Detect and locate broken insulator that resulted in conductor lying on and heavily charring a wooden crossarm.
  - Detect and locate catastrophically failed lightning arrester.
  - Detect and locate arc-tracked capacitor fuse barrel.
  - Detect and locate multiple problems involving capacitor banks.

Example 1

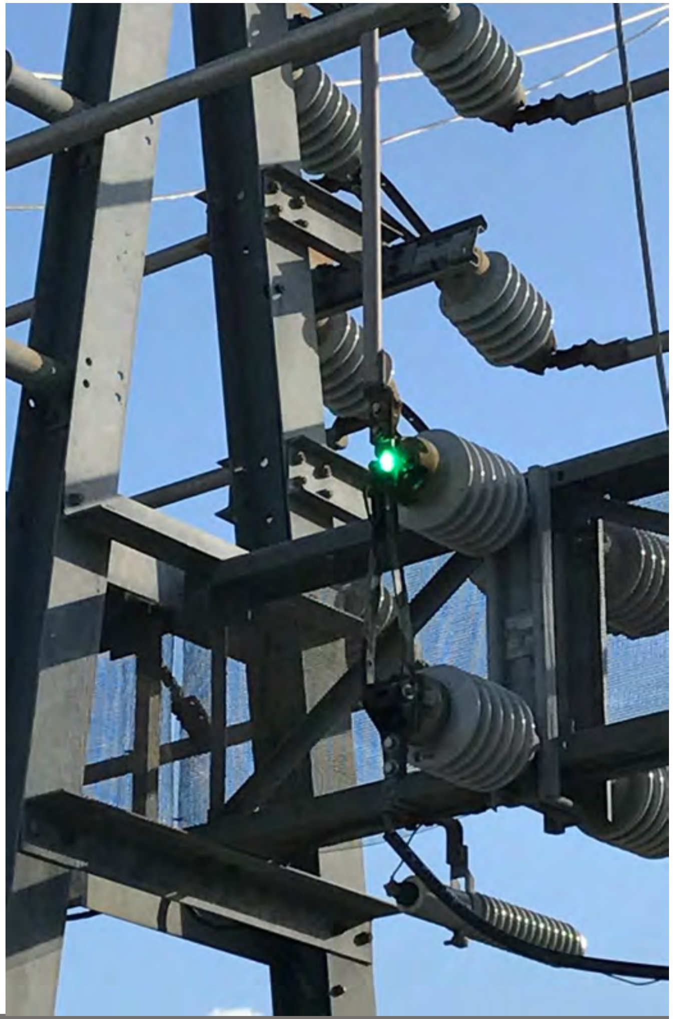
Failing Sub Switch (Series Arcing)

- Rural 25 kV distribution substation
- Three circuits, hundreds of customers
- Blade switch on substation metalwork
- Incipient failure
  - “Hot spot” visible in photograph
  - No customer calls
  - No indication from SCADA
  - No indication from smart meters, even when pinged after being alerted to the switch problem by the DFA monitoring system



A Momentary Aside

Brief Tutorial on Series Arcing

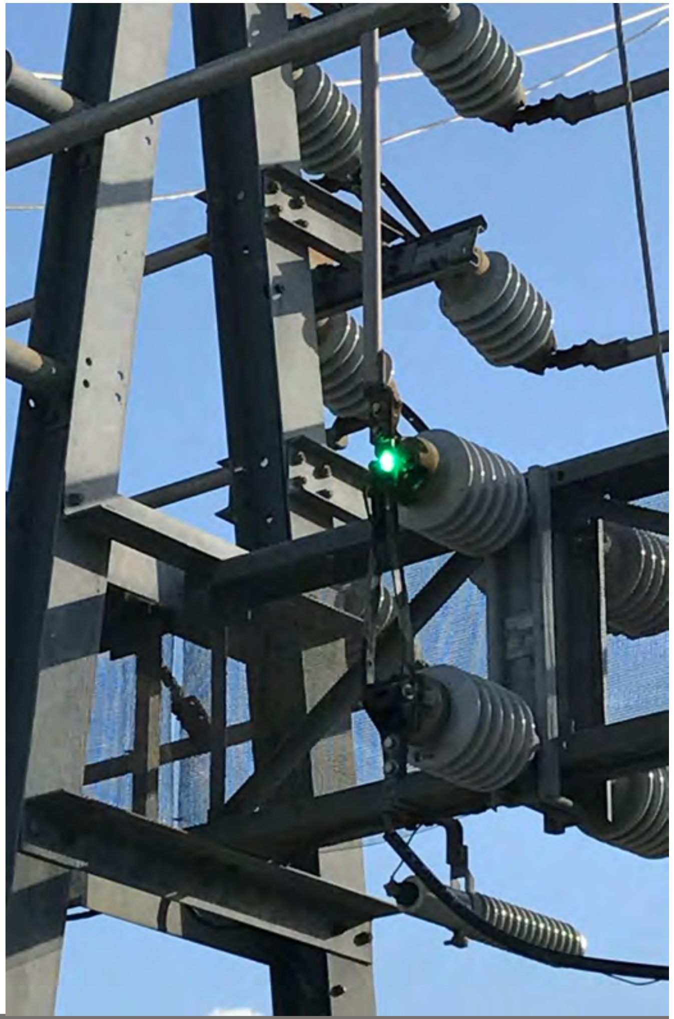


Arcing – two distinct types

- Shunt arcing: unintended current flow, usually phase-to-ground/neutral or phase-to-phase.
- Series arcing: “hot spot” resulting from failing contacts; interferes with intended current flow.

A Momentary Aside (cont'd)

Brief Tutorial on Series Arcing



Series Arcing – Some Characteristics

- Is poorly understood scientifically
- Affects load-carrying devices – clamps, switches, etc.
- Can exist for minutes to weeks prior to notice
- Tends to be highly intermittent - Can "flare up" for minutes and then go quiescent for days
- Causes vague symptoms, making it hard to diagnose
  - Flickering lights
  - Blown fuses (but replacement fuse may hold for a while)
  - Momentary operations, with successful auto-reclose
- Conventional location techniques (current magnitude or impedance) not applicable

A Momentary Aside (cont'd)

Miscellaneous Examples of Series Arcing

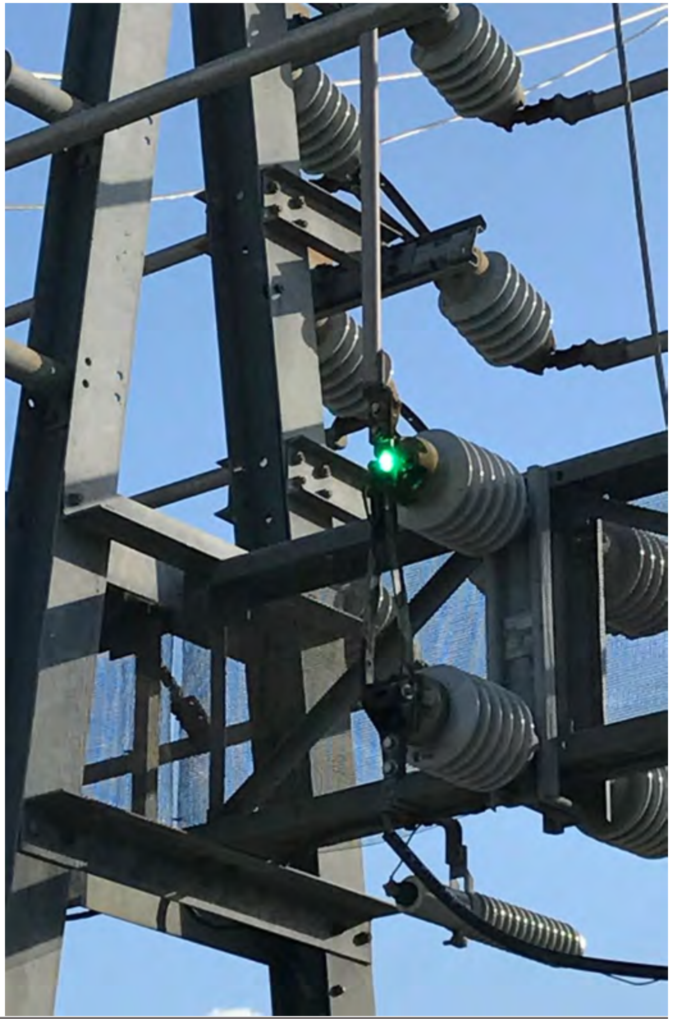
Eroded hotline clamp

Conductor burn-through at clamp

Sizzling substation blade switch

Example 1 (resumed)

Failing Sub Switch (Series Arcing)

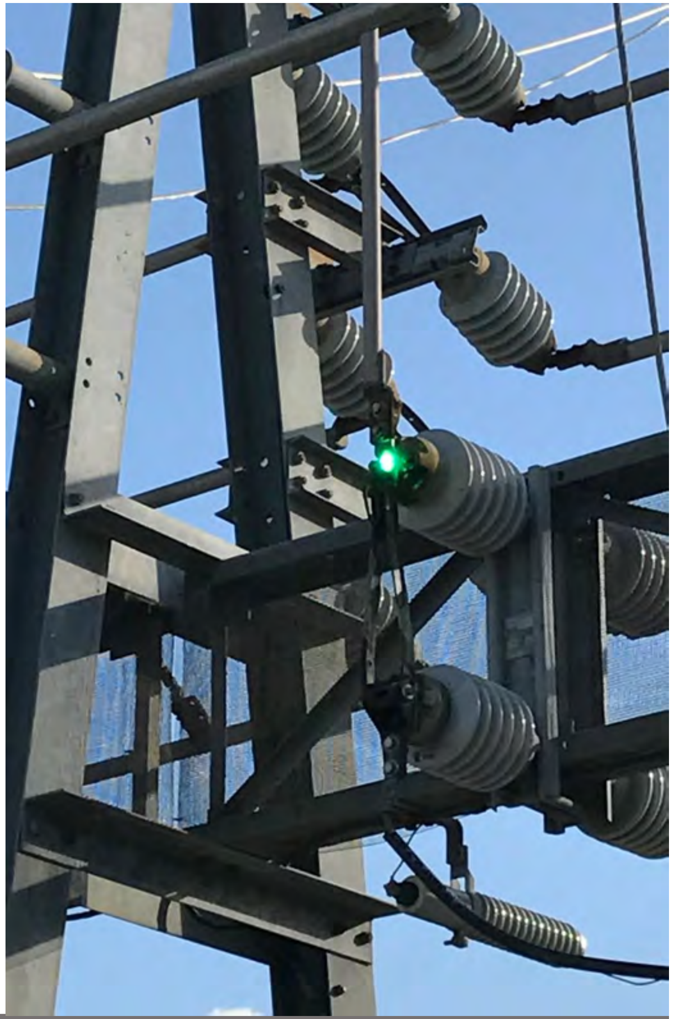


Chronology for This Example

- Received DFA notification mid-day Saturday.
- Checked SCADA (nothing), pinged meters (nothing).
- DFA software, based on waveforms, estimated that the failing device was carrying most of the circuit's load, so line crews patrolled near the sub.
- Lineman heard buzzing upon arrival at substation.
- Location took 1.5 hours (in rural environment).
- Utility called in repair crews (Saturday night).

Example 1 (cont'd)

Failing Sub Switch (Series Arcing)



Reliability impact

- Avoided prolonged outage to at least one circuit, possibly three circuits (100's of customers).

Safety impact

- Avoided catastrophic switch failure and potentially a substation fire (crew safety, public safety).
- Crews made repairs without time pressure inherent to large outage (crew safety).

Example 2

Fault-Induced Conductor Slap

- Fault-induced conductor slap (FICS) tends to occur repeatedly in specific spans.
- Each episode causes a momentary interruption and possibly an outage, typically of a full circuit.
- Each episode emits particles that can start a fire.
- Each episode causes progressive conductor damage, which can break a line.
- Months can elapse between episodes.
- FICS seldom is recognized or diagnosed correctly.

(See paper for full discussion of the FICS phenomenon.)

Example 2 (cont'd)

Fault-Induced Conductor Slap

<u>Specific Example</u>

- A tree far from the substation caused a fault.
- A mid-point recloser locked out to clear the fault.
- But FICS induced a second fault, miles closer to the substation, causing the substation breaker to lock out the circuit.
- DFA software reported this as FICS and provided fault current amplitude to guide location.
- Mid-South found arced conductor damage ("bright spots"), with burned grass beneath.

Example 2 (cont'd)

Fault-Induced Conductor Slap

- Without remediation, FICS occurs repeatedly in susceptible spans.
- Remediation is simple but occurs only if the FICS is recognized, which seldom happens.

Reliability impact

- Avoided future whole-circuit interruptions and outages.

Safety impact

- Consider the same span experiencing FICS again on a "red flag" (high fire risk) day!

Example 3

Charred Wooden Crossarm

The Circuit

- Long, rural 25 kV distribution line
- Next to pine forest with dry underbrush

The Condition

- A phase conductor broke free from its insulator and lay on the wooden crossarm.
- This contact caused significant charring along bottom of crossarm (see photo).
(Note: Problem had been corrected at the time the photo was taken.)

Example 3 (cont'd)

Charred Wooden Crossarm

- Condition caused two flashovers, about a day apart. Each trip/closed a mid-point recloser.
- DFA software reported each fault sequence of events (based on substation waveforms, without communications to recloser).
- Mid-South personnel noted the two similar events, a day apart, during fair weather, and investigated.
- Guided by their circuit model and DFA fault magnitude, a line crew readily located the problem (six spans from the prediction).

Example 3 (cont'd)

Charred Wooden Crossarm

Reliability impact

- Avoided additional interruptions to significant portion of circuit.
- Avoided long outage (broken line and/or crossarm).

Safety impact

- Avoided poletop fire or fallen, burning crossarm.
- Avoided possible downed conductor (fire hazard, crew safety, public safety).

Takeaways

- Electrical signals contain much information about line health.
- But conventional technologies waste most of it.
- Proper use enables:
  - Improved Reliability – fewer interruptions, outages, …
  - Improved Safety – fewer hazards to personnel and public, reduced fire risk, …
- Three examples in this presentation:
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Texas Power Line Caused Wildfire Mitigation Project

Project Description – Findings – Recommendations
March 2018

Introduction

In a three-year study period through 2011, Texas experienced more than 4,000 wildfires caused by power line events, as documented by the Texas A&M Forest Service. Many of these fires were minor, but others resulted in the loss of human life, disruption of lives and commerce, and hundreds of millions of dollars in property damage. This mirrors the occurrence of catastrophic fires in several other states.

In response to this statewide problem, the Texas legislature authorized three million dollars to support a four-year investigation of how power lines cause wildfires and what could be done to mitigate or prevent these catastrophic events. The project vision statement was as follows: To reduce wildfire risks and losses in Texas, using state-developed technologies to mitigate wildfires caused by power lines.

Enabling technology – Distribution Fault Anticipation (DFA)

Prior to the wildfire mitigation project, researchers at Texas A&M University, led by Dr. B. Don Russell and Mr. Carl Benner, had developed advanced diagnostic and monitoring technology for electric power distribution circuits. In a fifteen-year study, Texas A&M conducted the longest longitudinal study of naturally occurring power line failures. More than 1,000 circuit-years of high-fidelity electrical failure signatures of failing devices, apparatus, and abnormal power line events were recorded. This created the largest database in existence of failure signatures and enabled development of detection algorithms to characterize a wide variety of failures of line equipment. Designated Distribution Fault Anticipation, the system uses advanced waveform analytics and artificial intelligence to detect distribution circuit device failures and abnormal electrical events and report them to utility personnel for action.

The primary original purpose of DFA technology was to improve the reliability of distribution circuits, by detecting and identifying incipient failures of devices, before catastrophic failure. This enables condition-based maintenance, whereby operators can find and fix problems before an outage and often before a single customer calls. It was soon discovered that DFA technology had the capability of finding failing devices and power line problems in their early stages, before they became competent ignition mechanisms for wildfires. It was this concept that initiated the four-year statewide study with the aim of validating the use of DFA technology to reduce wildfire risk.

The Project

The following utilities, some in the highest risk wildfire areas, agreed to cooperate in this statewide study.

- Austin Energy
- Concho Valley Electric Coop
- Pedernales Electric Coop
- Bluebonnet Electric Coop
- Mid-South Synergy
- Sam Houston Electric Coop
- United Cooperative Services

More than 50 circuits were instrumented with DFA technology for continuous, multi-year monitoring. During the project study period, numerous failing devices and abnormal line events were detected, recorded, and analyzed. Initially, the purpose was to document that failing devices and events, such as conductor slap and vegetation intrusion, could be reliably detected and located before a wildfire was ignited. By the end of the project, utility personnel had learned to use the technology to find and fix many problems that pose high wildfire risk but also that adversely affected circuit reliability. This showed that circuit reliability and resilience could be improved using DFA technology, with the additional benefits of improving safety and reducing wildfire risk.

Project Findings

Over the course of the four-year project, DFA technology was proven to detect, diagnose and/or identify numerous failure mechanisms and apparatus misoperations that were competent ignition mechanisms. Recall, for a wildfire to ignite, sustain itself, and grow, numerous conditions must exist, including dry fuels, low humidity, high winds, etc. DFA technology can detect failing devices such as arcing hotline clamps which, under the right circumstances and conditions, can most certainly be competent ignition mechanisms for wildfires. Further, whether a fire occurs or not, a failing clamp represents a potential customer outage and may cause a downed energized conductor and create a public safety hazard.

During the course of the project, utility participants used DFA technology to identify various failure mechanisms, including the following.

Broken insulator	Conductor clash
Contact by vegetation	Lightning arrester failure
Clamp failure	Switch failure
Equipment arc tracking	Capacitor bank internal failure

Individually and collectively, the above failure mechanisms demonstrate all of the following primary fire ignition mechanisms from power delivery apparatus and lines; namely:

1. Burning embers from vegetation
2. Molten or combusting metal particles expelled during faults
3. Downed conductors, including high-impedance arcing faults
4. Burning insulating fluids expelled from transformers, capacitors, reclosers, etc.

Major Findings

The following findings are important to fully understand the power line ignition mechanisms for wildfires.

1. Conductor clash, including fault-induced conductor clash, is more common than conventionally understood. Each event represents the potential for ignition and also progressively weakens conductors, increasing the likelihood of future broken conductors.
2. Vegetation-induced faults often occur multiple times, spread over periods of days.
3. A single root cause may cause multiple faults, spread over weeks or months, without an outage.

4. Many failing devices manifest early stage detectable signatures long before catastrophic failure that would cause a fire or an outage.
5. Incipient failures of clamps and connectors often develop over weeks and ultimately can result in broken conductors on the ground, an obvious ignition mechanism.

The above mechanisms can be detected by DFA technology, often with sufficient lead time to find and fix failures before wildfire ignition. This was documented extensively during the course of the Texas wildfire mitigation project.

Recommendations

1. DFA technology can detect the incipient stage of numerous power line failure mechanisms that can cause wildfire ignition, outages, explosions, and other hazards.
2. The use of DFA technology by utilities would allow for continual, automated distribution circuit health assessment, which would improve the reliability and safety of electricity delivery.
3. DFA technology would allow utility operators to determine the cause of outages and reduce the duration of outages by targeting repair crews to specific root causes.
4. Since many failing devices develop over weeks or months, DFA technology can facilitate early cause identification and enable repairs before "red flag" wildfire ignition conditions exist.
5. DFA technology can immediately identify potential ignition events on distribution circuits on "red flag" days, when any fault or arcing event has a high probability of fire ignition, enabling more rapid response to fires.

Conclusion

The Texas wildfire mitigation project definitively demonstrated that many wildfires can be prevented by continually monitoring distribution circuits to keep those circuits healthy. Operators can identify and fix failures in their early, incipient stages. Many wildfires can be prevented in months when conditions are optimal for ignition, by detecting and correcting problems in advance.

DFA technology is a unique, transformational tool for utilities which will improve reliability, increase safety, and enable wildfire risk reduction, by providing advanced diagnostics and situational awareness for operators.

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Compendium of Selected Case Studies
Related to the Texas Power Line-Caused Wildfire Mitigation Project

1. Mid-South Synergy Uses DFA Technology to Diagnose Fault-Induced Conductor Slap
2. Pedernales Uses DFA Technology to Reduce Vegetation Wildfire Risk and Increase Reliability
3. Sam Houston EC Uses DFA Technology to Detect and Locate Failed Arrester
4. Mid-South Synergy Uses DFA Technology to Avoid Outage and Reduce Wildfire Risk

Mid-South Synergy Uses DFA Technology to Diagnose Fault-Induced Conductor Slap

Dr. Comfort Manyame, Sr. Mgr., Research and Technical Strategy
Robert E. Taylor, Engineering Specialist
Mid-South Synergy Electric Cooperative

Carl L. Benner, Research Associate Professor
Dr. B. Don Russell, Distinguished Professor
Texas A&M Engineering

June 2017

Distribution Fault Anticipation (DFA) technology helped Mid-South Synergy Electric Cooperative (MSEC) diagnose a complex fault event that included a difficult-to-diagnose condition known as fault-induced conductor slap (FICS). Absent remediation, FICS tends to recur. Each instance causes sparks that can ignite a fire. Repetitive instances progressively damage conductors, which can cause them to break and fall, endangering the public. Remediation of FICS typically is straightforward, if the utility is aware that it is occurring. DFA provided MSEC's only notice that FICS had occurred.

MSEC is one of seven utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration supported by the Texas legislature. As part of that effort, MSEC has instrumented ten circuits, primarily long, rural circuits, with DFA technology. Each is fitted with a single, substation-installed DFA device, which detects faults, failures, and other events along the circuit's length and reports them to a central master station server computer for access by personnel. MSEC has used DFA to diagnose multiple types of diverse issues on their circuits.

Fault-induced conductor slap, or FICS, is a complex phenomenon that occurs when an initial fault on a circuit causes line conductors to swing together and create a second fault. The second fault occurs closer to the substation and often results in a more widespread outage. FICS is an onerous problem, both because its complex nature makes it difficult to diagnose, and because, absent proper diagnosis and remediation, it tends to recur. Individual episodes may occur months or even years apart, making it difficult for personnel to recognize that a problem that occurred today is the same as the one that occurred six months ago.

The subject event was even more complex than conventional FICS. On 11 June 2017, a balloon string contacted a 25 kV circuit, causing a fault. An automatic circuit recloser (ACR) upstream of the fault locked out, as would be expected, but a second ACR and even the substation circuit breaker locked out, too.

MSEC's field crew found a burned jumper in the section of line between the first ACR and the second. They concluded that the passage of fault current from the first fault caused the jumper to fail, resulting in the second fault and tripping the second ACR. They also initially concluded that the complexity of the sequence of events had "fooled" the substation protection and caused it to trip.

DFA recorded the current and voltage signals of the full sequence. The DFA On-Line Waveform Classification Engine software analyzed those signals and reported probable FICS. Prompted by the DFA report, MSEC used their circuit model software to determine that the fault currents that caused the substation circuit breaker to trip were too large to have resulted from the balloon fault or from the jumper fault. Using model-based location predictions, they then patrolled a targeted area of the circuit and found conductors with the "bright spots," or arc pitting, typical of slapping conductors. On site, they spoke with a member of the public, who reported seeing the conductors slapping and causing a shower of sparks, further confirming the FICS. Notably the FICS was more than five circuit miles from the initial, balloon-induced fault.

Remediating the subject span was possible only because DFA made MSEC aware of the FICS. Left uncorrected, the span likely would have caused additional outages, in addition to the dangers associated with fire ignition and public safety.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software, known as the On-Line Waveform Classification Engine, to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the system-wide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can detect all problems, but DFA provides a quantum step forward in the detection and diagnosis of many failures and incipient failures.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Texas-based Power Solutions, LLC.

Headquartered in Navasota, Texas, Mid-South Synergy serves 22,500 members and 30,000 meters in a service territory covering parts of six counties in Central Texas. Mid-South has installed DFA technology on ten distribution circuits as part of its participation in the Texas Power Line-Caused Wildfire Mitigation project.

Pedernales Uses DFA Technology to Reduce Vegetation Wildfire Risk and Increase Reliability

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April 2016

Pedernales Electric Cooperative (PEC) improved reliability and reduced wildfire risk by detecting, locating, and clearing vegetation contacting a rural, overhead distribution line near Blanco, Texas. Distribution Fault Anticipation (DFA) technology enabled this by detecting early warning signs of the vegetation intrusion. Conventional technologies did not notify PEC of this condition. Rather PEC's only notification came from DFA.

PEC is one of six utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration effort supported by the Texas legislature. As part of that effort, PEC has instrumented ten distribution circuits, primarily long, rural circuits, with DFA technology. PEC has instrumented each of these circuits with a single, substation-installed DFA device, which detects and warns of faults, failures, and other events along the length of the circuit.

Latent power line conditions, such as vegetation intrusion and certain apparatus failures, can cause recurring fault events. Many such conditions are affected by weather conditions, such as wind and moisture, and therefore cause fault events only intermittently. These conditions are difficult to detect and locate with conventional technologies.

Like most utility companies, PEC applies automatic circuit reclosers at multiple locations on long circuits. Such a recloser attempts to clear temporary faults by tripping a section of line, waiting a few seconds, and then reclosing to restore service to customers. This momentary interruption clears most faults successfully, without causing a lengthy outage or requiring unnecessary patrols by line crews.

In the early morning hours of 06 March 2016, a fault caused a single momentary trip/close operation of a recloser on one of PEC's DFA-monitored circuits. Some 30 minutes later, the fault recurred and again caused a single trip/close operation. Eight hours later, the fault occurred a third time, once again causing a single trip/close operation. No customers experienced a sustained outage, no customers called to complain of the momentary "blinks," and no conventional technology notified PEC of a problem requiring investigation.

DFA detects and characterizes fault events. In addition, each time it detects a fault event, it calculates multiple parameters about that fault event, compares those parameters to those from recent fault events on the same circuit, and, if it detects multiple similar fault events, generates a special "recurrent fault" report. In the subject case, DFA detected that the three momentary trip/close operations likely resulted from the same fault condition, alerted PEC to this fact, and provided information PEC could use to locate the problem.

The circuit in question is a long rural circuit with 153 miles of primary line conductor. Upon receiving the DFA report indicating a recurrent fault, PEC utilized DFA-generated fault parameters, PEC's electronic circuit model, and "blink counts" from PEC's AMI (automated metering infrastructure) system to direct a search to a small portion of that long circuit. A PEC crew patrolled the indicated area and efficiently found and removed the cause of the recurrent fault: a tree branch on the overhead line. By responding in a timely way, the line conductors avoided damage and possible burn-down. In addition this preemptive action avoided possible future faults and interruptions to customers and removed the source of a possible future fire ignition.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device continuously monitors circuit currents and voltages, with high-fidelity, via conventional CTs and PTs. DFA devices use embedded, proprietary signal processing to characterize electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the fleet of DFA devices on circuits across the power system. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Power Solutions, Inc.

Serving more than 270,000 customers in a service territory covering 8,100 square miles in the Texas Hill Country, Pedernales Electric Cooperative is the largest electric cooperative in the United States. Pedernales has installed DFA technology on ten distribution circuits as part of its participation in the Texas Power Line-Caused Wildfire Mitigation project.

Sam Houston EC Uses DFA Technology to Detect and Locate Failed Arrester

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May 2016

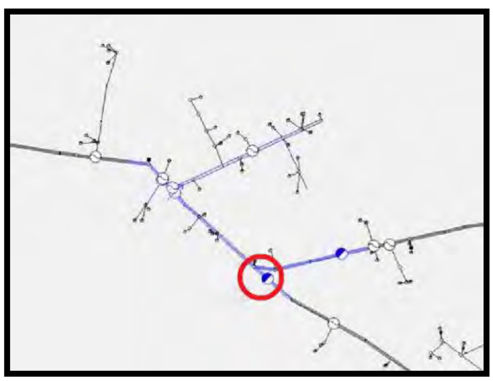
Sam Houston Electric Cooperative recently used Distribution Fault Anticipation (DFA) technology to detect and efficiently locate a failed lightning arrester, enabling its replacement. Failed arresters can reduce a line's surge suppression capability, affect service reliability, cause future short circuits, and create a risk of wildfire ignition. The Cooperative learned of the failure only from DFA, not from any conventional technology.

Sam Houston EC is one of six utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration effort supported by the Texas legislature. As part of that effort, Sam Houston is instrumenting ten distribution circuits, primarily long, rural circuits, with DFA technology. DFA instrumentation of a circuit consists of a single, substation-installed DFA device, which detects and warns of faults, failures, and other events along the length of the circuit.

During a storm on 30 March 2016, one of Sam Houston EC's DFA-instrumented circuits experienced a short-circuit fault. The Cooperative's conventional circuit protection properly detected the fault, tripped the circuit, and then reclosed two seconds later to restore service. Like most utility companies, Sam Houston utilizes automatic circuit reclosing to clear most faults without sustained outages for their customers.

Conventional systems detected and cleared the subject fault and notified the Co-op's dispatch center that the event had occurred, but indicated nothing more serious than a temporary fault. Temporary faults are common during storms and often require no utility follow-up, so system operators ordinarily would have had no reason to take action based on this fault and reclose. DFA recorded the electrical signature of the fault and the response of the protection system, but it also enabled diagnosis of the likely cause of the fault: a failed lightning arrester.

Knowing of arrester failures is important because a failing arrester can expel superheated fragments capable of igniting combustibles. A failed arrester also can leave detached pole-top components energized and free to swing and contact other pole-top apparatus, resulting in future faults and potential ignition events.



DFA technology enabled detection and efficient location of a failed arrester not detected by conventional systems.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the systemwide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance.

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The circuit in question is a long, rural circuit with multiple branches and 120 total miles of primary line. Upon receiving DFA-based notification that the likely cause of the fault was catastrophic failure of a lightning arrester, the Co-op used DFA-generated parameters, along with their electronic circuit model to predict the location of the failed arrester. A Sam Houston EC crew was dispatched with instructions to target a specific portion of the circuit, looking for a failed arrester, which they found with minimal time and effort. Absent DFA-based notification, there would have been no compelling reason to investigate the temporary fault, and consequently the failed arrester would have remained undiscovered.

Headquartered in Livingston, Texas, Sam Houston Electric Cooperative serves more than 71,000 consumers in ten counties. Sam Houston is installing DFA technology on ten distribution lines in conjunction with the Texas Power Line-Caused Wildfire Mitigation project.

Mid-South Synergy Uses DFA Technology to Avoid Outage and Reduce Wildfire Risk

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February 2017

Mid-South Synergy Electric Cooperative (MSEC) avoided a significant outage and reduced other risks, including potential wildfire ignition, by using Distribution Fault Anticipation (DFA) technology to discover a detached conductor lying directly on a wooden crossarm. Conventional technologies did not alert MSEC to the problem.

MSEC is one of seven utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration supported by the Texas legislature. As part of that effort, MSEC has instrumented ten circuits, primarily long, rural circuits, with DFA technology. Each is fitted with a single, substation-installed DFA device, which detects faults, failures, and other events along the circuit's length and automatically reports them to a central master station server computer for access by personnel.

Latent power line conditions can cause recurring faults. Some such conditions are influenced by weather conditions, such as wind and moisture, and cause faults only intermittently. Such conditions are difficult to discover with conventional technologies and can exist for days or weeks without notice.

Like most utility companies, MSEC applies automatic circuit reclosers at multiple locations along long circuits. A recloser clears temporary faults by tripping a section of line, waiting a few seconds, and then reclosing to restore service. These momentary interruptions successfully clear most faults and minimize customer outages and unnecessary patrols.

On 15 January 2017, a fault on one of MSEC's DFA-instrumented circuits caused a single momentary trip/close operation of a recloser. A similar fault occurred the next day. No members experienced outages or reported "blinks," and no conventional technology alerted MSEC of a problem requiring attention.

While reviewing events on the central DFA master station, MSEC personnel noted the two events and observed that they appeared unusual and similar to each other. The circuit is a long, rural line with 109 miles of exposure. MSEC used DFA-provided fault parameters, in conjunction with their existing circuit model software and remote polling of line devices, to dispatch a line crew to patrol a specific portion of the circuit. There the crew identified the cause of the problem, a line conductor displaced from its normal position on an insulator and lying on its wooden crossarm. As shown in the photograph above, the crossarm had substantial charring.

An outage at this location would have interrupted 138 members, all of whom would have been out of service for the full time needed to dispatch crews, locate the problem, and make repairs. Other potential consequences would have included a burned off cross arm, a broken conductor, and multiple mechanisms capable of igniting a fire. Key to avoiding the consequences was the DFA-enabled ability for MSEC personnel to learn of the problem, which in turn enabled them to investigate and make proactive repairs.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the system-wide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can detect all problems, but DFA provides a quantum step forward in the detection and diagnosis of many failures and incipient failures.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Texas-based Power Solutions, LLC.

Headquartered in Navasota, Texas, Mid-South Synergy serves 22,500 members and 30,000 meters in a service territory covering parts of six counties in Central Texas. Mid-South has installed DFA technology on ten distribution circuits as part of its participation in the Texas Power Line-Caused Wildfire Mitigation project.

Mid-South Synergy Uses DFA Technology to Avoid Substation Switch Failure

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May 2018

DFA technology provided Mid-South Synergy Electric Cooperative's (MSEC's) only notice of early stage substation switch arcing. MSEC averted potentially catastrophic failure by initiating emergency repairs within two hours of learning of the issue from DFA.

MSEC is one of seven utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration supported by the Texas legislature. Over the past three years, MSEC has used DFA to detect a variety of issues, including: conductor slap; a phase conductor charring a wooden crossarm; capacitor problems; failing switches; and other issues. MSEC initially installed DFA on ten circuits, primarily long, rural circuits, and currently is adding DFA to ten more. Each circuit has a single, substation-installed DFA device, which detects faults, failures, and other events along the circuit's length and reports them to a central master station server computer for access by personnel.

DFA detected the failing switch based on specialized software that monitors line currents and voltages continuously and automatically recognizes signal patterns indicative of switch failure. MSEC received the DFA report late on a Saturday afternoon and responded immediately.

MSEC did not know immediately which of the circuit's multiple switches was the culprit. MSEC had no active member complaints, and none of their other systems indicated a problem. MSEC operators used their AMI (advanced metering infrastructure) system to ping meters on the affected phase, based on the thought that meters downstream of the arcing switch might report something unusual, but that was not the case. DFA estimated that the offending switch was carrying most of the circuit's load, and MSEC used that information to direct patrols near or in the substation. Upon arriving at the unmanned, rural substation, the responding lineman distinctly heard "sizzling" and knew that he had found the arcing switch. Despite the remote location of the substation, MSEC located the arcing switch within two hours of their first notice.

MSEC found the switch on a Saturday evening. Because of the serious nature of the issue, they initiated corrective action immediately. Catastrophic failure of the switch would have caused an outage for at least one circuit. Because the switch was located on the substation buswork, its catastrophic failure could have caused an outage for the entire substation. In the extreme, it could have caused a substation fire, particularly if a high-current fault on the circuit precipitated the switch's final failure.

Replacement was timely, because MSEC's service territory experienced thunderstorms each of the next two days, and those storms caused multiple faults on the circuit. Had the weak switch still been in service, the added stress of carrying fault current and other system transients likely would have caused its catastrophic failure. The substation has three circuits, all three of which needed to be switched to alternative sources of supply while the switch was replaced. Early warning enabled all load to be switched to alternative sources without outage and without the time pressure that would occur had the switch failed and caused an outage to one or more circuits.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software, known as the On-Line Waveform Classification Engine, to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the system-wide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can detect all problems, but DFA provides a quantum step forward in the detection and diagnosis of many failures and incipient failures.

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Headquartered in Navasota, Texas, Mid-South Synergy serves 23,000 members and 30,000 meters in a service territory covering parts of six counties in Central Texas. Mid-South initially installed DFA technology on ten distribution circuits and currently is installing DFA on ten more.

Pickwick Electric Cooperative Uses DFA to Avoid PQ Problems and Catastrophic Switch Failure

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March 2017

Pickwick Electric Cooperative (PEC) used Distribution Fault Anticipation (DFA) technology to perform condition-based maintenance on a capacitor bank with a failing vacuum switch, thereby avoiding power quality problems and potentially catastrophic switch failure. No conventional technology, including a remote communications system PEC uses to manage their capacitor banks, alerted PEC to the problem.

Like many utility companies, PEC applies switched and fixed capacitor banks on its distribution circuits. PEC's remote capacitor communications capabilities enable them to detect problems such as blown phase fuses. Such systems cannot, however, detect latent or incipient problems such as switch bounce or symptoms of partial loss of vacuum in a switch.

On 17 February 2017, the DFA device on one of PEC's circuits detected a three-phase capacitor bank switching off and, more importantly, detected that one of the bank's switches had experienced severe restrike during the operation. Restrike is a phenomenon that occurs when switch contacts open and interrupt the flow of current, but immediately thereafter fail to withstand the voltage across them and consequently allow unintended current to flow, typically for a very short period of time.

The subject capacitor bank is programmed to open and close daily. For several days following the severe restrike, the bank switched normally, with no indication of restrike. Then on 22 and 23 February, DFA again detected and reported severe restrike.

PEC readily identified which of the circuit's capacitor banks was experiencing the restrike, by comparing the DFA-reported kvar bank size to the nominal size of the banks known by PEC to be on the subject circuit. They further confirmed the identification of the specific bank by comparing DFA-reported switching times with times reported by the bank's controller via SCADA.

Based on the notice of severe restrike and identification of the affected bank, PEC visited the bank on the afternoon of 23 February. They found that the bank had a switch with partial loss of vacuum. They opened the bank's fuses to isolate the bank, pending full repair. This prevented multiple possible problems, including power quality events for PEC's members and potentially catastrophic failure of the switch itself. DFA provided the only notice that PEC had that any problem existed.

PEC is one of more than 150 local power companies that buy bulk power from the Tennessee Valley Authority (TVA). Both PEC and TVA were key participants in the long-term development of DFA technology. The latent switch problem described herein is one of multiple problems and latent failures that PEC has detected, diagnosed, and corrected using DFA technology. It is PEC's experience that DFA provides them with a level of awareness of their circuits that they do not get from their conventional technologies, and that better awareness enables improved operations and better service to their members.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the system-wide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can detect all problems, but DFA provides a quantum step forward in the detection and diagnosis of many failures and incipient failures.

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Headquartered in Selmer, Tennessee, Pickwick Electric Cooperative operates 2427 miles of distribution and serves 20,555 members in a service territory covering parts of five counties in Tennessee and Mississippi. Pickwick has been a key, long-term participant in the development of DFA technology.

Tree Limb Burns Down Line, Causes Outage

DFA Technology Could Have Prevented Damage, Outage

John Bowers, Pickwick Electric Cooperative
Carl L. Benner and Dr. B. Don Russell, Texas A&M University
Ashok Sundaram, Electric Power Research Institute

At 6:57 AM on the morning of November 2, 2004, an overcurrent fault tripped a three-phase pole-top recloser on a feeder at Pickwick Electric Cooperative's North Adamsville substation. The recloser closed back in normally and the fault did not persist. As a customer of TVA, Pickwick participates in the Distribution Fault Anticipation (DFA) project that EPRI is sponsoring at Texas A&M University. A DFA Prototype at North Adamsville substation recorded this fault and others discussed in this article.

Faults like this are not uncommon, and there did not appear to be anything out of the ordinary. An hour later, however, there was another fault, with the same characteristics. This time, the recloser tripped and reclosed twice, but again, did not lock out. Figure 1 shows the RMS phase current the DFA measured at the substation during this second episode.

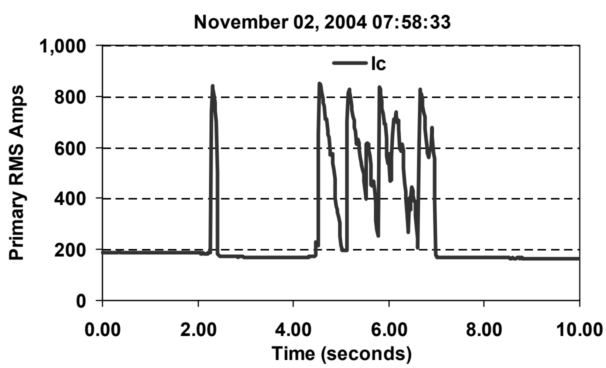

Figure 1. Second fault tripped recloser twice but did not lock out.

All was quiet for the next 16 hours. Then, shortly after midnight, another similar fault occurred. Over the next six hours, the fault recurred multiple times, tripping the recloser 11 more times. However, the faults were not close enough together in time to allow the recloser to lock out and isolate the problem. Then, at 6:19 AM, the fault became more persistent and locked out the recloser, during the episode illustrated in Figure 2. By this time, the recloser had tripped 17 times! The following list tabulates the individual interruptions:

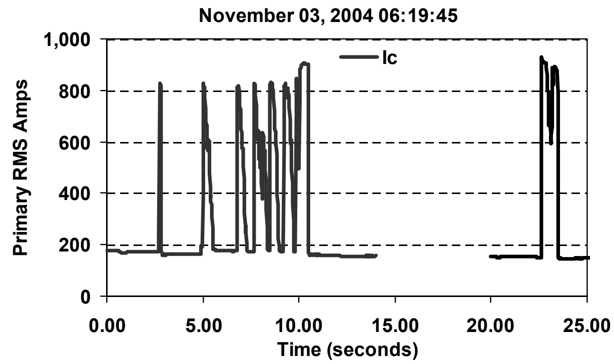

Figure 2. Final instance of fault locked out recloser.

Date	Time	Trips
11/02/2004	06:57:47	1
	07:58:33	2
11/03/2004	00:09:06	1
	00:16:48	1
	00:40:38	1
	00:40:53	1
	01:10:51	1
	01:12:37	1
	01:15:30	1
	03:24:47	1
	04:19:39	1
	04:30:36	1
	05:51:01	1
	06:19:45	3
	Total	17

The ensuing outage resulted in customer lights-out calls. Investigation revealed a broken tree limb that had burned down a span of line. 140 customers were without service for 62 minutes while the crew repaired the line.

The line was of standard single-phase construction, without crossarms. The phase conductor was mounted on pole-top insulators. The neutral conductor was mounted on standoffs several feet down the sides of the poles.

The crew found that a fork in the broken tree limb had hung on the phase conductor. The limb pulled the phase conductor down to within about two feet of the neutral conductor. The fork was in continuous contact with the phase conductor. Casual contact with the neutral occurred a few feet farther along the limb, causing the intermittent faults.

Figure 3. Tree limb tripped recloser 17 times and burned line down.

Figure 3 shows the offending tree limb. There is evidence of burning along about three feet of the limb's length. This would be consistent with the fork (left side of upper picture) hanging from the phase conductor and another position on the limb contacting the under-hung neutral conductor.

The DFA recorded each fault as it happened. The DFA currently is a research project and is not integrated into normal operations at Pickwick. Because a pole-top recloser operated, instead of the substation breaker, Pickwick had no indication of a problem until the lights-out calls that followed the burn-down.

If real-time DFA technology had been available to operations personnel, Pickwick would have dispatched a crew around 1:00 AM on November 3. Using information from the DFA, Pickwick personnel believe that they would have located the source of the problem within a few hours. They would have had time to take remedial action and could have avoided the burn down and the outage.

Bluebonnet Electric Uses DFA Technology to Detect Arrester Failure and Accelerate Response

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July 2016

Bluebonnet Electric Cooperative (BEC) recently used Distribution Fault Anticipation (DFA) technology to detect and locate a failed lightning arrester and initiate response by a line crew before receiving conventional notification of the failure. DFA enabled BEC to respond to this event sooner and with better diagnostic information.

BEC is one of six utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration effort supported by the Texas legislature. As part of that effort, BEC has instrumented fourteen distribution circuits with DFA technology. Instrumenting a circuit with DFA technology consists of installing a substation-based DFA device, which detects and warns of faults, failures, and other events along the length of the circuit.

During fair weather on the afternoon of 4 July 2016, a DFA-instrumented circuit experienced a short-circuit fault. BEC's conventional circuit protection properly detected and isolated the fault, blowing a fuse and interrupting service to a single member. Relying solely on conventional systems, BEC would have been unaware of this issue until a member reported an outage, which in this case did not happen for a full hour. As an aside, this was the only outage on this circuit for this entire day.

Electrical recordings by the substation-based DFA detected the fault and enabled determination that the likely cause was failure of a lightning arrester. BEC was otherwise unaware of the fault. The circuit in question is a long, rural circuit with more than 160 miles of total overhead line. The BEC control center used circuit model software to estimate the likely location of the fault and dispatch a line crew, informing the crew that the most likely cause was a failed arrester. The crew was en route when the dispatch control center received a "lights out" call from the affected member. Upon arrival on the scene, BEC's crew confirmed a blown fuse and failed arrester and effected appropriate repairs.

DFA technology enabled detection and identification of a failed arrester, thereby improving response.

BEC's proactive use of information from the DFA system enabled faster response and a shorter outage. In addition to the early notification, it generally is beneficial to know the likely cause of an outage, because identification of the cause of an outage sometimes can be quite challenging and time-consuming for the responding crew.

Beyond improving reliability, earlier awareness of failures and better diagnostic information about them can, in some cases, help mitigate fire hazards. The failure of a lightning arrester, for example, often draws an electrical arc in the air and expels superheated fragments that fall to the ground. Conventional technologies may not enable utility companies to detect failures and outages in a timely way, much less know details about their underlying causes. Although no technology will ever prevent all failures and risks, DFA technology appears to be able to provide quicker notification and better information, enabling an improved response.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the systemwide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can eliminate all failures, but DFA provides a step forward in detecting and diagnosing many failures .

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Power Solutions, Inc.

Headquartered in Bastrop, Texas, Bluebonnet Electric Cooperative serves more than 85,000 consumers in central Texas. Bluebonnet has instrumented fourteen distribution lines with DFA technology, in conjunction with the Texas Power Line-Caused Wildfire Mitigation project.

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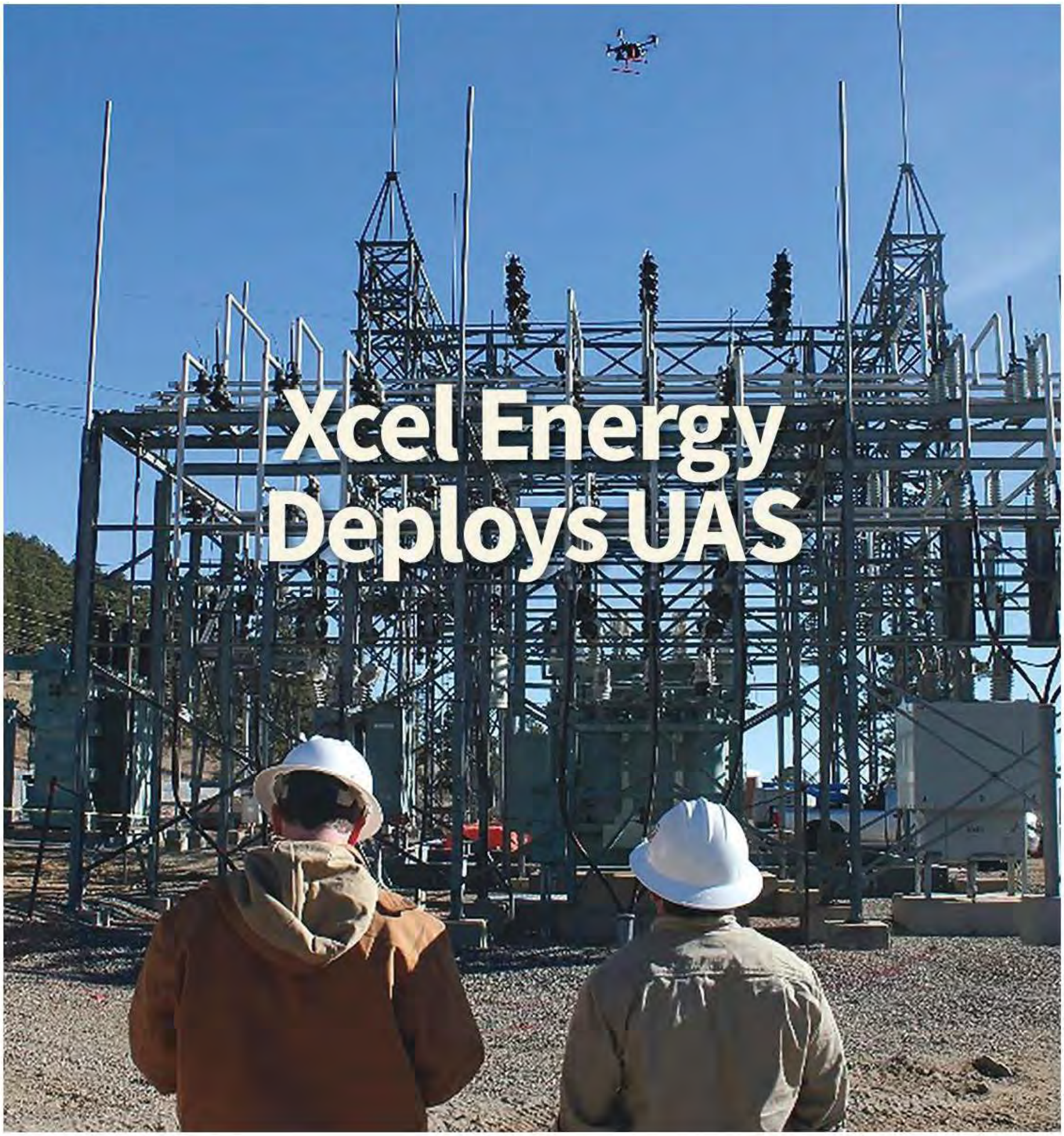


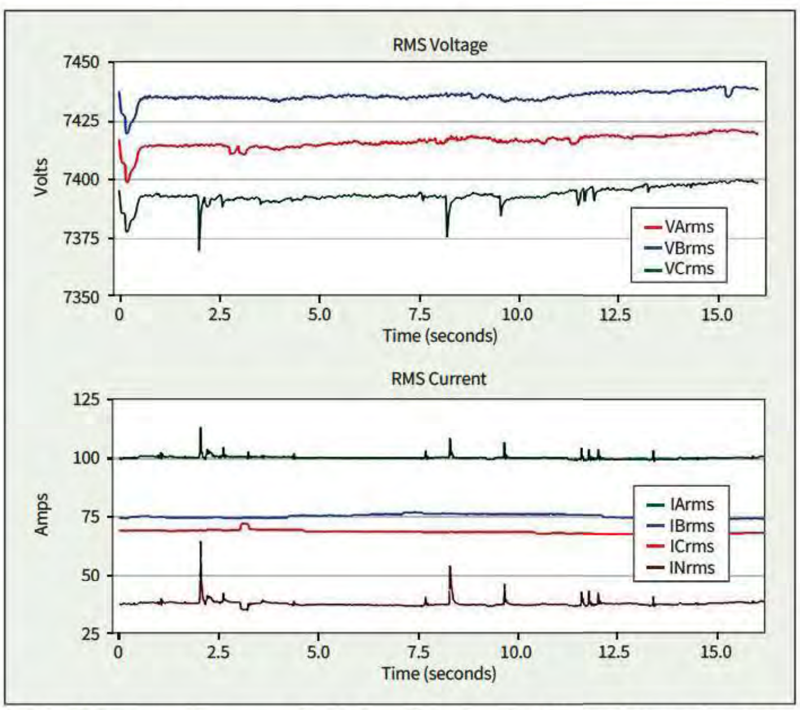
Fault Anticipation Improves Operations

Pedernales is improving the reliability and safety of its distribution system and reducing wildfire risk.

By **Robert A. Peterson**, Pedernales Electric Cooperative, and **Carl L. Benner** and **B. Don Russell**, Texas A&M University

Distribution utilities operate miles and miles of lines to serve large service territories. Knowing what is happening on those lines presents a real challenge. Pedernales Electric Cooperative and other utilities are improving the reliability and safety of their electric power distribution systems, using technology developed by Texas A&M University's College of Engineering. Known as distribution fault anticipation (DFA), the technology helps utilities to manage their systems better by giving them more awareness of what is happening on them.

Pedernales first began testing DFA in 2015, as part of a demonstration project known as the Texas Power Line-Caused Wildfire Mitigation project, supported by the Texas state legislature. As one of seven Texas utilities to participate in the project, Pedernales installed DFA monitoring on 11 distribution circuits. Pedernales and the other participants have used DFA to detect multiple line issues that otherwise could have started fires. Enhanced situational awareness increases crew efficiency and enables corrective actions that inherently improve service quality as well as reliability. Based on successful trials, Pedernales and several other utility companies have begun expanding their deployments of DFA, integrating DFA into their work flows and making DFA information available in their control centers.

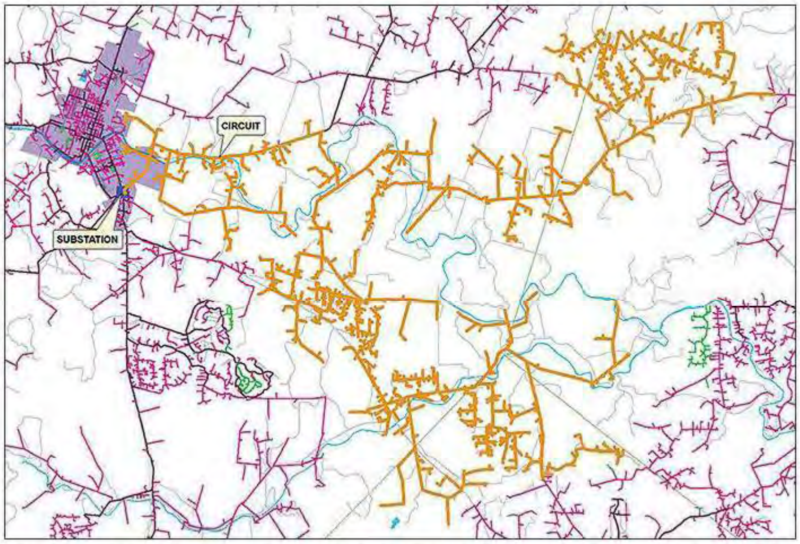


Incipient failures sometimes cause electrical manifestations that DFA reports hours, days or even weeks prior to catastrophic failure. Detection and reporting require specialized pattern-recognition algorithms and sensitive-data triggering relays that other conventional systems do not have.

Awareness Is Key

Knowing about a problem is the first step to correcting it. Pedernales uses 22,000 miles (35,400 km) of primarily overhead distribution lines to serve 300,000 meters across a service territory of 8100 sq miles (20,100 sq km). Unlike transmission lines — which generally run point to point or, perhaps, have a tee or two — distribution circuits have complex topologies with many branches and countless components. Distribution utilities cannot know the current condition of every component. A utility often learns of outages and other problems from customer reports.

Supervisory control and data acquisition (SCADA) and other conventional technologies provide notification of gross events, such as when a high current fault trips a substation circuit breaker. Smart meters can provide additional information, such as blink counts and targeted pings. DFA research and field demonstration programs have shown incipient



Distribution circuits have complex topologies and span wide geographic areas. Pedernales and other utilities use DFA to learn of events and then use DFA-reported parameters synergistically with other tools to track them down.

failures of line components sometimes cause low-amplitude electrical changes, measurable from substation sensors; however, SCADA and smart meters are not designed to detect these changes and, thus, cannot alert the utility to such problems.

Electric service is fundamental to modern society, but despite prudent construction standards and operational procedures, electrical events can cause fires. DFA technology provides awareness of some line conditions capable of starting fires, and awareness enables action. The Texas legislature supported a field demonstration project to document how utilities can use Texas A&M Engineering's DFA technology to reduce wildfire-ignition risk.

Participants installed DFA on select circuits and worked with Texas A&M Engineering to become familiar with the technology. The utilities were charged with documenting examples of DFA-detected events of which they otherwise would have been unaware, paying special attention to events with ignition potential.

Branch on a Line

An early success at Pedernales involved a detached tree branch that hung on a remote single-phase tap on a long rural circuit. The 12.5-kV circuit has more than 150 miles (240 km) of circuit conductor and serves more than 1000 meters.

Most faults result from temporary conditions and can be

The Distribution Fault Anticipation System

Texas A&M University's College of Engineering has been developing distribution fault anticipation (DFA) technology since the late 1990s. Initially funded largely by the Electric Power Research Institute (EPRI), DFA research pursued the fundamental premise that line events, including incipient failures, cause measurable changes in line currents and voltages. Sensitively triggered, high-capacity, high-fidelity waveform recorders were installed in substations to monitor line currents and voltages of 70 distribution circuits during routine operations. These and subsequent installations have provided the largest extant database of high-fidelity waveforms from non-staged faults and other circuit events, with more than 1000 circuit-years of data. Study of that database enabled researchers to identify characteristics of many line events and implement algorithms to recognize and report them.

The state of Texas and other entities have provided substantial support to the development of DFA technology. DFA originally was an acronym for distribution fault anticipation, but the evolving development of the DFA technology resulted in its providing functionality that goes well beyond anticipation of faults. Power Solutions, LLC provides DFA technology commercially, under license from EPRI.

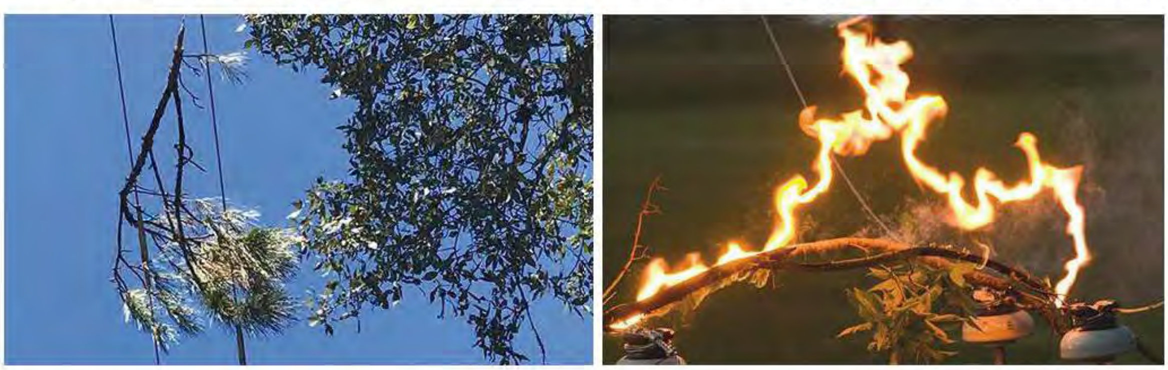
DFA technology is applied with a fleet of DFA monitoring devices and a central DFA master station. Each DFA device is installed in a 19-inch rack in a substation, monitors a single distribution circuit via conventional current transformers and potential transformers, and connects to a DFA master station at a central location through secure internet.

The DFA master station is a server computer with custom DFA software. It retrieves reports from the fleet of DFA devices and makes the reports available to users through a secure, password-protected website. The secret-sauce software that analyzes electrical waveforms to characterize line events resides in each circuit's DFA device. The system architecture is intended to make the system scalable because the centralized master station does not have to perform complex pattern-recognition computations. As algorithms are improved over time, the master station pushes new software to the fleet of devices.

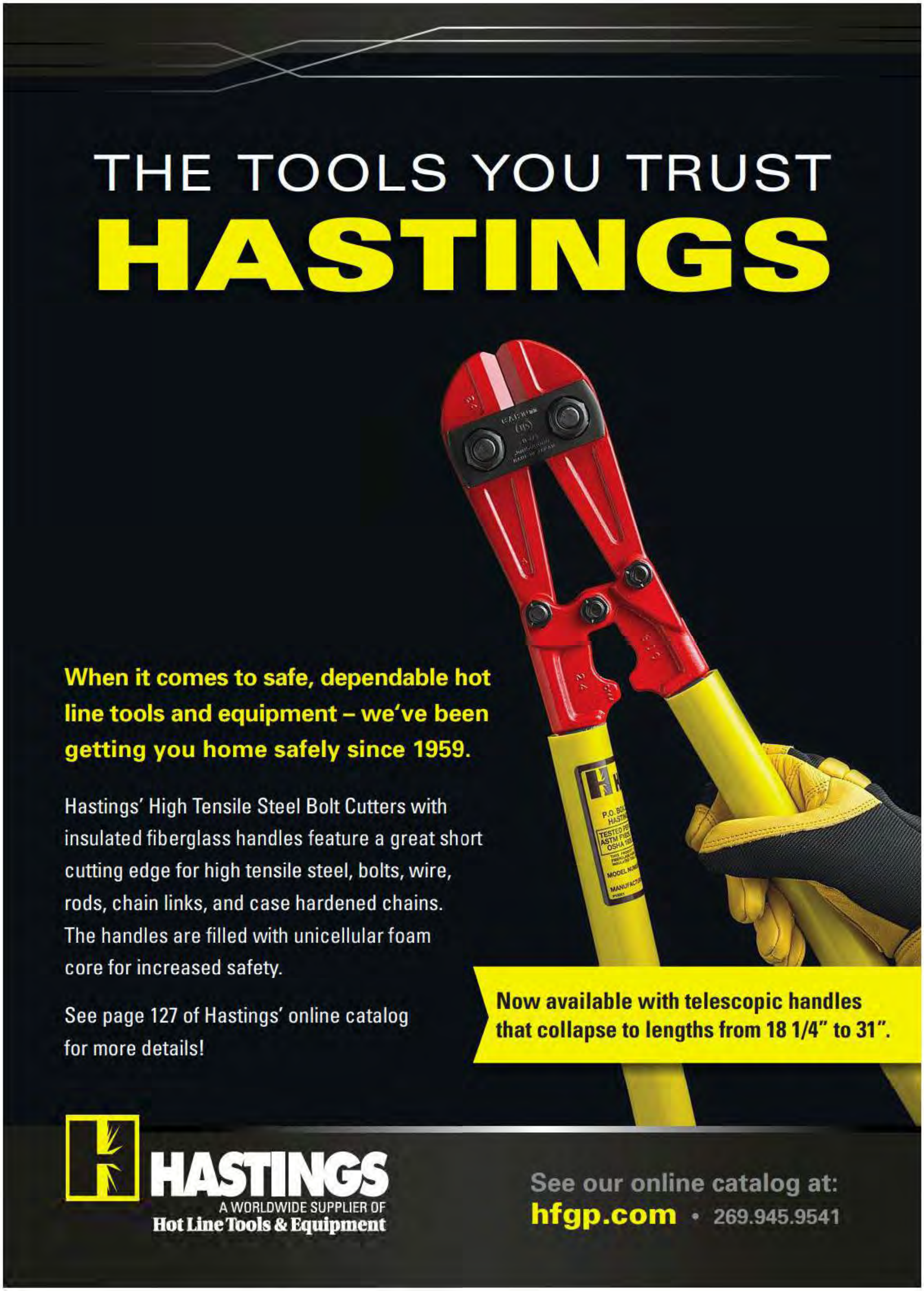
cleared by momentary trip-and-close operations, with no action needed by the utility. However, certain incipient failure conditions also cause momentary interruptions, which temporarily clear the faults but do not heal the underlying conditions. DFA field installations have documented numerous instances in which line conditions cause recurrent faults. Sometimes the faults are separated by minutes or hours, sometimes by days or weeks. Each fault episode is cleared by a momentary trip-and-close operation, but additional faults continue until the underlying condition is corrected, or until it evolves into a permanent fault and perhaps causes damage to facilities.

In the subject case, the tree branch caused multiple faults over a period of several hours during a storm. Each fault was cleared by a trip/close of a hydraulic recloser, with no operation of the substation breaker. Pedernales received no customer calls and ordinarily would have taken no action. By recording and analyzing substation-measured current-transformer and potential-transformer waveforms for this circuit, DFA software characterized each fault. Because DFA maintains a fault history and compares each new fault to that history, when it detects multiple instances of what appear to be the same fault, it reports a recurrent fault cluster. In the subject case, DFA reported the branch-caused faults in this way, resulting in an investigation by Pedernales.

Like many distribution circuits, the subject circuit has many branches. Such a topology means predicting location based



Branches on lines can cause repeated faults and momentary interruptions, degrading service quality and representing risk of ignition. Multiple participants in the Texas Power Line-Caused Wildfire Mitigation project have used DFA to detect and correct such conditions.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solely on fault current amplitude can result in multiple possible locations, resulting in inefficient patrols. Small fault currents generally result in more possible locations than large fault currents. Knowing which recloser is responding to the faults can focus patrols, but many reclosers are unmonitored, so the identity of the recloser must be inferred rather than determined directly by interrogating the recloser.

In the subject case, the recurrent faults drew a mere 300 A, so current-based prediction resulted in a significant number of potential locations. DFA reported each trip and close involved a single-phase recloser that temporarily interrupted approximately 15% of the affected phase's load. After using this information to eliminate some of the circuit's reclosers from consideration, Pedernales used its automated meter reading system to get blink counts from meters downstream of the suspected recloser and was able to confirm which recloser had been operating. Knowing this enabled a targeted patrol to locate the branch hanging on the line.

Without DFA, Pedernales likely would not have known about the problem. Once identified and located, correcting the problem was simple — remove the branch. The targeted patrol minimized crew time, and conductor damage was minimal. Had the branch remained undiscovered, it likely would have caused additional blinks and damaged the conductor. The branch on the line could have ignited, fallen free to the ground and started a fire. A more likely scenario would be progressive conductor damage, eventually dropping the conductor to the ground and potentially igniting a fire in that way.

Texas A&M Engineering has documented other recurrent faults, left uncorrected, that burned down lines or destroyed line equipment, causing lengthy outages; causes have included vegetation and damaged equipment. One that was very similar to the subject event involved a detached branch that eventually burned the line down. Despite more than a dozen trip-and-close operations from this branch, the utility in that case received no customer calls until the burned-down line caused a sustained outage.

Capacitor Management

With a fleet of more 530 capacitor banks to help maintain voltage and reactive power support, Pedernales has used DFA to detect and respond to multiple capacitor issues. Annual maintenance of banks detects failures such as blown fuses, but the annual nature of the cycle means a blown fuse can persist for months before being discovered. Other capacitor problems, such as internal arcing or partial loss of vacuum in a switch, need more timely response. In addition to multiple routine capacitor issues, DFA enabled Pedernales to correct a problem in which the close and open contacts for one phase of a bank had their leads swapped, causing the phase to come on when it was supposed to go off and vice versa. The utility has seen substantial value in using DFA for better oversight of its fleet of capacitor banks.

Unusual Events

DFA has made Pedernales aware of

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MOLDED PRODUCTS

Hendrix Molded Products, known for high density polyethylene insulators, invented by Bill Hendrix in 1961. Today Molded Products include designs for different line/pole configurations that utilities confront in the field.

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Hendrix kerite

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Maximizing Use of DFA Technology

Pedernales Electric Cooperative synergistically uses other tools to get the most benefit from distribution fault anticipation (DFA) and plans to use these more as it deploys DFA more broadly. The circuit model software can help to predict fault locations based on measured fault current amplitude. Its AMR system enables daily blink counts to determine which of a circuit's multiple reclosers is operating in response to recurrent faults. The AMR system also enables pings of selected meters to confirm suspected outages. AMR system constraints generally make it infeasible to ping on a circuit-wide basis. However, pinging a small number of meters — preselected based on DFA and circuit model information — can provide timely, useful information for problem resolution.

As an example of synergistic use, consider a scenario in which DFA reports a recurrent fault-causing intermittent momentary trip-and-close operations of an unmonitored recloser on a long circuit with multiple reclosers. DFA parameters can be used to infer which recloser likely is operating. AMR blink counts can be used to confirm the recloser. Circuit model software, using DFA-provided fault amplitude, can be used to predict location. Patrols then can be targeted beyond the recloser that is operating and further targeted by the prediction based on fault current amplitude. In such a case, DFA provides the most important element — awareness of the problem — then the multiple tools are used together to locate and enable repairs.

line events that are unusual but not recognized. One such event caused 23 single-phase current pulses, each 50 A to 100 A in magnitude, over a period of 13 seconds. The pulses were at regular time intervals, making the utility almost certain some sort of mechanical control was involved. The pulses were too large for a motor start or other individual load. Each pulse caused a voltage dip but lasted only about a cycle and, as measured from the substation, dipped the voltage by no more than 3.5%.

The cause of the pulses was not determined, and the event has not recurred. Still, knowing of such events has value. Customers sometimes report power problems about which the utility has no knowledge. Such problems can be difficult to diagnose. Investigations consume significant manpower and do not always lead to resolution. Having more information, from a sensitive continuous monitoring system such as DFA, can help the investigation. Similarly, when investigating customer problems, sometimes knowing the circuit is not experiencing events can have value and avoid wasting manpower looking for problems in places they do not exist.

Shared Experiences

A user group facilitated by Texas A&M Engineering has enabled Pedernales and other project participants to share their own experiences and gain from the experiences of others. Together, the group has documented a wide array of events:

• Detection and location of a broken insulator that resulted in a conductor heavily charring a wood crossarm

• Detection and location of arcing internal to a capacitor

• Detection, location and repair of multiple routine outages, without customer calls

• Detection and location of an intact tree intermittently pushing conductors together

• Detection and location of catastrophically failed lightning arresters

• Detection and location of an arc-tracked capacitor fuse barrel

• Detection and location of multiple instances of fault-induced conductor slap.

Most of these events represent the potential for ignition, given the right atmospheric conditions and available fuel loads. For each, the key DFA benefit was that it informed the utility that the problem existed.

Moving Forward

Distribution circuits have complex topologies, consisting of long lines and large numbers of components, spread over a large area. Situational awareness for such circuits is challenging. No technology detects all events, but Texas A&M Engineering's DFA has shown the ability to inform utilities of many events of which they otherwise were unaware. Pedernales and other utilities are using Texas A&M Engineering's DFA technology to improve situational awareness, thereby reducing fire ignition risk, making crews more efficient and improving the reliability and quality of electric service delivery. Based on successful trials, Pedernales and several other utility companies have begun expanding their deployments of DFA, integrating DFA into their work flows, and making DFA information available in their control centers. TDW

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For more information:

Pedernales Electric Cooperative | www.pec.coop
Power Solutions, LLC | www.powersolutionsllc.us
Texas A&M Engineering | engineering.tamu.edu

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DFA Technology System Manual

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Table of Contents

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1 Glossary of Terms

The following definitions apply to all parts of the DFA Technology System Manual. These definitions apply without regard to capitalization.

DFA Technology – Distribution Fault Anticipation technology.

DFA Technology System – A hardware and software system for the practice of DFA Technology and consisting of a DFA Master Station and a fleet of one or more DFA Devices. Where this document refers simply to "DFA," that means the DFA Technology System, except where context clearly indicates a different meaning.

DFA Master Station – DFA Master Station Hardware, loaded with DFA Master Station Software and acting as a fundamental component of the DFA Technology System, as more fully described in chapter 3, "Components of the DFA Technology System."

DFA Master Station Software – Proprietary, DFA Technology System-specific software, provided by Power Solutions, necessary for the DFA Master Station to perform its intended function, and not including operating system software or any other third-party software.

DFA Master Station Hardware – An appropriately specified computer or system of computers, not proprietary to Power Solutions, on which DFA Master Station Software is installed and used. DFA Master Station Hardware may consist of a single computer or of multiple computers configured to operate as a functional unit.

DFA Master Station Service – A fee-based service that provides the functionality of a DFA Master Station, as more fully described in chapter 3, "Components of the DFA Technology System."

DFA Device – A platform, provided by Power Solutions and consisting of DFA Device Hardware and DFA Device Software, acting as a fundamental component of the DFA Technology System, as more fully described in chapter 3, "Components of the DFA Technology System"; may be marketed under names such as DFA-Plus Device.

DFA Device Software – Proprietary, DFA Technology System-specific software, provided by Power Solutions, embedded in and running on DFA Device Hardware. DFA Device Software is available only as an integral component of DFA Devices, not as standalone software.

DFA Device Hardware – Hardware of proprietary design, to provide the sensing, computing, communications, and other requirements for running DFA Device Software; does not include power supplies, wiring, communications equipment, or other apparatus, except as embedded in and integral to the DFA Device Hardware itself.

DFA Software – Propriety software that is an integral part of the operation of the DFA Technology System and consisting of DFA Device Software, DFA Master Station Software, or both, as implied by context.

DFA Website – A browser-based website that provides each Customer with password-protected access to DFA Data from that Customer's fleet of DFA Devices and other functions.

DFA Fleet Management – A function of the DFA Technology System, whereby a DFA Master Station provides oversight and management functions for a fleet of DFA Devices.

Distribution Circuit or simply Circuit – A three-phase electrical circuit, operating at distribution voltage (i.e., from 1 kV to 35 kV), for conducting electricity from a distribution substation to electric loads; also known as a feeder or a line.

Distribution Company, or DISCO – An electric power distribution company or an entity performing power delivery functions typically ascribed to an electric power distribution company.

DFA Data – Electrical current and voltage waveform data, digitized by DFA Devices, and reports generated by DFA Software acting on that waveform data.

Customer – An end user of the DFA Technology System; typically, a Distribution Company; excludes agents and resellers.

DFA Analysis Service – A fee-based service under which Power Solutions assists the Customer in the interpretation and use of DFA Data, on a case-by-case basis, upon request by Customer, as more fully described in chapter 4, “DFA Analysis Service.”

Power Solutions – Power Solutions LLC, a Texas limited liability company.

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2 Principle of Operation, Intended Use and Limitations

This chapter on "Principle of Operation, Intended Use and Limitations" uses terms as defined in the accompanying "Glossary of Terms."

The fundamental principle underlying the operation of the DFA Technology System (or simply "DFA") is the fact that electrical events occurring on a Circuit affect the currents and voltages of that Circuit, and therefore that the behavior of those currents and voltages represents events on the Circuit. The starting of a motor, the switching of a capacitor bank, and the occurrence of a short-circuit fault are examples of events that affect a Circuit's currents and voltages. Each DFA Device senses current and voltage waveforms, detects and records anomalies in those waveforms, and uses proprietary software to analyze those recorded waveforms to infer Circuit events, as further described in chapter 3, "Components of the DFA Technology System."

The intended use of DFA is to provide improved awareness, or visibility, of Circuit events. DFA is most effective when used in concert with other data and information sources available to trained utility operators and engineers. DFA does not replace all functions of other data sources but rather complements them. No device or system, including DFA, will report all Circuit events and or do so without error.

DFA is considerably more sensitive than conventional systems, such as SCADA or protection devices, but physics dictates practical limits to sensitivity. The amplitude and other characteristics of waveform variations resulting from a given Circuit event depend on the nature of the event and on external factors, such as weather. There are inherent tradeoffs between sensitive detection and avoidance of false alarms. Based on industry input, DFA biases toward minimizing false alarms.

The Customer should make all decisions regarding how or whether to act based upon all available information, from DFA and other sources, and upon the Customer's inherently superior knowledge of its own Circuits. It is not expected that either the Customer or Power Solutions will ever review, investigate, or act upon all data from the DFA Technology System. Power Solutions will use commercially reasonable best efforts to respond to Customer requests for DFA Analysis Service within the timeliness and other parameters outlined in the chapter of this manual that describes that service.

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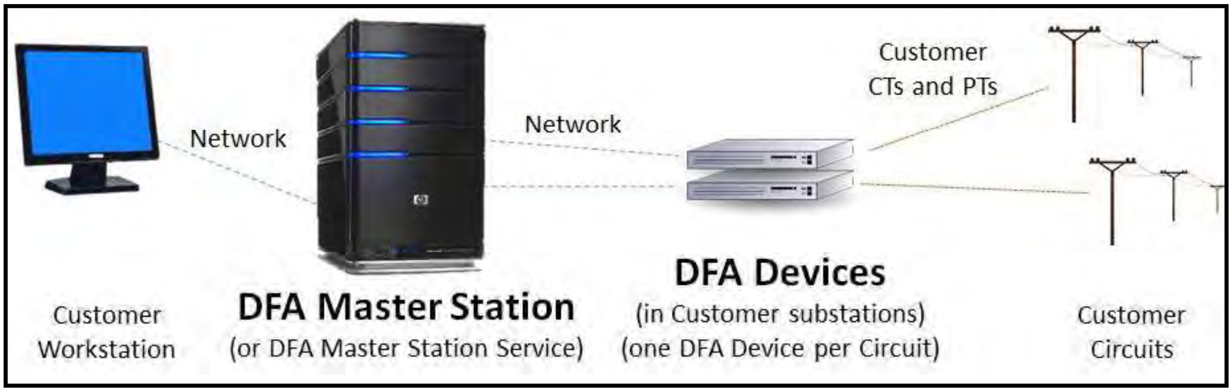
3 Components of the DFA Technology System

This chapter on "Components of the DFA Technology System" uses terms as defined in the accompanying "Glossary of Terms."

The DFA Technology System consists of two fundamental components, DFA Devices and a DFA Master Station, both of which are necessary to the basic use of the DFA Technology System.

Issues related to cybersecurity safeguards are discussed in chapter 8, "DFA Cybersecurity and Software Updates and Maintenance."

The following high-level schematic illustrates the relationship between the basic components. The Customer is fully responsible for all items other than the DFA Master Station and DFA Devices. A properly functioning network connection between each DFA Device and the DFA Master Station is necessary for operation of the DFA Technology System.



High-Level Schematic of the DFA Technology System

3.1 DFA Devices

DFA Devices monitor electrical waveforms, detect anomalies, and generate reports by using proprietary DFA Device Software to process those waveform anomalies and thereby infer Circuit events. Each DFA Device is intended to perform this function for a single Circuit. Inputs to each DFA Device are the secondary leads of a Circuit's conventional, three-phase current and potential transformers (CTs and PTs). Non-traditional current and voltage sensors have characteristic that make them inherently unsuitable as inputs to sensitive applications such as DFA. DFA Device Software operates on DFA Device Hardware and is not intended for use except in the context of DFA Device Hardware.

Each DFA Device communicates with and sends DFA Data to a DFA Master Station via conventional TCP/IP communications over Internet/intranet network service, which is provided by the Customer. Protocols such as SCADA, DNP, or IEC61850 are not suitable. Each DFA Device has a finite capacity of semi-permanent data storage for DFA Data and other information necessary to the function of the DFA Device. Housekeeping functions in the DFA Device Software manage available storage, including deletion of DFA Data, without warning or notice, as needed to maintain sufficient free space for ongoing operation of the DFA Device.

3.2 DFA Master Station and DFA Master Station Service

The DFA Master Station performs a variety of functions, including the following:

1. It retrieves DFA Data from the Customer's fleet of DFA Devices and retains that data in accordance with chapter 9, "DFA Data Backup and Retention."
2. It provides the DFA Website, which provides the Customer with secure, browser-based, password-protected access to the Customer's DFA Data.
3. It provides DFA Fleet Management functions for the Customer's fleet of DFA Devices. DFA Fleet Management relies upon a properly functioning, Customer-provided network connection between each of the Customer's DFA Devices and the DFA Master Station. DFA Fleet Management functions include:
    a. Enabling the Customer to monitor the health of its fleet of DFA Devices, including detection of various problems with the DFA Devices themselves and with network connections from the DFA Devices to the DFA Master Station. For example, a lack of communications between a DFA Device and the DFA Master Station for an extended period of time may indicate a problem with network service or with the DFA Device itself.
    b. Deploying updated DFA Device Software to each DFA Device in the fleet, as such updates become available.

Where Power Solutions provides the Customer with DFA Master Station Service, it provides Power Solutions personnel with access similar to the access it provides to Customer personnel.

The above is not represented as a comprehensive list or as containing all details about DFA Master Station functions, but rather provides the highlights of the function of the DFA Master Station.

The Customer has two options for obtaining DFA Master Station functionality, as described below. The difference is primarily one of ownership and operation of the DFA Master Station, rather than one of functionality.

3.2.1 Customer-owned DFA Master Station

Under this option, the Customer purchases, configures, owns, operates, and maintains its own DFA Master Station Hardware and loads it with proprietary DFA Master Station Software provided by Power Solutions. As a variant of this option, the Customer may enter into an agreement with Power Solutions under which Power Solutions purchases, pre-configures, and delivers to the Customer a "turn-key" DFA Master Station. In either event, the Customer owns the DFA Master Station Hardware, and Power Solutions' responsibility for the DFA Hardware is limited to the provisions of chapter 6, "Statement of Limited Warranty and Limitations of Remedies."

PSLLC intends to offer Customer-owned DFA Master Station at some point in the future but currently does not do so.

3.2.2 DFA Master Station Service

Under this option, the Customer does not own or operate a DFA Master Station. Instead Power Solutions provides equivalent DFA Master Station functionality to the Customer as a fee-based service, known as DFA Master Station Service. Power Solutions may accomplish this by owning and operating a physical DFA Master Station at its own facilities or through the use of an owned or leased collocated server (for example, Rackspace) or a cloud-based service (for example, Amazon Web Services), which are collectively referred to herein as "Cloud Hosting Providers." Power Solutions maintains multiple Customers' DFA Data on the same DFA Master Station. Each Customer accesses only its own DFA Data, via the DFA Website. Power Solutions has access to all Customers' DFA Data, subject to terms more fully described in "Privacy and Consent to Use Data Policy."

In the event that Power Solutions, in the future, stops providing DFA Master Station Service, Power Solutions will offer to provide DFA Master Station Software to Customer under then-prevailing commercial terms and pricing.

4 DFA Analysis Service

This chapter on "DFA Analysis Service" uses terms as defined in the accompanying "Glossary of Terms."

DFA Analysis Service is a fee-based service under which Power Solutions helps the Customer analyze and understand the Customer's DFA Data and related Circuit events more fully than possible than with the propriety, automated DFA Technology software alone.

The Customer initiates requests for DFA Analysis Service on a case-by-case basis. A typical request might involve a Customer's receiving a DFA-generated report of a Circuit event and requesting assistance to interpret it. Another typical request might involve a Customer's experiencing trouble, of unknown cause, and requesting assistance in the use of DFA Data to help diagnose the issue.

DFA Analysis Service typically consists of a dialogue between Power Solutions personnel and Customer personnel and generally occurs telephonically or via electronic mail (email). DFA Analysis Service normally is provided during normal business hours at Power Solutions offices in Texas.

Optimal understanding of Circuit events requires the Customer's inherently superior knowledge of its own Circuits, practices, and events. For example, the Customer may know of special loads on a particular Circuit, or of actions field crews have taken. As another example, the Customer's outage logs or other internal records may contain information concerning trouble calls. The efficiency and effectiveness of DFA Analysis Service depends on the Customer's timely provision of accurate, relevant information.

In the course of providing DFA Analysis Service, discussions often arise regarding courses of action that the Customer might take. Power Solutions may suggest possible options to the Customer, but all decisions related to whether and how to act are the Customer's responsibility and are to be based on the Customer's use of sound operations and engineering judgement, experience, and superior knowledge of its own Circuits, priorities, and prevailing conditions.

Effective provision of DFA Analysis Service requires that Power Solutions have full, direct access to Customer's DFA Data. If Power Solutions provides DFA Master Station Service to the Customer, the required access is inherently available. If the Customer owns its own DFA Master Station, Power Solutions strongly recommends that the Customer provide Power Solutions direct access to that DFA Master Station. Lack of full access substantially impedes the provision of DFA Analysis Service.

As a practical matter, it should be recognized that:

1. It is not feasible for either Customer personnel or Power Solutions personnel to review or act upon all DFA Data.
2. Not all cases that are reviewed will lead to correct conclusions or outcomes.
3. The Customer's active engagement and timely provision of information is key to achieving optimal benefits from DFA Analysis Service.

5 Customer Responsibilities

This chapter on "Customer Responsibilities" uses terms as defined in the accompanying "Glossary of Terms," and outlines some of the basic responsibilities inherently borne by the Customer.

The Customer is responsible for all aspects of installation and commissioning DFA Devices in a suitable environment, and for provision, installation, and proper wiring of conventional CTs and PTs, battery-backed unit power, and Internet service to each DFA Device.

The Customer is responsible for assigning properly trained personnel to review DFA Data on a regular basis. Customer personnel who will use the DFA Technology System should read and understand all pertinent documentation and understand the operation of the DFA Technology System prior to use.

The Customer is responsible for making all decisions regarding how or whether to act on DFA Data. This remains true in the event that Power Solutions provides DFA Analysis Service and/or discusses possible actions with Customer personnel.

6 Statement of Limited Warranty and Limitations of Remedies

This "Statement of Limited Warranty and Limitations of Remedies" uses terms as defined in the accompanying "Glossary of Terms."

Subject to the accompanying "Customer Responsibilities," Power Solutions makes the following "Limited Warranty":

1. Hardware.

    a. <u>DFA Device Hardware</u>. Power Solutions expressly warrants that all DFA Device Hardware will be delivered free from defects in material and workmanship.

    b. <u>DFA Master Station Hardware</u>. Power Solutions makes no warranty as to DFA Master Station Hardware. As defined in the "Glossary of Terms" and described in more detail in chapter 3, "Components of the DFA Technology System," DFA Master Station Hardware is not proprietary to Power Solutions and is not customarily provided by Power Solutions. In the event that Power Solutions purchases third-party computer hardware and configures it as DFA Master Station Hardware for turn-key delivery to Customer, Power Solutions will "pass through" to the Customer warranties of the manufacturer(s) of said third-party computer hardware, to the extent that Power Solutions has the right to do so ("Pass-Through Warranty").

2. Software.

    a. <u>DFA Device Software</u>. Power Solutions expressly warrants that all DFA Device Software will operate substantially in accordance with chapter 2, "Principle of Operation, Intended Use and Limitations" and any instructions or manuals that exist or may exist in the future.

    b. <u>DFA Master Station Software</u>. Power Solutions expressly warrants that all DFA Master Station Software will operate substantially in accordance with chapter 2, "Principle of Operation, Intended Use and Limitations" and any instructions or manuals that exist or may exist in the future.

3. <u>DFA Master Station Service</u>. In the event that the Customer opts for the DFA Master Station Service (see sub-section 3.2.2 in chapter 3, "Components of the DFA Technology System"), except for the limited warranty of the DFA Master Station Software (stated above), Power Solutions makes no warranty regarding the services provided by any Cloud Hosting Provider. By way of example and not limitation, Power Solutions makes no warranty regarding: (i) the temporary or total loss of Internet access, (ii) the partial or total loss of DFA Data hosted by Power Solutions or by a Cloud Hosting Provider, and or (iii) the partial or total breach of the Customer's privacy.

Power Solutions LLC
A Texas Limited Liability Company

Duration of the Limited Warranty. The Limited Warranty shall apply for a limited period that will terminate on the earlier of: (i) eighteen (18) months from the delivery of the shipment; or (ii) twelve (12) months from the date the product is installed for use. The limited period shall be extended upon the purchase of an extended warranty period.

Voiding of Limited Warranty. The Limited Warranty shall be voided upon the occurrence of any of the following events: (i) damage to the products resulting from improper storage; (ii) damage to the products caused by misuse, disasters (fire, flood, etc.), or tampering; and (iii) damage to the products resulting from repairs performed by service providers not approved by Power Solutions.

Exclusions from the Limited Warranty. The Limited Warranty shall not apply to (i) any add-on devices and or products; (ii) the design of any system prepared by any service provider or reseller; or (iii) the installation of any system by any service provider or reseller.

Disclaimer of Warranty and Limitations of Remedies. THE LIMITED WARRANTIES SET FORTH HEREIN ARE IN LIEU OF ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, WHICH ARE HEREBY DISCLAIMED AND EXCLUDED BY POWER SOLUTIONS, INCLUDING WITHOUT LIMITATION, ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE. BY WAY OF EXAMPLE AND NOT LIMITATION, EXCEPT AS SPECIFICALLY SET FORTH HEREIN, POWER SOLUTIONS MAKES NO WARRANTY AND SHALL NOT BE LIABLE FOR (I) THE MECHANICAL BREAKDOWN OF ANY COMPONENT OF THE DFA TECHNOLOGY SYSTEM, (II) MALFUNCTION OF ANY SOFTWARE COMPONENT OF THE DFA TECHNOLOGY SYSTEM, (III) TEMPORARY OR TOTAL LOSS OF INTERNET ACCESS AT ANY LEVEL, (IV) THE PARTIAL OR TOTAL LOSS OF DFA DATA HOSTED BY DFA MASTER STATION OR DFA MASTER STATION SERVICE AND/OR (V) THE PARTIAL OR TOTAL BREACH OF THE CUSTOMER'S PRIVACY REGARDING THE DFA DATA.

THE SOLE AND EXCLUSIVE REMEDIES FOR BREACH OF ANY AND ALL WARRANTIES AND THE SOLE REMEDIES FOR POWER SOLUTIONS' LIABILITY OF ANY KIND (INCLUDING LIABILITY FOR NEGLIGENCE) WITH RESPECT TO THE PRODUCT SHALL BE LIMITED TO EITHER REPAIR OR REPLACEMENT OF A DEFECTIVE ITEM OF PRODUCT AT THE SOLE OPTION OF POWER SOLUTIONS. IN NO EVENT SHALL POWER SOLUTIONS' LIABILITY FOR DAMAGES AND OR INJURIES INCLUDE LOST PROFITS AND ANY SPECIAL, INDIRECT, INCIDENTAL, OR CONSEQUENTIAL LOSSES OR DAMAGES, EVEN IF THE SELLER SHALL HAVE BEEN ADVISED OF THE POSSIBILITY OF SUCH POTENTIAL LOSS OR DAMAGE.

IF ANY PRODUCT DOES NOT CONFORM TO THIS LIMITED WARRANTY, THE CUSTOMER SHALL NOTIFY THE SELLER OF SUCH FAILURE, OBTAIN A RETURN MERCHANDISE AUTHORIZATION ("RMA"), AND SHIP IT TO POWER SOLUTIONS, AT AN ADDRESS, IN TEXAS, DESIGNATED BY SELLER, AT THE CUSTOMER'S EXPENSE. THE RMA MAY BE OBTAINED BY EMAIL FROM SELLER. AT ITS SOLE OPTION, POWER SOLUTIONS MAY REPAIR AND REPLACE THE DEFECTIVE PART, THEN RETURN IT TO THE CUSTOMER AT POWER SOLUTIONS' EXPENSE. ANY PRODUCT REPAIR OR REPLACEMENT SHALL BE COVERED BY THIS WARRANTY FOR THE LONGER OF ONE (1) YEAR FROM THE DATE OF REPAIR OR THE REMAINDER OF THE ORIGINAL WARRANTY PERIOD.

IF POWER SOLUTIONS FAILS TO REPLACE OR REPAIR AS AFORESAID, OR REACH A RESOLUTION ACCEPTABLE TO THE CUSTOMER, THEN POWER SOLUTIONS' ENTIRE LIABILITY SHALL NOT EXCEED THE ENTIRE AMOUNT PAID TO POWER SOLUTIONS BY CUSTOMER FOR THE PRODUCT IN

QUESTION, AND AS STATED ABOVE, IN NO EVENT SHALL POWER SOLUTIONS' LIABILITY OF ANY KIND INCLUDE ANY SPECIAL, INDIRECT, INCIDENTAL, OR CONSEQUENTIAL LOSSES OR DAMAGES, EVEN IF THE SELLER SHALL HAVE BEEN ADVISED OF THE POSSIBILITY OF SUCH POTENTIAL LOSS OR DAMAGE.

7 Privacy and Consent to Use Data Policy

This "Privacy and Consent to Use Data Policy" uses terms as defined in the accompanying "Glossary of Terms."

Power Solutions recognizes and respects its Customers' right to privacy. By purchasing, installing, accessing or using the DFA Master Station Service, Customer expressly consents to Power Solutions' collection, processing and use of the Customer's data according to this "Privacy and Consent to Use Data Policy." Power Solutions may share the Customer's data, as defined below, with its subsidiaries and affiliates, solely as described herein.

Through the remainder of this "Privacy and Consent to Use Data Policy," second person pronouns ("you," "your," and so on) mean the Customer and first-person pronouns ("we," "our," "us," and so on) mean Power Solutions.

WHAT IS THE SCOPE OF YOUR CONSENT TO OUR USE OF YOUR DATA?

The scope of your consent includes our collecting your DFA Data, analyzing it, and using it today and in the future for product improvements (for-profit commercialization), industry research and publications, and provision of DFA Analysis Service to you, as set forth in this "Privacy and Consent to Use Data Policy."

WHAT DATA DO WE COLLECT?

If you neither use our DFA Master Station Service nor request that we review your DFA Data, then we do not collect your DFA Data; however, if you use our DFA Master Station Service or request that we review your DFA Data, then we collect your DFA Data.

WHAT DO WE DO WITH YOUR DATA?

We may use your DFA Data to assist you with DFA Analysis Service and for the purpose of improving our commercial products. Additionally, we may share your DFA Data with the Texas A&M Engineering Experiment Station (TEES) and their affiliates for their research projects. Your DFA Data will be included with similar DFA Data collected from other Customers. These research projects may, or may not, be disclosed in industry publications (see below).

WHAT DO WE NOT DO WITH YOUR DATA?

We do not monitor or review your data on a real-time, daily, weekly, monthly, or annual basis in order to determine if your Circuits are defective, down, or otherwise experiencing a dangerous condition or other problem. We are not a "home or business security" service provider that monitors your home or business on a 24x7 basis or contacts you if the hardware and or software installed in your home or business signals a problem. You are responsible for reviewing your DFA Data, at intervals that your experience deems appropriate, to determine whether your Circuits are experiencing a problem. If you contact us regarding a specific issue involving your Circuits, we may review your DFA Data and assist you in interpreting relevant DFA Data. If we, in the course of reviewing your DFA Data, discover an indication of a possible Circuit event or condition that we believe may be of interest to you, we may, at our discretion, initiate contact with you regarding that event or condition, but we have no responsibility to do so, and doing so in one instance creates no obligation or expectation that we would do so for future events.

WHAT DATA DO WE DISCLOSE?

Customer Lists, Press Releases, and Marketing Materials

Power Solutions may publish customer lists, to include the name of your company and the approximate number of DFA Devices and related services you have purchased or are contemplating purchasing, which will be in the nature of customer lists, press releases and/or marketing materials.

Research Publications

Descriptions, summaries, and analyses that use DFA Data from your Circuits may be disclosed in research documents, publications, or reports, which are published and released to the industry, provided the name of your company and your employees shall not be disclosed in conjunction with specific, traceable examples of DFA Data. Power Solutions and its affiliates do not otherwise disclose the name of your company in its reports, except with your permission or in publications made jointly with you or your employees.

8 DFA Cybersecurity and Software Updates and Maintenance

This chapter on "DFA Cybersecurity and Software Updates and Maintenance" uses terms as defined in the accompanying "Glossary of Terms."

This chapter outlines Power Solutions' general strategy with regard to cybersecurity and software maintenance. This strategy is subject to change without notice.

8.1 DFA Device Cybersecurity

DFA Devices installed in Customer substations have multiple safeguards against unauthorized intrusion. Each DFA Device has an internal firewall that is configured to drop all incoming connections. Additionally, communications between a DFA Device and DFA Master Station is initiated by the DFA Device, not the DFA Master Station, allowing the Customer to install and configure a firewall, in the substation, to block all inbound communications to the DFA Device.

DFA Devices run a long-term support (LTS) version of the Linux operating system. Critical security patches are applied as needed to the operating system and other component software, as part of the overall DFA Device Software update process. DFA Devices do not have a user interface or user-executed software, minimizing the risk of personnel inadvertently installing a malicious program.

Communications between each DFA Device and the DFA Master Station is encrypted using industry-standard protocols.

8.2 DFA Master Station Cybersecurity

8.2.1 DFA Master Station Service

DFA Master Station Hardware, operated as part of the DFA Master Station Service by Power Solutions, runs Linux as its operating system. The DFA Master Station resides behind an IDS/IPS and firewall, which helps mitigate network-based attacks. Power Solutions configures its DFA Master Station to install security patches and software updates on a regular basis and, in the event of a critical security patch, will update the DFA Master Station as soon as reasonably feasible after a patch is available.

Each Customer accesses DFA Data related to that Customer's fleet of DFA Devices via secure (https) login to the browser-based DFA Website, protected by Customer-specific usernames and passwords. No DFA Technology-specific software is installed on Customer-owned computers.

8.2.2 Customer-owned DFA Master Station

Any Customer that owns its own DFA Master Station is responsible for securing network access, configuring virus protection, administering patch application processes, and all other aspects of cybersecurity for its DFA Master Station.

8.3 DFA Software Updates and Maintenance

Power Solutions evaluates DFA Device Software and DFA Master Station Software for security vulnerabilities (e.g., XSS, CSRF, code injection, etc.) and fixes vulnerabilities that are discovered in a timely manner. Where technically and commercially feasible, Power Solutions uses commonly available libraries and frameworks (e.g., OpenSSL, Apache, Flask, etc.) to reduce exposure to vulnerabilities. Updates for security vulnerabilities will be provided as part of the update processes for DFA Device Software and DFA Master Station Software.

9 DFA Data Backup and Retention

This chapter on "DFA Data Backup and Retention" uses terms as defined in the accompanying "Glossary of Terms."

If Power Solutions provides Customer with DFA Master Station Service, Power Solutions shall back up Customer's DFA Data and retain it for two years from the date the underlying Circuit events occurred. During that period, Power Solutions shall take commercially reasonable efforts to preserve Customer's DFA Data from loss. At its discretion, Power Solutions may choose for a backup copy of the data to reside on a cloud-based service, even if the DFA Master Station Service itself is not run on a cloud-based provider.

Customer's DFA Data shall not be deemed critical to Customer's operations, and Customer shall make no such assertion in the event of loss of DFA Data. At the end of the two-year retention period, Power Solutions may delete Customer's DFA Data, without notice to Customer and without backup by Power Solutions. Power Solutions may, at its discretion, maintain Customer's DFA Data past the two-year retention period, for purposes of product improvement.

Any Customer that owns and manages its own DFA Master Station is responsible for backing up its own data.

DFA Data backup and consequently retention presume proper function of Customer-provided network service between the Customer's fleet of DFA Devices and the DFA Master Station Service. DFA Data resident on a DFA Device is managed autonomously by the DFA Device and deleted substantially on a first-in-first-out (FIFO) basis, subject to the finite semi-permanent storage capacity of the DFA Device, described in section 3.1, "*DFA Devices*."

10 Special Provisions for Customers of Resellers

This chapter on "Special Provisions for Customers of Resellers" uses terms as defined in the accompanying "Glossary of Terms."

In some cases, Power Solutions may sell DFA Devices and/or DFA Master Station Service and/or DFA Analysis Service to a party (a "Reseller") whose intent it is to resell those products and services to an end-use customer.

10.1 Contractual Relationships

When a Reseller sells DFA Master Station Service and/or DFA Analysis Service to an end-use customer, the Reseller may fulfill those obligations to its end-use customer, fully or in part, via subcontract relationship between the Reseller and Power Solutions. In such an event, Power Solutions is acting as a subcontractor of the Reseller and does not have a direct contractual relationship with the end-use customer. The nature of this contractual relationship does not preclude direct interaction between Power Solutions personnel and personnel of the Reseller's end-use customer, on behalf of the Reseller.

10.2 Point of Delivery of Products and Services by Power Solutions

The point of delivery for DFA Devices, DFA Master Station Service, and DFA Analysis Service provided directly or indirectly to any party by Power Solutions is Brazos County, Texas, or other location within Texas designated by Power Solutions. This point-of-delivery designation applies to all products and services provided by Power Solutions, both for direct end-use customers of Power Solutions and to end-use customers of a Reseller that has subcontracted obligations to Power Solutions.

10.3 Jurisdiction, Venue, and Applicability of Limited Warranty

Consistent with this designated point of delivery for all Power Solutions products and services, the jurisdiction and venue for any dispute or other matter related to DFA Technology provided by Power Solutions is Brazos County, Texas. All provisions of chapter 6, "Statement of Limited Warranty and Limitations of Remedies," apply to direct end-use customers of Power Solutions and to end-use customers of Reseller.

11 Effects of Circuit Configuration on DFA Device Software

This chapter on "Effects of Circuit Configuration on DFA Device Software" uses terms as defined in the accompanying "Glossary of Terms."

This chapter uses the terms ground, grounded, and grounding interchangeably with the terms earth, earthed, and earthing.

The DFA Technology System was developed based on electrical waveform data from Circuits employing the most common configuration in the United States, namely three-phase, four-wire, solidly grounded Circuits operating at a nominal system frequency of 60 Hz. Many electricity customers on such Circuits receive service via single-phase transformers, having their primary terminals connected between one of the Circuit's phase conductors and its grounded neutral conductor. In this configuration, the neutral conductor intentionally carries current during normal operations.

Circuit configurations used by some Customers differ from the aforementioned configuration. Chief differences include the nature of the grounding of the distribution system neutral, the intentional use of the neutral conductor as a current-carrying conductor under normal system operation conditions, and the nominal system frequency, although there also may be other relevant configuration differences.

DFA Device Hardware is intended to operate at either 50 Hz or 60 Hz and without regard to the grounding of the Circuit neutral or the use of the Circuit neutral as a current-carrying conductor, but variations in Circuit configuration will affect some results produced by the DFA Device Software. Power Solutions believes that most functions of the DFA Technology System will work substantially as intended, without adaptation, but that adaptation of DFA Device Software will be required for some functions to work properly. The feasibility and amount of time necessary to develop, test, and deploy DFA Device Software adaptations depends on multiple factors, some beyond the control of Power Solutions, and therefore cannot be predicted with certainty. A fundamental requirement to enable such adaptation is the availability to Power Solutions of relevant DFA Data and other Customer-provided event information from Circuits having differing configurations. Power Solutions believes it possible to implement adaptations to address most variations in Circuit configuration but makes no specific guarantees.

A specific Circuit configuration that differs more dramatically from the typical United States configuration is known as "single-wire, earth return," or SWER. Power Solutions believes that the DFA Technology System will be able to be adapted to infer some events that occur on SWER lines but recognizes that SWER represents a more dramatic departure from more conventional Circuit configurations and therefore that SWER will present a greater challenge for adaptation and a greater uncertainty of outcome. As with other variations in Circuit configuration, provision to Power Solutions of adequate data from Circuits having SWER segments will be fundamental to enabling analysis of waveform differences and thus the possibility of adaptations of DFA Device Software.

12 Miscellaneous Terms

This chapter on "Miscellaneous Terms" uses terms as defined in the accompanying "Glossary of Terms."

12.1 Customer Consent

By purchasing and or using a DFA Technology System, the Customer consents and agrees to all of the terms and conditions set forth in this "DFA Technology System Manual."

12.2 Copyright and Trademark

Power Solutions, the Power Solutions logo, and all trademarks and service marks are trademarks and service marks of Power Solutions.

12.3 Customer Service

Issues related to the DFA Technology System should be sent to support@powersolutionsllc.us. Power Solutions will attempt to respond within two business days, but it does not represent that it will respond or that it will respond in a timely manner.

12.4 Governing Law and Jurisdiction

The purchase and use of the DFA Technology System, as well as the use and construction of the "DFA Technology System Manual" shall be governed, construed, and enforced in accordance with the laws of the state of Texas, United States of America without reference to conflicts of law principles. The parties agree that the exclusive jurisdiction of any legal dispute or actions arising out of, relating to, or in any way connected with the purchase and or use of a DFA Technology System shall be in the state or federal courts, as applicable, governing Brazos County, Texas, United States of America.

12.5 Licenses

To the extent that any Customer needs a license to use any aspect of a DFA Technology System, Power Solutions hereby grants the Customer a non-exclusive license to use the DFA Technology System in accordance with the purposes, terms, and conditions of this "DFA Technology System Manual."

13 DFA Device Installation

This chapter on "DFA Device Installation" uses terms as defined in the accompanying "Glossary of Terms." In this chapter, the terms "user" and "installer" are used to mean the Customer or an installer working at the behest of the Customer, and the terms "device(s)" and "unit(s)" mean DFA Device(s). The term "DFA Device" is used interchangeably with term "DFA-Plus Device."

13.1 Important Warnings – Risk of Serious Injury or Damage

DFA Devices should only be connected in accordance with the user's established practices, procedures, and policies. Installation shall be done only by qualified personnel familiar with the user's established practices, operation of the DFA Device, external components being connected to, and all associated hazards.

Only persons with electrical safety training and certification appropriate to installations in substations should install the DFA Device or access the connection terminals once the equipment has been installed.

Improper wiring or use of electrical circuitry may result in serious personal injury, damage or outage of the associated power system, and/or damage to the device, and may void warranty.

13.2 DFA Device Main Components

Prior to installing or commissioning a DFA Device, the user should be able to identify its main components and understand its basic connections.

The device is intended for installation in a 19-inch rack. None of the device's internal components are to be accessed by the user.

The device's front panel, shown in Figure 1, provides a Management Port that is intended for use only during installation and troubleshooting of the device. The device's rear panel, shown in Figure 2, has terminals for connection of three CTs, three PTs, battery-backed Unit Power, and an Ethernet port to enable continuous communications between the device and a centrally located DFA Master Station. User access to DFA Data is provided via the DFA Master Station only, not via direct connection to the Management Port or to the Ethernet port.

Figure 1: Front panel of DFA Device

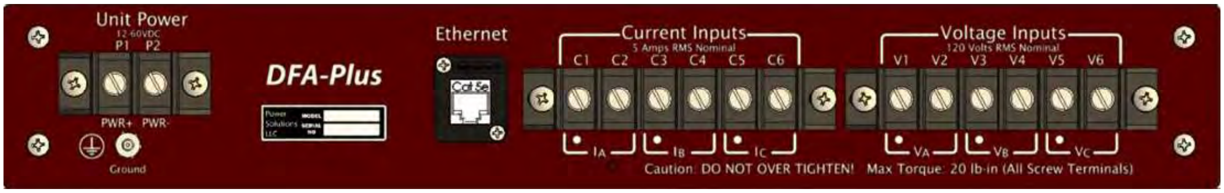


Figure 2: Rear panel of DFA Device

13.3 Device Installation Overview

Installation of a DFA Device requires the following steps.

- Preparing for the installation.
- Verifying that the device has the correct Current Input range, either five-amp or one-amp.
- Determining the proper configuration of CT and PT connection for the Circuit to be monitored.
  Important Note: No PT or other transformer that is to be used as a voltage input to the device (i.e., that is to be connected to a PT input terminal) may be used to supply power to the device or to any other equipment. Such use would distort the voltage waveforms coming from the PT or transformer and result in degraded, unpredictable results from the DFA Technology System.
- Selecting a rack-mount position for the device (19", 1.5U [2-5/8"]).
- Ensuring adequate long-term environmental conditions for the device where it will be installed.
- Arranging a suitable source of uninterrupted (i.e., battery-backed) DC Unit Power for the device.
- Providing a suitable grounding/earthing system.
- Preparing the necessary cabling, terminated with suitable terminals and associated hardware.
- Planning the installation to ensure no open circuiting of CT secondary circuits. Serious personal injury to personnel or damage to the DFA Device and/or other equipment may result.
- Arranging suitable network communications hardware and service.

The following tools are normally necessary for a standard installation:

- Torque screwdrivers (flat; for CT, PT, and Unit Power terminal screws)
- Pliers, wire cutters, wire strippers
- Shorting leads
- Crimping tools
- Multi-meter capable of measuring AC currents and AC and DC voltages.

Caution: Do not over-torque screw terminals on the device. Maximum torque is 20 lb-in.

13.4 Mounting DFA Device

This chapter provides guidance on how to mount and wire the device.

13.4.1 General Considerations

Mount the device in a 19″ rack with 1.5U (2-5/8″) rack size clearance and long-term provision for ventilation and cooling.

Make provision for uninterrupted supply of DC Unit Power and determine the optimal redundancy of such supply to comply with desired reliability requirements.

Mount the device horizontally and upright.

Note the exact serial number of the device for each circuit. The correct serial number for each Circuit's DFA Device must be used to configure the DFA Master Station, which uses the serial number to identify each specific device and consequently the Circuit to which it is applied.

Ensure proper phase and polarity when connecting all Current Inputs, Voltage Inputs, and Unit Power inputs. DFA Device Software analyzes phase relationships between Current Inputs and Voltage Inputs, and unexpected results will occur if phases are "rolled" or wired with incorrect polarity.

13.5 Wiring the Electrical Connections

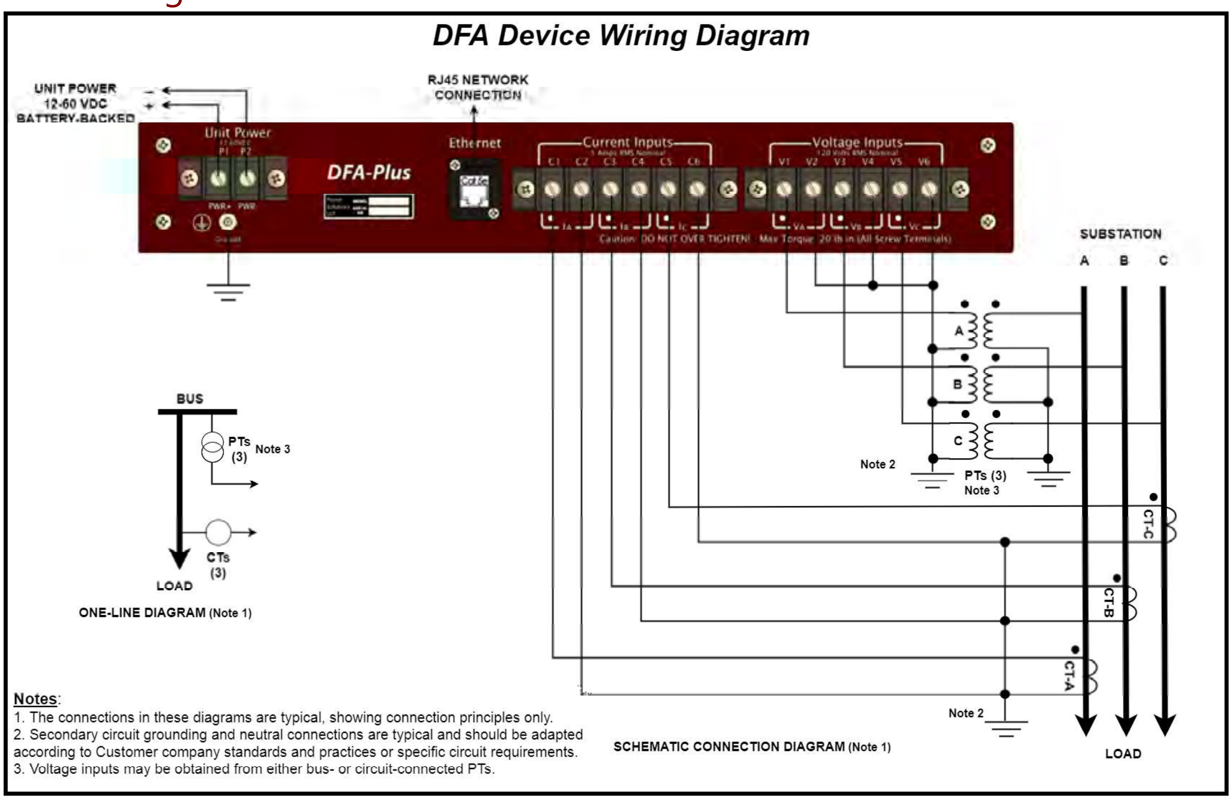


Figure 3: Wiring connection diagram and notes for DFA Device (note: some details of appearance may vary slightly from the diagram. If you have any uncertainty or question regarding connections, contact Power Solutions before commencing installation.)

13.5.1 Terminal Markings

Table 1 describes the markings and use of the Current Inputs (CTs), Voltage Inputs (PTs), and Unit Power terminals on the rear of each DFA Device. Input ranges for all inputs must be in accordance with the specifications for the specific model of DFA Device.

Table 1. DFA Device terminal designations (rear panel)

DFA Device Terminal	Intended connection to user-supplied CT, PT, or Unit Power leads
P1	DC unit power, positive
P2	DC unit power, negative
C1	Phase-A CT input
C2	Phase-A CT return
C3	Phase-B CT input
C4	Phase-B CT return
C5	Phase-C CT input
C6	Phase-C CT return
V1	Phase-A PT input
V2	Phase-A PT reference
V3	Phase-B PT input
V4	Phase-B PT reference
V5	Phase-C PT input
V6	Phase-C PT reference
Ground	Chassis ground (earth), to be connected in accordance with all relevant local codes and user's approved standard practices

- SAFETY CAUTION: Ensure that all connections are made only to the proper terminals and have the proper range and polarity, in accordance with the designations of Table 1 and the model number of the DFA Device. Serious personal injury or damage to the DFA Device and/or other equipment may result from improper connections.
- SAFETY CAUTION: Check the model number (stamped on the rear of the device) to ensure that only one-amp devices (i.e., those whose model numbers begin with R1 or S1) are wired to one-amp CTs and that only five-amp devices (i.e., those whose model numbers begin with R5 or S5) are wired to five-amp CTs. Serious personal injury or damage to the DFA Device and/or other equipment may result if five-amp CTs are wired to one-amp devices. Improper operation may result if one-amp CTs are wired to five-amp devices.

13.5.2 Connecting CT Secondary Leads to the DFA Device Terminals

The following guidance applies to the CT connections:

- SAFETY CAUTION: Do NOT create or allow an open circuit condition in the CT leads in the course of installing the DFA Device or at any other time. Take all necessary precautions to prevent such a condition. Serious personal injury or damage to the DFA Device and/or other equipment may result.

- SAFETY CAUTION: Do NOT fuse-protect CT leads, as doing so may lead to an open circuit condition in CT leads. Serious personal injury or damage to the DFA Device and/or other equipment may result.
- Connect CT secondary leads to the device in accordance with the terminal designations of Table 1. Ensure correct polarity.
- The grounding method for CT lead connections shown in Figure 3 is typical but should be adjusted to conform to user's established practices.
- Consider installing shunt switches in the CT leads, in accordance with user's established practices, to facilitate insertion and removal of the device from CT secondary circuits.

13.5.3 Connecting PT Secondary Leads to the DFA Device Terminals

The following guidance applies to the PT connections:

- Connect PT secondary leads to the device in accordance with the terminal designations of Table 1. Ensure correct polarity.
- The grounding method for PT lead connections shown in Figure 3 is typical but should be adjusted to conform to user's established practices.
- Consider installing appropriately sized fuses in PT leads, in accordance with user's established practices.
- Consider installing switches in the PT leads, in accordance with user's established practices, to facilitate insertion and removal of the DFA Device from PT secondary circuits.

13.5.4 Connecting DC Unit Power to the DFA Device Terminals

The following guidance applies to connecting unit power.

- Connect DC Unit Power leads to the device in accordance with the terminal designations of Table 1. Ensure correct polarity.
- Ensure suitable mounting of the external DC source if so required.
- Ensure long-term, stable battery backup for the DC source.
- Consider installing switches and/or appropriately sized fuses in Unit Power leads, in accordance with user's established practices.
- Important Note: No PT or other transformer that is to be used as a voltage input to the device (i.e., that is to be connected to a PT input) may be used to supply power to the device or to any other equipment. Such use would distort the voltage waveforms coming from the PT or transformer and result in degraded, unpredictable results from the DFA Technology System.

13.5.5 Grounding (Earthing) the DFA Device Chassis

- Ground (earth) the device chassis via the supplied Ground terminal and ensure that each device is wired directly to a common station grounding point.
- Do not cascade Ground (earth) connections between devices.

13.5.6 Connecting Network Service to the DFA Device Ethernet Port

- The rear of each DFA Device features a single RJ45 Ethernet port, which allows the device to connect to a DFA Master Station via user-provided network service.
- The Management Port on the front of the DFA Device is not functionally interchangeable with the Ethernet port on the rear of the device.
- Use network cabling having minimum 300V insulation and spanning no more than 100 feet.
- Shielding of network cabling should be grounded at one end only. Grounding at both ends may cause poor communications and/or damage the device.
- Avoid sharp bends in network cabling.
- Avoid installing network cabling in any manner that might cause a trip hazard or risk the cable's being be damaged or pulled out by being in a walkthrough area in an unsecured manner.
- DFA Devices internally use IP Subnet 10.245.245.0/29. Any user for whom this will create a conflict should contact Power Solutions for an update script and instructions on changing the DFA Device internet IP subnet.
- Power Solutions cannot guarantee protection from external surges (such as lightning or external arc) over 1500V that could couple into the network service. It is the user's responsibility to isolate the network service line. An optical converter placed near the device is recommended for this purpose.

13.6 Installation Summary

The following is a summary of the installation process:

- Plan the configuration of CT and PT connections prior to commencing work.
- Select a suitable rack space with adequate ventilation.
- Arrange a suitable source of Unit Power, including battery backup and any desired redundancy.
- Do not provide power to the DFA Device or to any other equipment from any PT to be connected to any DFA Device PT lead.
- Use and verify correct polarities of CTs, PTs, and Unit Power.
- Use and verify appropriate grounding for CTs, PTs, and the DFA Device chassis.
- Ensure that network cabling, not more than 100 feet long, is isolated at one end, and, if desired, optically isolated.
- Record the correct device serial number for each Circuit.

13.7 Powering Up the Device

The following is a summary of the process to power up the DFA Device for the first time:

13.7.1 Important checks before powering up the DFA Device

The following checks should be made prior to providing DC supply to the device:

- Verify that CT polarities, PT polarities, and Unit Power polarities are correct.
- Verify that CT connections and PT connections are grounded properly and in accordance with user's established practices.
- Verify that the DFA Device chassis is grounded properly and in accordance with user's established practices.
- Verify that CT leads are NOT fuse-protected. Serious personal injury or damage to the DFA Device and/or other equipment may result from an open-circuit CT condition.
- Verify that network cabling is mounted correctly, grounded only at one end, not longer than 100 feet, and preferably terminated by a fiber optic converter.
- Verify that all screw terminals have proper torque.

13.7.2 Applying power and CT/PT inputs to the DFA Device

- Apply Unit Power and use a DC multi-meter to verify correct voltage and polarity at the Unit Power terminals on the rear of the device.
- Energize all CT and PT inputs and use an AC multi-meter to verify expected current and voltage levels at the DFA Device terminals.

The following steps allow the installer to use the Management Port on the front panel of the DFA Device to view basic device and electrical information and to view and set communications-related parameters. Viewing basic electrical information while still in the substation enables discovery and correct of common wiring problems, before the installer leaves the substation.

- Using an Ethernet cable, connect a laptop computer to the Management Port on the front panel of the DFA Device.
- Open a browser on the laptop and browse to address http://dfa-plus.local. A DFA-Plus Management screen (referred to hereafter as the Management screen) similar to Figure 4 will appear. (The appearance of the Management screen will vary slightly, because of factors such as screen resolution, variety of browser, and version of the DFA Device software. Also certain information in the figure is blurred intentionally so as to avoid revealing specific IP addresses, etc.)

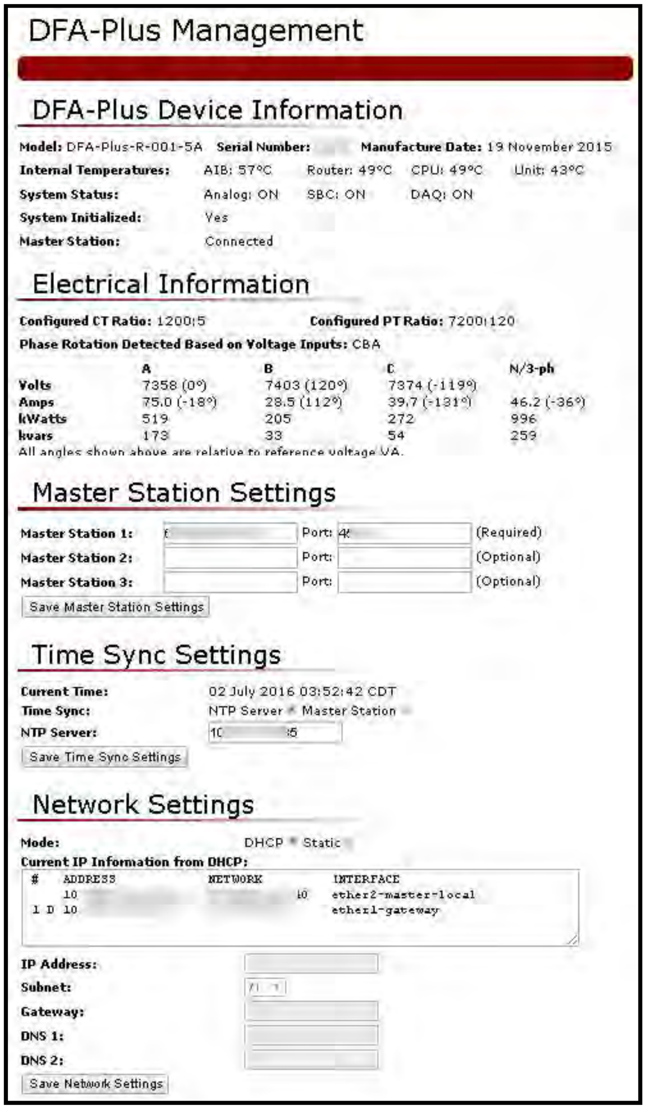


Figure 4: DFA-Plus Management Screen

- The DFA-Plus Device Information section of the Management screen provides basic information about the device itself.
- In the Electrical Information section of the Management screen:
  - Confirm that the Phase Rotation reading is as expected for the particular installation, either ABC or CBA. If there is no Phase Rotation reading, it may indicate that one or more PTs is not connected, that one or more PT switches is open, or that there is a wiring problem with one or more PTs.
  - Confirm that the Volts and Amps readings are reasonable and have expected values on all phases. If any readings (other than neutral amps) are near zero or have other unreasonable values, this may indicate that CT(s) or PT(s) may not be connected or that CT or PT test switches may not be in the correct position.

- Confirm that the kWatts readings are reasonable and have expected values on all phases. If all Volts and Amps readings seem reasonable, but kWatts do not seem reasonable, this may indicate a wiring error. If kWatts readings are negative on one or more phases, and negative power flow is not expected for the specific Circuit, this may indicate a wiring problem. Common wiring problems include reversed CT and/or PT polarities and/or "rolled phases" (e.g., one phase interchanged with another).
- Important Note: Amps, Volts, kWatts, and kvars are calculated based upon the CT and PT ratios programmed into the DFA Device. These ratios are shown in the Management screen. If CT and PT ratios displayed on the screen do not match the ratios of the CTs and PTs connected to the device, the installer should make note of this fact and report the correct CT and PT ratios to personnel responsible for managing the fleet of DFA Devices, so that they may correct the ratios remotely via the DFA Master Station. CT and PT ratios cannot be changed via the Management Port. For the purpose of validating correct installation of the DFA Device, if the CT and/or PT ratios are not correct, the installer can mentally adjust the Amps, Volts, kWatts, and kvars readings by dividing by the ratios shown on the Management screen and multiplying by the actual ratios of the connected CTs and PTs.

- Important Note: TCP ports 45123, 45124, and 45125 must be opened in the user's substation firewall to allow outbound connections from each DFA Device to the DFA Master Station. Each DFA Device also requires DNS and NTP access. If NTP is not provided, then the DFA Device can be configured to synchronize its real-time clock with the DFA Master Station, but with reduced time accuracy.
- In the Master Station Settings section of the Management screen, specify at least one Master Station to which the DFA Device is to connect, and then press the Save Master Station Settings button. At least one Master Station must be designated, and successful connection of the DFA Device to the Master Station must be accomplished to enable operation of the DFA Technology System. Note: Successful connection to a DFA Master Station requires that both the Master Station Settings and the Network Settings (see below) be correct.
- Important Note: It is not possible to connect to the DFA Device remotely unless both the Master Station Settings and the Network Settings are correct. Therefore it is critical that the Master Station Settings and Network Settings be configured correctly while at the substation. The Management screen will show a warning if the DFA Device is unable to communicate with a DFA Master Station.
- (optional) In the Time Sync Settings section of the Management screen, select whether time synchronization will be accomplished by synchronizing to a standard NTP time source or alternatively to the DFA Master Station (with possible loss of time accuracy), and then press the Save Time Sync Settings button. Setting of the Time Sync Settings can be accomplished via the Management screen or via the Master Station, provided that the Master Station is configured properly and communicating.

- In the Network Settings section of the Management screen, select either DHCP or Static as the IP Address Mode. If Static is selected, also enter network configuration parameters provided by your company's information technology department. Press the Save Network Settings button. Information in this section determines operation of the Ethernet port on the rear of the device, not of the Management Port on the front of the device.
- Note: The Management Port connection on the front of the device is used only for verifying basic wiring and for configuring device communications. The Management Port is not intended to be connected during normal operation. During normal operation, communications from the DFA Device to the DFA Master Station occurs via the Ethernet port on the rear of the device, and the user access DFA Data via a centrally located DFA Master Station, not via direct connection to the device. The Management Port on the front of the device is not functionally interchangeable with the Ethernet port on the rear of the device.

14 DFA Device Technical Specifications

The following technical specifications are preliminary and subject to change without notice.

14.1 Models and Input Ranges

DFA-Plus Devices are supplied with the following model numbers:

- Model R5A1-0: Rack configuration DFA-Plus Device with 5-amp current inputs
- Model R1A1-0: Rack configuration DFA-Plus Device with 1-amp current inputs
- Model S5A1-0: Stack configuration DFA-Plus Device with 5-amp current inputs
- Model S1A1-0: Stack configuration DFA-Plus Device with 1-amp current inputs

The four models differ by packaging configuration (rack and stack) and by nominal current input range (5-amp and 1-amp). Installation instructions and photographs provided in this "DFA Technology System Manual" correspond to the rack configurations. Stack-specific instructions and photographs have not been developed as of the writing of this document but may be developed and provided as a modification or supplement at a later date. The rack and stack configurations have identical intended function. Models beginning with R5 or S5 have five-amp nominal Current Inputs. Models beginning with R1 or S1 have one-amp nominal Current Inputs. Ratings for the Voltage Inputs are the same for all models.

14.2 Performance

- Analog-to-digital converters (six): 24-bit hardware resolution; >18-bit effective resolution
- Sampling rate: 256 samples per cycle per channel
  - 15,360 samples per second per channel for 60 Hz Circuits
  - 12,800 samples per second per channel for 50 Hz Circuits

14.3 Environmental

- Operating Temperature: -40 to +55 C
- Operating Humidity: 0-95% RH
- Storage Humidity: 5-95% non-condensing

14.4 Physical Dimensions

- 19" rack-mount enclosure of 1.5 U (2-5/8") height
- DFA Device enclosure: 19" W x 2-5/8" H x 11-3/16" D
  48.3 cm W x 6.7 cm H x 28.4 cm D
- DFA Device enclosure + rear terminal strips: 19" W x 2-5/8" H x 12-3/16" D
  48.3 cm W x 6.7 cm H x 31 cm D
- Weight: 13 lbs.
  5.9 kg

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14.5 Electrical Inputs

- DFA Device power: 12-60VDC, external, battery-backed (power source not supplied).
- Power consumption: 25 VA
- Current Inputs (5A models): Three phases, 5 amps AC nominal per phase.
- Current Inputs (1A models): Three phases, 1 amp AC nominal per phase.
- Voltage Inputs: Three phases, 120 volts nominal AC per phase.
- Sensing input burdens: < 1 VA CTs; < 1 VA PTs

14.6 Network Communications

14.6.1 Physical Connection

- The rear of the DFA Device has a single RJ45 (twisted pair) Ethernet port for connection to user-supplied Internet service, for the purpose of enabling the DFA Device to establish and maintain communications with a DFA Master Station. The Management Port on the front of the device is not functionally interchangeable with the Ethernet port on the rear.

14.6.2 Internet Requirements

- Recommended speed of at least one megabit per second per DFA Device. Lower Internet speeds can be accommodated with possible reduction in timeliness of information delivery.
- TCP ports 45123, 45124, and 45125 must be opened in the substation firewall to allow outbound connections from each DFA Device to a remote DFA Master Station.
- Each DFA Device requires DNS access.
- Each DFA Device ideally requires NTP access. If NTP is not provided, then the DFA Device can be configured to synchronize its time with a DFA Master Station, but time accuracy will be reduced.
- DFA Devices internally use IP Subnet 10.245.245.0/29. Any user for whom this will create a conflict should contact Power Solutions for an update script and instructions on changing the DFA Device internet IP subnet.

14.7 Timing Synchronization

- The DFA Device will support NTP synchronization with an in-substation clock source. If no in-substation clock source is available, the DFA Device can synchronize its time to NTP servers (e.g., maintained by the client or by a third party such as CERN, NIST, et. al.).

14.8 Memory Capacity

- DFA Device: Typically four weeks, depending on level of Circuit activity. Longer for certain types of events (e.g., recurrent faults).
- DFA Master Station: Indefinite and limited only by the DFA Data download and storage policies that the user may adopt. (See also chapter 9, "DFA Data Backup and Retention.")

14.9 Wiring Connections

All connections are on rear of DFA Device, except where otherwise noted.

- Current Inputs: Three pairs of screw terminals for connection of 5 AAC or 1 AAC (depending on model) secondary leads of current transformers (CTs)
- Voltage Inputs: Three pairs of screw terminals for connection of 120 VAC secondary leads of potential (voltage) transformers (PTs)
- Unit Power: One pair of screw terminals for battery-backed DC Unit Power
- Threaded lug and nut for device chassis safety grounding (earthing)
- RJ45 (twisted-pair copper) Ethernet connector on rear of device for long-term connection to remote (i.e., not in substation) DFA Master Station via Internet
- RJ45 (twisted-pair copper) Management Port connector on front of device, for temporary connection to laptop or similar, to facilitate installation and commissioning
- Wiring for CTs, PTs, DC Unit Power, Ethernet, and Ground to be supplied by Customer
- Battery-backed DC Unit Power to be supplied by Customer

15 Document Version History

Versions of this manual have been released on the following dates:

01 December 2017 (first version with tracked version date)

02 October 2018

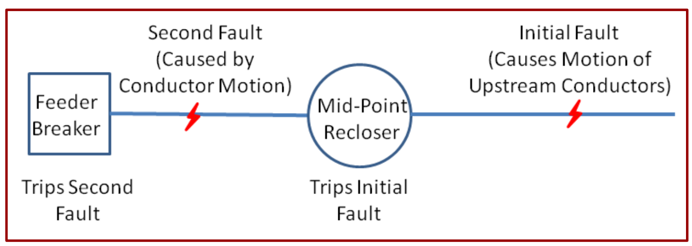
Tutorial: Fault-Induced Conductor Slap

Introductory Overview

The DFA technology system detects and reports multiple types of events that occur along the length of a distribution circuit.[1] One type of event is fault-induced conductor slap, abbreviated FICS. FICS occurs when an initial fault at one location on a circuit causes upstream conductors to slap together, resulting in a second fault. Because the second fault occurs closer to the substation, often much closer, it draws more fault current, and clearing it affects more customers. FICS involves conductor-to-conductor contact, emitting showers of hot or burning particles and damaging conductors. Susceptible spans can experience FICS repeatedly and incur cumulative damage. Correcting the cause of FICS prevents future interruptions, outages, system damage, and possible broken conductors, but correction requires awareness that FICS has occurred.

The FICS Phenomenon

Significant work has gone into understanding the FICS phenomenon, with Ward having provided perhaps the best practical description and mathematical modelling to predict the occurrence of the phenomenon based on line configuration parameters.[2]



The one-line diagram shown here is useful for understanding the basic FICS phenomenon. Consider an Initial Fault between two phase conductors. Fault current flows from the substation to the fault through one phase conductor and back through the other. These parallel, opposite-direction currents induce magnetic forces that push the conductors away from one another, displacing them from rest. After a time, the mid-point recloser trips, interrupting the fault current and suddenly removing the magnetic forces. Gravity pulls the displaced conductors toward their normal resting positions, and momentum causes them to pendulum through those resting positions. Under the right set of conditions, they can contact one another, resulting in a Second Fault. Most typically this occurs upstream of the mid-point recloser, sometimes while that device is open. The Second Fault is closer to the substation, so it draws more fault current than the Initial Fault and often trips protection upstream of the mid-point recloser. Therefore, a fault that should have operated only the mid-point recloser, affecting a relatively small number of customers, instead trips upstream protection and affects more customers.

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[1] DFA's On-Line Waveform Characterization Engine detects and reports events based upon signal processing of current and voltage waveforms measured from substation current and potential transformers (CTs and PTs) and does not require communications with substation relays, SCADA/RTUs, or line reclosers. DFA Technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, and is commercially available from Power Solutions LLC (www.powersolutionsllc.us).

[2] Daniel J. Ward, "Overhead Distribution Conductor Motion Due to Short-Circuit Forces," *IEEE Transactions on Power Delivery*, vol. 18, no. 4, October 2003, pp. 1534-1538.

Typical FICS Scenario

This section describes a composite scenario based on multiple documented FICS events and actions that utility companies have taken in response. Elements of the scenario have been documented multiple times via DFA field installations. Often, the underlying circuit was fitted with DFA, but DFA was being used in an evaluation mode, providing opportunity to document FICS and conventional utility responses.

The Event

Three miles from a substation, a tree leans into an overhead line and pushes two phase conductors together. This causes a phase-to-phase fault, which trips a mid-point recloser two miles from the substation, interrupting 500 customers. The recloser auto-recloses multiple times, but the fault condition is permanent, so the recloser locks open. The mid-point recloser has operated properly to sectionalize the circuit and limit the extent of the outage, but the substation circuit breaker trips and locks out, too, resulting in an outage to 2000 customers.

The Response

Upon detecting the outage, the utility dispatches a line crew to search for the cause, make repairs, and restore service. The crew first patrols the portion of the circuit between the substation and the mid-point recloser, because operation of the substation circuit breaker usually implies that the fault is on that portion of the circuit. The crew eventually expands the search and locates the tree fault, well downstream of the mid-point recloser. They make repairs, find no other damage to the system, and restore service. The duration of the outage has been prolonged because they initially spent time patrolling near the substation, far from the actual location of the tree fault.

The Investigation

In the aftermath of the outage and restoration, utility company personnel note that the mid-point recloser should have sectionalized the tree fault to prevent the circuit-wide outage. They also note that, following the unsuccessful initial patrol, closing the substation circuit breaker resulted in no ongoing fault upstream of the mid-point recloser. This set of facts typically indicates improper coordination between the substation and mid-point protection. Personnel analyze settings and trip curves for both locations. They retrieve and analyze records from relevant electronic devices, such as the substation relay and the mid-point recloser. They temporarily take the mid-point and substation protection devices out of service to test them. In the end, they identify no issue and close the investigation with "cause unknown."

Subsequent Events

The same sequence occurs a year later: a phase-to-phase fault, beyond the same mid-point recloser, results in another circuit-wide outage. The same sequence continues to happen from time to time. The underlying cause of the seemingly improper protection coordination and broadened outage remains identified.

Important Clarification

The foregoing discussion of a typical FICS scenario and utility company response is not intended as a criticism of utilities, their personnel, or their practices. Rather it demonstrates the inadequacy of conventional processes to diagnose FICS. By contrast, DFA technology often can detect FICS, report it to the utility, and provide parameters that enable the utility to locate the FICS and take corrective action. It also illustrates another aspect of FICS, namely that spans susceptible to FICS can experience it repeatedly, sometimes with long periods of time passing between episodes.

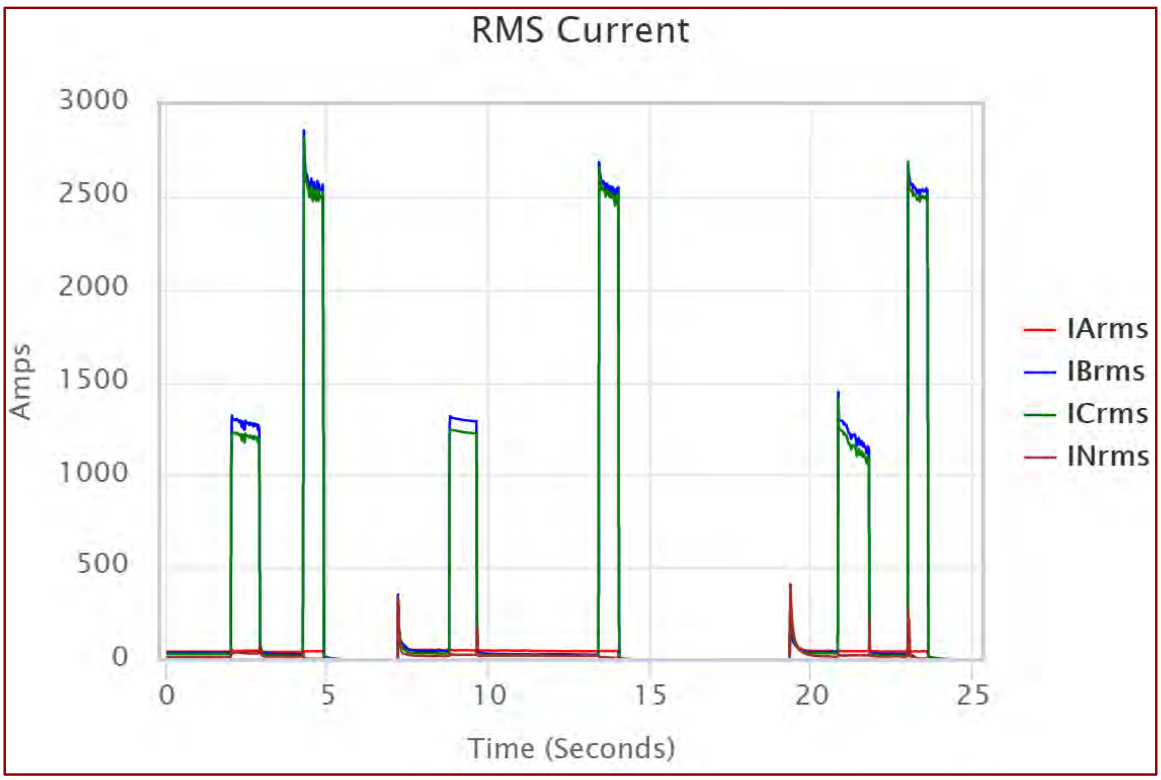
Real-World Example

This section details a specific, real-world example involving FICS on a DFA-monitored circuit.

DFA Web Report and Waveform Data

The DFA Web report below was available within minutes of the underlying event. It indicates that the substation circuit breaker locked out, which the utility company already knew via SCADA. It also reports 'Possible conductor-slap,' related to the event, which the utility company did not know. The graph below, also available via DFA Web, shows the RMS line currents that DFA recorded at the substation during the event, which took place over a period of approximately 22 seconds. DFA records high-speed current and voltage waveforms at a rate of 256 samples per cycle, but an RMS plot often provides the best "big picture" view. DFA software automatically detects the possible conductor-slap event by analyzing the recorded high-speed current and voltage waveforms.

Circuit	Event Type	Phases	Comments	Count	Last Occurred
[redacted]	Possible conductor-slap	BC	Breaker trip F-(53.0c,1267A,BC)-T-(0,24,32)%-1.4s- F-(37.0c,2595A,BC)-T-2.3s-C-1.6s- F-(51.0c,1272A,BCN)-T-(0,32,34)%-3.8s- F-(37.0c,2581A,BC)-T-5.3s-C-1.5s- F-(58.0c,1256A,BCN)-T-(0,24,31)%-1.2s- F-(37.0c,2591A,BCN)-T	6 ops	2018-03-18 11:26:09



Analysis of DFA Report

The preceding DFA Web report contains a sequence of events describing the six fault episodes, all involving phases B and C, and the protection system response. Information in the table below comes from the report's sequence of events. This remainder of this section then analyzes that information.

		% Load Interrupted			
Fault Episode	Amps	A	B	C	Protection Device (Inferred)
1	1267	0	24	32	Mid-Point Recloser (B and C only)
2	2595	All	All	All	Substation Circuit Breaker
3	1272	0	32	34	Mid-Point Recloser (B and C only)
4	2581	All	All	All	Substation Circuit Breaker
5	1256	0	24	31	Mid-Point Recloser (B and C only)
6	2591	All	All	All	Substation Circuit Breaker

Fault Current Amplitude

The amplitudes of the six fault episodes fall into two distinct groups, one having amplitudes ranging from 1256 to 1272 amps and the other having amplitudes ranging from 2581 to 2595 amps. The preceding graph of RMS currents also makes clear the two distinct groupings of amplitudes. Using terminology from the one-line diagram on the first page of this tutorial, the fault episodes with the lower amplitudes correspond to an Initial Fault, and the fault episodes with the higher amplitudes correspond to the Second Fault. Having two distinct groups of fault current amplitude is consistent with a diagnosis of FICS.

Protection Devices Involved

For the trips associated with the first, third, and fifth fault episodes, the SOE indicates interruption of essentially none of the phase-A load, 24-32 percent of the phase-B load, and 31-34 percent of the phase-C load. These values estimate the amount of load interrupted by the trips, as a percentage of the total pre-fault circuit load measured from the substation. Minor episode-to-episode variations in interrupted-load estimates (e.g., 24% versus 32% versus 24% for phase B; 32% versus 34% versus 31% for phase C) are common. That B and C both experienced partial load loss, by similar percentages, implies that phases B and C of a mid-point bank of single-phase reclosers tripped for those episodes. Effectively all load on all three phases was interrupted in response to the other three episodes, indicating trips of the substation circuit breaker.

In summary, analysis of the sequence of events indicates that phases B and C of a mid-point recloser tripped in response to the first, third, and fifth fault episodes and that the substation circuit breaker tripped in response to other three. A sequence that intermingles operations of a mid-point recloser and operations of the substation circuit breaker is consistent with a diagnosis of FICS.

Swing Times of Conductors

The timing information in the SOE is consistent with conductor-to-conductor contact, at the location of the Second Fault, occurring 1.4 seconds, 3.8 seconds, and 1.2 seconds after the three trips of the mid-point recloser. These time intervals seem believable for the periods of time that conductors might swing about, after interruption of the Initial Fault relaxes the magnetic forces, before contacting one another. Swinging conductors represent a dynamic condition, making it believable that one contact might take 3.8 seconds to occur and another just 1.2 seconds. The timing information is consistent with a diagnosis of FICS.

Field Investigation

Field investigation to locate this example of FICS proceeded based upon the following information.

- The Initial Fault was between phases B and phase C and had been determined by field personnel to have been caused by a tree pushing phase conductors together at a specific, known location.
- The mid-point recloser that operated to clear the Initial Fault had been identified.
- DFA reported a FICS (i.e., a Second Fault) as a consequence of the Initial Fault.
- DFA reported that the Second Fault was between phases B and C and drew 2590 amps.
- Because of the nature of the FICS phenomenon, the Second Fault must lie directly on the path between the substation and the mid-point recloser that cleared the Initial Fault.

The utility company used its circuit model and fault location software to predict circuit locations that would produce 2590 amps of fault current for a phase-to-phase fault. They considered only locations lying along the path between the substation and the mid-point recloser that cleared the Initial Fault.

Once an approximate location for the Second Fault has been predicted by circuit model software, evidence of FICS often is found to be in an unusual span near the prediction. Unusual span conditions can include excess slack, a longer-than-usual span, a transition span between horizontal and vertical, reduced spacing between the faulted phase conductors, etc.

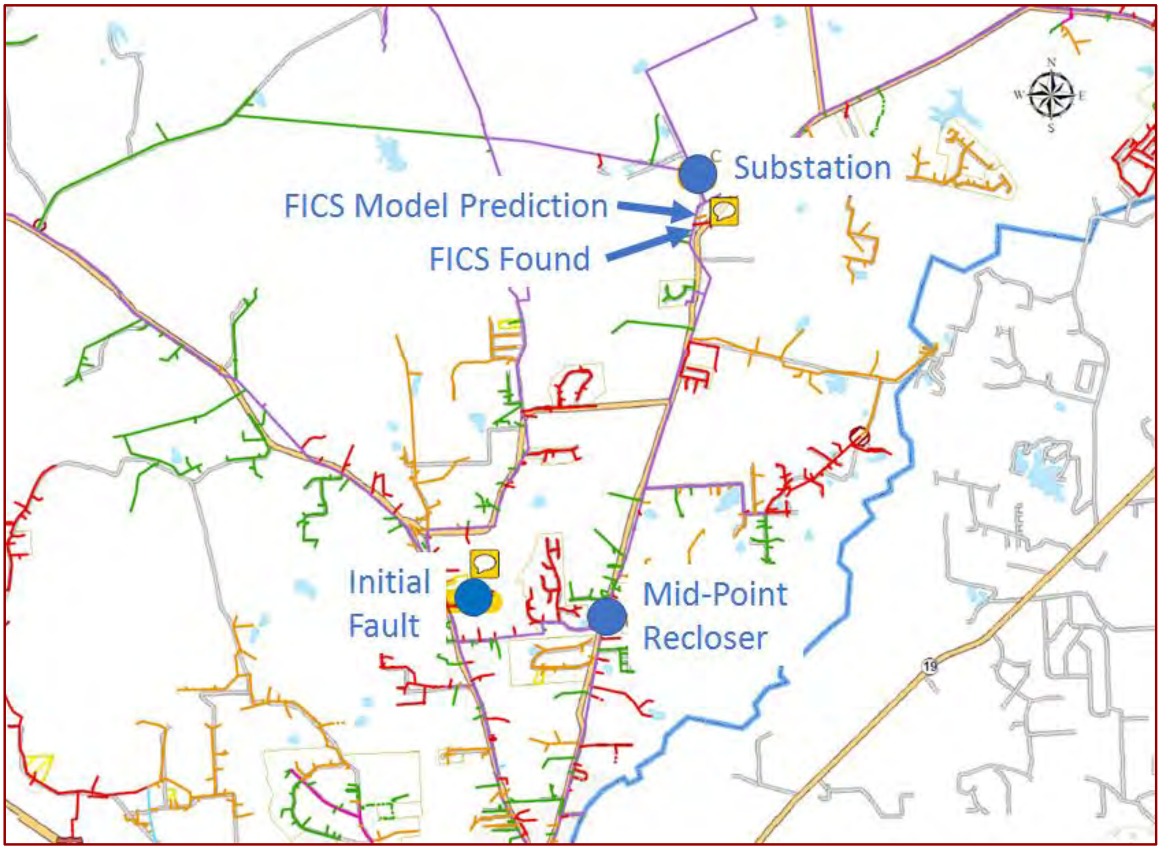
In the subject case, this process found evidence of FICS (i.e., the Second Fault), in the form of conductor pitting and "bright spots" five spans downstream of the model-predicted location. The FICS was near the substation and more than four miles upstream of the mid-point recloser. The FICS span was a transition from vertical to horizontal and had a length of 335 feet of 336.4 MCM ACSR.

Variations and Use of Judgment

Similar but distinct scenarios can result in FICS. Variations on the scenario include the following.

- The Initial Fault may be cleared by a mid-point line fuse, rather than an auto-reclosing device, although the one-shot nature of a fuse reduces the probability of multiple slaps at the point of the Second Fault and therefore lockout by upstream protection.
- There may be two mid-point reclosers in series between the Initial Fault and the substation, in which case the protection that clears the Second Fault may be a mid-point recloser, instead of the substation circuit breaker.
- The initial fault may involve one phase conductor and the circuit neutral conductor, rather than two phases, although all cases fully documented by DFA programs have involved at least two phases.

The real-world example detailed in this tutorial exhibited clear differentiation between the estimated amplitude of the Initial Fault (1260 amps) and that of the Second Fault (2590 amps). This was because the two fault locations were more than four miles apart. By contrast, however, if the two estimated amplitudes hypothetically were 1500 amps and 1600 amps, a diagnosis of FICS would be less clear. The 100-amp difference in fault current estimates could result from the faults occurring at two different locations, indicative of FICS. Alternatively, however, the two faults could be at the same location but have different amplitude estimates because of minor variations in fault geometry or other vagaries and therefore not be indicative of FICS.



Concluding Remarks

Fault-induced conductor slap, or FICS, represents a complex, difficult-to-diagnose phenomenon that can occur on distribution circuits. One fault induces another, often miles away, resulting in a more widespread interruption or outage. Seemingly (but not actual) improper coordination of system protection can misdirect patrols and prolong the outage. If the utility takes note of the seemingly improper protection coordination and attempts to use conventional methods to analyze the issue, the effort often fails. Intelligent signal processing, such as embedded in the DFA technology system, can recognize specific electrical patterns caused by FICS and provide parameters to assist in its location, based on CT and PT signals available at the substation. Proper diagnosis and correction of FICS are important, because they can prevent repeated outages, additional conductor damage, and possibly even a downed conductor.

Intent of This Document

This document describes in general terms the FICS phenomenon and related use of DFA technology. It does not purport to cover all scenarios. The intended audience is utility company personnel. Users should apply the information in this document in conjunction with sound engineering judgement, operational experience, and their inherently superior knowledge of their systems.

Tutorial: Series Arcing and DFA Arcing Switch/Clamp Reports

Introductory Overview

The DFA technology system detects and reports multiple types of events that occur along the length of a distribution circuit.[1] One type of event is series arcing. Series arcing often results in low-amplitude variations in line current and voltage and represents an incipient failure, or "hot spot," that is developing in the jaws of a load-carrying line device, such as a switch or a clamp. The condition can exist for hours, days, or weeks without customer complaints or other notice to the utility. It causes progressive erosion of line conductors and of the affected device's contacts and ultimately can result in intermittent voltage fluctuations, flickering lights, unexplained protection operations, and even broken conductors.

Related Types of Failures

A fused cutout can develop an incipient, series-arcing failure in its contacts, just as a blade switch can. Therefore, this discussion of incipient switch failure should be understood to include incipient failure of the contacts of a fused cutout.

DFA has not recorded a known failure of an in-line splice, which also may involve series arcing and manifest similar electrical signatures.

This discussion of series arcing does not include switches or other devices associated with capacitor banks. An incipient failure of a device associated with a capacitor bank behaves differently than one associated with a load-carrying device. DFA reports incipient failures of capacitor-related devices, but it reports them as capacitor issues, not as series arcing.

The Series Arcing Phenomenon

From a scientific point of view, the series arcing phenomenon is not fully understood. A theory generally consistent with observed manifestations is that degraded contact surfaces of a clamp, switch or other load-carrying device create a "hot spot" that behaves as a highly variable electrical impedance. The variable impedance, with load current flowing through it, results in "modulation" of line voltage downstream of the device. The modulated voltage and the resulting dynamic current response of downstream load cause a variety of symptoms, as described herein.

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[1] DFA's On-Line Waveform Characterization Engine detects and reports events based upon signal processing of current and voltage waveforms measured from substation current and potential transformers (CTs and PTs) and does not require communications with substation relays, SCADA/RTUs, or line reclosers. DFA Technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, and is commercially available from Power Solutions LLC (www.powersolutionsllc.us).

Observations Regarding the Behavior of Series Arcing

The following observations are based on investigations of multiple series arcing events that have occurred on DFA-fitted circuits. Events were recorded electrically by DFA and documented collaboratively by utility personnel and DFA researchers.

Intermittent Flare Ups

A device that is experiencing series arcing often flares up intermittently. A flare up may last for a fraction of a second or for many minutes. Quiescent periods between flare ups may last minutes at a time or days at a time. During flare ups, the condition can cause symptoms listed hereinafter. During quiescent periods, voltage may be steady and there may be no readily observable symptoms.

Even for a series arcing condition that causes hundreds of events, if those events are spread across a period of days, then the condition is active only for a small fraction of the total time period. This intermittency creates challenges for line crews attempting to diagnose symptoms such as flickering lights or mysterious operations of overcurrent protection, because symptoms may not be present when the crew is on site.

Loading and Environmental Influences

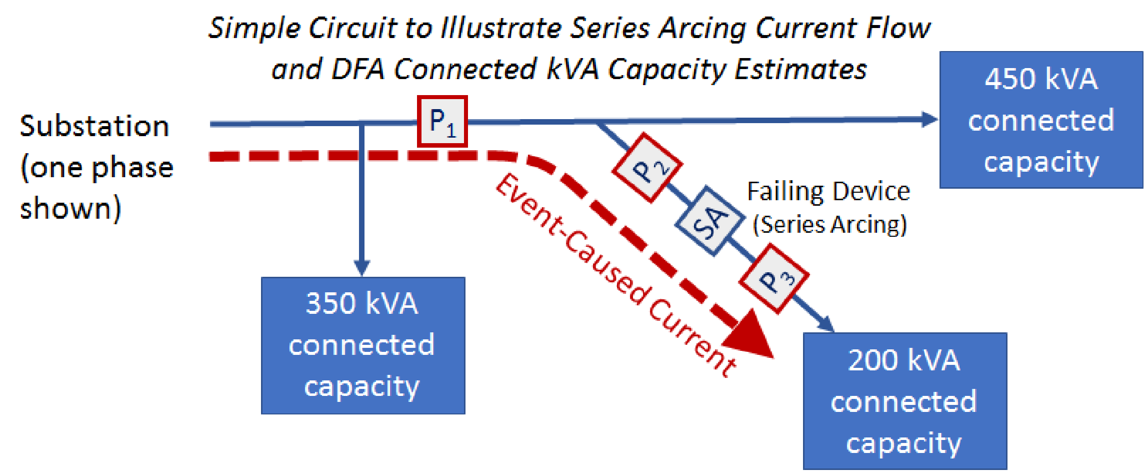
The amount of load current flowing through a failing device may influence series arcing. Environmental factors also can influence series arcing. On multiple occasions, clamps have been observed to flare up during periods of rain but become quiescent during non-rain periods. Heavy dew may have a similar effect. Wind can move conductors and apparatus mechanically, which may influence flare ups. Ambient temperature also may cause flare ups, although that effect may be partly indirect, as a consequence of the increased circuit loading that results during temperature extremes.

Mysterious Overcurrent Protection Operations

Series arcing modulates downstream line voltage, resulting in dynamic response of downstream loads and variations in line current. This Event-Caused Current, as it is referred to in the diagram that follows, usually has relatively small amplitude, but there are multiple documented cases in which series arcing has caused sufficient Event-Caused Current to operate conventional overcurrent protection.

Following a protection operation, replacing a fuse or resetting a recloser may restore service successfully, with the subject outage attributed to “unknown cause,” “weak fuse,” or similar, when in reality the root cause was incipient failure of a clamp or switch. Series arcing will return after a time and may cause additional overcurrent protection operations or other symptoms. Those subsequent episodes may result in identification and repair of the series arcing, perhaps without anyone’s recognizing that the same defect caused the earlier episode(s).

Although it is counterintuitive, series arcing can cause operation of overcurrent protection either upstream or downstream of the series arcing. This is because the Event-Caused Current flows from the substation source, through the failing device, to connected load downstream of the failing device, and therefore through all protection devices in that path. In the diagram, for example, the failing device labeled SA results in Event-Caused Current flowing through the illustrated path and resulting in possible operation of the protection devices at the points labeled P_1, P_2, and P_3.



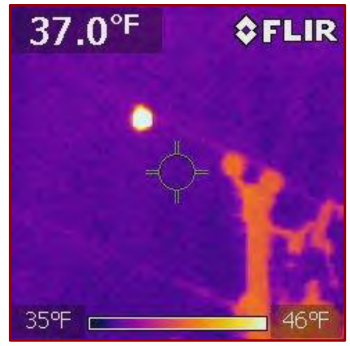
The total connected kVA capacity for this simple circuit is 350 + 450 + 200 = 1000 kVA. The failing device serves 200 kVA of that connected capacity. In the example shown, the DFA estimate likely would fall between 100 and 300 kVA, which would enable one to rule out consideration of a clamp or a switch serving three 15 kVA transformers, for example, but not to distinguish between taps with 150 kVA and 250 kVA of connected capacity.

The following overcurrent protection operations have been documented on DFA-fitted circuits.

1. Operation of a fuse upstream of a failing clamp. This case occurred on a DFA-fitted circuit, but the responding crew was unaware of DFA and therefore acted without DFA information. The subject 30-amp fuse protected a lateral serving more than a dozen customers. The failing clamp was downstream of the fuse and served three of those customers. When the fuse was replaced, the series arcing was not actively flaring up, so the fuse held and the crew concluded that the original fuse had been weak. The series arcing flared up again the next day and caused multiple additional problems, prior to the clamp's ultimately being determined to be the root cause.
2. Operation of a fuse downstream of a failing clamp. In this case, the fuse of a CSP (completely self-protected) transformer blew because of series arcing upstream of the transformer. The responding crew believed the transformer to be bad and replaced it, but they later tested it and found it to be healthy, except for the blown fuse.
3. Operation of a recloser downstream of a failing clamp. A 50-amp hydraulic recloser, downstream of a failing clamp, experienced multiple momentary interruptions and finally locked out, because of series arcing. The clamp flared up intermittently over the course of a month and is believed to have caused more than a dozen momentary operations of the recloser, prior to the lockout.
4. Operation of a recloser upstream of a failing clamp. In this case, a failing clamp caused a single momentary operation of a hydraulic recloser that was upstream of the failing clamp.

Audible Buzzing

Transformers downstream of series arcing may buzz abnormally. It is believed that voltage modulation causes dynamic magnetostriction in the transformer, resulting in the abnormal buzzing. Transformers and other line equipment may buzz during normal operation, but buzzing associated with series arcing may be more pronounced than normal. Crews responding to complaints of flickering lights and hearing abnormal buzzing may conclude incorrectly that a transformer is faulty and causing the flicker.



Radio Frequency (RF) and Infrared Effects

Series arcing can generate infrared (heat) and radio frequency (RF) signatures, which are believed most likely to be prevalent during flare ups. A series arcing failure can generate dozens or hundreds of DFA-detected events, each lasting a few cycles or a few minutes. If those events are spread across a period of days or weeks, however, the total cumulative duration of active flare up still may be a small fraction of the total elapsed time. Infrared cameras and RF detectors likely will identify a device experiencing series arcing if it is scanned during an active period but may not if that same device is scanned during a quiescent period.

Event-Caused Current Influenced Largely by Connected Capacity

The amplitude of the current variations that an active flare up causes appears to be influenced largely by the amount of connected load capacity downstream of the failing device. For example, series arcing of a failing clamp that has 250 kVA of downstream connected capacity tends to produce greater current variation ("Event-Caused Current" in the preceding diagram) than would series arcing of the same failing clamp if it had only 25 kVA of downstream connected capacity. The amplitude of the Event-Caused Current appears to be influenced more by downstream connected capacity than by how much of that load is switched on. DFA reports a gross estimate of the connected kVA past the failing device.

DFA Reports of Switch/Clamp (Series Arcing) Failures

The following image is a series arcing report, copied from the DFA website. Because series arcing most commonly involves a switch or clamp, the DFA report says "probable failure of switch or clamp," as this is believed to be accurate in most cases and more obvious in meaning than would be a report of "series arcing." As discussed in the section on "Related Types of Failures," failing devices related to capacitor banks exhibit different electrical manifestations and are reported separately by DFA.

In the report, the Count column indicates that DFA detected 496 transients, related to this single series arcing failure, and that those transients occurred over a period of 31 days. The DFA report does not list 496 lines of information, however. Instead it clusters the 496 transients together in a single, summary line item on the website. Clicking the + sign enables the user to expand the list to show the times of individual events within the cluster. As an aside, the list illustrates intermittency, showing that the last five events occurred at distinct times between 6:51 and 10:07 a.m. The Amps columns of the sub-events give a sense of the relative severity of the multiple events but should not be used for other purposes.

The report also provides a gross estimate of the kVA of connected capacity downstream of the failing device. Use of the reported kVA parameter is discussed further in the section on Locating Series Arcing.

Switches, clamps, and other connectors all can experience series arcing. The electrical manifestation of series arcing is fundamentally similar for all device types. Based on subtle differences that sometimes appear to differentiate switches from clamps, DFA software attempts to distinguish between the two and reports relative probabilities in the Comments column. Field experience, however, has shown that switches experiencing series arcing tend to go to final failure more quickly than do clamps. Switches often go to final failure within hours, whereas clamps often continue arcing intermittently for multiple days or weeks. Therefore an event that persists for many days likely is a clamp rather than a switch.

Expand	Substation	Circuit	Event Type	Phases	Comments	Count	Last Occurred
+	[illegible]	[illegible]	Probable failure of switch or clamp	B	Estimated load beyond switch/clamp: 194 kVA 80% likelihood switch; 20% likelihood clamp	496 transients (31 days)	2017-10-24 10:07:15

Event Type	Phases	Phase A Amps	Phase B Amps	Phase C Amps	Transients	Last Occurred
Probable failure of switch or clamp(C)	B	14	108	10	1	2017-10-24 10:07:15
Probable failure of switch or clamp(S)	B	10	64	8	6	2017-10-24 09:41:26
Probable failure of switch or clamp(I)	B	9	70	8	3	2017-10-24 09:11:26
Probable failure of switch or clamp(I)	B	5	57	6	2	2017-10-24 06:52:43
Probable failure of switch or clamp(I)	B	8	37	7	1	2017-10-24 06:51:30
Probable failure of switch or clamp(I)	B	8	102	8	1	2017-10-24 06:50:21

DFA's Bias to Minimize False Alarms

Based on industry feedback, DFA biases its reports, including series arcing reports, to minimize false alarms. It is possible for non-arcing events to mimic series arcing for a limited period of time. Such events, however, tend to be infrequent and non-recurring. Therefore part of the DFA's bias toward avoiding false alarms is to report series arcing only after detecting multiple individual events in a relatively short period of time. This inherently delays reporting for some period of time, and can cause some events to not be reported, but this intentional bias is believed to be consistent with general industry feedback and guidance.

Locating Series Arcing

Locating series arcing is challenging, but DFA-reported parameters can provide some help. The following information is intended to overview the use of DFA information for this purpose and to provide observations from field experience.

Because series arcing tends to cause switches to fail more quickly than clamps, an event that continues for more than a few hours likely involves a clamp rather than a switch. This is true even if DFA software, based on analysis of electrical waveform manifestations, reports high likelihood of a switch.

Because incipient failure of a device associated with a capacitor bank causes different electrical behavior than incipient failure of a load-carrying device, a DFA series-arcing report likely does not indicate a problem with capacitor bank hardware, including vacuum bottles, oil switches, fused cutouts, clamps, or any other hardware associated with a capacitor bank. Therefore inspection priority can be given to non-capacitor devices over capacitor devices.

DFA reports a gross estimate of connected kVA capacity downstream of the series arcing. As a rule of thumb, actual connected kVA capacity downstream of series arcing likely is between half of the DFA-reported value and twice the DFA-reported value. This gross estimate can be useful in some cases. The previously illustrated DFA series arcing report, for example, estimated 194 kVA, so that failure was unlikely to involve a device serving a 15 kVA transformer or a device serving 500 kVA of connected capacity. Conversely if DFA software were to provide an estimate of 30 kVA, then a device serving a single small transformer would be a reasonable target for consideration, but a device upstream of 500 kVA of connected capacity would not.

The kVA estimate should be compared to connected capacity, not to the amount of load that is switched on at the time of the transient. For example, if a clamp connects a single 15 kVA transformer, that 15 kVA capacity figure should be used, without regard to whether the transformer is lightly or heavily loaded at any given moment in time.

Where switches or clamps are used to connect an in-line recloser, the devices on the line and load sides of the recloser both should be examined, subject to estimated kVA being reasonable for the location.

Passage of fault current through a device can stress the device and precipitate series arcing. Therefore devices that recently have carried fault current may be good candidates for inspection. Devices can begin to exhibit series arcing without having been stressed by a recent fault, so it would not appropriate to consider only devices with recent fault exposure, but such exposure may prioritize searches.

For a conventional fault, the fault current amplitude depends largely on the impedance of the conductor and other system components upstream of the fault. On a given circuit, a conventional fault close to the substation produces more fault current than does one far from the substation. This is not true for series arcing. The amplitude of the Event-Caused Current seems relatively independent of conductor length or type, instead influenced more by the connected kVA capacity past the failing device. Consequently, conventional approaches to fault location, which use measured fault current amplitude (or quantities such as calculated impedance or distance to fault, which are based on measured fault current) are not applicable for predicting the location of series arcing.

Location of DFA-reported series arcing often requires use of DFA-reported information in conjunction with other information that system operators may have. For a variety of reasons discussed herein, it may prove impractical to locate some cases of series arcing prior to experiencing other trouble. This may be especially true where the DFA kVA estimate is small and therefore consistent with any one of many clamps connecting single transformers. When a trouble call is received, the DFA series arcing report may inform the ensuing troubleshooting activities. For example, if a fuse blows or a recloser operates on a circuit with an active DFA report of series arcing, but there is no record of a high-current event or other obvious cause for the operation, and if the fuse or recloser holds when replaced or reset, then it may be appropriate to instruct the responding line crew to look for a failing clamp or switch upstream or downstream of that protection device. As another example, if customers on a circuit with an active DFA series arcing report experience intermittently flickering lights, but the responding crew finds solid voltage and observes no flicker when on site, then it may be appropriate to instruct them to look for a failing clamp or switch. Use of the DFA report can prevent incorrect diagnoses (e.g., healthy transformers believed to have failed) and repeated complaints of symptoms such as flickering lights.

Use of Smart Meters to Assist in the Location of Series Arcing

Symptoms such as buzzing transformers and flickering lights, during series arcing events, are consistent with the belief that customer service voltage is modulated heavily by series arcing. There are no known high-fidelity recordings, however, of secondary customer voltages or of primary voltages downstream of a clamp or switch that is experiencing series arcing.

Some smart meters can detect certain voltage anomalies, such as sags, swells, interruptions, and in some cases harmonics. A reasonable question, therefore, would be whether smart meters might provide information that could assist the location of series arcing, even before customers report problems. To date there have been limited opportunities to assess this possibility, as described below.

The circuit that experienced the aforementioned 31-day, 496-transient series arcing event has a modern AMI system. A failing clamp was located and definitively determined to be the cause of the DFA-reported series arcing event. Subsequent analysis was conducted on data from smart meters downstream of the clamp. The AMI system is configured to record sags and brownouts, but the analysis found no evidence that the meters had detected such events for the subject failure. One possible explanation is that the line voltage may have experienced momentary reductions, perhaps many of them, but those individual voltage reductions were too short-lived to satisfy the meters' criteria for reporting "sag" or "brownout."

AMI systems can report a "blink" when a series arcing condition results in momentary operation of a recloser, just as they can for any other momentary protection operation. In some cases this may provide information useful to guide a search for series arcing, although its usefulness is limited by the fact that a recloser that operates in such a case can be either upstream or downstream of the series arcing.

AMI meters and systems have varying capabilities and configurable parameters that affect their sensitivity to blinks, brownouts, and other anomalies. This frustrates attempts to form generalized conclusions regarding the use of AMI to provide information related to detecting, confirming, or localizing series arcing. Other than blink counts, the limited opportunities to assess usefulness of AMI data for these purposes have not generated any relevant information.

Using DFA Series Arcing Reports to Assess Effectiveness of Repair

Preceding sections have described cases in which line crews, acting without knowledge of a DFA series arcing report, have replaced transformers or replaced fuses, without recognizing that series arcing was at the root of the problem. DFA can be used to confirm that repair actions truly have solved a problem, or conversely, that they have not. Because series arcing tends to have flare ups and quiescent periods, irregularly spaced in time, flickering lights and other symptoms may cease temporarily following repair actions, even if those actions did not actually address the underlying series arcing problem. Following repair actions, if a DFA series arcing report continues to indicate flare ups, even after hours or days of quiescence, then operators and line crews can use that fact as an indication that the problem remains unresolved, and they can take further appropriate actions.

A Comment Regarding Line Crew Actions

Nothing in this document should be taken as critical of operators or field personnel, the decisions they make, or the actions they take. They act based upon experience and upon information available to them at the time. More often than not, incorrect diagnoses such as those described herein result from a lack of good information, rather than from unsound judgement by field personnel. In the cited cases, the point is not that field personnel acted improperly, but rather that they need improved situational information, which in the case of series arcing sometimes can be provided by DFA.

Concluding Remarks

Incipient failure of a load-carrying switch or clamp can cause series arcing. Series arcing results in a variety of typically intermittent symptoms that can be difficult for line crews to diagnose and can cause operations of conventional overcurrent protection, either upstream or downstream of the failing device.

The DFA technology system reports series arcing as "probable failure of switch or clamp." DFA-provided parametric information can be used to learn of and better diagnose such conditions, particularly when used in conjunction with other information, such as mysterious protection operations and customer reports of intermittently flickering lights. DFA series arcing reports also can be used to help determine whether repair actions have been effective.

Intent of This Document

This document describes in general terms the series arcing phenomenon and related use of DFA technology. It does not purport to cover all scenarios. The intended audience is utility company personnel. Users should apply the information in this document in conjunction with sound engineering judgement, operational experience, and their inherently superior knowledge of their systems.

FAQ: Can my relays, power quality meters, and other devices (or waveform data recorded by those devices) be used to perform DFA functionality? Is the sampling rate sufficient?

Response: Relays and other devices do not provide data suitable for the practice of DFA. The sampling rate for DFA devices is 256 samples per cycle, which DFA developers have found to be sufficient for DFA functionality, but that does not mean that data from relays or other devices with sampling rates of 256 samples per cycle would be suitable.

Explanation: An example is useful for illustrating why sampling rate is but one factor in determining the suitability of a device for providing data for practicing DFA. Figures 1 and 2, on the pages that follow, show line currents and voltages of a circuit that is carrying several tens of amperes of normal load on each phase and that has a hotline clamp that has developed a “hot spot.” The photograph at right shows a hotline clamp that has experienced a similar failure process.

The waveforms of Figure 1 are sampled 256 times per second. For the sake of clarity, the figure shows current and voltage only for the phase with the failing clamp. Figure 2 shows RMS currents and voltages, at a rate of one value per cycle, and is intended to give the “big picture.”

Overcurrent relays trigger on relatively high-amplitude currents, and power quality meters on significant sags or swells in voltage. Figures 1 and 2 make it clear that the clamp-failure event manifests little change in either current or voltage. Consequently relays and power quality meters do not trigger, and therefore do not provide data for detecting such events, regardless of sampling rate.

More Details: The preceding paragraphs are intended to provide an illustration, in summary form, of why relays and other devices cannot provide data suitable for the practice of DFA. The following paragraphs are for the reader interested in additional details.

The data shown in Figures 1 and 2 come from a DFA device that monitors a 12.47 kV, multi-grounded-wye circuit of typical overhead construction that is serving several hundred customers. The DFA device is connected to conventional bus PTs and circuit CTs available at the substation head of the subject circuit.

A customer on the circuit reported “blinking lights.” When a utility lineman responded, the lights were not blinking, and voltage levels at the customer’s premises were proper and stable. The lineman checked and tightened secondary service connections as a precaution. Sometime after the lineman left, the customer again reported blinking lights. The lineman’s second visit had similar findings. Based on experience and on the fact that only a single customer was reporting trouble, the lineman concluded that the problem likely was on the customer's side of the service transformer. Consequently, he initiated a service request for a recording voltmeter to be placed at the customer's service entrance, to help diagnose the nature and location of the problem.

Prior to the recording voltmeter's being placed, however, a system operator found that the DFA website was reporting "probable failure of switch or clamp" on the same phase as the customer with blinking lights. Figure 3 is a screen capture of the DFA website. The main line item at the top of the report indicates that DFA had detected multiple individual episodes of the event and provides the time of the latest such episode. The user can expand the item, as shown in the figure, to list the times of individual events.

This DFA report of a "failing switch or clamp" refocused the lineman's attention to the primary, instead of the secondary (or the customer's premises wiring), and he then identified an arcing hotline clamp a few spans upstream of the customer's service. Replacing the clamp solved the problem.

Knowing of and locating the failing clamp saved multiple service calls and restored proper service to the customer days earlier than otherwise would have been likely. It also avoided further etching of the conductor and the possibility of a broken conductor. DFA detected the failing clamp based solely on its monitoring of CT and PT signals. DFA algorithms act autonomously to provide the report of Figure 3, so that the user does not have to analyze waveform data, but that data is made available if the user chooses to view it.

Figures 1 and 2 show that each of the circuit's phases was carrying 38 to 70 amps of normal load current. The failing clamp is on phase A of the circuit. Minor variations in load current are visible in the figures, particularly for the currents of phases B and C. Figure 1 shows the high-speed (256 samples per cycle) data for the affected phase for a ten-second period of time. Figure 2 shows the RMS quantities for the same ten-second period, with a time resolution of one cycle, and is intended to show the "big picture." The graphs show no obvious anomalies that would trigger recording by a relay or power quality meter. DFA uses specialized signal processing techniques to detect signal characteristics that are indicative of specific types of circuit events, in this case a failing switch or clamp on phase A, but that are not apparent to visual observation of the graphs. The point is that, although DFA can detect this event and classify it as a failing switch or clamp, the signals would not have triggered recording by a relay or power quality meter. If the event data is not recorded, then it cannot be analyzed to determine the underlying cause. Therefore, relays and power quality meters cannot provide data sufficient for the practice of DFA technology.

This is one of many events that illustrate the inadequacy of data from relays and power quality meters to support DFA functionality. Those devices are designed for specific purposes, and they serve those purposes well, but their purposes and consequently their data differ in important ways from DFA.

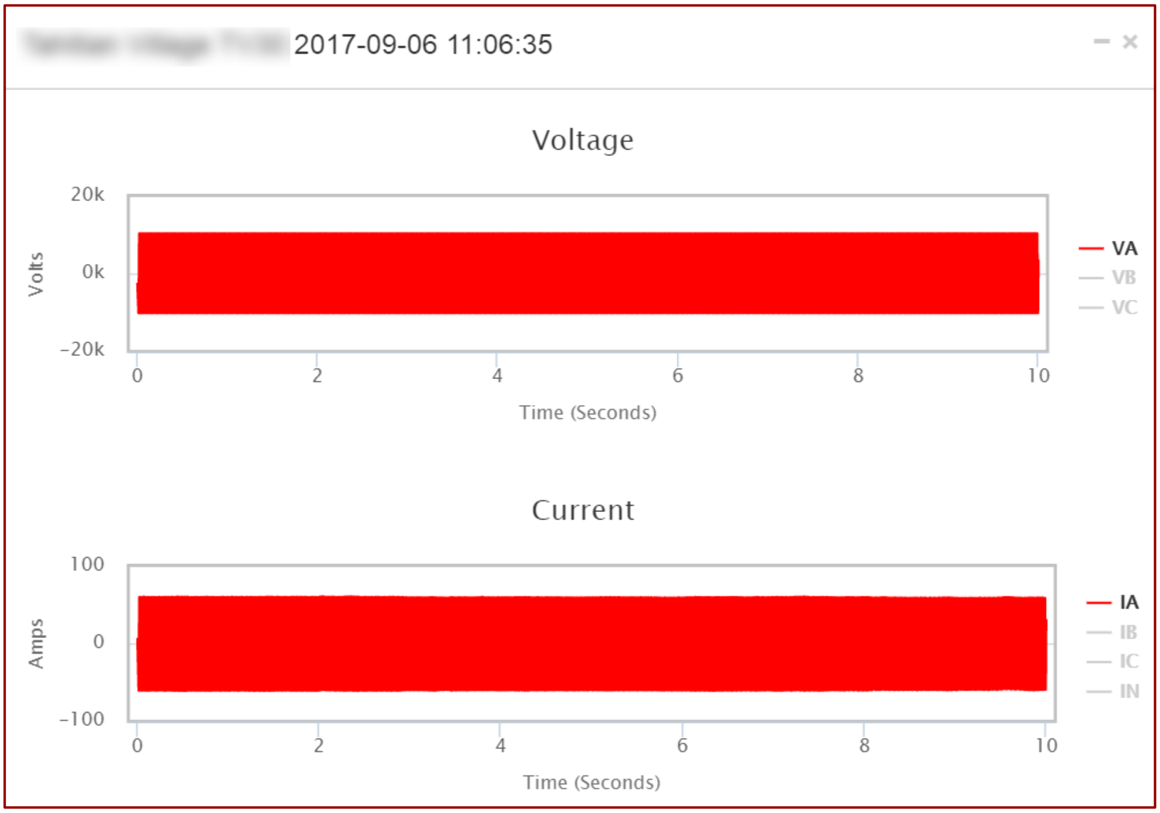


Figure 1. High-speed waveforms for a ten-second period in which a hotline clamp was actively arcing in its jaws. DFA records all three currents and all three voltages, but, for purposes of clarity, this figure shows only the phase with the failing clamp. The DFA gets its signals from substation-based CTs and PTs, so the signals contain all of the circuit's normal load, in addition to the manifestation of the failing clamp. The DFA On-Line Waveform Classification Engine software automatically identified this event as a "probable failure of switch or clamp." (256 samples per cycle.)

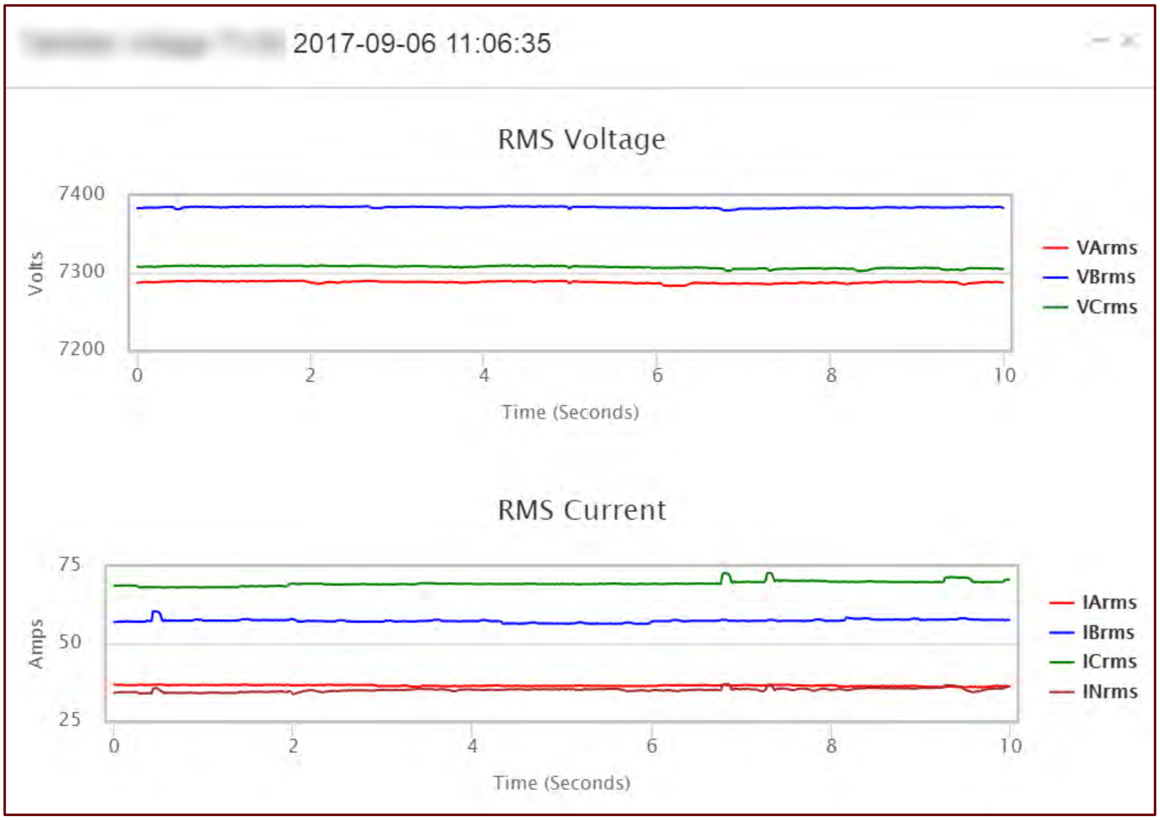
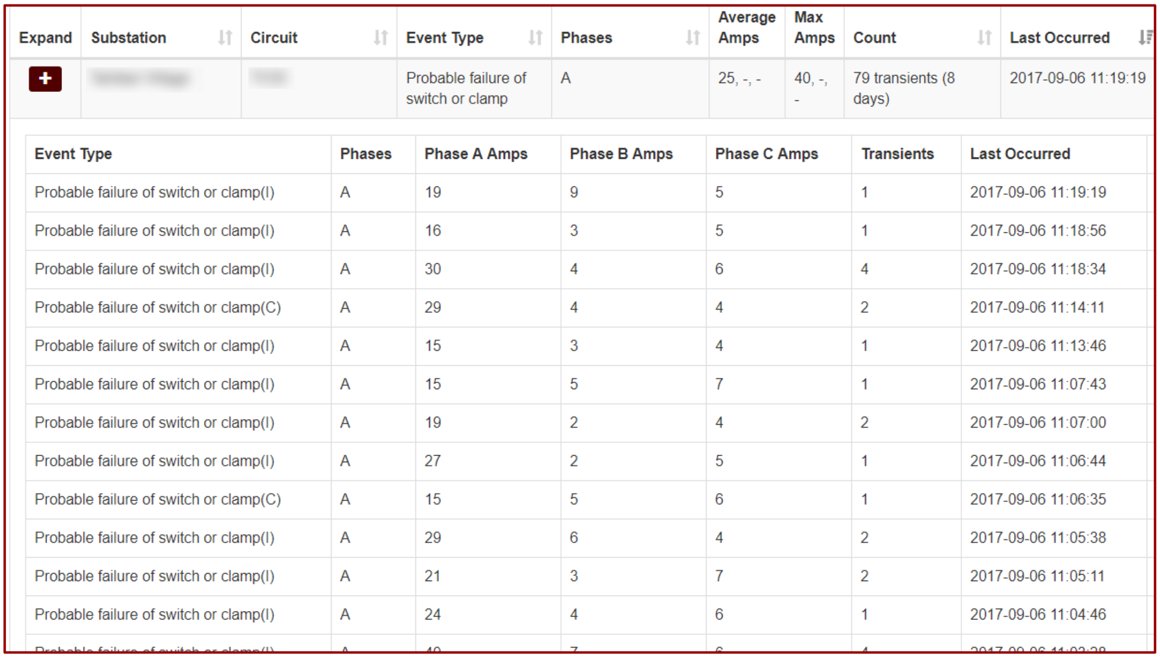


Figure 2. RMS line voltages and currents for the same ten-second interval as Figure 1. The DFA On-Line Waveform Classification Engine software automatically identified this event as a "probable failure of switch or clamp." (12.47 kV circuit. One RMS value per cycle.)



Expand	Substation	Circuit	Event Type	Phases	Average Amps	Max Amps	Count	Last Occurred
+	[illegible]	[illegible]	Probable failure of switch or clamp	A	25, -, -	40, -, -	79 transients (8 days)	2017-09-06 11:19:19

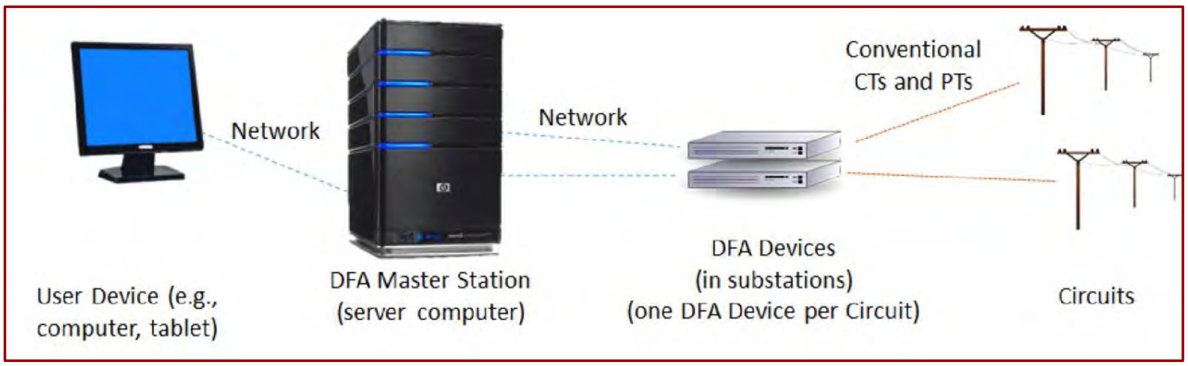
Event Type	Phases	Phase A Amps	Phase B Amps	Phase C Amps	Transients	Last Occurred
Probable failure of switch or clamp(I)	A	19	9	5	1	2017-09-06 11:19:19
Probable failure of switch or clamp(I)	A	16	3	5	1	2017-09-06 11:18:56
Probable failure of switch or clamp(I)	A	30	4	6	4	2017-09-06 11:18:34
Probable failure of switch or clamp(C)	A	29	4	4	2	2017-09-06 11:14:11
Probable failure of switch or clamp(I)	A	15	3	4	1	2017-09-06 11:13:46
Probable failure of switch or clamp(I)	A	15	5	7	1	2017-09-06 11:07:43
Probable failure of switch or clamp(I)	A	19	2	4	2	2017-09-06 11:07:00
Probable failure of switch or clamp(I)	A	27	2	5	1	2017-09-06 11:06:44
Probable failure of switch or clamp(C)	A	15	5	6	1	2017-09-06 11:06:35
Probable failure of switch or clamp(I)	A	29	6	4	2	2017-09-06 11:05:38
Probable failure of switch or clamp(I)	A	21	3	7	2	2017-09-06 11:05:11
Probable failure of switch or clamp(I)	A	24	4	6	1	2017-09-06 11:04:46

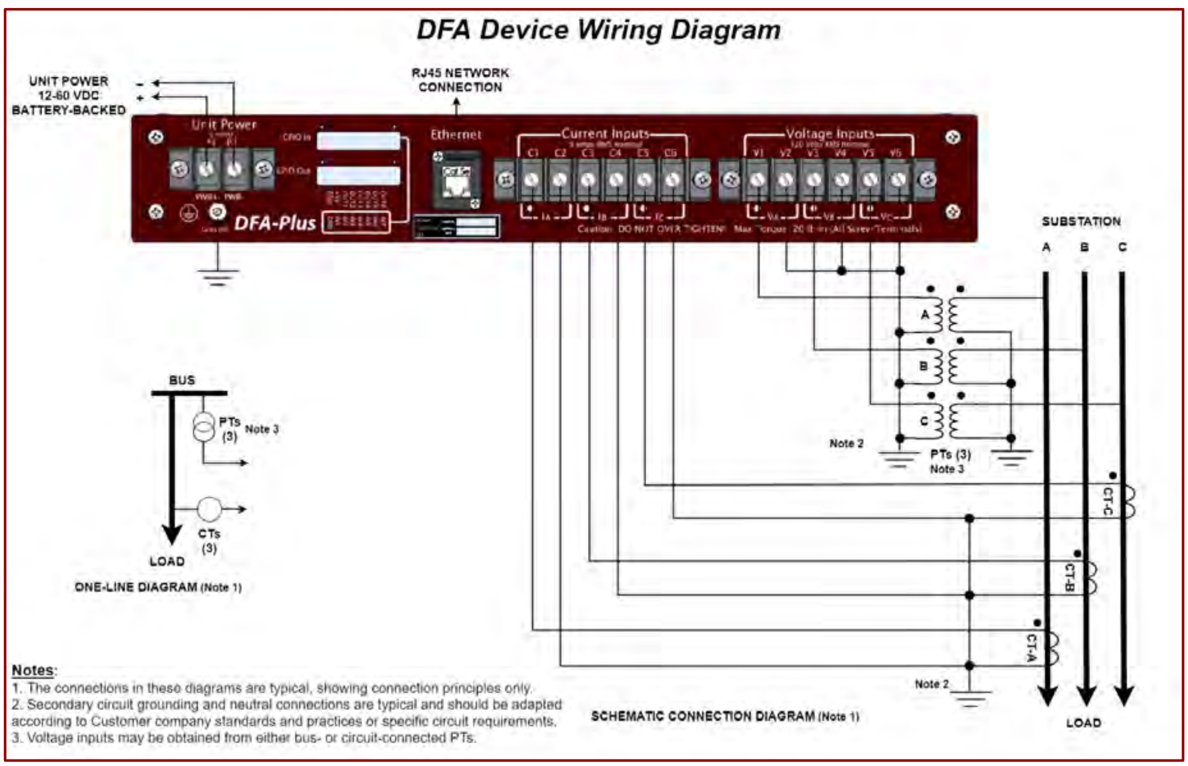
Figure 3. Screen image showing DFA web report of “probable failure of switch or clamp.”

FAQ: What are the components of the DFA Technology system, and how is the system installed and used?

Response: The DFA Technology system is implemented as a fleet of DFA Devices and a centrally located DFA Master Station server computer.

The DFA Master Station retrieves reports and other data from the fleet of DFA Devices and makes that information available to authenticated users via secure DFA web portal.[1] The first image below illustrates the relationships between the various components of the DFA Technology system. The second illustrates typical wiring for a DFA Device.





[1] A FAQ document, entitled, "I am concerned about the security of my DFA-related data and communications. What safeguards does the DFA system use to keep me from being hacked?" provides information on DFA data and communications security safeguards.

Each DFA Device is installed in a substation, to monitor a single circuit, and connects to conventional, three-phase current and potential transformers (CTs and PTs). The customer provides the CTs, PTs, battery-backed unit power, network service, and all associated racks, wiring, etc. DFA Device CT and PT inputs present low burden, enabling them to be "daisy chained" with the inputs of other substation equipment.

Each DFA Device continuously monitors its CT and PT inputs and uses sophisticated signal processing software, known as the Online Waveform Classification Engine, to infer circuit events. It sends pre-analyzed DFA reports to the DFA Master Station, via encrypted Internet, for access by authenticated users. The individual DFA Devices, not the DFA Master Station, apply the Online Waveform Classification Engine software to waveforms to create the reports. As updates to the Online Waveform Classification Engine software become available, the DFA Master Station deploys those updates to the fleet of DFA Devices, via the network.

The following screen captures come from the DFA website and provide two examples of DFA-reported incipient failure conditions. These reports were generated autonomously by the DFA Technology system, without human intervention. The first report relates to a phase-B hotline clamp or switch that has experienced arcing in its jaws intermittently over a period of eighteen days. The second report relates to a single incipient condition that has caused three phase-A faults, over a period of 20 days, each time causing a single trip/close operation of an unmonitored, single-phase recloser. Unless corrected, each condition likely will evolve to cause customer trouble and/or additional damage to system apparatus.

Probable failure of switch or clamp	B	Estimated load beyond switch/clamp: 212 kVA	14 transients (18 days)	2017-10-11 06:46:48

Phases	Phase A Amps	Phase B Amps	Phase C Amps	Transients	Last Occurred
B	12	34	12	1	2017-10-11 06:46:48
B	14	16	16	1	2017-10-11 06:33:50
B	9	106	10	1	2017-10-10 11:38:45
B	8	136	9	1	2017-10-10 11:38:12
B	6	81	6	1	2017-10-09 10:58:21
B	11	52	10	1	2017-10-07 23:38:41

Single-phase recurrent fault	A	Single-phase fault, 746 Amps	3 (20 days)	2017-10-09 08:01:05

Comments	Count	Last Occurred
F-(3.0c,757A,AN,68°)-T-(21,0,0)%-2.2s-C Est imp (ohms): 15.72z = 10.27r + 11.90x	1 op	2017-10-09 08:01:05
F-(3.5c,749A,AN,90°)-T-(12,0,0)%-2.2s-C Est imp (ohms): 16.05z = 10.72r + 11.94x	1 op	2017-09-18 13:52:36
F-(3.5c,733A,AN,84°)-T-(13,0,0)%-2.2s-C Est imp (ohms): 16.39z = 11.11r + 12.05x	1 op	2017-09-18 10:58:24

Question:

4) Refer to Mr. Blumenstock's direct testimony, page 136, and Exhibit A-48, pages 5 to 6. For each proposed 2021 and 2022 HVD Line Rebuild project, please provide the following:

a. The Concept Approval for each project;
b. The number of customers serviced by the line;
c. The number of outages on the line since 2011;
d. The length of each outage on the line since 2011;
e. The cause of each outage on the line since 2011;
f. The total projected cost (if different than shown in Ex A-48).

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request to that it seeks information as far back as 2011, which is irrelevant, overly broad, unduly burdensome, and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:

Exhibit A-48 (RTB-15), pages 5 and 6, and page 136 of my direct testimony, refer exclusively to 2022 HVD Line Rebuild projects. For each of the projects referenced therein:

a. Concept approvals were provided in Attachment #126 to Part III requirements for the following HVD Line Rebuild projects:

- Remus
- Wirtz Rd 2
- Big Rapids
- Maple City
- Rosebush
- Nashville
- Hodenpyl
- Merrill
- Wayland
- Morrice 2
- Shelby

For the remaining concept approvals for 2022 HVD Line Rebuild projects, please see Attachment 2 to this discovery response. Concept Approvals 21-0054 and 21-0026 both include the work in the Van Slyke #1 and Atherton/GMI/Aldrich projects.

b. Please refer to Attachment 1 to this discovery response for the number of customers on each line. Union City is a power tie line that does not directly serve any customers. Van Slyke #1 serves a single industrial customer.

c. Please refer to Attachment 1 to this discovery response for the outages on each line since 2011.

d. Please refer to Attachment 1 to this discovery response for outage durations on each line.

e. Please refer to Attachment 1 to this discovery response for outage causes on each line.

f. The total projected cost for each project is reflected in the respective concept approvals, including initial projected yearly breakdowns for some projects. However, yearly breakdowns may shift for multiyear projects due to the actual scheduling of work. Costs shown in Exhibit A-48 (RTB-15) are currently projected costs for the 2022 test year.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 1, 2021

Electric Planning

20963-MEC-CE-880
Attachment 1

Hughes Rd — 10402 Customers

Outage Information

Outage Date	Outage Duration (minutes)	Outage Cause
5/29/2011	2106	Pole
6/7/2011	302	Trees
7/15/2011	183	Conductor
8/27/2012	74	Insulator
2/27/2013	184	Crossarm
7/22/2013	141	Insulator
8/28/2013	152	Conductor
9/12/2013	342	Insulator
3/12/2014	398	Conductor
7/1/2014	393	Crossarm
3/22/2015	243	Conductor
5/10/2015	297	Conductor

Union City &
Union City 2 — 0 Customers

Outage Information

Outage Date	Outage Duration (minutes)	Outage Cause
5/29/2011	432	Crossarm
11/22/2013	36	Insulator

Morrice,
Morrice 2 &
Morrice - Perry Sub Tap — 8928 Customers

Outage Information

Outage Date	Outage Duration (minutes)	Outage Cause
4/10/2011	191	Crossarm
6/18/2012	302	Crossarm
8/7/2012	100	Trees
11/17/2013	1764	Pole
12/21/2013	221	Conductor
9/23/2014	114	Third Party Damage
8/2/2017	65	Trees
5/27/2018	87	Pole
10/20/2018	113	Trees
10/30/2018	63	Insulator

Hammond Rd — 4362 Customers

Outage Information

Outage Date	Outage Duration (minutes)	Outage Cause

1/14/2011	68	Third Party Damage
4/22/2011	73	Tree
3/10/2012	166	Third Party Damage
5/27/2012	95	Tree
12/21/2012	465	Tree
8/2/2015	395	Tree
7/1/2018	59	Tree
11/9/2018	227	Third Party Damage

Van Slyke #1 — 1 Customers

Outage Information		
Outage Date	Outage Duration (minutes)	Outage Cause
11/24/2017	87	Unknown

Atherton/GMI/Aldrich — 782 Customers

Outage Information		
Outage Date	Outage Duration (minutes)	Outage Cause
7/5/2012	627	Unknown

Wayland — 8990 Customers

Outage Information		
Outage Date	Outage Duration (minutes)	Outage Cause
11/18/2013	307	Conductor
7/12/2016	135	Trees

Rosebush — 5553 Customers

Outage Information		
Outage Date	Outage Duration (minutes)	Outage Cause
7/13/2012	248	Pole
5/10/2013	672	Insulator
4/12/2014	914	Pole
7/20/2019	316	Trees

Niagara — 5853 Customers

Outage Information		
Outage Date	Outage Duration (minutes)	Outage Cause
10/21/2013	202	Substation Equipment
11/17/2013	127	Pole
7/17/2015	423	Crossarm
8/22/2017	193	Conductor
9/10/2017	138	Crossarm

Hodenpyl & Hodenpyl 2 — 5669 Customers

Outage Information		
Outage Date	Outage Duration (minutes)	Outage Cause
10/22/2011	353	Third Party Damage

4/11/2013	462	Insulator
3/29/2015	31	Distribution
8/2/2015	366	Trees
1/24/2020	207	Insulator

Merrill 3931 Customers

	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
2/2/2011	743	Conductor
7/5/2012	144	Pole
4/28/2013	155	Third Party Damage
5/5/2013	98	Unknown
8/27/2013	67	Pole
12/22/2013	594	Conductor
12/22/2013	1006	Crossarm
2/20/2014	153	Insulator
5/3/2014	417	Conductor
9/12/2014	9	Substation Equipment
11/24/2014	173	Pole
3/8/2017	619	Conductor
7/20/2018	313	Insulator
6/10/2020	1608	Pole

Remus 1788 Customers

	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
9/2/2011	347	Trees
9/3/2011	174	Pole
5/21/2012	533	Insulator
4/12/2014	1232	Pole
3/8/2017	525	Pole
3/9/2017	417	Insulator
7/3/2018	317	Trees

Wirtz Rd 8469 Customers

	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
7/12/2012	3	Substation Equipment
9/22/2015	101	Trees
9/21/2017	461	Third Party Damage
5/8/2019	32	Trees

Big Rapids 5368 Customers

	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
3/9/2011	53	Insulator
3/1/2013	442	Transmission

6/6/2013	254	Insulator
4/12/2014	948	Conductor
4/13/2014	549	Conductor
4/13/2015	46	Pole
11/29/2017	215	Conductor
6/10/2020	915	Tree

Maple City	5528 Customers	
	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
7/26/2011	89	Substation Equipment
3/8/2012	587	Pole
12/21/2012	394	Conductor
12/21/2012	1214	Conductor
8/2/2015	2791	Trees
12/29/2020	300	Conductor

Cooper	7758 Customers	
	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
No Outages		

Sonoma	4134 Customers	
	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
3/30/2012	21	Insulator
6/11/2014	58	Insulator

Greenville	6086 Customers	
	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
4/10/2013	81	Insulator
2/24/2017	255	Insulator
10/5/2017	82	Conductor
10/23/2017	372	Conductor

Dietz-Gaylord	291 Customers	
	Outage Information	
Outage Date	Outage Duration (minutes)	Outage Cause
5/22/2011	55	Trees
7/26/2014	24	Third Party Damage
12/24/2015	44	Trees
12/26/2016	138	Trees
3/7/2017	67	Trees
11/9/2017	45	Conductor
8/28/2018	58	Trees
5/31/2019	287	Lightning

Saranac — 5082 Customers

Outage Information

Outage Date	Outage Duration (minutes)	Outage Cause
12/31/2013	249	Conductor
12/26/2013	106	Conductor
11/8/2016	182	Conductor
4/7/2017	307	Crossarm
5/9/2018	236	Pole
9/11/2019	435	Insulator

Goodale — 10152 Customers

Outage Information

Outage Date	Outage Duration (minutes)	Outage Cause
7/31/2012	550	Pole
8/27/2014	315	Third Party Damage
3/8/2017	705	Trees
1/1/2018	73	Third Party Damage
5/4/2018	253	Insulator
8/28/2020	476	Trees

Shelby — 2489 Customers

Outage Information

Outage Date	Outage Duration (minutes)	Outage Cause
3/2/2012	739	Substation Equipment
9/18/2012	190	Pole
2/20/2015	419	Conductor

Nashville &
Nashville Casite Sub Tap — 4662 Customers

Outage Information

Outage Date	Outage Duration (minutes)	Outage Cause
5/25/2011	82	Crossarm
9/29/2011	148	Trees
3/2/2012	83	Crossarm
5/3/2012	52	Third Party Damage
5/13/2013	102	Third Party Damage
12/22/2013	1207	Crossarm
12/23/2013	941	Trees
8/19/2014	32	Lightning
3/25/2015	668	Insulator
2/24/2016	869	Crossarm
5/29/2016	280	Conductor
10/18/2016	182	Trees
4/6/2017	360	Conductor
6/8/2017	374	Pole

Cement City 8779 Customers

Outage Information		
Outage Date	Outage Duration (minutes)	Outage Cause
4/16/2012	243	Third Party Damage
7/21/2013	42	Trees
5/12/2014	56	Lightning
6/3/2015	53	Substation Equipment
7/8/2016	328	Insulator
5/12/2018	72	Insulator
2/10/2019	68	Third Party Damage

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Consumers Energy
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CONCEPT APPROVAL

Concept Number: 21-0142

Project: **Hughes Rd West 46 kV Line – HVD Lines Reliability Rebuild** **County:** Calhoun

Date: March 10, 2021 **Need System Changes By:** 2/28/2022

Problem Description:

The Hughes Rd (016E) 46 kV line from structure #59049 to #1002 were installed around 1946. Per engineering, the 0.14-mile section of line has to be rebuilt in order to relocate a portion of line 025A out of the swamp.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild 0.14 miles of 016E line. HVD *Conceptual cost: $65,100*

Recommended Alternative:

Alternative #2 recommended. Rebuilding 0.14 miles of 016E line is needed in order to relocate a portion of line 025A out of the swamp. The section of 016E line will become a double circuit with line 025A. Without rebuilding this section of line, part of line 025A will not be able to be rebuilt/relocated out of the swamp. The rebuild on line 025A was approved under concept #21-0040. A rebuild will also replace the older conductor with modern standards and design.

Alternative #1 does not allow for a portion of line 025A to be rebuilt/relocated out of the swamp nor does it address the poles, crossarms and insulators on the line that needs to be replaced.

Alternative #2 Recommended Scope:

Alternative #2 recommended. Rebuild 0.14 miles of the Hughes Rd 46 kV 016E line from structure #59049 to #1002. Utilize single circuit 336.4 ACRS conductor and OPGW shield wire on the existing or a combination of existing easements and newly obtained easements as needed.

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METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2021 Cost with Overheads	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$21,000	$32,550	$21,000	$32,550	Rebuild 0.14 miles of the Hughes Rd 46 kV 016E line
Project Total	$21,000	$32,550	$21,000	$32,550	
Customer Contribution	$0	$0	$0	$0	
Total	$21,000	$32,550	$21,000	$32,550	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: KPBoynton **Team Leader:** Doug Meyers

Approvals:

Electric Reliability & Support Lead	Douglas R Meyers	Required
LVD System Engineer	Greg T Schultz	N/A
Director, LVD Circuit Planning	Julia A Fox	N/A
Director, HVD System Planning	Edward R Mathews	Required
Director, LVD System Planning	Donald A Lynd	N/A
Executive Director, Electric Planning	Richard T. Blumenstock	N/A
Vice President, Electric Grid Integration	Timothy J. Sparks	N/A

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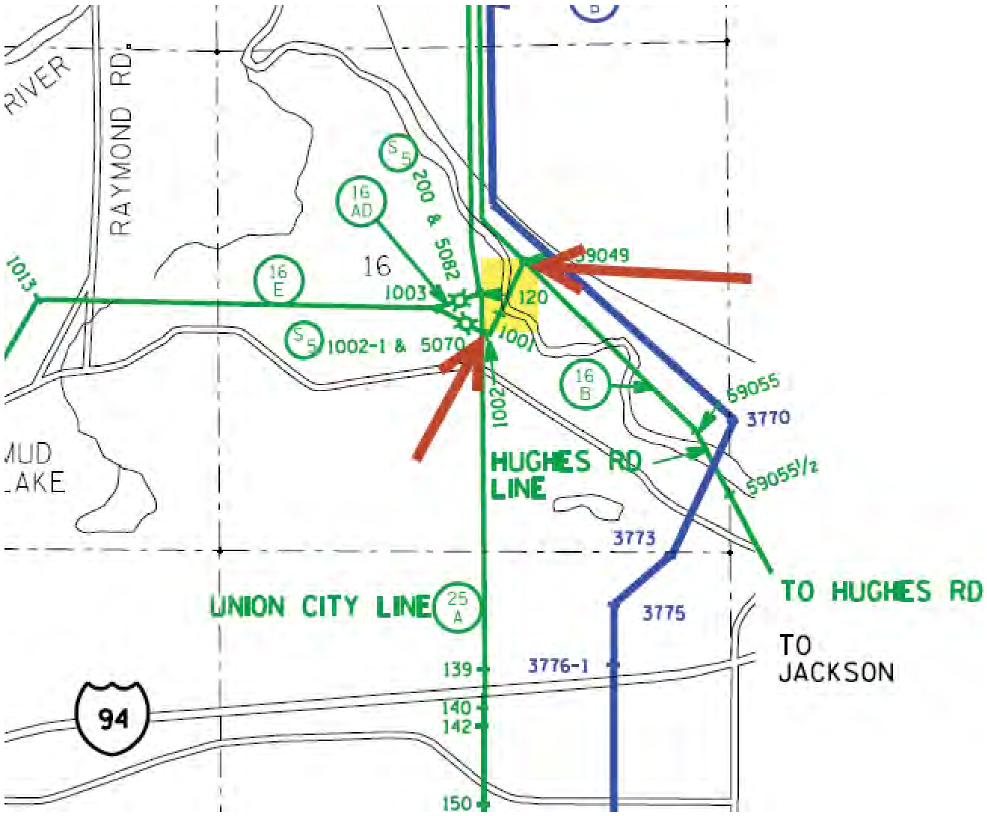

BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Friday, March 19, 2021 2:00 PM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Benjamin T. Scott; Jacob D. Roberson; KIMBERLY P. BOYNTON
Subject:	Approval has completed on 21-0142 Hughes Rd (0.14 Miles) 46 kV HVD Lines Reliability Rebuild.

Approval has completed on 21-0142 Hughes Rd (0.14 Miles) 46 kV HVD Lines Reliability Rebuild.

Approval on 21-0142 Hughes Rd (0.14 Miles) 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 3/15/2021 9:19 AM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $100,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 3/15/2021 10:23 AM
Comment:

Approved by Edward R. Mathews on 3/19/2021 2:00 PM
Comment:

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0040

Project: **Union City 46 kV Line – HVD Lines Reliability Rebuild** **County:** Calhoun

Date: January 16, 2020 **Need System Changes By:** 6/1/2021

Problem Description:

The Union City 46 kV line was constructed in 1943. Pole inspections have identified that 36 out of 122 (29.5%) poles are replacement candidates in this section of the Union City 46 kV line from structure #59046 to structure #227. Presently this line is non-standard unshielded 4/0 copper conductor construction. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild 5.34 miles of the Union City 46 kV line. *Conceptual cost: $2,439,000*

Recommended Alternative:

Alternative #2 is recommended. Rebuild of this line is needed to improve overall system reliability. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Rebuild also replaces the older non-standard conductor with modern standards and design.

Alternative #1 does not address the poles that need replacement or the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 Recommended Scope:

Rebuild the 5.34 mile section of the Union City 46 kV line from structure #59046 to structure #227 with single circuit 336.4 ACSR conductor built mostly on the existing centerline and a portion on newly obtained easements as needed. See attached

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map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2021 Cost with Overheads	Description
EH-95308	$1,602,000	$2,439,000	Rebuild Union City 46 kV line
Project Total	$1,602,000	$2,439,000	
Customer Contribution	$0	$0	
Total	$1,602,000	$2,439,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: KPBoynton/ALRoot **Team Leader:** Doug Meyers

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required

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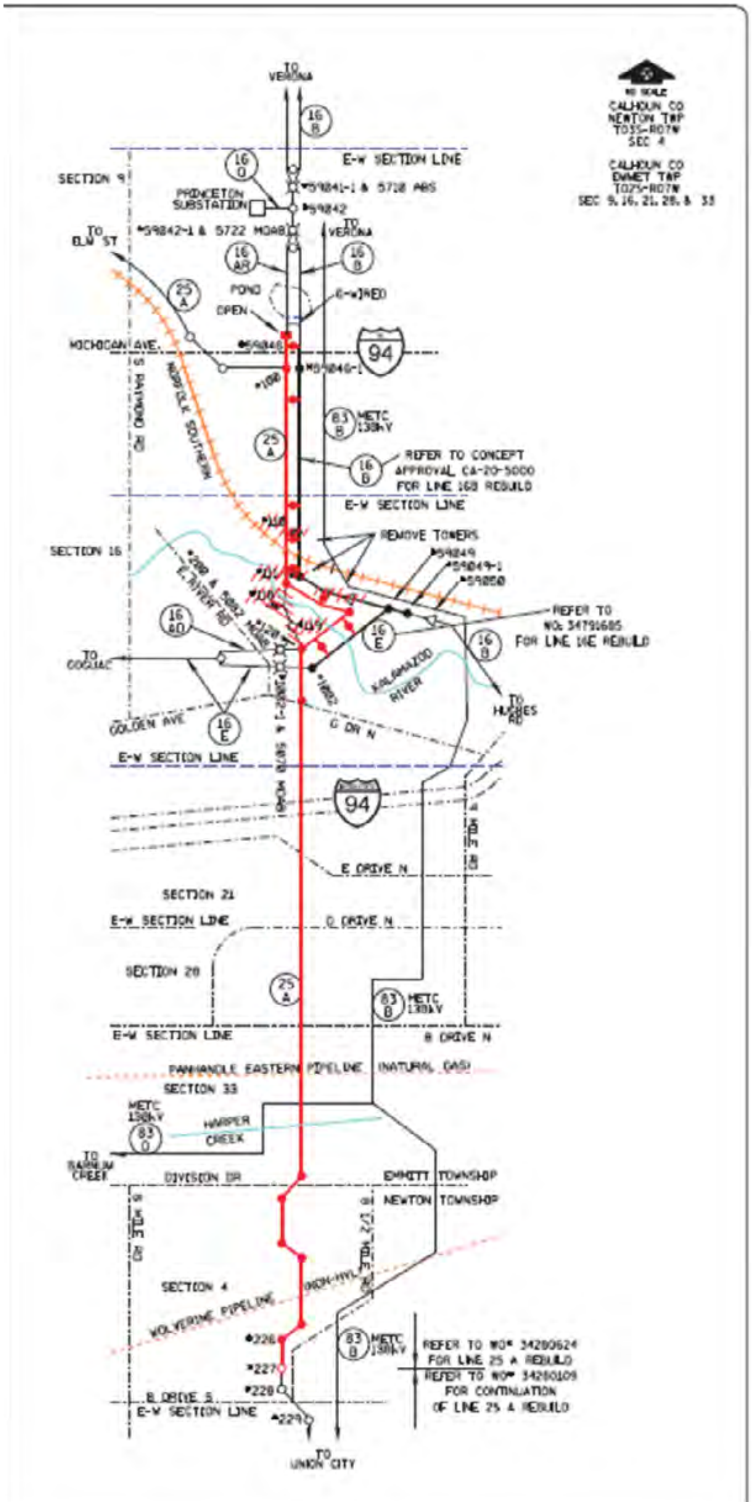

From:	SPAdvisor
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; KIMBERLY P. BOYNTON
Subject:	Approval has completed on 21-0040 Union City 46 kV HVD Lines Reliability Rebuild.
Date:	Sunday, January 19, 2020 12:51:52 PM

Approval has completed on 21-0040 Union City 46 kV HVD Lines Reliability Rebuild.

Approval on 21-0040 Union City 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 1/17/2020 11:23 AM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/17/2020 11:31 AM
Comment:

Approved by DWAYNE C. PARKER on 1/17/2020 12:10 PM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 1/17/2020 2:59 PM
Comment: Approved.

Approved by Timothy J. Sparks on 1/17/2020 5:02 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 1/19/2020 12:51 PM
Comment:

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0048

Project: **Union City 46 kV Line – HVD Lines Reliability Rebuild** **County:** Calhoun

Date: January 14, 2021 **Need System Changes By:** 4/30/2023

Problem Description:

The Union City (025A) 46 kV line from structure #227 to #422 were installed around 1943. 50 out of 179 poles (27.9%) in the 7.91-mile section of line requires replacement. There have been 2 forced outages on the line between 2016 and 2020 due to failed equipment. 4 of the poles were recommended as a "Rush" replacement and 46 were recommended as a "Planned replacement" by the 2018 pole inspection program. Currently this line is non-standard unshielded 4/0 copper conductor construction. HVD lines that are non-standard construction (unshielded or non-standard conductor), like this section of line, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Replace only the recommended pole replacements on the 7.91-mile section of line. HVD *Conceptual cost: $948,600 and* LVD *Conceptual cost: $152,037*
3. Rebuild 7.91 miles of 025A line. HVD *Conceptual cost: $3,678,150 and* LVD *Conceptual cost: $589,517*

Recommended Alternative:

Alternative #3 recommended. Rebuilding the 7.91 miles of 025A line is needed to improve the overall system reliability. Outage data has shown that after completing a rebuild, a line typically has zero or minimal line equipment related outages. A rebuild will also replace the older non-standard conductor with modern standards and design.

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Alternative #1 does not address the poles that needs to be replaced or the reliability of the system on the line and would result in a continual decrease in reliability.

Alternative #2 does not address some of the poles, crossarms and insulators on the 7.91--mile section of line 025A that needs to be replaced or the reliability of the system on the section of line and would result in a continual decrease in reliability.

Alternative #3 Recommended Scope:
Alternative #3 recommended. Rebuild 7.91-miles of the Union City 46 kV 025A line, including the associated LVD underbuild from structure #227 to #422. Utilize single circuit 336.4 ACRS conductor and OPGW shield wire on the existing or a combination of existing easements and newly obtained easements as needed.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	2023 Direct Cost	2023 Cost with Overheads	Description
EH-95308	$1,186,500	$1,839,075	$1,186,500	$1,839,075	Rebuild 7.91 miles of the Union City 46 kV 025A line
ED-95719	$190,167	$294,759	$190,166	$294,758	LVD Underbuild (025A)
Project Total	$1,376,567	$2,133,834	$1,376,566	$2,133,833	
Customer Contribution	$0	$0	$0	$0	
Total	$1,376,167	$2,133,834	$1,376,166	$2,133,833	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group and the Low Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

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RTBlumenstock
TJSparks
JFBrossoit

Prepared By: KPBoynton **Team Leader:** Doug Meyers

Approvals:

Electric Reliability & Support Lead	Douglas R Meyers	Required
LVD System Engineer	Gregory T Schultz	Required
Director, LVD Circuit Planning	Julia A Fox	Required
Director, HVD System Planning	Edward R Mathews	Required
Director, LVD System Planning	Donald A Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required

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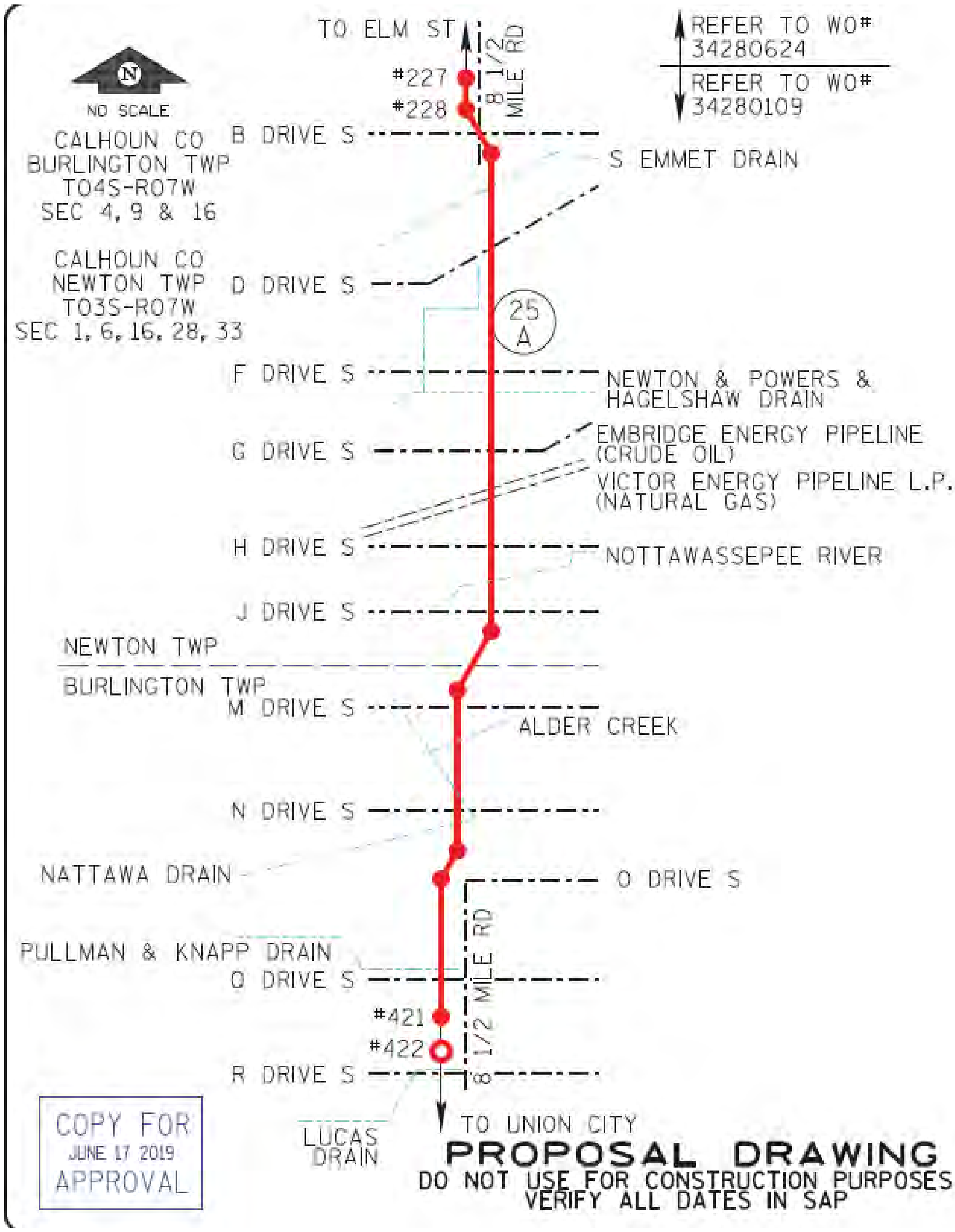

BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Thursday, January 21, 2021 2:40 PM
To:	Edward R. Mathews
Cc:	BRIAN C. MAZUR; Brian M. Bushey; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Benjamin T. Scott; Gregory E. Kral; Jacob D. Roberson
Subject:	Approval has completed on 22-0048 Union City (7.91 Miles) 46 kV HVD Lines Reliability Rebuild.

Approval has completed on 22-0048 Union City (7.91 Miles) 46 kV HVD Lines Reliability Rebuild.

Approval on 22-0048 Union City (7.91 Miles) 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by Edward R. Mathews on 1/14/2021 2:43 PM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/14/2021 3:16 PM
Comment: No comments

Approved by GREGORY T. SCHULTZ on 1/19/2021 10:21 AM
Comment: I approve

Approved by JULIA R. FOX on 1/19/2021 11:00 AM
Comment:

Approved by Edward R. Mathews on 1/19/2021 11:00 AM
Comment:

Approved by DONALD A. LYND on 1/19/2021 11:34 AM
Comment: Approved for LVD.

Approved by RICHARD T. BLUMENSTOCK on 1/21/2021 12:18 PM
Comment: Approved.

Approved by Timothy J. Sparks on 1/21/2021 2:39 PM
Comment: Approved.

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0025

Project: **Morrice 46 kV Line – HVD Lines Reliability Rebuild** **County:** Shiawassee

Date: January 16, 2020 **Need System Changes By:** 3/31/2022

Problem Description:

The Morrice 46 kV line (28C) has experienced 5 outage incidents between 2014 and 2018. The Morrice 46 kV line is ranked in the top 20 worst performing lines by number of incidents that occur. Presently the 4.58 mile north section of the line constructed in 1956 is unshielded, non-standard 1/0 copper conductor. The 6.52 mile center section of the line constructed in 1954 is a mixture of non-standard 1/0 copper and 3/0 ACSR conductor and is mostly unshielded. One out of the 5 outage incidents between 2014 and 2018 occurred in the 4.58 mile north section and another one of the 5 outage incidents occurred in the 6.52 mile center section. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like these line sections, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild the 4.58 mile north section and 6.52 mile center section of the Morrice 46 kV line. *Conceptual cost: $5,720,000*

Recommended Alternative:

Alternative #2 is recommended. Rebuild of this line is needed to improve overall system reliability and for the approximately 8,300 customers served from the Morrice 46 kV line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Rebuild also replaces the older non-standard conductor with modern standards and design.

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Alternative #1 does not address the poles that need replacement or the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 Recommended Scope:

Rebuild the 4.58-mile north section of the Morrice 46 kV line, including the associated LVD underbuild, from Springbrook Substation to pole #2590-5. Also rebuild the 6.52 mile center section of the line from structure #2590-5 to structure #584. Utilize single circuit 336.4 ACSR conductor on existing centerline on a combination of existing easements and newly obtained easements as needed. See attached maps.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2022 Direct Cost	2021 Cost with Overheads	2022 Cost with Overheads	Description
EH-95308	$1,380,000	$0	$2,101,000	$0	Rebuild Morrice 46 kV line North Section
EH-95308	$1,200,000	$750,000	$1,827,000	$1,142,000	Rebuild Morrice 46 kV line Center Section
ED-95719	$427,000	$0	$650,000	$0	LVD underbuild for the North Section
Project Total	$3,007,000	$750,000	$4,578,000	$1,142,000	
Customer Contribution	$0	$0	$0	$0	
Total	$3,007,000	$750,000	$4,578,000	$1,142,000	Grand Total Cost with Overheads: **$5,720,000**

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: KPBoynton/ALRoot **Team Leader:** Doug Meyers

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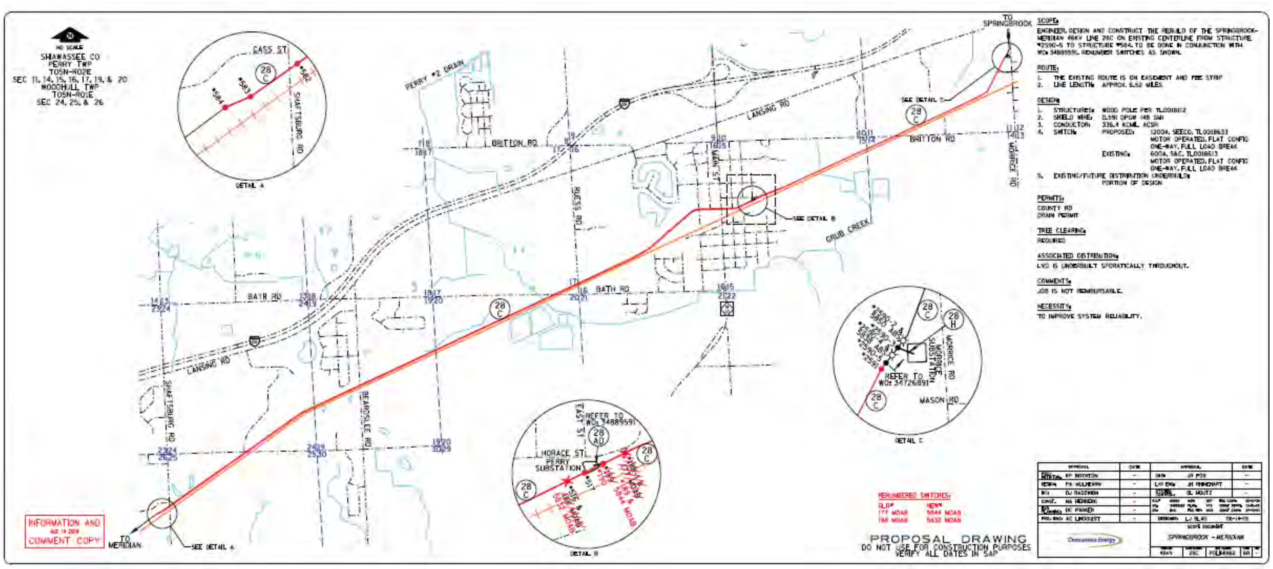
DRMeyers
JRFox
DCParker
DALynd
RTBlumenstock
TJSparks
JFBrossoit

Approvals:

Director, LVD Circuit Planning	Julia R. Fox	Required
Director, HVD System Planning	Dwayne C. Parker	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required



Morrice 46 kV Line – 6.52-mile Center Section

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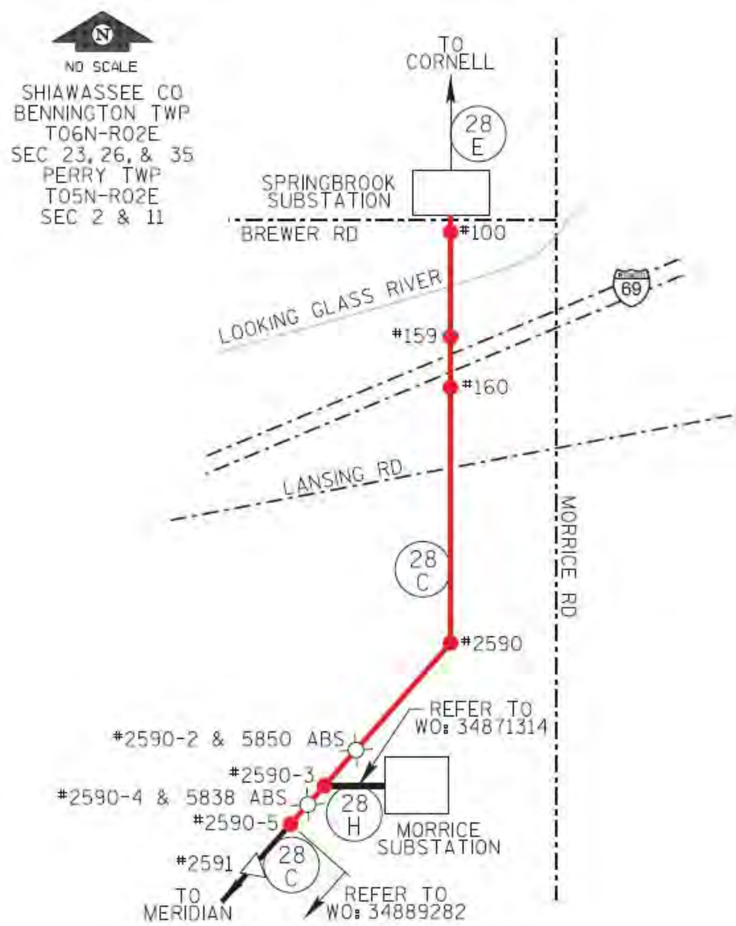
JFBrossoit



Morrice 46 kV Line – 4.58-mile North Section

From:	SPAdvisor
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; KIMBERLY P. BOYNTON
Subject:	Approval has completed on 21-0025 Morrice 46 kV HVD Lines Reliability Rebuild.
Date:	Wednesday, January 29, 2020 11:39:49 AM

Approval has completed on 21-0025 Morrice 46 kV HVD Lines Reliability Rebuild.

Approval on 21-0025 Morrice 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 1/16/2020 4:46 PM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/17/2020 7:47 AM
Comment:

Approved by DWAYNE C. PARKER on 1/17/2020 8:06 AM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 1/27/2020 10:56 AM
Comment: Approved.

Approved by Timothy J. Sparks on 1/27/2020 11:13 AM
Comment: Approved.

Approved by Jean-Francois Brossoit on 1/29/2020 11:39 AM
Comment:

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0149

Project: **Hammond Rd 46 kV Line – HVD Lines Reliability Rebuild** **County:** Grand Traverse County

Date: May 28, 2021 **Need System Changes By:** 4/30/2022

Problem Description:

The Hammond Rd 46 kV line was constructed pre-1940 by a local REA company and purchased by Consumers Energy in the early 1940s. The line is constructed with non-standard 2/0 copper conductor in an unshielded configuration. The section of the Hammond Rd 46 kV line between structure #3004-2 and structure #2877 has experienced 2 outage incidents between 2015 and 2019.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Top Rehabilitation of the line. *Conceptual cost: $568,000*
3. Rebuild 6.3 miles of the Hammond Rd 46 kV line. *HVD Conceptual cost: $2,837,000 and LVD Conceptual cost: $273,000*

Recommended Alternative:

Alternative #3 is recommended. Rebuild of this line is needed to improve overall system reliability and for the approximately 4,400 customers served from the Hammond Rd 46 kV line. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages.

Alternative #1 does not address the reliability of the system on this line and would result in a continual decrease in reliability.

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Alternative #2 does not address the aged copper conductor, poles or the unshielded configuration of the line.

Alternative #3 Recommended Scope:
Rebuild the 6.1 mile section of the Hammond Rd 46 kV line from structure #3004-2 to structure #2877 with a single circuit 336.4 ACSR conductor built on the existing centerline. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2022 Direct Cost	2021 Cost with Overheads	2022 Cost with Overheads	Description
EH-95308	$1,098,000	$732,000	$1,702,000	$1,135,000	Rebuild Hammond 46 kV line
ED-95719	$106,000	$70,000	$164,000	$109,000	LVD Underbuild Line Relocation O-At-Ka Sub – East Bay Ckt 0.54 miles, Bates Sub – Acme Ckt 0.16 miles, Bates Sub – Williamsburg Ckt 0.1 miles
Total	$1,204,000	$802,000	$1,866,000	$1,244,000	Grand Total Cost with Overheads: **$3,110,000**

Present Need: On approval, this document authorizes the Electric Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka **Team Leader:** Doug Meyers

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks

Approvals:

Senior Engineer Lead, LVD Circuit Planning	John P. Brack	Required
Director, HVD System Planning	Edward R. Mathews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required

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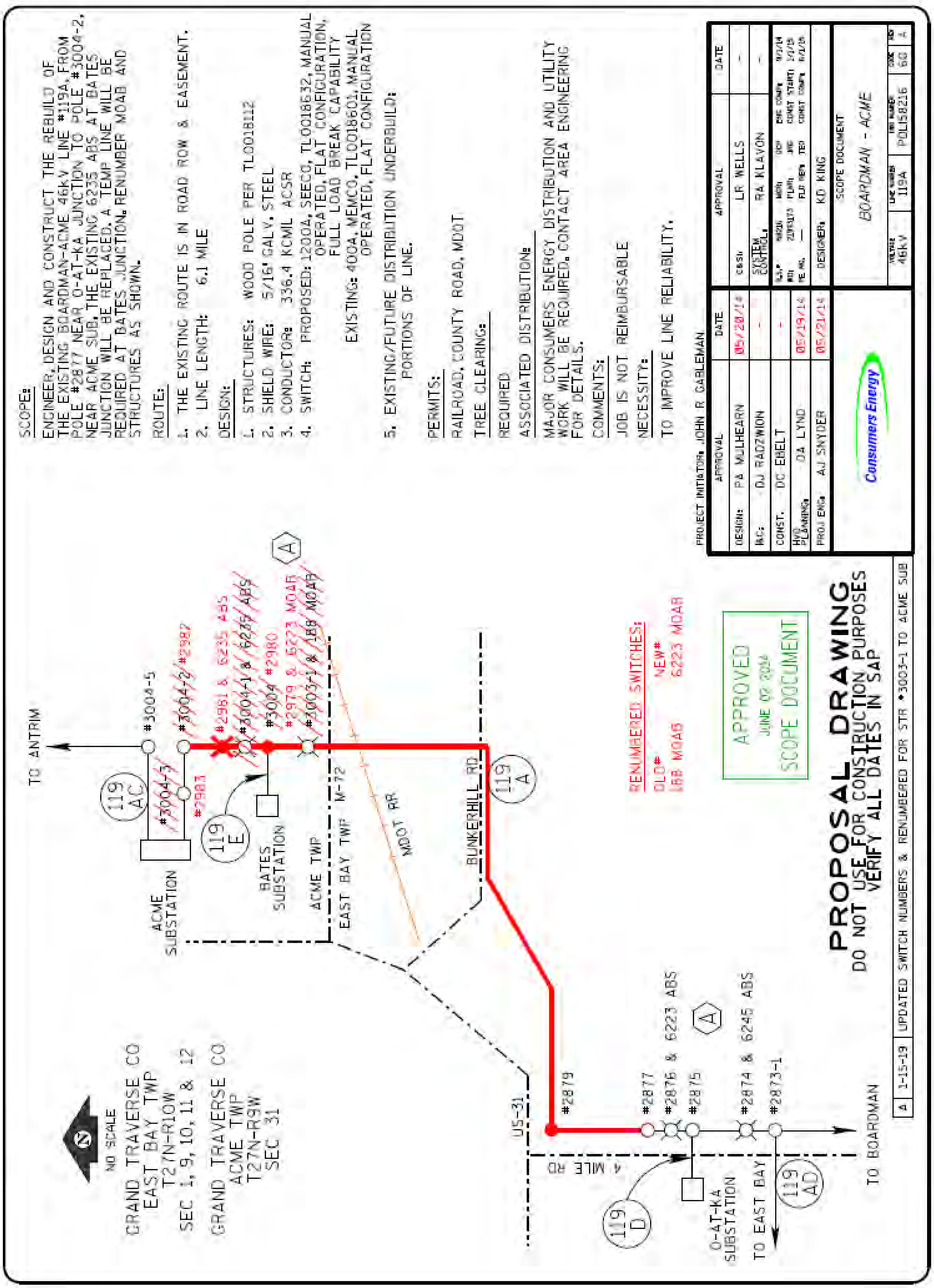
TJSparks



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Consumers Energy
Customer & Service Infrastructure
CONCEPT APPROVAL

Concept Number: 19-0011

Project: **Niagara 46kV line – Reroute out of swamp – Acquire ROW** **County:** Saginaw

Date: June 8, 2018 **Need System Changes By:** 5/15/2019

Problem Description:

As part of a 2016 HVD pole inspection, multiple poles on the Bristol and Niagara 46 kV lines were identified for replacement. These two circuits are parallel to each other in this area and consist of two six-wire connected double circuit pole lines. Orders were created for replacement but after an engineering review, there are multiple railroad crossings that would require Grade B construction upgrades over roughly half a mile of line. There is a large swamp that would require extensive crane matting to perform the pole replacements.

Alternative Solutions:

1. Replace the poles in their current locations and construct the necessary Grade B upgrades required for railroad crossings. This will require extensive crane matting ($500,000 Direct) and Grade B railroad crossing upgrades in the pole replacement sections ($127,000 Direct). **(Total Direct $627,000)**
2. Reroute the lines out of the swamp area and reconfigure the Niagara and Bristol Lines to minimize railroad crossings. The reconfiguration would transfer Bristol substation from the Bristol 46 kV line to the Niagara 46 kV line, transfer Davenport substation from the Niagara 46 kV line to the Bristol 46 kV line, remove ~1 mile of unnecessary conductor from the Bristol 46 kV line, and deenergize and remove 0.35 miles of 3/0 ACSR from the Niagara line ($143,000 Direct cost of removal) (see attached drawings). To prevent negatively affecting reliability for Steering Gear Substation, an Air Break Switch would be added to the South side of Steering Gear on the Niagara 46 kV line ($64,000 Direct). This project would require new Right of Way ($60,000 Direct) and construction of new 46 kV line at the edge of the swamp ($227,000 Direct). With the proposed line reconfigurations, the existing two double circuit six wire connected pole lines could be replaced with one single-circuit pole line at the edge of the swamp. This would also reduce 7 railroad crossings in total. The Construction Field Leader has advised that removal of the existing line in the swamp can be completed without crane matting.**($494,000 Total Direct)**

Recommended Alternative:

Alternative #2: By rerouting the line out of the swamp, not only does Consumers Energy reduce construction costs for the pole replacements, but it reduces the number of railroad crossings and improves access to the line for restoration and future construction purposes. The HVD system reconfiguration reduces over a mile of line exposure on the Bristol 46 kV line as well as increasing capacity on the Niagara 46 kV line by removing a section of 3/0 ACSR. The HVD system reconfiguration

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is necessary to reduce the number of railroad crossings and reduces construction costs by building a single circuit line rather than a double circuit line at the edge of the swamp.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2018 Direct Cost	2018 Cost with Overheads	Description
EH-95208	$60,000	$65,000	Acquire new ROW out of swamp and avoid R/W crossings.
WBS Element	**2019 Direct Cost**	**2019 Cost with Overheads**	**Description**
EH-95308	$227,000	$330,000	Reroute line out of swamp
EH-95008	$64,000	$93,000	Add 1200A ABS to Niagara 46kV Line South of Steering Gear Sub
EH-95008	$0	$0	Retire and Remove ~1.35 miles of 46 kV line between the Niagara and Bristol Lines
Cost of Removal	$143,000	$208,000	
Total	$494,000	$696,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: JRMcCormick **Team Leader:** ALRoot

Approvals:

Director, Customer & Service Infrastructure HVD	Dwayne C. Parker	Required
Executive Director, Transmission	James R. Anderson	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	N/A

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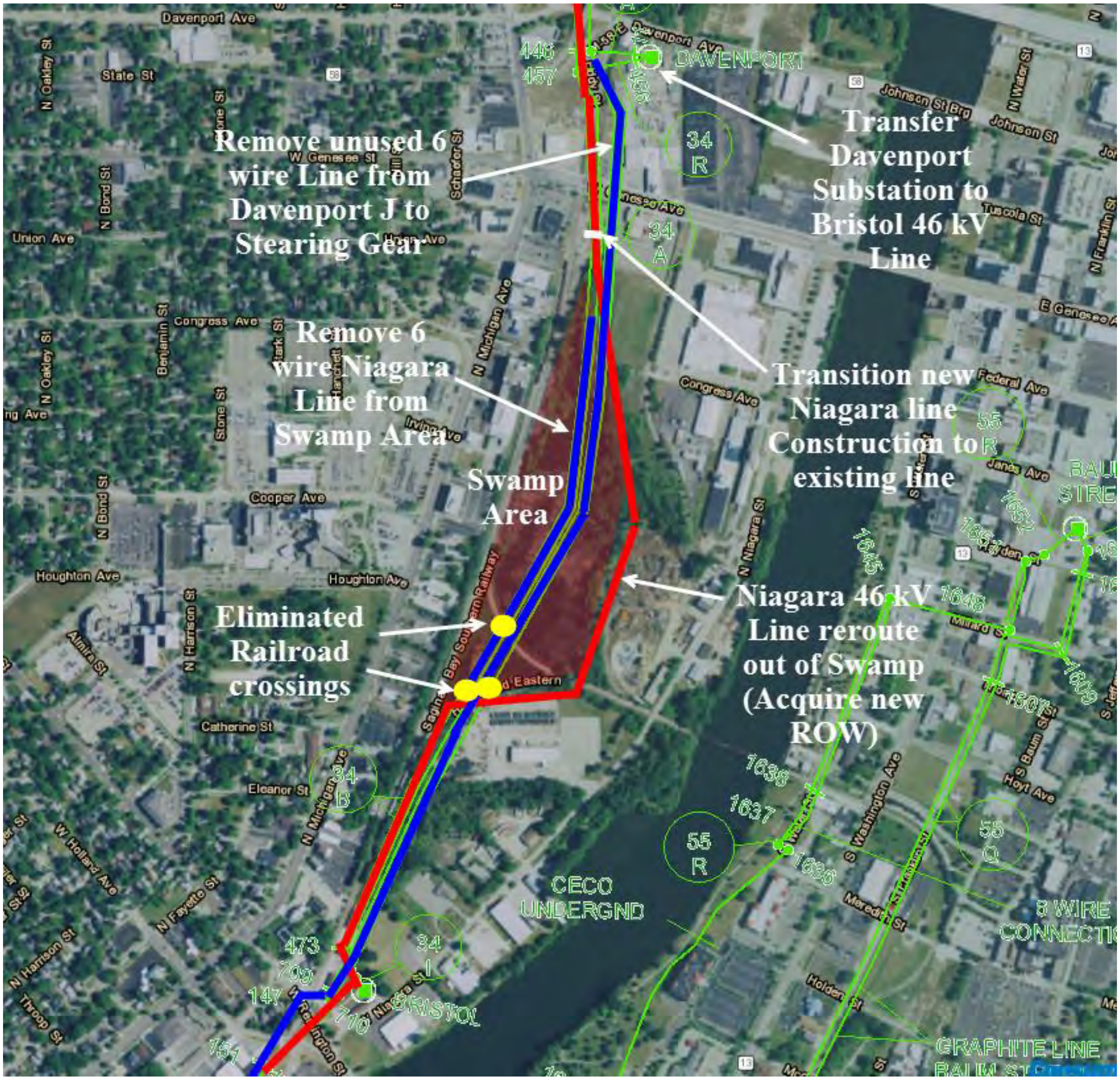
JRAnderson
TJSparks
SLWatters

Reroute Niagara Line out of swamp/ Remove Bristol Spur



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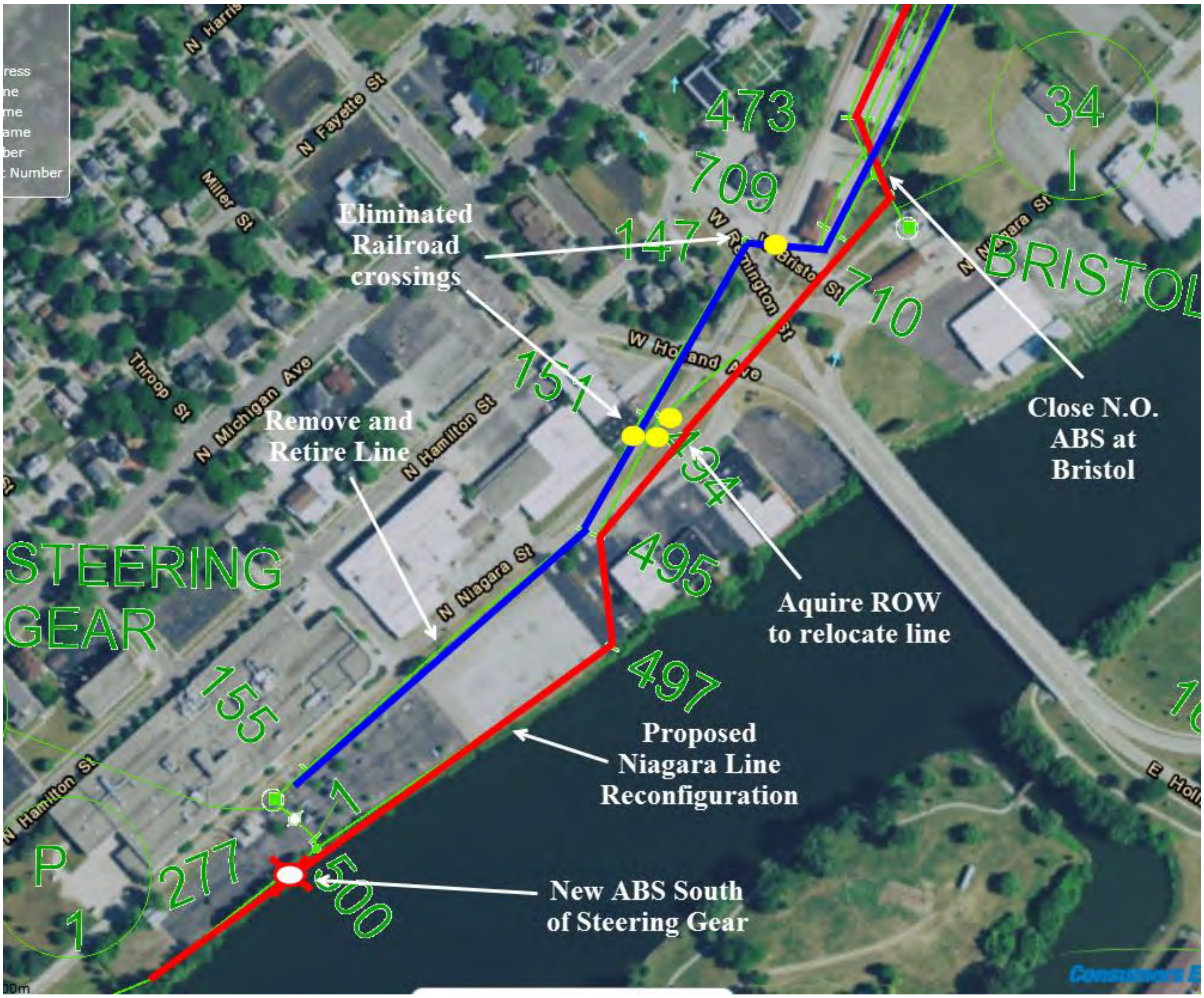
Relocate Niagara line to Avoid Railroad Crossing/Reconfigure Niagara and Bristol 46 kV lines



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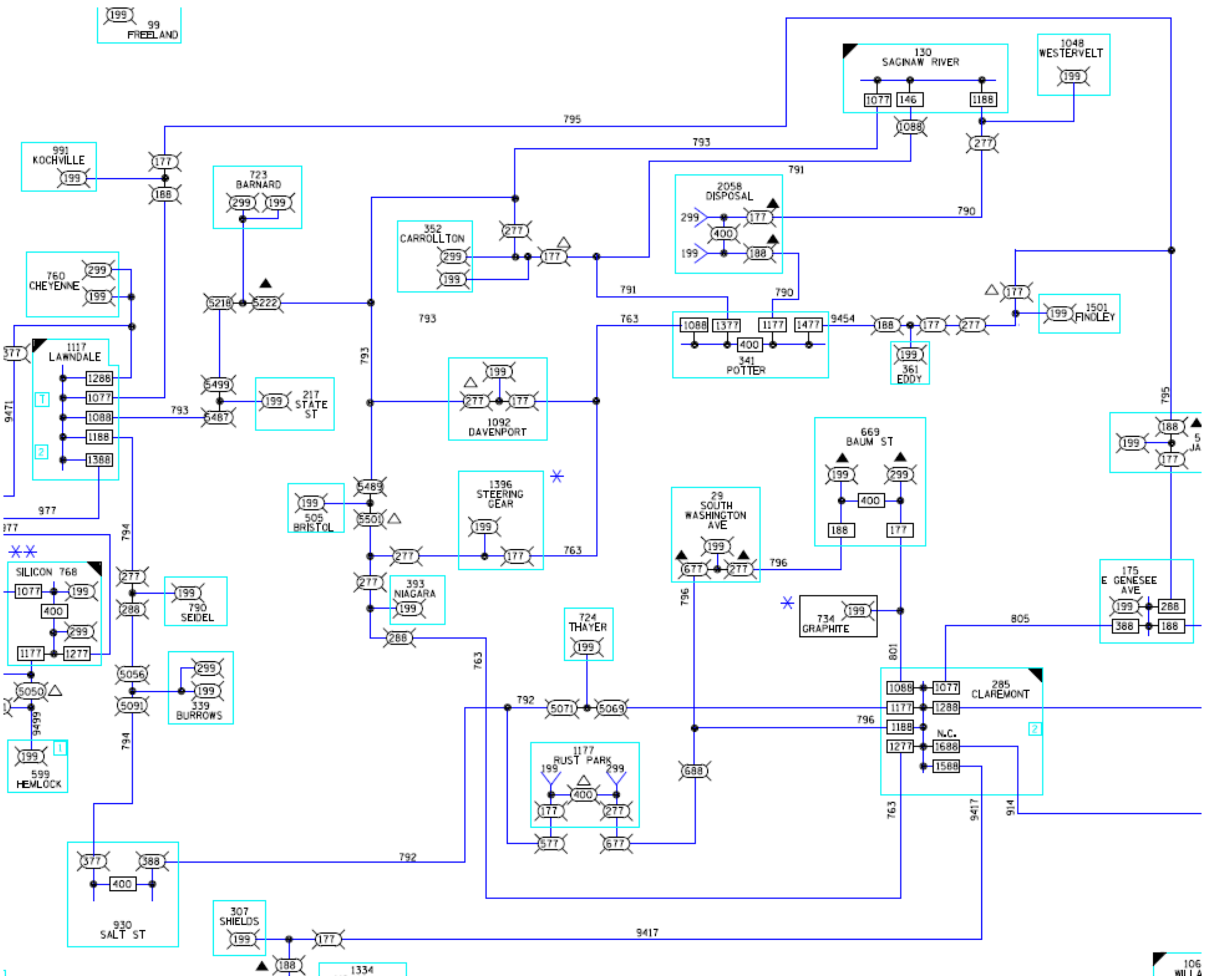
Existing System Configuration



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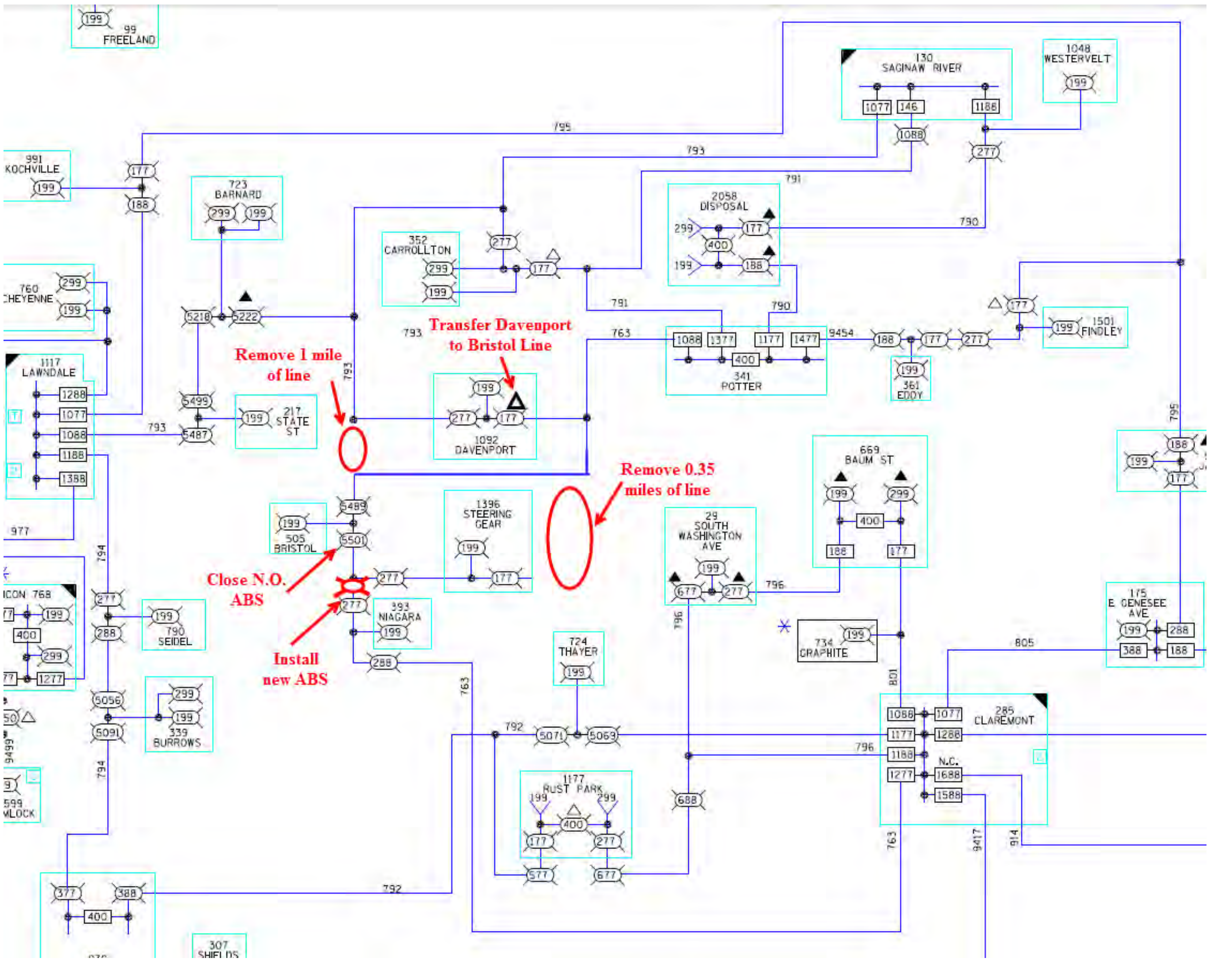
New HVD System Configuration



From:	Electric Asset Management
To:	SUSAN L. WATTERS
Cc:	SUSAN L. WATTERS; CINDY L. KEZELE; Brian M. Bushey; DONALD A. LYND; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews
Subject:	Approval has completed on 19-0011-Niagara_46kV_Line_Reroute_Line_Out_of_Swamp-Acquire_New_ROW.
Date:	Monday, June 18, 2018 10:13:01 PM

Approval has completed on 19-0011-Niagara_46kV_Line_Reroute_Line_Out_of_Swamp-Acquire_New_ROW.

Approval on 19-0011-Niagara_46kV_Line_Reroute_Line_Out_of_Swamp-Acquire_New_ROW has successfully completed. All participants have completed their tasks.

Approval started by SUSAN L. WATTERS on 6/8/2018 2:48 PM
Comment: A new document has been added to the C&SI HVD Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by ARIC L. ROOT on 6/11/2018 10:57 AM
Comment:

Approved by DWAYNE C. PARKER on 6/18/2018 9:29 AM
Comment:

Approved by James R. Anderson on 6/18/2018 7:38 PM
Comment: I approve. Tim, if questions, we can discuss with James McCormick as needed. I chatted with him today on this topic.

Approved by Timothy J. Sparks on 6/18/2018 10:12 PM
Comment: Approved.

View the workflow history.

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0076

Project: **Hodenpyl 46 kV Line – HVD Lines Reliability Rebuild** **County:** Wexford

Date: April 21, 2021 **Need System Changes By:** 2/28/2023

Problem Description:

Line performance data over the past five years has shown the Hodenpyl 46 kV line to be underperforming. The Hodenpyl 46 kV line, originally installed in 1931, has experienced 2 outage incidents between 2015 and 2019. The line has also been removed from service 3 times during that span due to crossarm and insulator failures. The line is constructed with non-standard 1/0 copper conductor in an unshielded configuration. Recent aerial inspections of the line have shown advanced deterioration of the crossarms and pole tops.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Top Rehabilitation of the line. *Conceptual cost: $432,000*
3. Rebuild 4.8 miles of the Hodenpyl 46 kV line. *HVD Conceptual cost: $2,160,000 and LVD Conceptual cost: $845,000*

Recommended Alternative:

Alternative #3 is recommended. Rebuild of this line is needed to improve overall system reliability and for the approximately 5,300 customers served from the Hodenpyl 46 kV line. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages.

Alternative #1 does not address the reliability of the system on this line and would result

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in a continual decrease in reliability.

Alternative #2 does not address the aged copper conductor, poles or the unshielded configuration of the line.

Alternative #3 Recommended Scope:
Rebuild the 4.8 mile section of the Hodenpyl 46 kV line from Hodenpyl Substation to structure #104 with single circuit 336.4 ACSR conductor built on the existing centerline with poles that will accommodate underbuild circuit. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	2023 Direct Cost	2023 Cost with Overheads	Description
EH-95308	$1,110,000	$1,665,000	$330,000	$495,000	Rebuild the Hodenpyl 46 kV line
ED-95719	$434,000	$651,000	$130,000	$194,000	LVD Underbuild Line Relocation Harrietta Sub Boon Ckt 4.8 miles
Customer Contribution	$0	$0	$0	$0	
Total	$1,544,000	$2,316,000	$460,000	$689,000	Grand Total Cost with Overheads: **$3,005,000**

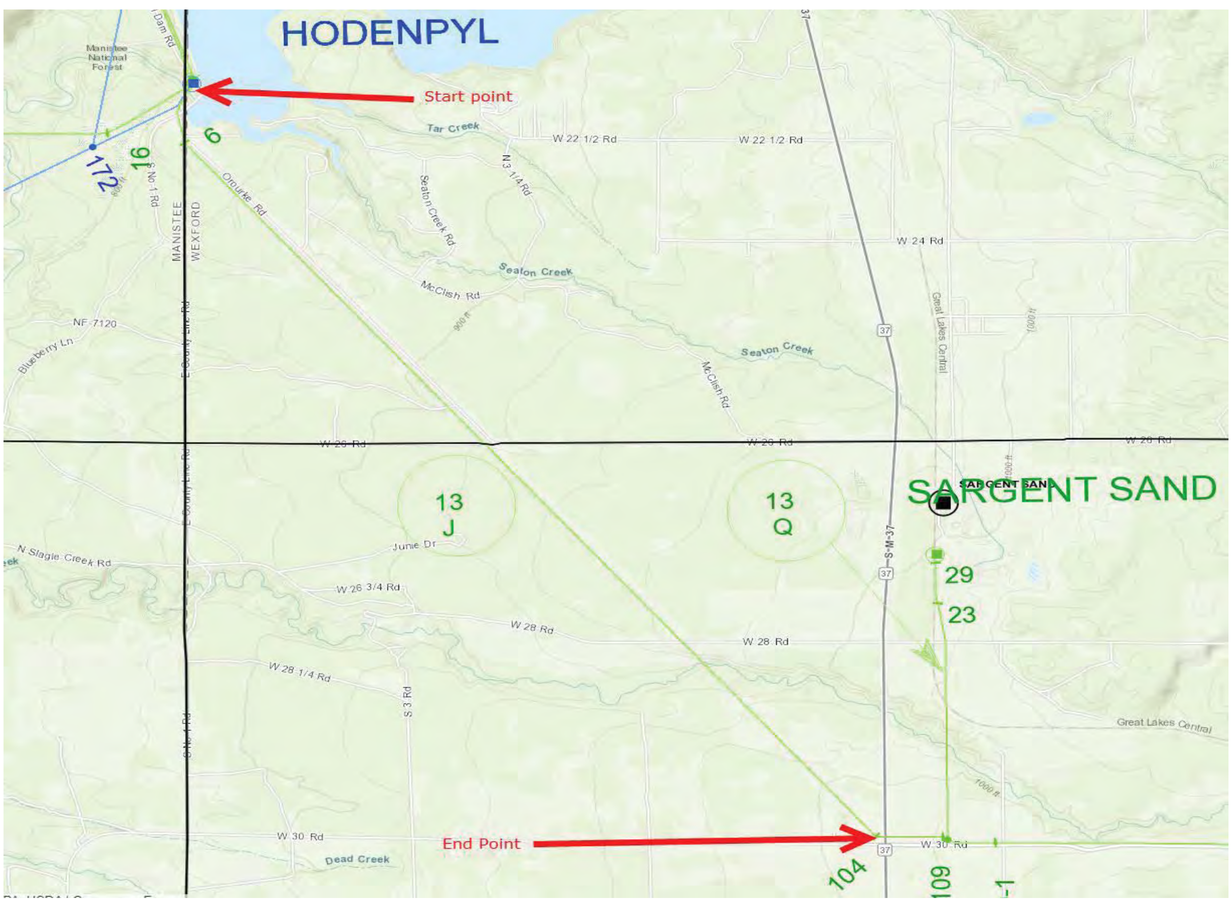
Present Need: On approval, this document authorizes the Electric Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka **Team Leader:** Doug Meyers

BCMazur
DRMeyers
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock
TJSparks

Approvals:

Senior Engineer Lead, LVD Circuit Planning	John P. Brack	Required
Director, HVD System Planning	Edward R. Mathews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required



BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Wednesday, May 5, 2021 5:58 PM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan Principe; Edward R. Mathews; ARIC L. ROOT; Benjamin T. Scott; Gregory E. Kral; Jacob D. Roberson; LOUIS B. HINCKA
Subject:	Approval has completed on 22-0076 Hodenpyl 46 kV HVD Lines Reliability Rebuild.

Approval has completed on 22-0076 Hodenpyl 46 kV HVD Lines Reliability Rebuild.

Approval on 22-0076 Hodenpyl 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 4/22/2021 9:33 AM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by JOHN P. BRACK on 4/29/2021 2:30 PM
Comment:

Approved by Edward R. Mathews on 4/30/2021 8:49 AM
Comment:

Approved by JULIA R. FOX on 5/5/2021 8:16 AM
Comment:

Approved by DONALD A. LYND on 5/5/2021 3:56 PM
Comment: Approved for LVD

Approved by RICHARD T. BLUMENSTOCK on 5/5/2021 4:03 PM
Comment: Approved.

Approved by Timothy J. Sparks on 5/5/2021 5:58 PM
Comment: Approved.

View the workflow history.

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0087

Project: **Cooper 46 kV Line – HVD Lines Reliability Rebuild** **County:** Kalamazoo

Date: May 28, 2021 **Need System Changes By:** 8/31/2022

Problem Description:

Pole inspections have identified that 6 out of 11 poles (~55%) in a 0.6 mile section of the Cooper 46 kV line need replacement. Presently this line section is non-standard #2 ACSR shielded construction. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Replacements. *Conceptual cost: $127,000*
3. Rebuild the 0.6 mile section of the Cooper 46 kV line. *Conceptual cost: $279,000*

Recommended Alternative:

Alternative #3 is recommended. Rebuild of this line is needed to improve overall system reliability and for approximately 7800 customers served from the Cooper 46 kV line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Rebuild also replaces the older non-standard conductor with modern standards and design.

Alternative #1 does not address the poles that need replacement or the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 addresses the poles that need replacement but does not address the non-standard #2 ACSR conductor.

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Alternative #3 Recommended Scope:

Rebuild the 0.6 mile Cooper 46 kV line from pole # 568 to the Cooper Substation with single circuit 3/0 ACSR conductor on a 20 foot offset of the existing centerline on existing easements. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$180,000	$279,000	Rebuild Cooper 46 kV line
Total	$180,000	$279,000	Grand Total with Overheads: **$279,000**

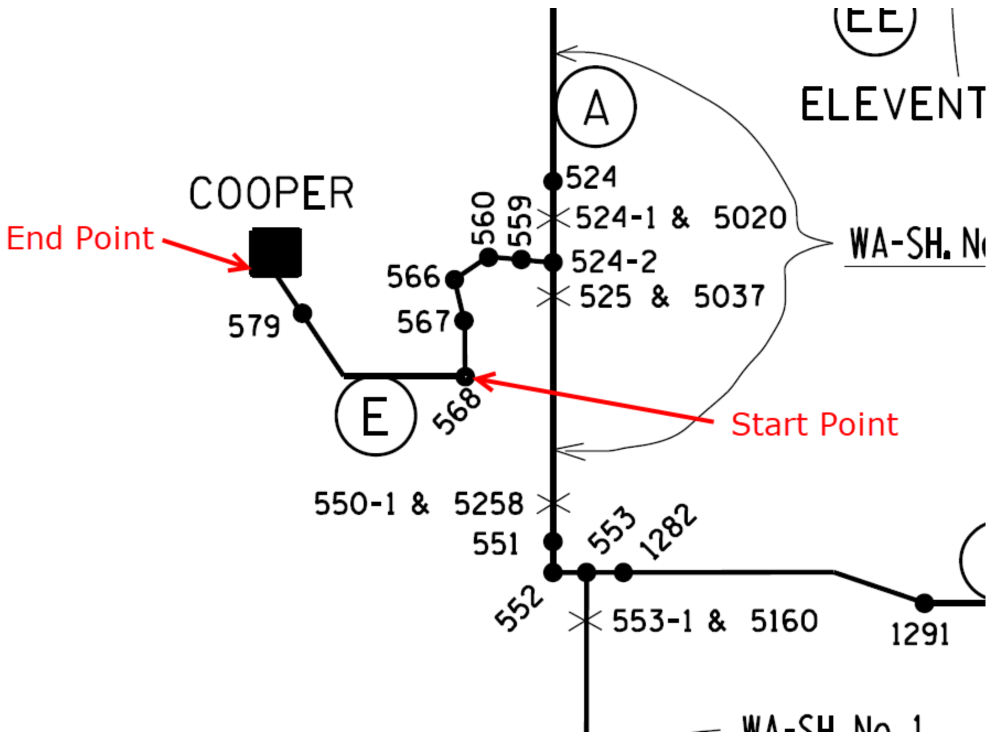
Present Need: On approval, this document authorizes the Electric Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka **Team Leader:** Doug Meyers

Approvals:

Director, HVD System Planning	Edward R. Mathews	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	N/A

BCMazur
DRMeyers
ERMathews
RTBlumenstock



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ERMathews
DALynd
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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0064

Project: **Sonoma 46 kV Line – HVD Lines Reliability Rebuild** **County:** Calhoun

Date: April 20, 2021 **Need System Changes By:** 11/30/2022

Problem Description:

The Sonoma (116V) 46 kV line from structure #982 to #994 were installed around 1947. There have been 3 outage incidents on the line and 1 in the 0.72-mile section of line between 2016 and 2020. 7 out of 13 (53.8%) of the structures were recommended for replacement in 2019 by the wood pole inspection program. The line utilizes standard 3/0 ACSR conductor with a shield wire construction.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Replace only the recommended pole replacements on the 0.72-mile section of line. HVD *Conceptual cost: $134,850 and* LVD *Conceptual cost: $12,000*
3. Rebuild 0.72 miles of 116V line. HVD *Conceptual cost: $334,800 and* LVD *Conceptual cost: $45,000*

Recommended Alternative:

Alternative #3 recommended. Rebuilding the 0.72 miles of 116V line is needed to improve the overall system reliability for approximately 4,025 customers and to address the recommended pole replacements identified by the pole inspector. An avoided outage would be a 0.385 SAIDI savings. Outage data has shown that after completing a rebuild, a line typically has zero or minimal line equipment related outages. Due to the number of poles requiring replacement in this section of line, it is more efficient to rebuild the section.

Alternative #1 does not address the poles, crossarms and insulators on the line that needs to be replaced or the reliability of the system on the line and would result in a

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continual decrease in reliability.
Alternative #2 only addresses the poles that were identified by the pole inspection program and does not account for other poles, crossarms and insulators on the 0.72-mile section of line 116V and would result in a continual decrease in reliability as those other poles, crossarms, and insulators continue to deteriorate.

Alternative #3 Recommended Scope:
Rebuild the 0.72-miles of the Sonoma 46 kV 116V line from structure #982 to #994. The HVD will utilize single circuit 336.4 ACRS conductor and a shield wire on the existing or a combination of existing easements and newly obtained easements as needed. The LVD will utilize single circuit, single phase #4 ACRS conductor.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$216,000	$334,800	Rebuild 0.72 miles of the Sonoma 46 kV 116V line
ED-95719	$29,032	$45,000	Rebuild 0.38 miles of the LVD Underbuild (116V) Watkins substation, Knapp circuit
Project Total	$245,032	$379,800	
Customer Contribution	$0	$0	
Total	$245,032	$379,800	

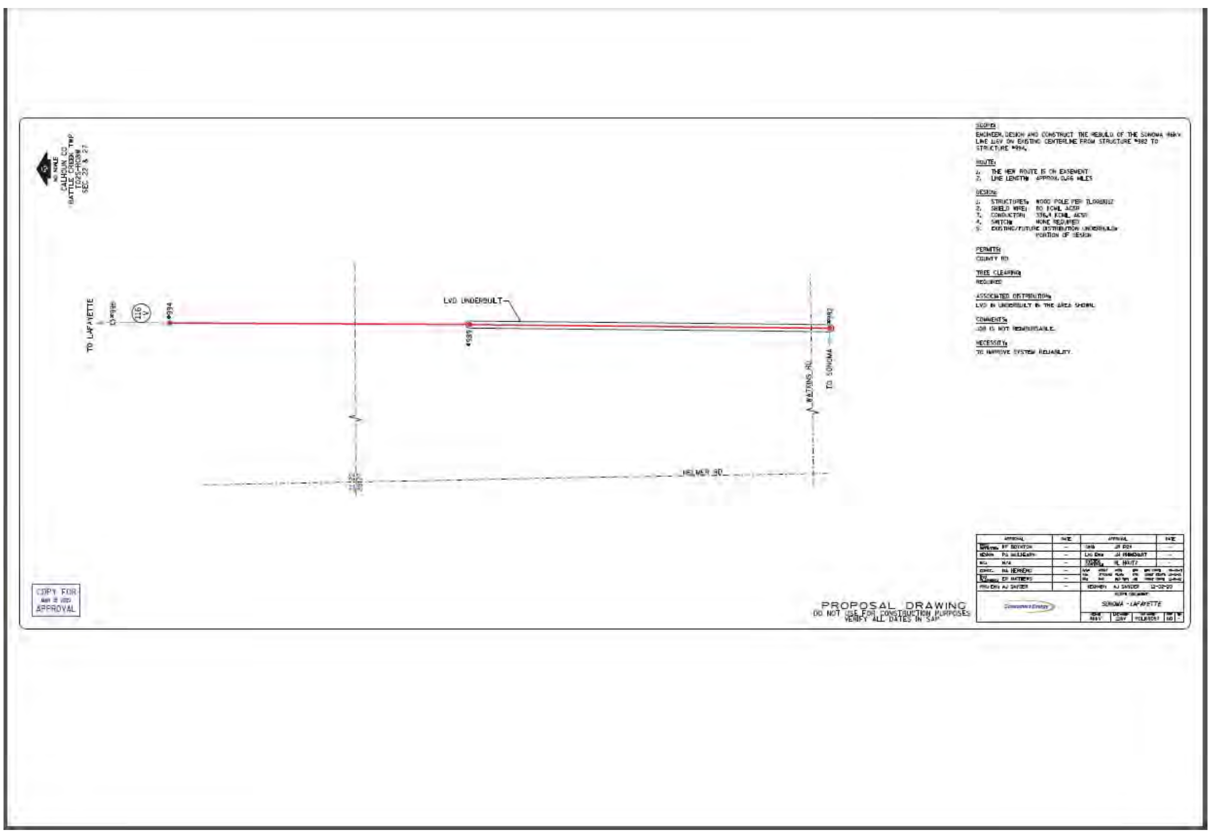
Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group and the Low Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: KPBoynton **Team Leader:** Doug Meyers

BCMazur
DRMeyers
GTShultz
JRFox
ERMathews
DALynd
RTBlumenstock

Approvals:

Electric Reliability & Support Lead	Douglas R Meyers	Required
LVD System Engineer	Gregory T Schultz	Required
Director, LVD Circuit Planning	Julia A Fox	Required
Director, HVD System Planning	Edward R Mathews	Required
Director, LVD System Planning	Donald A Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	N/A



BRIAN C. MAZUR

From: SPAdvisor
Sent: Monday, May 17, 2021 9:16 AM
To: BRIAN C. MAZUR
Cc: BRIAN C. MAZUR; Ivan Principe; Edward R. Mathews; ARIC L. ROOT; Benjamin T. Scott; Gregory E. Kral; Jacob D. Roberson; KIMBERLY P. BOYNTON
Subject: Approval has completed on 22-0064 Sonoma (0.72 Miles) 46 kV HVD Lines Reliability Rebuild.

Approval has completed on 22-0064 Sonoma (0.72 Miles) 46 kV HVD Lines Reliability Rebuild.

Approval on 22-0064 Sonoma (0.72 Miles) 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 5/6/2021 2:56 PM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 5/7/2021 8:38 AM
Comment:

Approved by GREGORY T. SCHULTZ on 5/10/2021 12:57 PM
Comment: Approved

Approved by JULIA R. FOX on 5/10/2021 5:31 PM
Comment:

Approved by Edward R. Mathews on 5/12/2021 10:00 AM
Comment:

Approved by DONALD A. LYND on 5/17/2021 9:01 AM
Comment: Approved for LVD

Approved by RICHARD T. BLUMENSTOCK on 5/17/2021 9:16 AM
Comment: Approved.

View the workflow history.

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ERMathews
JRFox
DALynd
RTBlumenstock

Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0077

Project: **Greenville 46 kV Line – HVD Lines Reliability Rebuild and Pole Top Rehabilitation** **County:** Ionia

Date: April 21, 2021 **Need System Changes By:** 12/31/2022

Problem Description:

Line performance data over the past five years has shown the Greenville 46 kV line to be underperforming. The Greenville 46 kV line, constructed in sections between 1945 and 1982, has experienced three outage and five momentary incidents between 2015 and 2019. Two of the three outage and all five momentary incidents between 2015 and 2019 occurred in the 6.2 mile sections of the 20B, 20K, 20M and 20O lines. The 1.8 mile section of the 20B line is non-standard 1/0 copper conductor and unshielded construction while the remaining 4.4 miles in the 20K, 20M and 20O sections of line are standard shielded construction with standard ACSR conductors.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Top Rehabilitation of the line. *Conceptual cost: $558,000*
3. Pole Top Rehabilitation of 4.4 miles and Rebuild 1.8 miles of the Greenville 46 kV line. *HVD Conceptual cost: $1,206,000 and LVD Conceptual cost: $236,000*

Recommended Alternative:

Alternative #3 is recommended. A combination of pole top rehabilitation and rebuild of this line is needed to improve overall system reliability and improve reliability for approximately 6,000 customers served from the Greenville 46 kV line. HVD lines that meet modern construction and design standards and have standard conductors, like the 20K, 20M and 20O sections of this one, are candidates for pole top rehabilitation versus a complete rebuild. The 1.8 mile section of the 20B line with non-standard 1/0 copper conductor and unshielded construction will need to be rebuilt to avoid further investment in pole replacements or pole top rehabilitation on a non-standard line.

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Outage data has shown that after completing a rebuild or pole top rehabilitation, as necessary, a line typically has zero or minimal line equipment related outages.

Alternative #1 does not address the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 does address the pole top assemblies along the entire route, increasing reliability of the line, but does not address the non-standard 1/0 copper conductor or unshielded construction on the 1.8 mile section of the 20B line.

Alternative #3 Recommended Scope:
Rebuild the 1.8 mile section of the Greenville 46 kV line from structure #605 to structure #642 with single circuit 336.4 ACSR conductor built on the existing centerline, also complete a pole top rehabilitation on the entire 20K and 20M line sections and the 20O line section from structure #300 to structure #320. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$804,000	$1,206,000	Rebuild 1.8 miles and complete a pole top rehabilitation on 4.4 miles of the Greenville 46 kV line
ED-95719	$158,000	$236,000	LVD Underbuild Line Relocation Peck Rd Sub – Ore-Ida Ckt 1.0 miles
Customer Contribution	$0	$0	
Total	$962,000	$1,442,000	Grand Total Cost with Overheads: **$1,442,000**

Present Need: On approval, this document authorizes the Electric Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

BCMazur
DRMeyers
GTSchultz
ERMathews
JRFox
DALynd
RTBlumenstock

Prepared By: LBHincka **Team Leader:** Doug Meyers

Approvals:

Senior Engineer Lead, LVD Circuit Planning	Jennifer M. Partlan	Required
Director, HVD System Planning	Edward R. Mathews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required

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GTSchultz
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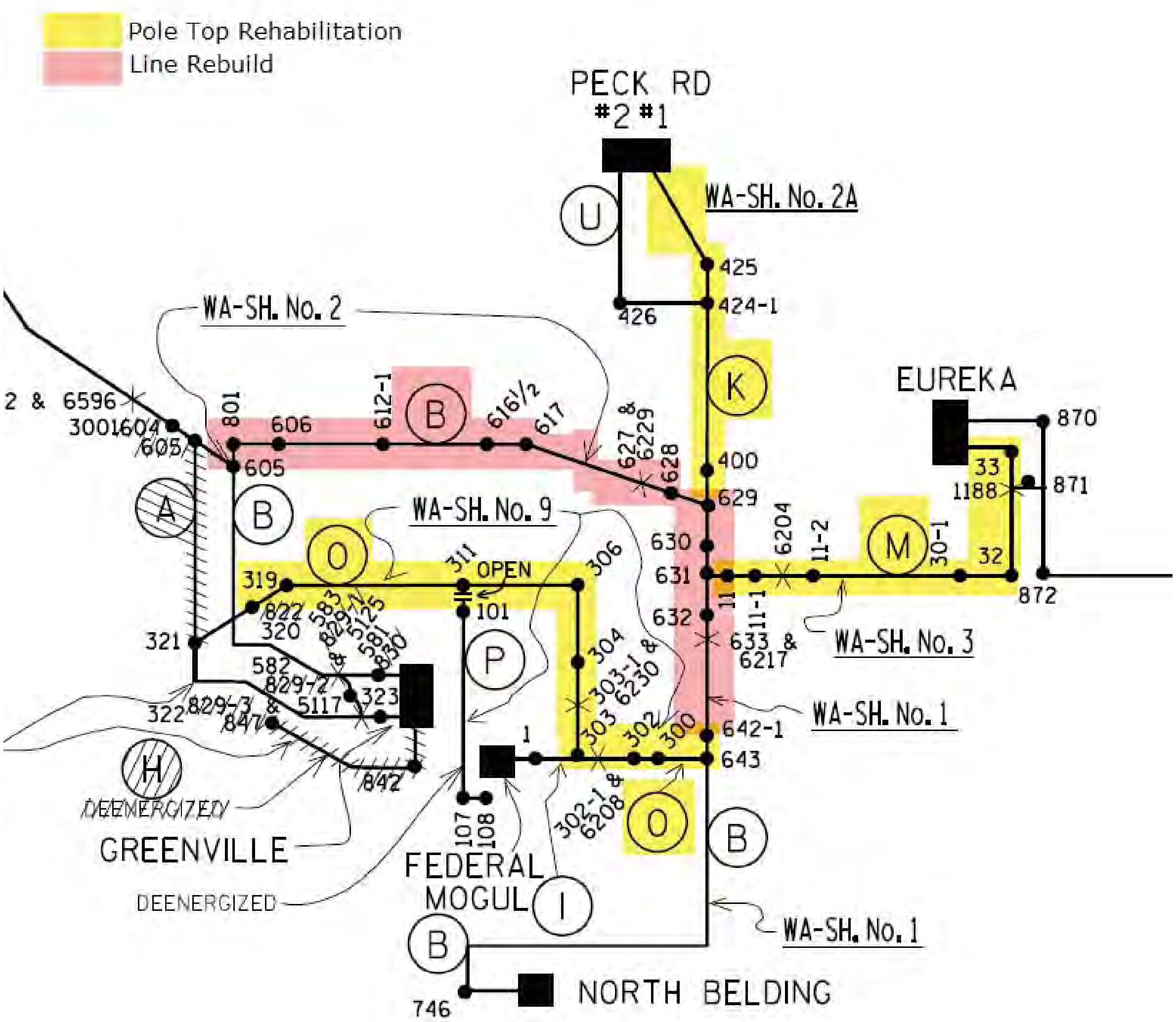

BRIAN C. MAZUR

From: SPAdvisor
Sent: Tuesday, April 27, 2021 11:51 AM
To: BRIAN C. MAZUR
Cc: BRIAN C. MAZUR; Ivan E. Principe; Edward R. Mathews; ARIC L. ROOT; Benjamin T. Scott; Gregory E. Kral; Jacob D. Roberson; LOUIS B. HINCKA
Subject: Approval has completed on 22-0077 Greenville 46 kV HVD Lines Reliability Rebuild and Pole Top Rehabilitation.

Approval has completed on 22-0077 Greenville 46 kV HVD Lines Reliability Rebuild and Pole Top Rehabilitation.

Approval on 22-0077 Greenville 46 kV HVD Lines Reliability Rebuild and Pole Top Rehabilitation has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 4/22/2021 9:35 AM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by Jennifer M Partlan on 4/22/2021 10:34 AM
Comment:

Approved by Edward R. Mathews on 4/26/2021 2:54 PM
Comment:

Approved by JULIA R. FOX on 4/27/2021 7:34 AM
Comment:

Approved by DONALD A. LYND on 4/27/2021 10:37 AM
Comment: Approved for LVD

Approved by RICHARD T. BLUMENSTOCK on 4/27/2021 11:50 AM
Comment: Approved.

View the workflow history.

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0074

Project: **Dietz-Gaylord 46 kV Line – HVD Lines Reliability Rebuild** **County:** Charlevoix

Date: April 21, 2021 **Need System Changes By:** 12/31/2022

Problem Description:

Line performance data over the past five years has shown the Dietz-Gaylord 46 kV line to be underperforming. The Dietz-Gaylord 46 kV line, originally installed pre-World War 2, has experienced 6 outage incidents between 2015 and 2019. The line is constructed with 3/0 ACSR conductor in an unshielded configuration. Recent increases in outage frequency has created customer dissatisfaction and complaints.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Top Rehabilitation of the line. *Conceptual cost: $216,000*
3. Rebuild 2.4 miles of the Dietz-Gaylord 46 kV line and convert the 6152 ABS into a MOABS. *HVD Conceptual cost: $1,215,000 and LVD Conceptual cost: $140,000*

Recommended Alternative:

Alternative #3 is recommended. Rebuild of this line and converting the 6152 ABS into a MOABS is needed to improve overall system reliability and for the approximately 285 customers served from the Dietz-Gaylord 46 kV line. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like this line section, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Converting the 6152 ABS will limit the extended outages seen by the customers of the Boyne Mtn sub, by reducing the exposure of the line by 15.2 miles.

Alternative #1 does not address the reliability of the system on this line and would result

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in a continual decrease in reliability.

Alternative #2 does not address the aged conductor, poles or the unshielded configuration of the line.

Alternative #3 Recommended Scope:
Rebuild the 2.4 mile section of the Dietz-Gaylord 46 kV line from Dietz Substation to Boyne Mtn substation with single circuit 336.4 ACSR conductor built on the existing centerline with poles that will accommodate underbuild circuit. Convert the existing 6152 ABS into a MOABS. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$810,000	$1,215,000	Rebuild the Dietz-Gaylord 46 kV line and add MOABS
ED-95719	$94,000	$140,000	LVD Underbuild Line Relocation Boyne Mtn Sub - Mountain Lodge Ckt 1.5 miles
Customer Contribution	$0	$0	
Total	$904,000	$1,355,000	Grand Total Cost with Overheads: **$1,355,000**

Present Need: On approval, this document authorizes the Electric Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka **Team Leader:** Doug Meyers

Approvals:

Senior Engineer Lead, LVD Circuit Planning	John P. Brack	Required

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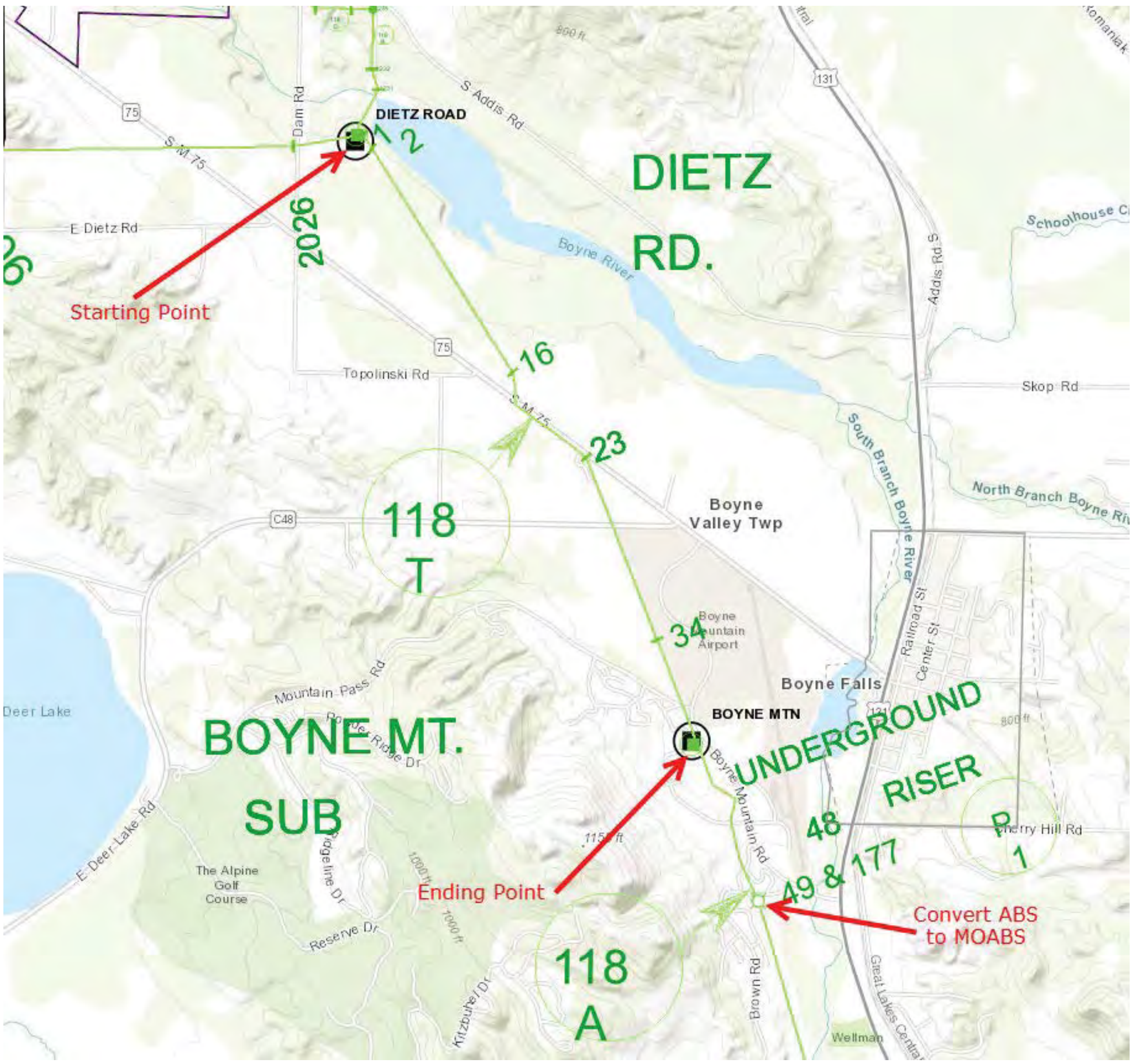
JPBrack
JRFox
DALynd
ERMathews
RTBlumenstock

Director, HVD System Planning	Edward R. Mathews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	N/A



BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Wednesday, May 5, 2021 3:55 PM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan Principe; Edward R. Mathews; ARIC L. ROOT; Benjamin T. Scott; Gregory E. Kral; Jacob D. Roberson; LOUIS B. HINCKA
Subject:	Approval has completed on 22-0074 Dietz-Gaylord 46 kV HVD Lines Reliability Rebuild.

Approval has completed on 22-0074 Dietz-Gaylord 46 kV HVD Lines Reliability Rebuild.

Approval on 22-0074 Dietz-Gaylord 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 4/22/2021 9:28 AM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by JOHN P. BRACK on 4/29/2021 2:28 PM
Comment:

Approved by Edward R. Mathews on 4/30/2021 8:47 AM
Comment:

Approved by JULIA R. FOX on 5/5/2021 8:15 AM
Comment:

Approved by DONALD A. LYND on 5/5/2021 3:49 PM
Comment: Approved for LVD

Approved by RICHARD T. BLUMENSTOCK on 5/5/2021 3:54 PM
Comment: Approved.

View the workflow history.

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0075

Project: **Saranac 46 kV Line – HVD Lines Reliability Rebuild and Pole Top Rehabilitation** **County:** Ionia

Date: April 21, 2021 **Need System Changes By:** 12/31/2022

Problem Description:

Line performance data over the past five years has shown the Saranac 46 kV line to be underperforming. The Saranac 46 kV line, constructed in 1949, has experienced four outage incidents between 2015 and 2019. Three of the four outage incidents between 2015 and 2019 occurred in the 9.8 mile section of the 111A line between structures 369 and 243. Presently this line is shielded 3/0 ACSR conductor construction, but a 2.3 mile section of the line has an extended history of conductor failures, with four conductor failures occurring over the last ten years.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Pole Top Rehabilitation of the line. *Conceptual cost: $882,000*
3. Pole Top Rehabilitation of 7.5 miles and Rebuild 2.3 miles of the Saranac 46 kV line. *HVD Conceptual cost: $1,710,000 and LVD Conceptual cost: $150,000*

Recommended Alternative:

Alternative #3 is recommended. A combination of pole top rehabilitation and rebuild of this line is needed to improve overall system reliability and improve reliability for approximately 4,900 customers served from the Saranac 46 kV line. HVD lines that meet modern construction and design standards and have standard conductors, like this one, are candidates for pole top rehabilitation versus a complete rebuild. The 2.3 mile section of line with multiple conductor failures will need to be rebuilt to avoid further conductor failures. Outage data has shown that after completing a rebuild or pole top rehabilitation, as necessary, a line typically has zero or minimal line equipment related outages.

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Alternative #1 does not address the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 does address the pole top assemblies along the entire route, increasing reliability of the line, but does not address the conductor failures seen on the 2.3 mile section of line.

Alternative #3 Recommended Scope:

Rebuild the 2.3 mile section of the Saranac 46 kV line from structure #243 to structure #272 with single circuit 336.4 ACSR conductor built on the existing centerline, also complete a pole top rehabilitation from structure #273 to structure 369. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$1,140,000	$1,710,000	Rebuild 2.3 miles and complete a pole top rehabilitation on 7.5 miles of the Saranac 46 kV line
ED-95719	$100,000	$150,000	LVD Underbuild Line Relocation Clarksville Sub – Clarksville Ckt 0.64 miles
Customer Contribution	$0	$0	
Total	$1,240,000	$1,860,000	Grand Total Cost with Overheads: **$1,860,000**

Present Need: On approval, this document authorizes the Electric Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

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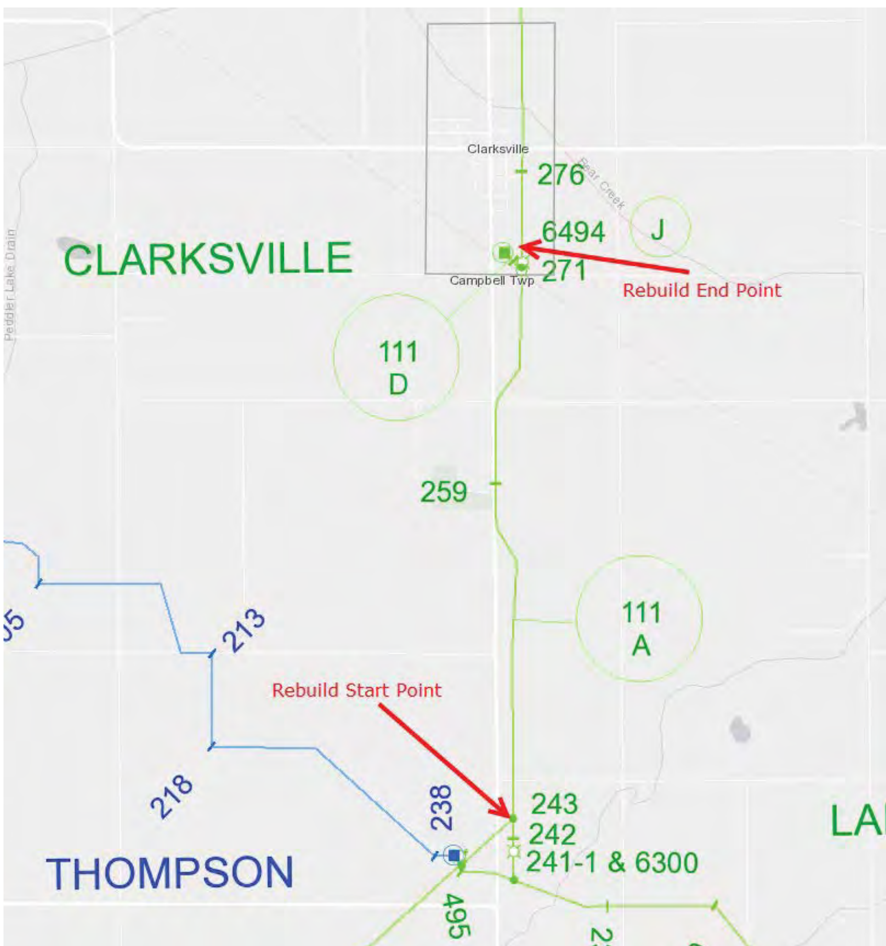
Prepared By: LBHincka **Team Leader:** Doug Meyers

Approvals:

Senior Engineer Lead, LVD Circuit Planning	Gregory T. Schultz	Required
Director, HVD System Planning	Edward R. Mathews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required



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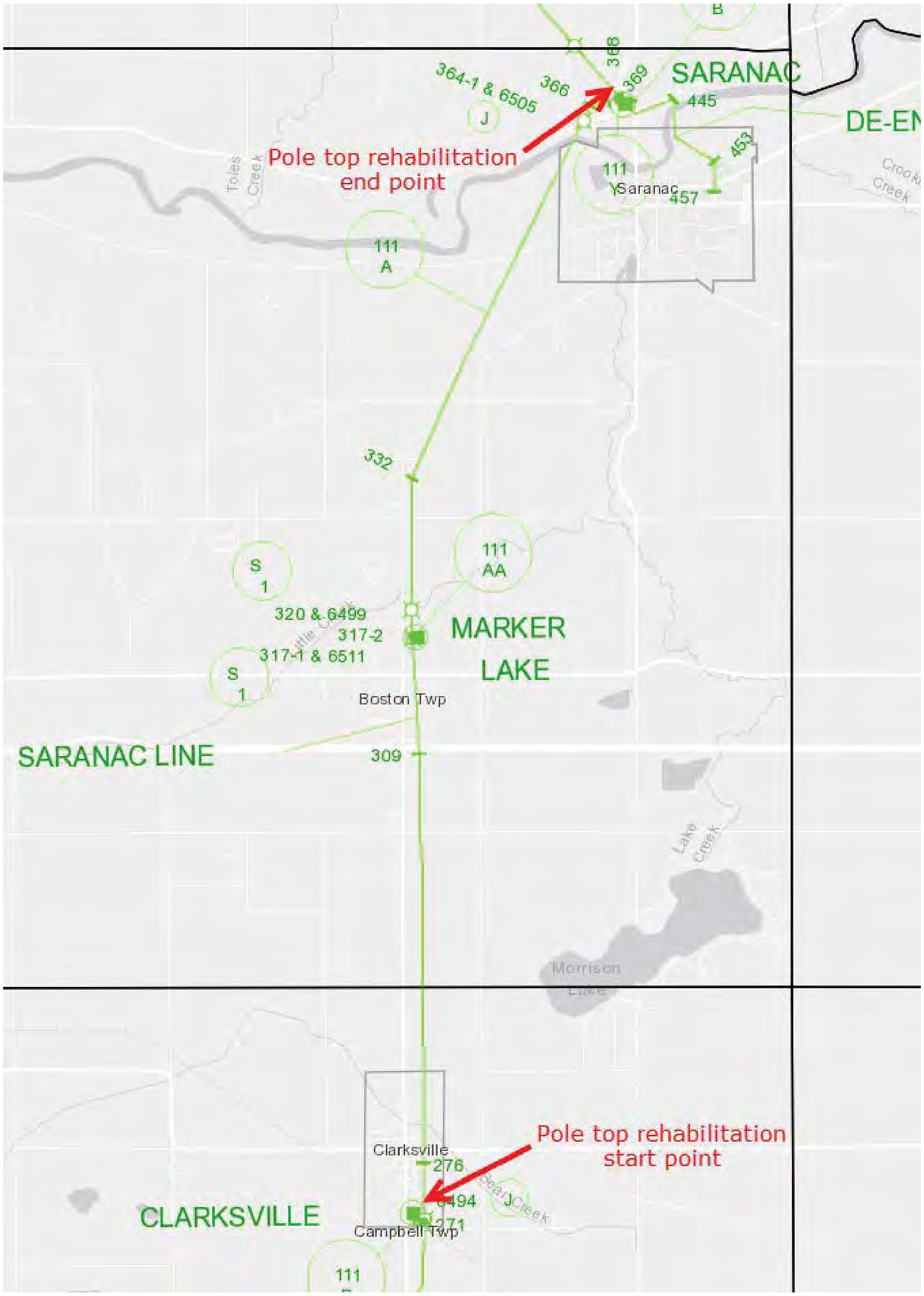

BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Wednesday, May 5, 2021 4:07 PM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan Principe; Edward R. Mathews; ARIC L. ROOT; Benjamin T. Scott; Gregory E. Kral; Jacob D. Roberson; LOUIS B. HINCKA
Subject:	Approval has completed on 22-0075 Saranac 46 kV HVD Lines Reliability Rebuild and Pole Top Rehabilitation.

Approval has completed on 22-0075 Saranac 46 kV HVD Lines Reliability Rebuild and Pole Top Rehabilitation.

Approval on 22-0075 Saranac 46 kV HVD Lines Reliability Rebuild and Pole Top Rehabilitation has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 4/22/2021 9:31 AM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by GREGORY T. SCHULTZ on 5/3/2021 1:09 PM
Comment: Approved

Approved by Edward R. Mathews on 5/3/2021 1:54 PM
Comment:

Approved by JULIA R. FOX on 5/5/2021 8:19 AM
Comment:

Approved by DONALD A. LYND on 5/5/2021 3:58 PM
Comment: Approved for LVD

Approved by RICHARD T. BLUMENSTOCK on 5/5/2021 4:07 PM
Comment: Approved.

View the workflow history.

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0052

Project: **Goodale 46 kV Line – HVD Lines Reliability Rebuild** **County:** Calhoun

Date: January 16, 2020 **Need System Changes By:** 6/1/2021

Problem Description:

The Goodale 46 kV line has experienced 4 outage incidents between 2014 and 2018 and is among the worst performing HVD lines by SAIDI. See attached HVD Lines Worst SAIDI 2014-2018. One of the four outage incidents between 2014 and 2018 occurred in this 2.9 mile section of the Goodale line. The line was constructed in 1926 and is non-standard 115kCMIL copper conductor with non-standard LE50 towers. HVD lines that are presently non-standard construction (unshielded or non-standard conductor), like these line sections, are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild 2.9 miles of the Goodale 46 kV line. *Conceptual cost: $1,324,000*

Recommended Alternative:

Alternative #2 is recommended. Rebuild of this line is needed to improve overall system reliability and improve reliability for approximately 9600 customers served from the Goodale 46 kV line. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Rebuild also replaces the older non-standard conductor with modern standards and design.

Alternative #1 does not address the towers that need replacement or the reliability of the system on this line and would result in a continual decrease in reliability.

Alternative #2 Recommended Scope:

Rebuild the 2.9-mile section of the Goodale 46 kV line from Verona Substation to

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Goodale Substation with single circuit 336.4 ACSR conductor on existing centerline on existing easements. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

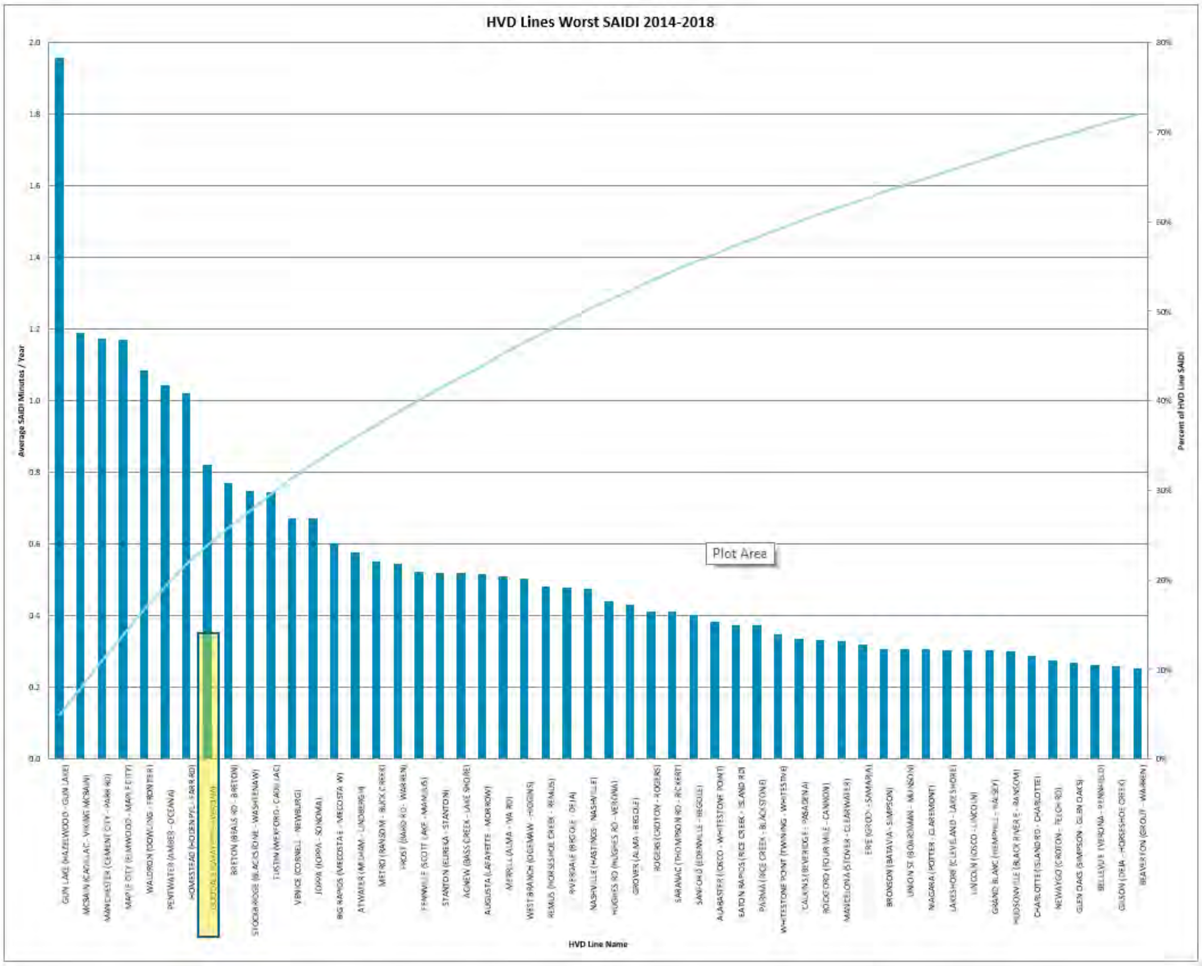
WBS Element	2021 Direct Cost	2021 Cost with Overheads	Description
EH-95308	$870,000	$1,324,000	Rebuild Goodale 46 kV line
Project Total	$870,000	$1,324,000	
Customer Contribution	$0	$0	
Total	$870,000	$1,324,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka/ALRoot **Team Leader:** Doug Meyers

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	N/A


HVD Lines Worst SAIDI 2014-2018
Average SAIDI Minutes / Year
Percent of HVD Line SAIDI
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
0%
10%
20%
30%
40%
50%
60%
70%
80%
Plot Area
HVD Line Name

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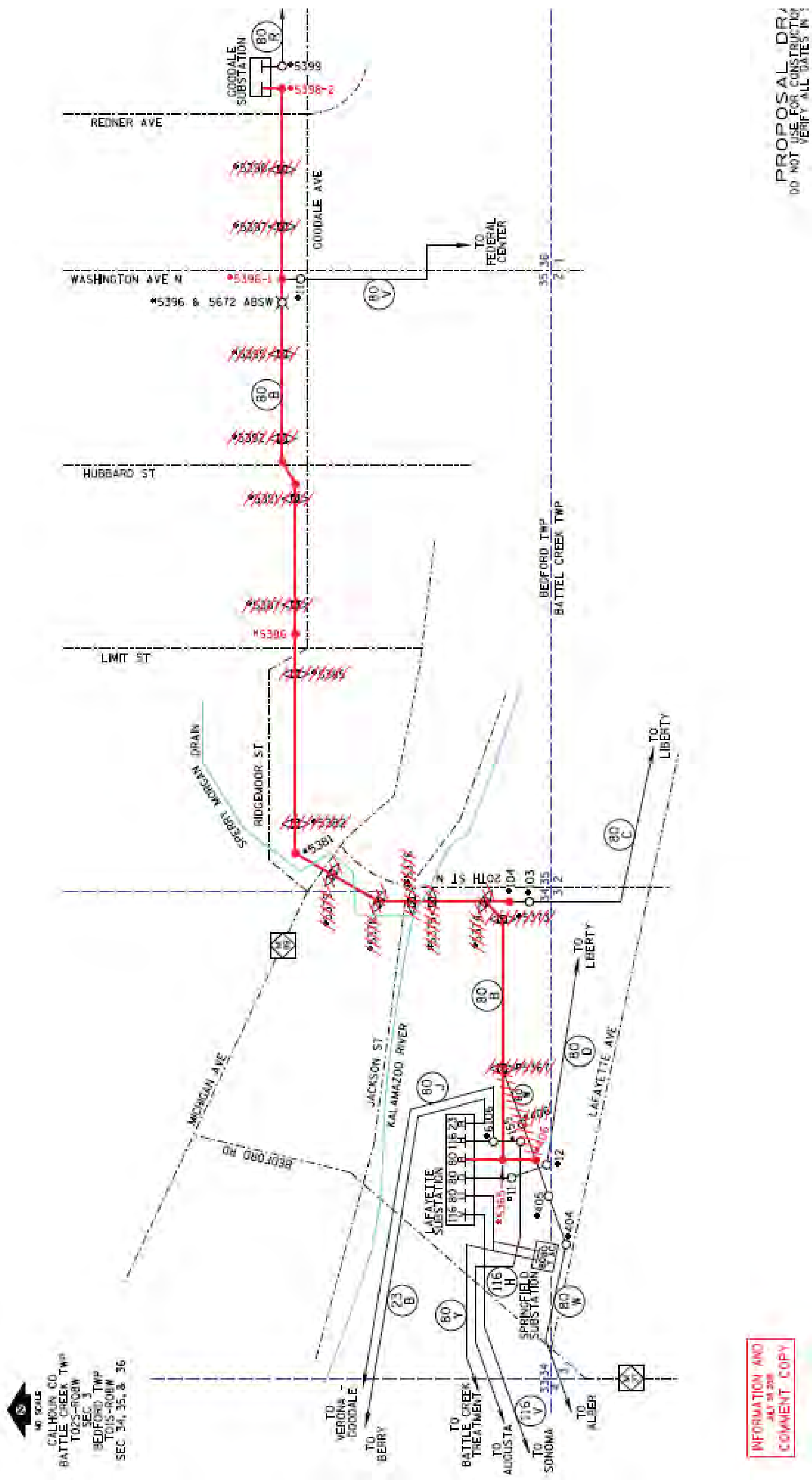

From:	SPAdvisor
To:	Edward R. Mathews
Cc:	BRIAN C. MAZUR; Brian M. Bushey; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; LOUIS B. HINCKA
Subject:	Approval has completed on 21-0052 Goodale 46 kV HVD Lines Reliability Rebuild.
Date:	Friday, January 17, 2020 4:50:22 PM

Approval has completed on 21-0052 Goodale 46 kV HVD Lines Reliability Rebuild.

Approval on 21-0052 Goodale 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by Edward R. Mathews on 1/16/2020 12:55 PM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/16/2020 2:41 PM
Comment:

Approved by DWAYNE C. PARKER on 1/16/2020 4:24 PM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 1/17/2020 3:53 PM
Comment: Approved.

Approved by Timothy J. Sparks on 1/17/2020 4:50 PM
Comment: Approved.

View the workflow history.

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 22-0065

Project: **Cement City North 46 kV Line – HVD Lines Reliability Rebuild** **County:** Jackson

Date: March 29, 2021 **Need System Changes By:** 12/31/2022

Problem Description:

The Cement City (025J) 46 kV line from structure #970 to #170 were installed between 1955 to 1973. There have been 3 outage incidents on the line between 2016 and 2020. Currently this line is non-standard unshielded 4/0 copper conductor construction. HVD lines that are non-standard construction (unshielded or non-standard conductor), like this section of line, are candidates for a rebuild versus further investment in pole replacements or pole top rehabilitation.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild 1.46 miles of 025J line. HVD *Conceptual cost: $678,900 and* LVD *Conceptual cost: $20,000*

Recommended Alternative:

Alternative #2 recommended. Rebuilding the 1.46 miles of 025J line is needed to improve the overall system reliability. Outage data has shown that after completing a rebuild, a line typically has zero or minimal line equipment related outages. A rebuild will also replace the older conductor with modern standards and design.

Alternative #1 does not address the poles, crossarms and insulators on the line that needs to be replaced or the reliability of the system on the line and would result in a continual decrease in reliability.

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Alternative #2 Recommended Scope:

Alternative #2 is recommended. Rebuild 1.46 miles of the Cement City 46 kV 025J line from structure #970 to #170. The HVD will Utilize single circuit 336.4 ACRS conductor and OPGW shield wire on the existing or a combination of existing easements and newly obtained easements as needed. The LVD will Utilize 1/0 ACRS conductor on the four 3-phase locations on the line and #4 ACRS conductor on the eight single-phase locations on the line.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2022 Direct Cost	2022 Cost with Overheads	Description
EH-95308	$438,000	$678,900	Rebuild 1.46 miles of the Cement City 46 kV 025J line
ED-95719	$12,900	$20,000	Rebuild 0.54 miles of the LVD Underbuild (025J) Micor substation, Wellworth circuit
Project Total	$450,900	$698,900	
Customer Contribution	$0	$0	
Total	$450,900	$698,900	

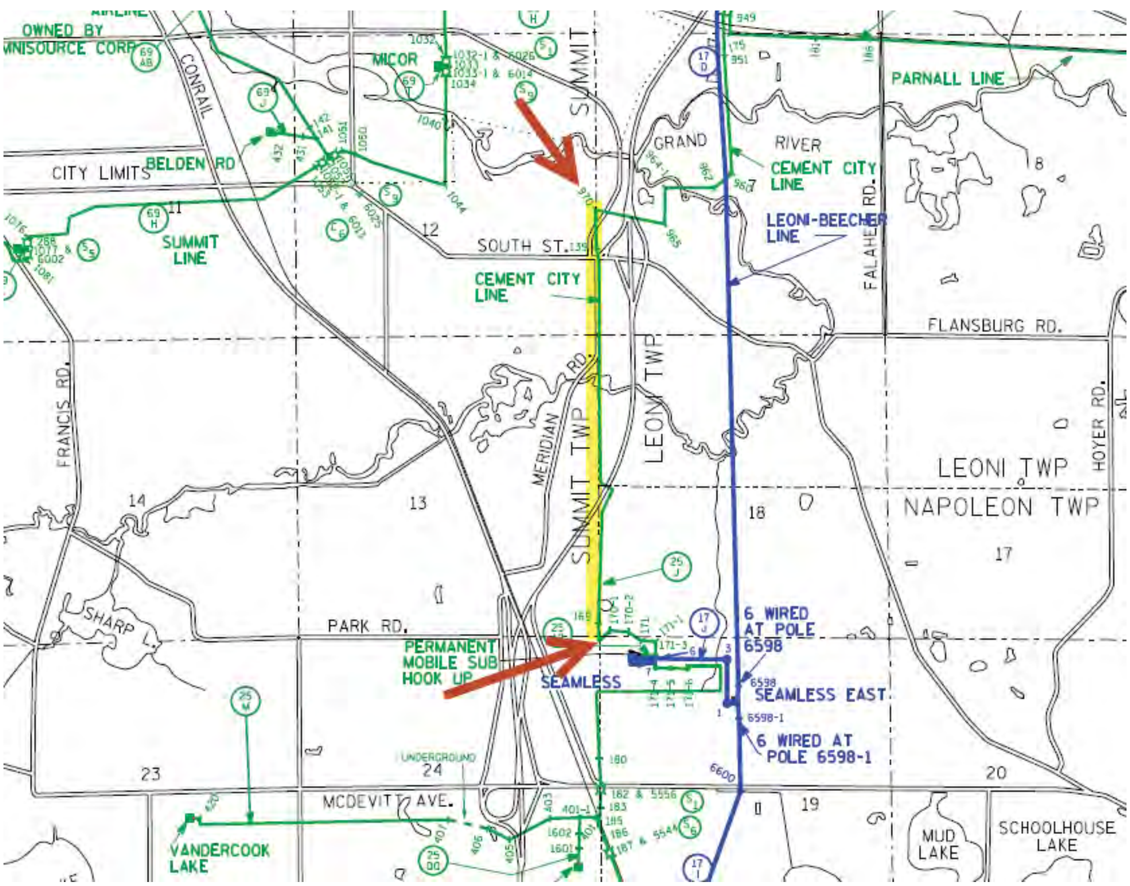
Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group and the Low Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: KPBoynton **Team Leader:** Doug Meyers

BCMazur
DRMeyers
MALabrie
JRFox
ERMathews
DALynd
RTBlumenstock

Approvals:

Electric Reliability & Support Lead	Douglas R Meyers	Required
LVD System Engineer	Michael A Labrie	Required
Director, LVD Circuit Planning	Julia A Fox	Required
Director, HVD System Planning	Edward R Mathews	Required
Director, LVD System Planning	Donald A Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	N/A



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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0026

Project: **Van Slyke #1/Chevy #4/Atherton 46 kV Lines – HVD Lines Reliability Rebuild** **County:** Genesee

Date: February 6, 2020 **Need System Changes By:** 12/31/2021

Problem Description:

Presently the 46 kV line corridor between Hemphill Substation and structure #453 is a non-standard, four circuit structure construction with a mixture of conductor types and circuits, including a de-energized circuit. The circuits sharing common structures include the Atherton (97A) 46 kV line, Chevy #4 (105R) 46 kV line, a six-wired section of the Van Slyke #1 (97F) 46 kV line and a section of the de-energized Chevy #1 (43C) 46 kV line. The structures in this section of line were constructed beginning in approximately 1946. Efforts to address pole-top issues on these circuits have been hampered due to lack of adequate access to some structures and electrical clearance issues created by the non-standard design of these multiple circuit structures. On 12/20/2019, a car-pole accident caused a pole fire at structure #407 in this line section (see attached pictures). All circuits in this section had to be de-energized simultaneously in order to provide proper clearance to make repairs to this structure. This was challenging from an operational standpoint and increased risk of further outages to the Flint area. The Van Slyke #1 46 kV line connects to Van Slyke substation, which is a dedicated substation serving GM's Flint Assembly Operations. Due to the design and location of the line, installation of fiber optic cables in this section of line is not feasible. The cables are necessary for communication between Van Slyke and Hemphill substations and would replace the analog phone lines that are being retired by the communication company. The 2.5 mile section of the Van Slyke #1 line that is not within this corridor has also been approved for rebuild under separate concept (CA #21-0054) due to similar access and non-standard design issues. Finally, the section of the Chevy #4 46 kV line between structure #453 and Aldrich Substation is presently double circuit construction with a de-energized circuit. HVD lines that are presently non-standard construction like these line sections are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard

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line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Rebuild the 2.5-mile multiple circuit section of the Van Slyke #1/ Chey #4 /Atherton/Chevy #1 46 kV lines between Hemphill Substation and Aldrich Substation. *Conceptual cost: $3,806,000*

Recommended Alternative:

Alternative #2 is recommended. Rebuild of this line corridor to present design standards is needed to improve operational flexibility, allow maintenance to be performed on these lines in the future and allow for the addition of fiber optic communication cable. In addition, rebuild of this corridor will improve reliability of the overall system and for the approximately 600 customers served from Atherton Substation. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Rebuild also replaces the older non-standard conductor with modern standards and design.

Alternative #1 does not address the need for operational flexibility to perform maintenance on the lines in this corridor or the need for fiber optic communication and would result in a continual decrease in reliability.

Alternative #2 Recommended Scope:

Rebuild the Van Slyke #1, Chevy #4 and Atherton 46 kV lines from Hemphill Substation to Structure #398. Also rebuild the Van Slyke #1 and Chevy #4 46 kV lines from Structure #398 to structure #453. Finally, rebuild the Chevy #4 46 kV line from structure #453 to Aldrich Substation. Total rebuild length is approximately 2.5 miles. Rebuild in the same corridor as the existing circuits but with standard single or double-circuit structures and 336.4 ACSR conductor. Also include fiber optic communication line. See attached map.

METC facilities are not required for this project.

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Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2021 Cost with Overheads	Description
EH-95308	$2,540,000	$3,806,000	Rebuild 2.5-mile section of the Van Slyke #1, Chevy #4 and Atherton Lines
Project Total	$2,540,000	$3,806,000	
Customer Contribution	$0	$0	
Total	$2,540,000	$3,806,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: KPBoynton/ALRoot **Team Leader:** Doug Meyers

Approvals:

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	N/A

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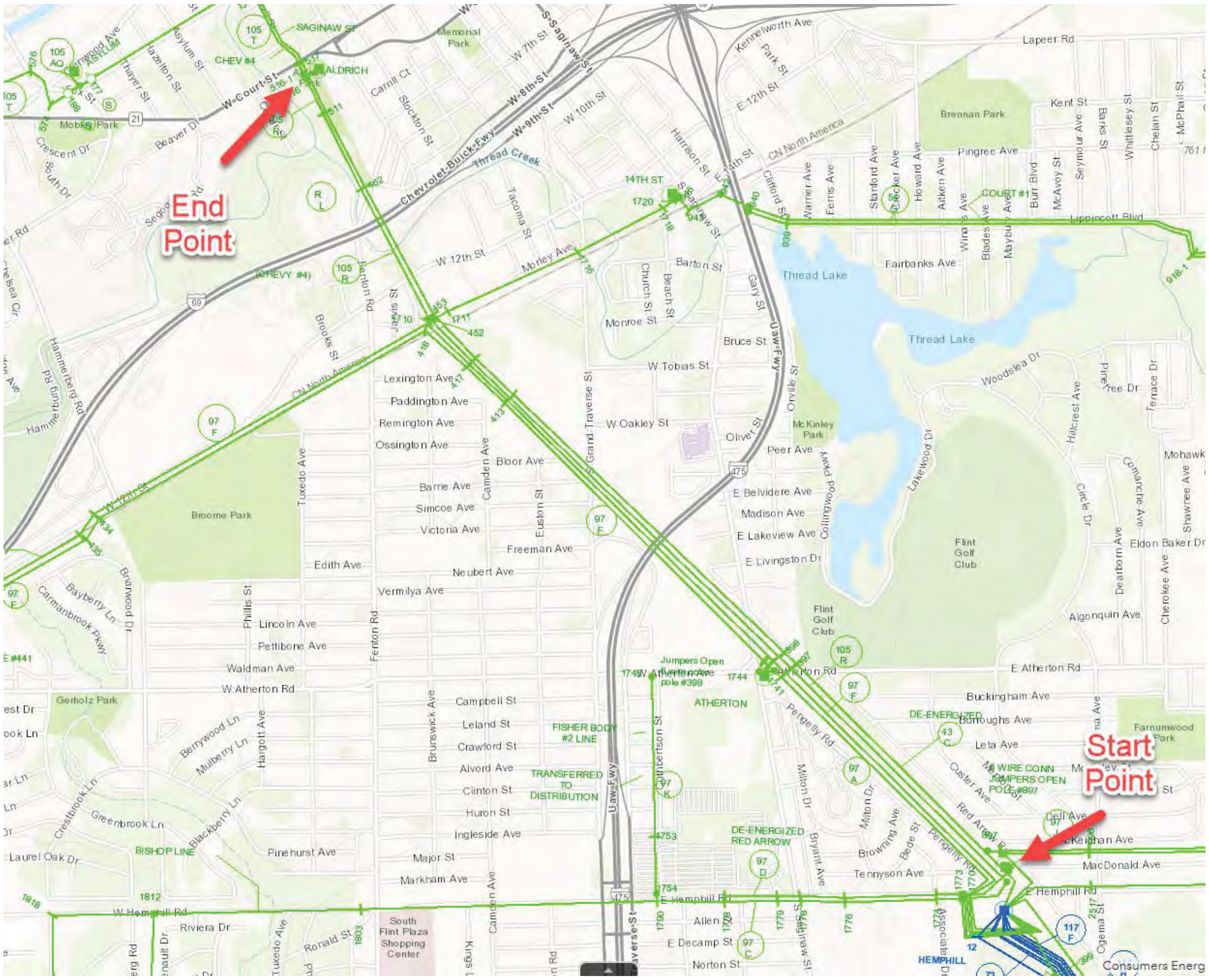
RTBlumenstock
TJSparks



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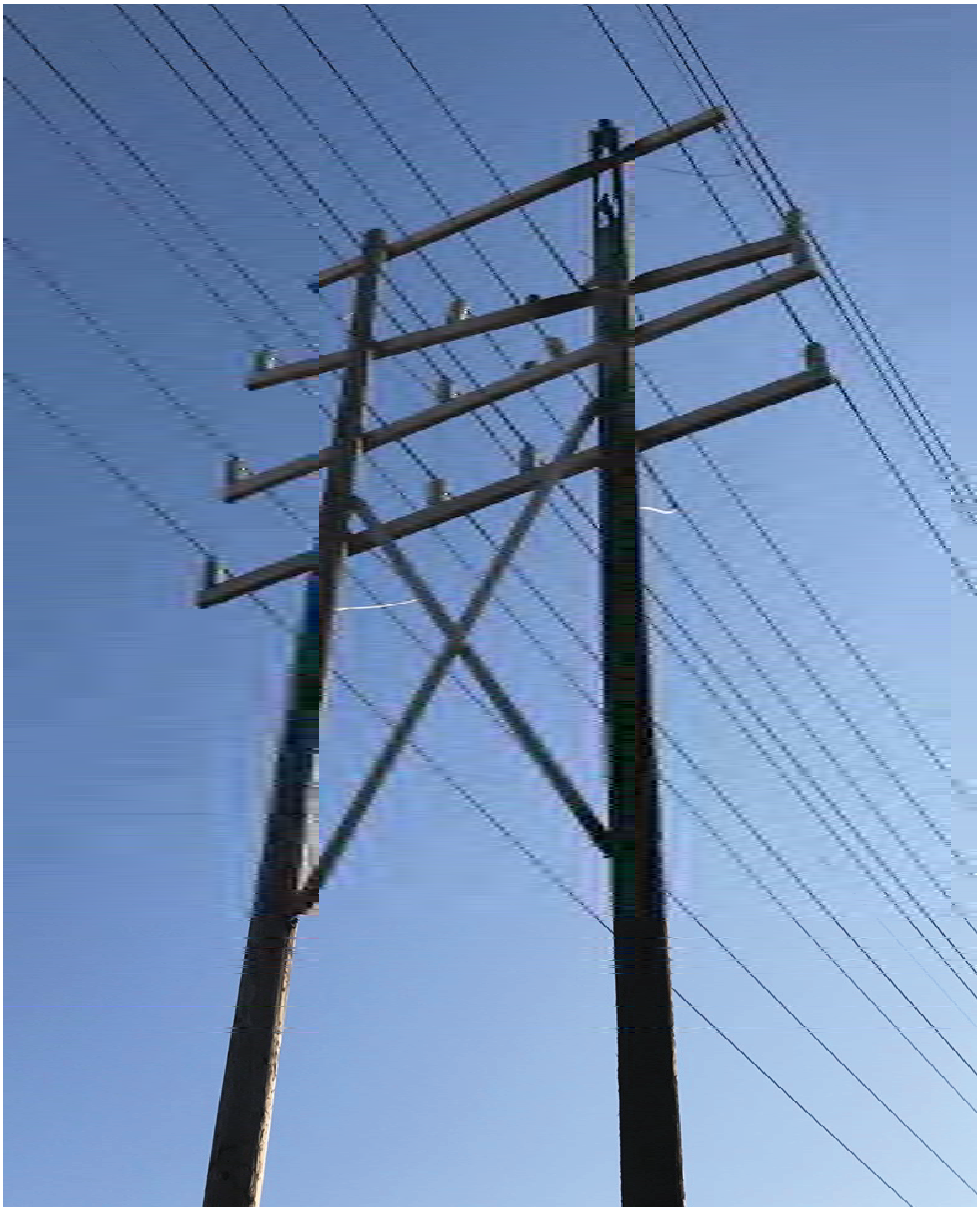
DRMeyers
DCParker
RTBlumenstock
TJSparks



Structure #407 showing damage resulting from a car-pole accident and subsequent pole fire on 12/20/2019. All circuits had to be de-energized to make repairs.

From:	SPAdvisor
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; KIMBERLY P. BOYNTON
Subject:	Approval has completed on 21-0026 Van Slyke 46 kV HVD Lines Reliability Rebuild.
Date:	Tuesday, February 18, 2020 9:04:51 AM

Approval has completed on 21-0026 Van Slyke 46 kV HVD Lines Reliability Rebuild.

Approval on 21-0026 Van Slyke 46 kV HVD Lines Reliability Rebuild has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 2/7/2020 8:07 AM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $5,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 2/7/2020 8:42 AM
Comment:

Approved by DWAYNE C. PARKER on 2/18/2020 7:58 AM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 2/18/2020 8:22 AM
Comment: Approved.

Approved by Timothy J. Sparks on 2/18/2020 9:04 AM
Comment: Approved.

View the workflow history.

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Consumers Energy
HVD System Planning
CONCEPT APPROVAL

Concept Number: 21-0054

Project: **Van Slyke #1 46 kV Line– HVD Lines Reliability Reroute** **County:** Genesee

Date: January 17, 2020 **Need System Changes By:** 12/31/2021

Problem Description:

The section of the Van Slyke #1 46 kV line between structure #398 and structure #444 was constructed in 1945. Presently the majority of this line section is non-standard, six-wire construction. Efforts to address pole-top issues on this circuit have been hampered due to clearance issues created by the non-standard design of this multiple wire circuit and the location of the structures near a heavily used railroad track. Due to the design and location of the line, installation of fiber optic cables in this section of line is not possible. The cables are necessary for communication between the connected substations and would replace the analog phone lines that are being retired by the communication company. HVD lines that are presently non-standard construction like these line sections are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation on a non-standard line.

Alternative Solutions:

1. Do nothing. *Conceptual cost: $0*
2. Relocate the existing 2.5-mile six-wire construction section of the Van Slyke #1 46 kV line to a new 2.1 mile corridor along Atherton and Van Slyke Roads utilizing single circuit 336 construction and fiber optic shield wire. *Conceptual cost: $1,005,000*

Recommended Alternative:

Alternative #2 is recommended. Rebuild of this line is needed to improve overall system reliability and to maintain reliable service to a major manufacturing customer. Outage data has shown that after completing a rebuild a line typically has zero or minimal line equipment related outages. Rebuild also replaces the older non-standard conductor with modern standards and design. The installation of a new line will also provide for the

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installation of fiber optic cables necessary to maintain communication paths between the Hemphill and Van Slyke substations. Alternative #2 also reduced the overall line length by 0.4 miles.

Alternative #1 does not address the poles and crossarms that need replacement, replacement of the communication path that will be lost when the existing phone lines are retired or the overall reliability of the system and would result in a continual decrease in reliability.

Alternative #2 Recommended Scope:
Relocate the existing 2.5-mile six-wire construction section of the Van Slyke #1 46 kV line to a new 2.1 mile corridor along Atherton and Van Slyke Roads utilizing single circuit 336 construction and fiber optic shield wire. See attached map.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2021 Direct Cost	2021 Cost with Overheads	Description
EH-95308	$660,000	$1,005,000	Rebuild 2.5-mile section of the Van Slyke #1, Chevy #4 and Atherton Lines
Project Total	$660,000	$1,005,000	
Customer Contribution	$0	$0	
Total	$660,000	$1,005,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: LBHincka/ALRoot **Team Leader:** Doug Meyers

Approvals:

BCMazur
DRMeyers
DCParker
RTBlumenstock
TJSparks
JFBrossoit

Director, HVD System Planning	Dwayne C. Parker	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required

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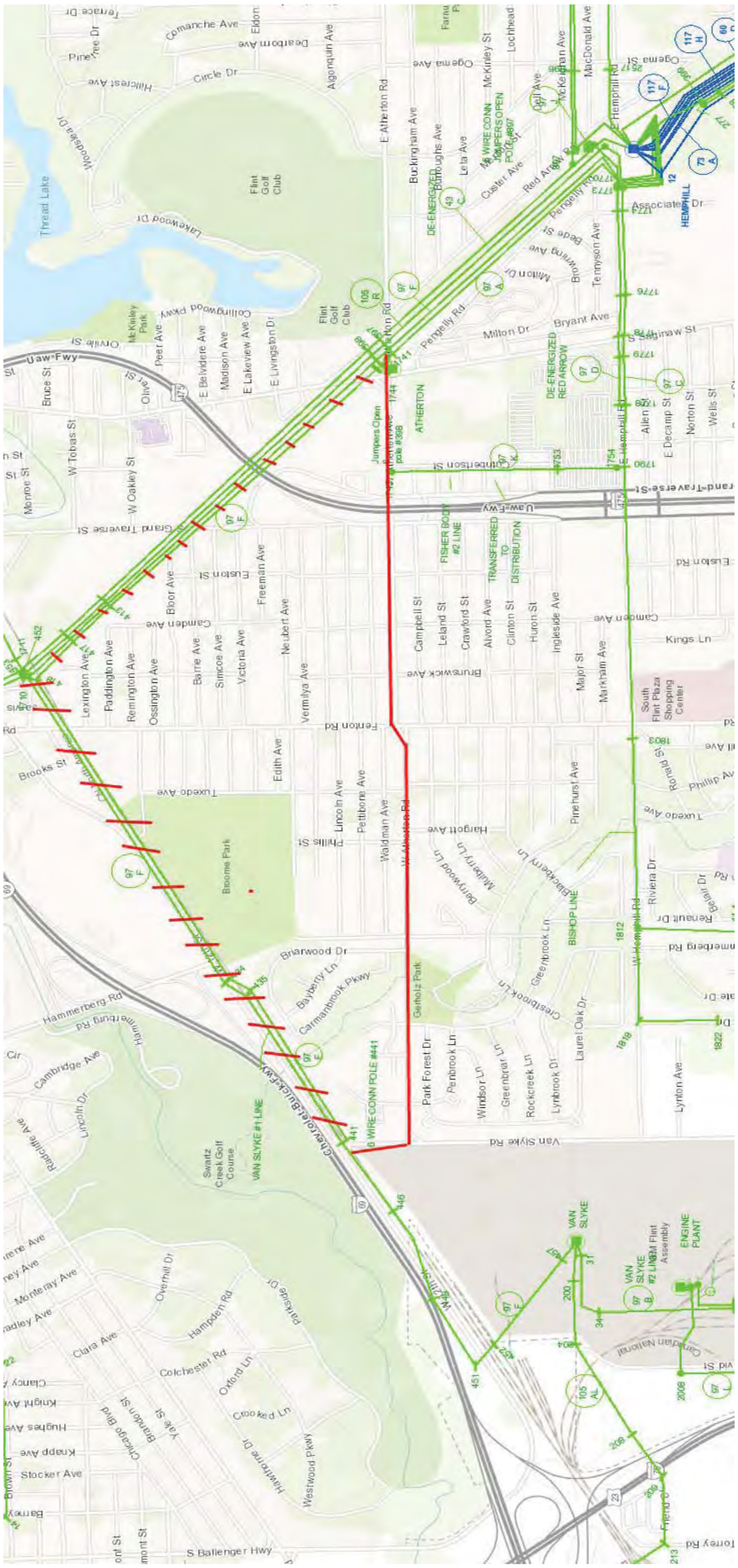

21-0054 Van Slyke 46 kV HVD Lines Reliability Reroute

From:	SPAdvisor
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; LOUIS B. HINCKA
Subject:	Approval has completed on 21-0054 Van Slyke 46 kV HVD Lines Reliability Reroute.
Date:	Wednesday, January 22, 2020 2:31:32 PM

Approval has completed on 21-0054 Van Slyke 46 kV HVD Lines Reliability Reroute.

Approval on 21-0054 Van Slyke 46 kV HVD Lines Reliability Reroute has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 1/17/2020 5:05 PM
Comment: A new document has been added to the HVD System Planning Project Collection under the approval limit of $2,000,000. Please view the document and approve or comment.

Approved by DOUGLAS R. MEYERS on 1/20/2020 11:15 AM
Comment:

Approved by DWAYNE C. PARKER on 1/21/2020 11:46 AM
Comment:

Approved by RICHARD T. BLUMENSTOCK on 1/21/2020 2:52 PM
Comment: Approved.

Approved by Timothy J. Sparks on 1/22/2020 2:31 PM
Comment: Approved.

View the workflow history.

Question:

6) Refer to Mr. Blumenstock's direct testimony, page 140, and Figure 42 on page 141. For each Line Rebuild project identified in Figure 42, please provide:

a. The cost of each project;
b. The date of each outage;
c. The duration of each outage;
d. The cause of each outage;
e. The Concept Approval (or other description and justification document) for each project; and
f. The number of customers affected by each outage.

Response:

Objection of Counsel: Consumers Energy Company objects to subparts a. and e. of this discovery request, which seek cost information and concept approvals for projects that were completed as long ago as 2009. Some of the requested concept approvals would pre-date 2009. Such information is irrelevant to this case, as even the most recent project was completed approximately four years ago, and these projects have been included for recovery in prior rate cases. Further objecting, the request is unduly burdensome and not proportional to the needs of this case.

The Company objects to subparts b., c., d., and f., on the basis that the requests are unduly burdensome and not proportional to the needs of this case.

Subject to the above objections, and without waiving them, the Company provides the following response:

The requested data and documents are not readily available.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 1, 2021

Electric Planning

Question:

15. Please refer to Concept Approvals for the HVD Lines Reliability Rebuilt projects, which were provided in Attachment 126 to Part III and in Attachment 2 in response to MEC-CE-880.
   a. Please explain in detail why HVD lines that are non-standard construction (unshielded or non-standard conductor) are candidates for rebuild versus further investment in pole replacements or pole top rehabilitation.
   b. Please explain how Consumers determines whether to rebuild or rehabilitate each candidate.
   c. Please identify each candidate for HVD line rebuild versus rehabilitation due to "non-standard construction," where the Company elected to rehabilitate rather than rebuild the HVD line.

Response:

a. HVD lines built with non-standard construction have a higher outage rate due to typically being in a deteriorated condition and utilizing outdated construction standards (i.e. unshielded conductor, small single layer conductor, or copper conductor). Pole top rehabilitation and pole replacement projects do not mitigate the increased outage risk posed by lightning to unshielded conductor. Pole top rehabilitation and pole replacement projects also do not mitigate the increased outage risk posed by deteriorated and less durable small single layer or copper conductors.
b. Please refer to page 130, lines 9 through 15, of my direct testimony.
c. The Company has not elected to rehabilitate a line of "non-standard construction" for the reasons given in sub-part a.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 15, 2021

Electric Planning

Question:

12. At page 161 of his direct testimony, Mr. Blumenstock states: "Studies by the PJM Interconnection, North American Electric Reliability Corporation, and the Electric Power Research Institute ("EPRI") have shown that operational challenges begin to manifest themselves when DER penetration reaches between 20% and 30% of the electric demand being served. At this point, DERMS is necessary to reliably manage DERs at peak conditions, and to generally coordinate DERs so as to not introduce voltage issues or other issues that threaten reliability. In short, while DERMS is not addressing a specific reliability threat that exists in 2021, it will prevent a reliability threat that is likely to exist by the time the project is complete if no action is taken."

a. Please provide the Company's actual and projected DER penetration in each of years 2020 through 2025.

b. Please identify the "reliability threat that is likely to exist" by the time the DERMS project is complete if no action is taken.

Response:

a. Please refer to discovery responses 20963-MEC-CE-476, 20963-MEC-CE-477, 20963-MEC-CE-518, and 20963-MEC-CE-519.

b. Please refer to discovery response 20963-ELPC-CE-475.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 21, 2021

Electric Planning

Question:

26. Refer to Figure 1 on page 3 of Ms. Houtz's direct testimony. Please:

a. Expand this table to include the same information for each year actuals for 2015, 2016, 2017 and 2020, and provide it in Excel with formulas intact.

b. Explain what inflation factors were applied by line item to determine the 2021 and 2022 expense level.

c. Explain why the service restoration expense declined in 2020 from 2019 if, as claimed by the Company, winds are now blowing stronger and more storms have occurred in recent years.

Response:

a. See Attachment U20963-AG-CE-867-Houtz_Att_1

b. Inflation rates are listed below:

Inflation Rates

Other Labor	3.2%	103.2%
OM&C Labor	3.0%	103.0%
Non-Labor 2021	2.5%	102.5%
Non-Labor 2022	2.3%	102.3%

c. In 2019, the Company responded to 2 catastrophic events that reached an ICS level 3 and 9 MEDs.

In 2020, the Company responded to 1 catastrophic event that reached an ICS level 3 and 8 MEDs.

The reduction in catastrophic events/MEDs in 2020 is the reason for the decline in service restoration expense.

Service restoration costs are volatile due to weather patterns and the Company has accounted for the potential in years that see fewer weather events by proposing a two-way deferral mechanism in this case.

Brenda Houtz

Brenda L. Houtz
May 28, 2021

Last Updated: 4/20/2021

Service Restoration Actuals 2015 - 2020

	2015	2016	2017	2018	2019	2020 (9 + 3 FC)	Grand Total	3 Year Avg (2018 - 2020)	Inflated 2021	Inflated 2022	2020 Actuals
Business Expense	$151,322	$124,669	$448,375	$158,726	$329,863	$116,445	$1,329,401	**$201,678**	**$206,720**	**$211,475**	133,560
Contractor	$15,559,075	$9,247,355	$24,208,233	$18,962,523	$39,018,235	$25,276,697	$132,272,118	**$27,752,485**	**$28,446,297**	**$29,100,562**	26,982,472
Exempt Labor	$1,132,544	$1,050,640	$2,919,993	$1,883,210	$3,780,786	$2,224,137	$12,991,310	**$2,629,378**	**$2,713,518**	**$2,800,350**	2,650,666
Material	$419,034	$910,278	$1,048,076	$1,300,668	$2,061,898	$1,461,370	$7,201,324	**$1,607,979**	**$1,648,178**	**$1,686,086**	1,531,972
Non Exempt Labor	$1,008,758	$752,670	$1,600,151	$1,702,025	$2,132,696	$961,600	$8,157,900	**$1,598,774**	**$1,649,935**	**$1,702,732**	1,129,920
OM&C Labor	$7,466,163	$7,462,007	$12,772,881	$12,604,957	$18,152,878	$12,905,381	$71,364,267	**$14,554,405**	**$14,991,037**	**$15,440,769**	14,907,644
Other Expense	$7,044,720	$5,920,941	($4,184,918)	$7,966,426	$9,667,000	$7,280,171	$33,694,340	**$8,304,532**	**$8,512,146**	**$8,707,925**	8,286,916
Other Labor	$5,385,096	$10,035,482	$11,359,171	$9,345,523	$16,985,282	$15,101,198	$68,211,752	**$13,810,668**	**$14,252,609**	**$14,708,692**	15,638,991
Grand Total	$38,166,712	$35,504,042	$50,171,961	$53,924,058	$92,128,638	$65,327,000	$335,222,411	**$70,459,899**	**$72,420,440**	**$74,358,592**	71,262,140

Inflation Rates

Other Labor	3.2%	103.2%
OM&C Labor	3.0%	103.0%
Non-Labor 2021	2.5%	102.5%
Non-Labor 2022	2.3%	102.3%

***Includes Insurance Recovery**

Question:

5) Refer to Mr. Blumenstock's direct testimony, page 136, lines 15 to 17, which states, "As part of HVD line rebuild and pole top rehabilitation projects, the Company clears the line ROWs and addresses hazard trees from a forestry perspective in advance of the line work. This line clearing forestry work is included as part of the project capital expenditures." Refer also to Mr. Blumenstock's direct testimony, page 229, line 22, to page 230, line 1, which states that LVD Lines Capacity subprogram includes some line clearing work.
a. For each HVD Line Rebuild and HVD Pole Top Rehabilitation project completed since 2016, please identify the cost of line clearing forestry work that was included as part of the project capital expenditures.
b. For each proposed 2021 and 2022 HVD Line Rebuild and HVD Pole Top Rehabilitation project, please identify the projected line clearing forestry work included as part of the project capital expenditures.
c. For each LVD Lines Capacity project completed since 2016, please identify the cost of line clearing forestry work that was included in the project. Please also identify whether the line clearing costs were capitalized.
d. For each proposed 2021 and 2022 LVD Lines Capacity project, please identify the cost of any line clearing forestry work that is included in the project. Please identify whether the line clearing costs are proposed to be capitalized.
e. Besides LVD Lines Capacity, HVD Line Rebuild, and HVD Pole Top Rehabilitation projects, does the Company include line clearing work in other non-forestry reliability or capacity programs? If so, please identify each program or sub-program, the total annual line-clearing cost each year since 2016, the projected line clearing costs for each sub-program in 2021 and 2022, and whether the line-clearing costs are capitalized.

Response:

a. Please refer to Attachment 1 to this discovery response for a list of all HVD capital forestry costs by work order since 2016.
b. The Company has not projected capital forestry costs on a project-by-project basis. The Company projects total forestry capital clearing miles for LVD and HVD, as shown in Exhibit PLB-1 and in Figure 8 in the direct testimony of Company witness Bolden, based on the overall amount of projected capital work. Actual forestry capital costs are assigned to HVD work orders and to LVD programs as the capital forestry work is completed. Note that the capital clearing costs shown in Figure 8 of Company witness Bolden's testimony only reflect capital costs for contractors, not for Company employees; capital forestry costs for Company employees are allocated based on the prior year's work mix of O&M and capital forestry work.
c. The Company tracks LVD capital forestry costs by program: Reliability, Capacity, and New Business. Please refer to Attachment 2 to this discovery response for LVD capital forestry costs by program since 2016.
d. Please refer to subpart b.
e. Please refer to subparts a and c.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 1, 2021

YR	Invoice Amount	Work Type	WO.
2021	$14,500.00	HVD Construction	
2021	$0.00	HVD Construction	33940279
2021	$115,543.66	HVD Construction	34707060
2021	$39,118.74	HVD Construction	34954899
2021	$29,537.26	HVD Construction	34955124
2021	$13,978.13	HVD Construction	36015087
2021	$37,584.21	HVD Construction	36097149
2021	$47,800.00	HVD Construction	36156726
2021	$0.00	HVD Construction	36223117
2021	$1,011.40	HVD Construction	34726891
2021	$1,011.40	HVD Construction	34869742
2021	$3,995.76	HVD Construction	34954899
2021	$3,525.60	HVD Construction	34955124
2021	$4,551.30	HVD Construction	35066794
2021	$3,596.53	HVD Construction	36015087
2021	$404.56	HVD Construction	36036730
2021	$303.42	HVD Construction	36245271
2021	$600.84	HVD Construction	36340705
2021	$1,011.40	HVD Construction	36367796
2021	$1,103.54	HVD Construction	36739581
2021	$1,011.40	HVD Construction	36783576
2021	$809.12	HVD Construction	37010664
2021	$1,618.24	HVD Construction	37098127
2021	$3,104.34	HVD Construction	37149237
2021	$1,011.40	HVD Construction	37358747
2021	$1,011.40	HVD Construction	37862811
2021	$300.42	HVD Construction	37961126
2021	$1,820.52	HVD Construction	38088105
2021	$505.70	HVD Construction	38390921
YTD Total	**$330,370.29**		
2020	$400.56	HVD Construction	33861468
2020	$3,298.50	HVD Construction	21992599
2020	$190,353.12	HVD Construction	21125785
2020	$27,500.00	HVD Construction	29334844
2020	$80,923.93	HVD Construction	33861468
2020	$185,000.00	HVD Construction	34726891
2020	$224,687.89	HVD Construction	35352259
2020	$35,045.60	HVD Construction	36080525
2020	$0.00	HVD Construction	
2020	$8,450.77	HVD Construction	21125785
2020	$9,513.30	HVD Construction	21992599
2020	$6,844.38	HVD Construction	22091165
2020	$1,787.68	HVD Construction	25561247
2020	$872.62	HVD Construction	25629900
2020	$5,756.07	HVD Construction	28357769

2020	$500.20	HVD Construction	28599346
2020	$1,502.10	HVD Construction	29334844
2020	$1,001.40	HVD Construction	29334847
2020	$600.84	HVD Construction	31679653
2020	$8,812.32	HVD Construction	31712106
2020	$800.32	HVD Construction	31750843
2020	$2,703.78	HVD Construction	32802718
2020	$494.16	HVD Construction	33027381
2020	$17,568.86	HVD Construction	33442600
2020	$1,001.40	HVD Construction	33814117
2020	$1,401.96	HVD Construction	33861468
2020	$1,602.24	HVD Construction	33887381
2020	$3,302.62	HVD Construction	34000993
2020	$3,504.90	HVD Construction	34065738
2020	$145,237.20	HVD Construction	34464454
2020	$3,839.04	HVD Construction	34501869
2020	$500.70	HVD Construction	34576634
2020	$2,071.50	HVD Construction	34726891
2020	$901.26	HVD Construction	34774421
2020	$500.70	HVD Construction	34821271
2020	$3,004.20	HVD Construction	34822086
2020	$14,139.04	HVD Construction	34976945
2020	$17,624.64	HVD Construction	34977228
2020	$901.26	HVD Construction	34980711
2020	$5,808.12	HVD Construction	35061162
2020	$5,007.00	HVD Construction	35115230
2020	$400.56	HVD Construction	35180713
2020	$801.12	HVD Construction	35205088
2020	$0.00	HVD Construction	35314298
2020	$400.56	HVD Construction	35315501
2020	$3,111.78	HVD Construction	35352259
2020	$19,120.80	HVD Construction	35353440
2020	$800.32	HVD Construction	35376967
2020	$1,440.08	HVD Construction	35452673
2020	$1,401.96	HVD Construction	35465197
2020	$18,439.50	HVD Construction	35484434
2020	$801.12	HVD Construction	35527352
2020	$801.12	HVD Construction	35559118
2020	$1,001.40	HVD Construction	35569361
2020	$1,001.40	HVD Construction	35680640
2020	$4,005.60	HVD Construction	35737499
2020	$14,805.92	HVD Construction	35799277
2020	$1,001.40	HVD Construction	35814298
2020	$3,815.64	HVD Construction	36015087
2020	$2,002.80	HVD Construction	36020565
2020	$2,485.80	HVD Construction	36080525
2020	$400.56	HVD Construction	36087436

2020	$300.42	HVD Construction	36095913
2020	$15,021.00	HVD Construction	36096825
2020	$1,001.40	HVD Construction	36097000
2020	$4,707.60	HVD Construction	36222599
2020	$1,001.40	HVD Construction	36255838
2020	$600.84	HVD Construction	36306500
2020	$500.70	HVD Construction	36341958
2020	$0.00	HVD Construction	36341968
2020	$1,001.40	HVD Construction	36353875
2020	$2,303.22	HVD Construction	36355162
2020	$7,020.12	HVD Construction	36364135
2020	$801.12	HVD Construction	36384260
2020	$300.42	HVD Construction	36419755
2020	$1,001.40	HVD Construction	36461898
2020	$500.70	HVD Construction	36555498
2020	$9,413.16	HVD Construction	36631563
2020	$600.84	HVD Construction	36715269
2020	$1,602.24	HVD Construction	36771707
2020	$709.44	HVD Construction	36805188
2020	$500.70	HVD Construction	36827203
2020	$500.70	HVD Construction	36838278
2020	$4,239.60	HVD Construction	36890221
2020	$439.52	HVD Construction	37282814
2020	$2,002.80	HVD Construction	37324502
2020	$2,002.80	HVD Construction	37354208
Total	**$1,160,879.16**		
2019	$740.52	HVD Construction	35072693
2019	$0.00	HVD Construction	14791529
2019	$136,400.22	HVD Construction	14795029
2019	$0.00	HVD Construction	15604332
2019	$0.00	HVD Construction	21125785
2019	$0.00	HVD Construction	22061165
2019	$95,115.45	HVD Construction	22091165
2019	$102,501.59	HVD Construction	25561247
2019	$86,278.62	HVD Construction	28055683
2019	$138,000.00	HVD Construction	29076351
2019	$0.00	HVD Construction	29916503
2019	$102,011.14	HVD Construction	30787231
2019	$7,108.00	HVD Construction	31711974
2019	$4,424.00	HVD Construction	31712157
2019	$11,059.60	HVD Construction	31712343
2019	$1,150.00	HVD Construction	31714007
2019	$1,032.00	HVD Construction	31714018
2019	$1,548.00	HVD Construction	31714149
2019	$55,683.00	HVD Construction	31750843
2019	$36,229.61	HVD Construction	31777997

2019	$110,701.20	HVD Construction	31832461
2019	$6,800.00	HVD Construction	32819517
2019	$69,090.21	HVD Construction	32837263
2019	$27,449.86	HVD Construction	32838034
2019	$35,563.20	HVD Construction	32971736
2019	$9,910.00	HVD Construction	
2019	$20,122.20	HVD Construction	14795029
2019	$10,157.26	HVD Construction	15137755
2019	$13,327.01	HVD Construction	15137758
2019	$1,106.96	HVD Construction	17960447
2019	$9,592.14	HVD Construction	21125785
2019	$3,351.21	HVD Construction	21992292
2019	$15,712.00	HVD Construction	21992599
2019	$14,379.50	HVD Construction	22091165
2019	$3,113.04	HVD Construction	22106353
2019	$2,361.98	HVD Construction	25561247
2019	$2,400.96	HVD Construction	26146428
2019	$1,474.79	HVD Construction	26559194
2019	$1,000.40	HVD Construction	26612728
2019	$2,345.60	HVD Construction	27367582
2019	$1,489.60	HVD Construction	27559793
2019	$35,615.00	HVD Construction	27632106
2019	$18,054.60	HVD Construction	28055683
2019	$800.32	HVD Construction	28599346
2019	$1,561.71	HVD Construction	29076351
2019	$4,001.60	HVD Construction	29099450
2019	$2,000.80	HVD Construction	29371404
2019	$4,502.72	HVD Construction	29391787
2019	$552.80	HVD Construction	30329358
2019	$3,452.52	HVD Construction	30614239
2019	-$290.64	HVD Construction	30669923
2019	$4,288.68	HVD Construction	30787231
2019	$2,834.84	HVD Construction	30788158
2019	$2,968.08	HVD Construction	31074131
2019	$1,293.45	HVD Construction	31092019
2019	$1,129.40	HVD Construction	31092373
2019	$4,947.05	HVD Construction	31119009
2019	$2,258.32	HVD Construction	31335413
2019	$4,001.60	HVD Construction	31374914
2019	$1,773.55	HVD Construction	31597984
2019	$3,235.00	HVD Construction	31724876
2019	$5,306.50	HVD Construction	31724877
2019	$5,306.50	HVD Construction	31725123
2019	$31,141.70	HVD Construction	31725129
2019	$5,239.26	HVD Construction	31725136
2019	$7,522.83	HVD Construction	31725500
2019	$39,446.10	HVD Construction	31725506

2019	$1,492.62	HVD Construction	31728362
2019	$3,210.92	HVD Construction	31728373
2019	$15,473.35	HVD Construction	31750843
2019	$2,216.12	HVD Construction	31750853
2019	$2,736.85	HVD Construction	31751348
2019	$9,193.02	HVD Construction	31751555
2019	$32,180.48	HVD Construction	31773980
2019	$4,399.58	HVD Construction	31832461
2019	$1,474.79	HVD Construction	31844023
2019	$4,469.20	HVD Construction	31844921
2019	$12,054.66	HVD Construction	31867906
2019	$3,966.18	HVD Construction	31998081
2019	$2,995.36	HVD Construction	32175604
2019	$10,250.84	HVD Construction	32743140
2019	$905.49	HVD Construction	32771841
2019	$1,000.40	HVD Construction	32838034
2019	$8,329.30	HVD Construction	32971720
2019	$1,000.40	HVD Construction	32971736
2019	$1,395.06	HVD Construction	33127501
2019	$845.34	HVD Construction	33180261
2019	$1,200.48	HVD Construction	33252745
2019	$4,668.24	HVD Construction	33479913
2019	$7,960.00	HVD Construction	33576974
2019	$400.16	HVD Construction	33703973
2019	$2,604.20	HVD Construction	33829622
2019	$1,166.83	HVD Construction	33881903
2019	$4,461.79	HVD Construction	33904152
2019	$1,434.12	HVD Construction	33913863
2019	$7,474.00	HVD Construction	34000993
2019	$2,691.28	HVD Construction	34064597
2019	$2,653.20	HVD Construction	34067111
2019	$2,985.88	HVD Construction	34105593
2019	$1,624.87	HVD Construction	34110610
2019	$12,472.40	HVD Construction	34162191
2019	$690.77	HVD Construction	34221338
2019	$4,564.24	HVD Construction	34233666
2019	$2,052.56	HVD Construction	34248246
2019	$6,653.26	HVD Construction	34315825
2019	$4,515.30	HVD Construction	34407115
2019	$500.20	HVD Construction	34556674
2019	$10,953.27	HVD Construction	34704877
2019	$5,235.80	HVD Construction	34759169
2019	$6,553.10	HVD Construction	34849855
2019	$3,864.27	HVD Construction	34889282
2019	$1,820.18	HVD Construction	35018432
2019	$3,270.76	HVD Construction	35035686
2019	$3,691.57	HVD Construction	35057183

2019	$1,326.60	HVD Construction	35069429
2019	$9,441.34	HVD Construction	35180398
2019	$400.16	HVD Construction	35309169
2019	$7,673.40	HVD Construction	35353440
2019	$7,325.48	HVD Construction	35448601
2019	$1,840.08	HVD Construction	35452673
2019	$1,600.64	HVD Construction	35799277
2019	-$4.83	HVD Construction	15137758
2019	-$1.92	HVD Construction	31074131
2019	-$1.92	HVD Construction	32175604
2019	-$2.91	HVD Construction	34407115
2019	-$3.51	HVD Construction	34849855
2019	-$10.60	HVD Construction	17960447
2019	-$17.76	HVD Construction	21992292
2019	-$12.72	HVD Construction	22106353
2019	-$19.61	HVD Construction	29391787
2019	-$4.77	HVD Construction	31092373
2019	-$8.48	HVD Construction	31335413
2019	-$25.44	HVD Construction	31751555
Total	**$1,590,921.08**		

2018	$106,576.23	HVD Construction	
2018	$0.00	HVD Construction	15136881
2018	$17,500.00	HVD Construction	15596837
2018	$38,000.00	HVD Construction	15604017
2018	$0.00	HVD Construction	21992202
2018	$179,140.00	HVD Construction	21992292
2018	$68,811.20	HVD Construction	21993161
2018	$0.00	HVD Construction	25561247
2018	$130,664.00	HVD Construction	27220557
2018	$15,990.00	HVD Construction	28345868
2018	$12,078.60	HVD Construction	28350976
2018	$0.00	HVD Construction	29048387
2018	$1,220.00	HVD Construction	29763516
2018	$0.00	HVD Construction	29916620
2018	$17,475.00	HVD Construction	31023844
2018	$0.00	HVD Construction	31080112
2018	$0.00	HVD Construction	31080122
2018	$17,475.00	HVD Construction	31166608
2018	$248,627.10	HVD Construction	31168480
2018	$159,980.00	HVD Construction	31333371
2018	$118,866.32	HVD Construction	31333373
2018	$58,477.34	HVD Construction	31456430
2018	$14,328.00	HVD Construction	31464065
2018	$48,703.00	HVD Construction	31535345
2018	$27,000.00	HVD Construction	31947857
2018	$0.00	HVD Construction	

2018	$2,630.00	HVD Construction	15136881
2018	$2,451.80	HVD Construction	15596837
2018	$5,844.68	HVD Construction	19713496
2018	$5,078.96	HVD Construction	21833840
2018	$0.00	HVD Construction	21992202
2018	$5,595.48	HVD Construction	21992292
2018	$2,625.96	HVD Construction	21992816
2018	$2,569.90	HVD Construction	21993161
2018	$540.00	HVD Construction	25561247
2018	$2,771.10	HVD Construction	25789111
2018	$6,698.92	HVD Construction	25853601
2018	$6,187.48	HVD Construction	25906204
2018	$2,618.56	HVD Construction	26144939
2018	$3,420.56	HVD Construction	26508149
2018	$4,967.25	HVD Construction	26562286
2018	$6,384.09	HVD Construction	26572316
2018	$290.96	HVD Construction	26573102
2018	$1,474.79	HVD Construction	26599643
2018	$3,912.58	HVD Construction	26602264
2018	$2,162.34	HVD Construction	26604368
2018	$2,648.10	HVD Construction	26604641
2018	$8,937.31	HVD Construction	26604648
2018	$2,780.57	HVD Construction	26612535
2018	$5,746.15	HVD Construction	27197868
2018	$5,873.70	HVD Construction	27220557
2018	$16,483.50	HVD Construction	27353895
2018	$5,999.35	HVD Construction	28337907
2018	$0.00	HVD Construction	28345868
2018	$4,486.36	HVD Construction	28350976
2018	$2,207.52	HVD Construction	28367132
2018	$7,092.20	HVD Construction	28381736
2018	$2,594.20	HVD Construction	28511504
2018	$4,279.78	HVD Construction	28994098
2018	$4,527.04	HVD Construction	28994421
2018	$1,535.36	HVD Construction	29197689
2018	$1,826.59	HVD Construction	29209617
2018	$643.86	HVD Construction	29323655
2018	$1,335.99	HVD Construction	29364928
2018	$12,213.32	HVD Construction	29365293
2018	$1,954.76	HVD Construction	29368453
2018	$821.44	HVD Construction	29368751
2018	$4,125.61	HVD Construction	29371404
2018	$1,082.78	HVD Construction	29372027
2018	$10,429.97	HVD Construction	29372917
2018	$1,568.04	HVD Construction	29373535
2018	$10,781.96	HVD Construction	29376669
2018	$1,610.42	HVD Construction	29384970

2018	$1,366.51	HVD Construction	29390830
2018	$610.00	HVD Construction	29763516
2018	$3,137.57	HVD Construction	29916053
2018	$1,416.72	HVD Construction	29957127
2018	$952.11	HVD Construction	30117906
2018	$2,280.18	HVD Construction	30120317
2018	$2,025.62	HVD Construction	30163010
2018	$6,894.58	HVD Construction	30221991
2018	$174.16	HVD Construction	30227571
2018	$1,850.00	HVD Construction	30227573
2018	$1,928.79	HVD Construction	30235521
2018	$2,740.66	HVD Construction	30346088
2018	$9,259.16	HVD Construction	30364054
2018	$1,785.90	HVD Construction	30379995
2018	$5,264.22	HVD Construction	30415026
2018	$1,287.72	HVD Construction	30420981
2018	$1,866.80	HVD Construction	30421629
2018	$2,609.11	HVD Construction	30427233
2018	$7,771.50	HVD Construction	30669923
2018	$7,069.55	HVD Construction	30710988
2018	$2,494.40	HVD Construction	30856463
2018	$1,159.78	HVD Construction	30934418
2018	$1,567.44	HVD Construction	30960927
2018	$551.88	HVD Construction	31023844
2018	$1,213.45	HVD Construction	31091338
2018	$10,099.01	HVD Construction	31091704
2018	$2,953.10	HVD Construction	31092033
2018	$1,390.74	HVD Construction	31092039
2018	$1,082.78	HVD Construction	31118745
2018	$2,338.60	HVD Construction	31187707
2018	$6,710.60	HVD Construction	31202959
2018	$5,645.92	HVD Construction	31287887
2018	$5,286.80	HVD Construction	31292587
2018	$905.49	HVD Construction	31293210
2018	$1,123.76	HVD Construction	31293217
2018	$996.89	HVD Construction	31299239
2018	$2,361.06	HVD Construction	31333361
2018	$1,880.00	HVD Construction	31333373
2018	$1,474.79	HVD Construction	31357032
2018	$551.88	HVD Construction	31419525
2018	$90.66	HVD Construction	31438461
2018	$4,139.10	HVD Construction	31456430
2018	$5,196.38	HVD Construction	31464065
2018	$6,720.89	HVD Construction	31465293
2018	$2,311.48	HVD Construction	31535345
2018	$10,124.46	HVD Construction	31546561
2018	$15,732.92	HVD Construction	31578646

2018	$300.12	HVD Construction	31597984
2018	$977.76	HVD Construction	31684934
2018	$558.72	HVD Construction	31684939
2018	$1,676.16	HVD Construction	31685155
2018	$1,813.20	HVD Construction	31697453
2018	$7,877.62	HVD Construction	31740000
2018	$13,233.45	HVD Construction	31769401
2018	$1,952.08	HVD Construction	31775073
2018	$2,441.56	HVD Construction	31825583
2018	$1,428.17	HVD Construction	31917843
2018	$2,139.78	HVD Construction	31919848
2018	$2,995.78	HVD Construction	31970517
2018	$12,740.79	HVD Construction	31971805
2018	$1,024.20	HVD Construction	31995053
2018	$1,024.20	HVD Construction	31997582
2018	$3,137.84	HVD Construction	32202158
2018	$1,149.75	HVD Construction	32236840
2018	$643.86	HVD Construction	32277072
2018	$1,773.55	HVD Construction	32378405
2018	$3,505.64	HVD Construction	32493081
2018	$6,438.60	HVD Construction	32500693
2018	$1,866.80	HVD Construction	32604460
2018	$2,778.55	HVD Construction	32643038
2018	$606.72	HVD Construction	32672070
2018	$7,119.73	HVD Construction	32702287
2018	$183.96	HVD Construction	32725811
2018	$1,814.53	HVD Construction	32734516
2018	$919.80	HVD Construction	32769051
2018	$2,055.90	HVD Construction	32786388
2018	$1,114.56	HVD Construction	32971477
2018	$946.46	HVD Construction	32972283
2018	$13,618.25	HVD Construction	33047693
2018	$906.60	HVD Construction	33084741
2018	$4,707.76	HVD Construction	33098241
2018	$8,207.42	HVD Construction	33102543
2018	$7,703.16	HVD Construction	33102546
2018	$3,922.85	HVD Construction	33236847
2018	$91.98	HVD Construction	33262639
2018	$1,359.90	HVD Construction	33294255
2018	$1,866.80	HVD Construction	33323136
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2018	$1,950.85	HVD Construction	33825472
2018	-$34.51	HVD Construction	22091165
2018	-$5.95	HVD Construction	25735762
2018	-$20.23	HVD Construction	25820905
2018	-$21.93	HVD Construction	26138472

2018	-$17.17	HVD Construction	26139437
2018	-$28.56	HVD Construction	26139783
2018	-$19.38	HVD Construction	28474817
2018	-$6.80	HVD Construction	29020080
2018	-$17.34	HVD Construction	29885747
2018	-$19.72	HVD Construction	30019042
2018	-$9.18	HVD Construction	30427239
2018	-$12.07	HVD Construction	31337341
2018	$2,850.00	HVD Construction	27220557
2018	$28,903.77	HVD Construction	31080112
2018	$943.80	HVD Construction	21993161
2018	$348.32	HVD Construction	30227573
2018	-$25.16	HVD Construction	26576321
2018	-$7.82	HVD Construction	26591040
2018	-$17.51	HVD Construction	26591052
2018	-$2.38	HVD Construction	26591695
2018	-$11.22	HVD Construction	27157649
2018	-$9.69	HVD Construction	29364695
2018	-$18.53	HVD Construction	30322736
2018	-$31.99	HVD Construction	31378656
Total	**$1,799,954.52**		
2017	$1,083.12	HVD Construction	21992816
2017	$300.00	HVD Construction	
2017	$2,440.00	HVD Construction	15595503
2017	$20,795.65	HVD Construction	21143701
2017	$7,800.00	HVD Construction	23869626
2017	$1,320.00	HVD Construction	25338497
2017	$16,482.00	HVD Construction	26508149
2017	$9,160.00	HVD Construction	26707032
2017	$16,740.00	HVD Construction	27244790
2017	$27,532.04	HVD Construction	27304736
2017	$19,829.45	HVD Construction	27634275
2017	$22,500.00	HVD Construction	28346071
2017	$68,779.20	HVD Construction	28962556
2017	$0.00	HVD Construction	
2017	$27,842.58	HVD Construction	21143701
2017	$475,252.38	HVD Construction	21992816
2017	$10,806.73	HVD Construction	21993173
2017	$11,136.87	HVD Construction	22091165
2017	$73,895.38	HVD Construction	23869626
2017	$785.00	HVD Construction	24770858
2017	$3,882.06	HVD Construction	24827665
2017	$2,475.58	HVD Construction	25657577
2017	$8,994.95	HVD Construction	25735762
2017	$4,310.85	HVD Construction	25735777
2017	$4,648.57	HVD Construction	25745015

2017	$4,088.46	HVD Construction	25789111
2017	$5,801.76	HVD Construction	25820905
2017	$4,548.68	HVD Construction	25990517
2017	$2,420.92	HVD Construction	26131209
2017	$684.50	HVD Construction	26131586
2017	$5,954.12	HVD Construction	26138472
2017	$5,156.69	HVD Construction	26139437
2017	$8,107.97	HVD Construction	26139783
2017	$10,001.52	HVD Construction	26247438
2017	$596.18	HVD Construction	26247971
2017	$6,120.72	HVD Construction	26255782
2017	$8,658.52	HVD Construction	26480156
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2017	$4,630.18	HVD Construction	26564279
2017	$1,943.52	HVD Construction	26568189
2017	$7,625.88	HVD Construction	26568191
2017	$2,986.20	HVD Construction	26568306
2017	$12,967.27	HVD Construction	26572860
2017	$1,152.25	HVD Construction	26575230
2017	$6,881.22	HVD Construction	26576321
2017	$2,923.02	HVD Construction	26591040
2017	$6,513.03	HVD Construction	26591052
2017	$884.87	HVD Construction	26591695
2017	$2,177.00	HVD Construction	26598468
2017	$368.72	HVD Construction	26598889
2017	$1,220.24	HVD Construction	26700916
2017	$1,370.66	HVD Construction	26718270
2017	$498.42	HVD Construction	26718347
2017	$25,121.70	HVD Construction	26722320
2017	$32,051.86	HVD Construction	26796506
2017	$1,088.50	HVD Construction	26812488
2017	$2,036.80	HVD Construction	26925880
2017	$3,294.98	HVD Construction	26941628
2017	$2,690.61	HVD Construction	27025735
2017	$3,957.08	HVD Construction	27157649
2017	$628.56	HVD Construction	27161565
2017	$4,413.60	HVD Construction	27219185
2017	$65,229.74	HVD Construction	27220557
2017	$1,993.68	HVD Construction	27387708
2017	$5,015.80	HVD Construction	27483713
2017	$4,312.50	HVD Construction	27612718
2017	$2,941.98	HVD Construction	27613267
2017	$373.82	HVD Construction	27812650
2017	$1,233.90	HVD Construction	27830196
2017	$8,081.80	HVD Construction	27857125

2017	$7,217.64	HVD Construction	27939970
2017	$12,753.28	HVD Construction	27952675
2017	$174.16	HVD Construction	27957642
2017	$696.64	HVD Construction	27958046
2017	$6,095.60	HVD Construction	27959814
2017	$618.52	HVD Construction	28005005
2017	$1,784.52	HVD Construction	28093997
2017	$258,938.65	HVD Construction	28114796
2017	$8,631.27	HVD Construction	28360486
2017	$7,519.26	HVD Construction	28474817
2017	$1,668.64	HVD Construction	28511308
2017	$2,102.52	HVD Construction	28900448
2017	$795.24	HVD Construction	28941297
2017	$1,410.00	HVD Construction	28962556
2017	$10,899.64	HVD Construction	28990508
2017	$9,390.99	HVD Construction	28990515
2017	$4,090.36	HVD Construction	28990686
2017	$1,793.29	HVD Construction	28998542
2017	$1,741.70	HVD Construction	29020080
2017	$1,290.52	HVD Construction	29116432
2017	$967.96	HVD Construction	29117870
2017	$6,055.62	HVD Construction	29219887
2017	$884.87	HVD Construction	29277641
2017	$1,019.77	HVD Construction	29339915
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2017	$2,100.30	HVD Construction	29561812
2017	$2,972.70	HVD Construction	29595687
2017	$2,342.70	HVD Construction	29673069
2017	$9,086.36	HVD Construction	29691695
2017	$2,144.82	HVD Construction	29709293
2017	$6,065.79	HVD Construction	29885747
2017	$176.72	HVD Construction	29894389
2017	$779.42	HVD Construction	29956514
2017	$3,405.43	HVD Construction	30010017
2017	$5,433.21	HVD Construction	30019042
2017	$8,395.52	HVD Construction	30155729
2017	$5,891.04	HVD Construction	30165221
2017	$5,024.37	HVD Construction	30271181
2017	$4,182.19	HVD Construction	30271384
2017	$7,905.14	HVD Construction	30322736
2017	$5,570.96	HVD Construction	30369523
2017	$2,834.50	HVD Construction	30427239
2017	$3,995.91	HVD Construction	30442172
2017	$13,553.60	HVD Construction	30577460
2017	$6,502.96	HVD Construction	30703381

2017	$696.64	HVD Construction	30787194
2017	$696.64	HVD Construction	30860501
2017	$3,253.28	HVD Construction	31041401
2017	$4,274.66	HVD Construction	31337341
2017	-$327.10	HVD Construction	15595503
2017	$82,224.25	HVD Construction	26255782
2017	$21,955.74	HVD Construction	26499862
2017	$75,493.48	HVD Construction	26500028
2017	$73,149.39	HVD Construction	27161565
2017	$38,481.16	HVD Construction	27189709
2017	-$13.23	HVD Construction	15019277
2017	-$39.69	HVD Construction	19957259
2017	-$66.15	HVD Construction	19974015
2017	-$95.76	HVD Construction	20851891
2017	-$63.18	HVD Construction	21143701
2017	-$15.84	HVD Construction	21992816
2017	-$110.25	HVD Construction	22568029
2017	-$1.32	HVD Construction	23869626
2017	-$24.57	HVD Construction	24827665
2017	-$9.24	HVD Construction	25657577
2017	-$46.31	HVD Construction	25735762
2017	-$28.04	HVD Construction	25735777
2017	-$21.80	HVD Construction	25745015
2017	-$23.00	HVD Construction	25769008
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2017	-$11.88	HVD Construction	25789111
2017	-$17.96	HVD Construction	25984172
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2017	-$32.13	HVD Construction	26475184
2017	-$24.82	HVD Construction	26475374
2017	-$36.40	HVD Construction	26480156
2017	-$5.46	HVD Construction	26563769
2017	-$19.03	HVD Construction	26564279
2017	-$48.85	HVD Construction	26568182
2017	-$106.53	HVD Construction	26568187
2017	-$8.58	HVD Construction	26568189
2017	-$18.26	HVD Construction	26568191
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2017	-$33.39	HVD Construction	26568307
2017	-$63.63	HVD Construction	26568310
2017	-$45.54	HVD Construction	26572860
2017	-$51.66	HVD Construction	26600032
2017	-$98.91	HVD Construction	26600118
2017	-$7.97	HVD Construction	26603395

2017	-$12.60	HVD Construction	26681715
2017	-$2.84	HVD Construction	26681895
2017	-$5.28	HVD Construction	26700916
2017	-$22.68	HVD Construction	26713325
2017	-$5.72	HVD Construction	26718270
2017	-$2.08	HVD Construction	26718347
2017	-$350.04	HVD Construction	26796506
2017	-$11.66	HVD Construction	26941628
2017	-$10.66	HVD Construction	27025735
2017	-$53.55	HVD Construction	27165924
2017	-$195.41	HVD Construction	27173034
2017	-$176.78	HVD Construction	27198501
2017	-$5.79	HVD Construction	27382201
2017	-$7.04	HVD Construction	27387708
2017	-$13.86	HVD Construction	27612718
2017	-$12.60	HVD Construction	27613267
2017	-$136.21	HVD Construction	27660972
2017	-$1.56	HVD Construction	27812650
2017	-$3.96	HVD Construction	27830196
2017	-$52.29	HVD Construction	27939970
2017	-$63.63	HVD Construction	27952675
2017	-$11.34	HVD Construction	28093997
2017	-$394.62	HVD Construction	28142710
2017	-$45.05	HVD Construction	28233390
2017	-$76.55	HVD Construction	28259765
2017	-$5.90	HVD Construction	28314791
2017	-$8.26	HVD Construction	28353504
2017	-$49.46	HVD Construction	28360486
2017	-$5.50	HVD Construction	28511308
2017	-$58.91	HVD Construction	28990508
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2017	-$6.60	HVD Construction	28998542
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2017	-$68.48	HVD Construction	29205577
2017	-$26.00	HVD Construction	29219887
2017	-$4.41	HVD Construction	29277641
2017	-$3.30	HVD Construction	29339915
2017	-$5.66	HVD Construction	29345927
2017	-$17.42	HVD Construction	29595687
2017	-$3.65	HVD Construction	29681287
2017	-$34.32	HVD Construction	29691695
2017	-$11.22	HVD Construction	29709293
2017	-$5.02	HVD Construction	29956514
2017	-$38.75	HVD Construction	30155729
2017	-$34.65	HVD Construction	30165221
2017	-$11.66	HVD Construction	30271181

2017	-$15.18	HVD Construction	30271384
2017	-$18.04	HVD Construction	30369523
2017	-$17.82	HVD Construction	30442172
2017	-$5.94	HVD Construction	30560512
2017	-$49.50	HVD Construction	30577460
2017	-$11.22	HVD Construction	30581441
2017	-$5.28	HVD Construction	30703381
2017	-$9.35	HVD Construction	6300070
Total	**$1,871,050.27**		
2016	$14,147.81	HVD Construction	27177327
2016	$320.00	HVD Construction	
2016	$62,786.39	HVD Construction	14850495
2016	$76,264.79	HVD Construction	15136880
2016	$17,550.00	HVD Construction	15137743
2016	$61,830.00	HVD Construction	15137748
2016	$570.00	HVD Construction	15595503
2016	$150,472.66	HVD Construction	19961998
2016	$81,674.40	HVD Construction	21886422
2016	$74,942.40	HVD Construction	22568029
2016	$99,552.79	HVD Construction	23311192
2016	$0.00	HVD Construction	24770858
2016	$57,906.40	HVD Construction	25338497
2016	$2,848.99	HVD Construction	25710925
2016	$8,816.00	HVD Construction	25711281
2016	$1,550.00	HVD Construction	25711299
2016	$12,364.00	HVD Construction	25715715
2016	$1,550.00	HVD Construction	25716184
2016	$1,550.00	HVD Construction	25716660
2016	$7,727.50	HVD Construction	25718543
2016	$10,011.00	HVD Construction	25758529
2016	$14,998.01	HVD Construction	25786082
2016	$0.00	HVD Construction	25990517
2016	$123,504.00	HVD Construction	26350519
2016	$89,831.75	HVD Construction	26350828
2016	$122,806.00	HVD Construction	26516543
2016	$38,132.41	HVD Construction	26516544
2016	$76,642.40	HVD Construction	26523350
2016	$0.00	HVD Construction	27161565
2016	$10,011.00	HVD Construction	27177327
2016	$27,362.00	HVD Construction	27190572
2016	$0.00	HVD Construction	27586082
2016	$12,536.35	HVD Construction	15019277
2016	$506.50	HVD Construction	15136767
2016	$21,286.85	HVD Construction	15136886
2016	$1,398.97	HVD Construction	15595503
2016	$1,041.90	HVD Construction	15596833

2016	$5,208.74	HVD Construction	18639434
2016	$5,421.50	HVD Construction	19213477
2016	$530.16	HVD Construction	19527046
2016	$5,976.79	HVD Construction	19957259
2016	$8,373.01	HVD Construction	19974011
2016	$10,532.53	HVD Construction	19974015
2016	$14,090.17	HVD Construction	20054532
2016	$15,784.70	HVD Construction	20463232
2016	$3,252.90	HVD Construction	20559284
2016	$17,086.00	HVD Construction	20851891
2016	$441.80	HVD Construction	21125785
2016	$542.15	HVD Construction	21672664
2016	$144,075.00	HVD Construction	21993173
2016	$9,587.84	HVD Construction	22568029
2016	$6,320.70	HVD Construction	22574970
2016	$105,390.76	HVD Construction	22575452
2016	$4,441.08	HVD Construction	22709598
2016	$4,276.20	HVD Construction	23421801
2016	$11,789.70	HVD Construction	23454971
2016	$7,576.60	HVD Construction	23455578
2016	$2,089.92	HVD Construction	23462455
2016	$11,067.09	HVD Construction	23677913
2016	$3,047.04	HVD Construction	23859030
2016	$2,854.08	HVD Construction	23859239
2016	$2,980.81	HVD Construction	23890685
2016	$3,189.00	HVD Construction	24042022
2016	$810.60	HVD Construction	24770858
2016	$3,626.62	HVD Construction	24923392
2016	$14,962.30	HVD Construction	25054902
2016	$20,445.64	HVD Construction	25060799
2016	$952.82	HVD Construction	25337581
2016	$2,862.10	HVD Construction	25338398
2016	$783.72	HVD Construction	25341639
2016	$1,366.08	HVD Construction	25348469
2016	$1,836.32	HVD Construction	25352567
2016	$2,004.92	HVD Construction	25353020
2016	$7,091.43	HVD Construction	25443424
2016	$1,199.17	HVD Construction	25443595
2016	$368.72	HVD Construction	25498955
2016	$1,063.00	HVD Construction	25505890
2016	$542.15	HVD Construction	25565792
2016	$1,626.45	HVD Construction	25565998
2016	$2,168.60	HVD Construction	25566546
2016	$1,131.91	HVD Construction	25614975
2016	$6,609.11	HVD Construction	25652073
2016	$629.74	HVD Construction	25653537
2016	$2,654.60	HVD Construction	25653800

2016	$14,879.28	HVD Construction	25658167
2016	$10,369.94	HVD Construction	25673830
2016	$3,484.25	HVD Construction	25676229
2016	$1,626.45	HVD Construction	25682190
2016	$5,661.87	HVD Construction	25710309
2016	$1,353.90	HVD Construction	25727616
2016	$4,844.24	HVD Construction	25769008
2016	$1,623.90	HVD Construction	25774866
2016	$2,024.86	HVD Construction	25785439
2016	$4,687.30	HVD Construction	25786082
2016	$8,813.63	HVD Construction	25801781
2016	$2,793.24	HVD Construction	25984172
2016	$1,088.97	HVD Construction	26103161
2016	$5,282.57	HVD Construction	26103390
2016	$12,339.11	HVD Construction	26113161
2016	$1,855.56	HVD Construction	26201241
2016	$1,767.20	HVD Construction	26203076
2016	$3,252.90	HVD Construction	26226654
2016	$706.88	HVD Construction	26247960
2016	$609.56	HVD Construction	26330113
2016	$11,100.37	HVD Construction	26350828
2016	$6,141.02	HVD Construction	26437163
2016	$2,866.64	HVD Construction	26458640
2016	$6,172.55	HVD Construction	26475184
2016	$4,585.38	HVD Construction	26475374
2016	$1,084.30	HVD Construction	26497645
2016	$174.16	HVD Construction	26499777
2016	$768.42	HVD Construction	26510344
2016	$10,456.00	HVD Construction	26516543
2016	$609.56	HVD Construction	26519618
2016	$24,917.98	HVD Construction	26523350
2016	$3,849.33	HVD Construction	26566864
2016	$7,545.14	HVD Construction	26568182
2016	$21,979.37	HVD Construction	26568187
2016	$14,966.48	HVD Construction	26568306
2016	$5,999.74	HVD Construction	26568307
2016	$870.80	HVD Construction	26568309
2016	$10,113.15	HVD Construction	26568310
2016	$4,458.40	HVD Construction	26572528
2016	$2,399.95	HVD Construction	26575850
2016	$348.32	HVD Construction	26598039
2016	$12,056.56	HVD Construction	26600032
2016	$19,624.84	HVD Construction	26600118
2016	$1,032.86	HVD Construction	26603395
2016	$1,259.35	HVD Construction	26604866
2016	$2,016.76	HVD Construction	26668619
2016	$1,251.00	HVD Construction	26681715

2016	$783.02	HVD Construction	26681895
2016	$1,908.52	HVD Construction	26713325
2016	$7,126.40	HVD Construction	26715012
2016	$1,118.90	HVD Construction	26716963
2016	$4,186.50	HVD Construction	26736378
2016	$5,462.60	HVD Construction	26763800
2016	$32,968.40	HVD Construction	26796506
2016	$250.00	HVD Construction	26810512
2016	$1,967.90	HVD Construction	26925880
2016	$2,176.08	HVD Construction	26985008
2016	$2,168.60	HVD Construction	26985317
2016	$10,452.64	HVD Construction	27165924
2016	$42,177.42	HVD Construction	27173034
2016	$19,585.60	HVD Construction	27177327
2016	$32,533.20	HVD Construction	27219185
2016	$14,569.48	HVD Construction	27335993
2016	$1,252.93	HVD Construction	27382201
2016	$1,084.30	HVD Construction	27434739
2016	$1,539.90	HVD Construction	27483122
2016	$26,622.83	HVD Construction	27660972
2016	$883.60	HVD Construction	27681336
2016	$2,168.60	HVD Construction	27845226
2016	$542.15	HVD Construction	27957787
2016	$1,873.50	HVD Construction	28005644
2016	$295,734.39	HVD Construction	28114796
2016	$4,472.24	HVD Construction	28233390
2016	$507.64	HVD Construction	28314791
2016	$759.01	HVD Construction	28340175
2016	$5,913.45	HVD Construction	28355803
2016	$433.72	HVD Construction	28523832
2016	$0.00	HVD Construction	19961998
2016	-$8.75	HVD Construction	22568029
2016	-$21.00	HVD Construction	24770858
2016	-$693.00	HVD Construction	25060799
2016	-$31.50	HVD Construction	25341639
2016	-$56.00	HVD Construction	25348469
2016	-$311.50	HVD Construction	25801781
2016	-$31.50	HVD Construction	26510344
2016	-$24.50	HVD Construction	26519618
2016	-$199.50	HVD Construction	26523350
2016	$200.00	HVD Construction	23311192
2016	$100.00	HVD Construction	26516543
2016	$18,983.44	HVD Construction	21993173
2016	$162.44	HVD Construction	25984172
2016	$55,847.71	HVD Construction	28114796
2016	-$55.11	HVD Construction	19961998
2016	-$92.70	HVD Construction	19974011

2016	-$186.94	HVD Construction	20054532
2016	-$45.42	HVD Construction	23454971
2016	-$12.16	HVD Construction	15080345
2016	-$18.24	HVD Construction	19527046
2016	-$486.40	HVD Construction	20463232
2016	-$105.00	HVD Construction	20559284
2016	-$200.64	HVD Construction	21486339
2016	-$94.24	HVD Construction	21993173
2016	-$2,690.40	HVD Construction	22575452
2016	-$155.04	HVD Construction	22709598
2016	-$105.00	HVD Construction	23421801
2016	-$245.00	HVD Construction	23455578
2016	-$72.96	HVD Construction	23462455
2016	-$105.00	HVD Construction	24042022
2016	-$168.00	HVD Construction	24336996
2016	-$126.16	HVD Construction	24923392
2016	-$490.00	HVD Construction	25054902
2016	-$38.50	HVD Construction	25337581
2016	-$22.80	HVD Construction	25338398
2016	-$66.12	HVD Construction	25353020
2016	-$79.50	HVD Construction	25443424
2016	-$12.16	HVD Construction	25498955
2016	-$35.00	HVD Construction	25505890
2016	-$17.50	HVD Construction	25565792
2016	-$52.50	HVD Construction	25565998
2016	-$70.00	HVD Construction	25566546
2016	-$91.20	HVD Construction	25652073
2016	-$413.44	HVD Construction	25658167
2016	-$43.85	HVD Construction	25673830
2016	-$723.52	HVD Construction	26113161
2016	-$12.16	HVD Construction	26154512
2016	-$63.84	HVD Construction	26201241
2016	-$60.80	HVD Construction	26203076
2016	-$57.76	HVD Construction	26273248
2016	-$156.56	HVD Construction	26273768
2016	-$36.48	HVD Construction	26330113
2016	-$17.51	HVD Construction	26458640
2016	-$28.88	HVD Construction	26484637
2016	-$6.08	HVD Construction	26499777
2016	-$296.40	HVD Construction	26516543
2016	-$560.88	HVD Construction	26523350
2016	-$9.12	HVD Construction	26568182
2016	-$15.20	HVD Construction	26568187
2016	$121.60	HVD Construction	26572528
2016	-$45.60	HVD Construction	26613184
2016	-$8.96	HVD Construction	26668619
2016	-$30.40	HVD Construction	26716963

2016	-$17.92	HVD Construction	26763800
2016	-$1,396.88	HVD Construction	26769646
2016	-$57.17	HVD Construction	26810512
2016	-$24.32	HVD Construction	26884342
2016	-$10.08	HVD Construction	26985008
2016	-$12.16	HVD Construction	27163742
2016	-$8.40	HVD Construction	27379805
2016	-$13.68	HVD Construction	28407729
Total	**$2,620,063.30**		

LVD Line Clearing Expenditure in Support of Capital Asset Installation

Work Type	2016	2017	2018	2019	2020	YTD 4/2021	Grand Total
Capacity	$448,729	$428,247	$276,069	$293,130	$524,843	$53,587	$2,024,605
New Business	$748,486	$946,683	$989,610	$1,275,153	$1,098,830	$314,751	$5,373,513
Reliability	$4,468,267	$4,606,586	$6,845,806	$3,998,744	$3,838,383	$1,470,671	$25,228,457
Grand Total	**$5,665,483**	**$5,981,516**	**$8,111,485**	**$5,567,027**	**$5,462,056**	**$1,839,009**	**$32,626,575**

Project Source: indicated	**Justification** Source: Concept Approval	**Number of Customers** Source: Ex MEC-32, Att. 1	**Outage information** Source: Ex MEC-32 (MEC-CE-880 Att 1)			**Total Project Cost (million)** Source: Concept Approval	**2022 Cost** Source: Ex A-48, pp. 5-6	**Alternatives considered** Source: Concept Approval
			Outage Date	**Outage Duration (minutes)**	**Outage Cause**			
Remus Ex MEC-26 Att 126 pp 71-80	4 outage incidents 2014-2018; 40 out of 157 poles identified as replacement candidates; non-standard construction	1788	9/2/2011	347	Trees	$5,905	$3,720	None
			9/3/2011	174	Pole			
			5/21/2012	533	Insulator			
			4/12/2014	1232	Pole			
			3/8/2017	525	Pole			
			3/9/2017	417	Insulator			
			7/3/2018	317	Trees			
Wirtz Rd 2 Ex MEC-26 Att 126 pp 81-87	1 outage incident 2016-2020; 16 poles recommended as a “Planned replacement” by 2018 pole inspection; non-standard #2 ACSR construction	8469	7/12/2012	3	Substation Equipment	$3,919	$3,720	$311,000 pole replacement
			9/22/2015	101	Trees			
			9/21/2017	461	Third Party Damage			
			5/8/2019	32	Trees			
Big Rapids Ex MEC-26 Att 126 pp 98-104	Line is underperforming; 1 of the 2 overall outages between 2015 and 2019; non-standard #2 ACSR conductor in a shielded configuration	5368	3/9/2011	53	Insulator	$3,741	$3,441	$668,000 pole top rehab
			3/1/2013	442	Transmission			
			6/6/2013	254	Insulator			
			4/12/2014	948	Conductor			
			4/13/2014	549	Conductor			
			4/13/2015	46	Pole			
			11/29/2017	215	Conductor			
			6/10/2020	915	Tree			
Nashville Ex MEC-26 Att 126 pp 135-142	7 outage incidents 2014-2018; 36 out of 144 poles identified as replacement candidates; non-standard 1/0 copper conductor with #2 ACSR shield wire	4662	5/25/2011	82	Crossarm	$5,480	$3,013	None
			9/29/2011	148	Trees			
			3/2/2012	83	Crossarm			
			5/3/2012	52	Third Party Damage			
			5/13/2013	102	Third Party Damage			

			12/22/2013	1207	Crossarm			
			12/23/2013	941	Trees			
			8/19/2014	32	Lightning			
			3/25/2015	668	Insulator			
			2/24/2016	869	Crossarm			
			5/29/2016	280	Conductor			
			10/18/2016	182	Trees			
			4/6/2017	360	Conductor			
			6/8/2017	374	Pole			
Wayland Ex MEC-26 Att 126 pp 164-170	52 out of 135 poles identified for replacement; non-standard construction	8990	11/18/2013	307	Conductor	$4,500	$2,108	None
			7/12/2016	135	Trees			
Morrice 2 Ex MEC-26 Att 126 pp 210-216	3 outage incidents 2016-2020; non-standard unshielded 115 KCMil copper and 1/0 copper conductor construction	8928	4/10/2011	191	Crossarm	$2,553	$1,969	None
			6/18/2012	302	Crossarm			
			8/7/2012	100	Trees			
			11/17/2013	1764	Pole			
			12/21/2013	221	Conductor			
			9/23/2014	114	Third Party Damage			
			8/2/2017	65	Trees			
			5/27/2018	87	Pole			
			10/20/2018	113	Trees			
			10/30/2018	63	Insulator			
Shelby Ex MEC-26 Att 126 pp 304-312	Non-standard 2/0 copper conductor in an unshielded configuration; 1 outage 2015-2019; 24 out of 102 poles are replacement candidates	2489	3/2/2012	739	Substation Equipment	$3,942	$1,880	$507,000 pole replacement
			9/18/2012	190	Pole			
			2/20/2015	419	Conductor			
Union City Ex MEC-32 MEC-880 pp 13-16	36 out of 122 poles are replacement candidates; non-standard unshielded 4/0 copper conductor construction	0	5/29/2011	432	Crossarm	$2,439	$930	None
			11/22/2013	36	Insulator			

<table>
<tr><td>Union City 2
Ex MEC-32
MEC-880
pp 17-21</td><td>50 out of 179 poles require replacement; 2 forced outages 2016, 2020; 4 poles recommended a Rush replacement and 46 a “planned replacement” by 2018 inspection program; non-standard unshielded 4/0 copper construction</td><td>0</td><td colspan="3">Union City & Union City 2 outage data combined</td><td>$4,266</td><td>$1,763</td><td>$1,100,000 pole replacement</td></tr>
<tr><td rowspan="10">Morrice
Ex MEC-32
MEC-880
pp 22-26</td><td rowspan="10">5 outage incidents 2014-2018; ranked in 20 worst performing lines by number of incidents; part of line is unshielded non-standard 1/0 copper conductor; another section of line is mixture of non-standard 1/0 copper and 3/0 ACSR conductor and is mostly shielded</td><td rowspan="10">8928</td><td>4/10/2011</td><td>191</td><td>Crossarm</td><td rowspan="10">$5,720</td><td rowspan="10">$1,209</td><td rowspan="10">None</td></tr>
<tr><td>6/18/2012</td><td>302</td><td>Crossarm</td></tr>
<tr><td>8/7/2012</td><td>100</td><td>Trees</td></tr>
<tr><td>11/17/2013</td><td>1764</td><td>Pole</td></tr>
<tr><td>12/21/2013</td><td>221</td><td>Conductor</td></tr>
<tr><td>9/23/2014</td><td>114</td><td>Third Party Damage</td></tr>
<tr><td>8/2/2017</td><td>65</td><td>Trees</td></tr>
<tr><td>5/27/2018</td><td>87</td><td>Pole</td></tr>
<tr><td>10/20/2018</td><td>113</td><td>Trees</td></tr>
<tr><td>10/30/2018</td><td>63</td><td>Insulator</td></tr>
<tr><td rowspan="8">Ex MEC-26
Ex MEC-32
MEC-880
pp 27-30</td><td rowspan="8">Line is constructed with non-standard 2/0 copper conductor in unshielded configuration; 2 outages 2015-2019</td><td rowspan="8">4362</td><td>1/14/2011</td><td>68</td><td>Third Party Damage</td><td rowspan="8">$3,110</td><td rowspan="8">$1,135</td><td rowspan="8">$568,000 pole top rehab</td></tr>
<tr><td>4/22/2011</td><td>73</td><td>Tree</td></tr>
<tr><td>3/10/2012</td><td>166</td><td>Third Party Damage</td></tr>
<tr><td>5/27/2012</td><td>95</td><td>Tree</td></tr>
<tr><td>12/21/2012</td><td>465</td><td>Tree</td></tr>
<tr><td>8/2/2015</td><td>395</td><td>Tree</td></tr>
<tr><td>7/1/2018</td><td>59</td><td>Tree</td></tr>
<tr><td>11/9/2018</td><td>227</td><td>Third Party Damage</td></tr>
</table>

Hodenpyl Ex MEC-32 MEC-880 pp 38-41	Line is underperforming; 2 outages 2015-2019; removed from service 3 times due to crossarm and insulator failures; constructed with non-standard 1/0 copper conductor in unshielded configuration	5669	10/22/2011 4/11/2013 3/29/2015 8/2/2015 1/24/2020	353 462 31 366 207	Third Party Damage Insulator Distribution Trees Insulator	$3,005	$2,139	$432,000 pole top rehab
Cooper Ex MEC-32 MEC-880 pp 42-44	6 out of 11 poles need replacement; non-standard #2 ACSR shielded construction	7758	No Outages			$279	$279	$127,000 pole top replacement
Greenville Ex MEC-32 MEC-880 pp 49-53	Line is underperforming; 3 outages 2015-2019; part of line is non-standard 1/0 copper conductor and part is standard construction; plan to rebuild non-standard section and rehab standard section	6086	4/10/2013 2/24/2017 10/5/2017 10/23/2017	81 255 82 372	Insulator Insulator Conductor Conductor	$1,442	$837	$558,000 pole top rehab for whole line
Dietz-Gaylord Ex MEC-32 MEC-880 pp 54-57	Line is underperforming; 6 outages 2015-2019; 3/0 ACSR conductor in unshielded configuration; “recent increases in outage frequency has created customer dissatisfaction and complaints”	291	5/22/2011 7/26/2014 12/24/2015 12/26/2016 3/7/2017 11/9/2017 8/28/2018 5/31/2019	55 24 44 138 67 45 58 287	Trees Third Party Damage Trees Trees Trees Conductor Trees Lightning	$1,355	$1,256	$216,000 pole top rehab
Goodale Ex MEC-32 MEC-880 pp 63-67	4 outage incidents 2014-2018; among worst performing SAIDI lines; non-standard 115kCMIL copper conductor with non-standard LE50 towers	10,152	7/31/2012 8/27/2014 3/8/2017 1/1/2018 5/4/2018 8/28/2020	550 315 705 73 253 476	Pole Third Party Damage Trees Third Party Damage Insulator Trees	$1,324	$1,349	None

<table>
<tr><td rowspan="7">Cement City
Ex MEC-32
MEC-880
pp 68-70</td><td rowspan="7">3 outage incidents 2016-2020; non-standard unshielded 4/0 copper conductor construction</td><td rowspan="7">8779</td><td>4/16/2012</td><td>243</td><td>Third Party Damage</td><td rowspan="7">$699</td><td rowspan="7">$698</td><td rowspan="7">None</td></tr>
<tr><td>7/21/2013</td><td>42</td><td>Trees</td></tr>
<tr><td>5/12/2014</td><td>56</td><td>Lightning</td></tr>
<tr><td>6/3/2015</td><td>53</td><td>Substation Equipment</td></tr>
<tr><td>7/8/2016</td><td>328</td><td>Insulator</td></tr>
<tr><td>5/12/2018</td><td>72</td><td>Insulator</td></tr>
<tr><td>2/10/2019</td><td>68</td><td>Third Party Damage</td></tr>
</table>

Service Restoration Actuals 2015 - 2020

Actual	2015	2016	2017	2018	2019	2020	Grand Total	5 Year Avg (2018 - 2020)	Inflated 2021	Inflated 2022
Business Expense	$151,322	$124,669	$448,375	$158,726	$329,863	$133,560	$1,346,516	**$239,039**	**$245,015**	**$250,650**
Contractor	$15,559,075	$9,247,355	$24,208,233	$18,962,523	$39,018,235	$26,982,472	$133,977,893	**$23,683,764**	**$24,275,858**	**$24,834,202**
Exempt Labor	$1,132,544	$1,050,640	$2,919,993	$1,883,210	$3,780,786	$2,650,666	$13,417,839	**$2,457,059**	**$2,535,685**	**$2,616,827**
Material	$419,034	$910,278	$1,048,076	$1,300,668	$2,061,898	$1,531,972	$7,271,926	**$1,370,578**	**$1,404,843**	**$1,437,154**
Non Exempt Labor	$1,008,758	$752,670	$1,600,151	$1,702,025	$2,132,696	$1,129,920	$8,326,220	**$1,463,492**	**$1,510,324**	**$1,558,654**
OM&C Labor	$7,466,163	$7,462,007	$12,772,881	$12,604,957	$18,152,878	$14,907,644	$73,366,529	**$13,180,073**	**$13,575,475**	**$13,982,740**
Other Expense	$7,044,720	$5,920,941	($4,184,918)	$7,966,426	$9,667,000	$8,286,916	$34,701,085	**$5,531,273**	**$5,669,555**	**$5,799,955**
Other Labor	$5,385,096	$10,035,482	$11,359,171	$9,345,523	$16,985,282	$15,638,991	$68,749,545	**$12,672,890**	**$13,078,422**	**$13,496,932**
Grand Total	$38,166,712	$35,504,042	$50,171,962	$53,924,058	$92,128,638	$71,262,140	$341,157,552	**$60,598,168**	**$62,295,177**	**$63,977,114**

Inflation Rates

Other Labor	3.2%	103.2%
OM&C Labor	3.0%	103.0%
Non-Labor 2016	1.3%	101.3%
Non-Labor 2017	2.1%	102.1%
Non-Labor 2018	2.4%	102.4%
Non-Labor 2019	1.8%	101.8%
Non-Labor 2020	1.2%	101.2%
Non-Labor 2021	2.5%	102.5%
Non-Labor 2022	2.3%	102.3%

ADJUSTED FOR INFLATION (through 2020)	2015	2016	2017	2018	2019	2020	Grand Total	5 Year Avg (2016 - 2020)	Inflated 2021	Inflated 2022
Business Expense	$165,107	$134,280	$473,009	$163,522	$333,822	$133,560	$1,403,301	**$247,639**	**$253,830**	**$259,668**
Contractor	$16,976,463	$9,960,279	$25,538,262	$19,535,495	$39,486,454	$26,982,472	$138,479,424	**$24,300,592**	**$24,908,107**	**$25,480,994**
Exempt Labor	$1,325,725	$1,191,716	$3,209,378	$2,005,664	$3,901,771	$2,650,666	$14,284,920	**$2,591,839**	**$2,674,778**	**$2,760,371**
Material	$457,207	$980,456	$1,105,659	$1,339,969	$2,086,641	$1,531,972	$7,501,903	**$1,408,939**	**$1,444,163**	**$1,477,379**
Non Exempt Labor	$1,180,825	$853,736	$1,758,734	$1,812,697	$2,200,942	$1,129,920	$8,936,853	**$1,551,206**	**$1,600,844**	**$1,652,071**
OM&C Labor	$8,655,329	$8,398,555	$13,957,272	$13,372,599	$18,697,464	$14,907,644	$77,988,862	**$13,866,707**	**$14,282,708**	**$14,711,189**
Other Expense	$7,686,474	$6,377,416	($4,414,842)	$8,207,140	$9,783,004	$8,286,916	$35,926,107	**$5,647,927**	**$5,789,125**	**$5,922,275**
Other Labor	$6,303,648	$11,383,008	$12,484,919	$9,953,206	$17,528,811	$15,638,991	$73,292,583	**$13,397,787**	**$13,826,516**	**$14,268,965**
Grand Total	**$42,750,778**	**$39,279,445**	**$54,112,390**	**$56,390,292**	**$94,018,909**	**$71,262,140**	$357,813,954	**$63,012,635**	**$64,780,070**	**$66,532,910**
Non Contractor	$25,774,315	$29,319,166	$28,574,128	$36,854,797	$54,532,455	$44,279,669	$219,334,529.52	$38,712,043		

Aggregate 2021	**102.8%**
Aggregate 2022	**102.7%**

2021 Service Restoration Cost (Includes Inflation)		**$64,780,070**
2021 Cost Reduction from Tree Trimming (Bolden Direct, p. 27)	$	(380,000)
2022 Cost Reduction from Capital Improvements	$	(190,000)
2021 Service Restoration less productivity		**$64,210,070**
2022 Aggregate Inflation		102.7%
2022 Service Restoration Cost (Includes Inflation)		$65,947,487
2022 Cost Reduction from Tree Trimming (Bolden Direct, p. 27)	$	(1,000,000)
2022 Cost Reduction from Capital Improvements	$	(500,000)
2022 Test-Year Service Restoration Cost		**$64,447,487**

Proposal	**$**	**64,400,000**

Present Value of Advancing the Neely and Gun Lake Capacity Ugrades 5 Years - Lost Deferral Value
U-20963

Year	Capital Cost	Escalated Capital Cost	Cumulative Capital	Fixed Charges	Sum of Total Annual Costs	Present Worth of Total Annual Costs ($1000)
2020	0	0	0	0		
2021	2107	2153	2107	265	265	$ 229
2022	400	418	2507	316	316	$ 236
2023				316	316	$ 205
2024				316	316	$ 177
2025				316	316	$ 153
2026				51	51	$ 21
2027						**$ 1,021**

Capital Costs, annual fixed Charges, and discount rates derived from Attachment 126, page 19

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	U-20963 ALJ Sharon Feldman

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony of Robert G. Ozar PE on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan and Exhibits MEC-19 through MEC-41** (with MEC-37 and MEC-41 reserved) was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC, NRDC, SC, and CUB

Date: June 22, 2021

Digitally signed by Breanna Thomas
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By: ______________________________

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