STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

Illinois Commerce Commission On Its Own Motion	)	
vs.	)	
Commonwealth Edison Company	)	
	)	ICC Docket No. 22-0486
Order Requiring Commonwealth Edison Company to File an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act	)	ICC Docket No. 23-0055 (cons.)
Commonwealth Edison Company	)	
Petition for Approval of a Multi-Year Rate Plan Pursuant to 220 ILCS 5/16-108.18 of the Public Utilities Act	)	

DIRECT TESTIMONY OF

PAUL J. ALVAREZ AND DENNIS STEPHENS

ON BEHALF OF
THE PEOPLE OF THE STATE OF ILLINOIS

AG Exhibit 1.0

PUBLIC VERSION

Information designated by Commonwealth Edison Company as confidential pursuant to the Protective Order is indicated with [BEGIN CONFIDENTIAL] _____ [END CONFIDENTIAL]

May 22, 2023

Commonwealth Edison Company
ICC Docket Nos. 22-0486 & 23-0055 (cons.)
Direct Testimony of Paul J. Alvarez and Dennis Stephens

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I. INTRODUCTIONS, PURPOSE, AND PREVIEW

Q. Mr. Alvarez, please state your name and business address.

A. My name is Paul J. Alvarez. My business address is Wired Group, P.O. Box 620756, Littleton, Colorado 80162.

Q. What is your occupation?

A. I lead the Wired Group, a small consultancy specializing in distribution utility planning, investment, regulation, and performance.

Q. Please describe your educational and professional background.

A. I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree from the Kellogg School of Management at Northwestern University in 1991. After several roles of increasing responsibility in Chicago-area businesses, my first role in the monopoly electric utility industry, beginning in 2001, was as a product development manager with Xcel Energy. I oversaw the development of new demand-side management ("DSM") programs, as well as programs and rates in support of voluntary renewable energy purchases and renewable portfolio standard compliance. My work developing DSM programs honed my understanding of various cost-effectiveness tests typically employed in the utility industry.

In 2010[1] and 2011[2] I led teams that completed the first two independent evaluations of smart grid investment program benefits as the utility practice lead for a boutique sustainability consulting firm. I started the Wired Group in 2012 to focus exclusively on distribution utility regulation, planning, investment, and performance measurement. I wrote *"Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment"* in 2014, and updated it with a second edition in 2018. In 2016, my Wired Group colleagues and I developed the *Utility Evaluator*™, an Internet-based software program which uses publicly available operating and financial data to facilitate utility performance benchmarking. In addition to leading the Wired Group, I teach a graduate course at the University of Colorado's Global Energy Management Program, and occasionally teach regulators and staff at Michigan State University's Institute of Public Utilities. I also publish and present at conferences on distribution utility regulation, planning, investment, and performance measurement.

Q. Have you testified before the Illinois Commerce Commission (the "Commission") previously?

A. Yes. I submitted Direct Testimony with Dennis Stephens in the consolidated docket concerning Ameren Illinois Company's multi-year integrated grid plan and

[1] Alvarez P. et al. *SmartGridCity® Demonstration Project Evaluation*, Colorado PUC 11A-1001E, Exh. MGL-1 to the Direct Testimony of Michael G. Lamb, Xcel Energy (Dec. 14, 2011).

[2] Alvarez P. et al., *Staff Audit and Assessment of Duke Energy Ohio Smart Grid* prepared by MetaVu, Inc. for the Staff of the Public Utilities Commission of Ohio (June 30, 2011), available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A11F30B73603I44077.

multi-year rate plan.[3] In addition, my participation in the workshops organized by the Staff of the Commission ("Staff") in advance of Commonwealth Edison Company's Multi-Year Integrated Grid Plan ("Grid Plan") filing was significant. I have also submitted testimony or commentary on behalf of consumer, business, and environmental advocates regarding grid policy, planning, investment, and performance before utility regulators in 17 states in the past seven years, including California, Georgia, Indiana, Kansas, Kentucky, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Washington, and Virginia. A complete list of my appearances in state utility regulatory proceedings is provided in my CV, attached as AG Exhibit 1.01.

Q. Mr. Stephens, please state your name and business address.

A. My name is Dennis Stephens. My business address is 1153 Bergen Parkway, Suite 130, Evergreen, CO 80439.

Q. What is your occupation?

A. I am an independent consultant specializing in utility distribution planning, investment, operations, asset management, reliability, and safety. I frequently work

[3] *Illinois Commerce Commission, On Its Own Motion, v. Ameren Illinois Company d/b/a Ameren Illinois, Order Requiring Ameren Illinois Company to file Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Compliance with the Public Utilities Act and Ameren Illinois Company d/b/a Ameren Illinois, Petition for Approval of a Multi-Year Rate Plan pursuant to 220 ILCS 5/16-108.18*, ICC Docket No. 22-0487 & 23-0087 (cons.), AG Ex. 1.00–1.05, Direct Testimony of Paul J. Alvarez and Dennis Stephens on behalf of the People of the State of Illinois, May 11, 2023.

for the Wired Group in support of the firm's clients.

Q. Please describe your educational and professional background.

A. After graduating from the University of Missouri with a bachelor's degree in Electrical Engineering, I began work for Xcel Energy (then Public Service Company of Colorado) in 1976 as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution planning, operations, and asset management, as well as in the innovative use of technology to assist with these functions. Positions I've held over the years have included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments, for all of Xcel Energy.

In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™ demonstration project in Boulder, Colorado, the first of its kind at the time, covering 46,000 customers. I developed the technical foundations for the project, including the development of all concepts presented to the Xcel Energy Executive Committee for project approval, and including the negotiations with technology vendors on their contributions to the project. As Director of Utility Innovations for Xcel Energy, I also worked with many software providers, including ABB, IBM, and Siemens, helping them develop their distribution automation ideas into practical software applications of value to grid owner/operators. I retired from Xcel Energy in 2011, and now work for the Wired Group on a part-time basis.

It may interest the Commission to know that I was directly responsible for distribution grid reliability in several of these roles, and indirectly responsible for grid reliability in all other roles. This is highly relevant in proceedings, such as this one, in which grid reliability is employed by a utility as justification for massive increases in grid investment. The Commission may also be interested to know that for a good portion of my career at Public Service Company of Colorado, capital spending was constrained due to regulatory scrutiny. My experience maintaining strong distribution grid reliability in the face of growing distributed energy resources and strict capital constraints is highly relevant to this testimony.

Q. Have you testified before the Commission previously?

A. Yes. I submitted direct testimony with Mr. Alvarez in the aforementioned docket regarding Ameren Illinois Company's multi-year integrated grid plan and multi-year rate plan.[4] Also, like Mr. Alvarez, I was an active participant in the workshops held in advance of Commonwealth Edison Company's Grid Plan filing. I have also submitted testimony or commentary on behalf of consumer, business, and environmental advocates regarding grid planning, investment, asset management, and reliability performance before utility regulators in 11 states in the past seven years, including California, Georgia, Indiana, Massachusetts, Maryland, Michigan, New Hampshire, North Carolina, Oklahoma, Virginia, and Washington. A

[4] *See id*.

complete list of my appearances in state utility regulatory proceedings is provided in my CV, attached as AG Exhibit 1.02.

Q. On whose behalf are you both appearing?

A. We are testifying on behalf of the People of the State of Illinois, represented by the Office of the Attorney General (the "AG" or the "People").

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide recommendations regarding the Grid Plan and the Multi-Year Rate Plan (the "Rate Plan," and, together with the Grid Plan, the "Plans") that Commonwealth Edison Company ("ComEd" or the "Company") filed in this proceeding on January 17, 2023. Our testimony includes recommendations to reduce certain categories of capital spending the Company proposes in its Grid Plan, thereby reducing the Company's requested rate increases. (The translation of recommended capital spending reductions into revenue requirement reductions in the Rate Plan is addressed in AG Exhibit 2.0, the testimony of AG witness David Effron, and the exhibits thereto.) Our testimony also includes important recommendations we urge the Commission to adopt regarding the administration of the multi-year rate plan form of ratemaking authorized under Section 16-108.18(d) of the Public Utilities Act (the "PUA"), which was adopted as part of the Climate and Equitable Jobs Act, Public Act 102-0662 ("CEJA"). In our experience, multi-year ratemaking which in Illinois, includes annual revenue requirement reconciliation that allows recovery or refund

of costs actually incurred with carrying charges at the weighted average cost of capital, creates unintended consequences that fundamentally alter the balance of interests between shareholders and customers, resulting in a loss of capital spending governance if not carefully regulated.

Q. Please preview your testimony.

A. Our testimony is divided into two main parts. In Part II, we explain our concerns regarding multi-year rate plan administration and provide recommendations for what the Commission can and must do to mitigate those concerns. Observations that our ratemaking discussion will cover include:

- Traditional ratemaking/cost disallowance risk encourages capital spending governance and mitigates information asymmetry;
- Multi-year ratemaking practically eliminates cost disallowance risk and capital spending governance, and increases regulator and stakeholder responsibilities;
- Traditional grid planning practices, with stakeholder participation, can restore capital spending governance and reduce information asymmetry.

In Part III, we explain our concerns with the Company's Grid Plan. We provide multiple examples that illustrate why extensive Commission action to restore capital spending governance and reduce information asymmetry is required under multi-year ratemaking. We begin with an overview of the Company's Grid Plan, highlighting the massive growth in plant additions of $1.86 billion, or 27.8%,

relative to recent history (2019-2022), as well as the massive rate increase—more than 60% in just five years—associated with Plan approval. We then take a deep dive into the primary drivers of rate base growth in the Company's Grid Plan, identifying multiple examples of practices or spending that are cost-ineffective, or inappropriate, or that can be deferred to a future Rate Plan period at low risk. These include the following drivers of plant addition increases relative to the most recent four-year period:

- System Performance growth of 55.9%, or $1.147 billion, relative to 2019-2022;
- Capacity Expansion growth of 63.7%, or $535 million, relative to 2019-2022; and
- IT Project growth 76.5%, or 329 million, relative to 2019-2022.

Q. Please summarize your recommendations.

A. Regarding multi-year ratemaking administration, our recommendations are intended to restore capital spending governance and mitigate information asymmetry, and include:

- That the Commission immediately commence a proceeding to develop a process by which stakeholders and utilities jointly develop grid investment plans, with the resulting process to be deployed initially in advance of the next Rate Plan proceeding; and

- That the Commission order that discretionary grid investment proposals—meaning those not strictly necessary for safe and reliable service delivery within the upcoming Rate Plan period—be subjected to risk-informed benefit-cost analysis as a test of cost-effectiveness as part of any future Rate Plan in Illinois.

Regarding the Company's Grid Plan, our recommendations recognize that a procedural schedule appropriate for traditional ratemaking practices is woefully inadequate to rigorously evaluate a multi-billion-dollar grid investment plan consisting of dozens of programs and thousands of projects. However, based on examples of practices or spending that are unnecessary, or that should be deferred to a future Rate Plan period, as well as the need to avoid rate shock, we recommend that historical average spending levels for System Performance, Capacity Expansion, and IT projects 2019-2022 be maintained for the Company's Grid Plan, adjusted for expected inflation, as summarized in Table 1 below. Our recommendations for the Company's Grid Plan therefore include:

- Cap System Performance capital spending for 2024-2027 at the 2019-2022 annual average ($513 million), adjusted for expected inflation 2023-2027;
- Cap Capacity Expansion capital spending for 2024-2027 at the 2019-2022 annual average ($210 million), adjusted for expected inflation 2023-2027;
- Cap IT Project capital spending for 2024-2027 at the 2019-2022 annual average ($107.5 million), adjusted for expected inflation 2023-2027; and
- Order that the Company's proposed fiber optic communications network

expansion be halted until a technical, operational, and economic review and comparison of available communications network options is completed by an independent expert, overseen by Staff, shared with stakeholders, and reviewed by the Commission; and

- Order that all project or program contingency budgets be excluded from revenue requirements determined through multi-year ratemaking in Illinois.

Table 1: Recommended Reductions in the Company's Proposed Grid Plan Plant Additions

System Peform/Capacity Expansion/IT Projects	'19-'22	Grid Plan				Grid Plan
($ in millions)	Act. Ave.	2024	2025	2026	2027	Total
AG Recommendation	830.500	882.043	900.830	920.739	941.547	3,645.159
Company Requested		1,190.000	1,228.000	1,328.000	1,587.000	5,333.000
AG's Recommended Reductions		(307.957)	(327.170)	(407.261)	(645.453)	(1,687.841)

Q. Do you sponsor any testimony exhibits?

A. Yes. In addition to our qualifications, which are in AG Exhibits 1.1 and 1.2, respectively, we have attached AG Exhibit 1.3, which contain selected responses to data requests issued by the People; AG Exhibits 1.4 and 1.5, which contain the confidential assessments of the proposed fiber optic communications project completed by Company; and AG Exhibit 1.6, which contains customer survey results.

II. MULTI-YEAR RATEMAKING UNDERMINES CAPITAL SPENDING GOVERNANCE, AND ONLY THE COMMISSION CAN RESTORE IT

Q. Please provide a preview of this section of testimony.

A. This section of our testimony provides support for our recommendations regarding the administration of multi-year ratemaking in Illinois. We believe these recommendations are essential to addressing fundamental changes to the balance of interests between shareholders and customers prompted by multi-year ratemaking, and to restoring capital spending governance lost as a result. Support for our recommendations is organized as follows:

A. Traditional ratemaking, regulatory lag, and cost disallowance risk encourage capital spending governance and mitigate information asymmetry;

B. Multi-year ratemaking practically eliminates regulatory lag and cost disallowance risk, as well as capital spending governance, and increases regulator and stakeholder responsibilities;

C. Traditional grid planning practices, with stakeholder participation, can restore capital spending governance and reduce information asymmetry.

A. Traditional ratemaking, regulatory lag, and cost disallowance risk encourage capital spending governance and mitigate information asymmetry.

Q. Please explain how natural monopolies for electricity came to be, and how they can provide distribution services in an economically efficient manner.

A. After the Chicago World's Fair in 1893, 130 years ago this summer, it became clear that Alternating Current (AC) would become the dominant form by which electricity would be distributed. Rather than a Direct Current (DC) generator in every home or business, it was clear that economies of scale could be achieved

through centralized generation employing large generating plants and an extensive distribution network—the grid as we know it today. It also became clear that massive amounts of capital would be required to build out this infrastructure, and states recognized that for-profit companies were adept at raising capital and managing risk. (For-profit utilities maintain strong capital-raising capabilities to this day.)

It also became clear that in every market, the first company to build out its network would dominate all other providers until only one company remained. It makes no economic sense to build two sets of wires down every street, as the costs customers would have to cover would double. Assuming that regulation is in place to manage a monopoly's pricing power, the cost savings of a single network exceeds the value of competition, a situation known as a "natural monopoly."

Q. How was the need to regulate natural monopolies' pricing power satisfied?

A. Eventually, a "regulatory compact" was struck between state governments and for-profit companies operating natural monopolies. The state governments allowed for-profit monopolies to operate as the exclusive provider of their service in a defined geography under two conditions: (1) the utilities were required to make the investments in their grids required to deliver service in a safe and reliable manner; and (2) the utilities agreed to serve all customers requesting service in the defined geography at prices determined by the state's utility regulator. In exchange, the state regulators agreed to set those prices at levels that provided the utilities with a reasonable opportunity to earn a rate of return on their investment in their grids

(profits, expressed as a percent of the amount of capital invested). The opportunity to earn profits is a critical feature, as profits encourage investors to buy utility shares (shareholders) and debt (bondholders), the proceeds of which the utilities use to invest in grid infrastructure.

Q. The regulatory compact seems like a reasonable arrangement. Are there drawbacks?

A. All regulation is imperfect. While this ratemaking arrangement, called cost-of-service ratemaking, does an excellent job of regulating profit percentages, it does a poor job of regulating profit amounts (in dollars). It became apparent that the more capital a for-profit utility invests, the more profits it earns, thus leading utilities to over-invest in their grids.[5] This incentive, called capital bias, needed regulating too. Utility regulators appropriately established for themselves the right to *disallow costs* from recovery from customers. A regulator can exclude from rates the recovery of any cost the regulator determines a utility incurred in an imprudent manner, or any cost that did not deliver a capability or capacity used and useful in the provision of safe and reliable service.

Q. What impact has the risk that regulators might disallow a utility's costs from recovery from customers had on utility capital spending?

[5] Harvey Averch and Leland L. Johnson, *The Behavior of the Firm Under Regulatory Constraint*, The American Economic Review, Vol. 52, No. 5 at 1059 (1962).

A. Cost disallowances can constitute significant financial penalties to utilities, reducing utility profits (in dollars) and profitability (in percent). As a result, utilities have historically invested conservatively in their grids, making only those investments they could reasonably justify to regulators as prudently incurred, and used and useful in the delivery of service in a safe and reliable manner. To reduce the risk of cost disallowances, utility management implemented significant internal controls to scrutinize and govern capital spending proposed by internal business functions, including grid operations. The regulatory compact, consisting of both incentives to invest (profit opportunities) and consequences for over-investment (cost disallowances), served the US economy and citizens well for over a century. It resulted in the low-cost, reliable electric grid we all enjoy today.

Q. What impact has the risk that regulators might disallow a utility's costs from recovery from customers had on regulatory staff and stakeholders?

A. Cost disallowance risk has historically meant that regulatory staff and stakeholders could limit the time and effort spent reviewing grid capital spending in rate cases. This is largely because staff and stakeholders could rely on the utilities to police themselves in their attempts to avoid cost disallowances. Cost disallowance risk has historically meant that neither regulatory staff nor stakeholders needed to intimately understand grid operations, engineering, technologies, planning, or asset management. Nor did they need to concern themselves with how utilities prioritized the selection of some investments over others based on operational risks (known in most industries as capital spending governance).

Q. Is the impact that cost disallowance risk has had on regulatory staff and stakeholders important?

A. Cost disallowance risk is critically important to sound regulation of monopoly distribution utilities. Not only does cost disallowance risk encourage capital spending governance, it mitigates *information asymmetry*. Expertise to understand grid operations, engineering, technologies, planning, and asset management is typically acquired primarily through employment in utility grid functions. *Information asymmetry* refers to the fact that it is difficult for regulatory staff and stakeholders to know as much about a utility's grid, operations, and situation as the utility itself knows.

It is difficult to overstate the value of cost disallowance risk to information asymmetry mitigation. Regulatory staff and stakeholders cannot reasonably be expected to rigorously evaluate or effectively challenge specific utility capital spending proposals because they simply do not have the information and expertise needed to do so. Further, unlike generating plants that can cost hundreds of millions of dollars each, distribution grid planning cycles are characterized by literally thousands of relatively smaller grid investment decisions, making staff and stakeholder resource levels a problem too. With enough resources it might be possible, after years of experience participating in a particular utility's grid planning and investment selection processes, for staff and stakeholders to gain the information and experience needed to rigorously evaluate and effectively challenge that utility's myriad grid investment proposals. But short of that, cost disallowance

risk—and the internal controls utilities themselves have historically applied internally to reduce that risk—has been the primary regulatory mechanism available to govern utility capital spending.

Q. What about regulatory lag? Doesn't regulatory lag serve to govern utility capital spending?

A. Yes. Regulatory lag describes the difference in time between when a utility makes a grid investment, and the time when the utility begins recovering the costs of those investments through rate increases. Regulatory lag also serves to govern utility capital spending to some extent, as it reduces a utility's ability to earn the target rate of return (profit percentages) when spending exceeds the levels the state regulator assumed when approving revenue requirements in the most recent rate case. Indeed, a reduction in regulatory lag is cited by proponents as the primary driver of alternative ratemaking constructs such as multi-year ratemaking, as it reduces the time lag between capital spending and recovery of those costs from customers. Unfortunately, as will be described later in this section, multi-year ratemaking practically eliminates the efficiency incentives inherent in regulatory lag as well as cost disallowance risk, with a devastating impact to utility capital spending governance.

Q. Is the capital spending governance prompted by regulatory lag and cost disallowance risk critical to electric affordability?

A. Capital spending governance is absolutely essential to electric affordability, as capital spending results directly in rate increases that typically last a long time (over the depreciation period of the equipment, which can be 40 years or longer). Approximately 1 in 6 residential customers struggles to pay their ComEd bill each month.[6] What's more, affordability is not a concern limited to residential and/or low-income customers. The productivity of the entire Illinois economy is linked in part to affordable electric rates. Higher electric rates reduce the disposable income of all consumers that could otherwise be put to productive use in the Illinois economy (for example in healthcare, entertainment, education, etc.). Businesses and governments pay higher electric rates too, impacting employment and taxes. Various studies indicate that employment falls between 0.0045 percent and 0.363 percent for every 1% increase in electric rates.[7] Further, the distribution grid is massive and complex. The grid's massive size and complexity mean that opportunities to deploy capital in pursuit of improving reliability, or in pursuit of "grid readiness" for distributed energy resources (DER) or electric vehicles (EV) or more general electrification, are almost limitless. To summarize, multi-year ratemaking requires new practices in utility regulation to replace the capital

[6] Based on the monthly credit, collections, and arrearages reports that ComEd files with the Commission, the number of residential customers assessed late payment fees or charges, and therefore potentially at risk of disconnection, has averaged 16.7% over the trailing 12 months. The monthly reports are available at https://www.icc.illinois.gov/industry-reports/credit-collections-and-arrearages-reports.

[7] Gilbert E. Metcalf, *The Relationship Between Electricity Prices and Jobs in Missouri*, February 27, 2013, at page 3. *See also id.* at Exhibit 1 (Selected Studies of the Relationship Between Electricity Prices and Employment in the United States). Article available at available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936039359.

spending governance that cost disallowance risk and regulatory lag formerly encouraged, and to reduce the information asymmetry that they formerly mitigated.

Q. How can the Commission ensure Illinois secures the grid it needs for a clean energy future in an affordable manner?

A. Given utility capital bias, and the loss of cost disallowance risk and capital spending governance associated with multi-year ratemaking, regulators and stakeholders are now responsible for ensuring that Illinois gets the distribution grid it needs for a clean energy future at the lowest possible cost. We believe the grid can be developed for the future at an affordable cost by:

- Identifying the right capabilities and capacities;
- Securing these capabilities and capacities through the most appropriate and cost-effective technologies;
- Deploying these capabilities and capacities at the right time (in advance of need, but not too far in advance); and
- Deploying these capabilities and capacities to a geographic extent that is no greater than necessary in any one grid planning cycle.

However, extensive resource commitments by regulators and stakeholders, on both an initial and ongoing basis, are required to restore capital spending governance and mitigate information asymmetry.

Q. You mention that the opportunities to deploy capital to improve reliability are almost limitless. Please explain this.

A. Businesses operating in competitive markets are under constant pressure to "do more with less." That is the beauty of competition: if a business fails to meet market needs better or more cheaply than competitors, the business will fail. The constant pressure to do more with less forces businesses operating in competitive markets to limit the amount of capital they invest to the smallest advisable amount given the business and operating risks they face. Whether they do so consciously or subconsciously, business managers quantify the risks they face, and make capital spending decisions, based on the following equation:

Operational Value at Risk ($)	=	Likelihood of an Adverse Event (%)	✖	Consequence of the Adverse Event ($)

A business operating in a competitive market will not invest more to reduce a risk than the likely cost of an adverse event given its likelihood. This concept should apply to electric distribution businesses too. Consider the adverse event of a service interruption. Assume for sake of argument that the likelihood of a one-hour service interruption on a particular circuit due to a particular cause is 5% in a year, and that the consequence of a one-hour service interruption on that circuit to customers is $100,000. In this example, the value to customers of entirely eliminating the likelihood of the service interruption from this particular cause is

$5,000 per year ($100,000 X 5%). Put another way, customers on this circuit should be willing to pay $5,000 annually to entirely eliminate a 5% service interruption likelihood from the particular cause identified. Unfortunately, utilities with no cost disallowance risk are unlikely to evaluate investments intended to improve reliability in this manner due to capital bias, compromising the option to prioritize or develop investments based on the relationship between cost and benefit.

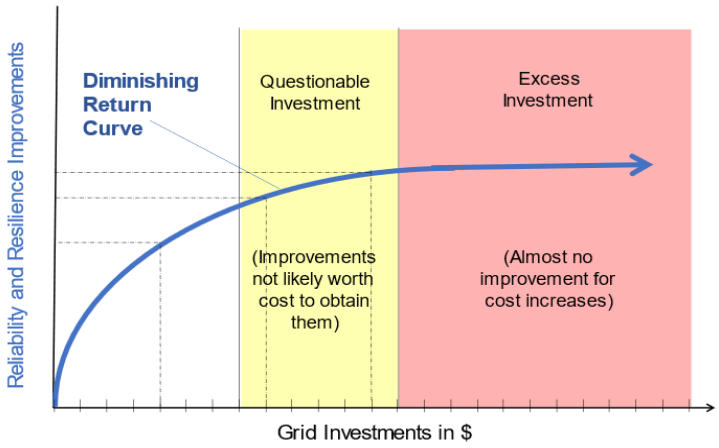
Q. If not for cost disallowance risk, how do utilities with capital bias regulate capital spending?

A. The short answer is that a for-profit utility without cost disallowance risk will not regulate capital spending, and will continue to over-invest in its grid until a regulator tells it to stop. Due to information asymmetry, it is almost impossible for a regulator to know how much grid investment is too much grid investment, or which particular grid investments (such as in particular circuits, poles, substations, technologies, software, etc.) are required or appropriate, or when they might be required or appropriate.

To illustrate the concept further, consider the law of diminishing returns as it applies to reliability improvements. The law of diminishing returns dictates that the level of incremental improvement in an activity (in this case, reliability improvements) falls ratably with each additional increment of resource input (in this case, capital spending). This means that at some point, the value customers receive from incremental improvements in reliability will be less than the cost

required to secure the improvements (the point of diminishing return). While a competitive business would never invest past the point of diminishing return, a utility with capital bias and no cost disallowance risk absolutely will. Figure 1 applies the law of diminishing returns curve to reliability-related grid investment.[8]

Figure 1: Law of Diminishing Returns Curve Applied to Reliability Investments



Q. Is there evidence that utilities are past the point of diminishing returns?

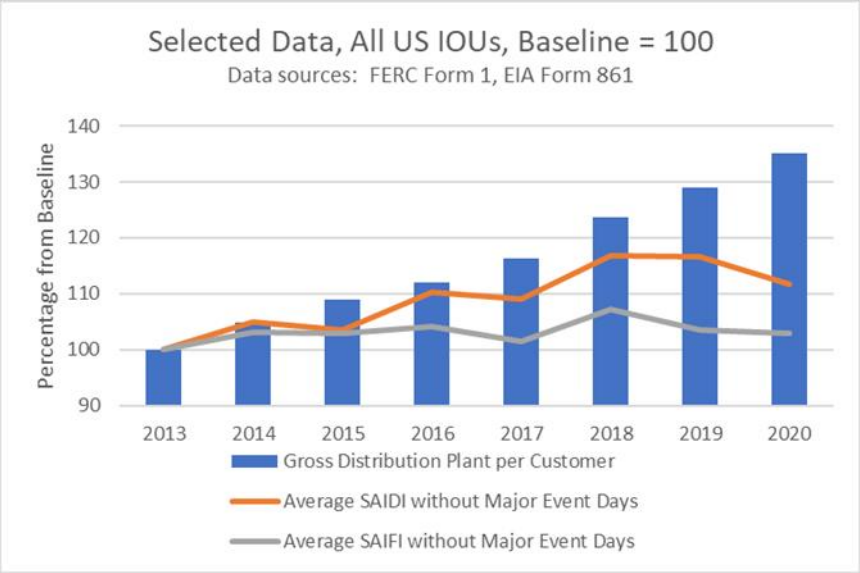
A. Yes. Despite exceptional growth in rate base per customer in recent years, service interruption frequency and duration have increased (gotten worse) among investor-owned utilities in the US (see Figure 2 below).[9] In addition, a study by Lawrence

[8] Paul Alvarez, Kenneth Costello, Sean Ericson, and Dennis Stephens, *Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers?*, The Electricity Journal, Vol. 35: 107200 (2022).

[9] Distribution rate base data was obtained from FERC Form 1. Customer counts, service interruption frequency, and service interruption duration were obtained from US Energy Information Administration Form 861.

Berkeley National Laboratory found no correlation between capital investment and reliability.[10]

Figure 2: Rate Base Growth vs. Reliability Performance, US Investor-Owned Utilities, 2013-2020



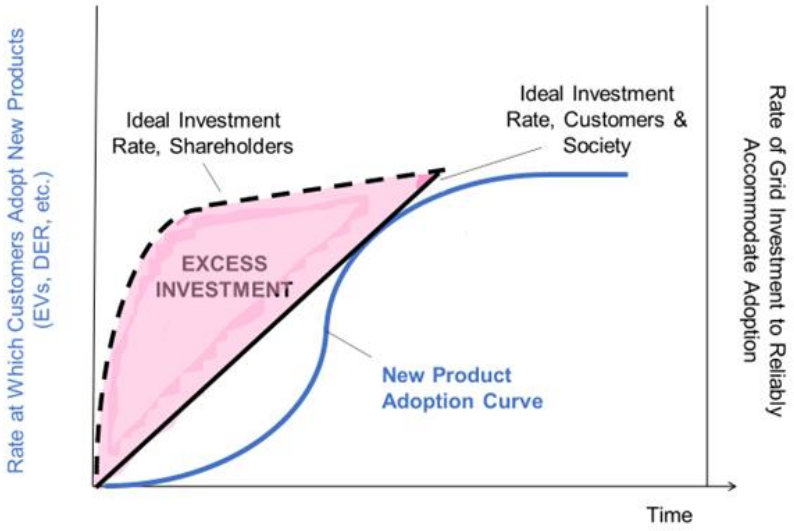
Q. Are you similarly concerned that a utility with capital bias and no cost disallowance risk will over-invest in grid readiness for DER and EV?

A. Yes, we are very concerned about this. Though the customer and societal benefits of DER and EV adoption are more difficult to quantify than the benefits of reliability improvements, it is clear that capital bias combined with a lack of cost disallowance risk will encourage a utility to invest more than necessary, earlier than

[10] Peter H. Larsen, Kristina H. LaCommare, Joseph H. Eto, and James L. Sweeney, *Assessing Changes in the Reliability of the U.S. Electric Power System*, Lawrence Berkeley National Laboratory Report LBNL-188741, August 2015 at 37.

necessary, in "grid readiness." Capital bias certainly encourages utilities to exaggerate the challenges presented by DER and EV adoption, stoking fear in regulators and environmental advocates that the grid will not be ready for the future without increased investments and enhanced cost recovery. Figure 3 illustrates how a utility with capital bias is likely to prepare for customer adoption of new technologies such as DER and EV. The figure illustrates that while some amount of advance investment may be required to meet customer adoption when it accelerates, a utility with capital bias has an incentive to invest more, and earlier, than the amount required to meet the need.

Figure 3: Ideal investment rate in "grid readiness," shareholder vs. customer perspective[11]



To summarize, a for-profit utility not constrained by cost disallowance risk and capital spending governance has no reason to constrain spending, and information

[11] Alvarez et al., *Alternative Ratemaking in the US*, supra note 8.

asymmetry ensures that it is very difficult for regulators, staff, or stakeholders to discern when grid capital spending is excessive, or earlier than necessary.

B. Multi-year ratemaking practically eliminates regulatory lag and cost disallowance risk, as well as capital spending governance, and increases regulator and stakeholder responsibilities.

Q. How does the multi-year ratemaking structure in this case affect cost disallowance risk?

A. Regulators in all states employing any form of alternative ratemaking, including multi-year ratemaking, require utilities to submit capital spending plans in advance. While this sounds like a good idea, in the unique and arcane world of monopoly utility regulation, the presentation of such plans in advance makes it practically impossible for regulators to exercise their right to disallow costs from recovery from customers.

Once a regulator approves a grid investment plan, the regulator's practical ability to exercise its right to disallow the costs of investments proposed in the plan falls to zero, for two reasons. First, a utility will argue that its plan was presented in advance, and that any opposition to the investments proposed in its plan should have been litigated before the capital was spent. This argument will be difficult if not impossible for a regulator to refute. Second, due to the extremely large dollar amounts involved, cost disallowances have a material effect on utility earnings, and thus a utility's cost of capital, which customers must cover. When it comes to excess spending that may have been approved as part of a grid investment plan, a regulator's hands are thus effectively tied. If the regulator does not permit recovery

of excess spending, it will face arguments that the disallowance will harm customers by increasing a utility's cost of capital. As a result, a utility regulator often does not exercise its right to disallow costs once approved as part of a grid investment plan. This effective pre-approval marks a fundamental shift in the balance regulators strive to achieve between shareholder interests and customer interests, and has significant implications for the ratemaking process.

Q. How does the presentation of advance investment plans change the ratemaking process?

A. Under traditional ratemaking, all the "action" in a rate case is in response to capital the utility has already spent. This timing is fundamental to cost disallowance risk, and prompts the significant internal controls utilities put in place to scrutinize and govern capital spending proposed by internal business functions.

Under multi-year ratemaking, staff and stakeholder focus shifts entirely to a utility's grid investment plan and the capital spending proposed in myriad projects and programs. A utility's capital bias enables management, beholden to advancing shareholder interests, to propose as much capital spending as management thinks it can possibly justify in these grid investment plans.[12] *Unlike traditional ratemaking, which involves a potential penalty for imprudent capital spending in the form of cost disallowances, there is no potential penalty for proposing more capital*

[12] Investor presentations by for-profit distribution utilities now routinely tout 8% compound annual growth in regulated rate base, and ComEd is no exception. *See* Exelon Spring 2023 Investor Presentation, slide 25, available at https://investors.exeloncorp.com/static-files/bb15cc63-6d8d-4f6e-b305-0e1ff4e33286.

spending than necessary. Instead, the regulator's responsibility is to impose some capital spending discipline when reviewing a proposed grid plan by recognizing and rejecting excessive capital spending, taking into account historical spending and future needs. The worst that can happen to a utility that proposes unnecessary, or unnecessarily early, capital spending in a grid investment plan is that regulators might order a reduction in the size of the plan's capital spending. Such a reduction ultimately does not affect the profits or profitability of the utility at all, the way a cost disallowance does. Relative to the high financial penalty of a cost disallowance, reductions in the amount of capital a utility proposes to spend in a grid investment plan reduces the utility's budget but represent no financial penalty.

Due to a lack of consequences for "over-proposing," a utility management team has nothing to lose, and everything to gain (rate base and profit growth), by proposing excessive capital spending in grid investment plans presented in advance, making the regulator responsible for scaling back excessive spending proposals. Economists call this situation "moral hazard." When an activity beneficial to a party (in this case, a utility proposing greater capital spending than necessary) involves no consequences (in this case, the absence of any financial penalty for "over-proposing"), moral hazard predicts the party will increase that activity. From multiple examples we provide later in this testimony, we believe the Commission will conclude that the Company is indeed proposing excess capital spending in its Plan, and has relaxed capital spending governance, in response to the practical elimination of cost disallowance risk and the moral hazard introduced by advance presentation of multi-year integrated grid plans.

Q. Does the administrative review of the utility's proposal allow staff and stakeholders to challenge specific utility grid investment proposals when they are presented in the grid plan?

A. In theory, yes. But the amount of information presented for four future test years and four years of investment is considerably more than is usually considered in traditional ratemaking involving a single test year. In addition, staff or stakeholders do not commonly have the resources to consider the dozens of programs and thousands of projects proposed in a grid investment plan, particularly when the utilities do not even know what many of the projects in the outlying years of a multi-year grid planning period will be,[13] making evaluation of such spending proposals difficult, to say the least. Significantly, a procedural schedule that may have been appropriate in a rate case in which a utility is exposed to regulatory lag and cost disallowance risk is completely inappropriate for a utility without these mechanisms to govern utility capital spending. In this proceeding, in addition to the four future test years, the Company has proposed $8.5 billion in grid capital spending 2024-2027,[14] including 546 programs and projects (not including unknown quantities of projects within "blanket" program budgets).[15] The Company included untold millions of dollars in its Grid Plan for project

[13] In this proceeding, the Company makes extensive use of "blanket" budgets. These are intended to serve as dollar placeholders for programs or projects of a particular type, or in pursuit of a particular objective, in the outer years of Grid Plan period, that a utility states will be in customers' interests, but that have yet to be specifically identified.

[14] ComEd Ex. 5.01 2nd CORR (Part 1), Table 5.4-1, page 172.

[15] *See* ComEd Ex. 9.02 – Projected Plan Additions – Redacted.xlsx.

548 contingencies that might or might not be spent, and these are included in the
549 Company's rate increase request.[16] There is simply no way for Staff or
550 stakeholders, particularly given their lack of information and experience as
551 described earlier, to secure the data needed to understand and evaluate capital
552 spending proposals of such size and number in the discovery period typical for a
553 traditional rate case proceeding.[17]
554
555 **Q. Has any utility regulator adopted practices to mitigate your concerns?**
556 Yes. The California Public Utilities Commission ("CPUC")—the state utility
557 regulator with more multi-year ratemaking experience than any other[18]—has taken
558 several steps we commend, although these are minor changes that, in our
559 experience, are insufficient to the challenges presented by multi-year ratemaking.
560 The CPUC's efforts include:
561 • Procedural schedules ordered by the CPUC generally provide for a
562 minimum of six months of initial discovery in rate cases.

[16] ComEd refused to provide contingency budgets included in its capital projects and programs, which are then employed to determine multi-year revenue requirements. *See* ComEd response to AG 10.23, as well as further discussion of this topic later in this testimony.

[17] In our own experience, we were able to complete two "rounds" of discovery regarding the Grid Plan—the first being AG Sets 6, 7, and 10 and the second being AG Sets 17 and 18—in the time between January 17, 2023 (the date of the Company's Grid Plan filing) and May 22, 2023 (the date this testimony is due). In many cases, the Company responded late, to the point that the ALJ changed the due date for Staff and intervenor direct testimony, or provided incomplete responses. At the same time, the Company asked the ALJ to limit discovery because it claimed the burden of timely responding to the parties' data requests was too heavy, a request the ALJ rightly rejected. To summarize, traditional rate case procedural schedules were not designed for, and are insufficient to address, the challenges of multi-year ratemaking.

[18] The CPUC was the first to approve multi-year rate plans in the mid-1980s.

- The CPUC recently ordered utilities to complete risk-informed benefit-cost analyses for significantly-sized capital spending program and project proposals[19] (an action we adopt as a recommendation in this testimony).
- Upon CPUC review and approval, an intervenors' costs for participating in a (multi-year) rate case are reimbursed by the utility submitting the rate case (with such utility reimbursements eligible for recovery from customers).

Q. Are there any provisions of Illinois law that address your concerns?

A. We are encouraged that the CEJA legislation anticipates some of our concerns about multi-year ratemaking. As examples, we cite the following CEJA elements:

- The implementation of a Consumer Intervenor Compensation Fund;[20]
- The declaration of "inclusive, comprehensive, transparent, cost-effective distribution system planning and disclosures processes" as State policy;[21]
- The grid plan shall be designed to provide "analysis of the cost-effectiveness of proposed system investments;"[22]
- The grid plan shall be designed to "provide delivery services at rates that are affordable to all customers;"[23]

[19] Cal. Pub. Util. Comm'n Decision 22-12-027 & Appendix A, *Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots*, issued in Cal. Pub. Util. Comm'n Rulemaking 20-07-013, *Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities*, decided Dec. 15, 2022 and issued Dec. 21, 2022 (hereinafter, "CPUC 2022 Decision"), available at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=500014668.

[20] 220 ILCS 5/9-229(b).

[21] *Id.* at 5/16-105.17(a).

[22] *Id.* at 5/16-105.17(d)(7).

[23] *Id.* at 5/16-105.17(d)(11).

- The specification of a process to include stakeholders in grid plan development;[24] and
- That the Commission, when evaluating grid plans, shall consider whether the plan "maximizes consumer, environmental, economic, and community benefits."[25]

Notwithstanding the extensive statutory attention to stakeholder workshops as a means to develop the utility's grid plan, the workshops did not result in constraining the utility's budget proposals. This means it is up to the Commission to administer multi-year ratemaking in a way that advances state policy, but does so at the lowest possible cost.

Q. What new responsibilities do multi-year ratemaking and new customer technologies place on regulators and stakeholders?

A. There are a number of significant responsibilities that regulators now face due to the obligation to review and approve a multi-billion-dollar utility grid plan. These responsibilities include:

- To distinguish between (1) capabilities required for safe and reliable service, including capabilities required to accommodate distributed energy resources ("DER") and electric vehicles ("EV"), within the Grid Plan

[24] *Id.* at 5/16-105.17(e).
[25] *Id.* at 5/16-105.17(f)(5)(A)(6).

period; and (2) proposed capabilities that are discretionary as to timing or extent;

- Of the capabilities required for safe and reliable service within the Grid Plan period, to identify the most cost-effective way to secure those capabilities; and
- Of the portfolio of proposed investments that are discretionary, to identify those that either (1) are cost-ineffective; or (2) can be deferred to a future Grid Plan period at low risk.

While these new responsibilities are significant, it is possible for the Commission, Staff, and stakeholders to manage them. With enough time, experience, resources, and effort, parties can develop reasonable capital spending budgets that advance the goals of Illinois law in an affordable manner. Utilities periodically employ routine grid planning practices designed specifically to prepare the grid for capacities and capabilities that will be needed in the future. These routine grid planning practices have proven adept at accommodating customer adoption of new technologies in the past, be it refrigeration in the 1930s and 1940s, or air conditioning in the 1960s and 1970s, or new computer and electronic technologies of the 1990s through the present. We believe that regulator and stakeholder participation in these routine grid planning processes can help replace the capital spending governance lost through multi-year ratemaking and reduce information asymmetry. Our testimony turns to these routine grid planning practices, and their application in a future of DER and EV, next.

C. Traditional grid planning practices, with stakeholder participation, can restore capital spending governance and reduce information asymmetry.

Q. What grid planning processes have utilities typically utilized?

A. While subject to differences in frequency and extent, the typical grid planning process is fairly consistent from utility and utility, and has remained consistent over time. The typical process steps were documented by the NARUC-NASEO Task Force on Comprehensive Electric Planning in its Jade Cohort Roadmap,[26] which we summarize in Table 2 below.

Table 2: Summary of Typical Distribution Planning Process Steps as documented by the NARUC-NASEO Task Force on Comprehensive Electricity Planning

Step	Description
Goals/Objectives	Establish goals and priorities for the grid plan, define metrics, and establish targets for metrics (objectives)
DER Forecast	Forecast DER capacity increases by circuit
Load Forecast	Forecast load growth by circuit, including loads from EV
(DER) Hosting Capacity Analysis	Quantify existing and available DER capacity by circuit, thus identifying constraints given DER forecasts. Identify any needed DER management capabilities that may be missing.
Grid Needs Assessment	Quantify existing and available load capacity by circuit, thus identifying constraints given load forecasts. Identify any needed load management capabilities that may be missing.
Identify Potential Solutions	Identify potential solutions to constraints (capacity expansion, third-party services, software, hardware, operating changes, customer programs/rates, etc.)
Evaluate Potential Solutions	Evaluate the technical, operational, and economic pros and cons of available solutions to constraints.
Select Solutions	Of the portfolio of needs and potential solutions, select solutions for implementation in the upcoming period, thus creating a grid plan and capital budgets. (We strongly encourage the use of risk-informed benefit-cost analyses to maximize customer "bang for buck" here.)

[26] *Jade Cohort Roadmap*. NARUC-NASEO Task Force on Comprehensive Electricity Planning. February, 2021. Available at https://www.naruc.org/taskforce/resources-for-action/roadmaps/

Implement Solutions	Implement the solutions selected as part of the grid plan.
Assess Results	Measure results against the targets identified in the Goals/Objectives step

Q. Do you think the Jade Cohort process documented by the Task Force will be sufficient to prepare for DER and EVs, and electrification?

A. Yes. The traditional grid planning practice documented by the Task Force involves completing the forecasting and constraint identification steps shown on a circuit-by-circuit, substation-by-substation basis. The speed at which customers adopt DER and EV, and other forms of electrification, will vary by circuit, and at least two to three decades will elapse before adoption of these technologies reaches saturation. Such variation and preparation times are ideally suited to traditional grid planning practices. Further, adoption of technology has resulted in major expansions of electricity usage in the past, such as refrigeration in the 1930s and 1940s, and air-conditioning in the 1950s and 1960s. The adoption of these technologies followed a similar pattern: unevenly by circuit, over a few decades. Traditional grid planning and investment practices fared just fine through these periods of technology adoption.

Q. Is the company's distribution planning process consistent with the Jade Cohort process documented by the NARUC-NASEO Task Force?

A. It seems to have all the same components.[27] The Company's Grid Plan describes the bottom-up development of projects and programs to be executed in the next three-year period. "Category Managers" develop these plans, and associated capital and O&M spending forecasts by year, along with lists of "unfunded risks". ("Unfunded risks" describe the risks the Category Managers would like to address if they had more capital to work with.)[28] The "bottom-up" development of projects and programs appears to incorporate the steps identified by the Task Force in its Jade Cohort process. Our concerns, the subject of significant discussion later in this testimony, relate to *how* ComEd completes the steps, not the steps themselves. For now, suffice it to say that the ComEd distribution grid planning process steps appear largely consistent with the steps identified by the Task Force in its Jade Cohort process.

Q. Do you believe the Company's existing grid planning process to be sufficient for accommodating a future of DER and EV?

A. We believe the NARUC-NASEO Task Force's Jade Cohort process steps, and the Company's planning process steps to the extent they are consistent with the Jade Cohort process steps, will be adequate for accommodating a future of DER and EV. The loss of cost disallowance risk and information asymmetry mitigation introduced by multi-year ratemaking we described earlier will require significant changes in how ComEd completes the steps. Specifically, we believe 1) risk-informed benefit-cost

[27] ComEd Ex. 5.01 2nd CORR, pages 23-55.
[28] Ibid, page 639 (Section 7.2 Appendix B).

analysis of discretionary grid investment proposals; 2) the use of risk-informed decision support to select some utility investment proposals for deferral to future grid plans; and 3) joint Staff/stakeholder/utility development of future grid plans will be required to re-establish capital spending governance and to mitigate information asymmetry. For now, we explain why we believe the traditional/Jade Cohort distribution planning process, with these changes, will deliver the future grid Illinois wants in the affordable manner Illinois needs.

Q. Do you agree with the argument that DER and EV technologies are different, requiring different planning practices?

A. No, but let's consider these technologies in turn, starting with electric vehicles. EVs do indeed represent new load that must be accommodated. But utilities are extremely adept at accommodating load growth, as they have been doing so since the dawn of the industry. Further, we believe the concern about EV demands on the grid to be overblown, for at least three reasons. First, research indicates that between 83% and 92% of electric vehicle charging occurs off-peak.[29] The smart meters the Company has installed enable the time-varying rates that will continue to encourage this charging behavior. Even industrial-sized vehicle charging, from buses to garbage trucks to delivery vehicles, will largely occur at night, when electric loads are lowest and most EVs are not in use.

[29] Tyler Fitch, Jason Frost, Melissa Whited, *Electric Vehicles are Driving Electric Rates Down, October 2022 Update*, Synapse Energy Economics and Natural Resources Defense Council, October 2022 Update, *available at* https://www.nrdc.org/sites/default/files/media-uploads/evs_are_driving_rates_down_dec_2022_update_0.pdf.

Second, EV are efficient users of electric energy. The Economist estimates that if every passenger vehicle in the US were electric, US energy use will rise 28%.[30] That may seem like a lot, but if such growth occurs over 28 years, and charging is largely off-peak, no rapid increase in peak demand due to EV appears imminent.

Third, decades will be required to transition the installed base of internal combustion engine ("ICE") vehicles to electricity. In 2020, 98% of vehicles sold were powered by ICE, and electric vehicle sales failed to grow at all in the U.S. between 2018 and 2020.[31] It will take at least a decade or two before ICE vehicle sales approach zero, and vehicles sold with ICE will remain on the roads for at least another decade or longer post-sale. In summary, traditional grid planning practices should easily cope with EV adoption over the next 20-30 years. All these observations indicate that the need for massive and immediate increases in grid capacity to accommodate daytime EV charging is overblown.

Q. Is accommodating distributed generation (DER) different than accommodating new EV loads?

[30] *Heat, Hope, and Hydrogen: Green gases can help in the shift from fossil fuels to electricity*, Chapter 6 of The Economist Technology Quarterly (June 25, 2022) at 2, available at https://www.economist.com/technology-quarterly/2022/06/23/green-gases-can-help-in-the-shift-from-fossil-fuels-to-electricity.

[31] "2030: 20 Million More ICE Vehicles Will Be on the Roads in the US Than in 2021," *EVAdoption* Blog Post, May 8, 2021, last accessed May 10, 2023, available at https://evadoption.com/2030-20-million-more-ice-vehicles-will-be-on-the-roads-in-the-us-than-in-2021/ (chart titled "US EV (BEV & PHEV) Sales & New Vehicle Sales Share: 2010-2020").

A. Yes, somewhat, but we consider utility concerns about accommodating DER to be overblown, and self-serving, given capital bias. Incorporating DER growth in traditional utility planning practices is certainly different from incorporating load growth (due to EV or other electrification). However, we believe utility concerns about DER growth to be overstated for at least three reasons.

First, there is a significant difference in the investment required to accommodate DER that is co-located with customer loads, and large DER that is almost always located in rural locations (where land for PV solar and wind installations is less costly). Only the latter will potentially require large expenditures for the new capacity to deliver the output to the grid. However, the difficulty and cost associated with "guessing" where DER capacity will arise makes advance investments in rural circuit capacity a fool's errand. A "build it and they will come" strategy advocated by Company Witness Dr. Tierney[32] would be prohibitively expensive, and would consist of incorrect guesses. As an analogy, a county or state highway department would never expand all its roads at once, betting that traffic could increase everywhere; instead, it carefully selects which roads to expand based on traffic levels as measured in different locations. Typical grid planning practices are consistent with the latter.

Further, we find that laypersons frequently confuse DER grid planning with DER interconnection cost allocation. The "last man in" problem described by Dr. Tierney (which she labels the "chicken and egg" problem)[33] is a result of

[32] ComEd Ex. 3.0, Direct Testimony of Susan F. Tierney, at 23:385.
[33] *Id.* at 23:394.

deficiencies in the latter, not deficiencies in the former. Current DER cost allocation principles assign all DER interconnection costs, including circuit capacity upgrade costs when needed, to each proposed DER as each new DER interconnection request comes along. This approach places responsibility for near-term interconnection costs with the DER developer, not with the utility or its customers, as is appropriate. However, when DER hosting capacity is reached on the circuit, this approach forces the "last man in" to cover the multi-million cost to upgrade the entire circuit's capacity, with the result that no new DER is built on that circuit.

This is clearly a cost allocation problem, not a DER planning or investment problem. We note that if all exporting DER were charged an ongoing fee for the use of the grid to get their products to market, rather than an up-front cost based on grid capacity expansion, the last man in problem is eliminated. Utilities charge load customers "over time" to cover the cost of the grid that delivers electricity; we ask, why not charge DER exporters in the same manner? Re-vamping the way DER exporters are charged for grid services is clearly one alternative to shifting costs to ratepayers through an unreasonably costly "build it and they will come" approach to the last man in problem. This one example shows that many options to massive, near-term rate increases for DER and EV accommodation are available.

Second, there is a significant difference between synchronous DER (spinning turbines, such as might be powered by landfill gas, or by heat that is a by-product of an industrial process) and inverter-based DER (solar panels and batteries). Utilities base most of their concerns about integrating DER on their past

752 experience integrating synchronous DER, which is admittedly difficult. Inverter-
753 based DER has no spinning momentum that complicates synchronization, thus
754 making it relatively easier to integrate. Further, the difficulty that inverter-based
755 DER lacks fault current[34] (often cited by utilities as justification for costly
756 replacements of relays with microprocessor-based versions) can be addressed
757 through a variety of potentially lower-cost technologies that utilities have yet to
758 consider, including grid-forming inverters and synchronous condensers.

759 Third, research indicates that complications associated with inverter-based
760 DER that is co-located with customer loads on a circuit typically arise only when
761 the capacity of all DER on the circuit approaches high levels relative to the loads
762 on that circuit.[35] The Company's interconnected DER capacity was just 3.9% of
763 system peak in 2022,[36] and even the Company's aggressive DER growth scenario
764 projects DER capacity equal to just 9% of system peak by the end of the Grid Plan
765 period.[37] Further, as with EV, future DER adoption is likely to vary widely by
766 circuit, and will take decades to reach saturation. With experience, utilities can
767 become much more comfortable with DER capacity, as grid engineers in California

[34] Inertia is the energy stored in a large rotating mass like a gas-fired turbine. Inertia helps keep the grid stable, acting like a car's shock absorbers that smooths the shock over bumps in the road (momentary disturbances). In the event of a fault or significant disturbance, inertia ensures that utility equipment will detect the anomaly and act accordingly. Inverter-based resources, such as PV solar and batteries, have no inertia of their own.

[35] Anderson Hoke, Rebecca Butler, Joshua Hambrick, and Benjamin Kroposki, *Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders*, National Renewable Energy Laboratory Journal Article JA-5500-55094, July 2012 at 13, available at https://www.nrel.gov/docs/fy12osti/55094.pdf.

[36] Current interconnected DER 832.4 MW per AG 6.25 Attach 2.xlsx; ComEd system peak 21,262 in 2022 per Company's response to Liberty 1.24.

[37] Forecast interconnected DER 1981 MW per ComEd Ex. 5.01 2nd CORR, Table 2.1-4, page 35.

and Hawaii, where DER adoption is high (17%[38] and 50%[39] of peak load, respectively), can attest. Finally, customer adoption of DER is unlikely to ever be anything remotely close to 100%, as EV adoption might be one day far in the future, because a large number of rooftops are unsuitable for solar panels (most commonly due to shading). For all these reasons we believe that utility DER investment can be targeted to address specific circuits when appropriate, and the need for immediate, widespread investment to prepare for future DER is overblown.

Q. But doesn't it make sense to invest more capital in grid readiness than necessary under a "better safe than sorry" principle?

A. No. Utility planning always involves prudently preparing for future needs, without spending more than will reasonably be "used and useful." While some advance spending for DER grid readiness may be prudent, as Figure 3 at page 23 above indicates, unquestioned acceptance of utility capital spending proposals as required for EV and DER is not at all appropriate. There are a great number of alternatives available for preparing the grid, with available alternatives each characterized by a wide variety of technical, operational, and financial pros and cons. This means that allowing utilities with capital bias and no cost disallowance risk to make

[38] Southern California Edison, *Southern California Edison's Grid Modernization Plan*, June 10, 2019, at 9 (Stakeholder workshop presentation showing installed DER capacity forecast at 4,000 MW in 2020). System peak of 23,328 MW from Southern California Edison's 2020 Form 861 submission to the U.S. Energy Information Administration.

[39] Hawaii Public Service Commission Docket No. 2019-0327, Hawaiian Electric Company response to CA-SIR-1(i). System Peak of 1,087 MW from Hawaiian Electric Company's 2020 Form 861 submission to the U.S. Energy Information Administration.

unconstrained grid readiness investments is a bad idea. Further, given the information asymmetry challenge of current ratemaking practices, neither regulators, nor staff, nor stakeholders can determine how much advance preparation, in which grid technologies, in which locations, is appropriate.

Further, the likelihood and consequences associated with the rare instances in which an EV charger or DER installation would have to be delayed can be identified and quantified. Let's assume, for the sake of argument, that the application of traditional grid planning practices resulted in a two-year delay for up to 5% of proposed EV charger or DER installations. A customer or societal opportunity cost can be calculated for such delays. This opportunity cost could then be compared to the cost of advance preparations that might have avoided those delays, but prepared for more installations than actually occur. This rational approach to grid preparation spending is preferable to simply accepting a costly utility plan that fails to demonstrate investment in the right technologies, in the right locations, at the right time. As a final consideration we note that if no EV charger or DER installation is ever delayed, the grid is over-prepared, and excess costs have been incurred. A low level of EV charger or DER delay risk is appropriate to accept, and is consistent with the concept of affordable grid development.

Q. Is it reasonable to expect that staff and stakeholders can restore capital spending governance and reduce information asymmetry by participating in traditional distribution planning processes with utilities?

A. Certainly the first planning cycle (or two) for each utility will be challenging for all parties. However, over time, we believe staff and stakeholders can and will gain the experience to understand and challenge specific utility grid spending proposals. We identify staff and stakeholder participation in integrated resource planning (prior to the advent of regional transmission operators) as an illustrative example. Further, we know of no other way (short of a return to traditional ratemaking) to address the loss of cost disallowance risk and the challenge of information asymmetry.

Q. What might Staff and stakeholder participation in a typical utility distribution planning process look like?

A. We envision that a grid plan developed with Staff and stakeholder participation, assuming that the NARUC-NASEO Jade Cohort process is employed, would require 24-36 months to complete. The schedule could be set such that a grid plan could be developed in the 24-36 months preceding a rate case, in which the utility would file its plan and outstanding issues would be litigated.

Q. How do you respond to the argument that because utilities bear the ultimate responsibility for providing safe and reliable service, they need to retain capital spending decision rights?

A. At the end of the day, the utility is responsible for providing safe and reliable service. Nevertheless, we believe participatory grid planning processes can be designed in a way that encourages consensus, and that staff and stakeholder participation in grid planning will result in both agreements and agreements to disagree. A utility would,

of course, be free to include contentious capital spending proposals in its grid plan for Commission review. As a result of the pre-filing plan development process, however, a rate case for a multi-year rate plan, and the decisions the Commission will have to make, will be focused on a relatively smaller number of utility capital spending proposals and issues.

Q. What level of commitment and participation do you expect the grid planning process, including staff and stakeholders, to require?

A. We expect that it will take a significant time, work, and resource commitment by all parties. We do not claim that participatory grid plan development would be easy, but a properly managed grid planning process can restore capital spending governance, address information asymmetry, and allow interested parties and communities to both advance Illinois energy policies and protect affordability. Our review of the Illinois utilities' grid plans indicates the utilities are proposing to spend lots of capital, now, on EV and DER difficulties that have been predicted and are theoretically possible but have not been actually experienced. While several workshop meetings were held from January to June 2022, little more than grid plan budgets were shared, and there was little opportunity for stakeholders to challenge capital spending programs, priorities, or amounts. Excessive spending on grid "readiness" can be expected to result in investments misplaced in time or geography, or spent on technologies that will become obsolete before their capabilities are truly needed.

Q. Are there spending proposals for things other than EV and DER installations that a Staff and stakeholder process could address?

A. We observe that ComEd's Grid Plan includes expenditures to improve reliability despite highly satisfactory reliability performance relative to utility peers and relative to customer expectations. The key question for Staff and stakeholders is whether further reliability investment is prudent and reasonable after twelve years of accelerated investment. Indeed, ComEd's accelerated grid capital spending 2012-2021 have already delivered a 41% improvement in system average interruption frequency,[40] and the Company's performance on that metric is in the top 10% of all investor-owned utilities in the United States.[41]

Q. What are your conclusions about Grid Plan development?

A. To summarize, the likelihood that capital spending will be excessive or premature under multi-year ratemaking as currently being practiced in Illinois (and elsewhere)[42] is extremely high. While a series of workshops required by statute preceded the Illinois utilities' Grid Plan and Rate Plan filings, there was insufficient time, information, and structure to result in a collaborative plan. A rigorous, inclusive

[40] ComEd Ex. 5.01 2nd CORR, Figure 3.5-1 on page 111.

[41] *Id*. Data on SAIFI with MEDs on 140 US investor-owned utilities from Energy Information Administration Form 861, 2021 reporting year.

[42] We note that electricity rates in California—the state employing multi-year ratemaking for more years than any other—are among the highest in the US despite fair weather and relatively high levels of low-cost renewable and natural gas-fired generation. *See* US Energy Information Administration, *State Electricity Profiles*, available at https://www.eia.gov/electricity/state/.

planning process that involves staff, stakeholders, and community participation is needed to inform the next set of grid plans in Illinois.

Our testimony now turns to multiple examples of excess and premature grid capital spending found in the Company's Grid Plan, which we believe to be symptoms of multi-year ratemaking's administrative challenges.

III. THE COMPANY'S GRID PLAN PROVIDES EXTENSIVE EVIDENCE OF INSUFFICIENT CAPITAL SPENDING GOVERNANCE AND GRID INVESTMENT PLAN INFLATION

Q. Please provide a preview of this section of testimony.

A. This section of testimony will begin with a review of the Company's Grid Plan from the perspective of Illinois consumers, businesses, and economy. Specifically, the Commission should be concerned about the 27.8% increase in Grid Plan plant additions compared to the heightened 2019-2022 spending under the formula rate law (also known as the Energy Infrastructure Modernization Act or "EIMA"), and the 60.5% rate increase the Company proposes through 2027 relative to 2022 rates. We will then describe two approaches to restoring capital spending governance the Commission should implement before the next cycle of multi-year rate plans is filed. These include 1) the use of risk-informed benefit-cost analyses to determine the cost-effectiveness of discretionary grid investments; and 2) the use of risk-informed decision support to optimize the grid projects or programs selected for implementation in a grid plan within affordability constraints.

We will then provide examples of excess or premature capital spending in the Company's Grid Plan. The Company's proposed 27.8% ($1.859 billion) increase in total grid capital spending 2024-2027 over 2019-2022 historical capital spending consists largely of increases in three categories. We will also discuss the inclusion of contingency dollars in Grid Plan budgets employed to calculate customer rates. Thus, after presenting our overall perspective on ComEd's Grid Plan, this section of testimony is organized as follows:

A. Discussion of System Performance growth of $1.147 billion or 55.9% over 2019-2022 spending;

B. Discussion of Capacity Expansion growth of $535 million or 63.7% over 2019-2022 spending;

C. Discussion of IT Project growth of $329 million or 76.5% over 2019-2022 spending;

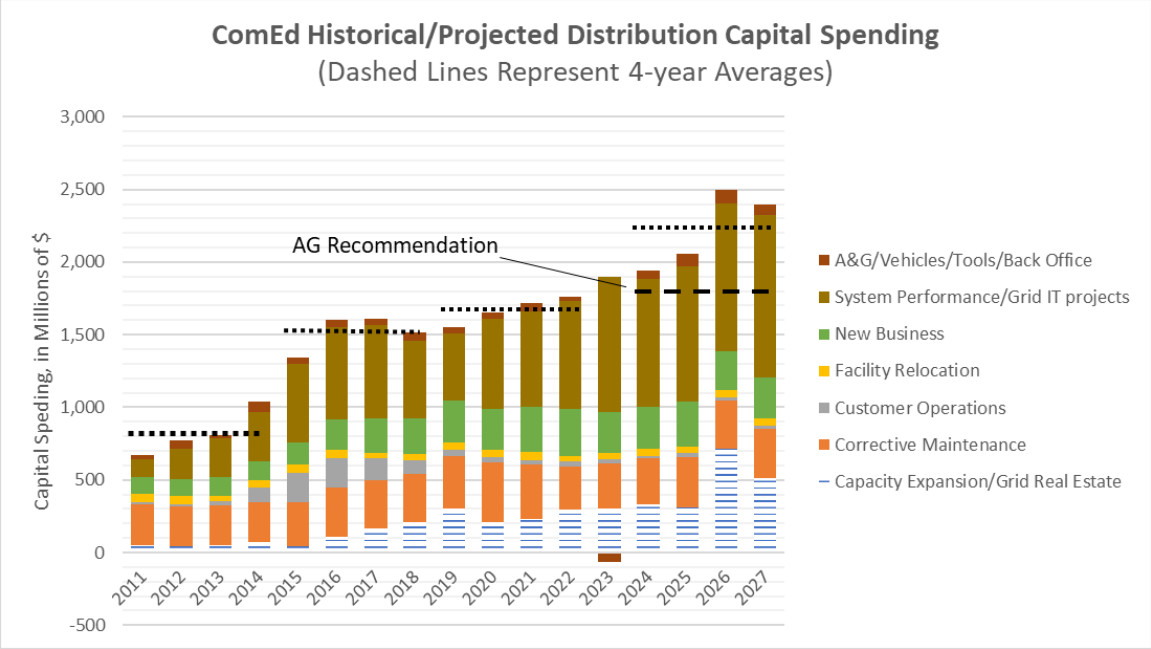
D. Discussion of Project Contingency dollars incorporated in Grid Plan budgets.

Q. Please provide your perspective on the Company's Grid Plan.

A. Our perspective is that the Company is taking advantage of the opportunity provided by multi-year ratemaking, the associated loss of cost disallowance risk, and information asymmetry to grow rate base (and earnings) to benefit shareholders at great cost to Illinois consumers and businesses, and to the Illinois economy. While the Company claims the need to improve reliability and ready the grid for DER and EV as justifications, we will provide multiple examples that these needs

are exaggerated, and that rate base growth of this magnitude is unnecessary, inappropriate, and threatens to make essential electric service unaffordable for more and more Illinois residents and businesses, and with unnecessary impacts to the Illinois economy. As Figure 4 indicates, the Company's proposed Grid Plan capital spending[43] represents not just 27.8% growth over recent historical levels;[44] it represents a 271% increase in spending over the post-EIMA capital spending ramp-up years (2011-2014).[45]

Figure 4: ComEd Historical and Projected Grid Capital Spending 2011-2027



Q. How does this growth in capital spending impact customer rates?

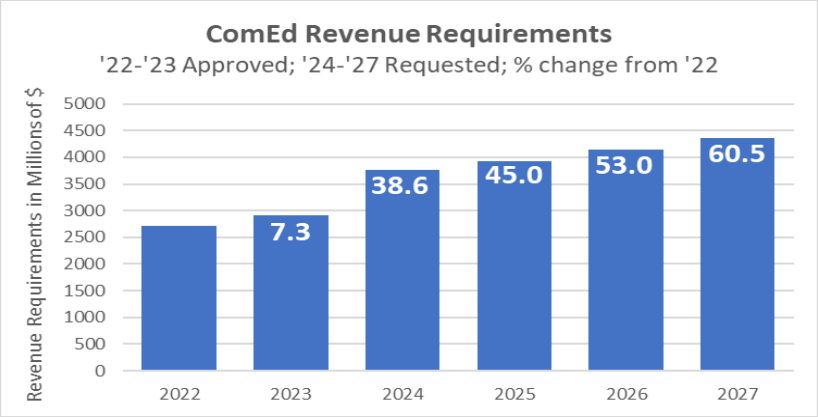
[43] ComEd Ex. 5.01 2nd CORR at 172, Table 5.4-1, Planned Capital by Investment Category (2024-2027).

[44] *Id.* At 160, Table 5.2-1, Historical Capital by investment category (2018-2022; also 2017).

[45] Historical capital spending 2011-2016 obtained from "Plant Additions" Schedules in Dockets 11-0721 (2011), 12-0001 (2012), 12-0293 (2013), 13-0312 (2014), 14-0312 (2015), and 15-0287 (2016).

A. If the Commission approves the Company's proposed spending and cost recovery, ComEd's revenue requirement will increase more than 60% from 2022 by 2027.[46]

Figure 5: ComEd approved/projected revenue requirements 2022-2027



Q. Do you believe that any of this capital spending, and associated rate increases, can be avoided or deferred to future Grid Plan periods?

A. Yes, and we propose logical and proven analytical techniques that can be applied to identify projects/programs that are not cost effective, or to identify projects/programs that can be deferred to a future grid plan at low risk. Risk-informed benefit-cost analyses can be applied to identify proposed projects/programs that are not cost-effective, and risk-informed decision support, or RIDS, can be used to identify projects/programs that can be deferred at low risk.

[46] 2024-2027 obtained from Direct Testimony of Robert R. Mudra, ComEd Ex. 12.0, Table 1 at page 3. 2022 and 2023 revenue requirements obtained from Appendix A, Attachment 1 (Summary) provided by the Company in Illinois Commerce Commission Docket No. 22-0302.

Q. Please provide an overview of risk-informed benefit-cost and risk-informed decision support (RIDS) analyses.

A. RIDS was initially conceived by the National Aeronautics and Space Administration ("NASA") and the U.S. Nuclear Regulatory Commission ("NRC"). As specialists in risky activities, these organizations recognized that the law of diminishing returns makes it financially infeasible to reduce the risk of any endeavor or activity to zero. As presented earlier in this testimony in the context of service interruption risk, the first risk reductions ("low hanging fruit") always involve the least costly and most impactful mitigations. But as risk falls, the mitigations available to secure each incremental unit of risk reduction become ever more costly. Thus, RIDS has always served as a means to optimize the selection of mitigations to implement from a portfolio of available mitigation options, and demonstrates that many mitigations do not deliver adequate risk reduction benefits relative to costs. Further, as the number and cost of mitigations selected for implementation grows, RIDS can also be used to answer a critical question for each managed risk: what level of risk is acceptable (risk tolerance)?

To answer this question, and to optimize the mitigation portfolio, both the costs and the benefits (risk reductions) of a mitigation must be denominated in dollars. Mitigations with costs to customers in excess of dollar-denominated risk reduction benefits should not be implemented. Depending on the level of risk tolerance established, even some mitigations with benefits in excess of costs to customers can be rejected. Of course, mitigation costs are relatively easy to estimate in dollars, but estimating risk reduction benefits in dollars is much more

challenging. The generally accepted method to estimate the benefit of a risk reduction in dollars, and the foundation of RIDS analysis, was presented earlier in this testimony, and repeated here in the context of a generic investment (a) designed to reduce the risk of a generic adverse event (b):

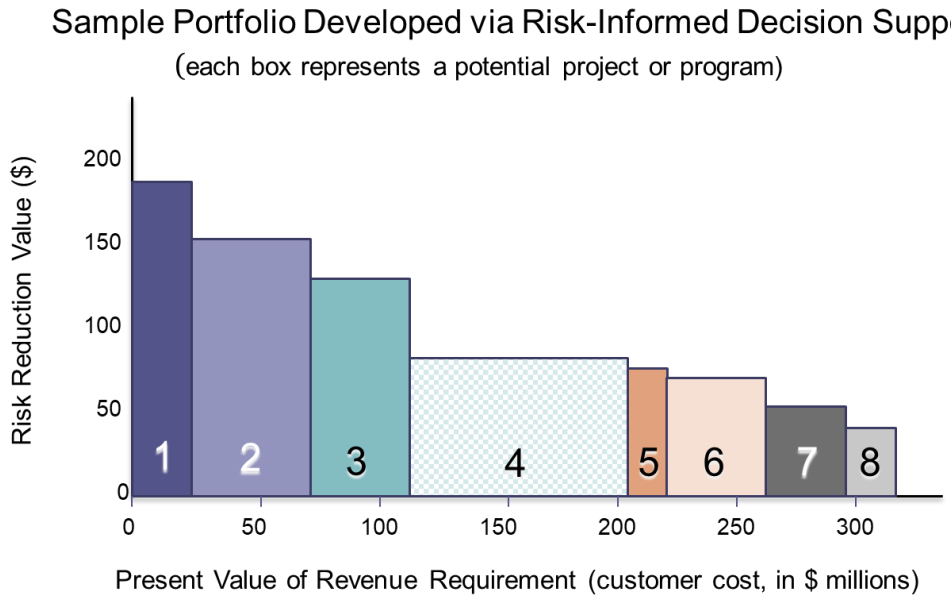
$$Benefit(a) = Reduction\ in\ Likelihood\ of\ (b)\ \ X\ Consequence\ Cost\ \$\ of\ (b)$$

Using this approach to estimate the benefit of a risk reduction in dollars, the risk reduction benefit of a proposed project or program can then be compared to its costs – a risk-informed benefit-cost analysis. A project or program which does not deliver risk reduction value (in dollars) in excess of cost are identified as cost-ineffective, and removed from a grid plan. As presented earlier, the value of a 5% reduction in the likelihood of an adverse event with a consequence of $100,000 is $5,000. As intuitively logical and valuable as this seems, there is actually an even broader and more strategic application of risk-informed benefit-cost analyses as part of RIDS.

Consider that a utility must manage many different kinds of risk – service interruption risks, safety risks, the risk that growing loads or DER will not be accommodated without a delay, and many others. Further, each one of these risks can be managed through a number of potential solutions, and each potential solution offers varying degrees of effectiveness in risk reduction. We believe it is best to develop various risks and available mitigations into a portfolio of potential combinations of risks to manage and solutions to manage them. By comparing the

risk reduction benefits (in dollars) available from various mitigations, the portfolio can be optimized to secure the greatest risk reductions for the least cost. Figure 6 below presents this portfolio approach.

Figure 6: Sample portfolio of potential investments analyzed via RIDS technique



Q. Once a portfolio of investment options has been developed using RIDS, what is the next step?

A. The next step is to select the investments to include in a grid plan. The projects and programs are ranked by their ability to reduce risk (measured in dollars), but the cost of each varies. Project/program 1 provides almost $200 million in risk reduction value for just $25 million and is a no-brainer to select for the grid plan. Project/program 4 provides about $80 million in risk reduction value, but costs $90 million, and therefore should be rejected. The four projects presented after it will cost about $150 million, but will deliver about $240 million in risk reductions, thus

representing much better risk reduction value than project/program 4. Using a portfolio approach, it is clear this grid plan could be improved by eliminating project/program 4 in favor of projects/programs 5, 6, 7, and 8.

Importantly, the portfolio approach also allows utilities, regulators, staff, and stakeholders to make *informed trade-offs* when developing a grid plan. For example, assume for the sake of argument that affordability dictates a maximum capital spend during a grid plan of $160 million. Given this constraint, it appears that selecting projects or programs 1, 2, 3, 5, and 6 delivers the optimal grid plan. The utility, regulators, staff, and stakeholders would be making a conscious choice to defer projects/programs 4, 7, and 8, and to reconsider them in the next grid plan. In doing this they are determining both a capital spending level and the level of risk they are willing to accept. As indicated earlier, risks can never be reduced to zero, and the opportunities to spend capital on the grid are virtually limitless, so determining the appropriate level of risks to accept while simultaneously determining the optimum level of projects/programs/capital investment to include in a grid plan is a valuable and important task.

Q. Does this mean that regulators, staff, and stakeholders are taking responsibility for the investments the utility should be making?

A. The utility is still responsible for making the investments required for safe and reliable service. Regulators, staff and stakeholders should help define the scope of investments beyond minimum requirements, thereby preserving affordability while advancing state policy. The goals of regulator, staff, and stakeholder participation

in grid plan development generally, and of RIDS specifically, are to help restore capital spending governance and to mitigate information asymmetry. Removing utility decision rights is not a goal of RIDS or joint grid plan development. Further, Staff and stakeholders have no interest in micromanaging every utility capital spending decision. Instead, we believe it is possible to establish grid planning processes and controls that restore capital spending governance and mitigate information asymmetry without resorting to micromanagement.

Q. What would grid planning processes and controls that restore capital spending governance and mitigate information asymmetry while avoiding micromanagement look like?

A. The first step in the process is to distinguish between necessary investments and discretionary investments. Utilities must, for example, connect new customers, relocate facilities in the way of public works projects, replace equipment that fails a functional or diagnostic test, replace equipment damaged by a storm, etc. There is no need to apply the RIDS technique to these investments, nor to involve regulators, staff, and stakeholders in these investment decisions, as they are required for safe and reliable service under the regulatory compact. The only concern Staff and stakeholders have regarding capabilities or activities that are truly required for safe and reliable service is that they be secured at the lowest possible cost.

However, the investments a utility proposes that are discretionary with regard to extent or timing should be subjected to additional steps: the application

of the RIDS technique to quantify risks and determine cost-effectiveness; the development of the discretionary investment portfolio; and the prioritization of some investments in the portfolio over others to create a grid plan. Once a grid plan is approved, the utility would have the flexibility to abandon some projects or programs if higher-priority needs arise. However, given that the Rate Plan associated with the Grid Plan establishes revenue requirements, the utility will be encouraged to remain within the overall capital spending budget. Any projects necessary for higher-priority needs that might arise should displace the lowest-risk projects in the Grid Plan, which would then be reconsidered as the next Grid Plan is developed.

Q. Have any state utility regulators with multi-year ratemaking ordered RIDS for distribution planning?

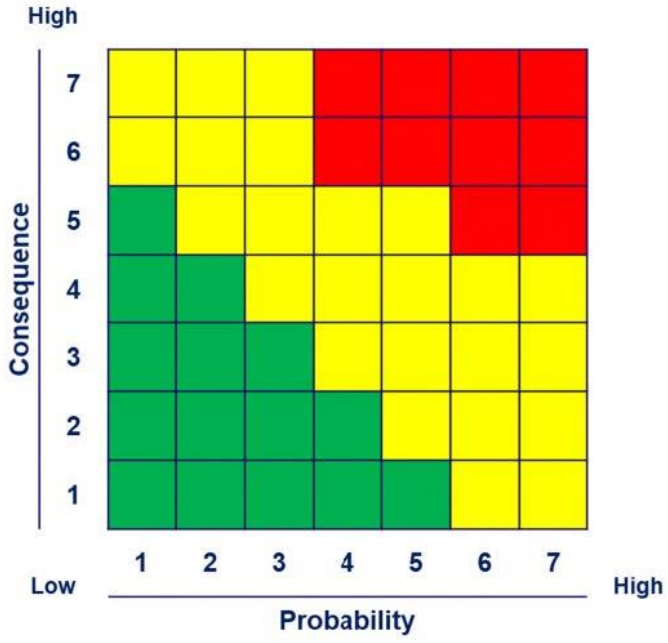
A. Yes. As identified earlier, the California Public Utilities Commission—the state utility regulator with more years' multi-year ratemaking experience than any other—ordered the utilities it regulates to apply risk-informed benefit-cost analyses and the RIDS technique when developing distribution investment plans late last year.[47] We consider this to be a significant development that all state utility regulators should consider, and we include it in our recommendations.

[47] CPUC 2022 Decision.

Q. How does RIDS compare to the Company's approach to selecting projects for inclusion in its Grid Plan based on risk?

A. There really is no comparison. The Company's approach is vastly inferior to RIDS. The Company scores proposed investments on investments' subjectively-estimated ability to reduce adverse event likelihoods on a 7-point scale. The Company then subjectively-estimates the size of the consequences associated with the adverse event in question on a 7-point scale (without using dollars). The proposed investments with the highest subjective likelihood and consequence scores on a heat map are prioritized for investment (the Company's heat map is presented in Figure 7 below).

Figure 7: ComEd Risk Matrix for Grid Plan Project Prioritization



There are two problems with this approach. First, a project or program's ability to reduce an adverse event should not be subjectively estimated. It should be based on industry research or Company pilots that conclusively measure the reduction in the likelihood of an adverse event the project or program has actually delivered in previous applications. While the Company claims its risk assessment approach is quantitative, we submit that the approach's use of numerical values does not make it quantitative. For example, the Company's asset management system undoubtedly contains data on in-service failures of equipment by type, which can be used to determine the annual likelihood of failure by equipment type. The Company also maintains extensive details on service interruptions. By analyzing these two data sets, the Company could (and should) calculate the annual likelihood of an in-service failure resulting in a service interruption for various equipment types with great precision. The Company could then deploy a risk mitigation on a pilot basis, measure the actual change in likelihood delivered by the mitigation, and use this data to complete a risk-informed benefit-cost analysis on the mitigation. The Company does not do this. From what we can determine, project sponsors do not even present reliability, safety, or environmental risk reductions relative to their costs when making their pitches for Company capital.[48]

Q. Did the Company recently update its risk scoring methodology?

[48] Review of 27 capital project overview presentations by project managers/leaders/sponsors to the Project Concurrence Committee provided by the Company in workpapers.

A. Yes, it did, which brings us to our second concern regarding ComEd's approach to risk assessment. The recent change the Company made was to expand the inputs used to subjectively estimate the adverse event consequence score from three categories (safety, reliability, and environmental) to twelve categories.[49] This change does nothing to alleviate our second concern, which is that consequences must be estimated in dollars, not subjectively represented by a score.

Estimating the consequence of an adverse event in dollars provides two critical advantages over subjective scoring methods. First, dollar-denominated consequences translate into dollar-denominated benefits from risk mitigation investments, which can then be compared to costs in a risk-informed cost-benefit analysis. Without dollar-denominated consequences, no cost-effectiveness test of a project or program is possible. For example, a proposed project/program intended to reduce the risk of an adverse event with a subjective likelihood score of 7 and a subjective consequence score of 7 can be deemed as more important to include in a grid plan than a project/program intended to reduce the risk of an adverse event with a subjective likelihood score of 5 and a subjective consequence score of 5. But heat maps are of absolutely no use in determining which project/program is more cost-effective. In fact, it is certainly possible that neither the 7 x 7 project/program nor the 5 x 5 project/program is cost-effective. Cost-effectiveness, or the delivery of risk reduction benefits to customers in excess of customer costs, is impossible to determine, because the risk reduction benefits of these

[49] ComEd Ex. 5.01 2nd CORR, Tables 2.1-9 and 2.2-9 on pages 54 and 55 respectively.

projects/programs are not denominated in dollars, therefore precluding comparisons to costs.

Q. What is the second benefit of denominating adverse event consequences in dollars?

A. The second benefit of denominating adverse event consequences in dollars is that a single denominator type (in this case dollars) permits the comparison of dramatically different adverse event types to each other. For example, a $100,000 safety incident consequence can be compared to a $100,000 service interruption consequence, and to a $100,000 load or DER delay accommodation consequence. Without dollar-denominated consequences, there is no way to reasonably compare reductions in types of risks that are dramatically different from one another. Without a way to compare adverse event types which are dramatically different from one another, the portfolio approach to maximizing the benefits of projects/programs within a constraint, as depicted and described as the portfolio approach to RIDS above, is not possible.

Q. Isn't it difficult to place a dollar value on risk, particularly when they have different consequences, such as safety, reliability, or DER interconnection delay?

A. Various types of risk are translated into dollars all the time. Workers' Compensation insurers quantify the cost of an injury, permanent impairment, or loss of life all the time. In our industry, the U.S. Department of Energy's

Interruption Cost Estimator tool is designed specifically to place dollar values on service interruptions of various durations for different customer classes. Earlier, we identified that a delay in accommodating a load or DER has a customer and societal cost that can be denominated in dollars. In fact, even in cases in which no research-supported data is available, parties can decide upon a mutually agreeable dollar value to use, and modify it over time as necessary; at a minimum, assumptions are known and documented. We consider this issue to be a red herring.

Q. How does the Company respond to your claim that its risk assessment approach is subjective?

A. The Company has asserted that its scoring is objective[50] because it has established ranges, or criteria, that must be reached for a certain score to be assigned. For example, the Company's scoring methodology indicates that for the consequence score of a project to be rated a 7 (high consequence), the project must address an adverse event that would affect [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[51] The use of discrete values does not make this measure objective, because the Company can establish the ranges or criteria at whatever level it wishes. By quantifying consequences in dollars, there is dramatically less subjectivity. The consequence of an adverse event (such as a service interruption) is determined in dollars by the count of customers for whom a service interruption would be avoided, their makeup (commercial vs. residential),

[50] ComEd response to AG 18.16.
[51] Liberty 3.29_Attach 1(CONFIDENTIAL AND PROPRIETARY).pdf. Page 9.

the duration of the service interruption avoided, the value of the avoided interruption as defined by the U.S. Department of Energy's online Interruption Cost Estimator tool, etc.

Q. Do you believe the Company's approach for determining which projects or programs to include in its Grid Plan produces a reasonable value to consumers for the cost?

A. No, we find the Company's approach to be inappropriate and ineffective. To summarize, while the decision-making process the Company employed to determine which investments should be included in its Grid Plan includes some quantifiable data points, these appear to be completely outweighed by subjective inputs, resulting in a highly malleable process for deciding which projects/programs to include in grid plan, subjecting such decisions to capital bias and reductions in capital spending governance. In recognition of these issues, as cited earlier, the California PUC recently ordered that the utilities it regulates complete risk-informed benefit cost analyses as part of projects/programs proposed in multi-year rate plans.[52]

In the rest of this section, we provide multiple examples of spending that is cost-ineffective, or that can be delayed to a future grid plan with very little risk. We strongly believe the conscientious application of risk-informed benefit cost

[52] CPUC 2022 Decision.

analyses and RIDS would have eliminated these projects entirely, or deferred them to a future grid plan.

A. System Performance capital spending increases ($1.147 billion/55.9% over 2019-2022)

Q. Does the Company's proposed increase in System Performance capital spending demonstrate capital spending discipline?

A. No. The Company's System Performance proposal requests a $1.147 billion increase in spending compared to the most recent 4-year period (2019-2022), resulting in a 55.9% increase. While there are many System Performance projects and programs we believe to be cost-ineffective, we will focus on the six most egregious proposals:

- Expansion of the Company's fiber optic grid communications network ($972 million to start);[53]
- Advance replacement of underground cable ($455 million)[54]
- Targeted undergrounding program ($210 million)[55]
- Premature replacement of substation equipment ($180 million)[56]
- Intelligent Substations ($141 million)/Relay Replacements ($20 million)[57]

[53] ComEd Ex. 9.02 – Projected Plant Additions 2024-2027. ITNs 59934, 69760, 77212, 77218, 77224, 77230, 77232, 77236, 77304, 81085, 83537
[54] Ibid, ITNs 4920, 46658, 59290, and 59292
[55] Ibid, ITN 59288
[56] Ibid, ITNs 56908, 63689, 68120, 69707, 74658, 76913, 77702, 77704, 77705, 77708, 77710, 77712, 77716, 77718, 50788, 50790, 56908, 80725, 80727, SS860, 80733, 80735, 80737, 80741, 80743, 80745, 80747, 83920, 84021, 84024, 84025, 84026, 84088, 84094, 84096, 84376
[57] Ibid, ITNs 65907, 66258, 69694, 51868, 75642; 54790, 55959, 64315, 67124, 69551, 76537, 77074, 77465

- Installation of full vacuum reclosers on lateral lines ($55.5 million)[58]

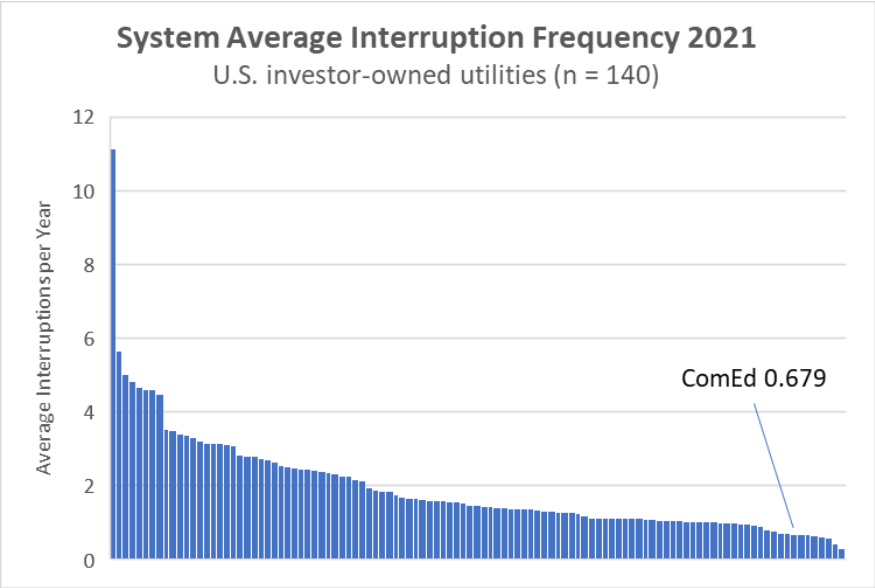
Before we begin, we would like to challenge the notion that ComEd needs to invest any incremental amounts at all to improve system performance.

Q. Why wouldn't ComEd need to increase its investments in improving system performance?

A. There are several reasons. First, ComEd has invested hundreds of millions of dollars, if not over a billion dollars, to improve system performance since the passage of the EIMA in 2011. These investments have largely achieved their objectives, and ongoing reliability spending is embedded in current budgets. As cited earlier, ComEd's system average interruption frequency has improved 41% since 2012, and is now in the top 10% of all investor-owned utilities in the United States (see Figure 8). Further, at 0.679 service interruptions per year, the average ComEd customer experiences a service interruption just once every 18 months. At these performance levels, ComEd's grid is likely already at or beyond the point of diminishing returns for additional investments in reliability.

[58] Ibid, ITN 68635

Figure 8: System Average Interruption Frequency (with Major Event Days), US investor-owned utilities, 2021



Second, ComEd's customers are dramatically more satisfied with ComEd's reliability than ComEd's rates. In the last several years' customer satisfaction surveys, every customer class has rated satisfaction with ComEd reliability at the highest levels of all attributes measured. In the same time frame, every customer class has consistently rated the reasonableness of ComEd rates at the lowest level of any attribute measured.[59] If ComEd were listening to its customers, the Company would prioritize affordability over incremental reliability improvements, and take steps to reduce capital spending. Unfortunately, beholden as they are to shareholder interests, ComEd managers are incentivized to continue to increase rate base and earnings per share. Thus, the Commission, Staff, and stakeholders become the only impediment to unbridled capital spending and rate increases.

[59] AG Ex. 1.6, customer survey results provided in response to AG 1.08.

Finally, ComEd has not completed "willingness to pay" research to determine the value customers place on reliability improvements.[60] "Willingness to pay" research is a subset of market research employed by product managers to estimate what customers would be willing to pay for various feature enhancements. For an electric utility, such research could be used to determine the rate increases customers would be willing to pay for various levels of reliability improvements. By any measure—reliability performance improvements in recent years, reliability performance relative to peers, and high customer satisfaction with the Company's reliability performance—ComEd's reliability meets or exceeds customer requirements and expectations, leaving no basis for increasing system performance capital investments.

Q. Let's turn to your concerns about the Company's System Performance capital spending proposals, starting with the $972 million proposal to expand its fiber optic data communications network.

A. Our first concern with the Company's proposal to expand its fiber optic communications network is its massive size, estimated at [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] over 10 years.[61] The $972 million in fiber optic projects ComEd proposes in the Grid Plan constitute just the initial installment on a massive capital commitment.

[60] AG Ex. 1.3 at 5, ComEd response to AG 1.08(b).
[61] AG Ex. 1.5 CONFIDENTIAL at 8.

A capital commitment of such massive size calls for strategic assessments of ComEd's fiber optic network proposal from the Commission, Staff, and stakeholders. Indeed, one of the value propositions of the fiber optic build-out identified by a consultant hired to quantify self-build benefits is the business opportunity for ComEd to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[62] Strategic questions the Commission should strive to answer include:

- What business is ComEd in?
- Does ComEd really need all the bandwidth fiber makes available? Put another way, is the network the Company is proposing to build used and useful, as it must be under the Public Utilities Act?
- Does recovery of fiber optic network costs from customers constitute a subsidy of other potential ComEd business interests?
- Does the self-build fiber optic network option expose customers to unnecessary financial risks and variation in business case assumptions?
- What options to fiber optic networks are available to meet increasing utility needs for data communications?
- What options or alternatives to proprietary utility ownership are available to meet increasing utility needs for data communications service?

While some of these strategic questions are long term questions that should be addressed in a more comprehensive grid planning process, we can contribute

[62] AG Ex. 1.4 CONFIDENTIAL at 3–4.

some valuable information on the last two points. ComEd has not compared the technical, operational, or economic pros and cons of the fiber optic network self-build option to the pros and cons of available alternatives.[63] For example, ComEd has not issued any requests for information or proposals to third parties that might be able to meet the Company's data communications needs at a lower cost to customers.[64] It seems to us these would be minimum pre-requisites to Commission approval of the Company's costly fiber optic network self-build proposal.

Q. Do you have any other perspectives to share on ComEd's fiber optic network proposal?

A. Yes. We have reviewed the estimated benefits identified by the consultant that evaluated the fiber optic self-build option. [BEGIN CONFIDENTIAL] [redacted]

[63] ComEd response to AG 7.02(c).
[64] ComEd response to AG 7.02(a).

[redacted] [END CONFIDENTIAL].[65]

Q. How do you recommend the Commission respond to ComEd's fiber optic network proposal?

A. We recommend that the Commission not approve any spending on this proposal. If ComEd intends to pursue this proposal, the Commission can direct ComEd to include this proposal in future grid planning processes where more information is available and subject to review by stakeholders.

Q. Please explain your concerns regarding ComEd's advance cable replacement program.

A. The Company operates two long-standing programs to replace underground cable in advance of an immediate need, including underground residential distribution ("URD") and mainline distribution cable replacement programs. The $455 million ComEd proposes to spend replacing cable in advance of failures in its Grid Plan is in addition to its emergent cable replacement programs, which replace underground cable sections as reliability-related needs to do so arise ($47.3 million in the Grid Plan). A "three strikes and you're out" policy is common; when a section of cable has experienced three faults, the reliability-related need to replace has been met, and the entire section of cable (perhaps serving a subdivision, neighborhood, or commercial development parcel) is replaced.

[65] AG Ex. 1.4 CONFIDENTIAL at 4 (Figure 1).

As the Company explained in its Grid Plan, certain types of underground cable are more prone to failure than others, and the Company's advance cable replacement programs prioritizes replacing these varieties over others. However, every cable installation is different. A variety of factors beyond cable type, including soil types, moisture levels, construction practices, tree root density, and others, impact cable life. What this means is that even among cable types known to be prone to certain types of failure, the average time to failure can vary dramatically from place to place. A program designed to replace all installations of a certain cable type within a certain timeframe, as the Company's program does, undoubtedly replaces cable sections that will have many decades of useful life remaining at the time of replacement. Due to capital bias, utilities have an incentive to replace equipment that is fully depreciated (earning no rate of return for shareholders) even if it is operating safely and reliably.

Q. What do you suggest?

A. There is no one answer; our point is that a significant amount of discretion in the rate at which underground cable is replaced is available. Rather than designing a program to replace all installations of a certain cable type within 10 years, it may be perfectly appropriate to reduce the annual replacement rate to a level which achieves the same goal in 20 or 25 years. The faults in that cable type can be monitored over time, and if the fault rates increase to intolerable levels, the replacement rate can always be increased again. A risk-informed benefit-cost analysis can be used to determine the optimum replacement rate, establishing an

appropriate balance between reliability and cost. As ComEd's grid is among the most reliable in the US, relaxation of cable replacement rates may be perfectly appropriate, spreading cable replacement capital investment out over a number of future grid plans.

Q. Please describe your concerns with the Company's targeted undergrounding program.

A. While the Company's proposed mainline and URD cable replacement programs replace cable that is already underground with new cable, the targeted undergrounding program replaces overhead conductors with underground cable. We appreciate Staff's focus, and the Company's focus, on customers experiencing frequent interruptions (measured by CEMI), and on customers experiencing especially long service interruptions (measured by CELID). We support worst-performing circuit programs, and believe every utility should have one. However, as indicated by the law of diminishing returns, an assessment of cost in relation to benefits is required. Our concern with the Company's targeted undergrounding program is that the program's costs are way out of proportion to reliability improvement benefits.

The Company proposes to spend $210 million to underground the overhead lines of customers experiencing frequent or long duration interruptions. The number of customers violating the Commission's CEMI and CELID standards is small. Over the last five years, the number of customers violating the CEMI standard has averaged just 1,552 customers per year, while the number of customers

violating the CELID standard has averaged just 451 per year. The law of diminishing returns is clearly apparent here, and independent research agrees. A study of undergrounding's benefits and costs in Texas—a state with frequent hurricanes—found that the benefits of undergrounding were just $0.30 for every $1 spent.

The problem is that undergrounding is unreasonably expensive, and ends up benefitting very few customers per dollar. ComEd reports a cost of $1.4 million to underground one mile of overhead line on average.[66] Given that ComEd operates 66,508 circuit miles[67] to serve its 4.1 million customers—an average of 62 customers per mile—a project which undergrounds one mile of overhead line will improve the reliability of just 62 customers on average, at an average cost of $22,580 *per customer* ($1.4 million divided by 62 customers).

Q. How do you recommend the Commission treat ComEd's three undergrounding proposals?

A. Our recommendation to cap system performance spending at recent historical levels, adjusted for inflation, will suffice here. By limiting the amount of capital spending available, the Commission will force the Company to allocate limited capital to its highest and best use. We believe the Company already recognizes that advance cable replacement and targeted undergrounding are among the least productive of the capital investments the Company could make. If the Commission

[66] AG Ex. 1.3 at 10–12, ComEd response to AG 6.17.
[67] ComEd response to AG 1.06.

adopts our recommendation to cap capital spending in this initial round of multi-year ratemaking, we believe the Company will respond by drastically slashing the targeted undergrounding budget, and slow the rate of mainline and URD cable replacement. Moving forward, we believe the risk-informed decision support process we described earlier is the best way to evaluate and select projects and programs from among a portfolio of proposed investment.

Q. Please describe ComEd's proposals to replace substation equipment.

A. ComEd describes its $180 million substation equipment replacement investment as "Programmatic replacements . . . based on ComEd's risk and health condition methodology."[68] We describe it as a cost-ineffective way to improve reliability.

Q. Why do you believe ComEd's substation equipment replacement program to be cost-ineffective?

A. As indicated by the referenced description, ComEd's program selects substation equipment for replacement as prioritized by its risk assessment approach, which we previously described as subjective, and through its approach to determining the health of individual pieces of equipment, called asset health indexing. We find the Company's asset health indexing approach similarly subjective, and that it results in replacing more substation equipment, more frequently, than traditional, objective approaches to identifying substation equipment in need of replacement. The fundamental question is, does the reliability improvement value to customers of

[68] ComEd Ex. 5.01 2nd CORR. Page 208.

replacing substation equipment more frequently than a traditional, objective approach exceed the incremental costs of the practice? Our assessment of the rarity of substation equipment failure, combined with the fact that such failures rarely result in service interruptions to customers (due to back-up capacity), indicates the practice is not cost effective.

Q. What are your concerns about the Company's asset health indexing approach to identifying substation equipment for replacement?

A. Our primary concern is that asset health indexing has yet to be proven superior to existing, objective methods utilities have been employing for decades to identify approaching failure in substation equipment. While unknown to many observers, all utilities, including ComEd, periodically conduct diagnostic and functional tests of all significant substation equipment, including power transformers, circuit breakers, switches, and relays.[69] These tests are objective, reliable predictors of approaching equipment failure, and they have been validated over decades of industry experience. When a piece of equipment fails a test, it is scheduled for relatively prompt replacement before it fails in service, thus avoiding service interruptions in almost all cases. We believe asset health indexing is being used to justify accelerated replacement of older, fully depreciated equipment that is operating safely and reliably as indicated by these objective tests. We note that

[69] ComEd response to Liberty 4.10.

capital bias encourages for-profit utilities to replace fully depreciated equipment because it earns no rate of return for shareholders.

Q. How does ComEd justify its use of asset health indexing to identify equipment for replacement?

A. The Company provides several justifications. First, it identifies the multiple factors considered in determining an asset's health,[70] though we question the decision-support value of these factors. In addition to objective test results, the Company's factors include subjective assessments of asset health, such as visual assessments of condition, operational "hassle factor" (our interpretation), and obsolescence.[71] Another factor the Company considers is "asset criticality," which is an adverse event consequence, not an asset health indicator, and which is double counted in the Company's approach to risk assessment. Another factor considered is asset age, though age is a poor predictor of equipment failure relative to objective test results. In summary, adding these subjective factors to test results simply waters down the most reliable and objective indicator of asset health available (testing), resulting in a highly malleable project selection process subject to capital bias and reductions in capital spending governance.

While the Company implies that more inputs is better, the Company has not validated that its asset health index approach is more reliable than objective

[70] ComEd Ex. 5.01 2nd CORR. Figure 2.1-10, page 49.
[71] ComEd response to AG 18.12(a).

diagnostic or functional tests at identifying approaching equipment failure.[72] The Company claims it has validated its approach by citing system-wide improvements in substation reliability since commencing the program, though we note that correlation is certainly not the same thing as causation. We also note that the Company has not compared the incremental cost of accelerated equipment replacements to the program's perceived (let alone rigorously measured) reliability benefits.[73]

Finally, the Company cites multiple authorities that recommend asset health indexing,[74] but we know of no organization or authority that recommends replacing equipment based on asset health index scores. In short, we believe the asset health indexing mechanism allows more equipment to be selected for replacement than can be justified using objective equipment test results.

Q. How should the Company evaluate its substation equipment replacement program?

A. A risk-informed benefit-cost analysis should be used to compare the benefits and costs of replacing substation equipment based on objective test results to the benefits and costs of replacing substation equipment based on the Company's risk assessment and asset health index scores. A program designed to reduce the incidence of in-service equipment failures must take into account the likelihood of such in-service

[72] ComEd response to AG 18.12(c).
[73] ComEd response to AG 18.21.
[74] ComEd response to AG 18.12(c).

failures as identified in historical data. The average annual in-service failure rate of a few types of substation equipment that are routinely and objectively tested are presented in Table 3 below. We further note that due to back-up capacity, substation equipment failures even more rarely result in service interruptions.

Table 3: In-service failure rates, substation power transformers and circuit breakers

Substation Device	Count in Service[75]	Average Annual Failures in Service[76]	Annual Failure in Service Likelihood	Likelihood that Failure results in a service interruption
Power Transformers	1,681	7.6	4.5 in 1,000	Even lower (due to back-up capacity)
Circuit Breakers	1,263	10.2	8.0 in 1,000	

In layman's terms, an annual failure in service likelihood of 4.5 in 1,000 means that 1,000 power transformers would need to be replaced to reduce failures by just 4.5 per year, and to reduce even fewer service interruptions (due to back-up capacity). At a cost of a few million dollars each, no one would recommend replacing 1,000 power transformers to avoid 4.5 failures in service annually, and fewer than 4.5 service interruptions annually. Yet, without a risk-informed benefit cost analysis, no one can be assured that bad investment decisions, in which costs outweigh risk-informed benefits, are not being made.

Q. Please describe the Company's Intelligent Substation and relay replacement programs.

[75] AG Ex. 1.3 at 2–3, ComEd's response to AG 1.05.
[76] AG Ex. 1.3 at 18–19, ComEd's response to AG 18.02.

A. The Company plans to spend over $140 million in its Grid Plan to transition just five substations to fully digitized versions—an average cost of $28 million per substation. Given that the average ComEd substation serves 4,773 customers,[77] the cost of an intelligent substation averages $5,866 *per customer*.

Q. What are your concerns with Company's Intelligent Substation and relay replacement programs.

A. We understand that an intelligent substation might be a nice thing for a grid engineer to have. The transition to an intelligent substation involves "upgrading electromechanical protective relays to modern microprocessor-based devices, replacing aging and poor performing circuit breakers, and technology to remotely monitor asset health in real-time."[78] But at an average cost of $5,866 per customer, we would expect the Company to have completed a well-supported business case, including a risk-informed benefit-cost analysis, to justify the program. Even though ComEd has upgraded 15 substations to "intelligent" versions since EIMA was passed,[79] at a cost of at least $134 million dollars,[80] ComEd has completed no such analysis on this program.[81] Further, when we requested information that would allow us to independently evaluate the benefits of this program, the Company's explanation of benefits was limited: "The objective of this program is to improve

[77] 4.1 million ComEd customers divided by 859 substations (per AG 1.03_Attach 1.pdf)
[78] ComEd Ex. 5.01 2nd CORR, page 210.
[79] ComEd response to AG 6.20. Page 2.
[80] *Baseline Distribution Grid Assessment of Commonwealth Edison*. Report prepared for Staff by the Liberty Consulting Group. April 22, 2022. Page 78.
[81] ComEd response to AG 18.25(b).

substation resiliency by modernizing relay and protection systems . . . SAIDI and SAIFI performance are not independently meaningful short term measures of the outcome of this program."[82]

Q. What are relays, and why does ComEd need modern ones?

A. A relay is a piece of equipment that tells another piece of equipment when to operate. For example, a relay can sense a fault and instruct a circuit breaker to open. They are very common; a utility ComEd's size probably operates tens of thousands of relays. In our experience a set of microprocessor relays (called a panel) costs about $150,000 to install. Assuming roughly one relay panel per circuit, given the thousands of circuits the Company is likely operating with older relays today, the decision to replace those relays is easily a multi-hundred-million-dollar decision. It should not be taken lightly, nor implemented all at once, but considered carefully, and implemented over decades, if indeed it is to be implemented at all.

Microprocessor relays have capabilities that older versions do not have. The Company claims that these capabilities improve fault-locating capabilities (thus reducing service interruption duration), improve adverse event records for forensic analysis, and provide real-time status reporting.[83] We note that relatively inexpensive fault indicators can also reduce fault location times, and that relatively inexpensive line sensors can record adverse event data and communicate grid status

[82] ComEd response to AG 10.20(e).
[83] ComEd Ex. 5.01 2nd CORR, page 210.

in near real-time. Thus, the Company should be able to get similar reliability benefits for lower costs.

Q. Are there other justifications, besides fault location and system visibility for reliability purposes, for such large investments?

A. Investor-owned utilities claim that high levels of PV solar systems and batteries, also known as inverter-based resources, can confuse relays without microprocessors, causing myriad problems. The "confusion" arises from inverter-based resources' lack of inertia.[84] (Spinning generators, such as gas-fired turbines, provide inertia to the grid; inverter-based resources do not.) The problems typically cited that might occur at high levels of DER include older relays' inability to detect islanding;[85] inability to "ride through" disturbances caused by large amounts of DER capacity disconnecting at once; and inability to operate properly in instances of reverse power flow (when current flows to the transmission grid from distribution, rather than the other way around).

We have several reactions to these claims. First, recall our earlier observations on DER capacity relative to peak at ComEd. By 2027, it estimates a small fraction of DER capacity relative to peak load. We also note that as of 2022,

[84] Inertia is the energy stored in a large rotating mass like a gas-fired turbine. Inertia helps keep the grid stable, acting like a car's shock absorbers that smooths the shock over bumps in the road (momentary disturbances). In the event of a fault or significant disturbance, inertia ensures that utility equipment will detect the anomaly and act accordingly. Inverter-based resources, such as PV solar and batteries, have no inertia of their own.

[85] "Islanding" refers to an instance in which a DER (or group of DER) continue providing power to a grid which is not electrified (for example, due to a service interruption). This is a very dangerous situation, as grid workers who believe the power to be off can be electrocuted. This is the reason every inverter is designed to disconnect its DER from the grid in the event the grid loses power.

only 3% of ComEd's circuits have more DER capacity than 10% of peak load interconnected, and that only 1% of ComEd's circuits have more DER capacity than 25% of peak load interconnected. This is much less DER than experienced routinely by Hawaii's investor-owned utility today. To a large degree, the level of DER capacity at which relays without microprocessors will begin to exhibit problems is unknown; it will also vary greatly with individual circuit characteristics and conditions. Further, such conditions may only ever exist on a few of ComEd's circuits. To prepare all circuits for conditions and impacts that can now only be guessed at is wasteful and expensive. When an identified "problem" is as diffuse as predicting the location and growth of DER, as well as the impacts of those DER on grid operations, risk-informed benefit cost analyses and RIDS become more and more valuable.

Second, the research on these topics is in its infancy. Concerns cited in research are supported by electrical engineers' calculations, or observed in computer simulations of grid conditions and reactions. The cited concerns are not based on real-world experience and observations. Indeed, ComEd has not yet experienced any of the DER-related problems it claims it must avoid through replacement of relays with microprocessor-based versions.[86]

Third, promising new technologies are being developed that may obviate the need to replace relays with microprocessor versions. Grid-forming inverters[87]

[86] ComEd responses to AG 18.22, AG 18.23, and AG 18.24.
[87] Inverters convert the direct current produced by PV solar panels and batteries into the alternating current of distribution grids. Inverters are a required component of every interconnect PV solar or battery system.

are being developed that create inertia. Synchronous condensers are already available to inject inertia into the grid. To summarize, we ask the Commission, Staff, and stakeholders to consider the possibility that conventional wisdom and widely-held assumptions about what the future grid will look like, what the grid will need, and what must be installed today to be ready, will be incorrect, and that rapid but premature spending may ultimately be unnecessary, or result in unanticipated obsolescence.

Q. Please describe your concerns with the Company's proposal to install full vacuum reclosers on laterals.

A. The Company proposes to spend $56 million installing full vacuum reclosers on laterals, which ComEd calls its DA Lateral (for distribution automation) program. Allow us to begin with a bit of background information. A lateral is a conductor that taps into a larger conductor. In our experience laterals are typically short, and typically serve 20 to 50 residential customers each at most utilities. ComEd estimates it operates over 55,000 laterals which serve an average of 38 customers each.[88]

It has been standard utility practice for many decades to install a fuse where a lateral taps into a larger conductor. When there is a fault on the lateral, these fuses blow, thus isolating the faulted lateral and avoiding a service interruption for all customers served by the larger conductor.

[88] ComEd response to AG 17.22

A recloser is a device that can be useful in instances of transient faults (for example, when a tree branch momentarily grazes a conductor). Rather than simply blowing like a fuse, a recloser makes one or two (or three) attempts to "reclose" (restoring power) after opening in response to a fault. With reclosers, transient faults do not result in sustained outages for customers. However for permanent faults, reclosers remain open, just like fuses.

Full vacuum reclosers are expensive and have traditionally been employed only at the backbone level, typically benefitting several hundred or a thousand or so customers each. In recent years manufacturers of full vacuum reclosers have introduced miniature versions (called "Trip Savers" or "Fuse Savers") designed for use on laterals, in place of fuses.

There are significant cost differences in these technologies. The continued use of a fuse that is already in place incurs zero incremental cost. To replace a fuse with a TripSaver costs several thousand dollars. ComEd reports that a full vacuum recloser costs $67,000 to install on average.[89] The critical variables in calculating a risk-informed benefit cost analysis are, in addition to costs: 1) the ratio of transient faults to permanent faults; and 2) the number of customers served by each installed device.

Q. Do you think full vacuum reclosers are a cost-effective way to improve reliability?

[89] AG Ex. 1.3 at 9, ComEd response to AG 6.15(u).

A. If the count of customers is large enough, and the incidence of transient faults high enough, they can be. However, if frequent transient faults are a problem, there are root causes, such as a need to complete tree trimming or repair or replace malfunctioning equipment, that should be investigated. Reclosers can be mis-used to treat symptoms, masking underlying problems. Further, in risk-informed benefit-cost analyses we have completed on Trip Savers in other jurisdictions, we have found they are only cost-effectively deployed on laterals serving high numbers of customers,[90] or on laterals serving significant percentages of commercial customers. The minimum number for Trip Savers seems to us to be at least 50-60 customers served. We do not believe Trip Saver installation on laterals with fewer customers to be cost effective.

Q. But ComEd proposes to switch from using Trip Savers at laterals to installing full vacuum reclosers on laterals, correct?

A. That is correct, and we are extremely concerned by this. If Trip Savers costing $5,000 are not cost effective for fewer than 50-60 customers on a lateral, a full vacuum recloser with an average cost of $67,000 certainly is not cost effective either. We appreciate that full vacuum reclosers have some capabilities that Trip Savers do not. However, without high numbers of customers served, or without significant percentages of commercials customers served, the incremental

[90] *See, e.g.,* Oklahoma Corporation Commission Cause No. PUD 2021-00164. Responsive Testimony of Dennis Stephens at 17:13 (April 27, 2022).

capabilities of full vacuum reclosers are simply not worth their incremental costs. We know of no utilities installing full vacuum reclosers on laterals.

Q. How does ComEd respond to your critiques?

A. In addition to citing the incremental capabilities, ComEd documents the reliability improvements it has secured from installing full vacuum reclosers on laterals. However, we note ComEd's reliability improvement data came from laterals serving an average of 319 customers each.[91] It is inappropriate to generalize the results of reclosers serving an average of 319 customers each into a decision to install full vacuum reclosers on laterals as a general policy, particularly when the average lateral serves just 38 customers. We believe a cost-effective approach to lateral protection might be to use fuses as a general rule; to use Trip Savers only on laterals with exceptionally high numbers of customers; and to use full vacuum reclosers only on laterals with extremely high numbers of customers. Here again, a risk-informed benefit-cost analysis would be extremely helpful in determining exactly which situations warrant the installation of which technology.

Q. Can you summarize your recommendations about the System Performance spending included in ComEd's proposed Grid Plan?

A. Increases in System Performance capital spending should not universally or automatically be deemed necessary for safe and reliable service. A great deal (if not the majority) of System Performance spending is discretionary, and as such,

[91] ComEd response to AG 18.04.

should pass a risk-informed benefit-cost test before capital is spent. The Company has not conclusively demonstrated that any of the projects or programs we present in this section of testimony delivers benefits to customers in excess of costs to customers. As such, we ask the Commission to cap System Performance levels at the amounts spent 2019-2022, adjusted for inflation, until a distribution planning process which restores capital spending governance and mitigates information can be implemented.

B. Capacity Expansion capital spending increases ($535 million/63.7% over 2019-2022)

Q. Does the Company's proposed increase in Capacity Expansion spending demonstrate capital spending discipline?

A. No. The Company's Capacity Expansion proposal requests a $535 million (63.7%) increase over its 2019-2022 spending. Given that load growth at ComEd has been flat for years, and is projected to remain flat through the Grid Plan period,[92] capital spending growth for Capacity Expansion does not appear justified at all.

We understand that during times of low or no system-wide load growth, pockets of load growth will still require some capacity expansion projects and capital spending. However, given that historical capacity expansion budgets have proven adequate to accommodate such "pockets" during periods of flat load levels system-wide in the past, we maintain that those same capacity expansion capital

[92] ComEd Ex. 5.01 2nd CORR, Figure 2.1-4, page 36.

spending levels should be adequate to accommodate load growth pockets during periods of flat load levels system-wide in the future.

Q. If not through load growth, how does ComEd justify a $535 million/63.7% increase in Capacity Expansion capital spending increases?

A. ComEd only justifies a portion of its Capacity Expansion capital spending through load growth. We inquired about the reasons behind 27 multi-million-dollar capacity expansion projects the Company proposed in its Grid Plan. "Load Growth" was cited as the rationale for just 11 of these projects. The majority of the projects were justified through subjectively-assessed requirements that appeared to have little to do with load growth, such as equipment obsolescence, operational flexibility, and asset health.[93]

In its description of grid planning practices related to Capacity Expansion, ComEd describes multiple sophisticated software systems and engineering analyses employed to identify capacity constraints and justify capacity expansions driven by load growth.[94] But then, as with System Performance, ComEd waters down careful quantification by adding multiple non-quantified and subjectively-assessed considerations to justify tens of millions of dollars in capacity expansion investments for reasons other than load or DER growth. This results in a highly malleable decision process subject to capital bias and reductions in capital spending

[93] AG Ex. 1.3 at 14–16, ComEd response to AG 17.28(a).
[94] ComEd Ex. 5.01 2nd CORR, section 2.1.1, "Engineering Analysis – Capacity Planning". Pages 24-44.

governance, and more capacity expansion spending than is necessary to accommodate load growth 2024-2027.

Q. Do other proposed Capacity Expansion projects concern you?

A. Yes. The Company's Capacity Expansion projects include $97 million for feeder upgrades related to EV.[95] The Company claims this estimate is based on a 90MW increase in EV charging during peak by 2027, but provided no workpapers to support this estimate.[96] ComEd's Grid Plan includes an intimidating chart on EV energy usage through 2041,[97] though we note that EV charging demand during peak, not EV energy usage, is the critical factor in determining EV accommodation costs.

Finally, we noted above that the Company's capacity expansion proposal is replete with capacity expansion projects not justified by load growth. These projects, from 4kV circuit conversions to substation transformer replacements, could certainly be deferred at low risk in favor of EV-related capacity increases in the event they are needed. To summarize, it appears that this $97 million proposal duplicates capacity expansion capital spending already incorporated elsewhere in the Company's overall Capacity Expansion budget.

[95] ComEd Ex. 9.02 – Projected Plan Additions – Redacted.xlsx. ITN 79628 2024-2027.
[96] AG Ex. 1.3 at 13, ComEd response to AG 10.30(a).
[97] ComEd Ex. 5.01 2nd CORR, Figure 2.1-2 on page 32.

Q. How do you recommend the Commission address the budget for Capacity Expansion in ComEd's proposed Grid Plan?

A. As with System Performance, the Company's claim that a massive $535 million/63.7% increase in Capacity Expansion capital spending is required must not go unchallenged. The examples presented here indicate that much of the Capacity Expansion spending increases the Company proposes are either inappropriate or discretionary, with the implication for the latter being that risk-informed benefit-cost analyses should be applied. Further, the challenge of information asymmetry is clearer in Capacity Expansion than in any other category of spending, as a few rounds of discovery are simply inadequate to examine every proposed Capacity Expansion project. As such, we ask the Commission to cap Capacity Expansion capital spending at the amounts spent 2019-2022, adjusted for inflation, until a distribution planning process which restores capital spending governance and mitigates information asymmetry can be implemented.

C. IT Project capital spending increases ($329 million, or 76.5%, over 2019-2022)

Q. Describe the Company's proposed increase in IT Project spending.

A. The Company's Grid Plan proposes IT Project capital spending that is 76.5% ($329 million) higher than the most recent 4-year period (2019-2022). While information technology is not our specialty, we do have extensive experience with grid-related software applications. We will provide perspective on the Company's

ADMS/GIS[98] capital spending proposal ($65 million) and Asset Management System proposal ($126 million).[99]

The Company's interest in deploying an ADMS appears to be driven in large part by an interest in managing complexities introduced by high levels of DER. As mentioned many times in this testimony, the level of DER capacity the Company anticipates by 2027 is not large relative to peak loads (9% by 2027 at most). This indicates that ADMS and related software deployment (such as DERMS)[100] may be premature. Further, we have observed significant problems with field equipment data accuracy in the geographic information systems upon which ADMS relies. Our experience is that differences between physical and digital realities have doomed almost all ADMS deployments to implementations that are costlier and longer than anticipated. We are concerned that due to the small portion of DER capacity on ComEd's system, or due to the lengthy deployment period, ADMS will not be used and useful within the Grid Plan period, yet note that revenue requirement calculations assume ADMS and GIS project capital spending with optimistic timelines.

[98] "ADMS" is an acronym for Advanced Distribution Management System. Historically, utility control systems have not typically extended beyond equipment in substations; ADMS purports to extend controls to equipment outside the substation fence, and adds other analytical capabilities. "GIS" is an acronym for Geographic Information System. GIS records information about equipment installed throughout a utility's grid, including equipment types, physical locations, capacities, the settings of various technical parameters, phase locations, and other information,

[99] ComEd Ex. 9.02 – Projected Plan Additions – Redacted.xlsx. ITNs related to ADMS, GIS, and Asset Management Suite 8 replacement projects.

[100] "DERMS" is an acronym for "Distributed Energy Resource Management System". It is software dedicated to the monitoring, management, and control of interconnected DER, such as PV solar systems.

Regarding the Company's proposal to deploy a new asset management system at a cost of $126 million, we have several concerns. First, of course, is cost. $126 million is only ComEd's portion of this project's cost, which will be shared across five Exelon utilities. That a new asset management system will cost as much or more than an ADMS is unique in our experience. Our second concern is the degree of discretion available for this project. ComEd already has an asset management system. Given that the Company's Grid Plan proposes a 27.8% increase in capital spending over the most recent 4-year period and a 60% rate increase in just five years, we would expect the Company to seek out capital projects that could be deferred at low risk. A new multi-hundred-million-dollar asset management application, when the Company already has an asset management application, seems to be highly discretionary, and to clearly fit into the "defer to the next grid plan at low risk" category.

Q. How do you recommend the Commission address the budget for IT project spending in ComEd's proposed Grid Plan?

A. As with System Performance and Capacity Expansion, we believe most IT projects to be largely discretionary, requiring justification for spending within the Grid Plan period that the Company does not provide. We again also note the challenge of information asymmetry. Thus, as with System Performance and Capacity Expansion, we ask the Commission to cap IT Project capital spending at the amounts spent 2019-2022, adjusted for inflation, until a distribution planning

process which restores capital spending governance and mitigates information asymmetry can be implemented.

D. Project Contingency dollars incorporated in Grid Plan budgets

Q. Is it appropriate to include project contingency budgets in the Company's capital spending projections?

A. No, and let us explain why. Multi-year ratemaking is different from traditional ratemaking on many levels. The calculation of revenue requirements on capital spending forecast to occur four years hence is difficult enough; variation in capital spending is to be expected. But the fact that capital spending levels are set in advance "bakes in" those capital spending levels. In our experience, it is extremely difficult to modify capital spending levels down once approved by a Commission.

These multi-year ratemaking characteristics have significant implications for how project contingency budgets should be handled in capital spending projections. Contingency budgets are very useful for project managers. They are intended to communicate to management the level of project implementation risk a project manager foresees, given the nature of the project and the level of detail at which a project's cost has been estimated. Contingency budgets are not a projection of costs the project manager expects; rather, they are projections of costs the project manager warns might be required over and above the project manager's best estimates at the time they are made.

Multi-year ratemaking's use of projected capital spending to set revenue requirements is intended to improve a utility's opportunity to earn the authorized

rate of return on plant in service by reducing regulatory lag. The use of projected capital spending is not intended to deliver unspecified increases in capital spending. When contingency budgets are included in a capital spending project used to calculate revenue requirements, a utility is assuming the contingency will be spent. But by definition, the need to spend contingency budgets is unknown; for any particular project, contingency budgets may go unused. For this reason alone, we believe contingency budgets should be excluded from capital spending projections used to calculate revenue requirements. To include contingency budgets in the capital spending is to artificially increase the total amount of capital available to a utility to spend.

Q. But the annual reconciliation process called for in CEJA should take care of this, should it not?

A. That has not been our experience in other jurisdictions. To the extent contingency budgets included in capital spending projections are not needed, utilities have found other ways to spend capital that has been budgeted but not used. From our perspective, contingency budgets become a way to increase capital spending projections to an extent larger than a utility needs to implement its grid plan.

This negatively impacts customers in two ways. First, it encourages utilities to increase project costs though the size of the contingency budgets, resulting in larger capital spending projections and rate base. Second, "built in" contingency budgets for which there are no consequences do not encourage project cost discipline. To be sure, including contingency budgets in capital spending

projections and in rates encourages utilities to spend all the contingency budgeted. If contingencies are excluded from capital spending projections and only collected if actually used, it is more likely that contingency spending will be on an "as needed" basis rather than already recovered as an actual cost. Further, contingency cost recovery will have to wait for a reconciliation process or rate case. Slower cost recovery constitutes a constraint for using contingency budgets, which is exactly as it should be.

Q. How significant an issue is this?

A. It is potentially very significant. ComEd did not provide total contingency budgets included in capital spending projections when requested in discovery.[101] However, in our review of 17 Project Concurrence Committee presentations the Company included in discovery, contingency budgets averaged 14.8% of total project budgets.[102] When this project contingency percentage is applied to the Company's entire proposed $8.5 billion Grid Plan, the amount represented by contingency budgets could be as high as $1.26 billion.

Q. How do you recommend the Commission address the treatment of contingency costs in ComEd's proposed Grid Plan?

[101] ComEd response to AG 10.23.
[102] Presentations to the Project Concurrence Committee for 17 projects specific to the ComEd jurisdiction the Company included in workpapers

A. We recommend the Commission prohibit contingency costs in capital spending projections used to calculate multi-year revenue requirements in Illinois. We note that the Maryland Public Service Commission has established just such a precedent for multi-year ratemaking that is currently being piloted in that state.[103]

IV. CONCLUSIONS AND RECOMMENDATIONS

Q. Please provide a preview of this section of testimony.

A. After providing some context, we will present our recommendations regarding multi-year rate plan administration. We will then provide context for, and recommendations on, the Company's Grid Plan.

Q. Please explain the rationales for your recommendations to the Commission regarding multi-year ratemaking administration.

A. As indicated in Sections II and III of this testimony, and through our experience participating in multiple state utility regulatory proceedings involving alternative ratemaking methods such as multi-year ratemaking, it is clear that these ratemaking methods and the advance investment plan presentation they require compromise capital spending governance, requiring active Commission oversight to avoid dire consequences for rate stability and affordability. These concerns inform our recommendations regarding the administration of multi-year ratemaking.

[103] Maryland Public Service Commission Case No. 9645. Order No. 89678 dated December 16, 2020. Pages 43-45.

Q. Are there any other structural issues that are implicated by alternative ratemaking methods?

A. The Energy Policy Act of 1992 removed the prohibition against cross-state ownership of utilities that was first established in the Public Utility Holding Company Act of 1935. Since then mergers and acquisitions have become very common, with holding companies owning utilities in multiple states. ComEd's parent company, Exelon, was formed by the ComEd-PECO merger, and the parent proceeded to acquire utilities in Maryland (Baltimore Gas and Electric), the District of Columbia (Potomac Electric Power), New Jersey (Atlantic City Electric) and other states (Delmarva serves customers in Delaware, Maryland, and Virginia). Cross-state ownership pits sister utilities against each other in a fight for capital from their parent companies. The job of a parent company's chief financial officer is to put the parent's capital where it will provide the greatest rate of return on capital (profit) at the least risk.

State regulators with jurisdiction over a subsidiary of a parent company with utilities in multiple states may also be concerned about competition for parent company capital. If state A offers lower (or no) cost disallowance risk than state B, a parent company with utilities in both states may favor the subsidiary in state A. However, the regulatory compact requires the parent company to invest the amount necessary for safe and reliable service, which extends to EV and DER accommodation.

Q. What do you make of this situation?

A. We believe regulators should only approve the amount of capital spending that is reasonably necessary, and reject the unsupported premise that more capital spending is always better than less. As discussed in this testimony, over-investment itself can be a problem. It leads to unnecessary rate increases that a state's business and consumers must pay, retarding economic growth and development. Over-investment can waste capital, putting it into technologies that may become obsolete before they are truly necessary. Over-investment can put capital into capabilities that do not deliver benefits in excess of costs. Over-investment prepares the grid earlier than necessary, resulting in rate increases that are earlier than necessary. Depending on where a utility is on the diminishing returns curve, more grid investment can be worse for a state's economy than less grid investment.

Assuming that a utility is already on the upper right side of the diminishing returns curve, a state whose regulators limit capital spending will actually be better off than a state allowing more capital spending under multi-year rate plans. By limiting requested capital spending, the utility must manage its spending in the same way that businesses competing in open markets do. A state that ensures its utilities are somewhat capital constrained (state B in our example) will actually be more competitive than a state which does not (state A), because the utilities in state B will offer safe and reliable service, and DER accommodation, at a lower cost to state B's economy.

In summary, we urge the Commission to recognize that grid over-investment is just as bad for a state's economy as grid under-investment. We

1892 further encourage the Commission to recognize that Illinois utilities, including the
1893 Company, are already on the upper right-hand of the diminishing returns curve for
1894 reliability, and that a utility's interest in investing in DER/EV "readiness" needs to
1895 be assessed in light of both the utility's capital bias and the actual growth and
1896 demonstrated need for additional investment to be ready for DER and EV. In short,
1897 we encourage this Commission to focus on increasing capital spending governance
1898 and mitigating information asymmetry, thereby encouraging the development of
1899 the Illinois distribution grid in a way that delivers the grid the State needs at the
1900 right time and at the lowest possible cost.
1901
1902 **Q. Given this context, please present your recommendations on multi-year**
1903 **ratemaking administration.**
1904 A. Our multi-year ratemaking recommendations are designed to restore capital
1905 spending governance and address information asymmetry, and include:
1906 • That the Commission immediately commence a proceeding to develop a
1907 process by which stakeholders and utilities jointly develop grid investment
1908 plans, with the resulting process to be deployed well in advance of the next
1909 Grid Plan proceeding; and
1910 • That the Commission Order that discretionary grid investment proposals—
1911 meaning those not strictly necessary for safe and reliable service delivery
1912 within the upcoming Grid Plan period—be subjected to risk-informed
1913 decision support analysis as a test of cost-effectiveness, and to optimize
1914 Grid Plan capital spending, as part of any future MYIGP in Illinois.

Q. Please explain the rationales for your recommendation that a pre-filing process be established to review the Company's Grid Plan.

A. As indicated in Section III of this testimony, the rate case procedural schedule was woefully inadequate for evaluating the Company's $8.5 billion grid investment plan and its 546 programs and projects. We received the plan on January 20, and were limited to a 115-day discovery period. While we would have preferred to have examined all 546 programs and projects in detail, and to have provided the Commission with our recommendation on each, such examinations are simply not possible during a typical rate case procedural schedule.

As we recommended above, a better way to develop grid plans is needed. However, based on the information we have reviewed since receiving the plan, it is clear that the substantial increases to the Company's recent, annual capital investment have not been justified. Although we found lack of support for many of the programs included in the grid plan, rather than make recommendations to the Commission regarding the specific programs and projects that should be removed from the Company's Grid Plan, we instead recommend that capital spending of the Company's overall grid plan be capped.

A capital spending cap forces the Company to apply limited capital to the risks the Company deems are the greatest, and to select the lowest-cost ways to mitigate each. These are excellent Grid Plan goals. We repeat that this is exactly how businesses competing in open markets make capital spending decisions. Given that the role of monopoly regulators is to serve as a substitute for competition, we

believe the implementation of a capital spending cap is both consistent with the law and the correct regulatory response to the Company's Grid Plan and Rate Plan. As demonstrated throughout this testimony, limiting the budget allows investment at current, historically high levels, and at the same time, allows capital spending programs and projects the Company recommends for this Grid Plan to be deferred to future grid plans. The Company's excellent reliability record and the long-term nature of DER and EV adoption demonstrates that the current Grid Plan capital budget can be limited at low risk while an improved approach to grid planning is developed.

Finally, Commission adoption of our Grid Plan spending cap recommendations offers the Commission a unique opportunity. The Commission should require the Company to identify the programs and projects it will eliminate from the Grid Plan as a result of the cap, and to track the effects of such eliminations for future analysis. The impact (or lack thereof) demonstrated by the elimination of programs and projects that the Company recommended but did not implement would certainly constitute information of great value in the development of future grid plans.

Q. How did you develop your recommended capital spending caps in dollars?

A. We believe a reasonable basis for establishing capital spending caps is to use the Company's actual capital spending from the most recent 4-year period (2019-2022) as a baseline, and to grow that baseline by expected inflation 2023-2027. We applied this logic to the three capital spending categories in which we identified the

most egregious examples of cost-ineffective spending, or spending that could easily be deferred to future Grid Plans at low risk. As described in Section III, these three capital spending categories are Corrective Maintenance, System Performance, and Capacity Expansion. We employed the same inflation assumptions as the Company assumes in this rate case from 2023 through 2027, which are 3.92% for 2023; 2.2% for 2024; 2.13% for 2025; 2.21% for 2026; and 2.26% for 2027.[104] Table 4 shows our recommended Grid Plan reductions by year, and by capital spending category. These capital spending reductions are reflected in the revenue requirements recommended by AG Witness Mr. David Effron in his Direct Testimony.

Table 4: AG Recommended Reductions by Year, by capital spending category

	19-'22	MYIGP				
	Act. Ave.	2024	2025	2026	2027	Total
Capacity Expansion						
Recommended (2019-2022 Ave. plus inflation)	210.000	223.033	227.784	232.818	238.079	921.714
Requested		305.000	292.000	308.000	470.000	1,375.000
Recommended Reduction		(81.967)	(64.216)	(75.182)	(231.921)	(453.286)
IT Projects						
Recommended (2019-2022 Ave. plus inflation)	107.500	114.172	116.604	119.181	121.874	471.830
Requested		175.000	237.000	157.000	190.000	759.000
Recommended Reduction		(60.828)	(120.396)	(37.819)	(68.126)	(287.170)
System Performance						
Recommended (2019-2022 Ave. plus inflation)	513.000	544.838	556.443	568.740	581.594	2,251.616
Requested		710.000	699.000	863.000	927.000	3,199.000
Recommended Reduction		(165.162)	(142.557)	(294.260)	(345.406)	(947.384)
System Peform/Capacity Expansion/IT Projects	'19-'22	Grid Plan				Grid Plan
($ in millions)	Act. Ave.	2024	2025	2026	2027	Total
AG Recommendation	830.500	882.043	900.830	920.739	941.547	3,645.159
Company Requested		1,190.000	1,228.000	1,328.000	1,587.000	5,333.000
AG's Recommended Reductions		(307.957)	(327.170)	(407.261)	(645.453)	(1,687.841)

Q. Do you have any other recommendations for the Company's Grid Plan?

[104] ComEd response to AG 9.10 and Attachment 2 thereto.

A. Yes. In addition to spending caps, we have a few specific recommendations we believe the Commission should adopt. One of these recommendations relates to the Company's proposal to expand its proprietary fiber optic communications network. The other recommendation relates to the inclusion of contingency budgets in capital spending projections used to calculate revenue requirements.

Regarding the Company's proposal to expand its fiber optic communications network, confidential documents provided in discovery indicate the total capital spending for such an endeavor will be much larger than that proposed in this Grid Plan.[105] Before the Company proceeds down this costly path, we recommend the Commission order an independent technical, operational, and economic review of the Company's communications network "build or buy" options, overseen by Staff and stakeholders. Such a review could easily be completed by the next grid plan, and is an example of the type of independent analysis that would be typical during a joint grid plan development process. Given that the Company's communications network capital spending focuses on substations with which the Company is already communicating, we believe the delay associated with an independent, Staff-led review of "build or buy" options to be virtually risk-free.

Q. What is your recommendation regarding project contingency budgets the Company includes in its Grid Plan and associated revenue requirements?

[105] *See* AG Ex. 1.4 CONFIDENTIAL and AG Ex. 1.5 CONFIDENTIAL.

A. As described earlier, the inclusion of contingency budgets in capital spending projections inflates those projections by amount that might not be needed. Due to capital bias, this encourages utilities to inflate contingency budgets and use them, which is not a benefit for customers. Providing accelerated cost recovery of contingency budget spending encourages a utility to spend through the contingency amount, thereby discouraging project cost discipline. As a result of these concerns and observations, we recommend the Commission order that contingency budgets are not to be included in grid plans in Illinois, thereby establishing an important precedent for future Rate Plans.

V. REVIEW

Q. Please review your testimony and recommendations related to multi-year ratemaking administration.

A. Our testimony on multi-year ratemaking administration began with a description of the value that cost disallowances available with traditional ratemaking offers to customers. We explained that traditional cost disallowance risk combined with regulatory lag encourages utility capital spending governance and mitigates regulator/staff/stakeholder information asymmetry. We then explained exactly how multi-year ratemaking practically eliminates cost disallowance risk and capital spending governance, and how it increases regulator, staff, and stakeholder responsibilities. Our testimony on multi-year ratemaking administration concluded with a discussion of the distribution planning process documented by the NARUC-NASEO Task Force, and described what staff and stakeholder participation in that

process, resulting in joint utility-stakeholder development of multi-year grid plans, might look like. Our recommendations for multi-year ratemaking in Illinois included:

- That the Commission immediately commence a proceeding to develop a process by which stakeholders and utilities jointly develop grid investment plans, with the resulting process to be deployed initially in advance of the next grid plan/rate case; and
- That the Commission Order that discretionary grid investment proposals—meaning those not strictly necessary for safe and reliable service delivery within the upcoming grid plan period—be subjected to risk-informed decision support analysis as a test of cost-effectiveness, and to optimize grid plan capital spending, as part of any future grid plan developed in Illinois.

Q. Please review your testimony and recommendations related to the Company's Grid Plan.

A. Our testimony regarding the Company's Grid Plan began with a summary of the Company's proposal, including capital spending proposals during the 4-year Grid Plan period that are 28.7% higher than the 2019-2022 period and 271% higher than the 2011-2014 period. We also highlighted that rates will increase more than 60% over 2022 levels by 2027 if the Commission approves the Company's recommended Grid Plan and cost recovery. We then introduced risk-informed decision support, or RIDS, as a more rigorous approach to evaluating and prioritizing utility capital spending proposals, and compared RIDS to the

project/program prioritization approach the Company employed in developing its Grid Plan.

We then provided multiple examples of capital spending in the Company's Grid plan that was not cost effective, or that could be deferred to future grid plans at low risk. The Company's Grid Plan recommends a $1.147 billion/55.9% increase in System Performance capital spending over 2018-2022 levels, and had had the greatest number of examples. But before describing them, we noted an absence of justification for spending any capital at all to improve system performance, citing:

- The Company's reliability performance has not only been improving, it is now among the top 10% of investor-owned utilities in the US; and
- That the Company's customers are more satisfied with the Company's reliability than with the Company overall (and that the customers were less satisfied with the Company's rates than with the Company overall); and
- That the Company had completed no research indicating that customers are willing to incur rate increases to improve reliability.

We then identified multiple System Performance projects or programs the Company recommended as cost-ineffective, inappropriate, or deferrable to future grid plans at low risk, including:

- Expansion of the Company's fiber optic grid communications network without a rigorous examination of alternatives ($972 million to start);
- Advance replacement of underground cable ($455 million);

- Targeted undergrounding program ($210 million);
- Premature replacement of substation equipment ($180 million);
- Intelligent Substations ($141 million)/Relay Replacements ($20 million);
- Installation of full vacuum reclosers on lateral lines ($55.5 million).

Our testimony then proceeded to examine the Company's proposed $535 million/63.7% increase in Capacity Expansion capital spending over 2019-2022 levels. We found no justification for such increases, citing:

- Flat load growth system-wide;
- Of 27 multi-million-dollar Capacity Expansion projects examined, only 11 were justified through load growth;
- The Company failed to provide workpapers justifying $97 million to accommodate EV load growth or 90MW in assumed system peak EV charging demand by 2027; and
- $87 million in Public School Carbon Free Assessment spending, which should have been included in expense budgets, was found among Capacity Expansion capital spending projections.

Our testimony next examined the Company's $329 million/76.5% increase in IT Project Capital spending. We expressed concerns over ADMS/DERMS software project need and timing, as well as concerns over the need and cost to replace the Company's existing asset management application (ComEd's share alone is $126 million). We closed our examination of the Company's Grid Plan with a discussion of the inappropriate incentives created by the inclusion of

contingency budgets in multi-year rate plan capital spending projections.

In response to these findings, we recommend the Commission reduce the grid capital spending the Company requests in its Grid Plan from $8.5 billion to $6.85 billion. (These reductions are reflected in AG Witness Mr. Effron's revenue requirement calculations.) These reductions were calculated using 2019-2022 capital spending baselines in the System Performance, Capacity Expansion, and IT Project categories, and adjusting them for expected inflation 2023-2027. We also made the following specific recommendations on the Company's Grid Plan:

- That the Commission order an independent technical, operational, and economic evaluation of the build or buy options available to the Company for its future communications network needs, overseen by Staff; and
- That the Commission order that project contingency budgets be excluded from all future grid plans in Illinois.

Q. Do you have any other comments?

A. Yes. In our opinion, CEJA is well-intended and forward-looking, but presents challenges to Staff and stakeholders and imposes enlarged responsibility on the Commission due to the lack of structural incentives to constrain capital spending. As a result, we urge the Commission to take the steps necessary to restore the balance between shareholder interests and customer (and State economy) interests that the traditional ratemaking construct offered by closely reviewing the Company's Grid Plan, and adopting our recommendations to limit grid spending to a reasonable level, and to require a consensus building process prior to the filing

of the next grid plan. We thank the Commission in advance for considering our perspectives on, and recommendations for, CEJA administration and the Company's Grid Plan as presented in this testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.