STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
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John A. Tuma	Commissioner

In the Matter of Xcel Energy's 2023 Integrated Distribution Plan	Docket No. E-002/M-23-452

INITIAL COMMENTS OF GRID EQUITY COMMENTERS: COOPERATIVE ENERGY FUTURES, ENVIRONMENTAL LAW & POLICY CENTER, SIERRA CLUB, AND VOTE SOLAR

March 1, 2024

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I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

In its Integrated Distribution Plan (IDP), Northern States Power Company, doing business as Xcel Energy (Xcel or the Company), projects substantial distribution budget increases, driven in significant part by distribution system capacity expansion to address forecasted electrification and growth of distributed energy resources (DERs). Xcel anticipates that its distribution budget will more than double in five years, increasing from $491 million in 2023 to $1,070 million in 2028—an increase of $579 million.[1] For its "System Expansion or Upgrades for Capacity" budget category specifically, which includes spending to enable electrification and DER integration, Xcel projects a $192 million increase, from $35 million in 2023 to $227 million in 2028.[2] These large budget increases raise potentially significant affordability concerns for customers, who would ultimately pay these costs if approved—concerns that are particularly significant for lower-wealth and other vulnerable customers least able to shoulder such increases. At the same time, it is critical for Xcel to upgrade and expand its system to facilitate electrification and DER growth, which state energy policy encourages through various mandates and programs. Moreover, the costs and the benefits of the Company's investments should be allocated as equitably as possible. To address affordability and equity concerns while still upgrading its system to facilitate the clean energy transition, Xcel will need to take advantage of areas where its budgets can be reduced, such as by leveraging DERs wherever feasible and appropriately quantifying their benefits. The Company will also need to continue to provide evidence that its planned investments yield the benefits they promise, including benefits like improved access to DERs that can result in cost savings for customers.

[1] IDP App. D at 17.
[2] IDP App. D at 17.

Cooperative Energy Futures, Environmental Law & Policy Center (ELPC), Sierra Club, and Vote Solar file here jointly as the Grid Equity Commenters (GECs).[3] Our organizations have filed together and separately in recent related proceedings, including Xcel's last IDP proceeding (Docket No. 21-694, as Community Power, ELPC, and Vote Solar (CEV)) and Xcel's most recent general rate case (Docket No. 21-630, as the Just Solar Coalition intervenors—Community Power, Cooperative Energy Futures, Minnesota Interfaith Power & Light, and Vote Solar—represented by ELPC). As we have in the past and as discussed further below in Section II, we center equity and energy justice considerations in our evaluation of Xcel's IDP and our recommendations. We appreciate the significant effort that Xcel put into this IDP and its responsiveness to stakeholder feedback and interests, as well as state policy priorities around enabling DERs. For example, we commend the Company's consideration of net load and the load-reducing impact of distributed generation, as well as its efforts to plan proactively for electrification and increasing volumes of DERs. We recognize that the IDP is an iterative effort by its nature and we intend our recommendations to build off the progress that Xcel has made to date. As discussed below, and supported by the attached technical memorandum from Cody Davis, Senior Engineering Manager of Distribution & Grid Modernization at Electric Power Engineers, we recommend that the Commission:

- **Accept/Reject Xcel's IDP (Question 14)—**Adopt the following modifications and other recommendations prior to accepting Xcel's IDP.
- **DERMS and Flexible Interconnection (Question 16.b.i)**—Prior to Commission approval and Company implementation of any DERMS investments, require Xcel to:
    - Demonstrate the Company's ability to integrate DERs with the tools available to it today and in the near term, including specifically through: (1) implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and (2) pursuing a staged approach

[3] The GECs also received technical assistance from the Interstate Renewable Energy Council (IREC) in developing these comments.

to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation, as discussed in more detail in response to Question 16(b)(i).

  - Require Xcel to be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owner/operators.

  - Provide a detailed roadmap for DERMS deployment that addresses the questions provided below in response to Question 16(b)(i). The Commission should ensure that Xcel has adequately addressed these questions prior to approving any DERMS investments.

  - Conduct robust stakeholder outreach, including specifically with DER owners/operators, and describe in a filing with the Commission its stakeholder engagement process, the materials it used to inform stakeholders about DERMS (addressing, e.g., costs, benefits, alternatives, purpose, problems it is solving, etc.), the feedback it received, and how it has addressed it.

- **Integrated Volt-Var Optimization (IVVO) (Question 16(b)(ii))**—Require Xcel to reevaluate IVVO, updating its analysis and assumptions consistent with the recommendations provided in response to Question 16(b)(ii), and refile its updated evaluation within 6 months of the Commission's final order in this proceeding. In particular, the GECs request that the Commission direct Xcel to explore ways in which IVVO could be deployed in a targeted way within "environmental justice areas," as defined in Minn. Stat. § 216B.1691, Subd. 1(e), to reduce customer bills.

- **Forecasted Distribution Budget (Question 16(b))—**Require Xcel: (1) to address any impacts from changes in rate design, in particular the use of time-of-use (TOU) rates, on its IDP forecasts and resulting investment planning; and (2) to continue to refine its incorporation of demand response and load flexibility programs into its forecasts in a more granular manner.

- **Planned Net Load (PNL) methodology and 15% Dependability Factor (Question 16(e))—**Require Xcel to continue to refine its PNL methodology, taking into account concerns discussed in response to Question 16(e) regarding the Company's conservative 15% dependability factor, including specifically to consider: (1) increasing its dependability factor, and (2) seasonal and/or otherwise differentiated dependability factors. Xcel should explain in its next IDP any decisions to change or not to change its dependability factor.

- **Budgets and Cost Allocation for DER-Enabling Distribution Upgrades (Question 17)—**
    - Require Xcel to incorporate both hosting capacity and equity considerations into its distribution budget prioritization process, as discussed in response to Question 17.
    - **Proactive Grid Upgrades (Question 17(f))—**
        - For its Grid Reinforcements Program, require Xcel to report on actual upgrades undertaken under this budget in its upcoming IDPs, such that the Commission and stakeholders can evaluate its deployment.
        - For its placeholder budget for proactive hosting capacity upgrades, require Xcel to: (1) target areas serving all or primarily residential and small commercial customers; and (2) consider the energy justice implications of its proactive grid investments, including specifically evaluating whether it can target upgrades to improve capacity for new load or hosting capacity within "environmental justice areas" where it has identified relatively low or constrained capacity.
        - Consider socializing the costs of such proactive hosting capacity upgrades, targeted to residential and small commercial customers, similar to the treatment of small customer load, as discussed in more detail in response to Question 17.
- **Aligning IDP and Rate Cases (Question 18)**—Reaffirm that the Commission will rely on the IDP when reviewing utility distribution investments in rate cases; and that if a rate case proposal is inconsistent with the utility's IDP, then the bar for Commission approval is significantly higher.
- **Cost-Benefit Analysis for Discretionary Distribution Investments (Question 19)—**
    - Clarify that Xcel should evaluate applying cost-benefit analyses to program-level investments.
    - As part of the above effort, require Xcel to explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.
- **Relationship of Xcel's IDP to Its Interconnection Process and Technical Planning Standard (TPS) (Question 24)**—Continue the Commission's investigation into the TPS, including its intersection with the IDP, and answer at a

minimum the following questions: (1) Which IDP projects and programs are impacted by the TPS, such that the associated investments are higher than they would be without the TPS?; and (2) Is it just and reasonable to allow full cost recovery of investments that are inflated by application of the TPS?

- **Flexible Load Programs (Question 24)—**Require Xcel to develop plans to expand load flexibility pilots such that residential customers can opt to participate and be compensated for their load flexibility, taking into consideration recommendations related to their impact on the local distribution system, discussed further below in response to Question 24.

In addition, regarding **Coordination Between Xcel's IDP and IRP (Question 24)**, particularly with respect to DER forecasts, the GECs request that Xcel supplement its discussion of this topic in its reply comments to the extent it has further information or insights to share regarding coordinating forecasts across the two plans now that the Company has filed its IRP. Specifically, we request additional explanation for the apparent divergence in the 2040 peak demand forecast between the IDP and IRP, as discussed further below in response to Question 24.

To support our recommendations, we have attached two documents to these comments:

- **Attachment 1:** Cody Davis, Technical Memorandum Regarding Xcel Energy's 2023 Integrated Distribution Plan (IDP) in Minnesota

  Through assistance from GridLab,[4] the GECs retained Cody Davis, Senior Engineering Manager of Distribution & Grid Modernization at Electric Power Engineers, to evaluate Xcel's IDP and offer his recommendations on key issues. Mr. Davis previously provided expert testimony in Xcel's last general rate case (Docket No. 21-630) on behalf of the Just Solar Coalition.[5] Prior to EPE, Mr. Davis worked at Ameren Illinois. In his last role at Ameren, Mr. Davis worked on DER Integration and Strategy, including: performing DER interconnection and system impact studies for larger solar installation; leading internal interconnection policy and criteria development; leading several initiatives and pilot analyses in hosting capacity, non-wires alternatives, the value of DERs to the distribution system, and the impact of

[4] GridLab provides comprehensive technical expertise to policy makers, advocates, and other energy decision makers on the design, operation and attributes of a flexible and dynamic grid. More information is available at: https://gridlab.org.

[5] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Testimony of Cody Davis on behalf of Just Solar Coalition (Oct. 3, 2022) & Surrebuttal Testimony of Cody Davis on behalf of Just Solar Coalition (Dec. 6, 2022).

smart inverter functions on Ameren's voltage optimization program. Before his role in DER Integration, Mr. Davis's job duties at Ameren included load forecasting, distribution system planning, project justification, reliability analysis and improvement, distribution design, project management, responding to customer technical complaints, drone piloting, and storm field checking. These comments incorporate Mr. Davis's analysis and recommendations throughout.

- **Attachment 2:** Dr. Bhavin Pradhan and Dr. Gabriel Chan, "Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area"

  Dr. Bhavin Pradhan and Dr. Gabriel Chan are researchers at the University of Minnesota Center for Science, Technology, and Environmental Policy. Their paper offers a detailed statistical analysis with an energy justice lens of electric service quality, involuntarily disconnections, and DER hosting capacity in the Company's service area. The authors find meaningful and robust evidence of disparities in the experience of extended outages and involuntary disconnections and suggestive evidence warranting further analysis of disparities in multiple outages and hosting capacity. The paper is further summarized below in Section II.B and its findings are incorporated through these comments.

II. INCORPORATING EQUITY AND ENERGY JUSTICE INTO DISTRIBUTION PLANNING

A. Recent Efforts to Address Equity and Energy Justice

In its last IDP Order, the Commission recognized the need for "continuing efforts to incorporate and address equity in the distribution planning process," and noted Xcel's ongoing efforts to develop and address these ideas in other proceedings.[6] Since then, the Commission has continued to weigh and consider the incorporation of equity and energy justice within utility planning and regulation.[7] In Xcel's most recent general rate case, the Commission took a

[6] *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project*, Docket No. E-002/M-21-694, at 6 (July 26, 2022) (citing *In the Matter of a Commission Investigation to Identify Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operation*, Docket No. E-002/CI-17-401; *In the Matter of Xcel Energy's Annual Report on Safety, Reliability, and Service Quality for 2019; and Petition for Approval of Electric Reliability Standards for 2020*, Docket No. E-002/M-20-406; and *In the Matter of Efforts to advance workforce diversity, inclusive participation, and equitable access to utility services for Xcel Energy*, Docket No. E-002/M-22-266).
[7] *See, e.g.*, *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Sherco Solar 3 and the Apple River Solar Power Purchase Agreement*, Docket No. E-002/M-22-403 (Commission asked "Has Xcel sufficiently considered energy justice in its petition, and does the Company's petition demonstrate a commitment to diversity, equity, and inclusion?" and, in its Oct. 25 2023 order, Commission adopted the

commendable step in explicitly recognizing the "the importance of Energy Justice tenets … in its proceedings, including general rate cases," responding to arguments and proposals advanced by the Just Solar Coalition intervenors: Community Power, Cooperative Energy Futures, Vote Solar, and Minnesota Interfaith Power & Light.[8] The Just Solar Coalition argued that consideration of energy justice was inherent in the Commission's "just and reasonable" rate-making authority and obligation and urged the Commission to consider Xcel's rate case application and proposals through an energy justice lens.[9]

The Legislature has likewise increasingly recognized equity and justice considerations in its clean energy policy. For example, as part of last year's 100% carbon-free electricity bill, the Legislature directed the Commission to implement the State's various clean energy standards "in a manner that maximizes net benefits to *all Minnesota citizens*," including by ensuring that "*all Minnesotans* share (i) the benefits of clean and renewable energy, and (ii) the opportunity to participate fully in the clean energy economy…."[10] Other subsections within this provision address ensuring that "workers have the necessary tools, opportunities, and economic assistance to adapt successfully during the energy transition, particularly in environmental justice areas,"

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recommendations of the Department of Commerce which evaluated Xcel's considerations of energy justice based on affordability and just transition/economic benefits); *In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation*, Docket No. E002/CN-23-212 Commission asked "Should the Proposed Evaluation Process be modified to include energy justice and other related metrics?" and, in its Nov. 3, 2023 order, Commission approved Xcel's proposal of a resource attribute matrix that included two energy justice attributes to evaluate proposals); *In the Matter of Xcel Energy's 2024-2040 Integrated Resource Plan*, Docket No. E002/RP-24-67 (Xcel included Appendix R that offers details of the Company's efforts to date to incorporate equity, energy justice, and environmental justice across different activities, including status updates on compliance activities under the Commission's Order Point 25 in its last IRP, including establishment of ESAG and EJAB).

[8] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order, at 139 (July 17, 2023); *see also id.* at 137-139, Order ¶ 121 (discussion and order re same).

[9] *See, e.g.*, *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Initial Brief of the Just Solar Coalition, at 1-18 (Jan. 11, 2023).

[10] Minn. Stat. § 216B.1691, Subd. 9(a) (emphasis added).

and that "statewide air emissions are reduced, particularly in environmental justice areas."[11] These statutory provisions are relevant to the Commission's consideration of Xcel's IDP because the IDP is a critical component of the successful implementation of Minnesota's clean energy goals and these specific justice-focused directives.

While the GECs recognize Xcel's attempts to grapple with equity concerns within the Commission-mandated Equity Stakeholder Advisory Group (ESAG), we emphasize, as some of our organizations did in the previous IDP and the most recent rate case, the need to integrate these principles into utility planning and decision-making to advance them in practice. We appreciate that Xcel has been studying disparities with respect to equity in reliability and service quality—disparities that the Just Solar Coalition surfaced in testimony in the Company's recent rate case[12]—and the Company has indicated its intent to "continue to explore how these equity metrics could be incorporated in our overall distribution planning process."[13] As the Commission has ordered in Docket Nos. 17-401 and 20-406, Xcel will file a disparity study on April 1, 2024.[14] With Attachment 2, the GECs highlight additional data showing ongoing inequities in

[11] *Id.*; *see also id.* Subd. 1(e) ("'Environmental justice area' means an area in Minnesota that, based on the most recent data published by the United States Census Bureau, meets one or more of the following criteria: (1) 40 percent or more of the area's total population is nonwhite; (2) 35 percent or more of households in the area have an income that is at or below 200 percent of the federal poverty level; (3) 40 percent or more of residents over the age of five have limited English proficiency; or (4) the area is located within Indian country, as defined in United State Code, title 18, section 1151.").

[12] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Direct Testimony of Dr. Gabriel Chan on behalf of Just Solar Coalition, at 16-38 (Oct. 3, 2022) & Surrebuttal Testimony of Dr. Gabriel Chan on behalf of Just Solar Coalition, at 9-24 (Dec. 6, 2022).

[13] IDP App. E at 12.

[14] *In the Matter of Xcel Energy's Annual Report on Safety, Reliability, and Service Quality and Petition for Approval of Electric Reliability Standards*, Docket No. E-002/M-20-406 & *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Docket No. E-002/CI-17-401, Order (May 18, 2023) ("3. Required Xcel to conduct an analysis that examines whether there is a relationship between poor performance on the five identified metrics displayed on the interactive map and equity indicators. Required Xcel to file this analysis with its next service quality report due April 1, 2024. 4. If Xcel's analysis determines there are disparities in any of the five metrics displayed on the map, required Xcel to identify preliminary steps it could take to rectify the disparities and if Commission approval is required, where and when it would expect to file solutions. This should include an analysis of whether modifications

Xcel's system today, summarized further below in subsection C. This analysis is consistent with the Commission's study directives to Xcel in Docket Nos. 17-401 and 20-406, and offers strong support for the Commission to take action in this proceeding to require Xcel to address persistent system inequities via its IDP. Our comments offer recommendations on how to address these demonstrated disparities in Xcel's distribution planning process and build off of clear precedents from other proceedings.

B. Defining Energy Justice

Energy justice refers to "the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those historically harmed by the energy system," often referred to as "frontline communities."[15] Like safety, reliability, efficiency, and affordability, energy justice is an important distribution planning objective, albeit one that is not yet explicitly integrated into the planning process, or effectively measured and evaluated. For example, the traditional practice of measuring and evaluating metrics like safety, reliability, efficiency, affordability at a bulk-system or rate-class level has thus far prevented a clear understanding of the unequal and inequitable community-level effects of the current system, and in turn hampered our ability to address them. The movement from the historic, centralized electricity system to a more dynamic, decentralized system has highlighted the need to rethink planning, measurement, and evaluation practices as well. Effectively integrating energy justice as a planning objective would result in more measurement and evaluation of whether just and equitable outcomes for customers are being achieved. In turn, such data should contribute to action and tangible changes, such as

to Xcel's Quality of Service Plan are necessary to address any identified disparities. Required Xcel to file this preliminary plan with its next service quality report due April 1, 2024.").

[15] Initiative for Energy Justice, The Energy Justice Workbook, Section 1, https://iejusa.org/section-1-defining-energy-justice (defining "energy justice" and providing alternative definitions)

improved reliability and resilience for vulnerable communities, improved affordability for those with high energy burdens, and wealth-building opportunities for marginalized and frontline communities, in particular through ownership of DERs, as discussed further below.

C. Existing Inequities in Xcel's Distribution System: Summary of "Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area" by Dr. Bhavin Pradhan and Dr. Gabriel Chan

Dr. Bhavin Pradhan and Dr. Gabriel Chan, researchers at the University of Minnesota Center for Science, Technology, and Environmental Policy, undertook an independent, statistical analysis with an energy justice lens of electric service quality, involuntarily disconnections, and DER hosting capacity in the Company's service area. They published their findings in "Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area," which we provide as Attachment 2 to these comments and summarize in this section. Drs. Pradhan and Chan find meaningful and robust evidence of disparities in the experience of extended outages and involuntary disconnections, and suggestive evidence warranting further analysis of disparities in multiple outages and hosting capacity. Their analysis is based on the integration of multiple data sources: Xcel Energy's Minnesota Electric Service Quality Interactive Maps (published annually from 2019 – 2022), Xcel Energy's Hosting Capacity Analysis for Generation, the U.S. Census American Community Survey's demographic and household estimates, and the Council on Environmental Quality's Climate and Economic Justice Screening Tool (CEJST) map of disadvantaged communities. Their analysis is consistent with the Commission's May 18, 2023 order in Docket Nos. 20-406 and 17-401 to examine relationships between poor performance and equity indicators. As noted above, the GECs recognize that Xcel is also conducting its own analysis of disparities in reliability and service quality,[16] and look forward to reviewing that report when Xcel files it.

Drs. Pradhan and Chan apply an energy justice lens by comparing grid performance metrics across communities with a high level of people of color (POC) and communities that are classified as "disadvantaged" by CEJST. The CEJST disadvantaged community designation is a critical metric of the Biden Administration's implementation of Executive Order 14008 and its Justice40 Initiative. Noting significant differences in grid topology and socioeconomic circumstances in the Twin Cities metro region and other areas of the Company's service area, Drs. Pradhan and Chan conduct analysis to account for county-level differences. The figures below summarize the analysis for the Company's entire service area and for just Hennepin and Ramsey Counties, which includes 62% of all Census Block Groups in the Company's service area. In Attachment 2, Drs. Pradhan and Chan apply more sophisticated statistical techniques to account for county differences.

Extended Outages: Drs. Pradhan and Chan find that households in CEJST-designated disadvantaged communities in the Company's service area experienced a higher incidence of extended outages (outages over 12 hours, CELI-12) than households in non-CEJST communities from 2018 to 2021. Within Hennepin and Ramsey Counties, households living in disadvantaged communities were 40% more likely to experience an extended outage than households in other communities, on average (27.9-29.5 households per 1,000 vs. 20.0-21.0 households per 1,000). This difference in the experience of extended outages is statistically significant and, therefore, unlikely to be the result of random variation in outages alone. Additionally, across Xcel's entire service area as well as within Hennepin and Ramsey Counties, communities in the top 10% of

[16] *See* IDP App. E at 11-12.

population of people of color experienced more outages than other communities. For example, from 2020 to 2022, the 10% of communities with the highest population of people of color were 47% more likely to experience an extended outage than other communities (46.4 households per 1,000 vs. 31.6 households per 1,000). This difference in the experience of extended outages is statistically significant and therefore unlikely to be the result of random variation in outages alone.

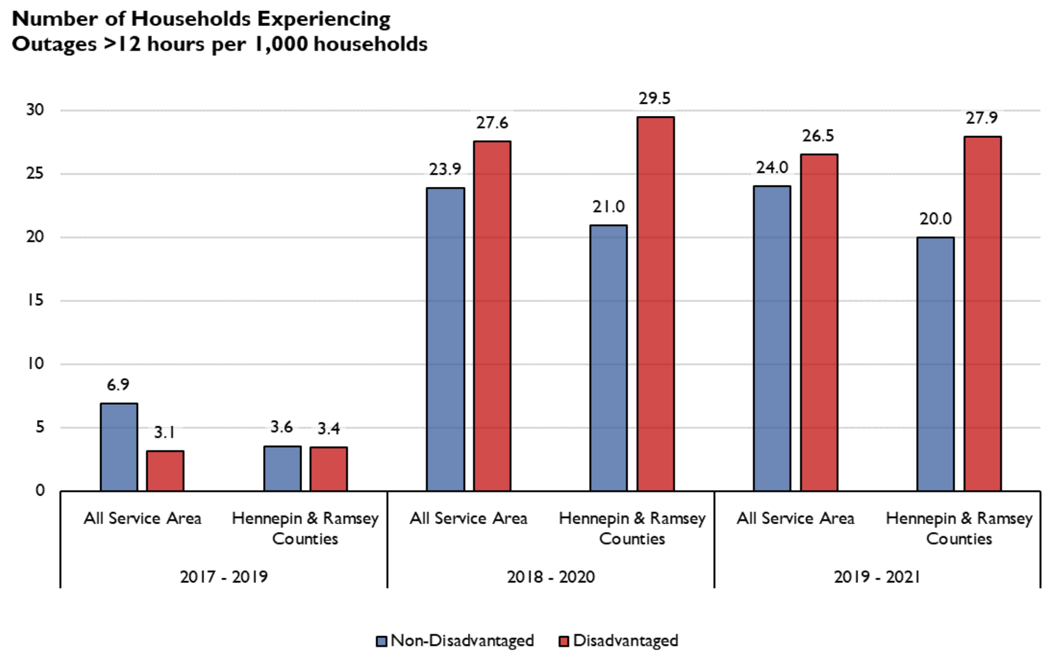

Figure 1. Number of households (per 1,000 households) experiencing outages longer than 12 hours (CELI-12). Comparing non-advantaged versus disadvantaged Census Block Groups in Xcel Energy's service area and Hennepin & Ramsey Counties from 2017-2021.

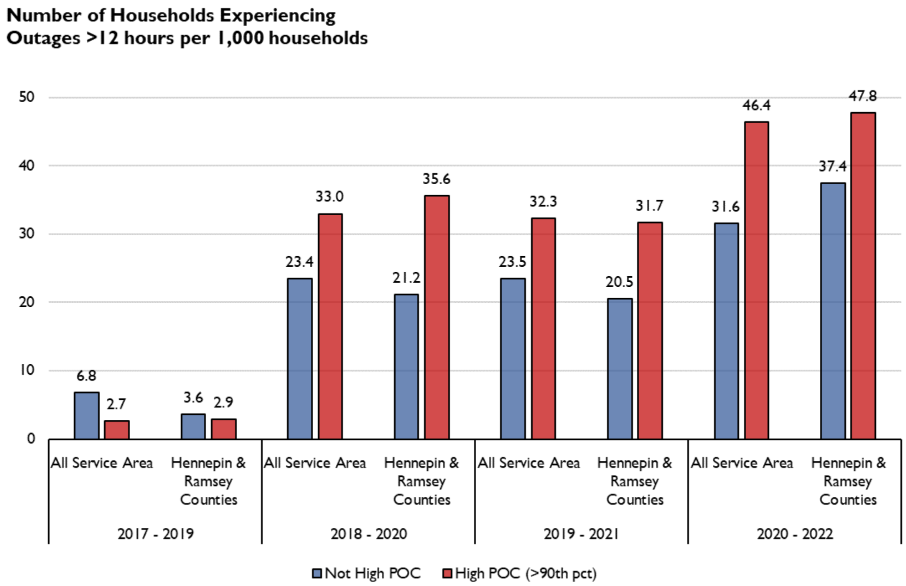

Figure 2. Number of households (per 1,000 households) experiencing outages longer than 12 hours (CELI-12). Comparing high POC Census Block Groups (> 90th percentile) with other Census Block Groups in Xcel Energy's service area and Hennepin & Ramsey Counties from 2017-2021.

Multiple Outages: Drs. Pradhan and Chan find limited evidence of disparities in the experience of multiple outages (more than 6 outages, CEMI-6). However, they find that from 2017 to 2019 within Hennepin and Ramsey Counties, households in disadvantaged communities were 41% more likely to experience more than 6 outages than other households (23.2 households per 1,000 vs. 16.5 households per 1,000). This difference in the experience of multiple outages is statistically significant and, therefore, unlikely to be the result of random variation in outages alone. Households in disadvantaged communities do not have a statistically significantly higher experience of multiple outages than other communities in other years (2018–2022) when all customers experienced notably fewer outages. Similarly, Drs. Pradhan and Chan find that from 2017 to 2019 within Hennepin and Ramsey Counties, households in the 10% of communities with the highest population of people of color were 46% more likely to experience 6 or more outages per year. However, this result is not statistically significant and no other years demonstrate a significantly higher rate of multiple outages in the communities with the highest population of people of color.

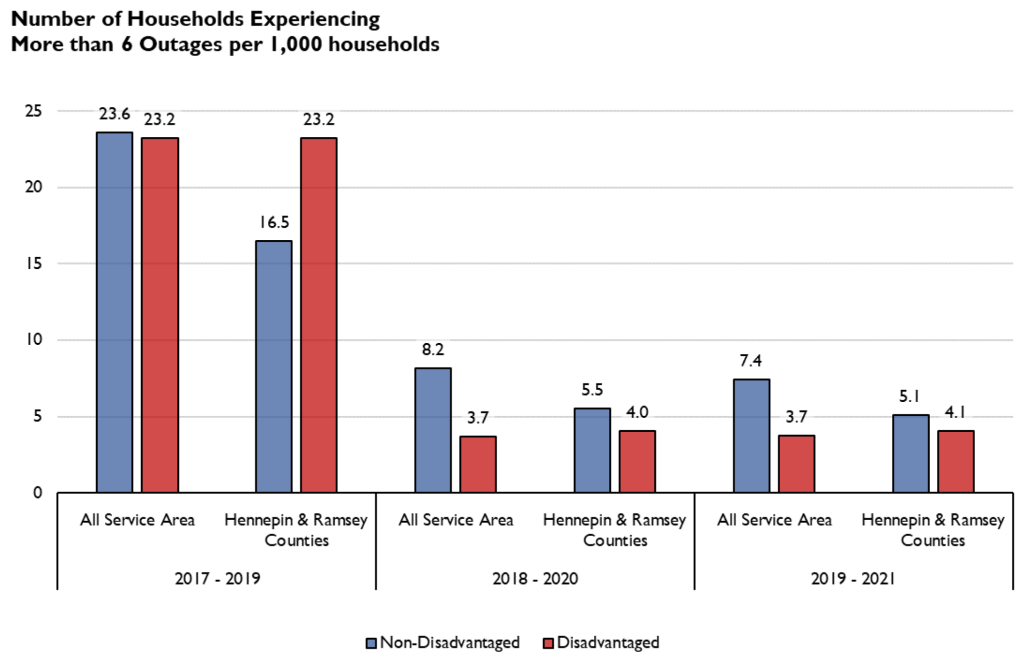

Figure 3. Number of households (per 1,000 households) experiencing 6 or more sustained outages per year (CEMI-6). Comparing non-advantaged versus disadvantaged Census Block Groups in Xcel Energy's service area and Hennepin & Ramsey Counties from 2017-2021.

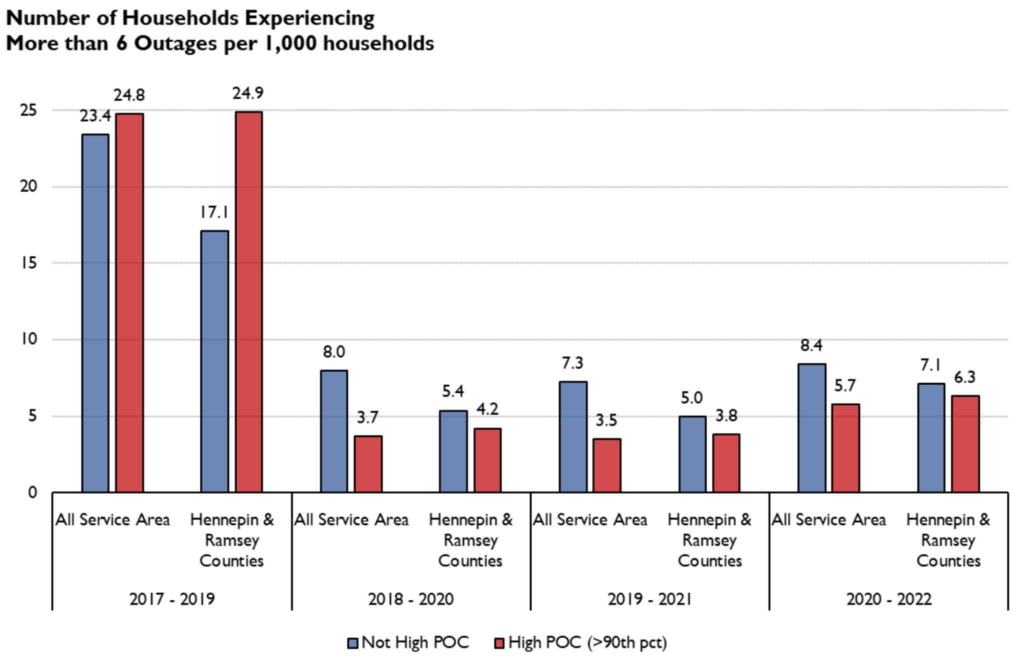

Figure 4. Number of households (per 1,000 households) experiencing 6 or more sustained outages per year (CEMI-6). Comparing high POC Census Block Groups (> 90th percentile) with other Census Block Groups in Xcel Energy's service area and Hennepin & Ramsey Counties from 2017-2021.

Involuntary Disconnection: Drs. Pradhan and Chan find significant and robust disparities in the incidence of involuntary disconnection across a community's median income, population of people of color, and disadvantaged community status. Involuntary disconnection is a key metric of affordability and indicates circumstances of extreme economic distress compounded by the energy system. To the extent to which distribution planning impacts affordability, inequities in the incidence of involuntary disconnections should be considered in reviewing the Company's distribution plan. Drs. Pradhan and Chan present visual evidence of the association between a community's population of people of color and the rate of involuntary disconnection across four time periods.

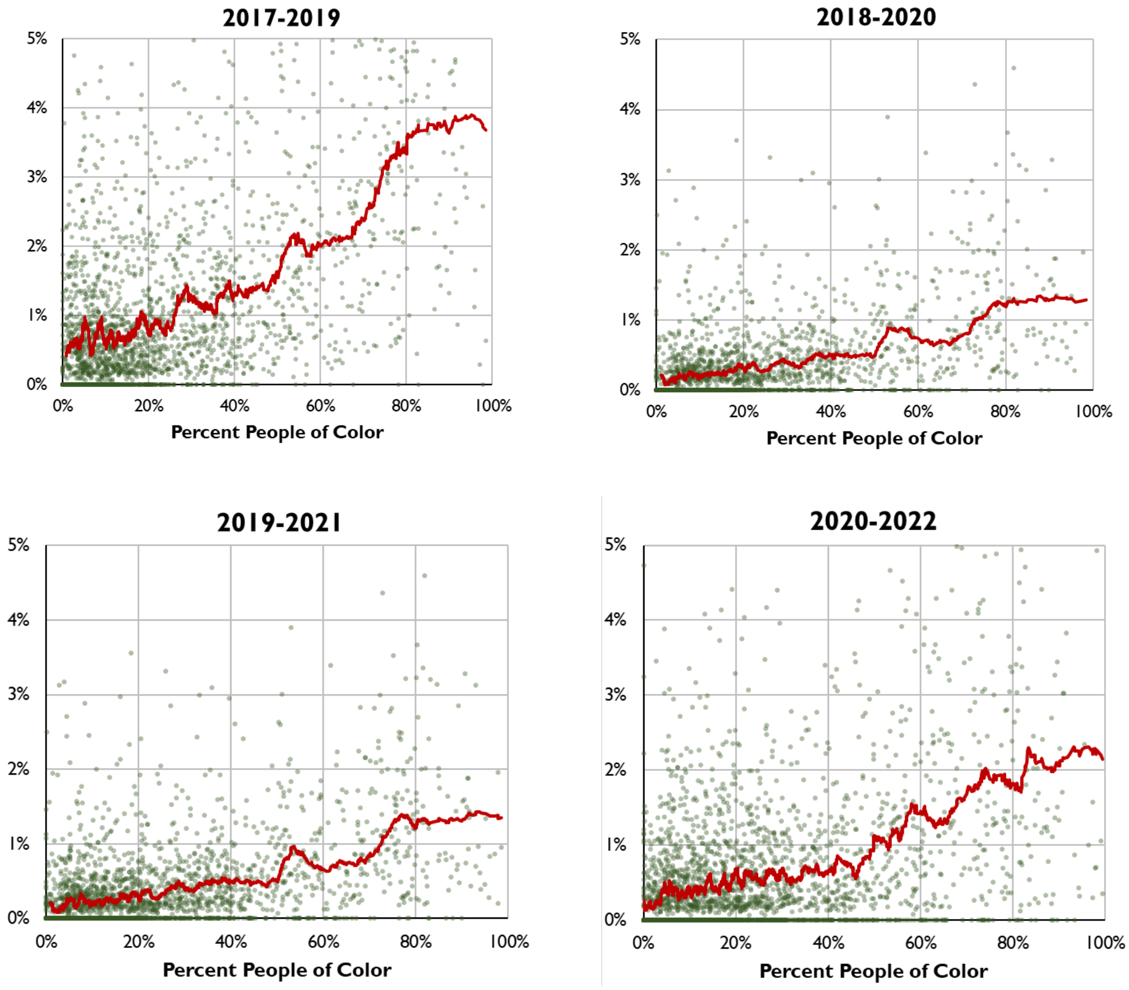

Figure 5. The relationship between Census Block Group average disconnection rates compared to its percent people of color, 2019-2022. The moving average line shows a clear positive relationship for all years. Disconnection rates are lower during the moratorium on disconnections during the COVID-19 pandemic.

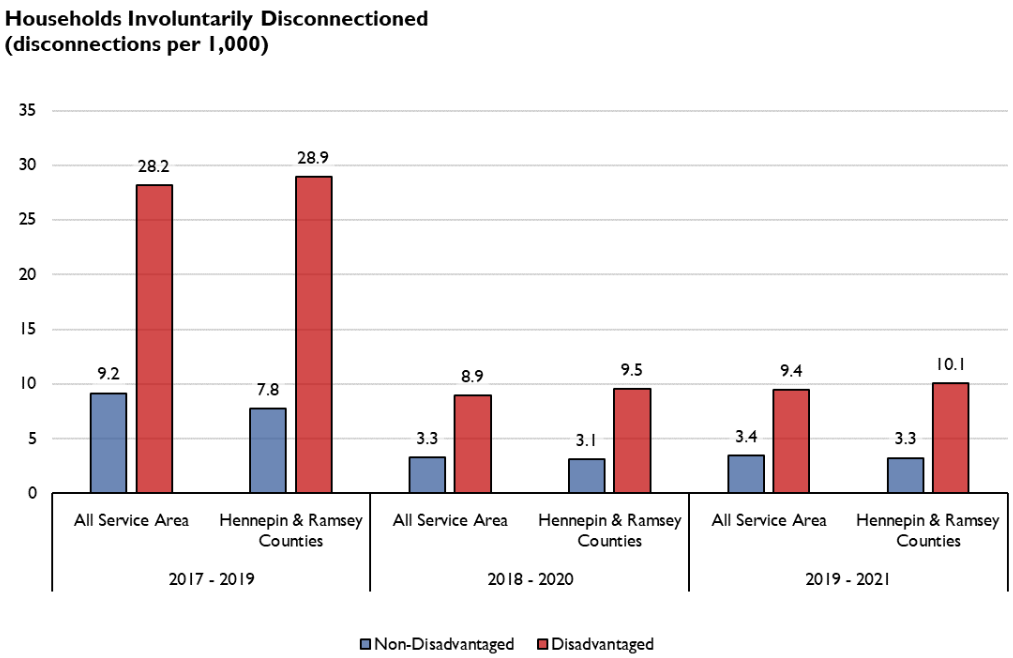

Figure 6. Number of households (per 1,000 households) disconnected involuntarily from 2017-2021, comparing disconnections between disadvantaged and non-disadvantaged communities in Xcel Energy's Service Area and Hennepin & Ramsey Counties.

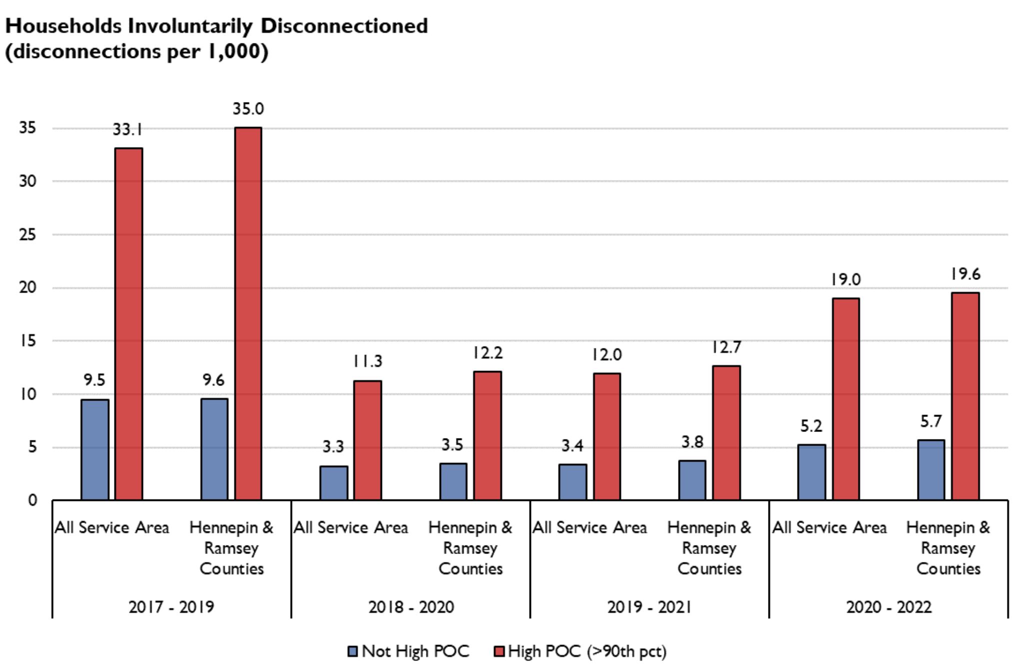

Figure 7. Number of households (per 1,000 households) disconnected involuntarily from 2017-2021, comparing disconnections between high People of Color (>90th percentile) and other communities in Xcel Energy's Service Area and Hennepin & Ramsey Counties.

One plausible explanation for the positive association between a community's percent of people of color and disconnection rate is confounding by income—meaning that an apparent racial disparity in disconnection could actually be an artifact of racial disparities in both disconnections and income. To address this possibility, Drs. Pradhan and Chan examine disconnection rates within bands of community median household income and bands of percent people of color. The figure shows that the upward association between disconnection rates and percent people of color holds even within communities with low or very low income, suggesting that racial disparities in disconnections compound income disparities in disconnections. Potential confounding between race and income is addressed more holistically in the regression analysis presented in Attachment 2, which finds consistent results.

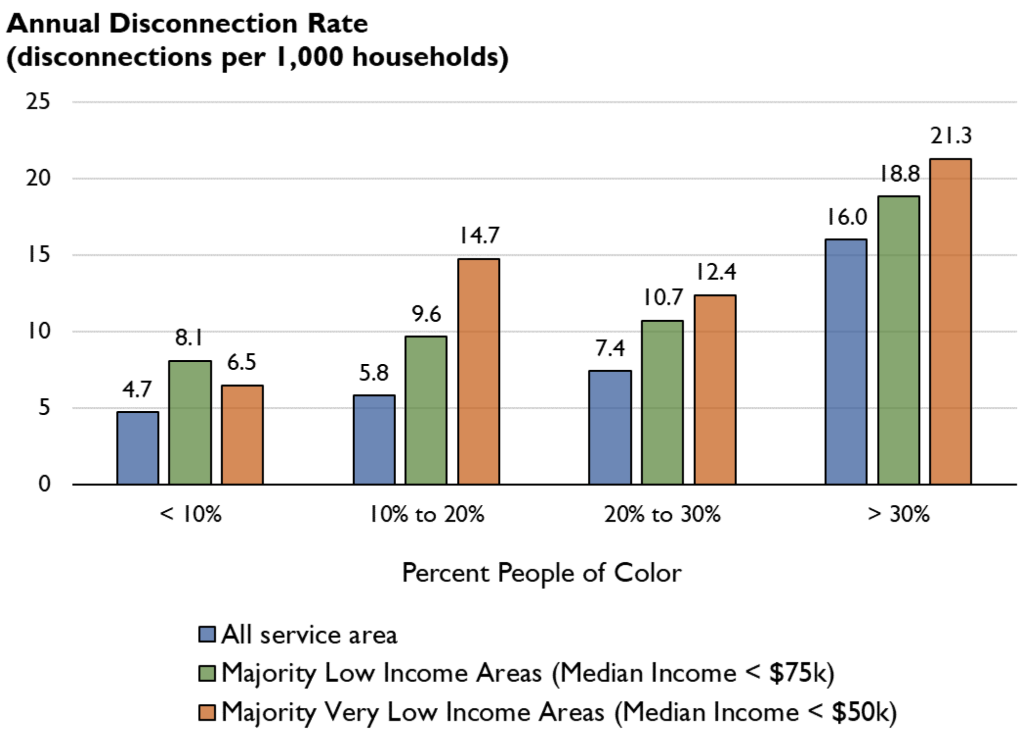

Figure 8. Rate of disconnection by an area's percent people of color overall and below different income levels, 2017-2022. Data for this figure combines data shown in Figure 2 for the period 2017-2019 and 2020-2022 to avoid double counting any years. Note that t*ime* period in this figure covers a moratorium on disconnections during the COVID-19 pandemic, and, therefore, disparities largely reflect disparities in disconnections from 2017-2019 and in 2022.

Hosting Capacity: Drs. Pradhan and Chan do not find evidence of regressive inequities in hosting capacity in the Company's service area. In fact, they find that disadvantaged communities and communities with the highest population of people of color have statistically significantly higher hosting capacity. Across the Company's service area, Drs. Pradhan and Chan find that maximum area hosting capacity is 37% higher in disadvantaged communities than non-disadvantaged communities (52% higher on a per-household basis). And within Hennepin and Ramsey Counties, maximum area hosting capacity is 16% higher in disadvantaged communities (26% higher on a per-household basis). These differences are statistically significant. These findings indicate that distributed generation could be integrated in many disadvantaged communities and communities with a high population of people of color with proportionally fewer grid integration barriers than other communities, suggesting significant potential for DER-focused strategies to address energy justice.

Detailed and accurate hosting capacity data could refine energy justice assessments by highlighting the disparities in access to DERs. More granular data would enable utilities to pinpoint underserved areas for targeted grid improvements, or even target areas with a high availability of hosting capacity to integrate DERs. Such data-driven strategies can inform strategies to address unique community barriers to DER adoption, facilitating a more inclusive and justice-focused energy transition.

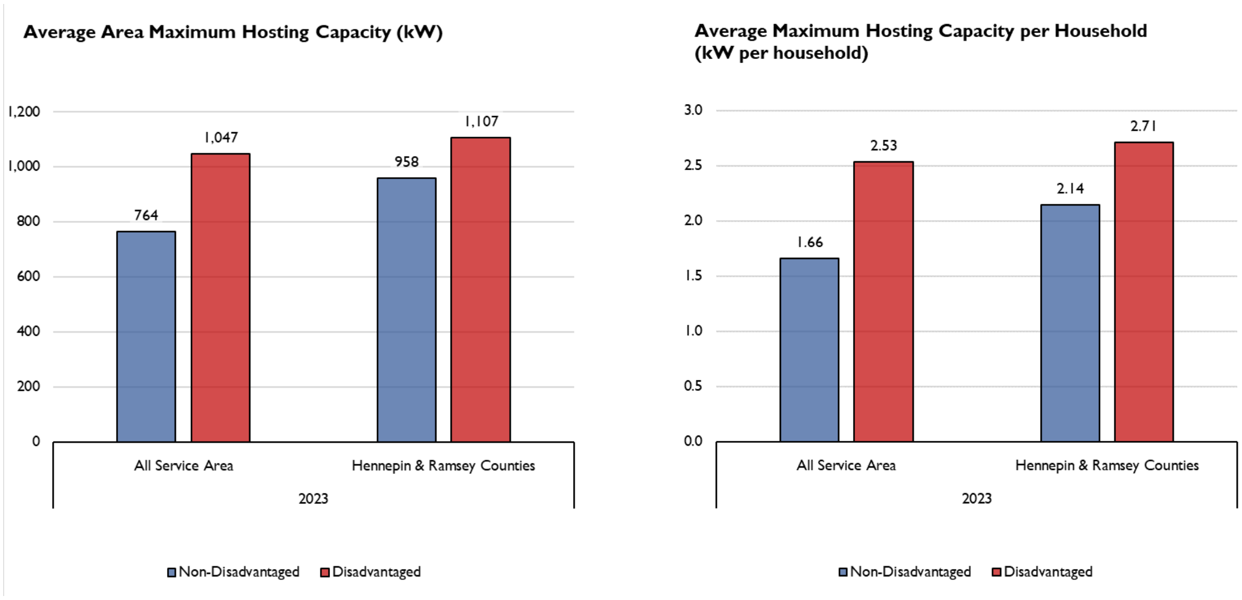

Figure 9. Average Area Maximum Hosting Capacity (kW) and b Average Maximum Hosting Capacity per Household (kW per household) for disadvantaged and non-disadvantaged Census Block Groups in Xcel Energy's Service Area and Hennepin & Ramsey Counties. The average area maximum hosing capacity (kW) averages the maximum hosting capacity value for each heatmap polygons to the Census Block Group level in Xcel Energy's Generation Hosting Capacity Maps. The average maximum hosting capacity per household is derived by dividing the average area maximum value by the total number of housing units in the Census Block Group.

D. Role of Distributed Energy Resources in Advancing Energy Justice

Enabling local ownership of DERs is essential to the movement toward energy justice, including through local wealth-building and improved community resiliency for marginalized and vulnerable communities.[17] Decisions about distribution system planning, investments, and operation, particularly to the extent they impact available hosting capacity, directly affect customers' and communities' ability to access and own DERs. Indeed, in its IDP Planning Objectives, the Commission has identified both customer engagement and empowerment (Objective 2) and the creation of grid platforms for new distributed technologies (Objective 3) as key goals. The GECs emphasize the importance of considering energy justice within these objectives to ensure that customers have equitable access to DERs—especially customers in

[17] *See, e.g.*, *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Testimony of Lorenzo Kristov on behalf of Just Solar Coalition (Oct. 3, 2022).

energy-burdened frontline communities. Ultimately, the GECs envision a distribution system that enables all communities, and particularly frontline communities and "environmental justice areas," to participate fully in the clean energy transition. Customer ownership of DERs is central to this vision, such that customers can produce clean energy locally in a way that benefits their communities and local economies, while also supporting the decarbonization of the greater electricity system. Because of the systemic marginalization of communities of color and low-income communities resulting, for example, in the inequities identified by Drs. Pradhan and Chan, institutions like the Commission and Xcel will have to act deliberately to change course and advance energy justice. Without consideration of energy justice in distribution system planning, and throughout electric utility planning and regulation, these benefits of DER ownership will continue to accrue primarily to more affluent customers. Integrating these principles is essential to equitable access to DERs and a just clean energy transition.

III. RESPONSES TO COMMISSION QUESTIONS 14-24

14. Should the Commission accept or reject Xcel Energy's Integrated Distribution Plan (IDP)?

The Commission should accept Xcel's IDP, with the modifications and other recommendations suggested by the GECs in these comments, as summarized Section I above, and discussed in more detail below.

15. Did Xcel Energy adequately address the Commission's IDP filing requirements and prior Orders, as outlined in Attachment 1 to this notice? Is additional information necessary for improved clarity?

Beyond our comments elsewhere in this section regarding deficiencies in Xcel's IDP filing, the GECs have no comment at this time but reserve the right to comment in reply.

16. Feedback, comments, and recommendations on the following areas of Xcel's IDP:

a. Non-Wires Alternative Analysis

The GECs support Xcel's ongoing efforts to effectively integrate non-wires alternatives (NWAs) into its distribution planning, and emphasize the need to continue to evaluate and improve the NWA selection and implementation process going forward. Effective use of NWAs within the distribution planning process can advance energy justice in at least three ways. First, NWAs can save Xcel and its customers money by deferring the need for costly upgrades and improving system efficiency, which can improve affordability, which is especially important for lower-wealth customers. Second, in addition to leveraging DERs for the economic benefit of the utility and all customers, NWAs can offer a value stream for DER owners, who are compensated for the benefits their DERs provide as local producers. When DERs are customer- or community-owned, this can mean local economic benefits, including local jobs, producer compensation, and pre-career educational-exposure for young people, which, again, can be especially meaningful in lower-wealth areas. Finally, effective use of NWAs can improve local reliability and resiliency, and potentially improve local air quality if they are eliminating the need for fossil generation, which can be especially beneficial in communities that have lower-quality reliability, resiliency, and air quality.

The GECs appreciate that Xcel has made improvements to its NWA identification process, in particular its proration of compensation based on expected distribution needs and costs.[18] While there remains room for improvement—for Xcel specifically, and for the use of NWAs by utilities generally—this modified approach results in improved NWA cost-effectiveness relative to past processes. The GECs have no additional comments on Xcel's NWA analysis at this time but reserve the right to comment further in reply.

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[18] IDP App. F.

b. Grid modernization plans, including but not limited to a Distributed Energy Resource Management System (DERMS), Virtual Power Plants (VPP), Integrated Volt-Var Optimization (IVVO), and Distributed Intelligence (DI)

i. Distributed Energy Resource Management System (DERMS)

In its IDP, Xcel explains its intent for a phased deployment of a DERMS to give it "more visibility and active management and coordination with DER to maintain a secure, reliable, and resilient distribution system."[19] Xcel characterizes DERMS as a "necessary step to integrate higher levels of DER."[20] The Company indicates that it is currently working with the Electric Power Research Institute (EPRI) to better understand how to leverage DERMS on its system and to develop an overall DERMS roadmap, and plans to conduct this examination and assess potential vendors "at least through the first half of 2024."[21] Given Xcel's intended timeline, the GECs emphasize that now is a critical time for the Commission to provide Xcel guidance regarding its evaluation of DERMS deployment.

The GECs agree with Xcel that a DERMS has the potential to facilitate the integration of more DERs—a goal we support—but urge the Commission to proceed with caution, especially in light of the potentially high costs of DERMS deployment and associated affordability concerns for customers. As Mr. Davis explains in his technical memorandum (Attachment 1): "There are certainly benefits that can be gained by the management of DER within these applications [of DERMS, as described by Xcel], but it is also important to clearly define the capabilities, approach, terms and conditions, and impact, especially to those customers whose resources will be managed." Moreover, as with other DER-enabling investments, to the extent DERMS implementation is a capital expenditure for the Company, Xcel is inherently

[19] IDP App. B1 at 24-25.
[20] IDP App. B1 at 25.
[21] IDP App. B1 at 25.

incentivized to pursue it to earn the associated return on equity. Therefore, the GECs encourage the Commission to scrutinize Xcel's DERMS proposals closely. As discussed further below, the GECs suggest that the Commission continue to require Xcel to demonstrate its ability to integrate DERs with the tools available to it today and in the near-term, including through static Flexible Interconnection, and provide further, robust justification for any DERMS investments prior to receiving Commission approval.

Flexible Interconnection

Flexible Interconnection is one of the use cases Xcel provides to justify DERMS deployment.[22] As Xcel explains, under a Flexible Interconnection approach, a DER would experience a temporary curtailment of generation during times of identified grid constraint and in turn be able to avoid costly system upgrades that would be necessary in the traditional interconnection process, thereby decreasing interconnection time and/or costs.[23] Xcel states that Flexible Interconnection may be implemented initially by relying on local and autonomous control, but states that "broader, more programmatic (e.g., multiple flexible interconnections on a substation or feeder) deployment … would require centralized control software [such as DERMS] to dynamically manage these generators."[24]

The GECs support Xcel's intent to implement Flexible Interconnection and agree that Flexible Interconnection is a promising approach to integrating more DERs. Given its complexity, however, we emphasize the need for thorough evaluation and Commission oversight, especially with respect to the role of DERMS. In addition, consistent with our recommendations regarding a DERMS roadmap below, we recommend that the Commission

[22] IDP App. B1 at 25; *see also id.* App. E at 4-6 (discussion of interconnection and flexible interconnection).
[23] IDP App. E at 4.
[24] *Id.*

require Xcel to be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owner/operators.

As Mr. Davis states in his technical memorandum (Appendix A):

> Flexible Interconnection shows significant promise in increasing the amount of DER that can be interconnected without requiring costly system upgrades. With that promise, however, comes considerable complexity and potential changes to many aspects of the current interconnection paradigm. EPRI, who Xcel is working with in assessing and developing DERMS capabilities, has published extensive materials detailing the concept of flexible interconnection,[25] options for prioritizing curtailment,[26] and cost allocation and risk.[27] From these materials, it is clear that there are many design decisions and trade-offs that must be made in developing and implementing flexible interconnection effectively in a way that is both practical and amenable to the needs of DER owners and operators.

In light of the complexity of Flexible Interconnection and the time it will take to implement fully, the GECs suggest that the Commission should require Xcel to explore intermediate opportunities. Specifically, in addition to the near-term recommendations included in the staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity discussed in more detail in the following subsection, the GECs suggest that the Commission require Xcel to implement static Flexible Interconnection prior to any DERMS approval. As Mr. Davis explains:

> One high-potential, low-cost opportunity to be considered is static flexible interconnection. Rather than setting dynamic maximum real power output points based on changing grid conditions, static flexible interconnection utilizes a local control system to ensure that total DER or site-wide power import or export does not exceed a pre-set threshold. For example, if a 2 MW solar PV system and a 2 MW Battery Energy Storage System (BESS) are installed by the same customer, they would traditionally be studied with a maximum of 4 MW of output and 2 MW of import. If this customer instead implements a local power control system, they can limit the maximum export to 2 MW if needed in order to avoid the need for costly distribution system upgrades. These capabilities are available today as part of Xcel's Technical Interconnection and Interoperability Requirements (TIIR) related to limited import and limited export. These types of

[25] https://www.epri.com/research/products/000000003002014475.
[26] https://www.epri.com/research/products/000000003002018506.
[27] https://www.epri.com/research/products/000000003002019635.

> interconnections generally have the import/export limits set by the initial interconnection application and enforced within the power control system.
>
> Extending full flexible interconnection capabilities to such locations would allow for additional import or export depending on grid conditions, impacting multiple resource types at one location. The ability to communicate with these control systems and adjust real power thresholds provides an important opportunity because these systems can be constructed today, with the potential for flexible interconnection to benefit them in the future with effectively no downsides. In order to realize this potential, interoperability and standardized communications requirements are important to establish as early as possible so that compatible power control equipment is selected and installed.

If Xcel can demonstrate success using static Flexible Interconnection, its success may offer the Commission some confidence in the Company's ability to successfully implement full Flexible Interconnection and help to justify any investment in DERMS to do so.

Mr. Davis also notes that other DERMS use cases that Xcel identifies along with Flexible Interconnection, namely FERC Order 2222 capabilities and virtual power plant facilitation, similarly involve communications to and control of customer-owned DER. Therefore, as we emphasize below in discussing the DERMS Deployment Roadmap, soliciting DER owner/operator and other stakeholder input, and addressing any concerns, will be critical before spending ratepayer money on acquiring or using DERMS.

Staged Approach to Flexible Interconnection, DERMS, & Dynamic Hosting Capacity

While the GECs recognize that DERMS may be appropriate and necessary in some circumstances, we do not agree with Xcel that the level of visibility and control it could provide is necessary in all circumstances to integrate higher volumes of DERs. Xcel should therefore expand its use of other strategies to integrate DERs, many of which are available now without large-scale and expensive DERMS investments. These strategies can be applied in a staged approach, similar to what Xcel proposed in their Interconnection Policy Roadmap in Figure E-1 of Appendix E, that would allow the expedited implementation of existing and vetted technologies like autonomous, edge-device, and third-party aggregator monitoring and control schema. As such, the GECs recommend that Xcel revise their Flexible Interconnection, DERMS implementation, and Dynamic Hosting Capacity adoption objectives to include the following tiered approach:

- Tier 1 – Autonomous and Dynamic Functions**:** Activation of tuned smart inverter functions such as volt-watt, and the utilization of hosting capacity analysis-informed and time-dependent export scheduling by the controls internal to the DER systems. While the GECs understanding is that Xcel has deployed or will soon deploy some of these functions, we are not aware of any plans to implement export scheduling. Such solutions should be specified in Xcel's IDP for deployment in the ***immediate near-term***, as export controls,[28] like autonomous smart inverter settings,[29] are validated and proven technologies.
- Tier 2 – Local Edge-Device Controlled: The utilization of grid edge devices placed near constrained grid equipment that monitor voltage and/or current for moments nearing a violation until a point in which curtailment controls for local DERs are triggered to avoid exceeding system thresholds. This strategy should be incorporated

[28] Prior to 2023, certified export-limiting enabling devices, known as Power Control Systems, using an addendum to the UL 1741 certification procedures referred to as the Certification Requirement Decision (CRD) for Power Control Systems. *See* Interstate Renewable Energy Council, *Toolkit & Guidance for the Interconnection of Energy Storage & Solar-Plus-Storage: III. Requirements for Limited- and Non-Export Controls* (March 2022). More recently, UL has published a new testing standard, UL 3141, that supersedes the CRD, creating a more straight-forward pathway for certifying power control systems used to control and schedule the export of DERs. *See* Underwriters Laboratory, UL 3141 Outline for Investigation for Power Control Systems (January 11, 2024); Xanthus Consulting International & Verdant Associates, LLC, Smart Inverter Operationalization (SIO) Working Group Report: Business Cases and Use Cases (February 1, 2024); https://gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf; https://energystorageinterconnection.org/iii-requirements-for-limited-and-non-export-controls/.

[29] Underwriters Laboratory, *UL 1741 Standard for Safety: Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources* (September 16, 2020). https://www.shopulstandards.com/ProductDetail.aspx?productId=UL1741_3_S_20210928

into Xcel's IDP in the *immediate near-term* as such technologies have been field-tested and validated both abroad[30] and domestically, albeit in a more limited capacity.[31]

- Tier 3 – EDC-Informed, Third-Party Aggregator DER Control: Pair circuit health information, which is obtained from local grid edge devices, with the control capabilities of third-party aggregators, which have monitoring and control capabilities over multiple DERs, to alleviate system congestion whenever it occurs. This should be considered a *mid-term solution to be implemented within a 2- to 3-year timeframe* as it requires systems integration between the Company and aggregator platforms.
- Tier 4 – System-Wide Centralized Control (DERMS): Deployment of system-wide, coordinated, and centralized DERMS. The GECs considers the timeframe proposed by Xcel, i.e., widespread deployment starting in 2028,[32] to be appropriate at this time, provided the Commission has determined that Xcel has conducted sufficient stakeholder outreach and adequately addressed the questions related to DERMS deployment posed below.

Roadmap for DERMS Deployment

The GECs recommend that the Commission require Xcel to provide a clear vision for DERMS deployment, along with a detailed roadmap showing the expected path to full

[30] See article on implementation of flexible interconnection solutions in the UK: https://news.smartergridsolutions.com/pressreleases/smarter-grid-solutions-underpins-worlds-most-advanced-electricity-network-control-system-2891819.

[31] See articles on the deployment of local-only DERMS deployment in the Avangrid utility in New York: (1) pilot project reacting to local voltage excursions, https://www.tdworld.com/distributed-energy-resources/article/21163388/reactive-power-dispatch-adds-flexibility-to-grid; (2) private project leveraging transformer current monitoring to increase available hosting capacity by over 400%, https://news.smartergridsolutions.com/the-case-for-flexible-interconnection-featuring-our-successful-flexible-interconnect-capacity-solution-fics-project-with-avangrid].

[32] IDP App. E at 5.

implementation. While Xcel has not yet asked for Commission approval of any specific DERMS investments, it seems clear from this IDP that the Company intends to pursue DERMS, and indeed is already well into its internal evaluation process. Therefore, Commission guidance regarding expectations for the Company with respect to justifying a DERMS investment is timely and necessary. Building from Mr. Davis's recommendations, the GECs suggest specifying that Xcel address the following questions in a roadmap, filed with the Commission, in advance of investing in and implementing DERMS:

- What are the alternatives to DERMS?
- What are the specific use cases for which DERMS will be utilized and who are the intended beneficiaries?
- Will participation in DER Management be voluntary or required? Will requirements vary based on resource size, resource type, program participation, market participation, or other factors? Will it be available for load interconnections (e.g., EV charging hubs) or interconnections utilizing limited import/export control systems?
- How will communications be established between Xcel's DERMS and customer DER? Who will bear the ongoing cost for any necessary communications infrastructure?
- How will capacity be allocated across new and existing managed and unmanaged interconnectors? How will capacity upgrades be justified and from whom will upgrade costs be recovered?
- How will prospective applicants understand the impact of DER management on the economics of their project? What information will be provided to prospective interconnectors related to expected curtailment and existing and expected grid conditions?
- What are the expected deployment and integrations costs for DERMS? What are the expected ongoing licensing, operating, and infrastructure costs to execute and maintain DERMS functionality? From whom will these costs be recovered?
- How are equity and energy justice principles being incorporated within the use cases, process design, and cost allocation?

The Commission should ensure that Xcel has adequately addressed these questions prior to approving any DERMS investments.

In addition, given the implications for DER owners and operators and, thus, the importance of integrating DER owner/operator feedback into a DERMS deployment plan, the GECs urge the Commission to require Xcel to solicit and prove it has achieved a critical threshold of stakeholder input, particularly from DER owners/operators, in advance of submitting any DERMS roadmap or proposal. In any future DERMS filing, in addition to addressing questions above, Xcel should describe its stakeholder engagement process, the materials it used to inform stakeholders about DERMS (addressing, e.g., costs, benefits, alternatives, purpose, problems it is solving, etc.), the feedback it received, and how it has addressed it.

ii. Integrated Volt-Var Optimization (IVVO)

As the Commission required in its order in the Company's latest rate case, Xcel included an assessment of whether IVVO is in the public interest in its IDP.[33] Xcel concluded that IVVO is not in the public interest because expected benefits have declined since the Company filed for IVVO certification in 2019 and its resulting benefit-cost ratio (BCR) is less than 1.[34] The GECs believe that Xcel has not provided adequate justification to support its conclusion and urge the Commission to require the Company to update its analysis. In particular, the GECs believe that IVVO has the potential to reduce bills for lower-wealth customers if deployed in an appropriately targeted way.

[33] IDP App. B1 at 28-32 (citing *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order, ¶ 36 (July 17, 2023)).
[34] IDP App. B1 at 28-32.

As Mr. Davis explains in his technical memorandum (Attachment 1), there are three areas where Xcel should revisit its analysis and underlying assumptions (emphasis added):

1. **First, there are still efficiency gains that can be achieved by reducing voltage, both now and in the future.** While some new loads or efficiency-related replacements may not benefit from voltage reduction, other new load additions will still see benefits. The T&D World article[35]cited by Xcel in their IDP response identifies a CVR factor for heat pumps as just under 0.6, which, while lower than historical CVR factors used in IVVO analysis, is much higher than zero. While the addition of new constant power loads for electrification may decrease overall CVR factors from a system perspective, it does not reduce the CVR factor for the individual equipment that remains connected, meaning there is still energy savings that can be achieved from reducing the voltage to that equipment. With the rate of load growth estimated by Xcel's forecast, all resources capable of reducing energy consumption and especially system peak load magnitude should be strongly considered.

2. **Second, before drawing broad conclusions, Xcel should explore the impact of the IVVO design choices made within the 2019 proposal and should consider whether changes to their approach would result in cost-effective savings that would be in the public interest.** Xcel's proposal in 2019 included significant costs for static var compensator devices and supporting software from Varentec.[36] Many utility deployments of IVVO have been successful without the deployment of such devices. In lieu of such devices, Xcel could identify circuits or substations on their system that could achieve IVVO benefits without significant reinforcements or system modifications beyond establishing communications to load tap changers, capacitor banks, or voltage regulators. Areas without existing low voltage issues, especially those with relatively flat voltage profiles, are prime candidates for low-cost deployments that could achieve worthwhile energy savings. Such areas could be identified from AMI voltage measurements or through power flow modeling. Additional considerations for targeted deployment could include deployment within disadvantaged communities, where reductions to customer bills may provide needed relief.

3. **Finally, deployment of IVVO can provide an important stepping stone to future deployments of operational control and optimization technologies like DERMS.** Fundamentally, executing flexible interconnection using a DERMS platform will likely share many similarities and foundational requirements with IVVO deployment

[35] https://www.tdworld.com/grid-innovations/smart-grid/article/20965787/cvr-is-here-to-stay.
[36] https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90E1276E-0000-C87B-896A-D252D87663CB}&documentTitle=201911-157133-04.

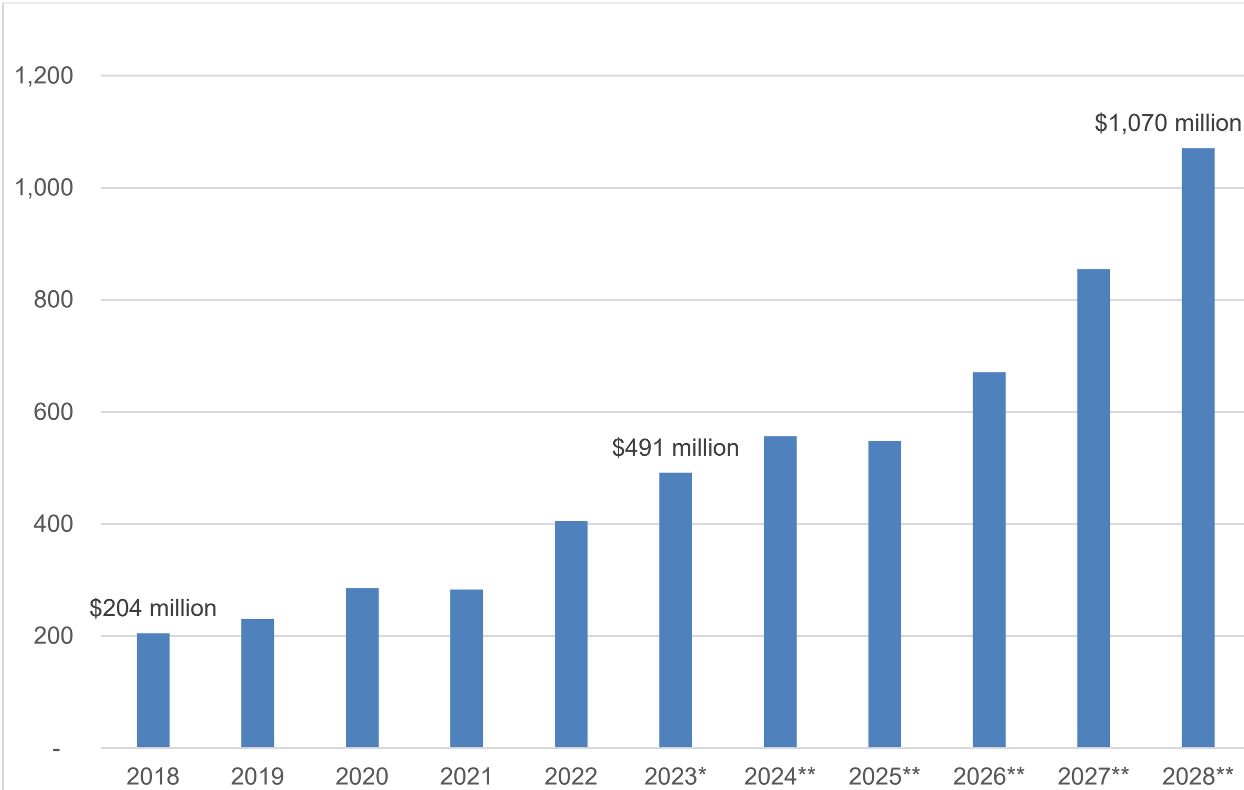
> through ADMS. Generally speaking, successful execution of IVVO through the ADMS platform requires high quality operational models for the affected circuits, establishing communications and controls capabilities to higher numbers of field resources, and executing an automated optimization of equipment states in response to grid constraints. The execution of flexible interconnection via DERMS will very likely include the same general components, but executed with larger numbers of field devices for different optimization goals. Building these capabilities and supporting processes today can provide important learnings and build supporting processes to reduce the barriers to deploying more advanced technologies in the future, which is in the public interest.

The GECs request that the Commission require Xcel to reevaluate IVVO with these suggestions incorporated into its analysis and assumptions and to refile its updated evaluation within 6 months of the Commission's order in this proceeding. In particular, the GECs request that the Commission direct Xcel to explore ways in which IVVO could be deployed in a targeted way within "environmental justice areas," as defined in Minn. Stat. § 216B.1691, Subd. 1(e), to reduce customer bills.

c. Forecasted distribution budget

Xcel anticipates substantial cost increases within its distribution budget, which it projects will more than double in the 5-year timeframe, from $491 million in 2023 to $1,070 million in 2028—an increase of $579 million.[37] The Company's projected growth in distribution expenditures reflects an acceleration in growth that has been occurring over the past several years, as illustrated below in Table 1.

[37] IDP App. D at 17.



* Forecast
** Budget

Figure 10. *Xcel Distribution Capital Expenditures 2018-2028 ($ millions)*[38]

Xcel's three largest budget categories are:

- Age-Related Replacements and Asset Renewal—$135 million increase, from $137 million to $272 million.
- System Expansion or Upgrades for Capacity—$192 million increase, from $35 million to $227 million. This category includes a placeholder $190 million budget for proactive hosting capacity beginning in 2025. It also includes Xcel's updated Grid Reinforcements Program, which involves proactive planning and installation of substations and feeders, particularly in congested metropolitan areas, to help enable

[38] Xcel Responses to Fresh Energy Information Requests Nos. 34 & 45 (revised).

electrification. We discuss both further below in Section III.17.f regarding proactive grid upgrades.

- System Expansion or Upgrades for Reliability and Power Quality—$228 million increase, from $40 million to $328 million.[39]

While the GECs support Xcel's intention to build its system to integrate the increased volumes of DERs and electrification that it forecasts, particularly through investments within its System Expansion or Upgrades for Capacity budget category, we are concerned by the magnitude of these increases and total budgets. We found the proposed budgets lacked specificity in their justification, which is especially concerning in light of Xcel's embedded incentive to make capital investments and earn a return on them. In other sections of these comments, we have identified particular concerns and questions regarding proposed projects and planning decisions, with an aim towards decreasing Xcel's distribution expenditures, including through better leveraging DERs, thereby improving system efficiency and affordability for customers. We have also highlighted areas where it is especially critical for the Commission to ensure that Xcel's investments yield intended benefits, specifically with respect to enabling local DER ownership and wealth-building, especially in frontline communities and "environmental justice areas."

The GECs also emphasize the need to ensure that Xcel continues to work towards making its electricity system more equitable, especially in light of its forecasts and expected spending. As the research from Drs. Pradhan and Chan (Attachment 2) shows, significant inequities exist within Xcel's system today, in particular with respect to long-term outages and involuntary disconnections. If all customers will ultimately pay for distribution system costs associated with

[39] IDP App. D at 17.

improving reliability and expanding system capacity, then all customers—and particularly lower-wealth customers and those in "environmental justice areas"—should have equitable access to the associated benefits, including specifically reliability improvements, as well as access to DER ownership, which can help improve affordability. The research from Drs. Pradhan and Chan (Attachment 2) shows that hosting capacity is somewhat higher on average in disadvantaged communities and communities with a higher proportion people of color. This finding may be related to the relative lack of DER adoption in these communities to date and/or the co-location of large customers in these communities that have required significant infrastructure investments. In any case, the GECs underscore the need to incorporate equity considerations into DER-enabling policies outside of the IDP, such that these customers can access and adopt DERs. In addition, within the IDP context, where specific environmental justice areas *do* have constrained hosting capacity, investing in expanding hosting capacity in these particular areas can help enable more equitable access to DERs.

Finally, the GECs recommend that the Commission require Xcel to address any impacts from changes in rate design, in particular the use of time-of-use (TOU) rates, into its IDP forecasts and resulting investment planning. Xcel recently filed an application for default TOU rates for residential customers (Docket No. 23-524), which envisions moving the majority of the Company's residential customers to such rates and anticipates resulting changes in customer electricity usage. Without getting into the details of that proposal here, we encourage the Commission to evaluate it with respect to its energy justice implications, including Xcel's support and education of low-income customers with respect to the rate change. Xcel should prepare these customers for this change, if approved, and equip them to benefit from it and avoid any harm. If the Commission approves Xcel's TOU proposal, resulting changes in electricity usage should impact Xcel's forecasts and planning. Therefore, we recommend that the Commission make clear that Xcel should incorporate rate design impacts, in particular but limited to impacts from its proposed TOU rates, into its IDP forecasts and proposals.

Related to this recommendation, as discussed further below in Section III.24.c, the GECs recommend improvements to Xcel's load flexibility programs. Xcel should also continue to refine its incorporation of demand response and load flexibility programs into its forecasts in a more granular manner.[40]

d. Initial LoadSEER forecasting results and methodology

The GECs support Xcel's efforts to incorporate LoadSEER forecasting into its distribution planning process. LoadSEER allows the Company to develop medium- to long-range (10-30 year) load forecasting of major distribution system components, including feeders and transformers, in part through simulating the impact of load and DER growth.[41] LoadSEER can enable Xcel to "better understand the potential location-specific impacts of the DER forecast scenarios on the distribution system …."[42] The Commission certified LoadSEER in Xcel's 2019 IDP proceeding and this 2023 IDP is the first time that the Company has presented its LoadSEER forecasts.[43] As Xcel notes in summarizing these forecasts: "The 30-year forecast shows all three scenarios increasing from around 8.5 GW today to 20 GW or more by 2052. It also creates perspective, in that the growth from 8.5 GW today to over 10.5 GW by 2033 is only the precursor to a much more rapid rate of growth in the following 20 years."[44]

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[40] *See, e.g.*, Xcel IDP App. A1 at 41-43.
[41] Xcel IDP App. A1 at 5, 48-72.
[42] Xcel IDP App. A1 at 49.
[43] Xcel IDP App. A1 at 48-49.
[44] Xcel IDP App. A1 at 68.

The GECs understand that Xcel is still in the early stages of determining how best to incorporate LoadSEER forecasts into its distribution planning process.[45] We also recognize that the forecasted DER growth will likely require growth in distribution spending budgets, as Xcel projects. The substantial growth in spending, however, underscores not only how critical it is for Xcel's LoadSEER forecasts to be as robust as possible and how essential it is for the Company to justify as clearly and specifically as possible why its projected DER growth necessitates its identified levels, but also how important it is for Xcel to quantify and account for the avoided transmission, distribution, and generation costs, and associated reductions in rate increases, that its investments may enable. Similarly, the GECs emphasize the relationship between DER forecasting and proactive spending, as discussed further below in Section III.17.f. Where there is a higher the degree of confidences in these forecasts, these proactive capacity investments are less risky. With these goals in mind, we look forward to Xcel's continued efforts to refine and incorporate LoadSEER into its distribution planning process.

We appreciate that the Company recognizes that it will also need to "continue investigating investments in technologies that may be needed to safely and reliably manage the grid of the future and could be used to *reduce the need for traditional capacity upgrades*."[46] The GECs emphasize that, beyond investigating additional investments it may need to make, the Company will also need to continue to explore other ways to lower its spending, including in particular through leveraging the growing volumes of DERs on its system and improving equity in DER access. Doing so can help to mitigate the customer affordability concerns that are likely to arise with the Company's expected growth in distribution budgets.

[45] Xcel IDP App. A1 at 68-69.
[46] Xcel IDP App. A1 at 69 (emphasis added).

e. Planned Net Load (PNL) methodology and 15% Dependability Factor

In its order on Xcel's last IDP, the Commission required the Company to begin prioritizing the use of "planned net loading" (PNL) in its load forecast processes,[47] a decision the GECs support. As Xcel explains: "Compared with 'peak loading,' the PNL would account for how the presence of DER on the distribution system offsets the absolute peak demand at any given time. This new initial methodology would allow for the consideration of certain distribution substations and feeders to have a reduced risk due to the load-masking impact of existing DER on the distribution system."[48] Xcel's initial PNL methodology recognizes that, though solar resources are not dispatchable, they are predictable enough to support their inclusion in capacity assessments, potentially deferring or avoiding capacity investments. The GECs support this change but believe that Xcel's methodology is overly conservative, in particular with respect to its reliance on a 15% dependability factor.

As Mr. Davis explains in his technical memorandum (Attachment 1):

> Xcel's proposed method applies the average of the three lowest months (November through January) to select the capacity factor of 15%, which is applied to both summer and winter peak contributions. Using the same data table (Table A1-11 from Xcel's IDP), the lowest value during summer daylight hours is 36.83% (August, 8:00-18:00) for tracking systems and 44.93% for fixed systems. Electing to apply summer-specific factors could more than double the capacity contributions allocated to DER systems at no cost and with minimal additional risk.
>
> Given Xcel's focus on meeting expected future capacity needs, maximizing the value of DER capacity contributions is critical to efficient distribution planning. To get a sense of scale of the opportunity size, the difference between the "Net Load" (the measured peak load across system equipment) and the "Native Load" (the total amount of coincident load served by the system and DER) is around 300 MW by 2033 in Xcel's non-coincident distribution peak demand forecast (Appendix A1 Pg 67). A 15% dependability factor applied to this difference results in 45 MW of capacity. Using a 35% factor instead increases this

[47] *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project*, Docket No. E-002/M-21-694, Order Accepting 2021 Integrated Distribution System Plan and Certifying the Resilient Minneapolis Project, Order ¶ 6 (July 26, 2022).
[48] IDP App. A1 at 30.

> contribution to 105 MW, a difference of 60 MW of capacity that is effectively free. Xcel should continue to refine its approach in the future, learning from and contributing to industry best practices in order to maximize DER capacity contributions and, subsequently, reduce unnecessary infrastructure investment.

As Mr. Davis demonstrates, Xcel's overly conservative dependability factor means that it is leaving usable capacity on the table rather than maximizing the value of available DER capacity. Not only is this inefficient, it is also costly. Instead of relying on free-to-the-Company DERs, Xcel will have to acquire that capacity, incurring costs that will be passed through to its customers. Using Xcel's NWA project results to give a sense of magnitude, reinforcing the Twin Lakes TWL065 feeder with only 2.2 MW of additional capacity would traditionally cost $2.5 million, and Xcel has valued its deferral at $424,281.[49] The negative impact on customer affordability of Xcel's overly conservative dependability factor is especially concerning in light of the significant growth in investments and budgets that Xcel projects in this IDP.

Therefore, the GECs recommend that the Commission require Xcel to continue to refine its PNL methodology with these concerns regarding the 15% dependability factor in mind, including specifically to consider: (1) increasing its dependability factor and (2) seasonal and/or otherwise differentiated dependability factors. The GEC's request that the Commission require Xcel to explain in its next IDP any decisions to change or not to change its dependability factor.

17. What guidance should the Commission give on budgets and cost allocation for distribution system upgrades to accommodate distributed energy resources (DER), including but not limited to: (a) Solar sited with customer load; (b) Solar sited in front of the meter; (c) Energy storage devices; (d) Electric Vehicles; (e) Space heating, water heating, and other electrification use cases; (f) Proactive grid upgrades in anticipation of future DER growth

The GECs focus our response to this question on proactive grid upgrades, as discussed further below. Generally speaking, however, the GECs urge the Commission to consider its

[49] IDP App. F at 30, 34.

vision for the future electricity system in making decisions about budgets and cost allocation for upgrades to facilitate DERs. As discussed above in Section II.C, the GECs suggest that a future grid should allow for all Minnesotans, in particular frontline communities and "environmental justice areas," to participate fully in the clean energy transition, including through DER ownership. Consideration of the budgets and allocation of costs to realize this vision necessarily requires considering that frontline communities and "environmental justice areas" have borne more than their share of the costs and burdens of the traditional energy system, enduring, for example, disproportionately poorer air quality and associated health burdens. Going forward, the Commission has an opportunity to incorporate equity considerations into its evaluation and approval of Xcel's proposed distribution upgrades and associated budgets to help to mitigate some of these past harms and move toward a more just future, with more equitable access to the benefits of DER ownership. And the Commission has an opportunity to consider how best to incorporate equity considerations into the allocation of costs necessary to upgrade the distribution system to integrate those DERs.

Regarding the budgets for distribution system upgrades to facilitate DERs, the GECs note that all of Xcel's distribution budget categories, or at least its three largest categories denoted above in Section III.16.c, could impact its system's ability to enable DERs. In other words, "upgrades to enable DERs" cannot necessarily be categorized separately from other system investments. For example, upgrades within Xcel's Age-Related Replacements and Asset Renewal budget category could not only replace system components at the end of their useful lives, but also increase hosting capacity for DERs. The same is true for upgrades within Xcel's System Expansion or Upgrades for Reliability and Power Quality budget category. For this reason, the GECs emphasize that when Xcel is prioritizing investments within its budget categories, it should include consideration of the potential to increase hosting capacity within its assessment to achieve this additional benefit as well as its other goals (safety, reliability, etc.).

Similarly, Xcel has the opportunity to consider the equity implications of its budget prioritization decisions. For example, it could consider to what degree an investment could improve reliability and power quality, or increase hosting capacity, and also whether it could do so in an "environmental justice area." As discussed above in Section II.B, as Drs. Pradhan and Chan have shown, at least some of these areas have faced disproportionately lower reliability. Xcel has an opportunity to address this disparity in its distribution planning. The GECs recommend that the Commission direct Xcel to incorporate both hosting capacity and equity considerations into its budget prioritization process.

The GECs recognize that the development of a fair cost allocation methodology for these DER-enabling upgrades is challenging, especially given their multiple potential system impacts and values. Moreover, to the extent these budgets facilitate higher volumes of DERs that, in turn, provide benefits to the system for all customers—for example, through smart inverter settings or managed EV charging—the question of cost allocation becomes further complicated. The GECs also suggest that the Commission should take into consideration non-energy benefits consistent with state energy policy, including in particular improving the ability of "environmental justice areas" to participate fully in the clean energy economy and bringing other benefits to these areas. In some cases, the benefits and costs are difficult, if not impossible, to attribute to a single customer or group, which suggests that socializing them across all customers may be appropriate. Such an approach could be particularly effective in enabling DER adoption by residential and small commercial customers.

Ultimately, the GECs emphasize that it is necessary to move beyond exclusive reliance on the "cost-causer pays" approach to cost allocation for DER-driven upgrades. Traditionally, this approach treats DERs as a novelty rather than a core utility service, like servicing new load. Because it responds in a first-come, first-served manner to DERs, exclusive reliance on the "cost-causer pays" approach fails to take advantage of strategic DER deployment and integration to provide system benefits and cost savings, and results in a less efficient and more expensive electricity system. Xcel's proposal for proactive hosting capacity upgrades represent one step away from this traditional, reactive approach. While the GECs support consideration of socializing the costs of proactive investments that have net system benefits, the success of such an approach will hinge on justifying the locations of such upgrades, as well as ensuring that Xcel leverages the DERs relying on the proactively provided hosting capacity, such that it optimizes benefits to its system and all customers.

The GECs look forward to reviewing comments from other parties on this question and to continuing to work together to address this challenging but critical topic.

f. Proactive Grid Upgrades

The GECs appreciate Xcel's recognition of the value of proactive upgrades to enable electrification, through its Grid Reinforcements Program, and DERs, through its inclusion of a $190 million placeholder budget for proactive hosting capacity investments starting in 2025.[50] On the proactive DER hosting capacity proposal, Xcel states: "We have heard from the state legislature, the Commission, and stakeholders that increased hosting capacity is a growing priority for the State of Minnesota."[51] While the GECs suggest that investments in other budget categories can also increase hosting capacity and should include hosting capacity as a

[50] IDP at 21, App. A1 at 25, App. D at 5-6.
[51] IDP at 21, App. D at 5.

prioritization factor, as discussed in the section immediately above, we support the inclusion of a dedicated proactive hosting capacity budget as well. The GECs appreciate Xcel's solicitation of stakeholder input on how to approach proactive investments in hosting capacity, including how to prioritize these investments.[52]

Consistent with the analysis provided by Mr. Davis in his technical memorandum (Attachment 1), the GECs identify two key elements to consider with respect to proactive electrification (customer load) upgrades and DER hosting capacity upgrades: (1) cost allocation and recovery; and (2) investment justification and prioritization. As Mr. Davis states: "These key elements of the distribution planning process should be thoroughly established prior to the execution of proactive investments for load or DER capacity in order to ensure that they are reasonable and necessary."

Cost allocation and recovery. As Mr. Davis points out, the size of an interconnecting load or whether it is a DER traditionally has affected the allocation of costs associated with it. Whereas a large customer or DER has to pay for the specific costs it causes due to required upgrades (less any revenue, for upgrades to serve customer load), system-level capacity upgrades for residential and small commercial customer load growth are generally captured within rates and allocated using ratemaking cost-allocation methods. However, it is not possible to apply this traditional approach to proactive investments, because the nature of the customer load or DERs is not known in advance in order to allocate costs when they are incurred. Therefore, a modified approach to cost allocation is necessary.

Investment justification and prioritization. Proactive capacity investments rely more heavily on forecasted load and DER growth as compared to reactive capacity investments, in

[52] IDP App. A1 at 25, App. D at 5.

which utilities can have higher confidence based on traditional distribution planning processes. Therefore, the degree of confidence in the load and DER forecasts is highly relevant. Proactive investments are less risky if they are made in areas where there is high confidence in growth forecasts.

Based on consideration of these two elements, Mr. Davis concludes (emphasis added):

> **With these two key elements considered, upgrades that provide load or DER hosting capacity to residential and small commercial customers are the clear frontrunners for candidate projects.** First, these customer groups historically do not bear specific system capacity costs related to their load additions. This means that existing cost recovery mechanisms will provide a similar level of functionality. For DER hosting capacity, enabling proactive investments to remove hosting capacity constraints that impact customers who are applying for relatively small systems would extend customer DER systems the same cost recovery treatment as load additions for capacity. Second, forecasting growth for large numbers of customers is generally more reliable than attempting to forecast the magnitude, location, and timing of load additions from smaller numbers of large commercial and industrial customers. Consequently, developing location-specific forecasts with sufficient accuracy to justify capital investment is more feasible.

Mr. Davis also highlights the need to consider treatment of larger customer interconnection costs in areas with proactive capacity investments. Any cost allocation methodology should avoid allowing these large customers to take advantage of proactive hosting capacity investments intended primarily or entirely for residential and small commercial customers, especially if the costs of those investments are socialized across some or all customers.

The GECs note that Xcel appears to be poised to take Mr. Davis's recommended approach to focus on residential and small commercial customers with its Grid Reinforcements Program, which the Company states should target capacity-expansion upgrades in "congested metropolitan areas,"[53] at least some of which are likely to have higher concentrations of residential and small commercial customers. The GECs recommend that the Commission require

[53] Xcel IDP App. D at 6.

Xcel to report on actual upgrades undertaken under the Grid Reinforcements Program in its upcoming IDPs, such that the Commission and stakeholders can evaluate its deployment.

With respect to the $190 million placeholder budget for proactive hosting capacity upgrades, consistent with Mr. Davis's recommendations, the GECs recommend that the Commission should require Xcel to target areas serving all or primarily residential and small commercial customers. Furthermore, the GECs recommend that the Commission require Xcel to consider the energy justice implications of its proactive grid investments, including specifically evaluating whether it can target upgrades to improve capacity for new load or hosting capacity within "environmental justice areas" where it has identified relatively low or constrained capacity. Consistent with our discussion above regarding the need to move beyond the traditional "cost-causer pays" paradigm for DERs, the GECs suggest that Xcel and the Commission should consider socializing the costs of such proactive upgrades, targeted to residential and small commercial customers, similar to the treatment of small customer load. However, the GECs note that justifying such socialization connects to Xcel's ongoing work to integrate and optimize the benefits of DERs on its system, such that the Company maximizes the benefits of DERs taking advantage of any socialized investments to all customers.

18. What decisions should the Commission make in the IDP to provide Xcel guidance in aligning distribution spending with forthcoming rate cases?

In Xcel's most recent rate case, the Just Solar Coalition recommended modifications that drew on Xcel's prior IDP and the Commission's IDP directives, noting inconsistencies in Xcel's rate case investments with the goals and requirements of its IDP, particularly with respect to leveraging DERs and expanding hosting capacity.[54] In the end, the Commission referred some of

[54] *See, e.g.*, *In The Matter of the Application of Northern States Power Company, d/b/a Xcel, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Initial Brief of the Just Solar Coalition, 42-64 (Jan. 11, 2023).

these proposals back to the IDP for further discussion and development, including specifically: incorporating consideration of hosting capacity impacts into the Company's prioritization process for asset health and reliability investments; better leveraging the capabilities of smart inverters to defer distribution investments; and better incorporating DERs into the Company's load forecasting, which it relies on to justify its distribution investments.[55] In responding to IDP-related recommendations from another intervenor, the Clean Energy Organizations, the Commission directed Xcel in its next IDP to "propose and discuss ways for the IDP process to inform financial and cost-recovery issues in rate cases, including … the decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases aligns with policy goals established through the IDP."[56]

The GECs recognize that an IDP and a general rate case have different purposes and goals, with the IDP focused more on policy and planning, and a rate case focused on cost recovery for actual investments and spending, including on the distribution system, and allocation of those costs in rates. However, consistent with the Just Solar Coalition's arguments in the rate case, we maintain that the IDP loses its value if Xcel does not implement the goals and plans developed within its IDP in the investments for which it seeks cost recovery in a rate case.[57] If the Commission does not closely link the IDP to the Company's rate cases, it risks allowing Xcel to receive cost recovery for long-term investments that do not reflect policies affirmed in the IDP, thereby locking in investment decisions inconsistent with policy goals. While we recognize that Xcel requires some degree of flexibility in managing its system, we

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[55] *See, e.g.*, *In The Matter of the Application of Northern States Power Company, d/b/a Xcel, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Findings of Fact, Conclusions and Order, at 142-46 (July 17, 2023).

[56] *Id.* at 49; *see also id.* at Order ¶ 29.

[57] *See e.g., In The Matter of the Application of Northern States Power Company, d/b/a Xcel, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Reply Brief of the Just Solar Coalition, at 33-34 (Jan. 27, 2023).

encourage the Commission to hold it accountable to the Commission's IDP goals and directives, as well as Xcel's own IDP commitments, when the Company seeks to recover the costs of its distribution system investments. A rate case can expose inconsistencies between Xcel's IDP and the Company's actual system investments and can provide a meaningful forum in which to address those inconsistencies. Therefore, the GECs request that the Commission explicitly reaffirm that it will rely on the IDP when reviewing utility distribution investments in rate cases. If a rate case proposal is inconsistent with the utility's IDP, then the GECs suggest that there should be a significantly higher bar for Commission approval.

19. Should the Commission require cost-benefit analysis for discretionary distribution system investments?

In its order in Xcel's most recent general rate case, the Commission directed Xcel to address in its IDP "ways for the IDP process to inform financial and cost recovery issues in rate cases, including but not limited to: a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget;…."[58] In adopting this requirement, the Commission recognized intervenor concerns regarding Xcel's large distribution spending budget, which had grown significantly since its prior rate case, and determined that "it is in the public interest to explore possible ways to achieve greater transparency and closer scrutiny of future distribution spending to ensure due consideration of ratepayer interests and other policy goals."[59] The GECs strongly agree with the Commission's determination and support requiring cost-benefit analyses for discretionary distribution system investments where feasible. Greater

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[58] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order, ¶ 29 (July 17, 2023).
[59] *Id.* at 49.

transparency and scrutiny of Xcel's distribution spending can help to ensure that it appropriately considers equity and energy justice considerations in its decisions.

In its IDP, Xcel essentially stated that it is not feasible for it to conduct cost-benefit analyses for budget items for which it does not already conduct cost-benefit analyses, such as its risk analysis for capacity projects and its NWA analysis.[60] The GECs find Xcel's response to the Commission's Order point insufficient. Xcel offers no evidence that it considered the feasibility of cost-benefit analyses for other budget items in any detail. Rather, Xcel appears to interpret the Commission's directive as requiring only consideration of cost-benefit analyses on a project-by-project basis and states that it is "not efficient to conduct a CBA [i.e., cost-benefit analysis] for all discretionary work."[61] It raises concerns about lack of consensus on the definition of "discretionary," potential disagreements about cost-benefit methodologies, particularly with respect to determining benefits, and the potential cost impact on customers of such studies.[62] The GECs appreciate these challenges but believe Xcel has missed an opportunity to address them more thoroughly in this IDP, including by putting forth constructive proposals for party feedback. Moreover, by assessing the feasibility of cost-benefit analyses only on a project-by-project basis, the GECs believe Xcel misinterpreted the Commission's Order, which required such an assessment of "discretionary *portions* of the distribution budget." (emphasis added) This language implies an interest in program-level or other categorical cost-benefit analyses as well, which could provide much-needed transparency while not raising the same degree of costs for Xcel and its customers.

[60] IDP at 24-25.
[61] IDP at 24.
[62] IDP at 24-25.

The GECs support Xcel's stated intent to work towards evaluating and developing an approach to "strategically applying CBAs to program level investments…"[63] Indeed, we believe this is what the Commission has already asked it to do in its prior Order, but suggest that the Commission may wish to clarify this point. As part of this effort, the GECs also suggest that the Commission require Xcel to explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits. Doing so would give parties an opportunity to provide more concrete feedback for Xcel's and, ultimately, the Commission's consideration with the hope of identifying programs or categories where cost-benefit analyses make sense, implementing them there, and improving spending transparency in light of the large budgets proposed.

As the Commission recognized in its rate case Order, such cost-benefit analyses offer the Commission and interested parties a chance to understand better how Xcel incorporates ratepayers' interests and other policy goals into its distribution spending decisions. The benefits that Xcel considers in turn inform how a budget item may be prioritized. The GECs understand that Xcel has traditionally considered elements like age and failure rate in evaluating the benefits of replacing distribution system components. As discussed above in Section III.17, we suggest that the Commission should direct Xcel to incorporate both the potential to increase hosting capacity and potential equity improvements—such as improved reliability, resiliency, or hosting capacity in environmental justice areas—as benefits considered within its evaluation and prioritization processes wherever possible. The GECs do not suggest that Xcel always prioritize these policy considerations over others; rather, we suggest that they should be explicitly and transparently included in Xcel's evaluation and analyses related to discretionary spending.

[63] IDP at 25.

20. Should the Commission discontinue IDP Requirement 3.A.9 as requested by Xcel?

GECs have no comment at this time but reserve the right to comment in reply.

21. Should the Commission revise the IDP Filing Requirements for Xcel Energy to remove the requirement that financial information be reported in IDP-specific categories, as requested by Xcel?

GECs have no comment at this time but reserve the right to comment in reply.

22. What should the Commission consider or address related to enhancing the resilience of the distribution system within Xcel's IDP?

GECs have no comment at this time but reserve the right to comment in reply.

23. Has Xcel Energy appropriately discussed its plans to maximize the benefits of the Inflation Reduction Act (IRA) and the IRA's impact on the utility's planning assumptions pursuant to Order Point 1 of the Commission's September 12, 2023 Order in Docket No. E,G-999/CI-22-624?

GECs have no comment at this time but reserve the right to comment in reply.

24. Other areas of Xcel's IDP or TEP not listed above, along with any other issues or concerns related to this matter.

a. Coordination Between Xcel's IDP and IRP

The GECs highlight the ongoing importance of coordination between Xcel's IDP and its Integrated Resource Plan (IRP). We appreciate the Commission's existing guidance to this effect (IDP Requirement 3.A.5) and Xcel's explanation of its efforts on this front.[64] In particular, we emphasize the importance of coordination between the two plans with respect to DER forecasts (IDP Requirement 3.A.5.a). We understand that, among other factors, the timing of the IDP filing and IRP modeling has made coordination challenging.[65] Now that Xcel has completed its IRP modeling and filed its IRP, the GECs request that the Company supplement its discussion of

[64] IDP App. A1 at 20-28.

[65] IDP App. A1 at 24.

this topic in its reply comments to the extent it has further information or insights to share regarding coordinating forecasts across the two plans.

Specifically, we note that there appears to be a substantial divergence in the IDP's "distribution peak demand 30-year forecast," which grows from about 8.5 GW to about 14 GW in 2040 and about 20 GW in 2052, and the IRP's "NSP system median base summer peak demand," which grows from about 9.5 GW to about 12.5 GW in 2040.[66] While we understand the IDP forecast to be based on Xcel's Minnesota service territory whereas the IRP is based on the larger NSP system (Upper Midwest), this difference does not explain the significant discrepancy in the numbers, especially since the IDP number, based on the smaller service territory, is higher than the IRP number. We request additional explanation of this divergence from Xcel in its reply comments.

b. Relationship of Xcel's IDP to Its Interconnection Process and Technical Planning Standard (TPS)

The GECs encourage the Commission to consider the intersection of Xcel's IDP and the Company's interconnection policies and practices. As Xcel notes, for example, in order to work toward deploying Flexible Interconnection, "additional interconnection policy factors, such as the inclusion of Daytime Minimum Load (DML) in the Technical Planning Standard (TPS) for DER interconnections, may need to be re-addressed by the Company."[67] The GECs strongly agree, and recommend that this review of necessary updates to interconnection policy are foundational to an accurate IDP. This review extends beyond the inclusion of Daytime Minimum

[66] Xcel IDP App. A1 at 68; *In the Matter of Xcel Energy's 2024-2040 Integrated Resource Plan*, Docket No. E002/RP-24-67, Xcel Energy: Upper Midwest Integrated Resource Plan 2024-2040 App. E at 4.
[67] IDP App. E at 4.

Load in the TPS, and includes the TPS itself as a whole, given that it may have significant impacts on Xcel's IDP.

As stakeholders have noted in other dockets and filings, the TPS is likely to significantly reduce available grid hosting capacity.[68] As such, it is at least conceivable (if not likely) that some of the investments and projects proposed in the IDP, such as proactive hosting capacity upgrades, are higher than they would be if the TPS were not being applied. In addition, reasonable questions remain as to the necessity for and design of the TPS, as indicated in the Commission's December 14, 2023 hearing, where the Commission ordered further discussions on the TPS, including options to apply it more granularly and options to set aside a smaller buffer.[69] In other words, the design and application of the TPS is, in the GECs' understanding, not a closed and foregone issue, and may be subject to change pending future Commission action. The GECs share the concerns expressed by the Interstate Renewable Energy Council (IREC) in the interconnection proceeding (Docket No. 16-521) regarding the TPS, including specifically with respect to the impact of the TPS on available hosting capacity. However, because the TPS is not subject to review and revision in the instant docket, we do not raise those concerns in further detail here.

In light of the above, the GECs urge the Commission to continue its investigation into the TPS, including its intersection with the IDP, and answer at a minimum the following questions: (1) Which IDP projects and programs are impacted by the TPS, such that the associated

[68] *See, e.g.*, *In the Matter of Proposed Changes to the Minnesota Distributed Energy Resource Interconnection Process or Agreements Identified by Distributed Generation Workgroup Subgroups*, Docket E-999/CI-16-521, Reply Comments of the Interstate Renewable Energy Council, Inc., on Proposed Changes to the Minnesota Distributed Energy Resource Interconnection Process or Agreements Identified by Distributed Generation Workgroup Subgroups, at 12 (Oct. 1, 2021).
[69] Minnesota Public Utilities Commission (Dec. 14, 2023), webcast recording available at https://mn.gov/puc/about-us/calendar/?trumbaEmbed=view%3Devent%26eventid%3D156924621.

investments are higher than they would be without the TPS?; and (2) Is it just and reasonable to allow full cost recovery of investments that are inflated by application of the TPS?

c. Load Flexibility Programs

The GECs are encouraged to see progress on multiple load flexibility pilots and demonstrations in the Company's IDP.[70] However, we are discouraged that several pilots remain only available to commercial customers and customers with home EV charging. While these are important loads to manage to improve overall system cost-effectiveness, they have limited applicability to directly addressing energy justice. We recommend that the Commission require the Company to develop plans to expand load flexibility pilots such that residential customers can opt to participate and be compensated for their load flexibility. Currently, as described in the IDP and the load flexibility pilot proceeding (Docket No. 21-101), there have been insufficient plans as to how the load flexibility pilots will be evaluated for the purposes of scaling up these programs and offering them to residential customers in a way that can address energy justice. Plans to scale load flexibility programs to address energy justice must be done carefully, but we believe there is significant potential in providing pathways to compensate communities for providing value to the grid through managing the energy consumption of the appliances that they own.

A recent paper, by Juan Pablo Carvallo and Lisa Schwartz of Lawrence Berkeley National Laboratory, looks at what the authors term "price-based demand response" in electricity planning.[71] The paper includes recommendations for improving consideration of price-based demand response in the context of long-term planning for bulk power and distribution systems.

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[70] IDP App. B3.

[71] Carvallo, Juan Pablo, Lisa C. Schwartz, The use of price-based demand response as a resource in electricity system planning, Lawrence Berkeley National Laboratory, November 2023. https://eta.lbl.gov/publications/use-price-based-demand-response

We urge the Commission to consider these recommendations in analyzing any proposals for scaling load flexibility pilot programs, as well as Xcel's TOU proposal mentioned above. At a minimum, the GECs suggest that the Commission should require Xcel to consider the recommendations proposed with regard to local distribution grids:

> For planning local grids, that includes evaluating price-based DR in NWA analysis both for deferring distribution system investments and meeting new loads, considering financial performance incentives to align utility shareholder and utility customer interests, improving grid data and making it publicly available, applying advanced planning tools, using a longer planning horizon, and conducting additional analyses and studies.[72]

IV. CONCLUSION

The GECs appreciate the opportunity to provide comments on Xcel's IDP. As emphasized throughout, we have centered equity and energy justice considerations in our evaluation and recommendations, which are summarized above in Section I. We respectfully request that the Commission adopt our recommendations prior to accepting Xcel's IDP.

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[72] *Id.* at 27.

Respectfully Submitted,

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CERTIFICATE OF SERVICE

RE: In the Matter of Xcel Energy's 2023 Integrated Distribution Plan
Docket No. E-002/M-23-452

I, Erica S. McConnell, hereby certify that on the 1st day of March 2024, I e-filed *INITIAL COMMENTS OF GRID EQUITY COMMENTERS: COOPERATIVE ENERGY FUTURES, ENVIRONMENTAL LAW & POLICY CENTER, SIERRA CLUB, AND VOTE SOLAR* with the Minnesota Public Utilities Commission and served a true and correct copy of the same upon all parties listed on the attached service list by e-mail and/or electronic submission.

/s/ Erica S. McConnell
Erica S. McConnell

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ATTACHMENT 1: Cody Davis, Technical Memorandum Regarding Xcel Energy's 2023 Integrated Distribution Plan (IDP) In Minnesota

Technical Memorandum Regarding Xcel Energy's 2023 Integrated Distribution Plan (IDP) in Minnesota

To: Grid Equity Commenters (GEC)
From: Cody Davis, Electric Power Engineers, on behalf of GridLab
Re: Technical Review and Comments on Integrated Distribution Plan Contents

This memorandum was developed at the request of the Grid Equity Commenters to provide technical analysis on topics within Xcel Energy's 2023 IDP in Minnesota. Support for the development of this memo was provided by GridLab in accordance with their mission to provide expert capacity and thought leadership to address technical challenges and reliability questions in the implementation of clean energy policies.

DER Management System (DERMS)

Within their 2023 IDP, Xcel identifies the implementation of a DER Management System (DERMS) as a necessary step to integrate higher levels of DER. Several use cases and drivers are identified, including FERC 2222 capabilities, virtual power plant facilitation, and flexible interconnection. One thing common to all the applications of the DERMS being considered for future deployment by Xcel is that they involve communications to and control of customer-owned DER. There are certainly benefits that can be gained by the management of DER within these applications, but it is also important to clearly define the capabilities, approach, terms and conditions, and impact, especially to those customers whose resources will be managed.

Flexible Interconnection is a concept that utilizes DER real power control to limit power production during times of distribution congestion. This is in contrast to the traditional interconnection study process, which requires interconnectors to pay for any system upgrades that would be necessary to accommodate the full generation capabilities of the new resource during the most constrained period. Flexible Interconnection shows significant promise in increasing the amount of DER that can be interconnected without requiring costly system upgrades. With that promise, however, comes considerable complexity and potential changes to many aspects of the current interconnection paradigm. EPRI, who Xcel is working with in assessing and developing DERMS capabilities, has published extensive materials detailing the concept of flexible interconnection[1], options for prioritizing curtailment[2], and cost allocation and risk[3]. From these materials, it is clear that there are many design decisions and trade-offs that must be made in developing and implementing flexible interconnection effectively in a way that is both practical and amenable to the needs of DER owners and operators.

One high-potential, low-cost opportunity to be considered is static flexible interconnection. Rather than setting dynamic maximum real power output points based on changing grid

[1] https://www.epri.com/research/products/000000003002014475
[2] https://www.epri.com/research/products/000000003002018506
[3] https://www.epri.com/research/products/000000003002019635

conditions, static flexible interconnection utilizes a local control system to ensure that total DER or site-wide power import or export does not exceed a pre-set threshold. For example, if a 2 MW solar PV system and a 2 MW Battery Energy Storage System (BESS) are installed by the same customer, they would traditionally be studied with a maximum of 4 MW of output and 2 MW of import. If this customer instead implements a local power control system, they can limit the maximum export to 2 MW if needed in order to avoid the need for costly distribution system upgrades. These capabilities are available today as part of Xcel's Technical Interconnection and Interoperability Requirements (TIIR) related to limited import and limited export. These types of interconnections generally have the import/export limits set by the initial interconnection application and enforced within the power control system. Extending full flexible interconnection capabilities to such locations would allow for additional import or export depending on grid conditions, impacting multiple resource types at one location. The ability to communicate with these control systems and adjust real power thresholds provides an important opportunity because these systems can be constructed today, with the potential for flexible interconnection to benefit them in the future with effectively no downsides. In order to realize this potential, interoperability and standardized communications requirements are important to establish as early as possible so that compatible power control equipment is selected and installed.

Prior to moving forward with a DERMS procurement, it is critical that Xcel provide a clear vision for how DER Management will be implemented and a roadmap showing the transition from the present state to full-scale deployment. Because customer-owned DER are the primary resources being managed, it is critical that this vision reflect stakeholder needs and feedback in order to ensure that customers are able to participate effectively and take advantage of the new capabilities. In addition to customer needs, there are also critical technical components that need to be addressed and which may impact implementation costs or operational decisions. Key questions that should be addressed in this roadmap should include:

- What are the specific use cases for which DERMS will be utilized and who are the intended beneficiaries?
- Will participation in DER Management be voluntary or required? Will requirements vary based on resource size, resource type, program participation, market participation, or other factors? Will it be available for load interconnections (e.g., EV charging hubs) or interconnections utilizing limited import/export control systems?
- How will communications be established between Xcel's DERMS and customer DER? Who will bear the ongoing cost for any necessary communications infrastructure?
- How will capacity be allocated across new and existing managed and unmanaged interconnectors? How will capacity upgrades be justified and from whom will upgrade costs be recovered?
- How will prospective applicants understand the impact of DER management on the economics of their project? What information will be provided to prospective interconnectors related to expected curtailment and existing and expected grid conditions?

- What are the expected deployment and integrations costs for DERMS? What are the expected ongoing licensing, operating, and infrastructure costs to execute and maintain DERMS functionality? From whom will these costs be recovered?
- How are equity and energy justice principles being incorporated within the use cases, process design, and cost allocation?

Considering these questions ahead of time is necessary for ensuring that a DERMS procurement is reasonable and necessary and that the solution procured is capable of meeting the anticipated requirements. Providing visibility to these design decisions and opportunities for stakeholder engagement will ensure that the new functionality will be able to achieve desirable benefits for interconnectors and customers.

Integrated Volt/Var Optimization (IVVO)

In Order Point 36 of the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630, the Commission required Xcel to file an assessment and explanation in the 2023 IDP of whether IVVO is in the public interest. In Xcel's response to this requirement, they stated that IVVO is not in the public interest. There are additional factors that should be evaluated before reaching such a conclusion.

First, there are still efficiency gains that can be achieved by reducing voltage, both now and in the future. While some new loads or efficiency-related replacements may not benefit from voltage reduction, other new load additions will still see benefits. The T&D World article[4] cited by Xcel in their IDP response identifies a CVR factor for heat pumps as just under 0.6, which, while lower than historical CVR factors used in IVVO analysis, is much higher than zero. While the addition of new constant power loads for electrification may decrease overall CVR factors from a system perspective, it does not reduce the CVR factor for the individual equipment that remains connected, meaning there is still energy savings that can be achieved from reducing the voltage to that equipment. With the rate of load growth estimated by Xcel's forecast, all resources capable of reducing energy consumption and especially system peak load magnitude should be strongly considered.

Second, before drawing broad conclusions, Xcel should explore the impact of the IVVO design choices made within the 2019 proposal and should consider whether changes to their approach would result in cost-effective savings that would be in the public interest. Xcel's proposal in 2019 included significant costs for static var compensator devices and supporting software from Varentec[5]. Many utility deployments of IVVO have been successful without the deployment of such devices. In lieu of such devices, Xcel could identify circuits or substations on their system that could achieve IVVO benefits without significant reinforcements or system modifications

[4] https://www.tdworld.com/grid-innovations/smart-grid/article/20965787/cvr-is-here-to-stay

[5] https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90E1276E-0000-C87B-896A-D252D87663CB}&documentTitle=201911-157133-04

beyond establishing communications to load tap changers, capacitor banks, or voltage regulators. Areas without existing low voltage issues, especially those with relatively flat voltage profiles, are prime candidates for low-cost deployments that could achieve worthwhile energy savings. Such areas could be identified from AMI voltage measurements or through power flow modeling. Additional considerations for targeted deployment could include deployment within disadvantaged communities, where reductions to customer bills may provide needed relief.

Finally, deployment of IVVO can provide an important stepping stone to future deployments of operational control and optimization technologies like DERMS. Fundamentally, executing flexible interconnection using a DERMS platform will likely share many similarities and foundational requirements with IVVO deployment through ADMS. Generally speaking, successful execution of IVVO through the ADMS platform requires high quality operational models for the affected circuits, establishing communications and controls capabilities to higher numbers of field resources, and executing an automated optimization of equipment states in response to grid constraints. The execution of flexible interconnection via DERMS will very likely include the same general components, but executed with larger numbers of field devices for different optimization goals. Building these capabilities and supporting processes today can provide important learnings and build supporting processes to reduce the barriers to deploying more advanced technologies in the future, which is in the public interest.

<u>Proactive Load Capacity and DER Hosting Capacity Investments</u>
Xcel identifies in their 2023 IDP that proactive investments in capacity, making it available before customers need it, is key to their distribution strategy. Proactive investments, from a technical standpoint, are not fundamentally different than those made under the more traditional reactionary distribution investment processes currently in place. The key differentiators proactive investments are how specific proactive investments are justified and whether and how cost allocation and recovery mechanisms will be applied. These key elements of the distribution planning process should be thoroughly established prior to the execution of proactive investments for load or DER capacity in order to ensure that they are reasonable and necessary.

Because proactive capacity investments are made before specific characteristics of new load or DER are known, there are important elements to consider related to cost allocation and recovery. In traditional interconnections, treatment of system capacity costs varies by customer size. Large customers interconnecting new large loads are required to pay for the cost of system capacity upgrades necessary to connect them (less the additional revenue expected to be gained, as detailed within the Company’s Rate Book). For large DER installations, the same costs would be captured as interconnection cost (without the revenue calculation). Growth related to residential and small commercial customers, on the other hand, does not result in any specific system capacity costs being allocated to specific interconnecting customers. Instead, such capacity upgrades are made and captured within rates and allocated using ratemaking cost allocation methods. These variations in treatment for capacity costs, as they exist today, cannot be directly applied to proactive investments without modification because the customer and load characteristics are not known in advance. Consequently, the methods by which the costs for proactive investments for load and DER hosting capacity will be allocated and recovered must be clearly specified and agreed upon prior to the execution of such investments. Absent these mechanisms, new proactive capacity investments will effectively create a "first come, first served" approach inconsistent with cost allocation and recovery goals.

In addition to the cost allocation challenges, the investment justification and prioritization methodology for proactive investments is fundamentally different than for traditional reactive capacity investments. For capacity investments today, the need for capacity investments is known with reasonable confidence for both magnitude and timing (at least within the next 1-3 years) as an output of distribution planning processes. Proactive capacity investments, in contrast, rely considerably more on future growth assumptions and forecasts and are inherently more speculative. Consequently, the degree of confidence in the forecast is much more critical of a factor when determining whether a proactive capacity investment should be made. Proactive capacity project justification should also consider the specific risk associated with proceeding through existing capacity planning procedures in a specific area. Because proactive investments are inherently "riskier" with regards to necessity, they should be reserved for areas where the existing process poses significant risks and where there is high confidence that the expected growth will materialize in the expected time.

With these two key elements considered, upgrades that provide load or DER hosting capacity to residential and small commercial customers are the clear frontrunners for candidate projects. First, these customer groups historically do not bear specific system capacity costs related to their load additions. This means that existing cost recovery mechanisms will provide a similar level of functionality. For DER hosting capacity, enabling proactive investments to remove hosting capacity constraints that impact customers who are applying for relatively small systems would extend customer DER systems the same cost recovery treatment as load additions for capacity. Second, forecasting growth for large numbers of customers is generally more reliable than attempting to forecast the magnitude, location, and timing of load additions from smaller numbers of large commercial and industrial customers. Consequently, developing location-specific forecasts with sufficient accuracy to justify capital investment is more feasible.

The handling of interconnections of large resources in areas benefited by proactive capacity investments must also be considered. Currently, larger systems are responsible for either a pro-rated portion (for load additions) or the full cost (for DER interconnections) of capacity investments needed to provide service. If such systems are permitted to utilize capacity deployed proactively, there would be no direct cost recovery mechanism under existing structures. Whether and how costs for proactive capacity upgrades are recovered from such customers is a question that should be answered prior to executing proactive capacity investments.

Finally, it is important to understand the mechanics of how new capacity is provided, as there are often other benefits achieved simultaneously that should be factored in to the decision-making process. For example, a circuit breaker that is not equipped with voltage supervisory reclosing capabilities may be a limiting factor for new DER interconnections on that feeder. If that breaker is also near the end of its useful life and has shown signs of degradation, the replacement of the circuit breaker also provides asset health and reliability benefits, which can help improve overall project economics. Proactive capacity investments should be considered holistically for their ability to provide benefits, the relative costs, and the degree of certainty that the expected DER growth will materialize.

Planned Net Load Dependability

Xcel's inclusion of a planned net load methodology to capture the capacity value provided by DER is a critical step forward in integrated distribution planning. Though solar resources are not dispatchable, they are predictable enough to support their inclusion in capacity assessments, a fact recognized in Xcel's initial methodology.

With that said, the proposed methodology is very conservative. Xcel has identified a 15% dependability factor for DER contributions and applies that factor to the estimated difference between net load and native load, a value lower than the nameplate capability. MISO, on the other hand, assigns a blanket capacity assumption of 50% to solar resources for capacity compensation during spring, summer, and fall time periods and a 5% factor for winter[6]. MISO's factor is also applied straight to the nameplate DER size, rather than the estimated production at the peak time. MISO's capacity factor is not directly comparable, as it serves a different purpose and deals with a more aggregated dataset but the differences in magnitude and method are notable when compared with Xcel's proposal. The use of separately calculated factors for different seasons is particularly critical.

Differentiating capacity factors for summer-peaking and winter-peaking areas would significantly increase the expected capacity allocated to DER contributions without any changes to the core methodology proposed by Xcel. Xcel's proposed method applies the average of the three lowest months (November through January) to select the capacity factor of 15%, which is applied to both summer and winter peak contributions. Using the same data table (Table A1-11 from Xcel's IDP), the lowest value during summer daylight hours is 36.83% (August, 8:00-18:00) for tracking systems and 44.93% for fixed systems. Electing to apply summer-specific factors could more than double the capacity contributions allocated to DER systems at no cost and with minimal additional risk.

Given Xcel's focus on meeting expected future capacity needs, maximizing the value of DER capacity contributions is critical to efficient distribution planning. To get a sense of scale of the opportunity size, the difference between the "Net Load" (the measured peak load across system equipment) and the "Native Load" (the total amount of coincident load served by the system and DER) is around 300 MW by 2033 in Xcel's non-coincident distribution peak demand forecast (Appendix A1 Pg 67). A 15% dependability factor applied to this difference results in 45 MW of capacity. Using a 35% factor instead increases this contribution to 105 MW, a difference of 60 MW of capacity that is effectively free. Xcel should continue to refine its approach in the future,

[6] https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf

learning from and contributing to industry best practices in order to maximize DER capacity contributions and, subsequently, reduce unnecessary infrastructure investment.

Cody Davis is a Senior Engineering Manager of Distribution & Grid Modernization at Electric Power Engineers. Mr. Davis provides consulting services primarily related to DER integration, distribution planning, and distribution operations management systems based on his experience performing distribution planning studies and supporting the implementation of new technologies and programs. A more complete summary of his experience can be found in his previous testimony to the Minnesota Public Utilities Commission.[7]

[7] https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={5064A383-0000-C729-9B98-A4E60BCC8D69}&documentTitle=202210-189514-04

ATTACHMENT 2: Dr. Bhavin Pradhan & Dr. Gabriel Chan, “Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy’s Minnesota Service Area” (available at https://conservancy.umn.edu/handle/11299/261434)

CENTER FOR SCIENCE, TECHNOLOGY, AND ENVIRONMENTAL POLICY

Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area

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February 2024

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Abstract

This paper asks whether disparities exist in access to shared infrastructure systems, focusing on the electric system, an essential service delivered by heavily regulated public utilities. We examine disparities in access to electricity service in the service area of Xcel Energy across three dimensions: utility disconnection, service reliability, and grid availability to host distributed energy resources. We quantify disparities across Census block groups by leveraging unique, high-resolution datasets of service quality and grid conditions that have only recently been made publicly available. We find significant and pervasive evidence of the disparities among different demographic groups across utility disconnection and service reliability. Across a battery of regression models, we find that living in poorer neighborhoods with a greater concentration of people of color is associated with a statistically and practically significant difference in the likelihood of disconnection from service due to non-payment and the experience of extended power outages. We also find evidence that hosting capacity for distributed generation is higher in disadvantaged communities and communities with high populations of people of color. These findings underscore the opportunity for policy initiatives to rectify deep-seated inequalities through affirmative investments and safety net programs that ensure all communities, regardless of their racial or economic composition, have equitable access to universal basic utility service and reliable, clean energy.

Keywords: racial equity; disconnection; distributional justice; grid hosting capacity; energy justice

1. Introduction

The impact of household energy insecurity on the physical, mental, and economic well-being of struggling families has been well documented (Harker Steele and Bergstrom, 2021; Hernández, 2016; Konisky et al., 2022; Memmott et al., 2021). In this paper, we look at multiple indicators that affect energy insecurity: involuntary disconnection from service, long-duration outages, and availability of the grid to interconnect consumer-owned energy resources. Utility disconnection can cause extreme economic distress (Baker et al., 2021; Flaherty et al., 2020). Utility disconnection can cascade into long-term financial hardship, homelessness, and even severe health-related issues (Flaherty et al., 2020). From 2019 to 2020, around 4.7 million U.S. households at or below 200 percent of the federal poverty line could not pay their energy bills, 4.8 million received a utility disconnection notice, and 2 million were disconnected from their electricity service (Memmott et al., 2021). Difficulty affording energy costs can create situations of "energy insecurity" that cause households into dilemmas, such as choosing between food and heat, especially during extreme weather events (Hernández, 2016).

Many low-income households and communities of color face significant, pervasive, and persistent conditions of energy insecurity due to their inability to afford energy bills and living in fear of being disconnected from their utility services (Graff and Carley, 2020; Hernández et al., 2014). To reduce their energy bills and to mitigate their utility-related issues, families use various coping strategies, such as keeping indoor temperatures at a unsafe or undesirable level, using gas stoves to heat living spaces, abstaining from air-conditioning, and delaying bill payments and arrearages (Carley et al., 2022; Cong et al., 2022; Hernández, 2016; Hernández et al., 2014). Turning down the heat and living in cold and damp housing—due to poor housing conditions or high energy prices—has been shown to have significant associations with decreased respiratory, mental, and sleep outcomes (Hernández and Siegel, 2019; Liddell and Guiney, 2015). However, the present-day household energy insecurity is not merely a function of affordability, housing condition, employment, home efficiency, poverty, or energy prices–but instead, deeply rooted in how cities and neighborhoods evolved over the century (Swope et al., 2022).

As the energy transition accelerates to meet climate goals and integrate distributed energy resources (DERs), such as rooftop solar and electric vehicles, scholars, policymakers, and advocates have identified opportunities to advance energy justice goals (Carley and Konisky, 2020; Chan and Klass, 2022; Elmallah et al., 2022; Welton and Eisen, 2019). Yet currently, adoption of DERs reflects existing inequalities across race and income, and addressing historic injustices in infrastructure investment will likely require careful implementation of justice-oriented infrastructure policy (Schott and Whyte, 2023).

In this paper, our research question is: *Is there evidence of neighborhood-level disparities across income and race in the electric service quality, involuntary disconnection, and access to the grid to interconnect distributed energy resources?*

We explore this question by looking at three outcome metrics in a large Midwestern utility using a unique compilation of datasets that report average service quality and distribution grid hosting capacity at a fine geographic scale. We link these datasets with demographic characteristics to quantify disparities across race, income, poverty rates, and population density in involuntary disconnections, long-duration electric outages, and hosting capacity on the local grid for DERs. We find robust, statistically significant associations between race, poverty, utility disconnection, and long-term service disruption in Minnesota. We also identify correlations that suggest neighborhoods with a higher proportion of people of color, lower income, and lower population density tend to have increased DER hosting capacity availability. However, this observation is not consistent across all models. The greater availability of DER hosting capacity in these more disadvantaged communities may reflect a lower adoption rate of DER among low-income populations in communities of color who live in densely populated areas, contributing to the expanding research in this area.

The results do not imply causality, as conventional quantitative methods that purport to estimate counterfactuals of race are often inconsistent with social-constructivist theories of racialization (Graetz et al., 2022). Instead, our analysis shows the critical associations between socioeconomic factors, including race, and key indicators related to advancing energy justice. It is important to distinguish that our findings do not necessarily imply deliberate racial bias on the part of energy system planners. Instead, the findings underscore how multiple systemic causes of economic hardship are reflected in yet another critical infrastructure system (Swope et al., 2022). The results point to a valuable opportunity to correct these inequalities through deliberate investments in the energy transition that affirmatively prioritize disadvantaged communities, low-income neighborhoods, and communities of color. By doing so, a more equitable energy system that provides reliable, high-quality utility services and equal opportunity to benefit from the energy transition for all people can be fostered, regardless of socioeconomic status or racial background. And further, grid planners have an opportunity to prioritize investments in communities that are at greatest risk for energy insecurity.

The paper is structured as follows: Section 2 describes the paper's data sources. Section 3 provides an overview of the methodology applied, Section 4 presents the results of the paper, and Section 5 concludes.

2. Data

Our study integrates three distinct data sources at the Census block group-level covering the service area of Xcel Energy, the largest electric utility in Minnesota: the U.S. Census American Community Survey's demographic and household estimates, the Council on Environmental Quality's Climate and Economic Justice Screening Tool (CEJST) map of disadvantaged communities, Xcel Energy's Minnesota Electric Service Quality Interactive Maps estimates of service quality and involuntary disconnections, and Xcel Energy's Hosting Capacity Analysis for Generation (Gen-HCA) estimates of distribution grid capacity to host DERs.

2.1. American Community Survey and Climate and Economic Justice Screening Tool

The unit of analysis for our study is a Census block group (CBG). A CBG is the "smallest geographic entity for which the decennial census tabulates and publishes sample data" and generally contains between 600-3,000 people (Bureau of the Census, 1994). The average CBG in our dataset has a population of approximately 1,250 people. We extract CBG-level average demographic and household characteristics from the 5-year American Community Survey (ACS) for variables such as building composition and age, race/ethnicity of the head of household, income and poverty level, education, unemployment rate, population density (a proxy for electric grid topology), and homeownership type.

We also integrate data from the Council on Environmental Quality's Climate and Economic Justice Screening Tool (CEJST). The CEJST map provides binary indicators of whether a census tract meets the definition of a "disadvantaged community" pursuant to Executive Order 14008, "Tackling the Climate Crisis at Home and Abroad." Federal agencies use the CEJST definition of disadvantaged communities to seek to deliver 40% of the overall benefits of certain investments in climate and clean energy to disadvantaged communities under the Justice40 Initiative. The CEJST identification of disadvantaged communities is based on indicators in eight categories: climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, and workforce development.

2.2. Disconnection and Service Quality Data

Our study leverages unique publicly available data on involuntary disconnections and service interruptions from Xcel Energy's Minnesota Electric Service Quality Interactive Maps published from 2019-2022 and covering data from 2017-2022. Xcel Energy is the largest electric utility in Minnesota and serves 38 percent of residential customers in some of the most densely populated areas of the state, including the Minneapolis-St. Paul metropolitan area (see Figure 1).

The dataset reports CBG-level averages of utility disconnection and service quality across Xcel Energy's service area. Utility disconnection is reported as ratio of the number of disconnected premises to the total number of premises in a CBG.

Service quality is reported in two metrics, CEMI-6 and CELI-12. CEMI-6 is the percent of customers in a CBG that experience 6 or more sustained outages per year. CELI-12 is the percent of customers in a CBG that experience an outage with a duration of 12 hours or more per year. For each year from 2019-2022, disconnection, CEMI-6, and CELI-12 rates are reported as three-year averages: 2017-2019 for the 2019 map, 2018-2020 for the 2020 map, and so on. Table 1 shows average yearly rates of disconnection, CELI-12, and CEMI-6 across CBGs.

Table 1. Disconnection and Service Quality Statistics for Xcel Energy's service areas from 2017-2022. All the numbers are per 1,000 households and standard deviations are included inside the brackets.

Years	Average disconnection rate (per 1,000 households)	CELI-12: Average number of households experiencing an outage longer than 12 hours (per 1,000 households)	CEMI-6: Average number of households experiencing 6 or more outages per year (per 1,000 households)
2017-2019	11.9 (14.2)	6.36 (28.7)	23.6 (57.7)
2018-2020	4.06 (6.06)	24.4 (55.7)	7.56 (30.3)
2019-2021	4.27 (6.16)	24.4 (55.3)	6.89 (28.0)
2020-2022	6.62 (10.6)	33.0 (70.4)	8.12 (31.0)
Overall	6.82 (10.51)	23.0 (57.19)	11.38 (38.97)

2.3. DER Hosting Capacity

We extract a CBG's DER hosting capacity from the publicly available 2023 Hosting Capacity Analysis for Generation (Gen-HCA) maps published by Xcel Energy. The Gen-HCA maps are used as a first-pass tool for developers to assist in site-selection processes for new DER generation, such as distributed solar, wind, and batteries. The Gen-HCA map is displayed as a heat map for a distribution feeder-line in most of Xcel Energy's service area in Minnesota. Hosting data was accessed in late 2023, representing a snapshot of current hosting capacity. Xcel Energy updates its hosting capacity analysis at each feeder at least once annually. Table 2 summarizes service area-wide descriptive statistics used in the regression.

Table 2. Descriptive Statistics of the variables used in the analysis.

Variable	Mean	S.D.	Min	Max
POC (0-100%)	25.09	23.04	0.00	99.54
Poverty (0-100%)	21.32	17.36	0.00	95.30
Median HH Income ($)	81,145	39,461	0	250,001
Population Density (1,000 households per sq. mile)	4.94	6.46	0.00	148.83
Unemployment Rate (0-100%)	4.08	4.53	0.00	56.72
Renters (0-100%)	30.16	25.60	0.00	100.00
Built after 90s (0-100%)	22.84	22.87	0.00	100.00
Disconnections (per 1,000 homes)	6.82	10.51	0.00	121.40
CELI-12: Average number of households experiencing an outage longer than 12 hours (per 1,000 households)	23.00	57.19	0.00	681.90
CEMI-6: Average number of households experiencing 6 or more outages per year (per 1,000 households)	11.38	38.97	0.00	525.50
Average Maximum Hosting Capacity Per Household (kW/household)	1.78	1.61	0.00	14.83
Maximum Area Hosting Capacity (kW)	801.37	605.52	0.00	4370.1

Unlike hosting capacity maps for used in previous research in states like California (Brockway et al., 2021), Gen-HCA maps intentionally omit specific details of distribution feeder lines due to security concerns, instead providing generalized representations as "blurred" spatial heat polygons. These polygons reflect only a snapshot of data and do not disclose the precise locations of the distribution lines. Based on the maximum area method, we execute a spatial overlay, aligning the 2010 Census Block Group (CBG) boundaries with the Gen-HCA maps. This process assigns unique CBG identifiers to each polygon, effectively integrating the two data sets.

Xcel's Gen-HCA polygons incorporate a variable denoting diverse hosting capacities along the distribution line; however, many polygons within the dataset have multiple hosting capacities. The Xcel Gen-HCA map uses the maximum value of each polygon to classify the available hosting capacity range (> 1 MW, 751-1 MW, 501-750 MW, 251-500 MW, 1-250 MW, 0 MW). To extrapolate the polygon data to a CBG level, we utilize the highest hosting capacity value from the Gen-HCA polygons, averaging these figures to derive a single hosting capacity metric for each CBG– this is the Maximum

Area Hosting Capacity (kW). Dividing this number by the total number of housing units in the CBG gives the Average Maximum Hosting Capacity per household (kW per household). This approach is conceptually consistent with the visual representation of the Gen-HCA map in the web interface. When polygons intersect with multiple CBGs, we attribute the polygon to the CBG covering the largest segment of the polygon, ensuring a representative allocation. To calculate per household hosting capacity i.e. Average Maximum Hosting Capacity per household (kW per household). for each CBG, we divide the calculated CBG hosting capacity by the total housing units in the CBG (excluding the two CBGs with fewer than 10 reported housing units). To remove outliers, we limit the average maximum hosting capacity per household value to 15 kW.

We note that our approach to averaging hosting capacity within a CBG could obscure more micro-level dynamics in hosting capacity within a CBG. Hosting capacity is a complex function of grid topology and depends on highly context-specific, often trade-secret characteristics of the grid. Nevertheless, our approach is still able to provide a high-level estimate of hosting capacity that approximates what could be considered a "screening" type of hosting capacity assessment. Detailed and accurate hosting capacity data could help in refining energy justice assessments by highlighting the disparities in access to DERs. The granular data would enable utilities to pinpoint underserved areas for targeted grid improvements, or even pinpoint areas with a high availability of hosting capacity to integrate DERs. Such data-driven strategies can inform nuanced energy policies that address unique community barriers to DER adoption, facilitating a more inclusive and justice-focused energy transition.

2.4. Descriptive Analysis

In this section, we present a descriptive analysis of disparities across our key outcome variables. Figure 1 shows maps that present spatial representation of key variables in our dataset, showing the resolution of our CBG-level data for the two largest counties in Xcel Energy's service area, Hennepin and Ramsey counties.

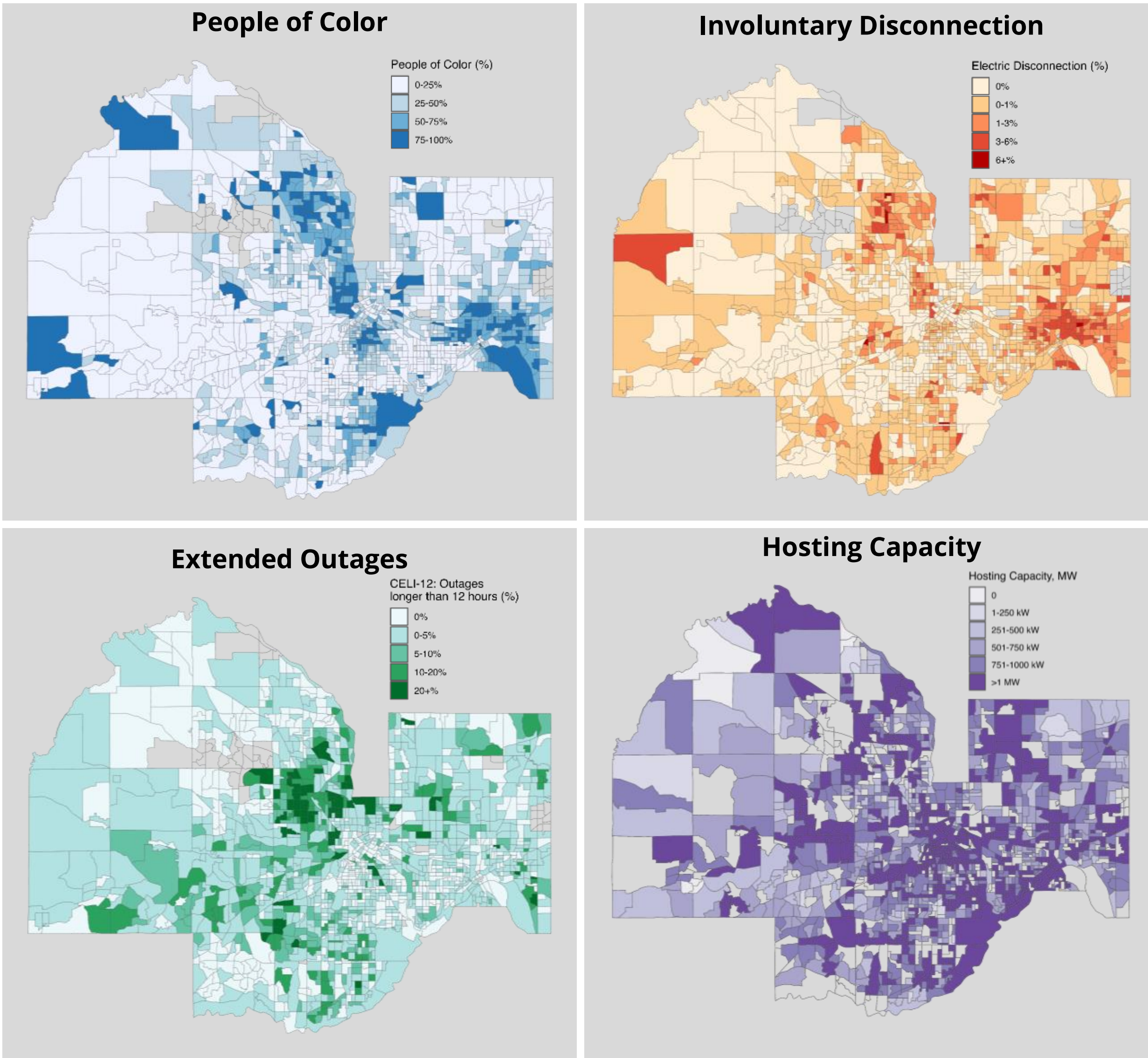

Figure 1. Illustration of data resolution. Maps display relative magnitude of key variables in the dataset at the Census block group-level for Hennepin and Ramsey counties (encompassing Minneapolis and St Paul and the majority of customers in Xcel Energy's service area). Top left: people of color as percent of population. Top right: involuntary disconnections as a percent of customers. Bottom left: extended outages over 12 hours per year as a percent of customers. Bottom right: hosting capacity of the distribution grid as percent of population.

2.4.1. Descriptive Analysis of Disconnections

The first line of inquiry is to explore the relationships between a CBG's percentage of people of color and the number of customers disconnected due to non-payment every year. Figure 2 shows scatterplots for the proportion of households disconnected due to non-payment across three-year periods with moving averages by a CBG's percent people of color. The figure shows upward trends across all three-year periods with communities with a higher percentage of people of color experiencing higher rates of electric disconnection. We display disparities in disconnection rates in CEJST-designated disadvantaged communities compared to other communities in Figure 3. And we affirm the relationship between disconnections and race shown in Figure 2 again in Figure 4, emphasizing the higher disconnection rate in the CBGs in the top 10% of population of people of color.

Our data covers a period during which Minnesota implemented a moratorium on utility disconnections that applied to Xcel Energy during the COVID-19 pandemic, which was in place from the start of the pandemic in early 2020 through August 2021 (Baker et al., 2021). The impact of the disconnection moratorium can be seen in the lower average disconnection rates in the periods with greater overlap with the moratorium. Yet we still see visually apparent upward trends between a CBG's population of color and disconnection rates.

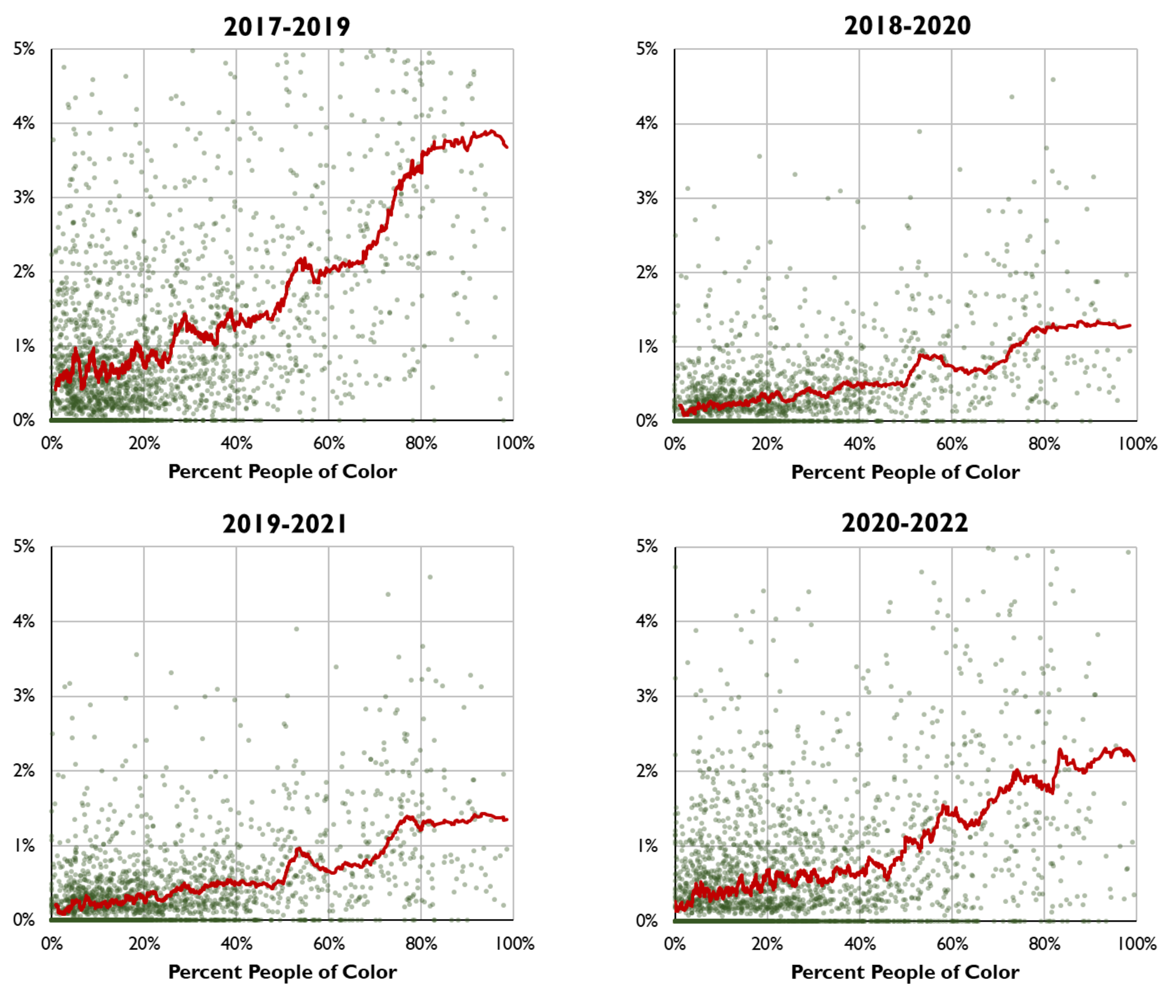

Figure 2. The relationship between CBG average disconnection rates compared to its percent people of color, 2019-2022. The moving average line shows a clear positive relationship for all years.

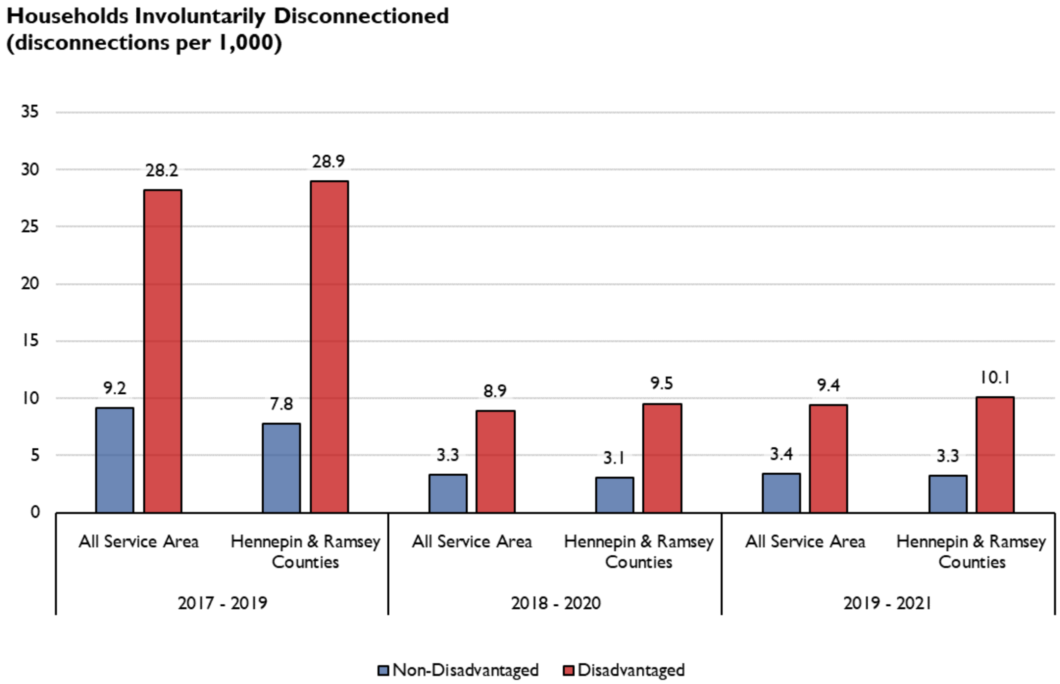

Figure 3. Disconnected households, comparing non-disadvantaged versus disadvantaged CBGs in Xcel Energy's service area and in Hennepin and Ramsey Counties from 2017-2021.

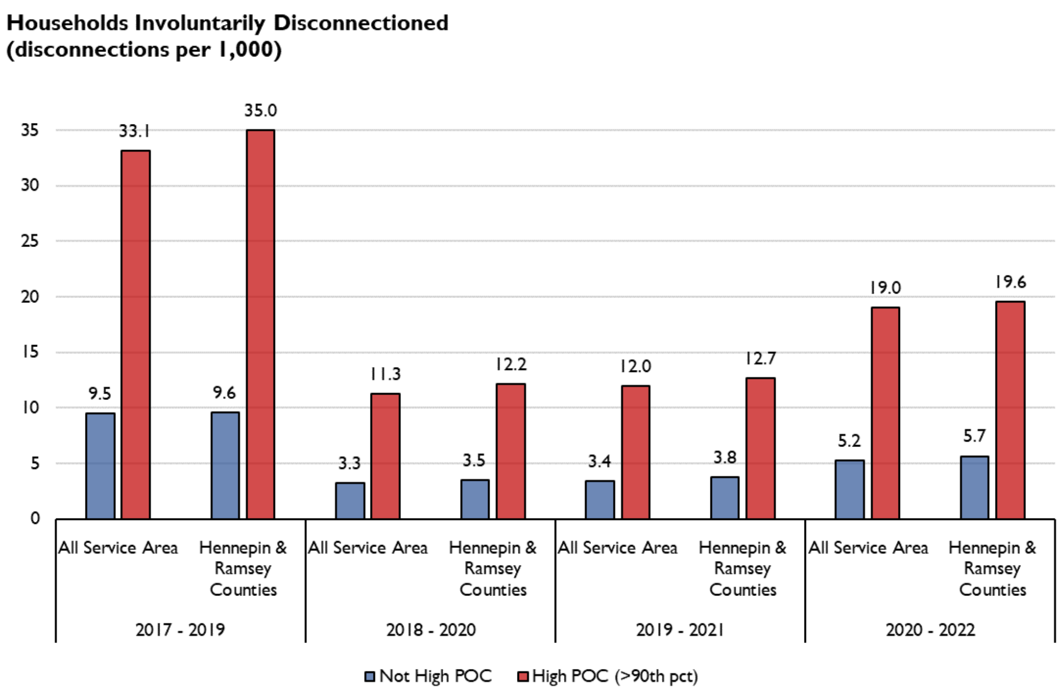

Figure 4. Disconnected households, comparing CBGs with high percentage of people of color (POC) with others in Xcel Energy's Service Area and in Hennepin and Ramsey Counties from 2017-2022.

One possible explanation for the positive association between a CBG's percent people of color and disconnection rate is confounding by income. To address this possibility, Figure 5 shows disconnection rates within bands of CBG median household income and bands of percent people of color. The figure shows that the upward association between disconnection rates and percent people of color holds even within CBG's with low income. Potential confounding is addressed more holistically in the regression analysis presented in Section 4.1.

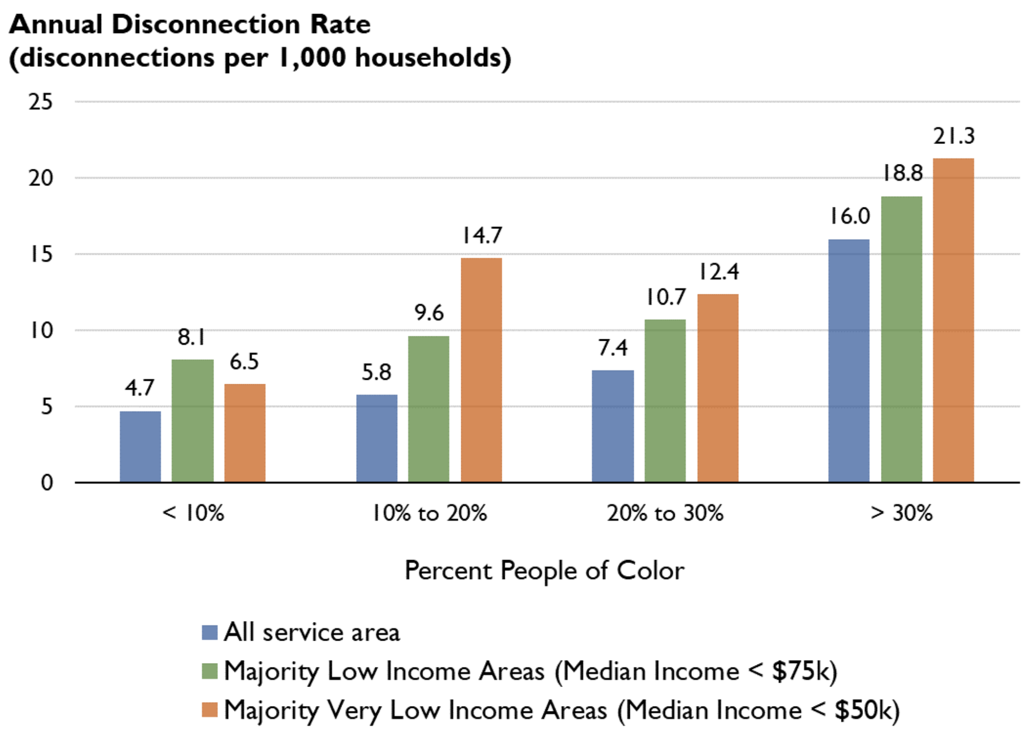

Figure 5. Rate of disconnection by an area's percent people of color overall and below different income levels, 2017-2022. Data for this figure combines data shown in Figure 2 for the period 2017-2019 and 2020-2022 to avoid double counting any years. Note that the time period in this figure covers a moratorium on disconnections during the COVID-19 pandemic, and therefore disparities largely reflect disparities in disconnections from 2017-2019 and in 2022.

2.4.2. Descriptive Analysis of Service Quality

Figure 6 reveals a concerning trend in power outage disparities between non-disadvantaged and disadvantaged communities across Xcel Energy's service area and specifically within Hennepin & Ramsey Counties over consecutive years from 2017 to 2021. We classify CBGs on their disadvantaged community status based on the White House's Climate and Economic Justice Screening Tool (CJEST). Despite fluctuations, there is a discernible pattern where disadvantaged CBGs consistently endure a greater frequency of power outages exceeding 12 hours (CELI-12). For 2018-2020 and 2019-2021, disadvantaged CBGs had a higher incidence of more extended power outages across all service areas and also within Hennepin & Ramsey Counties. This finding suggests potential systemic vulnerabilities or unequal distribution of resources affecting power stability. We do not analyze 2020-2022 because the Xcel service quality maps are based on census 2020 boundaries whereas the CJEST classifications are based on 2010 census boundaries.

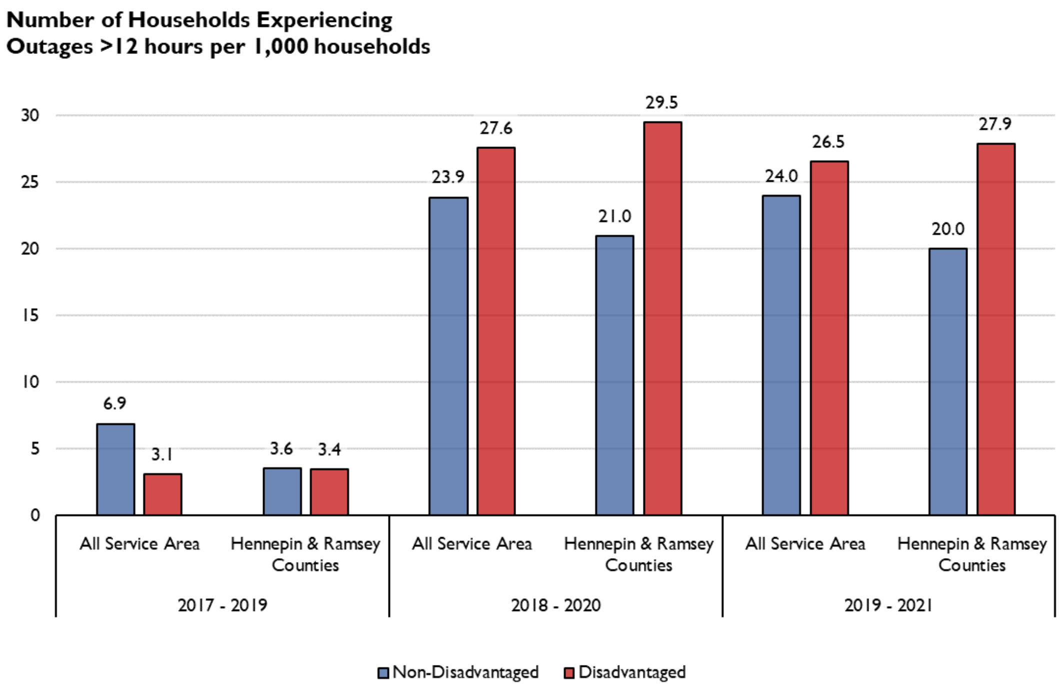

Figure 6. Households experiencing outages longer than 12 hours (CELI-12), comparing non-disadvantaged versus disadvantaged CBGs in Xcel Energy's service area and in Hennepin and Ramsey Counties from 2017-2021.

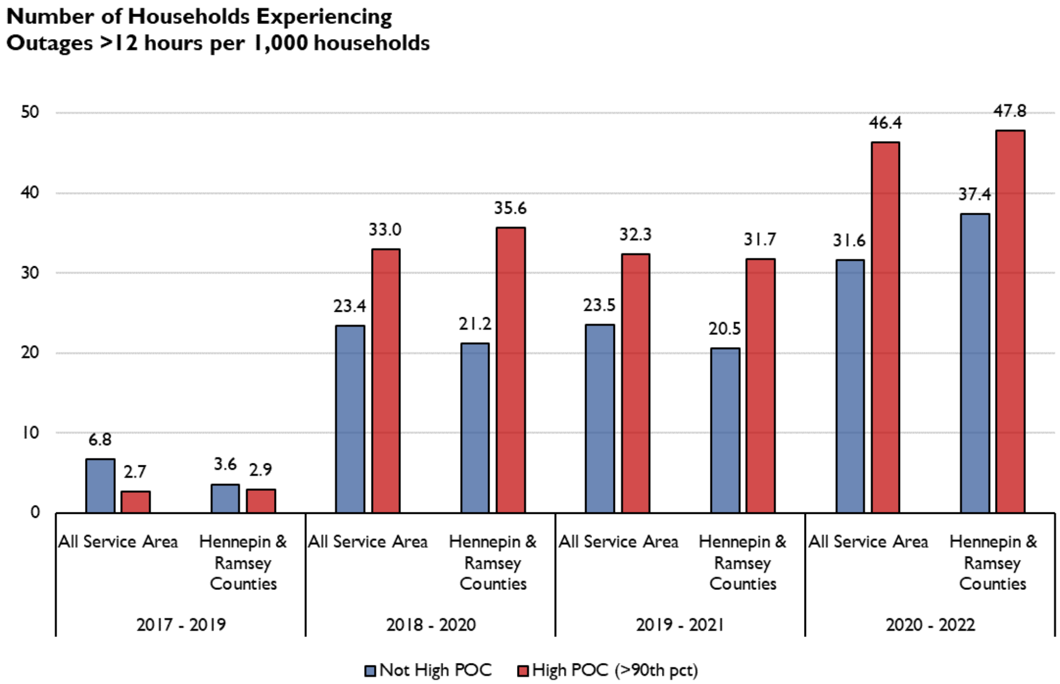

Figure 7. Households experiencing outages longer than 12 hours (CELI-12), comparing CBGs with high percentage of people of color (POC) with other CBGs in Xcel Energy's Service Area and in Hennepin and Ramsey Counties from 2017-2022.

Figure 7 provides a visual analysis of the stark differences in long-duration outages (CELI-12) for CBGs that have a high percentage of people of color (above 90th percentile) and those that do not, by comparing the metrics in Hennepin & Ramsey counties and all of Xcel's service area. The figure shows that, except for 2017-2019, high POC CBGs experienced significantly longer power outages. For instance, in the 2020-2022 period, Hennepin & Ramsey Counties reported nearly 48 outages per 1,000 high POC households, significantly more than the just over 37 outages per 1,000 non-high POC households. This pattern indicates not only a reliability issue within the power infrastructure but also underscores a social equity concern, as the communities with higher percentages of POC are disproportionately affected by power service disruptions.

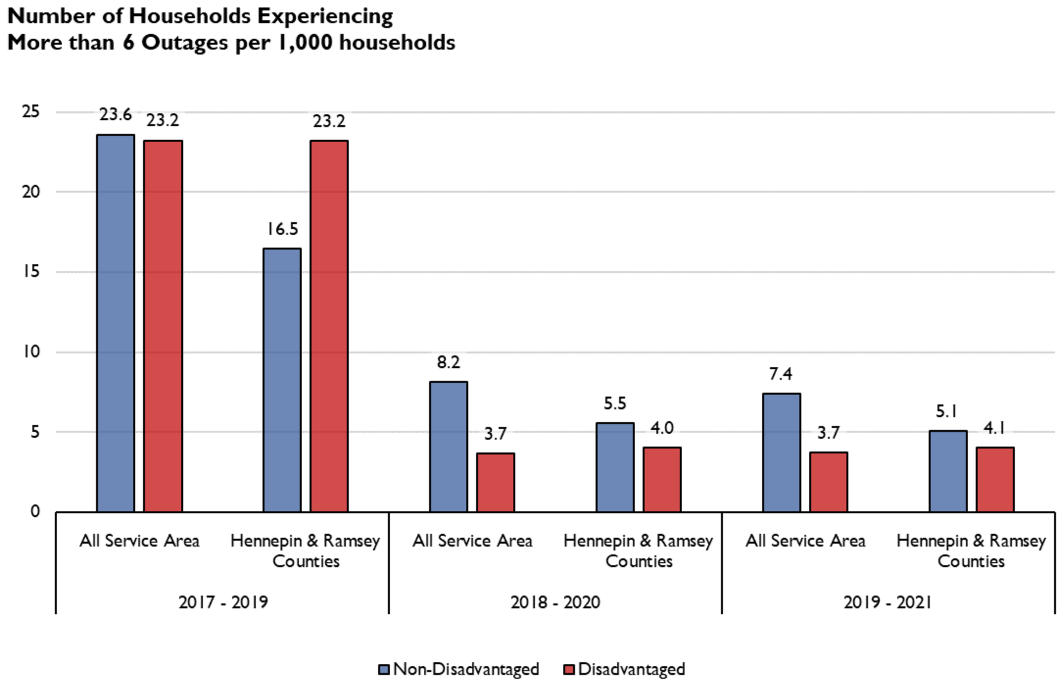

Figure 8. Households experiencing six or more sustained outages per year (CEMI-6), comparing non-disadvantaged versus disadvantaged CBGs in Xcel Energy's service area and in Hennepin and Ramsey Counties from 2017-2021.

Figure 8 shows the number of households per 1,000 experiencing 6 or more sustained outages per year (CEMI-6). Except for outages in Hennepin & Ramsey Counties in 2017-2019, disadvantaged communities in all of Xcel's Service Area and Hennepin & Ramsey Counties had lower incidences of frequent power outages. For disadvantaged communities in Hennepin & Ramsey Counties, the number of households experiencing more than 6 or more sustained outages also reduce significantly– from 23.7 in 1,000 households in 2017-2019 to about 3.7-4.1 per 1,000 households in 2018-2021.

Similarly, Figure 9 shows the number of households per 1,000 experiencing 6 or more sustained outages per year for CBGs classified into either high POC (more than 90th percentile) or not high POC. Like the trend shown in Figure 8, the number of households experiencing more sustained outages is higher for high POC CBGs only in 2017-2019, for all customers. The number of sustained outages experienced by homes in high POC CBGs within Hennepin & Ramsey Counties range from 3.7-6.3 per 1,000 households from 2018-2022. Likewise, 7.1-8.4 per 1,000 households homes (that do not get categorized as high POC) experience frequent outages.

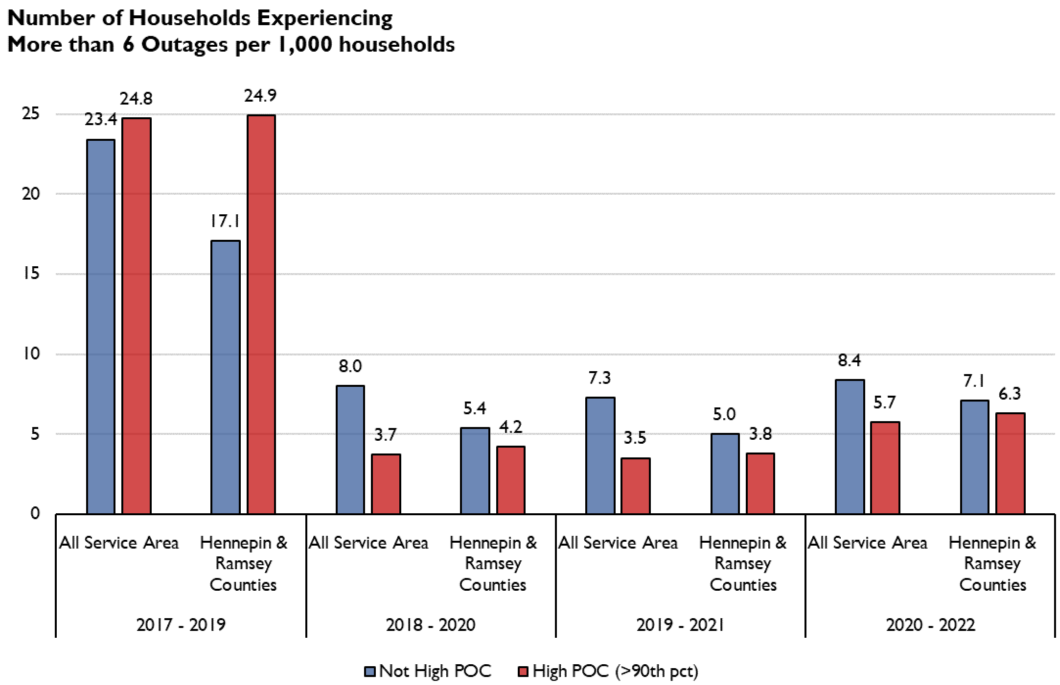

Figure 9. Households experiencing six or more sustained outages per year (CEMI-6), comparing CBGs with high percentage of people of color (POC) with other CBGs in Xcel Energy's Service Area and in Hennepin and Ramsey Counties from 2017-2022.

2.4.3. Descriptive Analysis of Hosting Capacity

Figure 10 compares hosting capacity metrics across CEJST-designated disadvantaged communities to other communities. The results show that hosting capacity is significantly higher in disadvantaged communities than other communities based both on the average area maximum hosting capacity and the average maximum hosting capacity per household.

Similarly, Figure 11 shows that hosting capacity is also higher on an area-average and per-household basis in communities in the top 10 percent of population of people of color.

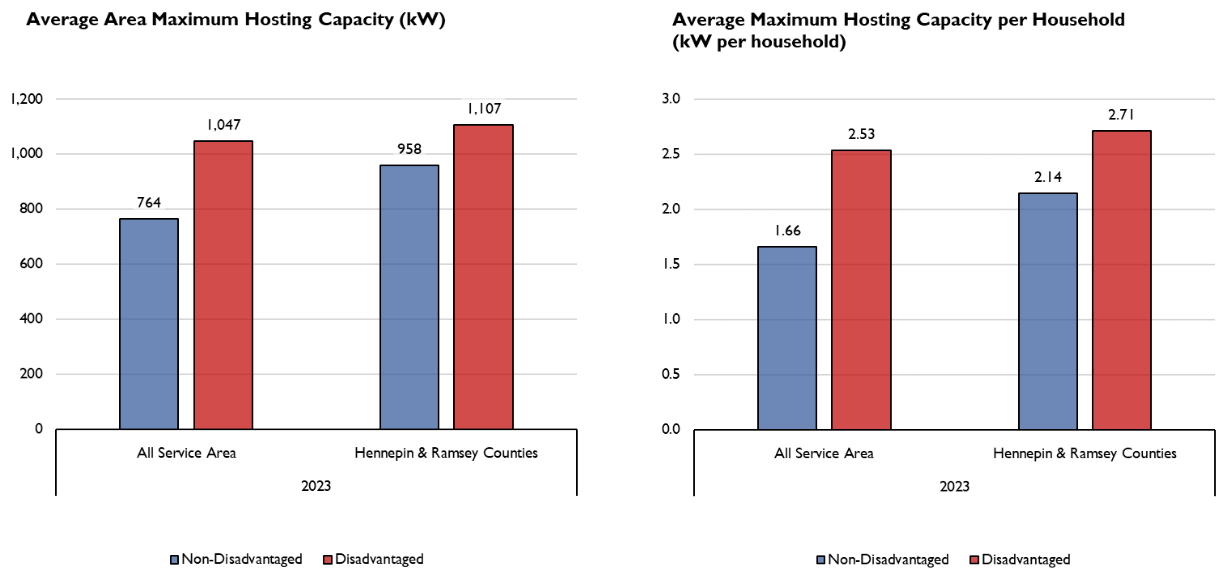

Figure 10. Average area maximum hosting capacity (left) and per household hosting capacity (right) comparing non-disadvantaged versus disadvantaged CBGs in Xcel Energy's service area and in Hennepin & Ramsey Counties from 2017-2021. Hosting capacity estimates shown for 2023.

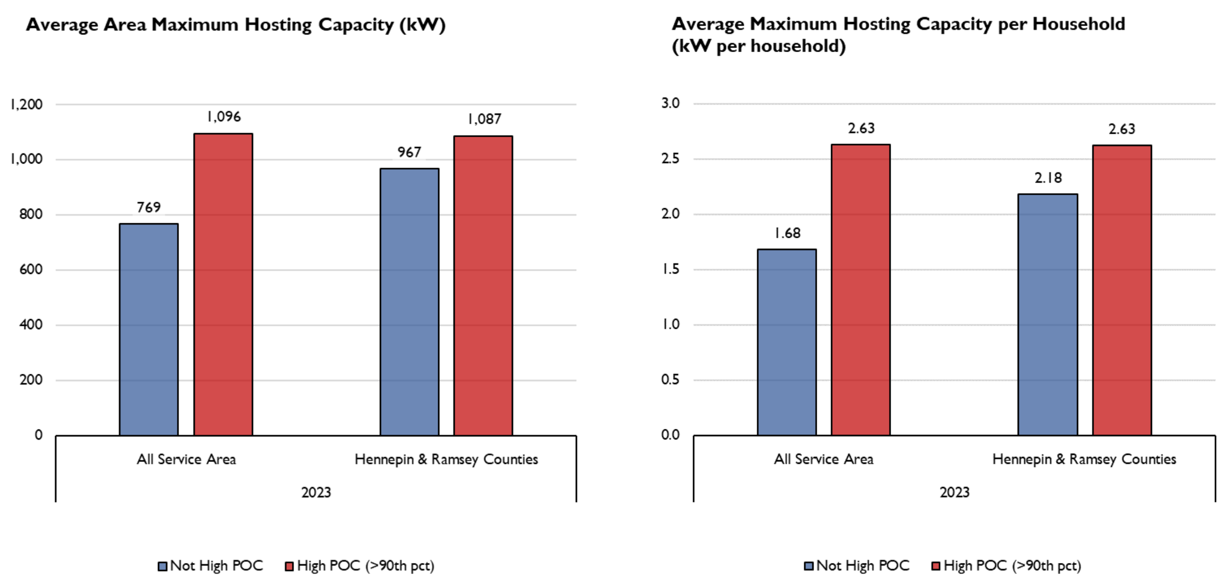

Figure 11. Average area maximum hosting capacity (left) and per household hosting capacity (right) comparing CBGs with high percentage of people of color (POC) with other CBGs in Xcel Energy's Service Area and in Hennepin and Ramsey Counties. Hosting capacity estimates shown for 2023.

2.4.4. Difference-in-Means Hypothesis Tests

In this section, we present results of difference-in-means hypothesis tests for each of the key outcome variables (long-term outages, multiple outages, involuntary disconnections, and hosting capacity) across each of the years of data. In Table 3, we conduct difference-in-means hypothesis tests comparing CEJST-designated disadvantaged communities to other communities. In Table 4, we conduct difference-in-means hypothesis tests comparing CBGs in the top 10% of population of people of color to other CBGs.

Table 3. Difference-in-means hypothesis tests comparing CEJST-designated disadvantaged communities to other communities across the rate of long-term outages, multiple outages, involuntary disconnections, and measures of hosting capacity.

		Non-Disadvantaged Communities (Non-DAC)	Disadvantaged Communities (DAC)	Difference (Non-DAC - DAC)	p-value	Statistically Significant?
Long-Term Outages: Customers Experiencing an Outage > 12 hours in a Year, per 1,000 households (CELI-12 x 1,000)						
2017-2019	All Service Area	6.90	3.12	3.77	0.0472	Yes
	Hennepin & Ramsey Counties	3.56	3.44	0.12	0.9037	No
2018-2020	All Service Area	23.89	27.60	-3.71	0.3803	No
	Hennepin & Ramsey Counties	20.98	29.51	-8.53	0.0414	Yes
2019-2021	All Service Area	24.01	26.54	-2.53	0.4905	No
	Hennepin & Ramsey Counties	20.02	27.91	-7.89	0.0247	Yes
Multiple Outages: Customers Experiencing > 6 Outages in a Year, per 1,000 households (CEMI-6 x 1,000)						
2017-2019	All Service Area	23.61	23.24	0.37	0.9231	No
	Hennepin & Ramsey Counties	16.48	23.23	-6.75	0.0312	Yes
2018-2020	All Service Area	8.16	3.69	4.47	0.0518	No
	Hennepin & Ramsey Counties	5.54	4.04	1.50	0.3946	No
2019-2021	All Service Area	7.41	3.74	3.67	0.0479	Yes
	Hennepin & Ramsey Counties	5.08	4.05	1.03	0.4767	No
Involuntary Disconnections, per 1,000 households						
2017-2019	All Service Area	9.17	28.19	-19.02	0.0000	Yes
	Hennepin & Ramsey Counties	7.76	28.95	-21.18	0.0000	Yes
2018-2020	All Service Area	3.30	8.92	-5.61	0.0000	Yes
	Hennepin & Ramsey Counties	3.08	9.54	-6.46	0.0000	Yes
2019-2021	All Service Area	3.42	9.43	-6.01	0.0000	Yes
	Hennepin & Ramsey Counties	3.25	10.07	-6.82	0.0000	Yes
Hosting Capacity (Maximum Area Hosting Capacity, kW)						
2023	All Service Area	763.90	1047.45	-283.55	0.0000	Yes
	Hennepin & Ramsey Counties	957.89	1106.81	-148.92	0.0000	Yes
Hosting Capacity per Households (Maximum Area Hosting Capacity per Household, kW/household)						
2023	All Service Area	1.66	2.53	-0.87	0.0000	Yes
	Hennepin & Ramsey Counties	2.14	2.71	-0.57	0.0000	Yes

Table 4. Difference-in-means hypothesis tests comparing communities with in the top 10% of populations of people of color to other communities across the rate of long-term outages, multiple outages, involuntary disconnections, and measures of hosting capacity.

		Not High People of Color Population (Bottom 90%)	High People of Color Population (Top 10%)	Difference (Not High POC - High POC)	p-value	Statistically Significant?
Long-Term Outages: Customers Experiencing an Outage > 12 hours in a Year, per 1,000 households (CELI-12 x 1,000)						
2017-2019	All Service Area	6.77	2.69	4.08	0.0655	No
	Hennepin & Ramsey Counties	3.61	2.90	0.71	0.5820	No
2018-2020	All Service Area	23.43	32.98	-9.55	0.0469	Yes
	Hennepin & Ramsey Counties	21.20	35.62	-14.43	0.0089	Yes
2019-2021	All Service Area	23.48	32.33	-8.85	0.0375	Yes
	Hennepin & Ramsey Counties	20.53	31.71	-11.18	0.0183	Yes
2020-2022	All Service Area	31.56	46.37	-14.81	0.0012	Yes
	Hennepin & Ramsey Counties	37.41	47.77	-10.36	0.0941	No
Multiple Outages: Customers Experiencing > 6 Outages in a Year, per 1,000 households (CEMI-6 x 1,000)						
2017-2019	All Service Area	23.42	24.77	-1.34	0.7635	No
	Hennepin & Ramsey Counties	17.09	24.92	-7.83	0.0641	No
2018-2020	All Service Area	7.99	3.69	4.29	0.1006	No
	Hennepin & Ramsey Counties	5.37	4.20	1.16	0.6172	No
2019-2021	All Service Area	7.27	3.50	3.76	0.0804	No
	Hennepin & Ramsey Counties	4.99	3.81	1.18	0.5449	No
2020-2022	All Service Area	8.39	5.74	2.65	0.1887	No
	Hennepin & Ramsey Counties	7.10	6.29	0.81	0.7087	No
Involuntary Disconnections, per 1,000 households						
2017-2019	All Service Area	9.52	33.15	-23.63	0.0000	Yes
	Hennepin & Ramsey Counties	9.58	35.03	-25.45	0.0000	Yes
2018-2020	All Service Area	3.25	11.29	-8.03	0.0000	Yes
	Hennepin & Ramsey Counties	3.47	12.15	-8.68	0.0000	Yes
2019-2021	All Service Area	3.42	11.98	-8.57	0.0000	Yes
	Hennepin & Ramsey Counties	3.76	12.68	-8.91	0.0000	Yes
2020-2022	All Service Area	5.25	19.01	-13.76	0.0000	Yes
	Hennepin & Ramsey Counties	5.67	19.56	-13.89	0.0000	Yes
Hosting Capacity (Maximum Area Hosting Capacity, kW)						
2023	All Service Area	768.82	1095.63	-326.81	0.0000	Yes
	Hennepin & Ramsey Counties	966.99	1087.00	-120.01	0.0027	Yes
Hosting Capacity per Households (Maximum Area Hosting Capacity per Household, kW/household)						
2023	All Service Area	1.68	2.63	-0.95	0.0000	Yes
	Hennepin & Ramsey Counties	2.18	2.63	-0.45	0.0002	Yes

3. Methods

In the three major analyses we conduct for disconnection rates, service quality, and DER hosting capacity analysis, we compute the conditional and unconditional annual rates (disconnections, CELI-12, and DER hosting capacity) using Ordinary Least Squares (OLS) regression models by regressing these rates on an indicator of the percent of households that identify as people of color, poverty rates, and median household income at the CBG level. We also use year and county fixed effects and an additional set of CBG-level controls. In equation (1), we show the basic model for our regression models.

$$y_{it} = \alpha_c + \lambda_t + \delta POC_{it} + \beta X_{it} + \varepsilon_{it} \quad (1)$$

where, y_{it} is the annual block group (i) dependent variable: disconnected homes (per 1,000 homes), CELI-12 (per 1,000 homes), and hosting capacity (kW per household), $\boldsymbol{\delta}$ represent the variables of interest- representing the impact of POC on the dependent variable, α_c are county-level fixed effects, λ_t are year fixed effects, and X_{it} includes block group characteristics: median household income, poverty rate, unemployment rate, population density, renters, multifamily housing, newly built buildings, and households with no access to the internet.

The way that Xcel Energy reports the disconnection and CELI-12 data (by average disconnection rates over 3 years) biases the actual rates due to multiple overlaps between different periods. For example, the 2020 rates (the average of 2018, 2019, and 2020) and the 2021 rates (the average of 2019, 2020, 2021) biases the actual rates which can lead to underestimation of the variability in the dataset and overstate the significance of the findings. To account for this possible violation, we create a panel using rates from two reporting periods: 2019 and 2022 to eliminate any overlapping years.

4. Regression Results

In this section we present the results of our analysis of disconnection rates (Section 4.1), rates of extended outages (Section 4.2), and hosting capacity (Section 4.3) against demographic indicators. For each outcome variable, we implement nearly identical regression model specifications.

4.1. Electric Service Disconnection

Table 5 presents the outcomes of a fixed effects model employed to examine the correlation between utility disconnection rates and various variables, with a focus on the percentage of people of color (POC) within a CBG. Model (1) only regresses the POC percent value with disconnection rates. The result of Model (1) shows that increasing a CBG's POC population by 10 percentage points is associated with an increase of 2.93 disconnections per 1,000 households, controlling for year and county-fixed effects. This is a practically significant finding when compared to the average disconnection rate of 6.82 disconnections per 1,000 households shown in Table 1. The estimate for POC across all models is statistically significant at the 0.01 level when controlled for the economic and structural characteristics of the block group (separately and together.

In Model (5), we control for the CBG's median household income ($100,000), poverty (%), population density (1,000 homes per sq. miles), unemployment rate (%), renters (%), and the proportion of homes built after 1990 (%). The linear regression model suggests significant correlations between a CBG's POC and the rate of electric utility disconnection. Model (5) reports that after controlling for a number of variables, a 10 percentage point increase in the POC share of the population is associated with the number of disconnected homes per 1,000 increasing by 2.24.

Table 5. OLS Regression Model of Electric Utility Disconnections for the panel of 2017-2019 average and 2020-2022 average disconnections

Dependent Variable:	Disconnected homes (per 1,000 households)				
Model:	(1)	(2)	(3)	(4)	(5)
POC (0-100%)	0.2927*** (0.0116)	0.2271*** (0.0132)	0.2645*** (0.0118)	0.2940*** (0.0118)	0.2236*** (0.0133)
Poverty (0-100%)		0.1201*** (0.0171)			0.0777*** (0.0210)
Med. HH Inc. ($100,000)			-3.492*** (0.3699)		-1.296** (0.5153)
Population Density (1,000 households per sq. mile)				-0.0147 (0.0307)	-0.0925*** (0.0321)
Unemp. Rate (0-100%)					0.1633*** (0.0528)
Renters (0-100%)					0.0184 (0.0112)
Built after 90s (0-100%)					-0.0379*** (0.0066)
Year FE	✓	✓	✓	✓	✓
County FE	✓	✓	✓	✓	✓
Observations	4,511	4,511	4,511	4,511	4,451
R^2	0.3638	0.3776	0.3737	0.3639	0.3852

Significance Codes: *** p < 0.01, ** p < 0.05, * p < 0.1

4.2. Service Reliability

In the following analysis, the focus shifts to long-duration outages as captured by the CELI-12 metric, which likely has a more pronounced impact on under-resourced communities compared to multiple short-duration outages, as gauged by the CEMI-6 metric.

Table 6. Regression Model of Long Duration Service Disruption in Minnesota for the panel of 2017-2019 average and 2020-2022 average service disruptions.

Dependent Variable:	CELI-12: Homes Experiencing Outages >12 hrs (per 1,000 households)				
Model:	(1)	(2)	(3)	(4)	(5)
POC (%)	0.0652 (0.0441)	0.1992*** (0.0563)	0.1009** (0.0452)	0.1089** (0.0042)	0.2078*** (0.0561)
Poverty (%)		-0.2455*** (0.0630)			-0.0770 (0.0790)
Med. HH Inc. ($100,000)			4.424** (1.814)		-7.307** (2.876)
Population Density (1,000 households per sq. mile)				-0.4941*** (0.1001)	-0.2258** (0.0989)
Unemp. Rate (%)					0.0177 (0.2021)
Renters (%)					-0.3180*** (0.042)
Built after 90s (%)					-0.3027*** (0.0275)
Year FE	✓	✓	✓	✓	✓
County FE	✓	✓	✓	✓	✓
Observations	4,511	4,511	4,511	4,511	4,451
R^2	0.1187	0.1213	0.1194	0.1211	0.1493

Significance Codes: *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$

The outcomes of the regressions are shown in Table 6. Model (1) estimates the association between a CBG's percent POC and CELI-12 rates, accounting for year and county fixed effects. Models (2-5) estimate multivariate regressions with multiple controls. For Models (2-5), the percent POC in a CBG is statistically significant, indicating the robustness of the estimated value. Model (5) estimates a coefficient of 0.2078 for POC. The interpretation of the estimate is that, after controlling for different neighborhood characteristics, a 10 percentage point rise in the POC population is associated with 2.078 additional homes experiencing long-duration outages, controlling for multiple socioeconomic factors. The estimates in Model (2-5) are statistically significant at the 0.01 level.

4.3. DER Hosting Capacity

Table 7 shows the effect of a CBG's demographics on the average maximum hosting capacity per household. Hosting capacity is measured in kilowatts (kW) per household. Model (1) estimates the impact of a CBG's POC concentration on the grid's available hosting capacity. The model's estimate shows that a 10 percentage point increase in the POC population increases the per household hosting capacity by 0.107 kW. However, this estimate is only robust when controlling with control (Model 1), and when controlling for Median Household Income (Model 3) and Population Density (Model 4), at the 0.001 level.

Table 7. Regression model of per household hosting capacity in 2023.

Dependent Variable:	Average Maximum Hosting Capacity per Household (kW per household)				
Model:	(1)	(2)	(3)	(4)	(5)
POC (%)	0.0107*** (0.0018)	0.0036 (0.0025)	0.0085*** (0.0021)	0.0112*** (0.0019)	0.0036 (0.0026)
Poverty (%)		0.0141*** (0.0039)			0.0111** (0.0047)
Med. HH Inc. ($100,000)			-0.1769* (0.1007)		0.1836 (0.1254)
Population Density (1,000 households per sq. mile)				-0.0059 (0.0046)	-0.0173*** (0.006)
Unemp. Rate (%)					0.0264*** (0.0088)
Renters (%)					0.0038 (0.0024)
Built after 90s (%)					-0.0041** (0.0016)
County FE	✓	✓	✓	✓	✓
Observations	2,028	2,028	2,028	2,028	1,985
R^2	0.213	0.225	0.213	0.213	0.232

Significance Codes: *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$

Model (3) includes the POC and median household income, excluding the poverty percentage. The coefficient for the median household income (-0.1769) is statistically significant at the 0.1 level, indicating that neighborhoods with higher median income are associated with a lower available hosting capacity.

From Model (5), the per household hosting capacity is not associated with the POC, as indicated by the estimate that is not statistically significant. However, Model (5) shows that the per household hosting capacity decreases in denser neighborhoods. The relationship shows that, controlling for various neighborhood characteristics, a 10 percentage point increase in the population density (1,000 households per sq. mile) of a neighborhood decreases the per household hosting capacity by 0.173 kW.

5. Conclusion

The findings of this paper reveal strong associations between socioeconomic variables, including race and income, with utility disconnections and reliability metrics. Although the findings do not make causal claims, we believe that these statistically significant associations demand attention from energy system planners and policymakers. While we do not believe that our findings necessarily imply deliberate racial bias on the energy system planners' part, this does not negate the potential for utilities and policymakers to take proactive steps toward fostering equity in the electric system through the principles of energy justice. Some measures to address these issues include protecting low-income customers from disconnections, investing in marginalized communities to improve utility service quality, and equitably expanding distributed energy resources capacity.

This paper highlights the urgent need for policy interventions to rectify these deep-seated disparities, ensuring access to reliable, high-quality utility services for all people, irrespective of their socioeconomic or racial backgrounds. Moving forward, the goal should not merely be to avoid deliberate injustices but to create systems that ensure fairness and equity, particularly as the energy system is poised to see once-in-a-generation infusions of capital to decarbonize the economy. While this research focused on Minnesota, the findings and proposed interventions have broader implications, offering valuable insights for other states grappling with similar disparities. We hope this study stimulates and encourages further research and dialogue toward policy changes prioritizing energy equity and justice.

Acknowledgments

The authors would like to thank Carl Ludewig and Matthew Grimley for their support in data preparation and interpretation.

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