ENVIRONMENTAL INTERVENOR POST-CHARRETTE #1 COMMENTS

The Iowa Environmental Council, Environmental Law and Policy Center, and Sierra Club (collectively the Environmental Intervenors) submit these Comments in response to the “Order Establishing Schedule and Designating Authority” filed in the above-captioned docket on August 7, 2023, and to address issues raised during the charrette discussions. These comments were written with assistance from RMI, an independent, non-partisan, nonprofit organization of experts across disciplines working to accelerate the clean energy transition and improve lives; Synapse Energy Economics, a research and consulting firm focused on the intersection of energy, economics, and the environment; Grid Strategies LLC, a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid; and GridLab, a non-profit organization that provides comprehensive technical expertise to policy makers, advocates and other energy decision makers on the design, operation and attributes of a flexible and dynamic grid.

I. Integrated resource planning advances statutory objectives.

Iowa has relied on a piecemeal approach to evaluating and approving utility expenses for over 15 years. These pieces include general rate cases, advance ratemaking, energy efficiency planning, demand response planning, emissions plan and budgets, and a variety of riders. The first charrette highlighted broad stakeholder support for integrated resource planning. We offer these comments both to provide additional detail regarding how IRPs could address deficiencies in Iowa’s regulatory regime and to respond to a few stakeholder questions about how IRPs could work.

As noted by stakeholders during the charrette, the Board has the authority to fit IRP-type capacity expansion modeling analyses into its existing regulatory framework, such as requiring load forecasts in energy efficiency proceedings or advance ratemaking dockets. However, there are drawbacks with pursuing this approach over adopting a standalone IRP process. Advance ratemaking dockets occur only at the initiation of the utilities. A utility could therefore prevent...
the Board from reviewing the cost-effectiveness, reliability and risk of its existing system by refraining from applying for advance approval of resource additions. While our organizations do not oppose the continued availability of advance ratemaking as a tool for pursuing resource additions, those additions must first be supported by integrated resource planning analysis -- including capacity expansion modeling -- to ensure they are reasonable in the context of the utility’s entire resource mix. IRPs should take place on a regular schedule, outside of advance ratemaking dockets, to facilitate transparent and accessible planning for Iowa’s energy future.

Standalone IRPs provide a way to regularly examine the economics of a utility’s whole fleet, and evaluate whether each of the Company’s existing resources is economically meeting load and other system needs relative to alternative resource options available in the market. As we discussed in our pre-charrette comments, capacity expansion modeling can help evaluate whether the Company’s current resource mix is cost-effectively serving load, and identify alternative portfolios that can more affordably meet system needs. This modeling identifies uneconomic resources that should be retired and new lower-cost resources that should be brought online. All this is done while accounting for risk, reliability, and customer needs, as well as Iowa policy goals. Iowa’s existing approach does not require this holistic review on any regular timeline. The danger in not requiring holistic resource planning analysis on a regular basis is that it inherently favors the status quo. But the existing resource mix is not inherently the lowest cost and lowest risk option. Given the pace and scale of change currently occurring in our state, regional, and national electricity system, Iowa ratepayers would be better served by regular reviews of their utility’s fleet to ensure the utility is being responsive to opportunities and risks associated with this transition.

It is important to be clear, though, that not all integrated resource planning processes are equally valuable. In some states, resource planning processes are paper exercises designed to justify utilities’ preferred courses of action, with minimal transparency or rigorous analytical backing. In our Pre-Charrette Comments, we cited RMI's recent report, Reimagining Resource Planning, as identifying best practices in modern resource planning.¹ For convenience, we have attached this full report to our comments, and urge London Economics to review it in its entirety (Attachment A).

Resource plans that are most effective at equipping utilities, regulators and stakeholders to evaluate resource decisions are comprehensive, transparent, and well-aligned. In other words, an IRP should:

- be informed by capacity expansion modeling that accurately represents costs and resources (with resource cost and performance data from industry-leading sources and company-specific data, as well as ideally based on recent market bids from responses to

an all-source Request for Proposals), and fairly consider all options across the transmission and distribution system (e.g., it should consider the value of distributed generation to the system);

- prioritize transparency by making planning assumptions publicly accessible and enable meaningful stakeholder input throughout the process;
- align with state and federal policy goals and other grid planning needs -- including modern approaches to planning for reliability, aligning with distribution planning, addressing affordability and economic development, and accounting for customer demand such as reduced greenhouse gas emissions.\(^2\)

To ensure an open and transparent process with robust stakeholder engagement, IRPs should take place in either a contested case setting or with sufficient regulatory oversight to ensure utilities are sharing the data needed for stakeholders to test the robustness of the utilities’ analysis. For example, in Minnesota, integrated resource planning does not occur in a contested case proceeding that requires formal intervention; instead, almost all of a utility’s data needed to conduct modeling analysis is publicly available, and all trade secret data (such as modeling files) is available through a broad discovery process, with Commission oversight over discovery disputes.

While many of the benefits of resource planning are in the exercise of planning itself, it is also critical that the regulator has a strong role in reviewing and approving the plans. The regulator’s approval of the plan, and finding that a plan is in the public interest, should be binding; that is, a utility can then use that plan approval as a basis for moving forward with retirements and acquisitions.

Some states have also increased the connection between the integrated resource plan’s outputs and resource procurement. In Colorado, planning requires approval and directly links to procurement decisions. Specifically, the Colorado Public Utilities Commission (CO PUC) is required to issue a written decision approving, disapproving, or ordering modifications to the utility's IRP. Approval of this IRP then authorizes utilities to proceed with issuing an all-source request for proposal (RFP) for the needs approved in the plan.\(^3\) As such, the resource planning rules and guidelines have a more direct role in shaping the future of Colorado’s electricity system. Washington and Georgia have similarly direct links between planning and procurement, elevating the importance of robust planning in their jurisdictions.

One of the core components of a strong IRP process is ensuring capacity expansion modeling assesses not only economic resource additions, but also the cost-effectiveness of the utility’s

\(^2\) *Id.* at 11.

\(^3\) For a review of Xcel Colorado’s all-source procurement approach and how it secured lower costs, see “Xcel’s record-low-price procurement highlights benefits of all-source competitive solicitations,” Utility Dive (June 1, 2021), available at https://www.utilitydive.com/news/xcels-record-low-price-procurement-highlights-benefits-of-all-source-compe/600240/.
existing generation. The U.S. electricity sector is evolving rapidly in ways that raise questions about the cost and risk of long-term reliance on coal generation: the costs of new renewable generation resources continue to fall; the inflexible operational characteristics (i.e. slow ramp rates, high minimum output levels, and high start costs) of coal plants make them poor grid resources; technologies like battery storage can offer the grid stability and reliability benefits historically associated with coal in a better and more cost effective manner and are increasingly widespread; and the cost risks associated with continued coal dependence continue to rise, especially as government regulations increasingly are directed at reducing coal plant emissions and waste streams. Utilities can no longer reasonably assume that continued heavy reliance on coal generation is the least-cost, least-risk option for customers; rather, they must be required to establish -- using the type of quantitative capacity expansion modeling analysis that has become a standard practice for utilities nationwide -- that any plans to continue to rely on coal plants are in the public interest. In our pre-hearing comments for the next charrette, we will offer detailed thoughts on best practices from other states to ensure utilities conduct quantitative capacity expansion modeling that examines the cost-effectiveness of existing generation.

A standalone IRP process would also create a venue where regulators can require utilities to examine the potential savings to customers from programs created by the Inflation Reduction Act (IRA). Minnesota, for instance, recently adopted a requirement that utilities discuss IRA opportunities in their integrated resource plans. One of the most significant IRA opportunities for utilities to deliver savings to ratepayers is the Energy Infrastructure Reinvestment (EIR) program, which provides the U.S. Department of Energy with $250 billion in loan authority to deploy low-interest debt to support the clean energy transition. This program can permit utilities to refinance outstanding balances of existing coal units at just above the federal government’s cost of borrowing and with repayment periods up to 30 years, allowing accelerated retirements while reducing the economic burden on Iowa ratepayers relative to traditional financing methods. Indeed, per statute, utilities must pass through the savings enabled by EIR to their customers. At the first charrette, London Economics asked stakeholders how the Board should treat undepreciated balances for plants that are deemed no longer “used and useful” -- i.e., plants that are no longer economic compared to replacement options. Iowa’s current ratemaking structure does not require utilities or the Board to consider the EIR opportunity. EIR loan authority expires in September 2026, and so under Iowa’s existing regulatory framework, Iowa may miss this opportunity entirely if utilities do not come in for rate cases before that time.

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4 In addition, coal prices were volatile in 2022; railroad labor shortages can impact coal deliveries, which created future operating risk in late 2022; cooling water may not be available at critical times in summer or winter due to drought or ice dams; and problems getting replacement parts for aging plants will grow, creating the potential for outages as already experienced for Culley Unit 3 in Indiana (see Ind. Regulatory Comm’n Cause no. 38708, Direct Testimony of Wayne D. Games (filed Nov. 16, 2022), at 18-20, describing a malfunction beginning in June 2022 that would not be repaired until 2023).

5 Minnesota PUC docket 22-624, In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act, order not yet published.
Incorporating consideration of IRA opportunities into a new integrated resource planning process could offer huge savings to customers.

As we noted in our Pre-Charrette Comments, a new standalone long-term integrated resource planning process also provides a venue for evaluating how well matched a utility’s resource mix is to the long-term reliability challenges facing the grid. As extreme weather events become more common, with the potential of inflicting high costs on customers (such as during Winter Storm Elliott), it is critical that utilities regularly undertake quantitative analysis of their systems’ ability to perform in all seasons. As described in our earlier sets of comments, utilities can supplement traditional capacity expansion modeling in their IRPs with probabilistic or scenario-based analyses that assess resilience to a range of challenging reliability scenarios (generally done using the same modeling platforms). To evaluate the resilience and reliability of a preferred resource mix in an IRP, utilities should conduct sequential hourly modeling and analysis of sub-hourly market prices to understand the value of flexible resources relative to inflexible resources. We have attached to these Post-Charrette Comments additional detail on how to incorporate reliability analyses into IRPs, drafted with the assistance of Grid Strategies and GridLab (Attachment B). **We recommend that London Economics dedicate time during the second charrette exploring ways in which other states approach assessing reliability in IRP processes.**

As noted in our pre-workshop comments, several states (including Minnesota and Michigan) are implementing integrated distribution planning (IDP) to complement their IRP processes. As explained by the Minnesota PUC, integrated distribution planning provides the Commission with the information necessary to understand utilities’ short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value. This allows states to move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies. We urge London Economics to closely review these IDP policies and consider how they can complement resource planning to ensure cost-effective utility investment in a safe, efficient, and reliable grid.

During the first charrette, the facilitators asked for feedback on how long-term planning processes should align with RTO planning processes. Capacity expansion modeling conducted during IRP processes should use RTO capacity accreditation (such as the MISO seasonal construct) in order to ensure utilities will cost-effectively meet MISO resource adequacy requirements. While MISO accreditation constructs will change over time, utilities in other states are assessing this uncertainty by using modeling sensitivities (e.g., higher or lower capacity

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accreditation for various resource options). Long term planning should also include RTO- 
required studies when planning for generation retirements -- for example, MISO Y2 studies 
should be conducted and included in an IRP filing so that the IRP can assess the most cost-
effective solutions to any reliability needs (as is done in Minnesota, for example). IRPs can also 
consider the long-term impact of MISO transmission plans on the costs of adding new resources. 
Interconnection costs in the Midwest are currently high due to transmission constraints; those 
costs should come down as new lines are built through the MISO Long Range Transmission 
Planning process, which will result in lower costs for new renewable resources.

At the first charrette, London Economics also asked stakeholders for initial thoughts regarding 
which other state IRP processes Iowa should look to as model examples. The facilitators 
expressed an intent to focus on states in the MISO/SPP region. While we will save our comments 
regarding specific states’ integrated resource planning processes for our pre-charrette comments 
for the second charrette, we note now that we believe it would be valuable to look beyond the 
MISO/SPP region when crafting recommendations for an Iowa IRP process. At minimum, we 
recommend looking to the other jurisdictions in which Iowa’s utilities’ sister subsidiaries 
operate, such as Washington and Oregon (for MidAmerican’s sister utility PacifiCorp).

Moreover, given that Iowa now generates a significant portion of its energy requirements from 
renewables, the Board may also find it useful to learn about other states that are similarly 
situated, even if they are outside the region.

During the charrette, MidAmerican expressed a concern that IRPs can limit flexibility by 
preventing the utility from taking advantage of new opportunities that arise between IRP cycles. 
This is not the case. In Minnesota, for example, utilities can come in for approval of new 
resource acquisitions that were not proposed in their IRP, so long as they include in their 
application capacity expansion modeling that demonstrates the reasonableness of pursuing that 
addition in light of their overall resource mix (i.e., demonstrates that the new resource would 
deliver total system cost reduction benefits and would contribute to a reliable system).8

8 Minn. Stat. § 216B.2422 subd. 6 states: “Consolidation of resource planning and certificate of need. A utility shall 
indicate in its resource plan whether it intends to site or construct a large energy facility. If the utility's resource plan 
includes a proposed large energy facility and construction of that facility is likely to begin before the utility files its 
next resource plan, the commission shall conduct the resource plan proceeding consistent with the requirements of 
section 216B.243 with respect to the proposed facility. If the commission approves the proposed facility in the 
resource plan, a separate certificate of need proceeding is not required.”

MidAmerican also asserted that IRPs can create an endless cycle of planning, without ever 
leading to resource mix changes. This claim does not reflect how IRPs work in practice. In fact, 
utilities can benefit from the certainty provided by IRPs. In 2022, the Minnesota PUC approved 
Xcel Energy’s proposal to reduce customer costs by retiring its remaining coal fleet and acquire 
or build up to 4,650 megawatts (MW) of renewable resources (solar, wind, and storage) by 
2032.9 Xcel now has multiple ongoing RFP dockets to expeditiously acquire those resources. In 

its 2023 IRP, PacifiCorp, which serves six states, proposes to develop the following portfolio by 2042: over 9,000 megawatts of new wind resources, over 8,000 MW of storage resources, nearly 8,000 MW of new solar resources (most paired with battery storage), nearly 5,000 MW of capacity saved through energy efficiency programs and nearly 1,000 MW of capacity saved through direct load control programs, in addition to non-emitting peaking facilities and nuclear, while also converting or retiring a significant amount of coal generation.\textsuperscript{10} The Michigan PSC recently approved a settlement of DTE Electric’s IRP, including the addition of more than 15,000 MW of solar and wind generation in Michigan and more than 1,800 MW of energy storage by 2042, as well as planning for certain coal plant retirements by 2032.\textsuperscript{11}

A stakeholder also raised the question as to whether IRPs are too costly. But the costs of IRP processes are negligible compared to the magnitude of savings they can deliver to customers. For example, in Alliant’s 2020 Clean Energy Blueprint, Alliant concluded that early retirement of Lansing Generating Station, conversion of Burlington Generating Station to gas, and the addition of up to 400 MW of solar in 2023 would save customers $300 million.\textsuperscript{12} By comparison, Alliant’s most recent rate case cost less than $3 million.\textsuperscript{13}

IRPs can also reduce the costs of subsequent rate cases. Under Iowa’s current regulatory framework, the prudence of costs associated with generation that is already in the rate base is reviewed in rate cases.\textsuperscript{14} So long as the IRP includes robust capacity expansion modeling that examines the cost-effectiveness of existing generation, and so long as parties have already had the opportunity to test the quality of the modeling in a contested case proceeding, the Board will already have vetted this substantial question before reaching a rate proceeding. Reviewing the prudence of past expenditures in a rate case places the regulators in the difficult position of denying costs that the utility has spent; in such circumstances, the utilities often assert that such denial will impact their credit ratings and therefore will have a longer term impact on customer costs. Utilities can also derive certainty from regulators reviewing the reasonableness of continuing to operate existing generation on a forward-looking basis in an IRP process, rather than backward-looking in a rate case.

\textsuperscript{14} “Final Decision and Order,” Docket no. RPU-2018-0003, at 35.
However, if the Board does not recommend adopting a standalone IRP framework, the Board should at minimum require utilities to file rate cases on a regular schedule, possibly with a requirement that a utility can go no longer than 5 years without a rate case. This is needed to otherwise account for the pace and scale of the electricity transition and other significant energy policy changes. For example, MidAmerican has not had a rate case since 2013. Among other major developments that have occurred since that time, 2017 tax reform lowered the corporate federal tax rate from 35% to 21%. MidAmerican has continued to collect excess taxes, which could amount to hundreds of millions of dollars. The Board has not yet determined how to treat that pot of money, and has several options for doing so.\textsuperscript{15} MidAmerican has asserted that a near term rate case would cause a substantial rate spike; however, it is not possible for outsiders to evaluate the validity of this assertion given the magnitude of uncertainty regarding issues such as the treatment of the excess accumulated deferred income taxes. The Board may want to consider an investigatory process short of a rate case to further understand the major factors that would influence MidAmerican’s rates.

\textbf{II. Advance Ratemaking Principles (ARPs)}

As noted above, IRP-type capacity expansion modeling analysis can and should be included as a filing requirement in advance ratemaking principle applications. Indeed, in its April 27, 2023 Order in the Wind PRIME docket, the Board held that “In any future ratemaking principle proceedings, MidAmerican shall provide in its prefiled testimony not only a robust analysis of the need for the project and comparison of the proposed generation facility with other feasible long-term sources of supply, but additional analysis regarding interaction of the proposed resources with the remainder of MidAmerican’s generation portfolio.”\textsuperscript{16} The Wind PRIME record extensively documents utilities’ history of including capacity expansion modeling in support of its resource addition proposals -- although this past modeling has had the significant shortcoming of not sufficiently examining the utility’s existing system.

In its September 6, 2023, filing, London Economics asked parties to address the following question:

Multiple stakeholders noted during discussions that the goal or intent of the advance ratemaking statute has been achieved and ARM may no longer be necessary. Does this view suggest that (i) Iowa no longer requires development of new generation assets and ARM can be removed, (ii) new generation assets will be developed without ARM and therefore it is not needed, or (iii) ARM needs to be revised for continued development of generation assets?

\textsuperscript{15} For a description of the pros and cons of these options, see pp. 8-9 of “Harnessing Financial Tools to Transform the Electric Sector,” available at https://www.sierraclub.org/sites/default/files/sierra-club-harnessing-financial-tools-electric-sector.pdf.

\textsuperscript{16} Docket no. RPU-2022-0001, “Final Decision and Order,” at 95.
First, we disagree that the goal of the advance ratemaking statute has been achieved, although the statute could certainly be improved. Iowa Code Section 476.53 has been an important tool for meeting increasingly widespread customer demand for clean energy, and has made Iowa a leader in wind generation. However, for all of the reasons discussed above, the approval of advance ratemaking principles going forward should be tied to a requirement that the proposed addition is grounded in an approved integrated resource plan, or alternatively that the application is supported by IRP-level capacity expansion modeling that demonstrates the cost-effectiveness and reliability and diversity benefits of the proposed addition in the context of the utility’s overall system.

As the economics and reliability of coal continue to worsen, it will be in ratepayers’ best interest for utilities to continue to invest in new, lower-cost, clean generation additions. Iowa will no doubt continue to be the nation’s “breadbasket” of wind generation, but solar and battery storage will also be critical to delivering a diverse and reliable generation mix. This need is illustrated by the recent MISO Regional Resource Assessment (RRA). The MISO RRA offers a modeling-based study of the resource additions needed to address the region’s decarbonization plans in a cost-effective and reliable manner. The chart below shows the amount of new resources the model selected for Zone 3 (which is Iowa).


III. Energy Efficiency

Iowa statute\(^{18}\) includes a largely unprecedented policy that allows any customer to opt out of paying for a utility’s energy efficiency ("EE") programs if they do not pass the Ratepayer Impact Measure (RIM) test. This approach undermines the deployment of cost-effective, least cost resources in Iowa, and prevents customers from accessing programs that enable them to effectively manage their own energy use.

The purpose of the RIM test is to indicate whether a resource will increase or decrease electricity or gas rates.\(^{19}\) Unlike other cost-effectiveness tests, the RIM test is a measure of distributional equity rather than net economic impacts across a population.\(^{20}\) Further, the RIM test offers an incomplete view of even distributional equity, leaving regulators with a picture of distributional rate impacts, but not bill impacts or program participation rates. As a result, regulators miss an understanding of the extent to which participating customers experience lower bills - they see whether rates will go up or not, but miss information about the magnitude of the increase and the proportion of customers that might experience an increase.

The test includes the same system costs and benefits measured in a utility cost test, but also considers utility lost revenue from EE investments as a cost. As a result, use of the RIM test does not result in effective energy efficiency programs, because a program can only pass the RIM test if it actually conserves relatively little energy. This is because a program that yields higher energy savings will perform worse on the RIM test, since the resulting reduced sales revenue is treated as a cost. This creates a perverse incentive for energy efficiency program administrators in program design and deployment.

Energy efficiency savings have decreased dramatically since Iowa adopted the RIM test policy in 2018. ACEEE data shows that net incremental electricity savings dropped from 421,963 megawatt-hours ("MWh") in 2017\(^{21}\) to just 200,324 MWh in 2021\(^{22}\) – a decrease of more than 50 percent. As a result, Iowa dropped from 24th place nationally to 35th in ACEEE’s annual state energy efficiency scorecard last year.\(^{23}\)

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\(^{20}\) Id. at 114.


\(^{23}\) Id.
There is a range of more appropriate approaches to cost-effectiveness testing and distributional analysis that Iowa regulators and policymakers can consider. For cost-effectiveness testing, a Utility Cost Test offers a picture of the impacts of energy efficiency on utility system cost and average customer bills; Total Resource Cost and Societal Cost tests offer additional perspectives into program participants and society, respectively. For distributional analysis, combining rate impact analysis with bill analysis and program participation analysis can offer insight into the equity consequences of different investments, including energy efficiency and other demand-side measures.

IV. Multi-Year Rate Plans

During the charrette, London Economics asked for stakeholder feedback on the concept of multi-year rate plans. Performance-based regulation (PBR) is a regulatory approach that aims to better align utility incentives with both customer and societal interests. When designed well, it does this by compensating utilities based on desired outcomes rather than on costs incurred, and by removing existing perverse incentives that are associated with the traditional cost of service regulatory model. There are several tools in the PBR toolbox that are designed to address the problematic incentives and outcomes associated with cost-of-service regulation.\(^{24}\) Multi-year rate plans (MYRPs) are one such PBR tool.\(^{25}\)

MYRPs are mechanisms intended to encourage cost efficiency and keep customer rates affordable. However, MYRPs are associated with many design choices, and the quality of the design is essential to whether a MYRP serves these outcomes in reality. When MYRPs are designed well, they encourage utilities to invest in clean energy and embrace distributed energy resources (DERs) where these resources provide cost saving opportunities. MYRPs also have the benefit of enhancing utility revenue stability, which makes the firms attractive to investors.

However, MYRPs are not guaranteed to result in savings for ratepayers. When MYRPs are poorly designed, they can reduce the risk associated with utility earnings, inflate shareholder profits, and fail to share utilities’ efficiency gains with customers. Moreover, the extent to which DER adoption is encouraged may depend on whether the utility can substitute cost-effective operational expenses for capital expenses and retain a portion of the savings in lieu of the lost opportunity for a return.

\(^{24}\) These comments on MYRPs were drawn from RMI testimony in the Duke Energy Carolinas Rate Case and PBR application, which also provides a complete description of the poor incentives associated with traditional cost of service regulation and how PBR is intended to overcome these shortcomings. See Direct Testimony of Gennelle Wilson, Docket No. E-7 Sub 1276, July 19, 2023, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?id=17003f8-9238-42c5-8b40-9ca9669e2fac.

\(^{25}\) There is significant scholarship on the design, benefits, and risks associated with MYRPs. A few seminal resources include Stragen’s 2019 Multi-Year Rate Plans: Core Elements and Case Studies report, RMI’s 2018 Navigating Utility Business Model Reform report, and the U.S. Department of Energy Grid Modernization Laboratory Consortium’s 2017 State Performance-Based Regulation Using Multivear Rate Plans for U.S. Electric Utilities report.
When considering MYRPs and their appropriateness for the Iowa context in future charrettes and discussions in this proceeding, it is important to consider the extent to which recent experience with MYRPs is attributable to poor design or alternative rate-setting approaches like a future test year. There is an opportunity to adopt MYRPs in Iowa in a way that is supportive of customer affordability and cost efficiency, and as part of this proceeding, the Iowa Utilities Board and stakeholders should consider the comparability of recent experience with rate freezes with MYRPs, how the effects of the rate freezes have differed from MYRPs adopted in other jurisdictions, and what MYRP design choices would yield outcomes in service of Iowa’s customers, utilities, and policy goals. Environmental Intervenors are open to exploring the MYRP concept through the charrette process.

V. Terms and Definitions

During the first charrette, London Economics requested stakeholder input into the regulatory definitions of the following terms: “reliability,” “affordability,” “just and reasonable,” “nondiscriminatory,” and “used and useful.” We offer some preliminary thoughts here, which we can refine in subsequent charrettes.

Reliability: Iowa should adopt a definition of reliability that is consistent with NERC, FERC, and MISO definitions. According to NERC, “NERC’s traditional definition of “reliability” … consists of two fundamental concepts -- adequacy and operating reliability:

- Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.”

Resource adequacy is ensured through MISO’s zonal capacity requirements and voluntary capacity auction, and is also addressed through state-regulated utility IRP planning and resulting resource procurement. Utilities can ensure long-term resource adequacy by conducting capacity expansion modeling that incorporates MISO’s capacity accreditation, seasonal construct, and zonal capacity requirements.

NERC further states that:

The Bulk-Power System (“System”) will achieve an adequate level of reliability when it possesses following characteristics:
1. The System is controlled to stay within acceptable limits during normal conditions;

2. The System performs acceptably after credible Contingencies;
3. The System limits the impact and scope of instability and cascading outages when they occur;
4. The System’s Facilities are protected from unacceptable damage by operating them within Facility Ratings;
5. The System’s integrity can be restored promptly if it is lost; and
6. The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.\(^{27}\)

MISO procedures and markets also ensure operating reliability. Utility planning in Iowa should account for how MISO markets procure the resources needed to maintain reliability. For example, utility planning should account for MISO market prices for different reliability services, and assess whether Iowa resources can cost-effectively provide services in those markets.

**Affordability:** as noted by various stakeholders at the charrette, the definition of affordability should incorporate the concept of energy burden. The U.S. Department of Energy defines energy affordability as “the idea that consumers should be able to pay for their home electricity use—lighting, heating, cooling, powering appliances—while also paying for other basic living expenses, such as food and medication, without having to choose or feel overburdened.”\(^{28}\)

A household’s energy burden is “the percentage of household income spent on energy bills”; researchers define households with a 6% energy burden or higher as experiencing a high burden.\(^{29}\) According to ACEEE, “about one-fourth of all households and more than two-thirds of low-income households live with a high energy burden. In fact, low-income households experience high energy burdens almost three times more than the average household and thirteen times more than non-low-income counterparts.”\(^{30}\) When assessing whether a utility’s electricity costs are “affordable,” it is essential that regulators do not limit themselves to considering average residential electricity costs; they must also assess whether utilities are adequately ensuring no Iowans are paying unacceptably high portions of their incomes to their electricity bill. This includes ensuring utilities are adequately providing programs that target delivering energy efficiency and clean energy benefits to those experiencing a high energy burden.

\(^{27}\) Id. at 6.
\(^{28}\) “Energy Accessibility and Affordability,” U.S. DOE, available at [https://www.energy.gov/eere/energy-accessibility-and-affordability](https://www.energy.gov/eere/energy-accessibility-and-affordability) (last visited Sept. 8, 2023). DOE also notes that energy affordability requires consideration of energy equity, a concept that “recognizes that disadvantaged communities have been systematically marginalized and overburdened by pollution, underinvestment in clean energy infrastructure, and lack of access to energy-efficient housing and transportation.”
\(^{30}\) Id.
Just and reasonable: the phase “just and reasonable” is a term of art in public utilities regulation and case law. We recommend that the Board refer to treatise and case law in defining this term, but briefly summarize some (but not all) key elements of the standard here. Reasonableness requires examining “all available cost savings opportunities” that are otherwise consistent with public policy.\footnote{Midwestern Gas Transmission Co. v. E. Tenn. Natural Gas Co., 36 FPC 61, 70 (1966), aff’d sub nom. Midwestern Gas Transmission Co. v. FPC, 388 F.2d 444 (7th Cir. 1968). The Federal Power Commission later rescinded its decision on unrelated grounds. Knoxville Utils. Bd. Vv. E. Tenn. Natural Gas Co., 40 FPC 172 (1968).} Evaluating the reasonableness of a utility’s cost requires using a prudence analysis.\footnote{Scott Hempling, Testimony on behalf of the South Carolina Consumer Advocate, at p. 10, available at https://dms.psc.sc.gov/Attachments/Matter/1a546ad6-63c6-4384-a1d5-a4c0feb05cc7} Prudence analysis “tests whether a utility has behaved reasonably, based on industry norms; it asks whether the utility has used all available professional tools objectively and competently.”\footnote{Id., citing Appeal of Conservation Law Found., Inc., 507 A.2d 652, 673 (N.H. 1986) (describing the prudence standard as “essentially apply[ing] an analogue of the common law negligence standard”).} Prudence also requires “a thorough, complete, and accurate evaluation of alternatives.”\footnote{Id. at 11 (citing Wisconsin Electric Power Company’s Request for Declaratory Ruling Approving a Proposed Plan to Increase Generation in Wisconsin. Application of Wisconsin Energy Corporation for Approval to Acquire the Stock of WICOR, 2001 Wisc. PUC LEXIS 69 (Oct. 17, 2001)).} As noted by renowned public utilities scholar (and current FERC Administrative Law Judge) Scott Hempling, a high prudence standard is required for monopoly public utilities because “[e]ffective regulation replicates the pressures of competition”: “[T]he state through its commission takes the place of competition and furnishes the regulation which competition cannot give”;\footnote{Id. at 12 (citing Delmarva Power & Light Co. v. Public Service Comm’n of Maryland, 370 Md. 1, 6 (Md. 2002) (quoting Oscar L. Pond, A Treatise on the Law of Public Utilities 29-31 § 901 (3d ed.1925)); see also Alfred Kahn, The Economics of Regulation: Principles and Institutions (1971, 1988), Vol. 2 at 112 (stressing the “importance of making regulation more intelligent and more effective in those circumstances in which competition is simply infeasible”).} “for if a competitive enterprise tried to impose on its customers costs from imprudent actions, the customers could take their business to a more efficient provider. A utility’s ratepayers have no such choice.”\footnote{Long Island Lighting Co., Case No. 27563, 71 P.U.R.4th 262, 1985 N.Y. PUC LEXIS 40 (N.Y. Pub. Serv. Comm’n Nov. 16, 1985).} While prudence review helps ensure utilities are controlling costs and therefore maintaining competitiveness, this is not the only relevant concern; the reasonable and just standard also incorporates public policy concerns. Reasonableness and justness requires balancing the interests of the utility’s investors, the ratepayers, and the public.\footnote{Kansas Gas and Elec. Co. v. State Corp. Comm’n, 720 P.2d 1063, 239 Kan. 483 (1986), citing Power Comm’n v. Hope Gas Co., 320 U.S. 591 (1944).} As such, the just and reasonable standard requires consideration of equity and energy justice in its application to utility rates and services.\footnote{See Chan, G. and Klass, A., Regulating for Energy Justice, 97 N.Y.U. Law Review 1426 (2022)(available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4032969).}

“Used and useful”: Traditionally, utilities can only earn a return on “used and useful” assets. An asset is generally deemed no longer used and useful when it is retired/no longer generating electricity. However, an asset may also no longer be used and useful when it is unduly expensive
compared to available alternatives. This is increasingly an issue with aging coal plants: they may have become uneconomic compared to other resource options, even as they continue to have large outstanding undepreciated balances. Retiring the asset before it is fully depreciated may be in customers’ interest; the remaining plant balance is known as a “stranded asset.” In more common terminology, this stranded asset is a “sunk cost” that should not be considered in the forward-looking evaluation of whether an asset is uneconomic in comparison to alternatives; this is because customers are on the hook for those costs regardless of whether it is retired or not.

The attached report, *Harnessing Financial Tools to Transform the Electric Sector* (Attachment C), adeptly summarizes regulators’ options when facing what it calls “the regulatory conundrum of early retirement” -- that is, how to fairly approach paying off stranded assets while encouraging utilities to make the economic decision for customers. The report notes that “regulators traditionally have three core mechanisms for handling stranded assets: disallowance, accelerated depreciation, or the creation of a “regulatory asset”—an asset that exists only on paper.” All of these approaches have disadvantages. The authors propose an alternative regulatory mechanism for avoiding the downsides of traditional approaches while delivering cost savings to customers and new opportunities for the utility, called “securitization.” Securitization is analogous to refinancing a home mortgage at a lower rate: a low-interest, ratepayer-backed bond is issued for the amount of capital needed to make the utility whole. This allows the undepreciated balance to be paid off, without requiring ratepayers to continue to pay the utility the comparatively-high rate of return they are otherwise owed. The attached report offers a detailed explanation of how securitization can benefit ratepayers. Until very recently, states seeking to use securitization had to pass legislation to enable the creation of the ratepayer-backed bonds. However, as discussed above, the Inflation Reduction Act’s EIR program is essentially the equivalent of a federal securitization program: utilities can now apply for federal, low-interest loans to pay off undepreciated plant balances of uneconomic plants, lowering overall costs to customers.

39 *Kansas Gas and Elec. Co. v. State Corp. Com’n* (excluding a nuclear plant from the rate base because it was unreasonably expensive compared to alternatives).
41 *Id.*
42 These disadvantages are outlined in depth in the referenced paper, pp 4-7.
43 *Id.*
Respectfully submitted this 8th day of September, 2023.

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