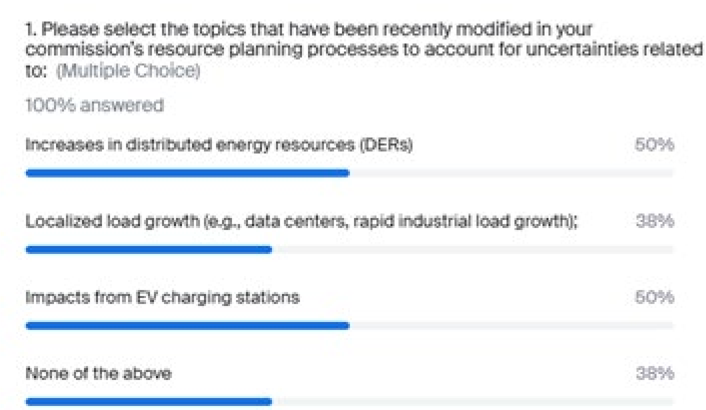
NARUC Regulators Roundtable Summary – Resource Planning and Regulatory Considerations May 16 and November 13, 2024

NARUC convened members, commissioners and commission staff, to facilitate a virtual roundtable on May 16, 2024, and an in-person workshop on November 13, 2024, (which also included stakeholders) to discuss resource planning. The focus of these peer sharing events was on integrated resource planning (IRPs) and regulatory approaches states are/or could be taking to support modernized planning that addresses emerging challenges in meeting electricity needs (e.g., resource adequacy, changing resource mix, state policy requirements, load growth).

This summary includes unscientific survey results on drivers for change among the dozen-or-so members who joined the May virtual roundtable, approaches that six states are taking to provide guidance to the utilities under their jurisdiction and engage stakeholders, and a series of actions that November workshop attendees identified that utility regulators and other decision-makers could take to modify planning processes towards considering a wider range of potential solutions (i.e., clean repowering, energy efficiency, geothermal, grid-enhancing technologies / reconductoring, virtual power plants).

Part 1: Changing Approaches and Requirements in IRPs – May 16, 2024



Highlights from state responses shared during the meeting are below in alphabetical order.

Indiana

- In 2021, the Indiana General Assembly passed House Enrolled Act 1520 (HEA 1520), which established an annual reporting mechanism for Indiana electric utilities to identify how they plan to meet their customers' electricity needs in the near-term. The commission is directed to then compile and analyze the utility data, investigate, and if necessary, act to address unsatisfactory conditions. Each year, the commission reports to the governor and legislature on the commission's findings based on the data submitted by the public utilities.

- The commission does not approve IRPs but the director of the research, policy, and planning division issues a report on each IRP, identifying strengths and weaknesses in modeling, assumptions, scenarios, stakeholder engagement, etc. The commission promotes the use of scenarios and sensitivities.
- The evolution of the IRP process is subtle and incremental. The commission expects utilities to engage in realistic modeling which entails the inclusion of 'known unknowns' like DERs, sizeable load additions related to economic development, and electrification, particularly from EV adoption. DER and EV adoption remains slow in Indiana and has little impact on IRPs in the short to medium term. Blocky load growth seems more likely.
- Due to robust statutory and administrative reporting requirements, consistent regulator engagement with RTOs, and frequent and transparent communications with our regulated utilities, the commission is not concerned about resource adequacy at present. This issue is front of mind for everyone at the commission and our utility and RTO partners and we are committed to ensuring the utilities fulfill their obligation to serve even with potential sizeable load additions throughout the state.

Missouri

- There is a particular focus on resource adequacy in IRP, with consideration for policy impacts (both state and federal). A state summit is scheduled to address ongoing resource adequacy concerns. Policy driven by the commission has been consistent, but changes may be coming to improve visibility and line-of-sight around resource adequacy.
- State policy makers are focusing on transmission projects to address the ongoing addition of renewable resources and the interplay with traditional (baseload) generation.
- The commission is still working to determine potential adjustments to engagement processes. There has recently been newer engagement with unregulated municipals and cooperatives to ensure coordination with regulated IOUs.

North Carolina

- There was a recent change to the commission's process in 2021 as a result of state legislative action (HB 951), a statute to decarbonize the state's electricity sector and be carbon-neutral by 2050. There is an interim target of 2030 with a 75 percent reduction from 2005 Co2 emission levels. The commission has used the decarbonization plan to drive the IRP process to address both in tandem (commission hearings are forthcoming in July to August 2024).
- The commission has traditionally addressed reliability, affordability, and safety in IRPs; carbon emission reductions will be a new element. This is the second IRP for North Carolina under the carbon legislation and establishing the process, then leveraging thorough guidance, is important. The commission can find a balance without providing overbearing direction to the utility.
- An important part of the NCUC Order was to ensure intervenors were able to access the utility's modeling assumptions and inputs to allow for comparison and additional analysis by outside parties; it's helpful to be able to understand targets, implementation costs, and

different pathways. The target of 2030 was allowed for some flexibility depending on what kind of long lead time resources were ultimately pursued; depending on the resources selected (e.g., small modular reactors, offshore wind), the 2030 target might be pushed out to 2033 or 2035. NC will continue to update/modify guidance for regulated utilities based on feedback and lessons learned from the utility, consumer advocates, etc.

Oregon

- The commission is grappling with the changing resource mix that we are seeing throughout the Western interconnection with additional intermittent renewables that were cost-effective coming into the portfolios, even ahead of the state's renewable portfolio standard.
- There have been discussions about how modeling can change to account for reliability and resource adequacy, pushing electric utilities to more sophisticated models that consider effective load carrying capacity (ELCC) of different resource types.
- Regional issues are important because there are layered proposals in multiple states, and the state commissions do not have an RTO in the West.
- For at least the last 3 years, there have been ongoing conversations and institution building around a Western resource adequacy program (WRAP). This has let us start to emulate the way an RTO might do resource sharing to reduce reserve margins (in each planning area). We still require the utilities to do that analysis in their IRPs for their own fleet and clarify how much they're leaning on the market for external resources. Utilities need to close any gaps, but the WRAP will provide visibility into other utilities looking to the market for resources, and whether the market will really have liquidity in those high-need hours.
- In 2021, the legislature passed a law that electric utilities must reduce carbon emissions to zero by 2040; the near-term goal is an 80 percent reduction by 2030. Oregon has embedded a clean energy planning process alongside our IRP process. The goal is to get a handle on how to identify least-cost and least-risk resources while integrating a carbon constraint in the annual total dispatch.
- The commission has provided some guidance for the new process. An initial round of guidance then resulted in the first EPS (similar to IRPs). The commission recently finished adjudicating the EPSs and issued orders on those in the last couple of months.
- Commission staff are now in the process of iterating potential changes ahead of the next IRP round. Staff will bring forward a straw proposal to kick-off a formal process to update Oregon's IRP guidelines considering the new WRAP and unique resource mix being so different throughout the west. Staff are looking closely at the longstanding IRP guidelines that have generally served the commission surprisingly well as the resource mix has begun to change.
- The commission will explore what needs to change with climate change requirements coming from the state legislature. It's possible that there will be a shift to examine the general characteristics, the need of the system and timeframe, and then proceed with a competitive, all-source RFP that might meet the requirements and system needs. This might lead to a result that is similar to the IRP, or it might look quite different if there have been other changes to the system or with other impacts. In addition, guidance on scenarios and sensitivities are among the possible areas for updates from staff; the electric utilities have leaned-in on this as have the stakeholders.

- Ultimately, the commission is going to be looking to push the IRP process into a more explicitly adaptive management model, where the portfolio is based on what the commission, utilities, and planners know today, and the points of uncertainty where the portfolio really might need to change---recognizing the inflection points where that preferred portfolio doesn't make sense and what it is we should be watching for that would indicate it's time to take a left turn ahead of the next IRP.

- The commission also conducts gas IRPs. Electric IRP guidelines have always included the gas companies as they face their own decarbonization rules. Oregon is moving away from buying a single commodity into needing a real resource portfolio that is different from the 3-year out hedging strategy that was used with the commodity approach. This approach involves stacking multiple portfolio options, comparing them against each other, and introducing multiple scenarios for each. Gas utilities are in a learning phase, exploring much longer-term resource, procurement, and generation options than in the past. They are considering the possibility of owning renewable natural gas facilities, getting into hydrogen production, and other options. The learning curve that comes with these new processes and options are challenging for all involved.

Washington

- The UTC does not provide guidance to the utilities for what or how they prepare their IRPs. The commission does not issue an order approving or rejecting the IRPs, but UTC staff examine the plans and the commission provides feedback through rules and letters.
- The state has experienced many changes over the last 5 years. The Clean Energy Transformation Act (CETA, passed in 2019) added new requirements that the utilities needed to include in their resource planning. Adopted rules also require utilities to include equity and resource adequacy. Resource adequacy is particularly incorporated in the IRP as part of the utility’s clean energy information implementation plans. Another change over the last 5 years involves the cap and invest law. The UTC does require the utilities to include scenarios and sensitivities, including social cost of greenhouse gases.
- Washington has gas IRPs which impact electric IRP considerations in terms of reducing carbon emissions. Washington also has legislation that requires the utilities to factor in the social cost of greenhouse gases in their IRPs, both in electric and gas. More recently, the state legislature passed a law requiring Puget Sound Energy, the largest combined gas and electric utility, to complete integrated gas and electric resource planning elements into a more integrated model so that they are no longer siloed. The Commission must establish rules for the integrated plan filing. The planning should include gas and electric IRPs, conservation planning, pipeline planning, clean energy implementation plans, and more.
- The state’s largest challenge involves organizing and designating roles for integrated and streamlined resource planning efforts.
- Because the UTC does not approve or reject the IRPs, the utilities don't necessarily do what we've suggested; however, with the new IRP, we will be approving that integrated plan, so the commission will have more sway with the utilities and will weigh in on what is actually approved in their plan.

Wisconsin

- Regulated utilities in the state no longer follow an IRP process that is approved or modified by the commission. IRPs were used many years ago until they were repealed by the legislature and the governor at the time, and replaced with something called a strategic energy assessment, which is what is used currently.
- The strategic energy assessment is a biennial assessment of utility data that's submitted to the commission and reviewed by commission staff to examine adequacy and reliability of the state's current and future electric supply. It is published as a draft by the commission each summer and released as a final draft in the fall every other year.
- States across the country, including Wisconsin, are facing complex issues around resource adequacy and affordability and environmental sustainability. These challenges require long-term, comprehensive planning and an IRP is something that many folks in the state have been working to get passed into law for a while. Most recently, it did come up as a governor's budget proposal in the last biennial budget, but right now we're doing more of an assessment of the data given to us.
- There is also a state planning reserve margin target, and the commission collects data from the load-serving entities in Wisconsin to conduct an evaluation under that requirement (an ongoing docket). The commission just recently opened a new refreshed docket specifically on a generic investigation into resource adequacy and potentially updating the State's planning reserve margin or exploring other avenues and issues. The commission continues to examine resource adequacy issues from multiple angles.
- The commission does not give guidance to electric utilities on their planning assumptions unless specifically requested. The commission does not promote the use of specific scenarios or sensitivities but does collect stakeholder input on scenarios and sensitivities being used by MISO in the commission's strategic energy assessment. The utilities have their own integrated planning and will informally present their internal planning to staff and request discussion and feedback.

<u>Part 2: Considering Newer Options to Address Load Growth in Planning – November 13, 2024</u>

Workshop participants (including commissioners, commission staff, and stakeholders) surfaced actions that different entities could take to unlock particular resources in planning processes (i.e., clean repowering, energy efficiency, geothermal, grid-enhancing technologies/reconductoring, virtual power plants). The following actions were identified during discussion:

To Advance Clean Repowering in Planning	
Actions **utility regulators** can take	• Ensure clean repowering is evaluated correctly: o Require evaluation of clean repowering in dockets o Consider all tax incentives and community benefits o Use independent modeling or confirm modeling with trusted stakeholders o Quantify tax base and jobs benefits to repowering o Require economic dispatch to enable replacement generation

	• Streamline existing processes and reform interconnection processes to speed up the process
	  o Consider clean repowering in RFP/Capital-predetermination dockets
	  o Work with RTOs on the optimization/reform of transferring interconnection rights
	• Incentivize/require utilities to make key data sources public, including interconnection data and an inventory of sites with space/capacity available

Actions **utilities** can take	• Make interconnection data public or leverage public data on underutilized interconnection to inform potential sites for clean repowering • Enter repowering tariffs
Actions that **Industrial and Consumer advocates** can take	• Raise awareness of the benefits of clean repowering to utilities and commissions • Fund local community energy burden advocates to bring in a community element and benefits (including business leaders)
Actions that **RTOs** can take	• Re-rate lines where possible to enable more clean repowering • Streamline interconnection process at locations that do not need network upgrades

To Advance Energy Efficiency in Planning	
Actions **utility regulators** can take	• Require utilities to update cost-benefit analysis to better determine the potential of demand-side resources, including energy efficiency, in light of projected load growth • Require utilities to treat energy efficiency as a resource option in planning (e.g., supply curve vs. artificial caps in a capacity expansion model) • Consider and adjust time-of-use rates to enable value of energy efficiency to be considered • Measure energy savings (e.g., use normalized metered energy consumption) to inform net load • Unite energy efficiency and virtual power plant discussions
Actions **utilities** can take	• Share data and hosting capacity maps to identify where energy efficiency would be most valuable • Ensure energy efficiency savings load shapes by hour are incorporated into planning

To Advance Geothermal in Planning

Actions **utility regulators** can take	• Open investigation to review procurements / RFPs / scoring sheet criteria (may benefit from supportive legislation) • Encourage utilities to evaluate geothermal when developing IRPs • Propose that large customers explore tariffs to procure geothermal • Encourage improved coordination among relevant state agencies
Actions **utilities** can take	• Establish and use a value for dispatchability when scoring RFP bids in resource planning • Create incentives to install geothermal heating and cooling • Gas utilities can investigate potential geothermal heating networks

To Advance GETs/Reconductoring in Planning	

Actions **utility regulators** can take	• Require grid-enhancing technologies (GETs) to be evaluated in IRPs and/or transmission plans. Similarly, require utilities to plan for reconductoring by incorporating reconductoring into power system planning
	• Seek out/provide estimates of GETs costs in cost-benefit analyses (CBAs), or even require utilities to use specific cost estimates for GETs in CBAs
	• Create a pilot or regulatory sandbox for innovative GETs and reconductoring
	• Create a financial incentive for GETs through a shared savings mechanism or performance incentive mechanism (PIM)
	• Inquire if and how utilities have considered GETs in relevant proceedings:
	    o If GETs aren't included in transmission planning proceedings, ask targeted questions to understand why not
	    o When a utility requests a certificate of public convenience and necessity (CPCN), ask if they considered GETs

Actions **utilities** can take	• Comprehensively evaluate the potential for advanced transmission technologies to cost effectively increase capacity • Consider all non-traditional benefits of GETs in CBA and when evaluating possible investment options (e.g., efficiency, optionality/future proofing, wildfire mitigation) • Leverage innovation teams within utilities to explore the potential for GETs
Actions **legislators** can take	• Encourage ISOs/RTOs to integrate GETs in transmission studies • Require the study and deployment of ATTs to support specific state goals
Actions other **stakeholders** can take	• Intervene in IRP process to increase information/education about GETs and reconductoring

To Advance VPPs in Planning

Actions **utility regulators** can take	• Establish regulatory requirements for more consistent integrated planning
	  o Ensure aggregated VPP characteristics (e.g., cost, response, etc.) are incorporated into resource plans
	  o Determine and account for the effective load carrying capacity (ELCC) for aggregated demand-side flexibility
	• Establish clear criteria for valuing VPPs
	  o Review existing approach to cost-benefit analyses (CBAs) to create and improve shared savings models
	  o Create opportunities to capture distribution system value
	  o Update DER compensation structure to better support VPPs
	  o Create opportunities to capture distribution system value
	• Include a requirement for evaluating both supply- and demand-side resources in planning
	• Encourage utilities to streamline the interconnection process for DERs
	• Identify incentives to unlock grid behavior and compensation
	• Require utilities to design a VPP program

Actions **utilities** can take	• Publish more transparent information on grid constraints • Evaluate compensation structure for distribution systems and weigh against bulk system • Use all-source procurements that are inclusive of both VPPs and utility-scale resources • Consider the full value of VPPs including energy, capacity, resilience and societal benefits • Identify and leverage new data and tools to determine when to use VPPs optimally
Actions that utilities in **RTO regions** can take	• Develop retail programs that are not dependent on FERC Order 2222
Actions that **legislators** can take	• Give statutory authority to enable VPPs to be used as aggregated DERs