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Next-Generation IRP: Planning for a Grid in Flux

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In light of rapid changes across the energy system, many utilities are rethinking their approaches to long-term planning. Historically, when addressing uncertainty, planners were generally focused on commodity price, policy, technology, and economic risks. Those risks persist, but they are now compounded by a new set of uncertainties. Rapid load growth, evolving reliability needs, transmission constraints, and growing interdependence between electric and natural gas systems increasingly require planners to adjust their approaches and broaden their perspectives.

Given this trend, many utility IRP processes have progressively become more iterative and complex. **In this briefing, we lay out the overarching issues in today's IRP landscape and highlight how we are helping clients respond to emerging challenges in three areas:**

- **Resource adequacy planning**
- **Transmission planning**
- **Natural gas planning**

What is an IRP?

An Integrated Resource Plan (IRP) is the process by which a utility seeks the best pathway to serve the long-term electricity needs of its customers. IRPs seek to find the best portfolio of resources—including generation, transmission, or demand-side options—that can serve customer requirements, while satisfying a range of planning objectives. IRP processes are often designed to be public, actively soliciting input from interested stakeholders, to ensure that planning processes are transparent and decisions reflect a range of (sometimes competing) objectives. IRPs naturally invite discussion and even disagreement among stakeholders, particularly since modern IRPs focus on balancing cost, reliability, and environmental performance while managing risks, satisfying policy objectives, and enabling local economic development.[1]

IRPs emerged in the 1970s and 1980s as a framework for identifying least-cost resource portfolios capable of reliably serving customer demand. By the 1990s, more than 30 US states required utilities to prepare IRPs, establishing the process as a core component of utility planning.[2] Over time, IRP practices evolved alongside the electric industry. Demand-side management opportunities, energy efficiency programs, participation in structured wholesale

1 https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf

2 https://eta-publications.lbl.gov/sites/default/files/sc_commission_day_1_irps_in_us_review_of_requirements_final.pdf

markets, emerging renewable energy resources, and changes to capacity accreditation methodologies—such as Effective Load Carrying Capability (ELCC)—were all incorporated into the planning process as utilities faced new opportunities and challenges.[3]

Despite decades of refinement and increasingly mature planning processes, IRP best practices and individual utility approaches remain dynamic, particularly as planners face new challenges associated with rapid load growth, customer behavior changes, significant technology advancement, and policy and technology uncertainty. As a result, the scope of IRPs has expanded to address more objectives, incorporate more analytical techniques, and integrate transmission, distribution, and natural gas system considerations.

Where traditional IRPs are facing challenges

The IRP process has delivered significant value to utilities over the last several decades, enabling a structured framework for long-term decision-making and system investment. In recent years, the IRP has been a driving force for the energy transition, supporting significant new generation additions, including emerging renewable and storage technologies; the incorporation of demand-side resources; and integration of transmission and distribution investments with those in the generation space. This has all been done through a process that provides regulatory transparency and opportunities for stakeholder engagement.

However, as the industry faces a new set of challenges associated with rapid load growth, the integration of more intermittent resources, and greater connections between generation investment and transmission and distribution implications, the traditional planning paradigm is sometimes falling short. Many of the assumptions that planners historically treated as relatively stable are now moving more quickly, interacting more strongly, and carrying greater financial and reliability consequences than in prior planning cycles.

Planners now face growing pressure to simultaneously maintain reliability, manage affordability, support economic development, integrate new technologies, satisfy increasingly complex policy objectives, and respond to rapidly changing market conditions. Together, these pressures are exposing limitations in traditional planning approaches and are creating a need for more adaptive and sophisticated planning frameworks.

Several themes are emerging as utilities, regulators, system operators, and other stakeholders find new avenues to improve IRP processes. They include:

[3] https://www.sciencedirect.com/science/article/pii/S0957178723001662

Cross-cutting pressures

- **Demand growth is highly uncertain.** After decades of relatively flat load growth, forecasts have trended up sharply due to the potential electrification of the economy and the growth in artificial intelligence (AI)-driven data centers. Beyond just increasing demand for electricity, forecasts have also grown more uncertain. For example, in its forecast for growth in the data center sector, EPRI projects that U.S. data center electricity consumption could range from approximately 380 TWh to 790 TWh by 2030.[4] This wide range illustrates the challenge facing planners: load forecasts can shift materially within a single planning cycle as data center development, electrification, economic activity, and customer behavior evolve.
- **Planning objectives often interact and sometimes compete as metrics evolve.** Utilities must simultaneously manage reliability, affordability, rate stability, environmental sustainability, resilience, and economic development objectives. These objectives usually interact and sometimes compete, so it is critical for planners to identify the correct metrics to evaluate when assessing tradeoffs, including evolving resource adequacy and reliability metrics and the expansion of analysis frameworks across the broader electric and natural gas systems.

Reliability and accreditation

- **Future capacity accreditation is unknown.** Resource accreditation values are becoming increasingly dynamic as technology performance, system conditions, and resource penetration levels evolve. Planning assumptions that were once considered stable are becoming both more uncertain and more consequential. Capacity accreditation assumptions that were often developed from historical data or public Independent System Operator (ISO) reports are now subject to ongoing methodological refinement and can change materially as resource mixes and reliability risks shift.
- **Established reserve margin targets no longer guarantee resource adequacy.** Traditional planning frameworks often equate reliability with maintaining a target reserve margin. Increasingly, however, resource adequacy challenges are emerging even in systems with established reserve margin frameworks. A utility portfolio can satisfy its reserve margin requirements on paper while remaining exposed to meaningful reliability risks if the broader market experiences stress or if market conditions evolve in a different fashion than expected. Understanding the distinction between local planning targets and system-wide reliability conditions is becoming increasingly important to managing reliability risks.
- **New flexibility resources are emerging.** Demand response, virtual power plants (VPPs), managed EV charging, and distributed energy resources are being increasingly explored as avenues to delay, limit, or complement generation investments. However, their value depends on customer participation, operational performance, persistence over time, and

their ability to contribute during periods of system stress. As planners incorporate these resources into long-term plans, questions remain regarding achievable scale, accreditation, performance consistency, costing best practices, and interactions with other planning assumptions. Utilities can incentivize participation, but participation ultimately depends on customer adoption and sustained engagement.

Deliverability and transmission constraints

- **Location matters more than ever.** A load's system impact and a resource's value are determined not only by their cost and operating characteristics, but also by where they are located, how they use the electric and natural gas networks, and how the broader system is impacted. Transmission headroom in one part of the system may vary from another, resulting in a range of required interconnection costs, while locational marginal prices can differ significantly across some service territories, impacting the costs of load and the value for generation. Importantly, in the era of large load growth, new load and generation additions may impact the broader system differently depending on where they are located.

Energy-system linkages

- **Energy sector linkages are growing.** Natural gas, electric, transmission, and supply-chain systems have often been planned separately or with limited coordination. Increasingly, however, decisions in one system affect outcomes in another. Expansion of natural gas generation may require significant gas fuel infrastructure investment. Transmission expansion may alter generation needs and locational economics, while local generation investments may defer or avoid transmission and/or distribution upgrades. Further, generator investments may be assumed to be deliverable to customers, when they are in fact limited by transmission and import constrictions. In some interlinked systems, effective planning may require examining these systems together rather than in isolation.

Thus, more than ever, the primary requirement of an IRP is to make robust decisions that perform well across a range of plausible futures and system conditions, while understanding the circumstances under which those decisions may need to change. This requires planners to evaluate not only expected outcomes, but also the risks associated with alternative futures. Decisionmakers must understand the potential downsides to which customers and stakeholders may be exposed and identify opportunities to proactively mitigate those risks. As a result, modern planning frameworks are increasingly focused on resilience, adaptability, and risk management in addition to traditional measures of cost and reliability while actively seeking to understand and simulate the wider system landscape.

Shifts we're making in response to these changing dynamics

As planning environments become more complex and uncertain, utilities may need analytical frameworks that go beyond the traditional IRP toolkit. In response to our evolving and growing customer needs, CRA has been investing in new modeling capabilities and working with clients across the energy sector to improve how decisions are evaluated, stress-tested, and communicated.

In particular, the following three shifts have shaped our current approach to planning.

1 Reliability modeling must reflect system operational realities

Traditional resource adequacy assessments often assume that reliability can be represented through a fixed reserve margin or a static set of accreditation assumptions. Increasingly, those assumptions are proving dynamic. Resource value depends on system conditions, resource penetration levels, weather patterns, operational constraints, and interactions across the fleet. This can create situations where a resource appears attractive because of its accredited capacity value, only for that value to decline as the resource is deployed at scale and system conditions evolve. Resources are often selected based on assumptions that may no longer hold by the time the assets are actually placed into service.

Perhaps the clearest example is solar generation. Solar historically offered strong power output that was relatively coincident with peak system demands during afternoon summer hours. As such, it was given relatively high accreditation to capture its positive impact on system resource adequacy. As its deployment accelerated, however, its incremental resource adequacy value began to decline. While additional solar generation reduces reliability risk during daylight hours, it contributes little to none during evening and nighttime hours, periods in which system risk is increasingly shifting. As markets adapt to reflect these changing risk conditions, solar accreditation values have declined or are expected to decline materially.

This example is not intended to discount the value of solar resources, either in the past or into the future. Rather, it highlights the growing importance of accreditation uncertainty in resource planning, portfolio selection, and contract negotiations. As deployment levels increase, a resource can alter the very system conditions used to determine its capacity value. Consequently, accreditation values are not static and may change as the resource mix evolves. Recent changes, as well as accreditation reforms in ISOs across the country, further illustrate this dynamic. The accreditation value assigned to storage resources, for example, can vary substantially depending on system conditions, resource penetration levels, accreditation methodologies, and market rules. As a result, planners must consider not only expected accreditation values, but also the potential for those values to change over time as the grid evolves.

Accreditation and reserve margin accounting uncertainty also extends to emerging resource types like demand response, virtual power plants (VPPs), managed EV charging, and distributed energy resources (DERs). This is because their value ultimately depends on their operational characteristics, customer participation, ability to perform during periods of system stress, and the degree to which those contributions can be demonstrated and sustained over time.

Our solution

We work closely with our clients to understand and manage these risks through a combination of resource adequacy fundamentals and detailed reliability modeling, helping identify emerging market risks before major investment decisions are made. Rather than treating accreditation as a fixed assumption, we increasingly view it as an input that will evolve over time and potentially represent a source of uncertainty. Instead of asking whether a portfolio satisfies today's accreditation rules, we evaluate how it performs as market conditions evolve, resource mixes change, and accreditation methodologies are refined. This approach helps clients avoid overreliance on assumptions that may or may not hold by the time new resources enter service and supports investment decisions that remain resilient across a range of future system conditions.

We are also placing greater emphasis on operational realism. Storage resources are modeled with charging requirements, duration limitations, seasonal performance variation, and multi-day stress events rather than a single capacity value. Thermal fleets are evaluated under aging-related degradation, correlated outages, fuel supply constraints, and extreme weather conditions.

Finally, we are distinguishing between local utility adequacy and regional system adequacy. A utility may appear compliant with a planning reserve margin while operating within a tightening market that faces broader resource adequacy challenges. Understanding this distinction is increasingly critical as reliability risks become more regional, dynamic, and interconnected.

2 Deliverability and congestion are increasingly relevant to the resource decision

Nameplate megawatts, and even accredited megawatts, can be misleading in some areas if transmission constraints limit the ability to deliver power where it is needed. That elevates the importance of transmission capability, import limits, interconnection timing, and location-specific development risks, particularly in regions experiencing increasing congestion, rapid load growth, or rising infrastructure costs.

Increasingly, regulators and utilities are recognizing that resource plans now have greater opportunities to integrate broader questions associated with transmission access and costs. As

load growth accelerates and infrastructure requirements expand, planners may need to perform additional analysis to assess whether resources can be interconnected at a reasonable cost, that generation can be relied upon when system conditions become stressed, and that local congestion impacts will not adversely affect the rest of the portfolio.

Our solution

We are seeing growing interest in opportunities to better understand the interactions between generation and transmission planning. Rather than assuming future imports, transmission expansions, or resource additions will occur exactly as planned, and at a single pricing point, we are helping planners consider the implications of delays, attrition, siting challenges, permitting risks, changing development timelines, and evolving nodal price profiles.

3 Natural gas system planning is increasingly tied to the electric sector

Beyond transmission and generation, natural gas and electric systems are becoming increasingly interdependent. Electric load growth is raising demand for gas-fired generation, while decarbonization policies and consumer preferences in some jurisdictions are driving a shift from gas heating to electric alternatives. Electrification can therefore increase demand for gas-fired generation while decreasing gas demand in the residential and commercial sectors. These competing dynamics are making gas system planning more complex as they challenge traditional approaches.

How these dynamics affect individual utilities will depend on local system characteristics and customer technology choices. Building electrification can reduce annual gas consumption, but customers may keep gas heating as a backup during extreme cold, so peak requirements stay in place. For utilities that serve gas-fired power plants, growing power-sector demand may also offset some of the reduction from electrification. Many utilities could therefore see lower annual throughput with little change in peak delivery requirements. That would spread infrastructure costs that stay largely the same over fewer gas sales.

These shifts pose a challenge for planning processes that have traditionally treated gas and electric reliability separately. Gas utilities typically assess supply and infrastructure against their own demand forecasts and design day obligations. Electric utilities and system operators, meanwhile, evaluate resource adequacy under separate assumptions about fuel availability. Those assumptions often rely on unplanned outage rates from historical events. They implicitly assume that past fuel availability for gas resources on interruptible contracts is indicative of future conditions. This separation can obscure shared vulnerabilities during extreme cold, when heating demand and gas-fired generation compete for constrained fuel supply, or fail to capture evolving grid and heating dynamics. Winter Storm Uri in February 2021 illustrated these risks: extreme cold caused wellhead freeze-offs and electric generation outages, with power outages

further constraining gas supply and leaving customers without electricity for days.[4] These interdependencies reinforce the need for coordinated gas and electric system planning where heating demand is closely linked to the electricity system.

Our solution

These market shifts, together with growing affordability pressures, are prompting regulators to require gas utilities to adopt more formal long-term planning processes like those used in the electric sector. We are now helping utilities navigate this complex landscape by developing long-term gas plans and evaluating key planning decisions, including infrastructure investments and non-pipeline alternatives (NPAs). Our broader six-part framework for long-term gas planning integrates these decisions with scenario analysis, demand forecasting, gas-electric coordination, capital strategy, and continuous planning.

We have seen particular momentum in the coordinated planning space and are working with clients to take practical first steps, such as aligning demand forecasts and weather assumptions across both systems. Linked gas and electric models can then evaluate whether supply and transportation infrastructure can meet coincident demand and how potential shortfalls could affect reliability. This coordination can provide a stronger basis for evaluating long-term infrastructure needs and investment alternatives while balancing system reliability, ratepayer affordability, and regulatory prudence.

Closing thoughts

All three of these shifts point to a growing focus on two primary best practices for utility planners going forward, as described below.

Uncertainty is the analysis, not the appendix

The range of planning uncertainties is growing, and utilities must address them all head-on. Utilities are comfortable evaluating ranges for capital costs, fuel prices, power prices, policy incentives, and load growth, but now must also increasingly consider those associated with resource accreditation, planning reserve margin, transmission interconnection costs, nodal congestion, and natural gas system impacts.

[4] Joshua W. Busby et al., “Cascading risks: Understanding the 2021 winter blackout in Texas,” Energy Research & Social Science 77 (2021): 102106, https://doi.org/10.1016/j.erss.2021.102106

Decisions that appear optimal under one set of assumptions may look very different under another. As a result, planning cannot focus solely on identifying a single least-cost outcome. It must also evaluate how portfolios perform when key assumptions change.

CRA works with clients to identify the uncertainties that are most relevant to the planning decision at hand and to evaluate their potential impact through scenario analysis, sensitivities, and, where appropriate, probabilistic approaches. The goal is not simply to produce more scenarios. It is to understand which uncertainties matter most, how they influence investment decisions, and which portfolios remain resilient across a wide range of future conditions.

Planning must be continuous and iterative

Traditional IRPs were often built around a multi-year planning cycle, with major updates occurring only when the next filing began. Each update can be a major organizational effort, requiring months of work and input from experts across the utility organization. Increasingly, that model is becoming difficult to sustain. Load forecasts can change materially within months as data center opportunities emerge and large customers accelerate expansion plans, and major federal policy or market design changes are rarely in sync with the traditional planning cycle. Questions that once could wait until the next IRP cycle increasingly require answers in real time.

As a result, planning is becoming a more continuous capability rather than a periodic exercise. Utilities are being asked to evaluate new large-load opportunities, assess resource alternatives, respond to market developments, and brief leadership on emerging risks long before the next formal planning cycle begins. The organizations that respond most effectively are increasingly investing in the tools, processes, and teams needed to evaluate these questions quickly and consistently.

The goal of continuous planning is not to completely overhaul the normal IRP cadence. It is to ensure that assumptions are continuously questioned, models are adaptable to changing external conditions, and insights are regularly refreshed.

The bottom line

Next-generation IRP is not a bigger model or a longer document. It is a tighter connection between analysis and decision-making and a recognition that frameworks need to adapt quickly to the surrounding environment. It recognizes that reliability requirements are evolving, that transmission questions are directly relevant to generation ones, and that systems are increasingly linked. The goal is to identify strategies that remain effective as conditions change and to understand the circumstances under which they should adapt.

This whitepaper series will continue with deeper dives into the three key trends that will shape the next generation of IRPs:

- Beyond validation: Integrating **transmission** intelligence throughout the IRP
- An emerging nexus: Integrating **natural gas**-electric interdependence into planning
- **Resource adequacy** in motion: Evolving reliability considerations for the IRP

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