COMMERCE DEPARTMENT

April 10, 2020

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: **Reply Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/M-19-666

Dear Mr. Seuffert:

Attached are the reply comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> Xcel Energy's Integrated Distribution Plan (IDP) and Advanced Grid Intelligence and Security Certification Request.

As allowed by the comment opportunities set forth in the Minnesota Public Utilities Commission's (Commission) December 31, 2019 *Notice of Comment Period In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, the Department provides the attached reply to stakeholder initial comments and further clarification and justification for the contested case proceeding requested in our March 17, 2020 comments.

The Department recommends that the Commission accept Xcel Energy's IDP Report, require annual updates of a subset of IDP requirements, and refer Xcel Energy's Advanced Grid Intelligence System certification request to a contested case hearing. The Department takes no position on certification of the Advanced Distribution Planning Tool (APT) or other grid modernization investments at this time, due to the reasons contained herein, and will reevaluate upon further record development. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ MATTHEW LANDI	/s/ TRICIA DEBLEECKERE
Rates Analyst	Planning Director

ML/TD/ja
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Reply Comments of the Minnesota Department of Commerce Division of Energy Resources

Docket No. E002/M-19-666

I. INTRODUCTION

On November 1, 2019, Northern States Power Company, d/b/a Xcel Energy (Xcel, Xcel Energy, or the Company) filed its 2019 Integrated Distribution Plan (IDP) as required by the Minnesota Public Utility Commission's (Commission) July 16, 2019 Order in Docket No. E002/CI-18-251 (the Order).[1] The Company's 2019 IDP included the Company's certification request of its proposed Advanced Grid Intelligence and Security (AGIS) Initiative and an Advanced Distribution Planning Tool (APT).[2] The AGIS Initiative includes Advanced Metering Infrastructure (AMI), a Field Area Network (FAN), Fault Location and Isolation Service Restoration (FLISR), an Integrated Volt-Var Optimization (IVVO).

The Company anticipates incurring capital expenditures totaling $582 million and operation and maintenance (O&M) costs totaling $152 million for the overall AGIS Initiative (exclusive of Advanced Distribution Manage System or ADMS) from 2020-2029.[3] The APT is expected to cost $9.3 million in total, with $4 million attributed to Northern States Power-Minnesota (NSPM), and minimal ongoing costs for the annual software hosting fee and internal maintenance.[4]

On December 31, 2019, the Commission issued a *Notice of Comment Period* (Notice). The Notice reaffirmed the purpose of the Commission's IDP filing requirements:

- Maintain and enhance the safety, security, reliability, and resilience of the electric grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution-system plans, the costs and benefits of the specific investments, and a comprehensive analysis of ratepayer cost and value.

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[1] *Order Accepting Report, and Amending Requirements*, dated July 16, 2019, Docket No. E002/CI-18-251.

[2] Xcel 2019 IDP, dated November 1, 2019, Docket No. E002/M-19-666.

[3] IDP, at 153-154.

[4] IDP Executive Summary, at 11-12.

The Commission's Notice included the following topics related to Xcel Energy's 2019 IDP:

1. Should the Commission accept or reject Xcel Energy's Integrated Distribution Plan (IDP)?
2. Does the IDP filed by Xcel Energy achieve the planning objectives in the filing requirements approved in the Commission's July 16, 2019 Order [footnote omitted]?
3. What IDP filing requirements provided the most value to the process and why?
4. Are there filing requirements that are not informative and/or should be deleted or modified, and why?
5. Should the Commission accept Xcel Energy's request to file the next IDP no later than November 1, 2021? Should the Commission move from an annual to biennial IDP filing for the Company going forward?
6. Are there other issues or concerns related to this matter?

The Commission's Notice also included the following topics related to Xcel Energy's certification requests:

7. Should the Commission approve, modify, or deny certification of the following investments which are components of Xcel Energy's Advanced Grid Intelligence and Security (AGIS) Initiative at this time:
    a. Advanced Metering Infrastructure (AMI)
    b. Field Area Network (FAN)
    c. Fault Location, Isolation, and Service Restoration (FLISR)
    d. Integrated Volt-Var Optimization (IVVO)
8. Should the Commission certify the Advanced Distribution Planning Tool (APT) at this time?
9. What, if anything, should the Commission set as conditions or clarify if granting certification of these distribution projects?
10. What should the Commission consider or address related to realizing benefits of each of the investments in the Company's AGIS Initiative for ratepayers?
11. At the stage of certification, what consideration should the Commission give to subsequent cost recovery, via either the Transmission Cost Recovery rider or general rate case, for each of the AGIS investments?
12. Are there any other issues or concerns related to this matter?

On or before March 17, 2020, the following parties—including the Minnesota Department of Commerce, Division of Energy Resources (Department)—submitted Initial Comments in this proceeding:

- The Office of the Attorney General—Residential Utilities Division (OAG);
- The City of Minneapolis;

- Clean Energy Economy Minnesota (CEEM);
- Fresh Energy;
- Citizens Utility Board of Minnesota (CUB);
- Xcel Large Industrials (XLI);
- IPS Solar;
- Interstate Renewable Energy Council, Inc. (IREC); and
- Environmental Law and Policy Center (ELPC) and Voter Solar

The Department offers these reply comments in response to the initial comments of the above-referenced stakeholders.

II. DEPARTMENT ANALYSIS

A. ANALYSIS OF STAKEHOLDERS' RECOMMENDATIONS REGARDING XCEL'S IDP

The Department appreciates the thorough review and thoughtful consideration from multiple stakeholders in this proceeding. Many of the recommendations and comments from stakeholders involve modifications or additions to the requirements for future IDP reports. The Department addresses the merits of these proposed changes in the broader context of distribution system planning in Minnesota and the concurrent IDP processes at other regulated utilities.

The Department believes this broader context is important in order to ensure an optimal outcome for ratepayers and the public interest. The Department provided our position on consistent IDP requirements among utilities in our initial comments in Docket Nos. E017/CI-18- 253, E015/CI-18-254, and E011/CI-18-255. The Department reiterates our position here:

> [T]he Department is supportive of draft IDP requirements for OTP that are as consistent with Xcel's IDP to the greatest extent practicable when appropriate, and is supportive of an evolutionary regulatory process that leads to consistent requirements between utilities to the greatest extent practicable.
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> The Department notes that it is important to adapt IDP requirements to the unique circumstances and characteristics of each utility such that a completely uniform set of requirements is likely precluded. Further, flexibility is an essential feature that should permeate throughout this regulatory effort. Utilities are likely to need time to adjust and grow into this regulatory paradigm as internal planning processes are exposed to regulatory oversight and are harmonized with the Commission's IDP requirements. As the IDP process matures, the Department anticipates that a process that converges rather than diverges planning requirements for each of Minnesota's utilities is likely to lead to the most optimal outcome for ratepayers and the public interest.

> Consistent regulatory requirements and standards in Minnesota utilities' IDPs are likely to lead to better results for all of Minnesota's ratepayers than a paradigm where IDPs vary to the extent that they result in inconsistent criteria used to assess the costs and benefits of distribution system planning, investments, and operations. Distribution system planning informs utility capital budget construction budgets, which currently includes typical distribution system improvements, equipment replacements, and service extensions.[footnote omitted] Utilities also rely on load forecasts down to the individual substation or feeder, and modeling designed to identify system reliability helps prioritize required capital projects.[footnote omitted] It's important to understand how utilities plan their distribution systems to assess how utilities avoid creating lock-in effects that could prevent a utility from considering other options, how utilities capture the full consideration of various alternatives, how utilities share information, and how utilities ensure that their planning results in efficient uses of ratepayer resources.
>
> Uniformity and interoperability may help position utilities to leverage future technological advancements, to achieve economies of scale, enable distributed energy resource integration, improve system efficiency, and ultimately, reduce costs and increase benefits for Minnesota's ratepayers.

The Department's analysis of other stakeholder recommendations related to Xcel's IDP requirements considers the larger picture of distribution system planning in Minnesota. The Department considers whether recommended modifications: (1) are reasonably likely to result in a benefit for ratepayers and the public interest; and (2) can be reasonably incorporated into other utilities' IDP requirements.

The Department also evaluates all other stakeholder recommendations related to the IDP in these reply comments, but withholds final recommendations until supplemental comments.

1. *ELPC and Vote Solar Recommendations*

ELPC and Vote Solar recommended modification of IDP Requirements 3.E.1 and 3.C.3, and the creation of a new IDP requirement. In addition to these IDP requirement recommendations, ELPC and Vote Solar recommended that the Commission take the following actions:

- Create a separate docket to address Xcel's non-wires alternatives (NWA) analysis and direct Xcel to form a NWA Stakeholder Advisory Group;
- Align the IDP process with the performance metrics framework by requiring Xcel to include a report of Xcel's performance on metrics related to Xcel's distribution system in the next IDP; and
- Compile Xcel's IDP requirements as amended by Commission Orders.

a.) Modification of IDP Requirement 3.E.1

ELPC and Vote Solar recommended the following modifications to IDP Requirement 3.E.1 Non-Wires (Non-Traditional) Alternatives Analysis:[5]

> Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. **For each distribution system project satisfying those criteria, Xcel shall explain the hour(s) and day(s) during which an NWA would be called upon to deliver energy and demand, if an NWA were to defer or avoid the project.** For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value. **In determining how non-wires alternatives compare to forthcoming projects or projects in the filing year in terms of price, Xcel shall consider all revenue streams available to the non-wires alternative project. For projects that involve N-0 risks, Xcel shall issue a request for proposals soliciting NWA solutions addressing those risks.**

ELPC and Vote Solar explained that providing additional information regarding the hour(s) and day(s) during which an NWA would be called upon to deliver energy and demand would provide stakeholders and third-party developers with the information needed to evaluate Xcel's internally developed NWA solutions and enable third-party developers to propose NWA solutions through a Request for Proposal (RFP) process.[6]

The Department agrees that this additional information would be helpful in evaluating Xcel's NWA proposals, and that an RFP process would increase transparency of costs and benefits, and generally result in an opportunity for third-party developers to propose NWA solutions that are cost-competitive with traditional utility investments in physical infrastructure.

However, the Department declines to recommend this modification to IDP Requirement 3.E.1 at this time. While the Department agrees that more refined analyses of potential benefits of a NWA solution would be helpful and is indeed a necessary component of performing a comprehensive evaluation of a NWA solution, IDP Requirement 3.E.1 currently contains language that could be interpreted to require Xcel to provide the specific information that ELPC and Vote Solar recommend be provided. The Department interprets the following provision of IDP Requirement 3.E.1 to facilitate the provision of information that ELPC and Vote Solar seek:

[5] ELPC and Vote Solar Initial Comments, dated March 16, 2020, at 11.
[6] ELPC and Vote Solar Initial Comments, at 10.

> For any forthcoming project or project in the filing year, which cost two million dollars or more, ***provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.*** [emphasis added]

The current language of the IDP Requirement 3.E.1 can be reasonably interpreted to induce Xcel to provide that information in its NWA analysis. Further, there is nothing in the record to suggest that without the requested modification to IDP Requirement 3.E.1, Xcel would fail to provide such a discussion in future IDPs or in response to information requests. The Department therefore concludes that ELPC and Vote Solar's recommended modification is unnecessary at this time.

Additionally, ELPC and Vote Solar's analysis of the first candidate project on Xcel's NWA analysis list, the "Reinforce Kasson TR1 and Feeder" project, does not show that if Xcel considered additional revenue streams, the project would have been a viable, cost-effective alternative to the traditional solution. It is not clear from the record that requiring Xcel to initiate an RFP process at this time would result in more cost-effective outcomes for ratepayers.

The Department will provide a final recommendation in supplemental comments once Xcel has an opportunity to weigh in on ELPC and Vote Solar's recommendation and provides additional information related to its NWA analysis.

b.) Modification of IDP Requirement 3.C.3

ELPC and Vote Solar recommended a modification of IDP Requirement 3.C.3 Distributed Energy Resource Scenario Analysis:[7]

> Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels. **Provide a discussion of whether external control through utility communication with smart inverters, above and beyond the autonomous functions associated with smart inverters, would be necessary to ensure the safe and reliable operation of the grid at the listed penetration levels.**

ELPC and Vote Solar argued that Xcel's responses to information requests related to the Company's plans for a Distributed Energy Resource Management System (DERMS) did not establish a reasonable basis for its current plans to implement a DERMS in the 2024-2025 timeframe, noting that California does not require a DERMS system despite having higher levels of DER penetration today than Xcel projects to have in the 2024-2025 timeframe.[8]

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[7] ELPC and Vote Solar Initial Comments, at 13.
[8] ELPC and Vote Solar Initial Comments, at 12-13.

The Department does not support ELPC and Vote Solar's recommended amendment to IDP Requirement 3.C.3 at this time. Again, the current language of IDP Requirement 3.C.3 could reasonably be interpreted to require Xcel to consider the specific items that ELPC and Vote Solar recommend be considered. The Department interprets the following provision of IDP Requirement 3.C.3 to facilitate the provision of information that ELPC and Vote Solar seek:

> *Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient.* Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and *the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.* [emphasis added]

The current language of the IDP Requirement 3.C.3 can be reasonably interpreted to require a discussion of whether a system such as DERMS is required to manage DERs at projected future levels of DER penetration, and whether smart inverter functions are insufficient to control DER in order to ensure safe and reliable operation of the grid. There is nothing in the record to suggest that without this modification to IDP Requirement 3.C.3, Xcel would not provide such a discussion in future IDPs or information requests. The Department therefore concludes that ELPC and Vote Solar's recommended modification is unnecessary at this time.

c.) Creation of IDP Requirement 3.F

ELPC and Vote Solar recommended the creation of IDP Requirement 3.F Locational Reliability and Equity:[9]

> **3.F. Locational Reliability and Equity.**
> 1. Xcel shall provide a map that illustrates the reliability of the Company's distribution system at a feeder-level.
> 2. Xcel shall describe how its proposed reliability investments will prioritize those portions of its system with poor reliability performance.
> 3. Xcel shall explain how its proposed reliability investments will advance equity across its service territory.

ELPC and Vote Solar argue that Xcel's description of its Incremental System Investment (ISI) Initiative and its general spending within the Asset Health and Reliability budget grouping does not enable sufficient review of Xcel's plans to target specific portions of its distribution system with poor reliability performance (as described in Xcel's annual Service Quality Report filings) such that stakeholders are unable to determine whether Xcel's proposed spending is reasonably tailored to address poor reliability performance.[10]

[9] ELPC and Vote Solar Initial Comments, at 15.
[10] ELPC and Vote Solar Initial Comments, at 14.

As a result, ELPC and Vote Solar recommended that Xcel illustrate the reliability of its distribution system on a feeder-level basis and explain how its proposed ISI Initiative (or other targeted reliability spending) would prioritize the portions of its system with poor reliability performance. ELPC and Vote Solar also recommended that the Company explain how its proposed targeted reliability spending would advance equity across its service territory.

The Department is also interested in the potential merit of targeted reliability spending to address poor-performing areas of Xcel's distribution system and the potential opportunity to advance equity by targeting investment to particularly vulnerable customers within Xcel's service territory.

Before taking a position on whether to adopt ELPC and Vote Solar's recommendation to create a new IDP Requirement, however, the Department is interested in the Company's response to whether the provision of the information envisioned by ELPC and Vote Solar would result in better outcomes for ratepayers. Moreover, the Department generally expects that the ISI Initiative will be subject to rate case prudence review, which will provide a forum for stakeholders interested in Xcel's capital spending related to Asset Health and Reliability and the ISI Initiative to obtain more specific information and better evaluate Xcel's planned investments. Additionally, the Department also recommends, as discussed below, that the ISI investments should be included in a referral to the OAH of this matter (to the extent the ISI investments affect and relate to AGIS).

At this time, the Department does not support ELPC and Vote Solar's proposed additional IDP Requirement, but will evaluate any additional discussion provided in reply comments and provide a final recommendation in supplemental comments.

2. CUB Recommendations

CUB recommended that Xcel's multi-year rate plan (MYRP), integrated resource plan (IRP), and IDP planning processes should be harmonized such that an approved or accepted IRP or IDP action plan (such as the five-year action plan required by IDP Requirement 3.D.2) informs the setting of base rates or target revenues for the subsequent MYRP control period.[11]

Other states are looking at this alignment between the related case types, MYRP, IRPs, IDPs, and performance incentives. While the Department is not recommending specific action at this time, it notes that this issue will continue to arise and would be assisted by properly setting the system frameworks and expectations (system plans, as discussed above), now, that would inform future MYRPs and could support alignment of performance incentive mechanisms.[12] The Department further notes that Commission proceedings are not undertaken in isolation, however, timing of the proceedings should occur in a way that does not preclude the Commission's ability to harmonize the results of each proceeding.

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[11] CUB Initial Comments, Attachment *Review and Recommendations for Xcel Energy Integrated Distribution Plan* prepared by Strategen Consulting, dated March 17, 2020, at 10.
[12] Michigan Public Service Commission Staff Report on Distribution System Planning Framework, dated September 1, 2018, at 21.

The Department concludes that it is not necessary to take action to harmonize Xcel's IRPs, IDPs and MYRPs at this time.

3. *City of Minneapolis Recommendations*

The City of Minneapolis made three recommendations for Commission action:

(1) Reduce the two million dollar project cost threshold for NWA analysis (in effect, modify IDP Requirement 3.E.1);[13]
(2) Xcel should be required to propose a NWA pilot by November 1, 2020, in lieu of filing an IDP;[14] and
(3) Xcel should be required to consider the energy and climate goals of Minnesota communities it serves along with customer preference trends when responding to the IDP Requirement 3.A.32 and Order Point #7 of the Commission's July 2019 Order in future IDPs.[15]

The City of Minneapolis recommended to reduce the two million dollar project cost threshold for NWA analysis, citing Xcel's identification of 22 capacity projects planned between 2022 and 2024, but only 9 of them exceeding the cost threshold for NWA analysis.[16] The City of Minneapolis also cited that other states use a differentiated cost approach for NWA analysis (citing a report by Rocky Mountain Institute and the approaches taken in New York, Rhode Island, and Vermont).[17]

While there may be merit to employing a differentiated cost approach for NWA analysis, at this time, it is not clear what the potential benefits or implications for Xcel's NWA analysis would be. None of the nine projects identified by Xcel in its IDP for NWA analysis were cost-effective, and it is not clear whether any of the lower cost projects would have had different results had they also been analyzed. The Department is concerned about asking Xcel to perform redundant analysis only to arrive at the same conclusion that NWA solutions are not cost-effective at present. The Department does not support the City of Minneapolis' recommendation at this time, but will review any further discussion on the topic that may be provided by Xcel and other stakeholders.

The Department also does not support the City of Minneapolis' second recommendation, that Xcel propose a pilot NWA program by November 1, at this time. After developing a more comprehensive approach to NWA analysis in coordination with stakeholders, a pilot program may be appropriate; however, an NWA pilot would be premature at this time. Additional information may also be gleaned by Xcel and Center for Energy and the Environments' geo-targeting pilot with a report expected to be released in April 2020.[18]

[13] City of Minneapolis Initial Comments, dated March 17, 2020, at 4.
[14] City of Minneapolis Initial Comments, at 6.
[15] City of Minneapolis Initial Comments, at 8.
[16] City of Minneapolis Initial Comments, at 4.
[17] City of Minneapolis Initial Comments, at 4.
[18] IDP, at 100-101

Xcel summarized the current state of NWA analysis in the electric utility industry as follows:[19]

> NWA Analysis, from a holistic standpoint, is an emerging analysis that many utilities across the U.S. are just beginning to tackle. Not only do these alternatives use some non-traditional solutions but they also use traditional ones in new ways and may combine solutions to fully mitigate an issue. These complexities along with differing implementation and operational strategies will take time and considerable effort to build and maintain.
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> We note that we are just at the beginning of the future NWA process. Xcel Energy and the industry as a whole, is trying to create a comprehensive method that will focus on the projects that have the most potential and then evaluate them in an efficient manner against traditional alternatives. We believe much work needs to take place both from the Company and the industry before success can happen. At present, the effort needed to analyze one project for potential NWA is substantial and increases greatly according to the number of risks associated with it.

Additionally, Xcel explained that its current approach to NWA analysis is dependent upon disparate internal systems and requires a time consuming and manual process to conduct thoroughly:[20]

> For implementation and deployment, currently we are seeing NWA solutions which require a disparate set of systems to separately operate the different elements of equipment that would comprise an NWA portfolio solution (e.g. a battery- only platform or demand response- only mode).
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> Without integration across different systems, this makes the facilitation of NWA a custom, one-off solution that requires extensive oversight and management.
>
> …
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> Today, NWA analysis is very time consuming and manual – especially as the risks associated with a project increase. The process requires that we pull peak load curves for feeders and substation transformers from historical monitoring data and advance that to the forecasted year of interest. Those curves are then blended together, where applicable, for contingency situations that are unique for each. We then tailor and add in DR and existing generation curves and additional solar if necessary, in order to determine final energy and demand values that can be used to size an appropriate energy storage device. This is necessary for every identified risk that a traditional project is mitigating.

[19] IDP, at 96.
[20] IDP, at 90, 98.

In consideration of the information contained in Xcel's IDP and the current state of the industry, the Department expects that a NWA pilot program would be premature and imprudent at this time. However, the Department withholds a final recommendation until it reviews stakeholder reply comments.

In regards to the City of Minneapolis' third recommendation, the Department provides the language of IDP Requirement 3.A.32 and Order Point #7 of the Commission's July 16, 2019 Order[21] below:

> 32. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.
>
> 7. Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.

The City of Minneapolis recommends that the Commission require Xcel to consider community energy and climate goals, as well as customer preference, in forecasting DER penetration. The City of Minneapolis stated the following in support of their recommendation:

> [S]everal of the communities Xcel serves in Minnesota, including Minneapolis, Brooklyn Park, Saint Paul, and Saint Louis Park have local solar energy generation and equity goals that the distribution system could more cost effectively support if the utility takes these goals into consideration during its planning process. The utility is a critical partner for communities if we are to achieve our goals. It is a less than optimal use of resources if Xcel disregards the official energy policy of the communities it serves.
>
> Public utilities are entrusted to make decisions about how to best invest billions of their customers money to meet the needs of the people they serve. It is a tremendous responsibility because as Xcel notes, it can make the difference for whether a family, a business, or a school is able to cost effectively interconnect their own rooftop solar system or have electric vehicle charging on-site. [footnote omitted]

First, the City of Minneapolis appears to be supporting the concept of burdening all of Xcel's ratepayers with incremental costs incurred in support of the goals of a single ratepayer, or subset of ratepayers, without a showing of benefits to all of Xcel's ratepayers. This concept does not conform to Minnesota's regulatory construct, including cost causation principles. However, the City of Minneapolis cited Xcel's IDP, explaining that forecasting tools that enable geographic-specific

[21] *Order Accepting Report, and Amending Requirements*, dated July 16, 2019, Docket No. E002/CI-18-251.

forecasting are very limited at this time, and further, costs related to the interconnection of DERs are borne by the party wishing to interconnect (in line with cost causation principles). Therefore, it is not clear what specific change in Xcel's planning processes the City of Minneapolis wishes to see.

Further, it appears that Xcel's DER forecasting ability (at this time) is limited to a system-wide consideration, rather than forecasting DER in specific areas of its distribution system, such as one of the municipalities referenced by the City if Minneapolis (including Minneapolis itself). The Department notes that the closest approximation to a geographic consideration of DER location (other than specific DER interconnection requests) is found in Xcel's hosting capacity analysis proceeding (Docket No. E002/M-19-685). However, this proceeding does not involve geographic forecasting of DER levels, and instead attempts to determine how much DER Xcel's distribution system can interconnect at more granular areas of its distribution system.

The Department does not support any of the City of Minneapolis' recommendations at this time, but will reassess this position in light of any further discussion provided by Xcel or other stakeholders in reply comments.

4. IPS Solar Recommendations

IPS Solar also recommended that the two million dollar project cost threshold for NWA analysis be reduced to one million dollars (in effect, to modify IDP Requirement 3.E.1) and to include asset health projects as well as new capacity upgrades.[22]

Xcel's NWA analysis only considered capacity projects in its 2019 IDP, and excluded Mandated and Asset Health and Reliability projects for various reasons, including but not limited to: (1) capacity projects are driven by a capacity deficiency that can be offset or otherwise deferred by DER; (2) mandated projects are currently more time prohibitive due to a misalignment of the planning processes the Company currently needs for NWA analysis and municipal project design, funding, and implementation; and (3) asset health and reliability projects are essential to maintaining customer connectivity to the distribution system and the risk of customer outage is currently too high for these types of projects to be suitable for NWA analysis.[23]

In addition to Xcel's explanation and the Department's disposition toward the City of Minneapolis' recommendation to also reduce the project cost threshold articulated in the previous section, the Department does not support IPS Solar's recommendation at this time.

5. CEEM Recommendations

CEEM did not offer any specific recommendation in their initial comments other than a general suggestion to re-frame the NWA analysis from a discreet requirement that reviews marginal projects to a broader system view and policy concept. The Department does not specifically respond to this suggestion, as it appears to be only a suggestion and not a specific proposed change, however, the

[22] IPS Solar Initial Comments, dated March 17, 2020, at 2.
[23] IDP, at 91-93.

Department notes that it may be reasonable for a utility to establish an internal plan or framework for review of NWAs. The Department believes that CEEM's suggestion is reasonable and will be developed through future iterations of IDPs, as Xcel installs and utilizes advanced system technologies, making NWA analysis a less manual process.

6. IREC Recommendations

IREC recommended that the Commission replace the Distributed Energy Resources Interconnection Process's (MN DIP's) interconnection screens with hosting capacity analysis (HCA),[24] and require that Xcel allow any interested person to participate in stakeholder engagement meetings regarding its IDP and HCA.[25]

The Department does not support IREC's first recommendation and suggests that IREC offer this insight and recommendation in the appropriate forum(s) related to both the MN DIP process and the HCA instead of the current proceeding involving Xcel's IDP.

The Department agrees that all stakeholders who wish to participate in Xcel's ongoing stakeholder engagement meetings should be allowed to do so. Xcel should make a good faith effort to be as inclusive and open in its stakeholder process as possible.

B. ANALYSIS OF STAKEHOLDERS' RECOMMENDATIONS REGARDING XCEL'S CERTIFICATION REQUEST OF THE AGIS INITIATIVE AND APT

1. Overview of Recommendations

Only one stakeholder, IPS Solar, recommended certification of *both* the AGIS and APT investments. All other parties either recommended that the Commission either deny or defer a decision on certification of the AGIS investments (CUB, Fresh Energy, XLI, and ELPC/Vote Solar) or took no position (OAG, City of Minneapolis, CEEM and IREC). IPS Solar and Fresh Energy recommended certification of the APT, and no other parties made a recommendation on that tool.

The Department evaluates each of the positions and recommendations under the headings below.

2. Certification and Use of Riders for Recovery

Consistent with Department initial comments, it appears that there is concern among stakeholders regarding certification and use of riders, generally, to recover investments in projects like the AGIS proposal; projects involving significant investment and that span multiple years can easily have cost-containment and double recovery issues (as costs easily overlap into other cost categories, including those recovered through existing rates).

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[24] IREC Initial Comments, dated March 17, 2020, at 3.
[25] IREC Initial Comments, at 7.

The City of Minneapolis and CUB both, as a preferred approach, recommended denial of the certification and instead, consideration of the proposal under a MYRP.[26] CUB noted in its comments that while it recommends certification denial, the Commission could direct the Company to move forward with AGIS, and require conditions to ensure ratepayer protections in any future cost recovery request.[27]

CEEM took no position on the certification but noted that the certification in this context, "gives the appearance of a request for pre-approval commitment."[28] Fresh Energy and ELPC/Vote Solar both argued that Xcel needed to establish first why rider recovery was appropriate (discussed below).

Generally, the Department agrees with the arguments put forth by CUB that the certification process is discretionary and that the determination on certification should be made with the totality of the circumstances of the request (including factors such as timing of the next MYRP, size of investment, low cost to benefit ratio, unclear customer class impacts and others). CUB argued that the analysis would be incomplete if it did not also account for the impact the certification would have upon the efficacy of the utility's MYRP and that certification and rider recovery would likely undercut the Commission's ability to ensure that the Company's next MYRP would result in just and reasonable rates.[29] CUB also argued that the use of riders shifts the amount of risk that is borne by the overall customer base compared to risk borne by the Company. The City of Minneapolis and CEEM had similar concerns.[30]

XLI argued that approving Xcel's request for certification "… promotes negative policies and utility incentives, avoids a rate case where the requests can and should be fully analyzed by the Commission and stakeholders, and attempts to: 1) undermine the regulatory compact and is contrary to law,[31] 2) combine a rate case and a resource plan, and 3) recover a multi-year investment … "[32]

Generally, the Department believes that approval of a certification request, which is discretionary, should be granted only if it is determined that rider recovery of the investment is in the public interest. The Department's position is consistent with that of CUB, that rider recovery for the AGIS Initiative would reduce transparent accounting of all distribution system costs and could lead to double recovery (once through the Transmission Cost Recovery (TCR) Rider, and again through base rates, or through

[26] City of Minneapolis Initial Comments, at 1-3; CUB Initial Comments, at 2.
[27] CUB Initial Comments, at 2.
[28] CEEM Initial Comments, at 9.
[29] CUB Initial Comments, at 5-6.
[30] CEEM Initial Comments, at 9; City of Minneapolis Initial Comments, at 8
[31] XLI Initial Comments, dated March 17, 2020, at 4-6. XLI argued that with the expiration of the MYRP, Xcel is not allowed to request certification under Minn. Stat. 216.2425. The Department does not weigh in on this issue, however, the Department notes a related issue was discussed in the Commission's March 13, 2020 Order in Docket No. E002/M-19-688, which states, "The petition is not offered as a settlement to an existing rate filing, but as an alternative to taking up a rate proceeding at this time. What Xcel has presented the Commission is a proposal for maintaining the status quo upon the conclusion of a Commission-approved multiyear rate plan established under Minn. Stat. § 216B.16, subd. 19. Minn. Stat. § 216B.16, subd. 19, is silent about how to handle utility rates in the event that a multiyear rate plan ends absent a new rate determination."
[32] XLI Initial Comments, at 1 and 6

overlapping cost categories.[33] These issues support the Department's position that additional scrutiny is warranted prior to authorizing rider recovery (or any proceeding deemed appropriate for cost recovery purposes), to ensure Xcel, stakeholders, and the Commission have a common understanding of the costs, project scope, and system functions that are being proposed.

The Department notes that the issues of segmented recovery and incomplete cost review have arisen in 2017 and 2019 TCR proceedings and anticipates this to continue in the next MYRP and future TCR Rider proceedings.[34] Related costs of the Time of Use (TOU) Pilot (which includes portions of FAN and AMI costs) and ADMS costs are already being recovered in part through the past 2015 MYRP, the 2017 TCR Rider, and are proposed for recovery through the 2019 TCR Rider, and are anticipated to be requested in both the next MYRP (TOU Pilot and embedded FAN and AMI costs) and future biennial TCR Rider petitions.[35] The Department notes that costs for the TOU Pilot and ADMS are relatively minor compared to the costs and recovery iterations that could occur with the AGIS Initiative (if certified and rider recovery is authorized).

The Department agrees that the AGIS Initiative should not be certified at this time. However, the Department does not recommend denial of certification. Instead, the Department sees a referral of the AGIS Initiative (and aspects of Xcel's planned distribution system capital investments) to a contested case hearing overseen by the Office of Administrative Hearings as an optimal path forward, in terms of providing a forum for a level of evaluation and analysis of Xcel's proposal akin to a rate case, helping to ensure important ratepayer and customer privacy protections, proceeding in an efficient and timely manner, and allowing for additional, important input from the public. The hearing process would ultimately align with either the next MYRP or next TCR filing, and the outcome would be a determination of reasonable costs, identification of important ratepayer and customer protections, and a clear vision for the future of Xcel's distribution system that is in the public interest.

The Department concludes that a decision on certification at this time (without additional scrutiny) would be inefficient, as the issues are likely return to the Commission and stakeholders, regardless, in either the next MYRP or 2021 Transmission Cost Recovery (TCR) Rider petition. Therefore, it is prudent to conduct this evaluation at this time and in manner consistent with the scope of the request. The Department has modified its Recommendation 3, as noted below, to incorporate language or additional consideration by other stakeholders, where relevant or appropriate.

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[33] CUB Initial Comments, at 8.

[34] See DOC Attachment 1, Xcel's Response to Commission Staff Information Request No. 1, dated January 19, 2018, Docket No. E002/M-17-776. Xcel's Response indicated revisions to the various projects' cost components (which again needed clarification at the May 2019 Commission Agenda Meeting).

[35] IDP, Attachment M1 - Gersack Direct, at 37. "Further, because ADMS cost recovery has been approved under the TCR Rider, and the ADMS implementation process is at an advanced stage, we propose to continue to recovery of the ADMS costs under the TCR Rider. While the costs of the TOU Pilot were also certified for potential recovery under the TCR Rider, we are requesting that TOU Pilot costs incurred during the MYRP be included in base rates to align with the stage of the pilot and future AMI efforts." It is unclear if this same request will be made in the next MYRP, or if AGIS costs will be proposed to be recovered fully through the TCR Rider.

Last, Xcel noted multiple times in its 2019 IDP that its grid modernization investments are a result of the Company's efforts to "lead the transition to a clean energy future."[36] It appears, therefore, that Xcel's investment decisions regarding distribution grid investments are occurring ahead of any similar decisions by other regulated utilities in Minnesota. The Department concludes that it is important to ensure Xcel's distribution system investments include sufficient customer and grid-data access and protections, so that future cost-effective customer or third party-supplied system resources and solutions are not precluded. For example, the cost effectiveness of the AGIS and APT investments is reduced for customers if the additional data and data granularity are not utilized to the fullest extent while protecting customer privacy. At a minimum, additional transparency and processes for review of Xcel's internal partnerships with third parties may be necessary to ensure that Xcel's investments result in the intended benefits for ratepayers. Department Recommendation 3, below, is a modified version of Recommendation 3 of the Department's Initial Comments. The following language supersedes the original text of Recommendation 3:

The Department recommends that the Commission refer Xcel's AGIS Initiative proposal (AMI, FAN, FLISR, IVVO) to the OAH for a contested case hearing for further record development. The referral should include consideration of the proposed costs associated with the Incremental System Investments and increased distribution system spending, as necessary, and as they relate to the AGIS Initiative. The evaluation should consider, under any criteria that may be established by the Commission, at a minimum:

1. **Public interest determination for the AGIS Initiative**
2. **Public input**
3. **Delineation of project costs, scope, and expected functions, including but not limited to:**[37]
    a. **Clearly identified costs, including the following subcategories of Company costs:**
        i. **Total revenue requirements on total-company and MN-jurisdictional bases (including identification of the MN jurisdictional allocator used)**
        ii. **Incremental/new capital costs and depreciation lives and support for the depreciation lives**
        iii. **Incremental expenses and revenue (all expenses and revenues not already in rates, including expenses that are in rates that will be reduced (i.e. all changes in expenses and revenues)**
        iv. **Identification of any future AGIS Initiative-related investment costs that would be needed to maximize the potential of the AGIS Initiative as outlined in the IDP**
    b. **Fixed cost recovery caps for AMI and FAN capital costs (no more than the lower of actual costs incurred or costs as proposed in Xcel's 2019 IDP)**[38]

[36] IDP, at 2, 5, 10, 12, 148, 152, and 169.
[37] Item 3 is a combination of DOC, OAG-RUD, and XLI cost information requests in Initial Comments, modified and combined by the Department. See DOC Initial Comments, at 21, 24; OAG-RUD Initial Comments, dated March 17, 2020, at 4; and XLI Initial Comments, at 7.
[38] City of Minneapolis Initial Comments, at 11 (modified); CUB Initial Comments, at 11 (modified).

  c. **Variable cost recovery caps, including O&M and labor, for AMI and FAN (no more than the lower of actual incurred costs or Xcel's variable costs as proposed in the 2019 IDP, applied on a per-meter basis)[39]**

4. **Impacts of distribution investments on transmission-level customers[40]**
5. **Cost allocation options, including outline of bill impacts for each customer class over an initial five-year period[41,42]**
6. **Pass-through methodology and/or development of a process or mechanism to pass the savings and revenues associated with the AGIS Initiative on to the Company's customers in a reasonable timeframe[43]**
7. **Other necessary conditions for customer value and ratepayer protection[44]**
8. **Specific plans and timelines for future customer offerings and system capabilities and their implications, including recommendations on whether Commission approval is required or warranted.[45] Plans or timelines should include at a minimum, the following:**
    a. **Service Tier Plans: potential new options and pricing options for levels of system service expected to be enabled by the AGIS Initiative, including identification of the impacts on non-participant ratepayers, opt-out provisions, etc.[46]**
    b. **Remote Connect/Disconnect Procedures[47]**
    c. **Customer Notice Plan for AMI Installation[48]**
    d. **Customer Data Access Requirements and Rights, including Xcel's intentions regarding:[49]**
        i. **Customer data rights and terms for inadvertent data release**
        ii. **Green Button Connect My Data after smart meter deployment**

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[39] CUB Initial Comments, at 11 (modified).
[40] XLI Initial Comments, at 7 (modified).
[41] XLI Initial Comments, at 7 (modified).
[42] Xcel noted that it is intending to develop advanced rate design plans once the majority of meters are installed, however, more than half of the AGIS investment will have already been made and potentially recovered from ratepayers by that time (estimated to be end of 2024) and therefore, it is uncertain how long those advanced rate design proposals will take to implement either during or after new meter installation. Currently, the TOU Pilot that was scheduled to start on April 1, 2020—and was planned to inform development of additional advanced rate designs—has been delayed due to the COVID-19 pandemic. Therefore, questions exist of the current bill impacts for all customer classes as well as additional uncertainty surrounding the future customer benefits of advanced rate design. See DOC Attachment 2, Xcel Letter *Pilot Postponement* filed in Docket No. E002/M-17-775, dated March 18, 2020.
[43] DOC Initial Comments, at 21, 24; CUB Initial Comments, at 18.
[44] DOC Initial Comments, at 21.
[45] IDP, Attachment M1 - Gersack Direct, at 44, 123, 144-154, and 187; Attachment N3, at 70. The Department is aware that Xcel has drafted proposed plans for several areas of expected system performance or customer participation (opt-out drafts, customer privacy, customer education and awareness, etc.) however, those plans are draft form only, have had no vetting by stakeholders, and have no process for public, stakeholder, or Commission review and/or approval. While it would be inefficient and potentially impossible to have pre-approval of all of these plans (or all details) prior to approval or cost recovery, it is reasonable to require at least some expectations for content, timing, and agreement as to the level of Commission oversight as conditions of the initial approval.
[46] DOC Initial Comments, at 24.
[47] DOC Initial Comments, at 24.
[48] DOC Initial Comments, at 24.
[49] DOC Initial Comments, at 24; CUB Initial Comments, at 14-16; City of Minneapolis Initial Comments, at 8-9.

iii. **Home Area Network functionality issues**
iv. **Format for providing customers with customer usage data and rate schedules**
v. **Potential enhancements to Saver's Switch, and the timing of any enhancements**
i. **Third-Party Service and Data Sharing Plans including whether such plans would result in revenues that would offset costs or reduce rates;**

e. **Distributed Generation Interconnection Agreement and Process Modification**[50]
f. **Metrics, Baselines, and Targets for System Performance: including baseline data for performance evaluation and reporting plan (or proposal for how advanced grid metrics will be tied to or incorporated into to the Commission's Performance Incentives Mechanisms proceeding) including a minimum 1.5% reduction in customer energy consumption from IVVO technologies**[51,52]
g. **Advanced Rate Design Roadmap that offers a specific timeline and implementation strategy for advanced rate offerings to customers (including the 400 MW of demand response by 2023 as noted in Xcel's current Integrated Resource Plan, Docket No. E002/RP-19-368). The Advanced Rate Design Roadmap should include:**[53]
    i. **Xcel's current advanced rate designs and demand management programs**
    ii. **A summary of industry best practices**
    iii. **A timeline and implementation plan (including education and outreach) for the Company to offer updated dynamic rates for all residential and commercial customers (including, the introduction of time-varying rates), which should include demand response offerings**
    iv. **Potential low-income rate reform options**
    v. **Enrollment mechanisms for convenient customer participation**
    vi. **Evaluation plans for monitoring, verifying, and improving the effectiveness of advanced rate designs**
    vii. **Opportunities for utilizing distributed energy resources and/or beneficial electrification technologies in conjunction with planned dynamic rates and/or demand management programs**

(Recommendation 3, as modified)

Last, the Department affirms Recommendation 5 from Initial Comments, which recommended a hard cost cap of $4 million for the APT and to delineate the specific scope and functionality expected from the APT, if the Commission chooses to certify the APT). There is inherently less risk to certifying the forecasting tool, as it is an industry known and vetted tool (e.g., LoadSEER), it has a defined cost that is (relatively) equitable to its benefit, and it is filling gaps in Xcel's ability to forecast distributed energy

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[50] DOC Initial Comments, at 24.
[51] See generally *Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, dated September 22, 2017, Docket No. E002/CI-17-401.
[52] OAG-RUD Initial Comments, at 4-5; Fresh Energy Initial Comments, at 14 and 16-17; ELPC/Vote Solar Initial Comments, at 17.
[53] DOC Initial Comments, at 21 and 24; Fresh Energy Initial Comments, at 7-8; CUB Initial Comments, at 2-3.

resource load on the distribution system.[54] The APT would allow Xcel to improve the next iterations of its IDP, future hosting capacity analyses, and generally, distribution level forecasting.

3. *Lack of Criteria and Proposal to Establish Criteria*

Both ELPC/Vote Solar and Fresh Energy provide similar comments and concerns regarding the lack of clear criteria for evaluation of the proposals and both declined to weigh in on certification of either the AGIS Initiative or the APT until criteria are established. ELPC/Volt Solar stated the following in its Initial Comments: [55]

> The Commission's past determination that a project (ADMS) is consistent with Minn. Stat. 216B.2425 is not clear, logical, or workable test because the statute does not provide a standard for certification requests.
>
> ….
>
> The Commission should use C. Schuerger's criteria from 2016, and upon a showing that these investments need to be recovered via a rider, ELPC/VS will weigh in but cannot, absent that information.

Both suggest review and consideration of 2016 proposed criteria for evaluation[56] and withhold their recommendations on certification until Xcel provides a response to the use of these criteria. Fresh Energy also recommended that the Commission establish criteria for future certification requests using the language proposed in 2016 by Commissioner Schuerger (2016 Criteria):

> A utility must demonstrate the project is necessary to modernizing its distribution system with respect to (i) enhancing system reliability, (ii) improving system security, and/or (iii) increasing energy conservation by facilitating communication between the utility and its customers.
>
> A utility must demonstrate that the project is a "priority project," that is, a project of such importance that it warrants current cost recovery through a rider while the project is being executed rather than delayed cost recovery in a rate case after the project has been completed.
>
> The information that the Commission requires to make its certification determination includes but is not necessarily limited to:
>
> - information establishing the necessity of the proposed project, including discussion of any alternatives to the project and the reasons the alternatives have been rejected, and discussion of how the

[54] See Xcel Response to Fresh Energy IR No. 21, dated January 23, 2020, at 94 of 220. See DOC Attachment 3 for additional information related to LoadSEER.
[55] ELPC/Vote Solar Initial Comments, at 5 and 21-22.
[56] *Revised Decision Options*, dated May 24, 2016, Docket No. E002/M-15-962.

proposed project comports with the Commission's grid modernization investigation in Docket No. 15-556;
- identification of the expected improvements in distribution system reliability, security, and/or energy conservation that would result from the project, and how the project's performance will be measured to establish whether it has achieved the expected improvements;
- estimated cost of the project, including all mechanisms that will be employed to maximize cost reductions and minimize cost increases; and
- criteria that will be used by the utility to determine whether at any point it has become imprudent to bring the certified project to completion due to the project failing to meet its performance and/or cost expectations.

As noted in initial comments, the Department shares this concern in relation to the AGIS Initiative and agrees that criteria should be established, at a minimum, for future certification requests. Here, the 2016 Criteria appear useful, as they provide some benchmark for evaluation; however, stakeholders have not vetted the 2016 Criteria and the 2016 Criteria could be improved by considering rate case, certificate of need, and/or integrated resource planning criteria. The Department believes the 2016 Criteria are a good start, but additional stakeholder feedback would be useful if intended for use in future years.[57] Notably, the 2016 Criteria only require demonstration of *one* of three factors listed in Minn. Stat. 216B.2425, Subd. 2(e) (reliability, security, and/*or* energy conservation) when the statute uses all three terms.

If used for this proceeding, the Department believes that while some aspects of the AGIS Initiative might meet the ELPC/Vote Solar and Fresh Energy proposed criteria, the alternatives analysis of technology options—both for the meter and the wireless network comparisons—were lacking from a review standpoint. It appears there was no AMI meter-to-meter comparison (only AMI to AMR) and Xcel selected the newest (potentially most advanced) Itron meter.[58] Additional information would be useful (as well as more public information) in the comparison analysis, beyond what was in the testimony of Block, Schedule 10 (which was trade secret). The Department also questions whether the Schedules included the entirety of the meter selection information analysis as it was largely related to vendor selection only (and not meter selection analysis).

4. *Proposed Conditions if Certified – Customer Benefits*

Additionally, the Department believes that the conditions crafted by parties as 'back-up' proposals in the instance that the Commission may certify the AGIS proposal are insufficient for an investment of this magnitude and considering the facts of this case (unclear criteria, insufficient process, overlapping

[57] If the Commission is seeking to establish criteria for future years, the Commission could establish criteria at this decision point, or issue a notice for comment on criteria for Xcel's future certification requests using Commissioner Schuerger's proposed criteria as a starting point. For additional Department input on this matter, see the Department's Initial Comments in this proceeding and the Department's January 4, 2016 Initial Comments in Docket No. E999/M-15-962.
[58] IDP, Attachment M2 - Bloch Direct, at 144 and Schedule 10 (Trade Secret).

rate case information without rate case analysis, etc.). The conditions proposed by parties need additional consideration, which would also occur through the contested case hearing process should the Commission decide to pursue that option.

If the Commission declines to adopt the Department's recommendation to refer the AGIS Initiative to the OAH, the Department recommends conditioning certification on the outcome of a short comment period that allows stakeholders to propose and respond to proposed (or potentially new) conditions regarding ratepayer protections. (Recommendation 6)

The Department suggests using the Department's modified Recommendation 3 as a starting point for a notice of comment period. If certification at this stage is authorized without comment, the Department recommends use of a modified Department Recommendation 3 as a certification condition requiring a compliance report or series of reports.

5. Due Date and Docket for the ADMS Annual Compliance Filing

The Department did not initially comment on the request for submittal of the ADMS annual compliance filing ordered in Docket No. E002/M-17-797 to be filed in this and future IDP dockets and to have a due date of January 25 of each year.[59] The Department notes that a January due date would not align with the November filing dates of the TCR and IDP dockets, and information contained in the ADMS annual compliance filing would likely relate to and inform both dockets.

The Department recommends that the Commission require Xcel to file the ADMS annual compliance filing from Docket No. E002/M-17-797 on November 1 of each year in the most current IDP and TCR dockets. (Recommendation 7)

6. Certification Conclusion

The Department would like to acknowledge that the proposals put forward by Xcel are forward looking and demonstrates the Company's commitment to facilitating customer engagement in their electricity usage. Advanced metering and new grid technologies are evolving and the Department appreciates the work Xcel has done to date. The Department also appreciates the thorough comments put forward by stakeholders in the initial comment period.

[59] See also, Xcel Initial Filing, dated November 1, 2019 in Docket No. E002/M-19-721, at 9, footnote 5: "The Commission's September 29, 2019 Order approving the 2017-18 TCR also required two other ADMS related compliance filings. One compliance filing is due 120 days after the Commission's Order (i.e., at the end of January 2020). *See* Order Point 5. The other compliance filing is an annual filing, but the timeline has not yet been set. *See* Order Points 7 and 8. In our Integrated Distribution Plan (IDP), filed on November 1, 2019, in Docket No. E002/M-19-666, we proposed to submit a single ADMS report on January 25, 2020 in the TCR docket and the IDP docket, and request that January 25 be the due date for the ongoing annual ADMS report, beginning January 25, 2021 – and that these annual ADMS reports be filed in the most recent docket of future IDPs."

At this time, the Department is not recommending that the Commission deny Xcel's certification requests.[60] The Department is seeking to continue the analysis in a manner that aligns with the scope and scale of the investments and their resulting system impacts. The Department concludes that increased transparency and analysis is necessary for the AGIS Initiative and that additional evaluation should include review of the $2.5 billion in investments in the ISI Initiative and increased distribution system spending.

Approval of any investments of this scale should include appropriate ratepayer protections, clear plans for system benefits, and clear outcomes that would inform future Commission decisions. The Department is open to solutions or proposals that may meet this objective in another manner, but continues to recommend a contested case proceeding. The Department's concerns appear to be in alignment with most other stakeholders (however, stakeholder's proposed process recommendations vary).

As noted by Xcel, the six-month certification process would provide the utility with cost recovery assurance by authorizing rider treatment,[61] however, the timeframe does not allow full consideration of ratepayer protections, and it is potentially the most limited process (comment and reply) utilized by the Commission. The AGIS proposal involves significant multi-year capital investments which are unsuited for rider recovery, especially here, where the proposal includes a system transformation (potentially without conditions), at a high cost, over many years (beyond that of even a single MYRP), and with significant ratepayer impacts, many of which are unknown at this time.

As exemplified by stakeholder comments, the criteria for certification are unclear and therefore stakeholder evaluation is inconsistent and potentially lacking.

As proposed, use of the rider process allows for the piecemeal review and disjointed recovery of project costs for a large and complicated investment. The use of rider recovery in this instance shifts the cost risk to ratepayers throughout the term of the investments (10+ years) and shifts the burden of negating cost prudency of the 'necessary' investment to stakeholders and the Commission.

Through certification of the ADMS and subsequent requests for its cost recovery, it has been shown that certified projects lack cost control or clarity (as costs are piecemealed and hard to track and evaluate) and there are questions surrounding the certification process to date regarding costs. Estimated costs have increased between the certification phase and the cost recovery phase through the TCR Rider. While this may not always be the case, the Department is concerned that certification is *not* acting as a cost cap, and the TCR Rider review is not a prudence review (as the projects have been

[60] The Department is less concerned with the certification of the APT due to its relative lesser costs and the existing industry experience with the tool purchased by Xcel, LoadSEER software, however, recommends setting certification criteria for use in future years.
[61] See Xcel Response to Commission Staff IR No. 1, dated December 23, 2019: "For context for this response, we note that we view Commission certification as providing the Company with assurance that it can proceed with the certified project(s) and seek recovery under the Transmission Cost Recovery (TCR) Rider. The Commission would additionally have the opportunity to review actual costs and expenditures as part of the Company's subsequent TCR or general rate case filings, when the Company seeks cost recovery for the projects."

deemed 'necessary'), and this process creates a disincentive for Xcel to contain costs. Additionally, riders allow recovery for incremental, year-to-year costs, which adds unnecessary layers of complexity to a project of this scope and magnitude. [62,63,64] Rider recovery for the AGIS Initiative is simply an inappropriate forum for review of a cost recovery request of this magnitude and complexity, particularly since it involves capital investments in new technologies that can fundamentally change the concept of electric service. Rider recovery absent a thorough review through a contested case would result in significant risk for ratepayers.

Last, in initial comments, the Department noted that it appeared there was sufficient time and reason to proceed with a contested case process. The Department also notes that if a contested case process is not ordered here, and certification is granted, the Department would likely request a contested case for the next TCR Rider petition. The Department sees efficiencies in evaluating the proposal in a rigorous and transparent process, once, as the most efficient outcome. Evaluation now could also be concluded before or during the next MYRP or the Commission could defer the evaluation until the MYRP is filed.

III. DEPARTMENT RECOMMENDATIONS

The Department appreciates the opportunity to further comment on Xcel Energy's 2019 IDP and certification request and looks forward to the review of other stakeholder comments. The Department makes the following recommendations (new or modified recommendations are emphasized in bold):

- The Department recommends that the Commission accept Xcel Energy's 2019 IDP compliance with reporting requirements. (Recommendation 1)

- The Department recommends that the Commission require Xcel to file its next IDP no later than November 1, 2021 and move from an annual to biennial IDP filing going forward, but to file an annual update of the following IDP requirements and provide the following information:

    - Baseline Financial Data, IDP Requirements 3.A.26-30; and
    - Non-Wires (Non-Traditional) Alternatives Analysis, IDP Requirements E.1-2. (Recommendation 2)

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[62] IDP, Attachment M3 - Harkness Direct, at 47 of 143. "Q: Are Business Systems AGIS capital and O&M costs included in the CBA beyond the next several years meant to be "rate case quality" numbers? A: While these cost assumptions are reasonable and well-supported based on the information available today, they are not intended to reflect more specific budgets as in a standard rate case budget. Rather, they are subject to refinement like all costs that will be incurred several years into the future. This is consistent with my experience, and with most cost projections that represent work to be completed in the longer-term."

[63] Since the Commission has not approved the recently proposed ADMS project costs of $69.1 million in Docket No. E002/M-19-721, and have only approved costs as proposed via certification (Docket No. E999/M-15-962), it is not known how the Commission views costs in exceedance of certified estimates.

[64] Under the review of the ADMS and TOU Pilots, there is consideration tracking through IRs and discovery of what costs were recovered in the 2015 MYRP, what are being proposed for recovery in the TCR rider, and what costs are proposed for either future MYRP recovery or TCR petitions.

- **The Department recommends that the Commission refer Xcel's AGIS Initiative proposal (AMI, FAN, FLISR, IVVO) to the OAH for a contested case hearing for further record development. The referral should include consideration of the proposed costs associated with the Incremental System Investments and increased distribution system spending, as necessary, and as they relate to the AGIS Initiative. The evaluation should consider, under any criteria that may be established by the Commission, at a minimum:**

  1. **Public interest determination for the AGIS Initiative**
  2. **Public input**
  3. **Delineation of project costs, scope, and expected functions, including but not limited to:**
     a. **Clearly identified costs, including the following subcategories of Company costs:**
        i. **Total revenue requirements on total-company and MN-jurisdictional bases (including identification of the MN jurisdictional allocator used)**
        ii. **Incremental/new capital costs and depreciation lives and support for the depreciation lives**
        iii. **Incremental expenses and revenue (all expenses and revenues not already in rates, including expenses that are in rates that will be reduced (i.e. all changes in expenses and revenues)**
        iv. **Identification of any future AGIS Initiative-related investment costs that would be needed to maximize the potential of the AGIS Initiative as outlined in the IDP**
     b. **Fixed cost recovery caps for AMI and FAN capital costs (no more than the lower of actual costs incurred or costs as proposed in Xcel's 2019 IDP)**
     c. **Variable cost recovery caps, including O&M and labor, for AMI and FAN (no more than the lower of actual incurred costs or Xcel's variable costs as proposed in the 2019 IDP, applied on a per-meter basis)**
  4. **Impacts of distribution investments on transmission-level customers**
  5. **Cost allocation options, including outline of bill impacts for each customer class over an initial five-year period**
  6. **Pass-through methodology and/or development of a process or mechanism to pass the savings and revenues associated with the AGIS Initiative on to the Company's customers in a reasonable timeframe**
  7. **Other necessary conditions for customer value and ratepayer protection**
  8. **Specific plans and timelines for future customer offerings and system capabilities and their implications, including recommendations on whether Commission approval is required or warranted. Plans or timelines should include at a minimum, the following:**
     a. **Service Tier Plans: potential new options and pricing options for levels of system service expected to be enabled by the AGIS Initiative, including identification of the impacts on non-participant ratepayers, opt-out provisions, etc.**
     b. **Remote Connect/Disconnect Procedures**
     c. **Customer Notice Plan for AMI Installation**
     d. **Customer Data Access Requirements and Rights, including Xcel's intentions regarding:**

i. **Customer data rights and terms for inadvertent data release**
ii. **Green Button Connect My Data after smart meter deployment**
iii. **Home Area Network functionality issues**
iv. **Format for providing customers with customer usage data and rate schedules**
v. **Potential enhancements to Saver's Switch, and the timing of any enhancements**
vi. **Third-Party Service and Data Sharing Plans including whether such plans would result in revenues that would offset costs or reduce rates;**

e. **Distributed Generation Interconnection Agreement and Process Modification**
f. **Metrics, Baselines, and Targets for System Performance: including baseline data for performance evaluation and reporting plan (or proposal for how advanced grid metrics will be tied to or incorporated into to the Commission's Performance Incentives Mechanisms proceeding) including a minimum 1.5% reduction in customer energy consumption from IVVO technologies**
g. **Advanced Rate Design Roadmap that offers a specific timeline and implementation strategy for advanced rate offerings to customers (including the 400 MW of demand response by 2023 as noted in Xcel's current Integrated Resource Plan, Docket No. E002/RP-19-368). The Advanced Rate Design Roadmap should include:**
   i. **Xcel's current advanced rate designs and demand management programs**
   ii. **A summary of industry best practices**
   iii. **A timeline and implementation plan (including education and outreach) for the Company to offer updated dynamic rates for all residential and commercial customers (including, the introduction of time-varying rates), which should include demand response offerings**
   iv. **Potential low-income rate reform options**
   v. **Enrollment mechanisms for convenient customer participation**
   vi. **Evaluation plans for monitoring, verifying, and improving the effectiveness of advanced rate designs**
   vii. **Opportunities for utilizing distributed energy resources and/or beneficial electrification technologies in conjunction with planned dynamic rates and/or demand management programs**

(Recommendation 3, as modified)

- If the Commission certifies all or a portion of the AGIS Initiative, inclusive of the costs as represented by Xcel in its certification request, the Department recommends strong cost caps and clear descriptions of what is certified to protect ratepayers from cost exceedances, changing project descriptions, and in the event that the capabilities, functionalities, and benefits that Xcel represented in the certification request do not materialize. The Department also recommends that any certification should be conditioned on a presumption that all revenues from the AGIS Initiative belong to ratepayers unless otherwise approved by the Commission. (Recommendation 4)

- If the Commission chooses to certify the APT, the Department recommends that the Commission limit cost recovery to a hard cost cap of $4 million and the Commission detail in its order the specific scope and functionality expected from the APT (potentially, as detailed in Xcel's filing). (Recommendation 5)

- **If the Commission declines to adopt the Department's recommendation to refer the AGIS Initiative to the OAH, the Department recommends conditioning certification on the outcome of a short comment period that allows stakeholders to propose and respond to proposed (or potentially new) conditions regarding ratepayer protections. (Recommendation 6)**

- **The Department recommends that the Commission require Xcel to file the ADMS annual compliance filing from Docket No. E002/M-17-797 on November 1 of each year in the most current IDP and TCR dockets. (Recommendation 7)**

/ja

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☐ **Public Document – Not Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002/M-17-776
Response To: MN Public Utilities Commission Information Request No. 1
Requestor: Hanna Terwilliger, Michelle Rosier, Tricia DeBleeckere
Date December 21, 2017 **SUPPLEMENT**

Question:
Provide more detail on the overall cost of grid modernization investments between 2018-2027 for the state of Minnesota in the chart below. If estimates are not final, please give an estimated range. Add more columns and rows, if necessary, to describe where costs will be recovered.

Capital Costs (State of Minnesota)

Grid Mod Program	Total Cost	Amount seeking recovery through TCR Rider	Amount accounted for in multi-year rate case	Amount from other source of recovery	Source of "other" recovery
ADMS					
FAN					
Wi-MAX					
Wi-SUN					
FLISR					
TOU					
AMI					
TOTAL					

O&M Costs (2018-2027, State of Minnesota)

Grid Mod Program	Total Cost	Amount seeking recovery through TCR Rider	Amount accounted for in multi-year rate case	Amount from other source of recovery	Source of "other" recovery
ADMS					
FAN					
Wi-MAX					
Wi-SUN					
FLISR					
TOU					
AMI					
TOTAL					

Response:
By way of background to our response, we believe it is important to distinguish between our Advanced Grid Intelligence and Security (AGIS) initiative and more "business-as-usual" grid investments. Our AGIS initiative is intended to identify significant, strategic projects that advance our distribution system, provide customers with more choices, and enhance the distribution services and functions we provide to our customers.

Generally speaking, the foundational elements of AGIS consist of the Advanced Distribution Management System (ADMS) and the Field Area Network (FAN). These elements provide a solid foundation and important flexibility and scalability to support functionalities such as the Time of Use (TOU) Rate Pilot and the Fault Location, Isolation, and Service Restoration (FLISR) projects, for which we have requested certification. We anticipate the next step with AGIS in Minnesota will involve an Advanced Metering Infrastructure (AMI) proposal, which will also require an expansion of FAN infrastructure to support the significant numbers of advanced meters and volumes of metering data that will result from a broad AMI deployment.

The flexible, open, building block approach we are taking to AGIS affords the opportunity to pause before taking the next step. For example, the level of FAN infrastructure deployment is designed to match the specific functionalities it will support. This balances the level of investment with the benefits the functionalities are expected to deliver to our customers and our operations. This approach also guards against being locked into a path certain with a specific vendor, or building a communications network with significant amounts of unused capacity that may never be used. For example, with respect to our present certification request, the level of proposed FAN investment will support FLISR and the TOU Pilot. Our future AMI proposal will also include a FAN component that scales-up the FAN to support it.

Consistent with the context of this docket, we focus this response on our AGIS initiative. Our AGIS investments can be distinguished from the more typical grid modernization investments that we have been making – and will continue to make – in the normal course of business. As distribution equipment ages or breaks and replacements are needed, we have replaced that equipment with available, compatible and updated technology at the speed of value to our customers. Specific examples of these standard investments that have facilitated incremental change include core network infrastructure upgrades to support the Company's Wide Area Network (WAN), automated switches and reclosers, and various changes to supporting information systems. Looking forward, we expect this type of investment will continue as part of the normal course of business.

Therefore, in the interest of clarity, we have modified the Tables in the Question to account for the components as we presently anticipate implementing them. For example, as we have discussed, the FAN is scalable to support the number of devices and volume of data involved in deployment of a particular functionality. We have therefore split-out the FAN in the manner we anticipate implementing it. We also added an "AGIS Other" category to the Capital and O&M tables. These Other amounts we have in our five-year forecast for potential future capabilities are placeholders. As we discuss in more detail in our response to MPUC Information Request No. 5, we are purposefully building a flexible foundation and taking a building block approach to future functionalities that will be informed by our initial implementations, learnings from other utilities, and insights gained from pilots, customers, and stakeholders. Thus, while we have budgeted placeholder investments, actual planned investments are likely to change.

Finally, we have denoted To-Be-Determined (TBD) in a number of places in the tables. The path for certain components – like AMI – is still being finalized and scoped. In terms of the intended cost recovery mechanism, we generally expect to seek cost recovery through the TCR Rider (assuming certification), and we have noted such in the TCR Rider column.

Estimated AGIS Capital Costs (2018-2027) – State of Minnesota

(millions)

Note: See Supplement below for explanation of redline updates

AGIS Program	Total Cost*	Amount seeking recovery through TCR Rider	Amount accounted for in multi-year rate case	Amount from other source of recovery	Notes
ADMS	~~$43.4 (2016–2022)~~ ~~$24.5 (2023–2025 Forecast)~~ $69.1	$~~22.6~~18.8 (costs through 2018; additional TCR recovery may be sought at a later date)	~~$2.3~~ $6.6	N/A	The Company will seek recovery of remaining costs for ADMS through the TCR Rider or base rates, as appropriate at the given time.
FLISR	$65.3	Expect to submit request post-certification	$2.3	N/A	N/A
FLISR - FAN	$64.1		N/A **	N/A	N/A
TOU Pilot	$7.6	Expect to submit request post-certification	N/A	N/A	N/A
TOU Pilot – FAN	$3.0		$8.9 **	N/A	N/A
AMI	TBD	Expect to submit request post-certification	N/A	N/A	N/A
AMI - FAN	TBD		N/A	N/A	N/A
AGIS - Other	$20.4 (2018-2022)	Expect to submit request post-certification	$19.7	N/A	Five-Year Forecast

Note: Costs included in total and rate case columns for ADMS include assumed internal labor expenses; however, TCR rider recoveries exclude internal labor costs in order to follow proper rider recovery requests.
* Amounts include internal labor and therefore may not match cost recovery requests where internal labor is excluded.
** At the time of the Company's MYRP filing, FAN costs were not specifically allocated to FLISR or the TOU Pilot. The allocation between the two initiatives was determined at the time of the Company's grid modernization certification request. Both the TOU Pilot and FLISR will benefit from the FAN WiMAX infrastructure included in the MYRP.

Estimated AGIS O&M Costs (2018-2027) – State of Minnesota (millions)

AGIS Program	Total Cost	Amount seeking recovery through TCR Rider	Amount accounted for in multi-year rate case	Amount from other source of recovery	Notes
ADMS	$6.0M	$0.1M	N/A	N/A	The Company will seek recovery of remaining costs for ADMS through the TCR Rider or base rates as appropriate at given time.
FLISR	$5.4M	Expect to submit request post-certification	N/A	N/A	N/A
FLISR - FAN	$5.2M		N/A	N/A	N/A
TOU Pilot	$3.2M	Expect to submit request post-certification	N/A	N/A	N/A
TOU Pilot – FAN	$0.1M		N/A	N/A	N/A
AMI	TBD	Expect to submit request post-certification	N/A	N/A	N/A
AMI - FAN	TBD		N/A	N/A	N/A
AGIS - Other	$2.1	Expect to submit request post-certification	N/A	N/A	N/A

<u>Supplement:</u>

While preparing a response to an Information Request in the Company's 2017 Transmission Cost Recovery Rider docket (Docket No. E002/M-17-797), we discovered an error that affects the estimated ADMS costs reflected in the above Capital Costs chart. Specifically, we found an additional ADMS parent workorder that changes the capital amount accounted for in the MYRP, and the amount for which we are seeking cost recovery through the TCR Rider. We have made these updates in redline in the above Capital Costs chart. In sum, this change reduces the amount we are seeking in the TCR Rider by $3.8 million.

We also discovered that the total capital cost of the ADMS project we initially reflected in this response did not match our 2017 TCR Rider petition, so we have made that update in redline in the above Capital Costs chart. For clarity, we also provide an updated ADMS Capital Costs chart for ADMS below. This does not impact our requested cost recovery, as this was just an inconsistency between the two sets of numbers; the numbers provided in the TCR Petition were correct.

Estimated AGIS Capital Costs (2018-2027) – State of Minnesota (millions)

ADMS Corrected

AGIS Program	Total Cost*	Amount seeking recovery through TCR Rider	Amount accounted for in multi-year rate case	Amount from other source of recovery	Notes
ADMS	$69.1**	$18.8 (costs through 2018; additional TCR recovery may be sought at a later date)	$6.6	N/A	The Company will seek recovery of remaining costs for ADMS through the TCR Rider or base rates, as appropriate at the given time.

Note: Costs included in total and rate case columns for ADMS include assumed internal labor expenses; however, TCR rider recoveries exclude internal labor costs in order to follow proper rider recovery requests.
* Amounts include internal labor and therefore may not match cost recovery requests where internal labor is excluded.
** Includes hardware costs.

Preparer: Anthony O. Russeth
Title: Manager, Financial Planning and Reporting
Department: Financial Planning and Reporting
Telephone: 612.330.5933
Date: January 19, 2018 **Supplemented:** March 20, 2018

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

March 18, 2020

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: LETTER – PILOT POSTPONEMENT
RESIDENTIAL TIME OF USE RATE DESIGN PILOT
DOCKET NO. E002/M-17-775

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Letter to the Minnesota Public Utilities Commission regarding the Company's Residential Time of Use Rate Design Pilot (the Pilot). The Company has been preparing to launch the Pilot, referred to as Flex Pricing, on April 1, 2020. Due to the current COVID-19 Pandemic and its impact on residential electric use in the pilot areas, the Company is postponing the start date of the Pilot.

We continue to observe the situation and will provide an update as a new launch date is determined. The Company is communicating with pilot customers about this change through bill message, email, and direct mail, as well as through our community relations representatives.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies on all parties on the attached service list. If you have any questions about this filing, please contact Amber Hedlund at (612) 337-2268 or amber.r.hedlund@xcelenergy.com or me at holly.r.hinman@xcelenergy.com. or (612) 330-5941.

Sincerely,

/s/

HOLLY HINMAN
REGULATORY MANAGER

c: Service List

At Pacific Gas & Electric
2012

Prior to selecting Integral Analytics, PG&E completed a two year review of its existing processes and methods, and chose LoadSEER as the preferred tool to improve its capabilities in several areas including circuit load forecasting, identifying capacity shortfalls, incorporating micro-grid impacts, insuring consistency with corporate planning, streamlining regulatory data requirements, creating more defensible long term load forecasting methods, and automating and streamlining various aspects of the decision and approval process.

The economic downturn has made it tougher to accurately forecast circuit and bank peak loads. In fact, PG&E is finding that economic risk is now a larger threat to circuit planning than weather. Basing regression forecasts on temperature alone is inadequate. When the economy returns, will you be prepared, or get caught short of capacity? Will commercial and industrial loads ramp up quickly as the economy improves or will they remain flat? Which economic drivers are the key ones for each of your circuits? LoadSEER automatically models up to 100 economic drivers, along with weather, to provide you with the best combination of influences, circuit by circuit.

In addition to economic risks, the added risks emerging from the advance of micro grids, solar, DG, EV, the Smart Grid push, is making the job of the distribution planner increasingly complex. LoadSEER's acre-level granularity, comprehensive statistical forecasting algorithms, and powerful GIS engines can tackle this complexity, and let you actually do planning, instead of data modeling.

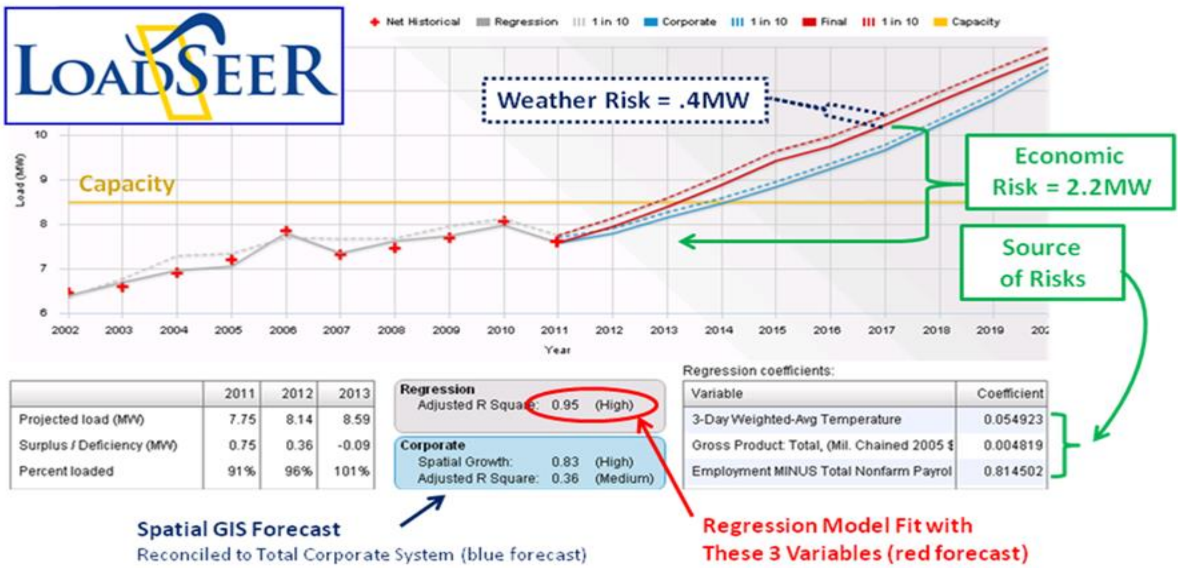
This new system reconciles and approves 3,500 circuit forecast models, and monitors more than 70 distribution engineers during the forecasting process. Prior to PG&E's implementation of LoadSEER, the large Northern California utility was using a typical spreadsheet solution for its electric load forecasting needs at the distribution and transmission levels. That solution was more or less manual for approximately 250 distribution planning areas.

The manpower being expended in data gathering, processing and reporting is now be better utilized to review the forecasts for accuracy and focus more time on planning the distribution system to accommodate the forecasted load.

What Are the Key Improvements to PG&E Distribution Forecasting?

- **Ability to forecast up to 100 economic influences, by circuit, in addition to weather. Powerful automated regression model fitting, with recommended forecasts to choose from, so the engineer simply has to pick the best one.**
- **A GIS spatial forecast, at the acre level, based on 20 years of NASA satellite histories, yielding key insights into how your loads grow within your specific regions. Comprehensive quality checking, process review, and log history, for use in data requests and defensibility, as well as oversight of who is doing what.**
- **Ability to directly integrate solar forecasts, EV forecasts or other micro grid impacts, down to the acre or customer level. We then export it to your power flow tool.**

In the example below, note some key insights. Economic risk over the next 6 years is 2.2 MW versus the weather risk at .4 MW. LoadSEER automatically scours up to 100 factors for you. Here we find the best 3 that lie at the heart of the risk for this circuit. We actually provide 2 different forecasts via very different methods. One is traditional regression (red line forecast, 3 influences). The second one uses 20 years of historical NASA satellite data, but is aligned to your overall corporate system projected growth, decomposed to customer classes down to the one acre level (blue line forecast). We even calculate the optimal blending of these forecasts, to take advantage of both approaches. Or you can pick one or the other, or overwrite your own, based on local knowledge.



LoadSEER provides in-depth model diagnostics for you, to determine your level of confidence in the forecasts. Below are the best 1 variable, 2 variable and 3 variable model fits, selected from among 100 possible key drivers. Note that weather does not enter the modeling as significant, until at least 2 economic variables are chosen. When we do add in weather in the 3 variable model, we see a nice improvement in Model Reliability and Adjusted R squared. All of this work is done for you, automatically, in LoadSEER. You can review, approve, or modify based upon your own local knowledge.

Number of Variables	Variables	Adjusted R Square	Model Reliability
0	n/a	0.00	24.19
1	Income: Total Personal, (Mil. $)	0.76	11.79
2	Gross Product Total, (Mil. Chained 2005 $) Employment MINUS Total Nonfarm Payroll, (Ths.)	0.87	10.65
3	Gross Product Total, (Mil. Chained 2005 $) Employment MINUS Total Nonfarm Payroll, (Ths.) 3-Day Weighted-Avg Temperature	0.95	6.40

LoadSEER™

Spatial Electric Expansion & Risk

**The Hybrid Solution for
Accurate, Traceable Spatial Load Forecasting**

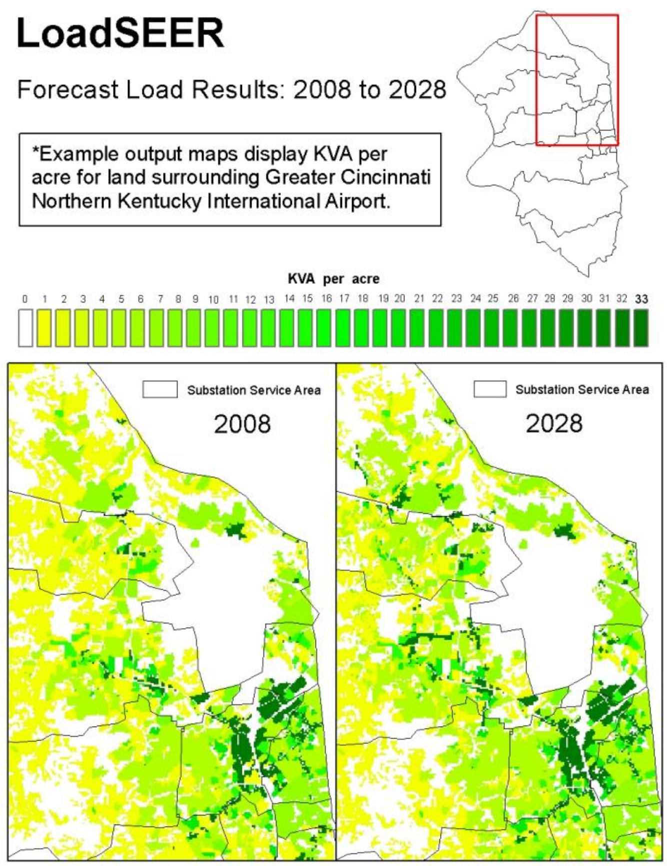
The Proof is in the Planning

How much power must be delivered, and where and when it will be needed? All good electric distribution system planners recognize the need to answer these questions in order to plan the efficient operation and economical capital expansion of the electric power delivery system. A LoadSEER spatial load forecast answers these questions for both short-term trends and long-term expansion. The LoadSEER hybrid model provides planners with a solid plan for managers, utility regulators and the community with defensible data and visual proof.

LoadSEER is the only hybrid software on the market today that combines trending and simulation analysis through spatial electric load forecasting. LoadSEER provides planners with tabular substation load forecast data and one acre resolution end-use expansion maps using a traceable methodology for predicting future demand based on load history and the temporal, spatial and magnitude information of the future load growth.

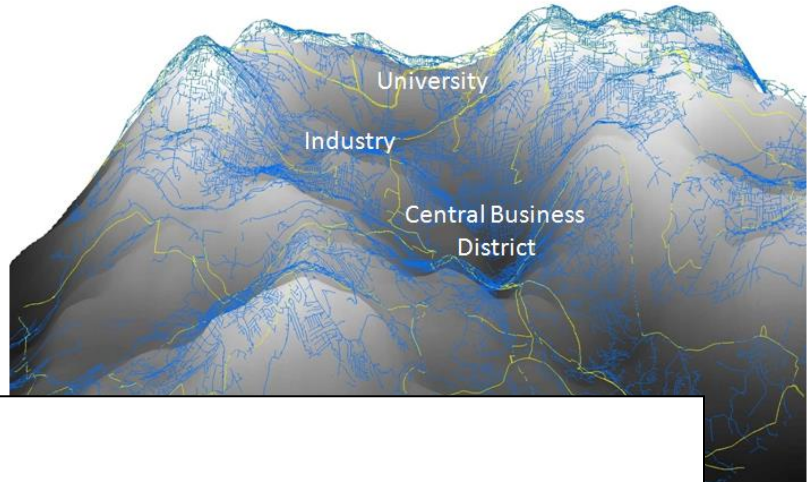
LoadSEER has the answers

- Is our capital expansion decision good for the long run, or will we regret it in just a few years?
- Do we need to plan for a second transformer four years from now in the substation we're building?
- How long will this plan be an effective solution to the problem and what is the risk?
- Eventually, how much residential, commercial or industrial load will that feeder need to serve?



Giving Sight to Spatial Change and Time

From system expansion and reliability targets to energy efficiency and avoided costs, transmission and distribution (T&D) companies can maximize the effective use of capital investments by using LoadSEER as a framework to visualize how much, when and where electric demand will change. The key focus of LoadSEER's design and functionality is to provide a comprehensive T&D spatial load forecasting tool that, at the same time, accommodates risk analysis, integrates resource planning with demand-side management (DSM) measures, and delivers a tool to better value electric-related decisions that have significant locational influences.



The LoadSEER Advantage

Consistency LoadSEER visualizes a utility's corporate forecast given a full set of growth rules, then follows them to allocate growth. For every model generated, it produces tabular results for each substation area separately, and summarizes the change in load and customer profiles for each substation area respectively.

Traceability LoadSEER shows planners, managers and customers where all conclusions came from for each interim result and each interim decision. During model building, running, and calibration, LoadSEER's user interface saves ffull sets of growth rules and corresponding map documents for review.

Documentation LoadSEER is self-documenting in order to prove consistency and traceability. Planners can quickly change and apply growth assumptions and rule sets across an entire service territory, preserving old parameters for comparison and calibration.

Improving the Long-Term Value of Short-Term Planning Decisions

LoadSEER's hybrid software gives planners a clearer perspective on the long-range value and risk comprised in a short-term decision. That means LoadSEER not only provides proof for the long-term (via simulation), but accuracy in the short-term (via trending).

The software's simulation methods replicate urban development processes based on historical land-use change, zoning information from government, customer rate class from utilities, and the load curve model of consumption patterns. This method has a good to excellent long-range usefulness for planning.

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The trending methods look to fit past load growth patterns and estimate the future load based on functional fit. The advantages of this trending method include ease of use, simplicity, and short-range response to recent trends of load growth patterns. However, this method often fails to have a usable estimate of the long-range load.

> Produce an accurate, traceable long-term load forecast that actually improve the value of short-term decisions!

LoadSEER's ideal hybrid method responds well to recent trends of load history in the short-range and maintains the long-range accuracy of simulation methods. Plus, it is user-friendly and does not require special skills from the user.

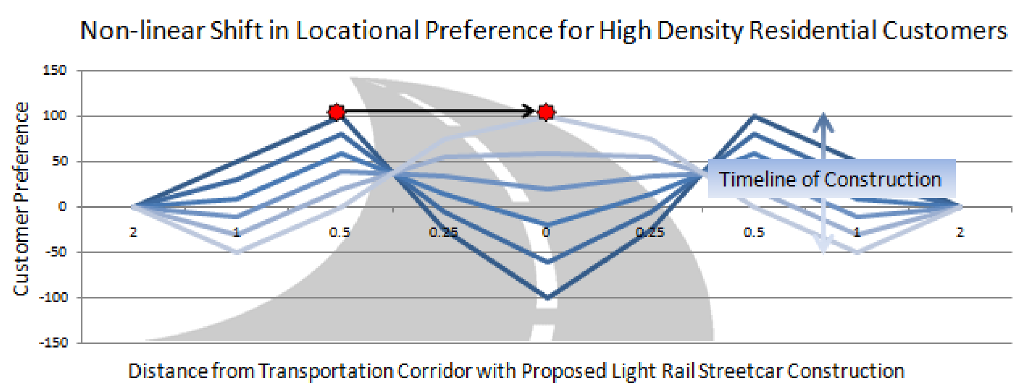
Simulation that Delivers Non-Linear Locational Behavior

Scenario-Driven Forecasting

Core algorithms determine where growth will occur by applying rules about the distribution of land usage in a city or region. The rules have been developed from years of input from the utility industry, urban planning, and other infrastructure planning arenas and include water, highways, schools and municipal services, and environmental elements.

Using three basic categories of rules – regional influence rules, local preference rules, and land availability rules – LoadSEER's simulation engine enables planners to run infinite growth scenarios created from sets of specific assumptions (e.g., the economy, manufacturing plants, commercial retail, residential, transportation).

Even after it has generated a full set of forecast maps, LoadSEER is not necessarily finished with its forecast. Planners can change and apply growth assumptions and rule sets across an entire service territory, create a model, and save it.



Non-Linear Proximity and Surround Factor Calculations

In fact, planners can mathematically construct roads, passenger rail, employment and activity centers, and more with the software's Preference Matrix. This feature utilizes agent-based modeling to model constituents' locational behavior in a causal simulation using mathematical values.

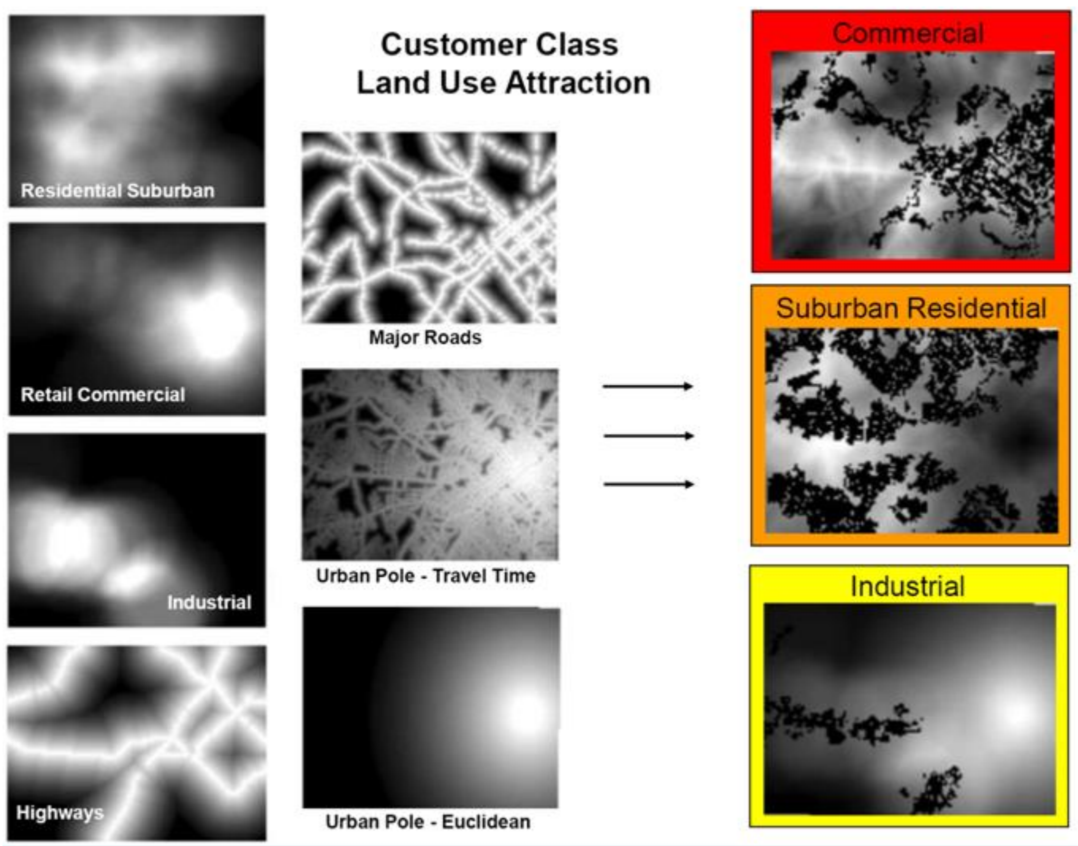
Herein lies the beauty of LoadSEER: its capacity to illustrate the non-linear aspect of conditions. It offers time and space manipulation that can be factored in mathematically, allowing a planner to create multiple proximity maps to the same real-world objects. Some scenarios will be spot-on; some may be wrong.

It is this ability to visualize multiple factors and conditions that sets LoadSEER apart from other GIS analysis programs. Planners achieve a real – and justifiable – understanding of the big picture.

Intuitive User Interface and Model Set-Up

The user interface is designed to guide planners through a logical planning process. First, planners input existing data into the database, such as county land use and transportation maps. Next, the planner will input proximity, surround and regional factors, such as zoning laws, land value anomalies, geography or terrain, as well as regional customer preferences, such as seasonal peak load or 24-hour peak-load-by-customer classes.

Last, a planner will gather more specific growth rate information from the utility's economic forecasting and corporate forecasting departments.



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Functionality of the Intuitive User Interface

- Provides the most intuitive framework to cellular automata. Planners can quickly change and apply growth assumptions and rule sets across an entire service territory, preserving old parameters for comparison and calibration.
- Simulates growth from proposed transportation and major employment and activity centers with mathematical, non-linear modeling.
- Can change customer preferences across time. For example, LoadSEER can slowly increase customers' attraction to new transportation or retail center.
- Identify specific regional attractors and detractors with a point and click on a simulation map.
- Establish default non-linear proximity and surround factor calculations. For example, LoadSEER can measure residential customers' preferences to live close to, but not too close, to highways.
- Full LoadSEER license includes 10 years of historical land use data and advanced logistic regression probability maps.

Trending that Improves Short-Term Accuracies

Follow the S-Curve

LoadSEER's trending follows a Gompertz S-curve. The tool extrapolates past trends in peak demand growth on a local area basis using the trending methods driven by LoadSEER output and ancillary data, such as feeder capacity.

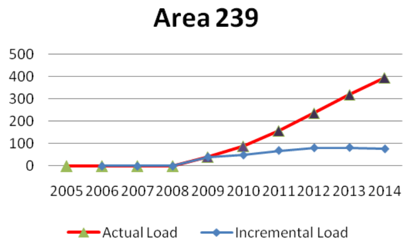
Three parameters control the shape of the S-curve: horizon year load (saturated load), time to the start of ramping, and slope of the load growth. This trending method is advantageous because it is easy of use, simple, and allows for human input regarding recent trends of load growth patterns.

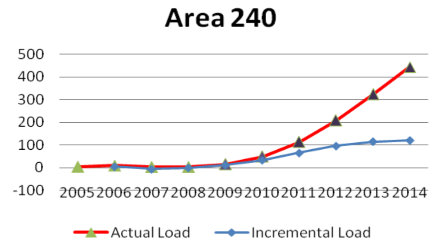
LoadSEER's trending tool features four functional models:

1) **Weather normalization module** applies a weather normalization method to a utility's historical load data to generate the adjusted historical load. Different utility companies may have different weather normalization methods, which this module accommodates.

2) **Horizon year load module** takes land use data (current and future) from LoadSEER and adjusted historical load data to generate load densities for each land-use type as well as the horizon year load (HYL) for each small area. It then selects the small areas with higher HYLs than the current load as the areas of interest in which to prioritize forecast load growth.

3) **Neighborhood module** builds a neighborhood table according to the total number and the location, sometimes adding in load information, of the selected areas of interest.





4) **Forecast module** includes three sub-modules. A bottom-up module iteratively fits S-curves and aggregates historical load and HYL for each small area in each level based on the neighborhood table. A top-down module takes the S-curve parameters from the bottom-up module as references and allocates the utility's system forecast from the top level to the bottom level. A result representation module fine tunes the raw forecasting results and displays the forecast load in both data sheets and map format.

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Trending with a Human Touch

A unique quality-assurance element of the trending tool is that it not only allows, but requires, human participation. LoadSEER requires planners to co-construct the intelligence housed in the database by contributing their years of experience and intimate knowledge of local development, economics, politics, and more to the database. This helps guarantee the quality and accuracy of the forecast.

Due to uncertainties of electric load data, the results from a solely computerized program may conflict with the nature of the load growth. Sometimes, the computerized program is not aware of the local development because the land use data lacks such information. This is another area where LoadSEER differentiates itself: by taking human judgment into consideration. When a human expert is integrated into the problem-solving loop, he or she provides heuristics and insights to correct or confirm the results from the computer.

Although well-tuned load densities can provide overall matching with a current load of most small areas, there remain a few which are treated as outliers. Local rules may differ significantly from calculated load densities. Even among the small areas used in an optimization problem, the variance of mismatches could be very large, due to particular local information that a computer program doesn't have. This information must be input by local planners.

Creating Tools for Defensible Proposals

Documentation & Traceability

LoadSEER helps meet the planning and forecasting needs of T&D and DSM planners by providing advanced statistical tools and geographic information systems (GIS) to develop and document a defensible long-term plan. A hybrid load trending and land simulation algorithm models corporate forecasts on a GIS platform. It is driven by feeder growth rates and historical satellite land change and is constrained by regional future land use maps, zoning, land value, terrain, and local employment.

LoadSEER is a self-documenting program that, during model-building, generation and calibration, saves parameters and map documents for review. For each model run, LoadSEER generates tabular results for every substation area separately and summarizes the change in load and customer profile for each substation area respectively. Models generated are output into the user interface via a "map document," which can be printed and saved.

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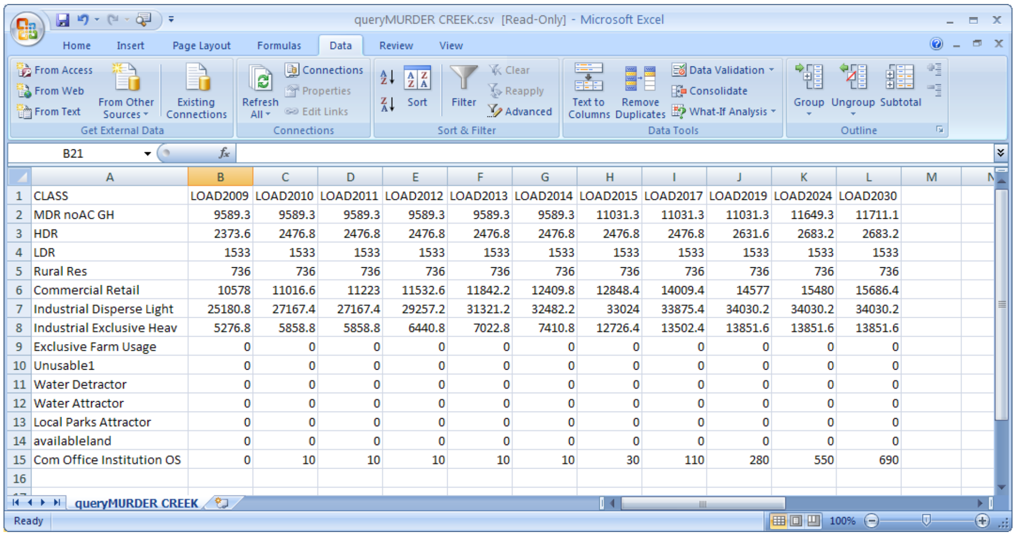
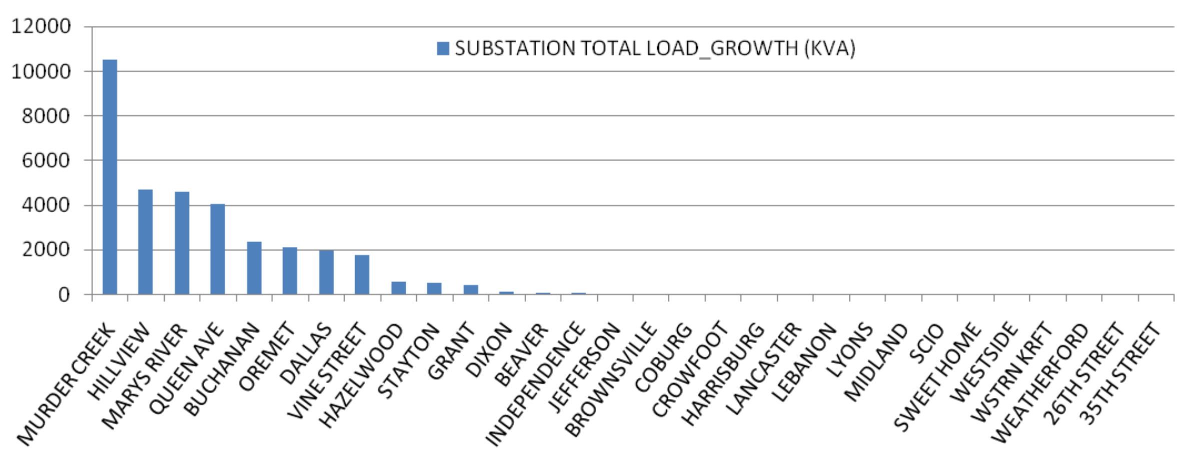


queryMURDER CREEK.csv [Read-Only] - Microsoft Excel

	A	B	C	D	E	F	G	H	I	J	K	L
1	CLASS	LOAD2009	LOAD2010	LOAD2011	LOAD2012	LOAD2013	LOAD2014	LOAD2015	LOAD2017	LOAD2019	LOAD2024	LOAD2030
2	MDR noAC GH	9589.3	9589.3	9589.3	9589.3	9589.3	9589.3	11031.3	11031.3	11031.3	11649.3	11711.1
3	HDR	2373.6	2476.8	2476.8	2476.8	2476.8	2476.8	2476.8	2476.8	2631.6	2683.2	2683.2
4	LDR	1533	1533	1533	1533	1533	1533	1533	1533	1533	1533	1533
5	Rural Res	736	736	736	736	736	736	736	736	736	736	736
6	Commercial Retail	10578	11016.6	11223	11532.6	11842.2	12409.8	12848.4	14009.4	14577	15480	15686.4
7	Industrial Disperse Light	25180.8	27167.4	27167.4	29257.2	31321.2	32482.2	33024	33875.4	34030.2	34030.2	34030.2
8	Industrial Exclusive Heav	5276.8	5858.8	5858.8	6440.8	7022.8	7410.8	12726.4	13502.4	13851.6	13851.6	13851.6
9	Exclusive Farm Usage	0	0	0	0	0	0	0	0	0	0	0
10	Unusable1	0	0	0	0	0	0	0	0	0	0	0
11	Water Detractor	0	0	0	0	0	0	0	0	0	0	0
12	Water Attractor	0	0	0	0	0	0	0	0	0	0	0
13	Local Parks Attractor	0	0	0	0	0	0	0	0	0	0	0
14	availableland	0	0	0	0	0	0	0	0	0	0	0
15	Com Office Institution OS	0	10	10	10	10	10	30	110	280	550	690

Geographic Queries and Reports

Planners can query and create tabular reports for predefined service polygons or user-defined sketches. LoadSEER's on-the-fly graphic operations also give planners the ability to measure the peak load changes by adding or subtracting land and customers to or from a substation.



Visualizations

Visualizations are the components of the map document, which is a customized, deterministic set-up noting calibration, load creation and more. Visualizations illustrate the non-linear proximity and surround maps based on a planner's inputs and assumptions, culminating in final results, new growth, preference maps, and regional factors.

LoadSEER utilizes ESRI map display and overlay functionality. It is a stand-alone desktop application that uses ESRI grid or raster data sets. Integral Analytics Inc. is an Authorized ESRI

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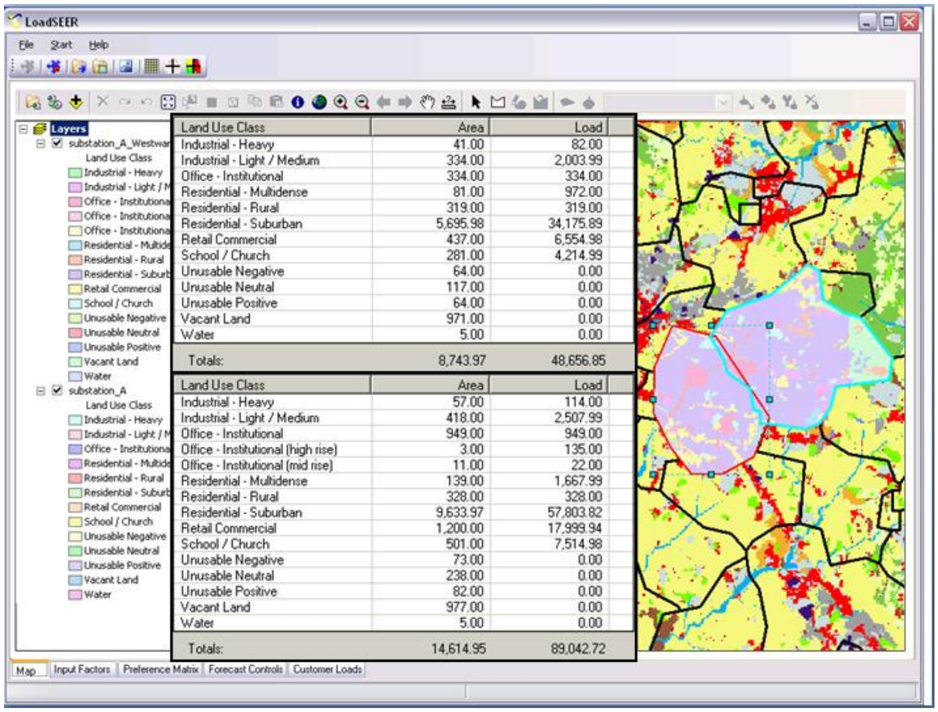
Business Partner, and the LoadSEER application license includes Arc Engine 9.2 with Spatial and Geodatabase Update Extensions.



Best of All, LoadSEER gets Everyone Talking

Because LoadSEER operates under the premise that integration of planners' local knowledge is essential for a useful forecast, it requires human input throughout the entire process, especially that relating to a region's socio-economic system, past and present trends, local rules and even politics.

LoadSEER Services

- Training
- Database Creation
- Model Set-Up
- *Other?*

Therefore, the best and most accurate forecasts rely on planners to interact with analysts, corporate forecasters, engineers, managers and the community *prior* to final forecasting and planning.

The reality is that analysts, utility company managers, planners and the community operate in a political environment. They all need to understand the decision-making process, what information is most useful to that process, and how it can best be presented – all in advance of the actual planning and forecasting.

Thorough, advance discussion and information-gathering among all participants in the planning and management process ensures the quality of the forecast.

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Integral Analytics, Inc.

Integral Analytics (IA) is an analytical software and consulting firm focused on operational, planning, and market research solutions for every aspect of the energy industry. Its proprietary analytical, programming, and statistical methods offer clients more precise valuation, faster and more affordably.

DSMore™

2007 AESP Winner of "Outstanding Achievement in New Product Innovation

Demand Side Management Option Risk Evaluator (DSMore) is a powerful financial analysis tool designed to evaluate the costs, benefits and risks of demand-side management (DSM) programs and services. Its power lies squarely in its ability to process millions of calculations within seconds, resulting in thousands of cost-effectiveness results that vary with weather and/or market prices.

By viewing DSM performance and cost-effectiveness over a wide variety of conditions, managers and regulators can better measure the risks and benefits of employing DSM measures versus traditional generation capacity additions.

IDROP™

Integral Analytics' Integrated Dispatchable Resource Optimization Portfolio (IDROP) uses the Smart Grid in a completely novel approach – to allow a utility to proactively manage customers within the Smart Grid in a manner much like it has treated their generation resources. Specifically, IDROP allows a utility to optimize at a systems level the micro-dispatch of appliances, electric vehicles, photovoltaic generation, wind generation, and distributed storage units, such that the utility can maximize its value given customer-established constraints, cost of service, compliance histories, expected load, and market prices.

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LoadSEER™
Spatial Electric Expansion & Risk

The Hybrid Solution for Accurate, Traceable Spatial Load Forecasting

LoadSEER™
Spatial Electric Expansion & Risk

The Proof is in Distribution Planning

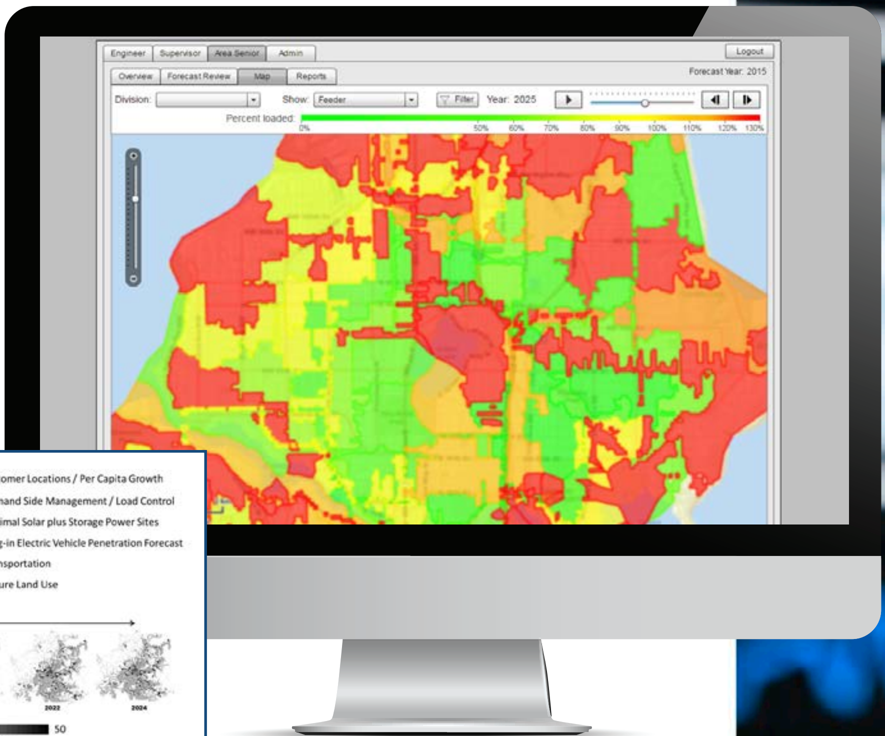
Providing reliable electrical service has always been a key focus for distribution planners. Traditional forecasting and planning approaches have historically used average load growth over wide areas, basic analysis of weather impacts, and little, if any, attention to changing economic, resource deployment, or network topology changes. Exactly how resources and loads operate, interact, and provide power and reliability within the service territory must be analyzed in greater detail to adequately plan for, and integrate emerging distributed resources with changing load trends. And with emerging distributed energy resources (e.g., solar, storage, electric vehicles, demand response), the diversity of forecasted peaks on the T&D systems are changing in a significant way. These supply-side and demand-side resources emerging at the grid edge present new operational challenges which require more detailed and granular planning tools.

LoadSEER, developed by Integral Analytics, is a spatial load forecasting tool which is used by electric distribution system planners to predict load and power changes, where on the grid the loads will occur, how DG changes the load shape, and when it must be supplied. LoadSEER spatial load forecasts address both short-term circuit trends and long-term grid expansion, while remaining consistent with the overall corporate load forecast for energy and peak demand. The resulting forecast provides system planners with substation, circuit and small-area resolution time-series load growth and load shape changes.

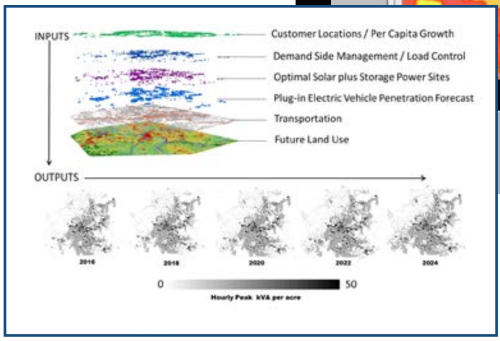
LoadSEER has the Answers

- How will EVs and DG change my peak coincident hours over the next 10 years?
- What if the economy rebounds during an extreme weather year?
- What's the value if I can get new resources to locate where I need them?
- How can I use distributed resources to mitigate risk?

LoadSEER produces a powerful time-series analysis for future load growth based on the forecast scenarios. The tool specifically highlights circuits at risk from changes in demand and capacity. Red areas are circuits over capacity and are most cost-effective candidates for EE, DR, and DERs while green areas have surplus capacity and are least cost load building, such as EV charging stations or new economic development. (The map to the right is simulated data for a Northeast US utility and used for presentation purposes only)



LoadSEER uses a rich set of geospatial data layers and rule-based land use simulation to determine where new load growth is likely to occur.



Giving Sight to Spatial Change and Time

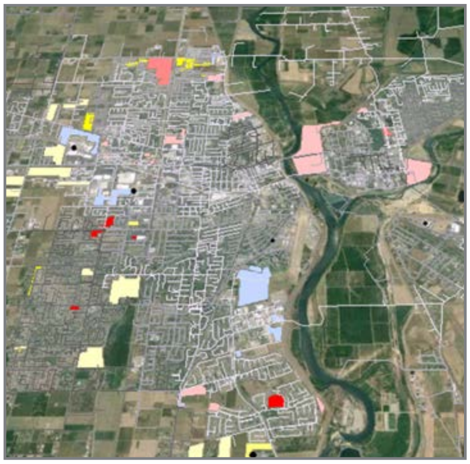
LoadSEER (Spatial Electric Expansion & Risk) is a spatial load forecasting software tool designed specifically for transmission and distribution (T&D) planners who face increasingly complex grid decisions caused by emerging microgrid technologies, extreme weather events, and new economic activity. The objective of LoadSEER is to statistically represent the geographic, economic, distributed resources, and weather diversity across a utility's service territory, and use that information to forecast circuit and bank level peak loads, sub-sections of the circuit, acre-level changes, and impacts from various scenarios over the planning horizon. Planners are able to decompose system impacts using map layers superimposed on the spatial representation of the T&D infrastructure.

The LoadSEER Advantage

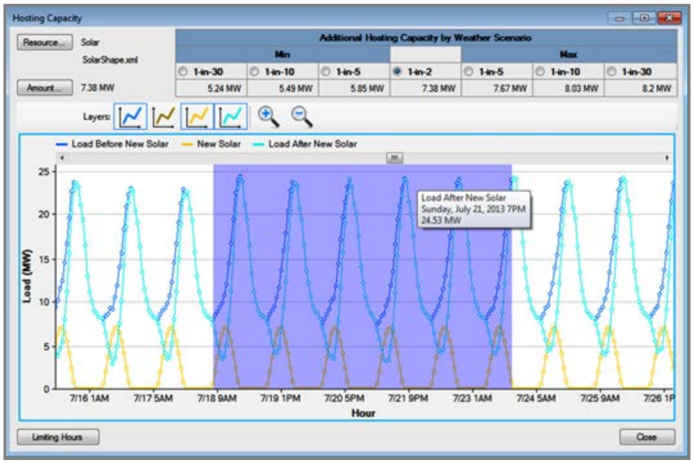
Accuracy	Acre level detail, necessary for resources at the grid's edge
Traceability	All loads are tracked from the bottom up, reconciled to Corporate
Documentation	Clear, transparent and highly defensible results and reporting

The strategic benefits of LoadSEER are many:

- Leverages up to 100 economic factors, by circuit, in addition to weather. Economic risk often trumps weather risk at the circuit level.
- Automated forecast model fitting, with recommended forecast results, so planning engineers can minimize the time spent developing forecasts, yet still incorporate their local knowledge of known or expected growth.
- A GIS spatial forecast, based on 20 years of NASA satellite histories, modeling geographic influences unique to the regional customer base and the landscape.
- Ability to target DSM or DG to target circuits, without jeopardizing reliability.
- Comprehensive quality checking, process review, and log history for use in data requests and defensibility, as well as oversight and management during the forecast period.
- Ability to directly integrate solar forecasts, EV forecasts or other microgrid impacts, down to the customer level.
- Quick export to your power flow analysis tool, or DMS (Distribution Management System), with full hourly load shapes across all weather scenarios.
- Leverages multiple forecasting methods to triangulate on the truth.
- Very sophisticated approach to scenario analysis, especially for factors that do not exist in the past load history (new DG, EV, commuter rail lines, new economic centers, etc.)
- Provides the analytical detail needed for DMS, optimal switching/transfers, improved power flow modeling, forecasting future LMP congestion and detailed calculation of distributed marginal costs and prices.
- Accounts for historical transfers of load between circuits. Statistical finds transfers, fault, imputes missed reads, and weather adjusts SCADA loads.
- Ease of use, and increased productivity, due to automation of forecasting process.
- Significantly more defensible within regulators and management.



LoadSEER connects local load increases (shown in color) to line sections for improved power flow analysis in other modeling software, such as CYME, Synergi and Milsoft.



LoadSEER accommodates DER plans, including Integration Capacity Analysis, subsequent changes in load shapes, and calculating the maximum allowable amount of specific DERs, such as PV.

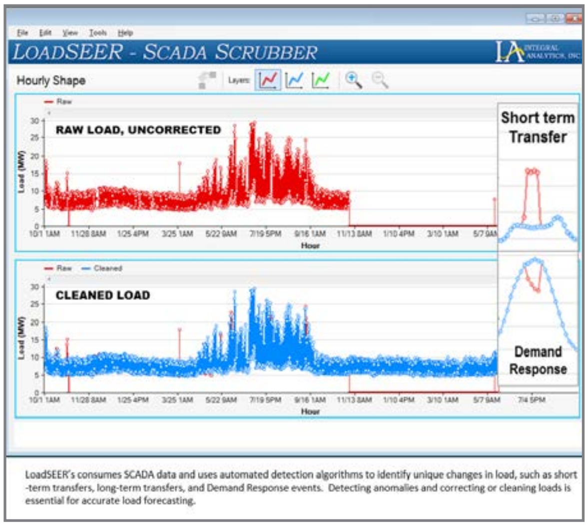
Simulation that Delivers Non-Linear Locational Behavior

Scenario-Driven Forecasting

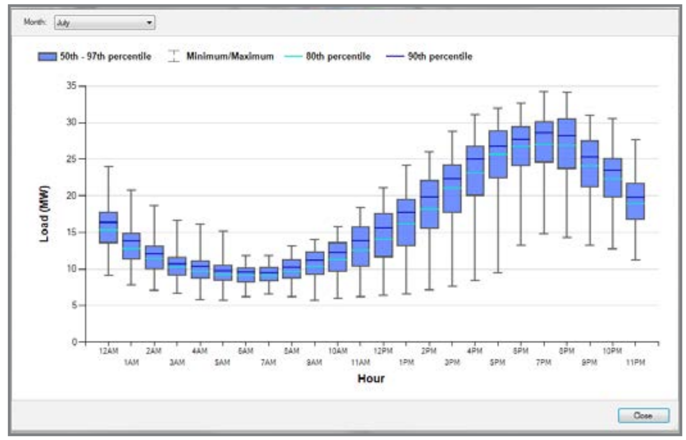
The core algorithms automatically model geographic and economic drivers, along with weather, to provide engineers with the most representative circuit by circuit forecast models.

In some cases, one circuit might respond to retail sales, while another might be sensitive to employment, personal income, housing starts, or various combinations.

This process enables planners to analyze specific future scenarios such as transportation network expansion, suburban sprawl, urban redevelopment, new manufacturing, various mixes of solar, electric vehicles, demand response, energy efficiency or additional employment centers. The final forecast results can be leveraged to enhance an existing suite of planning tools, including direct exports to power flow analysis tools, used in forecasting future transmission congestion, calculation of local avoided costs for optimal DER integration, and Distribution IRP requirements.



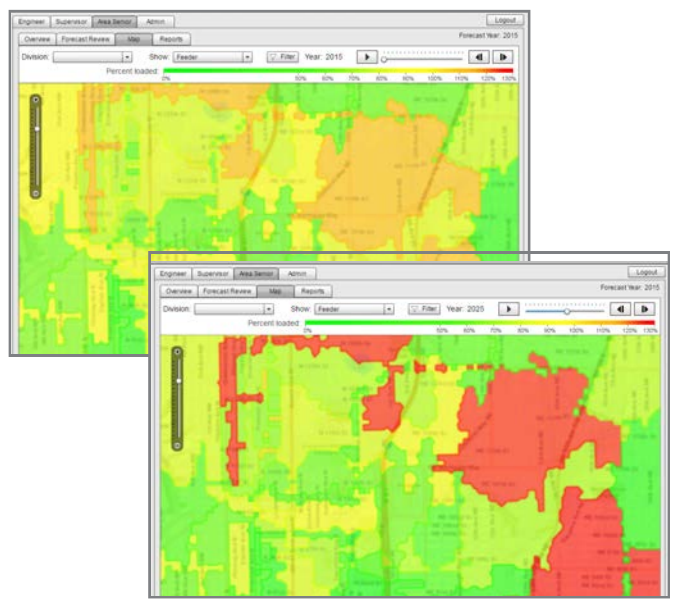
LoadSEER's load cleaning tool imports SCADA data and uses automated detection algorithms to identify unique changes in load to improve model performance.



LoadSEER houses hourly load profiles that are weather normalized and itemized by customer class and in aggregate to create unique substation, circuit and line section shapes.

LoadSEER houses two distinct modules, the FIT (Forecast Integration Tool) module and LoadSEER-GIS (Geographic Information System) module.

1. LoadSEER-FIT employs three methods for forecasting loads, is housed within a web services user interface and is the place where distribution planners conduct most of their forecasting and data management tasks.
2. The LoadSEER-GIS module houses the spatial data information and analytics. Includes hundreds of GIS layers so users can overlay multiple scenarios and results for further analysis or impressive displays of results.



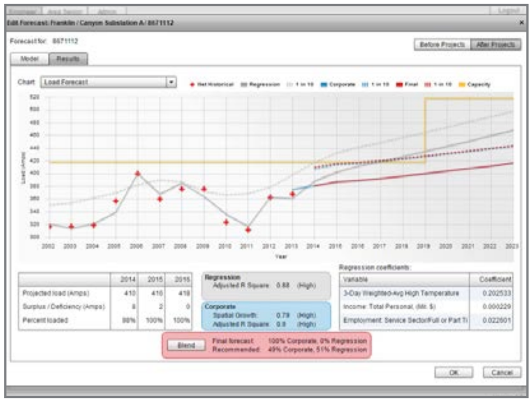
LoadSEER's distinctively designed to handle multiple scenarios. For instance, the adoption of DERs will affect feeder load shapes and may either exceed feeder capacity from increased load (EV charging station) or may help defer a capacity addition from decreased load (EE/DR/PV). LoadSEER models adoption probabilities for DERs, highlighting which circuits may be at further risk or may benefit from incentivized participation in utility programs.

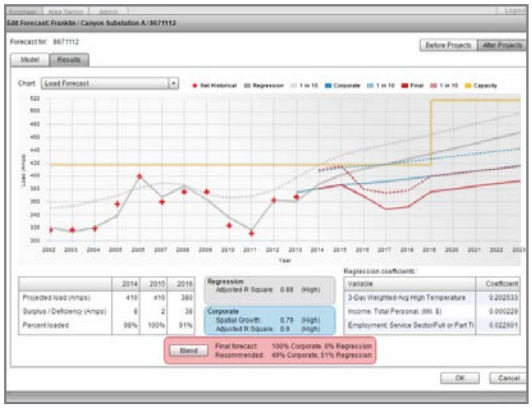
LoadSEER employs three different types of load forecasting including a regression of peak circuit loads on weather and economic variables, an econometric forecast of energy using these same or similar independent variables, and a spatial load forecast using GIS land use and geographic information. The use of three different methods provides increased convergent validity where two or more of the distinct forecasts produce similar forecast results. In addition, the local distribution planner's knowledge of the local load situation can be incorporated to further enhance the forecast accuracy of any of the three methods.

LoadSEER also provides an option to statistically blend the three forecasts based on the statistical goodness of fit diagnostics for each method. Alternatively, if the local distribution planner has unique, local knowledge that one of the three forecasts is likely to be more accurate than the others, more weight can be placed on that forecast. LoadSEER not only provides a weather normal forecast of loads, but also incorporates a forecast overall all possible weather conditions, circuit by circuit.

Produce an accurate, traceable, long-term load forecast that actually improves the value of short-term decisions!

LoadSEER™
Spatial Electric Expansion & Risk





The LoadSEER Advantage

Consistency

LoadSEER visualizes a utility's corporate forecast given a full set of growth rules, then follows them to allocate growth. For every model generated, it produces tabular results for each substation area separately, and summarizes the change in load and customer profiles for each substation area respectively.

Traceability

LoadSEER shows planners, managers and customers where all conclusions came from for each interim result and each interim decision. During model-building, running, and calibration, LoadSEER's user interface saves full sets of growth rules and corresponding map documents for review.

Documentation

LoadSEER is self-documenting in order to prove consistency and traceability. Planners can quickly change and apply growth assumptions and rule sets across an entire service territory, preserving old parameters for comparison and calibration.

LoadSEER Services

- Model Set-up, calibration, and simulation
- Database creation, data hosting services
- LoadSEER architecture
- Training workshops, site visits
- Technical Support

About Integral Analytics, Inc.

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CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Reply Comments

Docket No. E002/M-19-666

Dated this **10th** day of **April 2020**

/s/Sharon Ferguson

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