STATE OF IOWA

BEFORE THE IOWA UTILITIES BOARD

IN RE: INTERSTATE POWER AND LIGHT COMPANY	))))))))	DOCKET NO. RPU-2023-0002

PUBLIC VERSION

DIRECT TESTIMONY OF
CODY DAVIS
ON BEHALF OF
ENVIRONMENTAL LAW & POLICY CENTER AND
IOWA ENVIRONMENTAL COUNCIL

April 16, 2024

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A. Introduction and Witness Qualifications

Q. Please state your name, business name, and address.

A. My name is Cody Davis and my business address is 1904 S First St, Champaign, IL 61820.

Q. By whom are you employed and in what capacity?

A. I am employed as a Senior Manager of Distribution and Grid Modernization by Electric Power Engineers, LLC.

Q. Please describe Electric Power Engineers.

A. Electric Power Engineers, LLC (EPE) is a consulting firm comprised of leading electrical engineering consultants focused on the energy transition, providing power systems engineering services to a diverse client base.

Q. On whose behalf are you submitting this direct testimony?

A. I am testifying as an expert witness on behalf of the Environmental Law and Policy Center and Iowa Environmental Council.

Q. Please summarize your educational background.

A. I received a Bachelor of Science degree in Electrical and Computer Engineering from Southern Illinois University Edwardsville in 2014.

Q. Please summarize your professional experience.

A. I have over 9 years of experience working within a distribution utility and as a consultant on projects in a variety of power distribution subject matter areas including distribution design, distribution planning, DER interconnection, and distribution system operations.

Q. What are your current job duties and responsibilities?

A. I lead a team of power systems engineers which provides consultation services to a variety of clients with different roles related to power distribution systems. My team supports utility clients, regulatory bodies, non-profit organizations, generation developers, and commercial and industrial businesses by providing expertise in matters related to the distribution system. This includes areas such as distribution system planning and load forecasting as well as the integration of emerging technologies like solar, battery energy storage, distributed energy resources (DER), advanced metering infrastructure (AMI), advanced distribution management systems (ADMS), and DER Management Systems (DERMS), among others. I am responsible for providing expert consulting services to clients, as well as overseeing and ensuring the quality of information, deliverables, and services provided by my team.

Q. Please describe your professional experience prior to joining Electric Power Engineers, LLC.

A. Prior to joining Electric Power Engineers in 2020, I was a Career Engineer at Ameren Illinois working on DER Integration and Strategy. During my time in this role, I performed DER interconnection and system impact studies for larger solar installations and led internal interconnection policy and criteria development. I also led several initiatives and pilot analyses in hosting capacity, non-wires alternatives, the value of distributed energy resources to the distribution system, and the impact of smart inverter functions on Ameren's voltage optimization program. Before my role in DER Integration, I worked for Ameren Illinois as a Division engineer and was responsible for a wide variety of job duties within a specific geographic region. These duties included load forecasting, distribution system planning, project justification, reliability analysis and improvement, distribution design, project management, customer technical complaints, drone pilot, and storm field checking.

Q. Have you testified in front of the Iowa Utilities Board before?

A. No, I have not.

Q. Have you testified or participated in regulatory proceedings in other states?

A. Yes. I provided direct and rebuttal testimony before the Illinois Commerce Commission on the value of distributed energy resources to the distribution system. I have also provided direct and rebuttal testimony in Minnesota within Xcel Energy's most recent rate case. In addition, I led EPE's engagement with the Maine Public Utilities Commission to investigate the design and operation of the distribution system of the two investor-owned utilities operating within the state. As part of that effort, EPE filed an investigation report, stakeholder feedback report, gap analysis, and distribution system roadmap. I presented the resulting findings in a webinar involving all interested stakeholders.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibit:

- EI Davis Direct Exhibit 1: IPL Response to EI Discovery Request 19, Attachment B
- EI Davis Direct Exhibit 2: IPL Response to OCA Discovery Request 105 (CONFIDENTIAL)
- EI Davis Direct Exhibit 3: IPL Response to OCA Discovery Request105, Attachment A (CONFIDENTIAL)
- EI Davis Direct Exhibit 4: IPL Response to OCA Discovery Request105, Attachment B (CONFIDENTIAL)

- EI Davis Direct Exhibit 5: IPL Response to LEG Discovery Request 63
- EI Davis Direct Exhibit 6: IPL Response to EI Discovery Request 20
- EI Davis Direct Exhibit 7: IPL Response to EI Discovery Request 31
- EI Davis Direct Exhibit 8: IPL Response to EI Discovery Request 29
- EI Davis Direct Exhibit 9: IPL Response to EI Discovery Request 23
- EI Davis Direct Exhibit 10: IPL Response to EI Discovery Request 25
- EI Davis Direct Exhibit 11: IPL Response to EI Discovery Request 26
- EI Davis Direct Exhibit 12: IPL Response to EI Discovery Request 27
- EI Davis Direct Exhibit 13: IPL Response to EI Discovery Request 45
- EI Davis Direct Exhibit 14: IPL Response to OCA Discovery Request 175, Attachment A
- EI Davis Direct Exhibit 15: IPL Response to EI Discovery Request 33
- EI Davis Direct Exhibit 16: IPL Response to EI Discovery Request 46 (CONFIDENTIAL)
- EI Davis Direct Exhibit 17: IPL Response to OCA Discovery Request 175
- EI Davis Direct Exhibit 18: IPL Response to EI Discovery Request 65

B. Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a fair, reasonable, and independent analysis of the Company's proposed investments and practices primarily related to the distribution system. This includes providing context and expert opinion and analysis regarding the impact of planned investments on customers and on the ability of the distribution system to support the integration of renewable energy sources and other distributed energy resources (DER).

Q. How is your testimony organized?

A. My testimony is organized into four sections:

- In Section 1, I address the Company's Undergrounding standard.
- In Section 2, I discuss further exploring specific use cases for the Company's ADMS system.
- In Section 3, I discuss the Company's approach to FERC Order 2222 and DER monitoring and control.
- In Section 4, I discuss the Company's proposed fiber communication build-out.

Q. Please summarize the conclusions of your testimony.

A. I conclude the following:

- The cost per mile data developed by the Company and used in its justification of their undergrounding standard is insufficient to estimate the expected cost to construct new underground facilities or replace existing overhead facilities with underground equipment on a system-wide, per mile basis.
- The Company's system-wide approach to undergrounding as standard practice will increase the cost for customers to connect new line extensions to the distribution system and remove customers' ability to choose the type of line extension that best meets their cost and benefit needs.
- The Company does not accurately characterize how the requirements of FERC Order 2222 will impact distribution utilities.
- The Company's statements regarding DER monitoring and control are premature and not sufficiently supported by their current plans and capabilities.
- The Company has not sufficiently demonstrated that fiber is the only cost-effective way to achieve the communication requirements for a modern distribution system.

Q. Please summarize your recommendations.

A. I recommend the following:

- I recommend that the Board direct the Company to revisit its undergrounding standard and the underlying cost and benefit methodologies and provide the results as part of an integrated grid plan.
- I recommend that, without such ana analysis, the Board not approve the proposed level of undergrounding expenses, especially those intended to provide reliability.
- I recommend that the Company analyze its system to identify where FLISR can provide cost-effective reliability improvement and present its methodology and findings as part of an integrated grid plan.
- I recommend that the Company conduct detailed studies to identify specific circuits where Conservation Voltage Reduction has the potential for cost-effective energy savings, especially in the regions where it could potentially benefit historically disadvantaged communities, and present the findings within an integrated grid plan.
- I recommend the Company develop a roadmap for DER monitoring and control, taking into account public stakeholder feedback, and present it within an integrated grid plan.
- I recommend that the Company provide more specific cost and benefit data and should assess hybrid communication architectures in order to determine the most reasonable and cost-effective path forward for communications.
- I recommend the Company incorporate communications needs within an integrated grid plan.

I. UNDERGROUNDING

Q. Please describe this section of your testimony.

A. In this section of my testimony, I discuss the Company's undergrounding standard, the cost and benefit information provided by the Company to justify that standard, and my recommendations to improve the Company's decision-making and stakeholder communications for undergrounding moving forward.

A. Review of the Company's Undergrounding Philosophy and Proposed Spending

Q. How does the Company approach overhead and underground facilities as part of its distribution design practices?

A. The Company has elected to design its facilities moving forward with underground (UG) construction as the standard practice and overhead (OH) construction to be utilized only by exception.[1] In August of 2019, the Company issued guidance to its engineers that "every effort should be made to construct new parts of our system as UG if possible."[2] In the same guidance, the Company identified some conditions which would warrant overhead construction instead. These conditions are primarily focused on the feasibility of underground construction. Significant cost increases are identified as a reason not to construct facilities underground for larger, high capacity conductors (three phase 600 Amp terminated underground sections). Notably, the Company identifies that "there is no cost trigger for underground single phase or three phase 200 amp project segments,"[3]

[1] EI Davis Direct Ex. 1, IPL Response to EI DR 19, Attachment B at page 5.
[2] EI Davis Direct Ex. 1 at page 2.
[3] EI Davis Direct Ex. 1 at pages 5-7.

indicating that such facilities should be constructed as underground where physically possible regardless of the additional cost.

Q. What justification has the Company provided for its decision to standardize on underground design instead of overhead?

A. The Company has identified the "high reliability and resiliency of underground lines" as the driver for choosing its undergrounding standard.[4] In response to data requests, the Company has also provided the cost/benefit analysis used to justify undergrounding distribution lines.[5]

Q. Has the Company identified capital dollars within this rate case that will be used to construct underground facilities?

A. Yes. Within the budget category and spending information provided by Company Witness Boston, the Company has identified a total of $37 million within the "Reliability – Line Asset - Large UG" as actuals for 2021 and 2022 and an additional $161.6 million forecasted in these categories for 2023 through 2025.[6] In addition, there is significant underground spending for "Externally Driven – Road Moves", "Externally Driven – New Revenue", and "Special Projects – Regulatory Rebuild."

[4] IPL Boston Direct Testimony at page 6, lines 12-13.
[5] EI Davis Direct Ex. 2, IPL Response to OCA DR 105 CONF.
[6] IPL Boston Direct Ex. 1 (E) at page 1.

B. The Company's method for estimating generalized costs for OH and UG lines is flawed.

Q. What values did the Company provide for the cost per mile for overhead and underground facilities?

A. The Company provided the following table in its response to OCA DR 105, which requested an "updated economic analysis of the cost levels at which the higher cost of underground distribution lines is justified by the increased reliability of underground lines."

[redacted]

Q. Did you have any immediate concerns with these values, prior to reviewing the underlying method and data used to generate them?

A. Yes. The cost per mile to construct single-phase rural overhead construction (1PH Rural – OH) is listed as [redacted] cost per mile to construct three-phase rural overhead (3PH Rural – OH), which is not reasonable as a generalized conclusion. Single-phase construction, all else being equal, should be significantly cheaper than three-phase construction on a per mile basis because it requires two less conductors, does not require crossarms, and generally uses less poles due to longer allowable span lengths, among other factors. In a similar vein, the single-phase rural overhead data is also higher than several of the other cost categories that I would expect to be higher and is in fact higher than every other cost category except urban three-phase underground. From these results, it is clear that the Company's method for developing generalized costs per mile for overhead and underground lines is flawed and results in unreasonable generalized estimates.

Q. How did the Company develop these cost per mile estimates?

A. The Company used data from work orders from 2020 to 2023 and computed the average cost per mile based on total cost and total miles constructed in each category. For work orders containing both single-phase and three-phase construction, work orders appear to have been categorized based on which construction type covered the largest distance as a percentage of the total for the work order.

Q. Did you identify any issues with this method?

A. Yes. The Company includes three-phase distance and the associated construction costs within work orders that are considered single-phase for the purposes of the cost per mile estimates. For the single phase rural overhead category, the Company developed its average cost based on the results from just two work orders,[7] one of which had [redacted] of its total distance as three-phase while the second had [redacted] three-phase.[8] Because the cost per mile for three-phase is higher (all else being equal), the inclusion of three-phase costs within single phase work artificially inflates the cost per mile for single-phase construction.

[7] EI Davis Direct Ex. 3, IPL Response to OCA DR 105, Attachment A_CONF, "1PH Rural Loaded CPM Boxplot."
[8] EI Davis Direct Ex. 4, IPL Response to OCA DR 105, Attachment B_CONF.

Q. Are there other issues with the use of this method to develop cost/mile estimates?

A. Yes. The Company's approach applies statistical techniques to historical work order data in order to estimate generalized cost information. This approach is not inherently bad. Individual work orders may have varying conditions and cost drivers, so using historical averaging can help develop more generalized information to facilitate system-level decision-making. Unfortunately, the Company does not have sufficient volumes of data to apply these techniques adequately for all the categories for which estimates are provided. For the single phase rural overhead category, the Company's historical data includes just two work orders, both of which it marked as "statistical outliers" and, as identified previously, include significant three-phase construction costs.[9] For three-phase rural overhead, the Company has based its estimated cost off of four work orders, three of which are marked as "high variance" in excess of 50% higher or lower than the average.[10] Taken together, the Company has used data from just six work orders, five of which are "high variance," to estimate the cost per mile that would be associated with rebuilding 15,211 miles of its rural overhead system. Given the low volumes and high variance of the cost per mile data provided, it is clear that this data is not a solid foundation from which to draw broad, system-wide conclusions about expected costs.

Q. The Company categorizes costs by rural versus urban lines and single phase versus three phase lines. Are there other categorizations that should be considered as well?

A. Yes. The Company should differentiate between the expected costs for new construction and the expected costs to rebuild existing overhead lines.

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[9] EI Davis Direct Ex. 3, "1PH Rural Loaded CPM Boxplot."
[10] EI Davis Direct Ex. 3, "3PH Rural Loaded CPM" (hidden tab).

Q. Why is it important to differentiate between the costs of new line extensions and line rebuilds?

A. Separately analyzing and understanding the costs for new construction and rebuilds for underground facilities can lead to much more targeted and effective policies and strategies. Currently, the Company is using the results of its analysis, which does not differentiate between new line extensions and rebuilding facilities, to justify a full system undergrounding standard. In practice, the implementation of this standard involves both constructing new lines underground and converting existing lines to underground. The cost to construct a new line extension underground is often significantly lower than the costs to reconstruct an equal distance of existing overhead facilities as underground, which the Company is not currently incorporating in its analysis. In addition, as I will discuss later in my testimony, customers connecting new loads to the distribution system can bear some of the cost to extend new lines. In contrast, rebuilds of existing infrastructure are much more likely to be driven by the Company, with the expenses borne by existing customers. Given the different treatment of these two types of construction and the potential differences in cost, it is reasonable to consider them as distinct categories within a cost-benefit analysis and any subsequent policy decisions.

Q. What do you conclude about that cost per mile data used by the Company in the justification of its undergrounding standard?

A. The cost per mile data developed by the Company and used in its justification of their undergrounding standard is insufficient to estimate the expected cost to construct new underground facilities or replace existing overhead facilities with underground equipment on a system-wide, per mile basis.

Q. Do you have any other concerns related to the cost information used in the justification of the Company's undergrounding standard?

A. Yes. As I explained previously, the Company issued guidance to its engineers that all single-phase construction was expected to be underground and that "there is not a cost per mile trigger for underground single phase or three phase 200A planned project segments"[11] to instead be constructed using overhead methods. In effect, the Company has directed its engineers to disregard any location-specific information and use underground for all single phase and 200A three phase projects where physically possible, regardless of the cost differential. Even if the results of a system-level analysis conclusively demonstrated a net lower life-cycle cost for underground facilities (which, as stated previously, I do not believe to be the case here), design and construction are not performed at a system level. Design and construction occur as a set of individual projects designed and built by local resources capable of making project-specific decisions based on observed conditions at the site. Consequently, the individuals performing the design and construction have site-specific information that directly impacts the cost to construct facilities. The Company's direction that field resources utilize underground design for single-phase and 200 Amp three-phase areas, regardless of local, site-specific cost drivers, is very concerning and likely to result in higher than necessary costs.

[11] EI Davis Direct Ex. 1.

C. The benefits of undergrounding calculated by the Company do not justify full system undergrounding.

Q. Putting aside the cost issues, do you have any other concerns with the Company's justification for its undergrounding standard?

A. Yes. I have specific concerns with the reliability benefits included within the Company's analysis. I also have more structural concerns with how the Company is utilizing reliability benefits within its cost/benefit analysis.

Q. What reliability benefits did the Company include in its cost/benefit analysis for undergrounding?

A. The Company calculated reliability benefits using the Interruption Cost Estimate (ICE) calculator, which is a tool that estimates the value of avoided outages by calculating the change in the total estimated cost of interruptions to customers that results from a specific change to improve reliability. The Company has also included the value of the energy that can now be delivered that would otherwise have been unable to be delivered due to an outage.

Q. What concerns do you have with regard to these reliability benefits?

A. Within the ICE calculator results used in the Company's cost/benefit analysis, 99% of the benefits go to non-residential customers, despite over 80% of the Company's customers being residential.[12] Since underground conversions are capitalized, residential customers would bear a significant portion of the conversion cost despite seeing very little of these benefits. Given the $198.6M of reliability-driven underground spending identified by the Company in this rate case ($37M actual and $161.6M forecasted through 2025), the

[12] EI Davis Direct Ex. 3, "ICE" and "Sales Forecast."

consequences of this benefit discrepancy are significant. While the Company also includes other benefits, the benefits identified from the ICE calculator are a significant portion of the overall total, especially for 3-phase areas.

Q. Does the Company need to underground its entire distribution system to achieve these reliability benefits?

A. No. The Company's justification is based on a system-level assessment, which spreads all the estimated benefits out across all the estimated costs. In reality, the reliability benefits would be very "lumpy," with some locations being significantly more beneficial than others. Overhead areas with significant tree encroachment, for example, may be much better candidates for undergrounding due to both reliability improvements and a reduction in tree trimming maintenance spending. In contrast, the same length of line in an open area may have a similar rebuild cost, but a much lower level of benefit. The most efficient way to make decisions, given this kind of variation, is not to average the effects out across all locations, but to utilize location-specific information within the design process to optimize the costs and benefits.

In addition to the concerns with using system-level benefits, the Company is also assuming these benefits are realized without accounting for the other potentially more timely or more cost-effective ways to achieve them. A net positive cost benefit analysis, on its own, is not sufficient to determine whether a specific decision should be recommended or whether an investment is reasonable and necessary. For any given system capacity issue or reliability improvement opportunity, there are often many alternatives that have net positive benefit to cost ratios. The goal of the Company, in such cases, should be to maximize the benefits and minimize the costs to achieve the desired outcomes. In some cases, undergrounding some facilities may be the best option. In other cases, alternative solutions may provide higher levels of benefits or have lower costs or both. Specific opportunities should be evaluated on a project-by-project basis based on actual costs and realizable benefits for the specific alternatives being considered. A framework for making such decisions and effectively evaluating the benefits could be developed and communicated as part of an integrated grid planning process, as I explain later in my testimony.

D. Impact of Company's Undergrounding Philosophy on Customer Line Extensions

Q. Are there other types of costs impacted by the Company's use of underground as the standard for construction?

A. Yes. In addition to conversion and rebuilding projects, the undergrounding standard also can increase the cost to construct new line extensions to serve new interconnections.

Q. Who is responsible for paying the costs to construct new line extensions?

A. Costs for line extensions are governed by the Company's Electric Tariff, Section 11 of the General Rules and Regulations for Electric Service Extension Policy. Under this policy, the customer requesting the extension may be responsible for a portion of the cost, depending on the length of the extension, whether the existing lines are overhead or underground, and whether the customer's line extension will be overhead or underground. The rest is furnished by the Company as part of its "Externally Driven – New Revenue" spending.[13]

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[13] IPL Boston Direct Ex. 1 (E) at page 1.

Q. Is the Company requiring customers to pay for new line extensions to be underground even if they would prefer overhead?

A. Yes. In areas where existing facilities are underground, the Company is allowed to require customers to pay for the additional costs for underground facilities (section 11.05 of General Rules and Regulations for Electric Service Extension Policy). In the future, if the Company continues with its undergrounding standard, this will drive up the cost to connect new line extensions by taking the overhead option away from customers.

Q. Does IPL's undergrounding design strategy have any other impacts related to the cost to connect new customers?

A. Yes. The Company provides less free footage for underground lines, providing 50 feet for overhead services but only 34 feet for underground service,[14] further increasing the potential costs to new line extensions in underground areas. In addition, the Company's undergrounding standard can lead to higher costs to connect new line extensions in another way. In overhead areas, span lengths between poles typically range 100 to 300 feet, and new poles can be set between existing poles to facilitate new overhead primary extensions or service transformers. In areas with underground primary, the National Electric Safety Code (NESC) requires the system neutral to connect to a grounding electrode connection every 1250 feet. To comply with this requirement, it is common for utilities to set switchgear or primary junction boxes approximately every 1250 feet in rural areas, with shorter distances only where switchgear or primary junction boxes are needed to facilitate connecting line extensions to customers. If a new customer is

[14] EI Davis Direct Ex. 5, IPL Response to LEG DR 63.

connecting to an existing underground line, extending underground primary conductors to the nearest junction box may require up to 750 feet of additional construction distance, relative to similar overhead lines. It is possible to dig in to the existing primary and install a new junction box instead of connecting to the existing junction boxes, but it is considerably more expensive to dig up and splice the underground cable to create the new junction box and may require de-energizing other customers for crew safety. In either case, line extensions from underground facilities can have noticeably higher cost in some cases than similar line extensions from overhead facilities. The Company did not perform any analysis to identify potential changes in interconnection costs for new interconnections as a result of its undergrounding standard.[15]

Q. Does undergrounding new customer line extensions improve reliability to existing customers?

A. Generally, no. New line extensions (both overhead and underground) are frequently installed with a fused disconnect. This fuse is a protective device which isolates permanent faults, preventing an issue on the new tap from causing a sustained outage on existing facilities. There are cases where fusing new line extensions is not practical due to high fault currents or the inability to coordinate with existing upstream protective devices. In such cases, the reliability benefits of undergrounding would not accrue to all customers, but rather to only the set of customers served by the next upstream protective device that would experience an outage in the event that a fault occurred on the new line extension.

[15] EI Davis Direct Ex. 6, IPL Response to EI DR 20.

Q. Who is the primary beneficiary of the reliability benefits of undergrounding a new line extension?

A. The customer who is served by the line extension would be the primary beneficiary of any avoided outages that result from undergrounding the facilities. To the extent that additional customers connect to the same line extension in the future, they may benefit from the reliability, but as I explained previously, they may also experience additional costs to construct their line extension.

Q. What do you conclude about the impact of the Company's undergrounding standard on customer line extensions?

A. The Company's system-wide approach to undergrounding as standard practice will increase the cost for customers to connect new line extensions to the distribution system and remove customers' ability to choose the type of line extension that best meets their cost and benefit needs.

E. Undergrounding Recommendations

Q. You have identified some significant concerns with several aspects of the costs and benefits the Company identified in support of its undergrounding standard. How do you recommend the Board address these concerns?

A. The Company has not provided sufficient evidence in the record to justify the level of underground spending it proposes. I recommend that the Board direct the Company to revisit its undergrounding standard and the underlying cost and benefit methodologies and provide the results as part of an integrated grid plan. Without such analysis and results, the Board should not approve the proposed level of undergrounding expenses, especially the reliability focused spending.

As part of this analysis, the Company should identify site-specific conditions that justify the use of underground design for single-phase and 200A three-phase construction. These specific conditions should be based on the actual benefits achieved or actual expected costs reduced by the use of undergrounding at the construction location. For cost data, rather than relying on generalized work order data, the Company should developed estimated costs for both overhead and underground construction for the same projects in order to identify expected cost differences across the set of scenarios considered. Example conditions that I would recommend considering include tree proximity, whether the line is a new extension or a rebuild of existing facilities, and whether trenching can be utilized for underground cable installation. I also recommend that the Company explicitly allow customers in areas with existing overhead facilities to pursue overhead line extensions if they so choose.

Q. You suggest the Board direct the Company to present and justify its undergrounding analysis and standards as part of an integrated grid plan. What is an integrated grid plan?

A. Integrated grid plans (also called integrated distribution plans) provide a systematic approach to satisfying customer service expectations and state grid planning and design objectives such as reliability, resiliency, operational efficiency, the integration of DER, and other elements of distribution planning, investment, and operational decision-making.[16] These are typically documents filed by distribution utilities to describe both existing and future challenges, design decisions, long-term plans, grid modernization

[16] https://emp.lbl.gov/publications/state-approaches-distribution-system

efforts, DER integration efforts, and or other key distribution focus areas relevant to how the distribution system is planned, constructed, and operated. Often, integrated grid plans are used to facilitate discussion and strategy related to long-term initiatives that will be impactful to more than just a specific rate case. Example jurisdictions that are using this approach include Integrated Grid Plans in Illinois, Integrated Distribution Plans in Minnesota, and Distribution System Implementation Plans (DSIP) in New York, among others.

Q. Why is such a plan an appropriate venue to discuss the Company's undergrounding standard?

A. An integrated grid plan provides a constructive, technically focused venue where distribution planning methods, investment planning, reliability and resiliency goals, and long-term strategies can be presented and discussed with public stakeholders. Presenting the overall goals, strategies, and specific topics and methods within an integrated grid plan gives stakeholders an opportunity to provide feedback on the overall direction as well as their specific needs, goals, and concerns with specific elements of the content.

The Company has many methods of improving reliability, including tree trimming, animal guarding, undergrounding, circuit tie construction, and FLISR, among others. An integrated grid plan is a suitable venue for considering all the available solutions and the strategies available to the Company and to select the most reasonable solution to deploy for a given problem or area. It also provides an opportunity for transparency with regard to the justification and decision drivers and enables broad, structural discussion that can streamline consideration for future rate case investments. By identifying distribution system goals and then evaluating how to cost-effectively and efficiently meet those goals, distribution system planning can reduce overall system cost without jeopardizing key reliability, resiliency, and affordability goals.

II. ADMS UTILIZATION EXPANSION

Q. Please describe this section of your testimony.

A. In this section of my testimony, I discuss two common applications of ADMS systems that I would recommend the company consider for implementation and future expansion: Fault Location, Isolation, and Service Restoration (FLISR) and Conservation Voltage Reduction (CVR).

Q. What is an ADMS System?

A. ADMS is an Advanced Distribution Management System, which is an operations technology that integrates a variety of available real-time operational data and control capabilities to improve distribution operations outcomes. Many of the most promising applications of ADMS utilized automated control of telemetered devices such as reclosers, switches, capacitors, or voltage regulators to reduce outage impacts, mitigate voltage violations, or improve efficiency.

A. Fault Location, Isolation, and Service Restoration (FLISR)

Q. What is FLISR?

A. FLISR generally refers to the use of remotely controlled switches or protective devices to reconfigure the distribution system connectivity in response to an outage in order to automatically restore service to as many customers as possible.

Q. Does the Company use FLISR?

A. Yes, the Company currently uses FLISR in a relatively limited fashion. In its previous rate case, the Company indicated that it performed three pilot projects with FLISR[17] and that the Company planned for just two installations per year starting in 2021.[18] Company witness Boston does not discuss FLISR in his direct testimony in this rate case and does not identify specific FLISR spending in the Base Electric Distribution Investments Summary (Boston Direct Exhibit 1 (E)).

Q. Why doesn't the Company use FLISR in more locations?

A. The Company has previously stated that "Undergrounding is often the best option since it improves reliability five-to six fold" and that FLISR is very effective "in cases where underground or even rebuilding is not a viable option."[19] From these statements, it is reasonable to conclude that the Company does not utilize FLISR for reliability more broadly because of the Company's preference for undergrounding.

Q. Is it reasonable to compare undergrounding and FLISR as reliability improvement projects?

A. For individual projects, yes sometimes. At a system level, it is much more difficult to compare them in a way that enables prioritizing one over the other as a general philosophy. FLISR and undergrounding can both improve reliability, but the two are often significantly different in total cost and in the benefits provided as well as in the types of outages they are able to prevent.

[17] RPU-2019-0001, Dyer Direct at page 19.
[18] RPU-2019-0001, Dyer Rebuttal at page 28.
[19] RPU-2019-0001, Dyer Rebuttal at page 28.

Q. How do the overall costs of FLISR and undergrounding compare to each other?

A. While specific costs will vary by location and design needs, FLISR is typically much less expensive than undergrounding on a per-circuit basis. The Company's estimated average cost per mile for 3-phase underground in rural areas is [redacted].[20] In my experience, it is often possible to install a three recloser FLISR scheme, providing fault isolation and automated restoration capabilities to two feeders, for less than the Company's cost to convert just one mile from overhead to underground.

Q. How do the overall benefits compare to each other?

A. FLISR can significantly improve reliability by reducing the number of customers impacted by feeder-level outages by transferring those customers to a different (still energized) circuit. This makes it well suited to reliability improvement in areas that have experienced feeder outages, as it can cut the number of customer outages in half or more for relatively low cost. In the Company's FLISR 2 and 3 Pilot project results, FLISR exceeded the Company's expectations by reducing the duration of outages by a total of 669,000 customer outage minutes.[21]

Undergrounding, in contrast, improves reliability by preventing some common outage causes (storms, tree limbs, etc.) and any associated asset repair costs, though it often comes with significant implementation cost. It is also noteworthy that, while undergrounding prevents some common outage causes, it still has its own associated failure modes (notably, cable faults and dig-ins) that can still leave customers without power until manual switching or repairs enable restoration. It is also noteworthy that

[20] EI Davis Direct Ex. 3 "3PH Rural Loaded CPM."
[21] RPU-2019-0001, Dyer Direct at page 28.

FLISR and undergrounding are not mutually exclusive solutions. FLISR can also be deployed in underground areas using padmounted equipment in order to minimize the impact of feeder outages from cable failures and dig-ins.

Undergrounding also has the benefit of replacing existing, potentially aged assets with new assets. In areas where, for example, the existing line assets are near the end of their useful life, undergrounding may be a reasonable alternative since overhead replacement costs would be incurred in the near term. In other areas where existing facilities are in good condition, the assets health benefits of an underground rebuild are much less of a factor.

Q. How should the Company consider these potential costs and benefits when making investment decisions?

A. Because these benefit drivers can vary so significantly by location, equipment condition, and historical outage causes, it is important to evaluate the specific costs and benefits for specific areas of need. An integrated grid plan is an appropriate venue to consider these costs and benefits in a more holistic manner, facilitating identification of areas where FLISR can cost-effectively increase reliability, where undergrounding can significantly improve benefits or avoid costs, and integrating these considerations with other distribution system investment plans and solution options. A general justification of either undergrounding or FLISR can lead to overuse and, subsequently, inefficiency and overspending, while a more locational analysis can allow for more tailored solutions and better cost management.

Q. Does the Company's limited use of FLISR have an impact on the justification for the Company's undergrounding standard?

A. Yes. Because both undergrounding and FLISR can provide reliability benefits (although in different forms), a portion of the reliability benefits currently attributed to undergrounding could instead be realized by implementing FLISR in specific areas of need (where also cost-effective). If the reliability benefits were realized through FLISR instead of undergrounding, it would reduce the relative benefits of undergrounding in the system-wide cost/benefit analysis performed by the Company. As I mentioned previously, the Company's FLISR pilot projects resulted in a significant reduction in the number of customer minutes of interruption on the feeders for which FLISR was deployed.

Q. What do you recommend regarding the Company's approach to FLISR?

A. I recommend that the Company analyze its system to identify where FLISR can provide cost-effective reliability improvement and present its methodology and findings as part of an integrated grid plan. High potential opportunities for analysis may include, for example, feeders that have recently experienced feeder-wide outages and have existing circuit ties. Evaluating FLISR as part of an integrated grid plan will allow for a comparison with undergrounding and other solutions options with identified goals and specific examples in mind so that the Company's investment is demonstrated to be a cost-effective and efficient way to achieve outcomes. Without such a plan, the Company has not justified the significant investments it has proposed in undergrounding for reliability improvement.

Q. Why is an integrated grid plan an appropriate venue for the Company to communicate and justify its FLISR plans?

A. Reliability improvement is a complex, multi-faceted goal that involves many different approaches, initiatives, and technologies. An integrated grid plan provides an avenue for different types of projects (for example, FLISR and underground conversions) to be presented holistically and to ensure that the most cost-effective project mix is selected to achieve a desired level of benefit at an acceptable cost. A holistic approach also helps ensure that potential reliability improvement benefits that can be achieved through multiple means are not double counted.

B. Conservation Voltage reduction

Q. What is Conservation Voltage Reduction?

A. Conservation Voltage Reduction (CVR) is a method used by the electric utilities to reduce customer energy consumption by systematically lowering the voltage on the distribution system. CVR aims to maintain the voltage within allowable limits while producing considerable energy savings by operating at the lower end of the allowable range instead of at the higher end.

Q. Has the Company deployed CVR in the past?

A. Yes, in the past IPL has conducted a pilot study to test the viability of automated line equipment to allow for centralized conservation voltage regulation as a function of the ADMS.[22]

[22] RPU-2019-0001, Dyer Direct Ex. 5 (Final)(E) at page 7.

Q. Are there benefits to CVR other than energy savings?

A. Yes, beyond energy savings, CVR provides multiple additional benefits. First, CVR assists with demand reduction which is most helpful during peak usage times when the grid is under most strain, providing additional capacity on distribution assets. Second, CVR provides enhanced control over the voltage levels throughout the distribution network where CVR is implemented. This is especially relevant given the increasing adoption of DER, which can create complications that make traditional approaches to voltage regulation more challenging. Rather than relying on pre-set local settings and decisions, CVR allows the system to utilize all available measurements and data to respond to system conditions, preventing voltage violations and increasing efficiency.

Finally, implementing CVR can serve as a preparatory step towards more advanced DER management that the Company has proposed. Successful execution of CVR through the ADMS platform requires high quality operational models for the affected circuits, establishing communications and controls capabilities to higher numbers of field resources, and executing an automated optimization of equipment states in response to grid constraints. The execution of DER monitoring and control will very likely include the same general components, but executed with larger numbers of field devices for different optimization goals. Because of these similarities, implementing CVR could help the Company build the necessary experience, capabilities, and processes to effectively monitoring and control DER in the future.

Q. Does the Company have the capabilities to implement CVR today?

A. The Company does not currently have everything needed for implementing the CVR functionality, but they have many of the key elements. The Company has already implemented the base ADMS system and AMI, which are key enablers. In addition to these, the Company will need the following ADMS modules implemented: distribution power flow, distribution state estimation, and Volt/Var Optimization. Out of these based on a response to a data request,[23] the Company is planning to implement distribution power flow and distribution state estimation, but the Company has not listed Volt/Var Optimization in the list of functionalities to be implemented in the ADMS.

Q. Has the Company proposed CVR investments within this rate case?

A. No, the Company has not proposed any CVR investments in this rate case. In response to the data request[24] the Company has not listed VVO as one of the functionalities that is planned to be implemented. As a part of another data request,[25] the Company has clarified that VVO has not been part of previous implementations.

Q. What do you recommend with regard to CVR?

A. I recommend that the Company conduct detailed studies to identify specific circuits where CVR has the potential for cost-effective energy savings, especially in the regions where CVR could potentially benefit historically disadvantaged communities. In such communities, the energy savings and subsequent bill reductions are particularly meaningful and can reduce the energy burden on those customers least able to bear it. This would involve assessing the feasibility and expected benefits of CVR implementation

[23] EI Davis Direct Ex. 7, IPL Response to EI DR 31.
[24] EI Davis Direct Ex. 7.
[25] EI Davis Direct Ex. 8, IPL Response to EI DR 29.

without compromising the service quality. Following the study, I recommend that the Company present their findings as well as the implementation plan in an integrated grid plan to facilitate a more coordinated and effective implementation.

Q. Why is an integrated grid plan an appropriate venue for the Company to communicate and justify its CVR plans?

A. An integrated grid plan serves as the ideal platform for the Company to present and validate its CVR strategies due to the wide-reaching impacts of this implementations on energy savings, demand reductions and potential savings for both the Company and its customers, especially for historically disadvantaged communities. The methods by which the Company selects feeders to pursue or not pursue, as well as the results, are highly relevant for public stakeholders. Because this is a long-term program beyond just a specific rate case, an integrated grid plan would help ensure a clear and consistent path forward and will ensure that the CVR implementation are aligned with Company's other planned initiatives as well as the public interest.

III. FERC 2222 AND DER MONITORING AND CONTROL

Q. Please describe this section of your testimony.

A. In this section of my testimony, I discuss the Company's statements and approach to FERC Order 2222 and DER monitoring and control.

A. FERC 2222 and DER Monitoring and Control

Q. What is FERC Order 2222?

A. FERC Order 2222 directs the relevant FERC-regulated entities (include MISO) to make changes to enable the participation of aggregations of DER in energy markets. The details of the order include a number of specific requirements and modifications, some of which will directly impact distribution utilities.

Q. What are aggregations of DER in this context?

A. An aggregation of DER refers to a set of DER that are coordinated and grouped to achieve a sufficient size to enable market participation or other grid services[26]. This enables individual DER to provide maximum value and have access to market structures.

Q. Who are the primary parties involved in implementing FERC 2222 within the Company's territory?

A. MISO is the primary party impacted by FERC Order 2222 within the Company's territory and is responsible for developing and submitting compliance filings for its proposed implementation of the order. Electric distribution companies (EDCs), in this case the Company, and Relevant Electric Retail Regulatory Authorities (RERRAs), in this case the Board, are also expected to play a role in some facets of the changes proposed and ultimately implemented by MISO to comply with the FERC order.

Q. How has the Company characterized the impact of FERC 2222 to distribution and the role of the Company's ADMS system?

A. Company Witness Bremel, in his direct testimony in this rate case, repeatedly mentions that the company plans to monitor and control DER using its ADMS system in his response on the impact of Order 2222 on the Company's distribution infrastructure upgrade efforts. A few notable examples include:

[26] https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy

- "The ADMS can optimize the operation of DERs to meet demand. It can manage the dispatch of DERs." (Bremel Direct at page 7, lines 10-11)
- With regard to Customer Empowerment, "customers with their own generation and storage devices can allow IPL to use the ADMS to manage their energy production and consumption" (Bremel Direct at page 7, lines 19-20)
- "An ADMS will allow IPL to conduct data analytics to address these specific technical and business challenges by efficiently and cost-effectively managing these generation sources" (Bremel Direct at page 8, lines 18-20)
- "IPL anticipates that implementation of its ADMS will include additional functionalities supporting the requirements of Order 2222 and will be completed by the end of 2025" (Bremel Direct at page 9, lines 11-13).

Q. Does MISO's proposed implementation of FERC Order 2222 require the Company to be able to monitor or control DER?

A. No. The proposed framework allows for distribution utilities to monitor and control DER, but does not require it. This is illustrated within MISO's October 2022 compliance filing in response to FERC's request for information regarding the "coordination protocols and processes for the operating day that allow EDCs [the Company] to override MISO dispatch of a DEAR [Distributed Energy Aggregated Resource] in circumstances where such an override is needed to maintain reliable and safe operation of the distribution system." In its response, MISO indicates that "the distribution interconnection process will establish communication and operational protocols between the DER Owner and the relevant Electric Distribution Company. Each RERRA [the Board] and Electric Distribution Company [the Company] may have different rules requiring flexible language to support the State jurisdiction over interconnection and distribution operations."[27] From these statements, it is clear that decisions related to DER interconnection, monitoring, and operational control are a matter to be determined between the Company and the Board, rather than by MISO or FERC.

Q. How would you characterize DER monitoring and control within MISO's proposed implementation of the FERC 2222 requirements?

A. MISO's proposal anticipates that distribution utilities may implement monitoring and control and may wish to use such capabilities alongside DER market participation in order to maintain reliability. Consequently, this capability is addressed within its proposal, but MISO does not attempt to require it because the interconnection of DER and the reliability of distribution systems are not within its jurisdiction.

Q. Is the Company currently able to monitor and control DER through its ADMS system?

A. No, and it is not clear when they will be able to do so. In response to a data request,[28] the Company indicated that "Real-time operation of the DERs that have a communication link are visible in the ADMS system today, however, the ability to control DERs is an ADMS system function included as part of planned future system module implementation." In a separate data request,[29] the Company did not include the DER Monitoring and Control module in the list of modules it plans to deploy by the end of 2025.

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[27] https://cdn.misoenergy.org/2022-10-11%20Docket%20No.%20ER22-1640-001626599.pdf page 55-56.
[28] EI Davis Direct Ex. 9, IPL Response to EI DR 23.
[29] EI Davis Direct Ex. 7.

Q. Are there other restrictions that would prevent the Company from monitoring and controlling DER?

A. Yes. When asked which customer DER it would monitor and control, the Company cited the Iowa Administrative Code Chapter 45, which states that "Utility requirements for monitoring and control of distributed generation facilities are permitted only when the nameplate capacity rating is greater than 1 MVA."[30]

Q. Does the Company have any plans to address this limitation in order to monitor or control smaller DER?

A. Not that the Company is willing to share. When asked in a data request if the Company had identified any changes to the interconnection process that would be necessary as a result of the use of DER monitoring and control, the Company stated it will provide any recommendations during future rulemaking dockets regarding Iowa Administrative Code Chapter 45.[31]

Q. Company Witness Bremel identifies customer empowerment as one element of FERC Order 2222 that the Company supports. How does the Company characterize its support for customer empowerment?

A. The Company states that it supports customer empowerment and provides a specific example to clarify how. Company Witness Bremel states "IPL's ADMS will enable customers to have more control over their energy usage and choices. For example, customers with their own generation and storage devices can allow IPL to use the ADMS

[30] EI Davis Direct Ex. 10, IPL Response to EI DR 25.
[31] EI Davis Direct Ex. 11, IPL Response to EI DR 26.

to manage their energy production and consumption, and even sell excess energy back to the grid."[32] In a subsequent data request, the Company stated that "IPL has not identified any specific plans at this time regarding customer empowerment using ADMS and DER monitoring/control" and "IPL will provide information to customers to enable them to make decisions."[33]

Q. Do you agree with the Company's approach to customer empowerment as part of FERC 2222?

A. No. I believe that engaging customers and other stakeholders to understand their needs and goals is a necessary component of customer empowerment in this initiative, and it is not included within the Company's current plans. Customer resources and, subsequently, customers' economic decision-making capabilities, are directly impacted by the details of any DER monitoring and control implementation framework. The Company's approach ignores this critical step and intends to provide customers with the information the Company believes they will need, rather than engaging with stakeholders and listening to their feedback to understand what they actually need to facilitate customer empowerment. In order for DER Monitoring and Control to be effective in Iowa, it has to work for both customers and utilities.

Q. What do you conclude about the Company's capabilities and plans for monitoring and controlling DER?

A. The Company does not accurately characterize how the requirements of FERC Order 2222 will impact distribution utilities. The Company's statements regarding DER

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[32] IPL Bremel Direct at page 7, lines 17-21.
[33] EI Davis Direct Ex. 12, IPL Response to EI DR 27.

monitoring and control are premature and not sufficiently supported by their current plans and capabilities.

Q. How do you recommend the Company approach DER monitoring and control?

A. DER Monitoring and control has the potential to increase the cost-effectiveness of DER interconnections and facilitate more efficient system design and operations. It is also very complex to implement and impacts a wide variety of stakeholders, including direct impacts on customer-owned DER and their ability to generate energy. Consequently, the Company should start with a clear vision for how it will implement DER monitoring and control. This vision should reflect the needs and feedback of the owners of the resources who will be impacted in order to ensure that customers are able to participate effectively, take advantage of new capabilities, and make economic decisions. There are also critical technical components with associated costs that the Company must be consider. Given the variety of decisions and impacts to different stakeholders, I recommend the Company develop a roadmap for DER monitoring and control, taking into account public stakeholder feedback, and present it within an integrated grid plan. One recent example of this concept is the DER Orchestration plans to be developed in Illinois by Ameren Illinois and Commonwealth Edison as ordered by the Illinois Commerce Commission within the multi-year integrated grid plan process.[34]

[34] https://www.icc.illinois.gov/docket/P2023-0082/documents/345318/files/602917.pdf (Section V.C.6.a.i.(a)).

IV. FIBER COMMUNICATIONS DEPLOYMENT

Q. Please describe this section of your testimony.

A. In this section of my testimony, I provide the overview of the Company's communication architecture upgrade in terms of needs for the upgrade and the justifications provided by the company to use private fiber over other options. I have also highlighted the gaps that exist in the overall upgrade process and my recommendations for improvements.

A. Overview and Gaps in the Company's Communication Infrastructure Upgrade Plans

Q. What communication upgrades has the company planned?

A. The Company in 2017 did a strategic analysis of its communication architecture concluding that the Company's existing communication architecture will not be sufficient to support the Company's vision of Advanced Energy Grid and identifying a need to install "5000 miles of fiber optic cable to connect critical infrastructure throughout its service territory in the next 10 years."[35] The Company has classified the planned fiber optic deployments in three routes: core transport, distribution, and access. The company is currently working on the core transport route and has completed Phase 1 of fiber deployment. In this application the Company is proposing Phase II of the core deployment.

Q. What is the core transport, distribution and access routes?

A. The Company defines them as follows:

"**Core Transport** routes are long-haul paths that connect major data centers and operations centers. These connections require the most capacity, highest availability, and redundancy in the network.

[35] RPU-2019-0001, IPL Dyer Direct Ex. 1 (Final)(E) at page 20.

Distribution routes are shorter than core routes and provide more regional paths. They will have less capacity than Core routes and may not carry the same level of redundancy. **Access** routes connect premise locations such as substations back into Core or Distribution sites. They may include radial routes without fiber redundancy."[36]

Q. What has the Company completed so far?

A. Company Witness Bremel in his direct testimony stated that "Phase I has been completed between Cedar Rapids, Dubuque, and Decorah, Iowa, also connecting with facilities in Wisconsin to complete the loop."[37]

Q. What does the Company plan to do as a part of Phase II deployments and what is the forecasted investment for Phase II?

A. Mr. Bremel in his direct testimony has stated that "The Phase II fiber deployment will continue build out of the Core Transport Routes and include the installation of approximately 410 miles of fiber. The fiber will connect approximately 75 IPL facilities including field offices, communication towers, substations, and generating plants. The fiber will be constructed in a loop, starting from a point along the current Phase I route near Cedar Rapids, heading west through Marshalltown to Ames, then north to Mason City and finally east back to another point along the Phase I route near Decorah"[38]

The Company has planned an investment of approximately [redacted] for Phase II deployments.

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[36] RPU-2019-0001, IPL Dyer Direct Ex. 1 (Final)(E) at page 21.
[37] IPL Bremel Direct Testimony at page 15.
[38] IPL Bremel Direct Testimony.

Q. Has the company performed any analysis about the performance of the Phase I fiber installation before proceeding with Phase II?

A. No, the company has not provided any information/analysis to assess the performance of the fiber comparative to previously used technologies in terms of latency improvements or other performance parameters, which in my opinion is an important step before proceeding with phase II deployments. In response to a data request about the communication and reliability performance of Phase 1 of the fiber install the company stated that "The Phase 1 fiber installation has performed with high reliability since it was placed in service in 2021. There have been a few instances where dig-ins caused damage to the fiber or conduit, but since IPL / Alliant uses a ring configuration, in each case the damage did not cause a communication outage. Communication traffic was automatically routed in the opposite direction around the ring. Additionally, the combination of properly marked fiber and well architected topology minimized the frequency of damage and decreased the time to isolate and repair fiber."[39]

Q. What reasons has the Company provided for the communication architecture upgrade?

A. The Company has identified three drivers for the communication architecture upgrade:

[39] EI Davis Direct Ex. 13, IPL Response to EI DR 45.

1. The existing communication network is inefficient to support the Company's vision for an Advanced Energy Grid.[40]
2. The Company has also highlighted the increase in Distributed Generation, Electrification, and regulatory changes like FERC Order 2222 as another driving factor for building a high-capacity data network.
3. The need for a robust communication network for real-time monitoring and control of DERs and supporting ADMS and its functionalities.

Q. Are these justifications sufficient to justify the Company's proposed fiber build-out plan?

A. No. As I mentioned earlier, monitoring, controlling, and managing DER is a complex undertaking which needs a comprehensive strategy to seamlessly integrate technology, communications, operations, and stakeholder feedback. The Company is moving towards communications upgrade without defining the other facets involved in planning for DER management and control, FERC Order 2222 implementation or electrification. Additionally, upgrading communication architecture is a capital intense undertaking which requires systematic planning, phased deployments, and assessing different technologies to identify the most cost-effective mix, and integration with existing and future grid operational technology like ADMS.

Q. How should the Company address communications needs related to these?

A. Because of the need for communications across a variety of applications and the impacts across multiple business processes, the Company should incorporate communication as a component of an Integrated Grid Planning framework and present a holistic solution to cover every aspect of grid communication from core transport routes to edge devices. An

[40] IPL Dyer Direct Ex. 1 (Final)(E) at page 20.

integrated grid plan should incorporate cost and benefit evaluations and stakeholder feedback throughout the process. It also helps ensure that the planning and decision-making framework remains dynamic, adapting to new information, technology, and stakeholder needs.

Q. What justification has the company provided to choose fiber over other options?

A. The company has shared a few drivers for selecting fiber as the preferred technology for the communication architecture upgrade and it states that "A private fiber architecture is the only technology that meets all of these requirements."[41] The Company argues that only a utility owned fiber system delivers all the following critical benefits to the utility – reliability, resiliency, physical and cyber security, affordability/financial benefits, and performance – bandwidth and speed.[42] The Company has identified 8 functional use cases[43] that it claims demonstrate the likely needs of the Company with upcoming influx of DERs. These use case themes include distribution automation, monitoring, and control of DERs, demand response, ongoing substation construction, growth in "internet of things" (IOT) devices and AMI deployment to list a few. Out of all the technology assessed, the Company argues that only privately owned fiber is capable of catering to all the defined use cases[44].

Q. Do you agree with the Company's assessment of private fiber being the only technology which fulfills the Company's Advanced Energy Grid.

A. No, I don't agree with the Company's assessment that private fiber is the only communication technology which provides the benefits as listed by the Company. Table 1

[41] EI Davis Direct Ex. 14, IPL Response to OCA 175, Attachment A at page 2.
[42] IPL Bremel Direct Testimony.
[43] EI Davis Direct Ex. 14.
[44] EI Davis Direct Ex. 14at page 8.

in Mr. Bremel's direct testimony displays that utility-owned fiber is the only solution which fulfills the criteria without providing any information of the references used to create the table. In response to a data request[45] for more information, the Company provided additional documentation, but even this documentation fails to provide a strong comparison of different technologies under consideration with credible references. Also, no consideration is given by the company to a hybrid architecture with a mix of multiple technologies like public and private fiber, wireless technologies, etc. to ensure a cost-effective solution is implemented.

The Company as of now has identified the three routes mentioned earlier, namely core transport, distribution, and access. The Company is working towards deploying fiber along the core transport route, but as the Company moves forward with the distribution and access routes, the Company should assess a hybrid architecture between public/private fiber, wireless and other technologies to find the solution which while being technology efficient, is also cost efficient.

Q. Has the Company provided any Cost Benefit analysis?

A. As a part of a data request,[46] the Company provided the cost benefit analysis from the last rate case (RPU-2019-0001). Also, as a part of a data request,[47] the Company provided additional analysis from Q2 2023 stakeholder collaboration and stated that it does not possess any additional cost benefit analysis for fiber investments.

[45] EI Davis Direct Ex. 15, IPL Response to EI DR 33.
[46] EI Davis Direct Ex. 16 CONF, IPL Response to EI DR 46.
[47] EI Davis Direct Ex. 17, IPL Response to OCA DR 175.

I have been advised by legal counsel that Article X.A.2 of the Non-Unanimous Partial Settlement Agreement (Settlement) of the Interstate Power and Light Company (IPL) electric rate review (Docket No. RPU-2019-0001) requires that "prior to deploying Phase II of the Fiber Project, IPL will undertake one or more additional cost-benefit analyses regarding the construction and deployment of Phase II, including seeking stakeholder feedback." The Company has indicated that the material provided during the Q2 2023 stakeholder collaboration meeting fulfills this requirement.[48]

Q. Is the cost-benefit analysis provided by the Company satisfactory?

A. No. The cost-benefit analysis provided by the Company is not sufficient to justify the proposed level of investment for the Company's fiber built-out plan.

Q. Can you elaborate by discussing the information provided in these two documents provided by the Company?

A. The Company provided the cost-benefit analysis from the last rate case in response to the data request.[49] The document is labelled as "Strategic Communication Architecture" and does not contain concrete cost and benefit calculations or specific data. Instead, it outlines a strategic communication architecture solution including different technologies and a consultant vendor's recommendation. It prioritizes the exploration of a communication framework over a rigorous analysis of cost and benefits associated with specific projects or technologies. Additionally, [redacted]

[48] EI Davis Direct Ex. 17.
[49] EI Davis Direct Ex. 16.
[50] *Id.*.

[redacted]

The other justification document[53] provided by the Company is provided as a response to Article X.A.2 of the Non-Unanimous Partial Settlement Agreement (Settlement) of the Interstate Power and Light Company (IPL) electric rate review (Docket No. RPU-2019-0001), which requires that "prior to deploying Phase II of the Fiber Project, IPL will undertake one or more additional cost-benefit analyses regarding the construction and deployment of Phase II, including seeking stakeholder feedback.". This document also fails to provide sufficient additional information about the costs and benefits of the Company's proposed investment. Table on pg. 10 of the document contains a rough comparison of cost between private fiber, public fiber, cellular LTE, Microwave (11 GZ) with the Company making statements such as:

- "This would lead to leased circuit O&M costs increasing to the $10M's annually."

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[51] EI Davis Direct Ex. 18, IPL Response to EI DR 65.
[52] *Id.*
[53] EI Davis Direct Ex. 14.

- "IPL estimates the capital cost of $100's of millions of dollars to build this network for the Phase 2 projects."
- "bandwidth and capacity needed to support the identified use cases would require a build out of multiple dishes on multiple towers located at intervals every fifteen miles along the route, resulting in capital cost in the $100's of millions of dollars for the Phase 2 projects."[54]

These text examples reflect orders of magnitude costs with variability of $100 Million or more, rather than well-defined and estimated costs and variance ranges that would be expected in a formal cost/benefit analysis. Also, this analysis did not consider any costing for a hybrid approach between different technologies. Consequently, this document functions more as a use case definition document than an effective cost/benefit analysis.

Q. Do you have any concerns with the use cases that the Company identifies?

A. The Company has justified the use of private fiber deployment by mentioning that the private fiber meets all the needs of the functional use cases identified by the Company. With regard to the specific use cases, I will address each individually.

1. The first use case listed is the distribution automation and implementation of FLISR and Var Control schemes. However, as mentioned earlier in my testimony, FLISR is being used by the Company in a very limited fashion and no details about future implementations or costs are provided by the Company's witnesses in this rate case. Additionally, in response

[54] EI Davis Direct Ex. 14 at page 10.

to the data request associated with FLISR the Company stated that "IPL has established cellular as the preferred and standard communication medium for FLISR to provide the switch status (switch operation) to the Distribution System Operator. Fiber communications for FLISR is an alternative communication option when cellular interference exists, typically in an urban area. This would be considered an exception to the standard installation." This is inconsistent with the Company's use case for fiber in FLISR deployment.

2. The next functional use case that I would like to point out is supporting monitoring and control of distributed generation. As I mentioned earlier in my testimony, the Company's specific plans and capabilities to monitor and control distributed generation are not well defined and, in response to a data request,[55] the Company did not include DER Monitoring and Control module in the list of modules that the Company plans to deploy by the end of 2025. Additionally, as mentioned earlier in my testimony, the Company so far has identified no plans for monitoring and control of DERs less than 1 MVA. Overall, the Company's plans around DER monitoring and control are not sufficiently developed to justify fiber deployment to support them.

3. The Company has also highlighted consumer centric resources like solar PV systems, electric vehicles, etc. and demand response programs as another use case, but the Company has not provided any information about how these programs will be framed, if there are

[55] EI Davis Direct Ex. 7.

any opportunities for pilot projects, and how the consumer benefit and participation will be handled. Programs like demand response require extensive stakeholder engagement to ensure that the program is well defined and successful.

Q. What do you conclude about the Company's use cases and justification for fiber communication?

A. The Company has not sufficiently demonstrated that fiber is the only cost-effective way to achieve the communication requirements for a modern distribution system. Implementing functional use cases, as mentioned above, requires an integrated approach which includes technological aspects as well as a strategic framework for operational success and sufficient stakeholder engagement to ensure participation and success. The determination of a suitable communication architecture which can support these use cases is a subsequent phase of planning where the primary focus should be on the definition of the use cases and the evaluation of all available technology options. Incorporating communications within an integrated grid plan can significantly aid in this process. It facilitates comprehensive and holistic planning framework which integrates various aspects of defining the use cases, including associated technology, operational strategies and stakeholder engagement, thereby enabling a more informed strategic selection of communication technologies. Given the large capital investment needed to implement the Company's approach to fiber (with [redacted] in capital investment planned for Phase II deployments), clear and holistic planning and justification is critical to efficient and cost-effective deployment.

B. Recommendations

Q. What are your overall recommendations towards Company's Communication Infrastructure Upgrade?

A. Upon reviewing the Company's overall communication architecture upgrade, accompanying needs, justifications, and cost benefit analysis, I recommend the following:

1. Beyond the Core transport route, the Company should analyze hybrid technology options (combination of fiber, wireless and other technologies) to implement cost-effective communications solutions.

2. The Company should provide more specific cost and benefit data and should assess hybrid communication architectures in order to determine the most reasonable and cost-effective path forward for communications. This will ensure a comprehensive analysis of economic and operational impacts of different communication technologies.

3. The functional use cases outlined by the Company would need thorough planning from operational technology to communication technology and stakeholder feedback to ensure the most efficient and effective solution is implemented. I recommend the Company incorporate communications needs within an integrated grid plan. Because communications is becoming more critical to many different business processes and programs, considering communications needs holistically as part of an integrated grid plan can help ensure that specific needs are met in a cost-effective manner.

V. CONCLUSION

Q. Please summarize your recommendations.

A. I recommend the following:

- I recommend that the Board direct the Company to revisit its undergrounding standard and the underlying cost and benefit methodologies and provide the results as part of an integrated grid plan.
- I recommend that, without such ana analysis, the Board not approve the proposed level of undergrounding expenses, especially those intended to provide reliability.
- I recommend that the Company analyze its system to identify where FLISR can provide cost-effective reliability improvement and present its methodology and findings as part of an integrated grid plan.
- I recommend that the Company conduct detailed studies to identify specific circuits where Conservation Voltage Reduction has the potential for cost-effective energy savings, especially in the regions where it could potentially benefit historically disadvantaged communities, and present the findings within an integrated grid plan.
- I recommend the Company develop a roadmap for DER monitoring and control, taking into account public stakeholder feedback, and present it within an integrated grid plan.
- I recommend that the Company provide more specific cost and benefit data and should assess hybrid communication architectures in order to determine the most reasonable and cost-effective path forward for communications.
- I recommend the Company incorporate communications needs within an integrated grid plan.

Q. Does this conclude your direct testimony?

A. Yes.

AFFIDAVIT OF CODY DAVIS

STATE OF __Illinois______________)
) ss.
COUNTY OF__Champaign_________)

I, Cody Davis, being duly sworn on oath, state that I am the same Cody Davis identified in the testimony being filed with this affidavit, that I have caused the testimony to be prepared and am familiar with its contents, and that the testimony is true and correct to the best of my knowledge and belief as of the date of this affidavit.

/s/Cody Davis______________________________
Cody Davis

State of _Illinois____________

County of _Champaign______

Subscribed and Sworn before me this __16 day of April, 2024.

/s/__Alexandra Jade Johnson__________________
Notary Public