TECHNICAL BRIEF

State of Hydrogen Modeling in Electric Company Integrated Resource Planning

1 INTRODUCTION

Hydrogen is an energy carrier that is typically produced by extracting pure hydrogen from hydrogen-containing compounds such as fossil fuels, water, or biomass [1]. The use of hydrogen in the power sector is a topic of burgeoning interest worldwide. In 2020, the International Renewable Energy Agency (IRENA) described a new wave of interest in green hydrogen, driven by low costs of variable renewable energy, the readiness of electrolysers to scale up, the potential power system reliability and cost benefits, government objectives, the interest of multiple stakeholders and the synergies of using hydrogen across the entire economy [2]. Technology breakthroughs in the last few years have been especially promising for those envisaging a deeply decarbonized electricity sector [2, 3, 4, 5]. These breakthroughs include the development of gas turbines that can blend both hydrogen and natural gas, and improvements in compression technologies that allow the energy density of hydrogen to be increased to a level similar to natural gas—signaling the potential for hydrogen to play a role similar to fossil generation in the power sector today [6]. In turn, the International Energy Agency identified hydrogen as a key pillar of decarbonizing the global energy system [7].

Key hydrogen production processes include steam methane reforming, coal or biomass gasification, and electrolysis [1]. In the electricity sector, power-to-hydrogen-to-power systems have the potential to provide grid services such as capacity, balancing, and seasonal/long-duration energy storage by modulating hydrogen production as a flexible load and/or generating power by using gas turbines, engines or fuel cell technologies [1]. While industrial applications of hydrogen have been in use for decades, interest in making use of hydrogen for power generation has grown in the past decade.

Driven in part by decarbonization policies and goals, many electric companies have indicated a particular interest in using low-carbon hydrogen to generate power. Green hydrogen, whereby water is split into hydrogen and oxygen within an electrolyser, is an area of special interest for many companies [1]. The scale of electrolysis is steadily growing; in 2022 global manufacturing capacity doubled to nearly 8GW per year and the International Energy Agency has suggested that installed electrolyser capacity could grow to 134-240 GW by 2030 [7].

The Challenge

Hydrogen is a promising emerging resource that may be a critical enabler of a low-carbon future. The development of large-scale hydrogen turbines for power generation is accelerating in response, with encouraging results [8]. Electric companies are increasingly interested in understanding and incorporating hydrogen facilities into their resource plans.

By monitoring advancements in both the techno-economic space and its inclusion in resource plans, resource planners can assess their progress and level of understanding against industry norms while also identifying gaps and next steps for their own plans.

This technical brief addresses the following questions:

- What are current perspectives on the role of hydrogen in electric company integrated resource planning?
- What challenges and benefits can electricity companies expect when incorporating hydrogen into long-term planning?
- How can current efforts inform priorities and lessons for future studies?

2 CURRENT APPLICATIONS OF HYDROGEN IN ELECTRIC COMPANY INTEGRATED RESOURCE PLANS

One way that resource planners ensure that integrated resource plans are achievable is to limit the technology options considered to those that have reached technical maturity or, at minimum, have been identified as an option in global- or national-level decarbonization pathways studies. Pathway studies often lay out strategies to achieve policy goals (typically associated with emissions reductions) by selecting technologies while minimizing costs. The outcomes of these studies inform what resources are likely viable and cost-effective depending on the length of the planning horizon. These studies act as a 'canary in the coal mine', helping electric companies understand what technologies to monitor. It must be cautioned that the expected role that hydrogen may play varies greatly between pathway studies. This variation might be explained by differing assumptions and modeling approaches. In the absence of publicly available detailed modeling information, it is difficult to discern whether the models employed accurately capture the benefits and drawbacks of hydrogen.

Given the context of global and national pathways studies, it is perhaps unsurprising that most electric companies whose current Integrated Resource Plans (IRPs) incorporate hydrogen have done so only in the most recent planning cycle. Prior to 2020, only a handful of IRPs in the U.S. mentioned hydrogen and typically, this was limited to one or two sentences describing it as an area of continuing research.

Despite its relative obscurity in previous planning cycles, hydrogen has surfaced as an important resource to consider. In interviews with utilities, planners noted that there is a strong desire to not only include hydrogen as an option in resource plans, but to also model it with the same level of sophistication of existing resources. In some jurisdictions, there is a strong desire to develop plans based on a future in which no new natural gas-fired generation is built and/or existing natural gas generation is decommissioned. Some IRPs seek to develop scenarios that facilitate this, where hydrogen can provide the characteristics that could otherwise be provided by natural gas-fired generation (such as storage or firmness).

Inclusion of Hydrogen and Transparency of Modeling Techniques

Quarton et al. (2020) reviewed the representation of hydrogen in 12 global studies, categorized into four stages: (1) no mention in the scenario; (2) not modeled but discussed; (3) modeled but with no data assumptions provided; and (4) modeled with data assumptions provided. Using this same framework, EPRI reviewed 115 IRPs in regulated states in the U.S. that consider hydrogen and categorized them into one of four phases representing the level of transparency and completeness of models. Most IRPs fall into the first two categories and several in the third. Only two IRPs represented hydrogen according to the fourth category, as summarized in Figure 1.

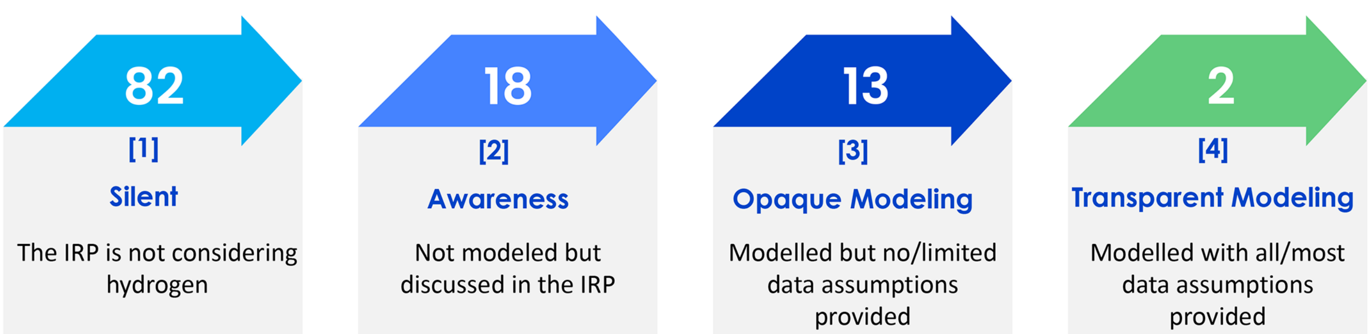

Figure 1: *EPRI's review of 115 IRPs in regulated states in the U.S. found that the level of transparency and completeness of the models varied, with the majority silent on hydrogen.*

Several IRPs categorized in the Awareness group explicitly describe the reasons for not yet incorporating hydrogen.

Key reasons for not yet incorporating hydrogen in IRPs include:

1. **Uncertainty:** Whether hydrogen appears in IRP technology portfolios depends on its anticipated costs (both capital and fuel costs) and its performance characteristics. These are still far from certain, and in the case of electrolysis are also affected by the future cost of electricity. The pace of technological advancement is increasing, with most hydrogen projects currently in demonstration stages. There remains uncertainty about the timing of when the technology will reach maturity and the development of the required infrastructure (i.e., to compress and transport hydrogen).
2. **Modeling Techniques:** Many capacity expansion software tools have recently incorporated power-to-X capabilities, which allow users to model the entire conversion process. Also called P2X, this modeling considers electricity production, conversion to an energy carrier (e.g., hydrogen), and storage. As a relatively new feature of capacity expansion, it will take time for resource planners to determine their preferred implementation, considering elements like the amount of detail to include (e.g., how accurately to represent operational constraints), the sensitivity of the model to its inputs, and tractability. This is further complicated by a lack of comparative studies and academic consensus on techniques for modeling hydrogen in capacity expansion tools.
3. **Technological Maturity:** Many IRPs noted that the technology for using hydrogen in the power sector is evolving. In some cases, the time horizon for the IRP is shorter than when the technology is expected to be both available and cost-effective for commercial operation. In some cases, the screening methodology for candidate resources in capacity expansion tools can act as a barrier. While excluding emerging resources as candidates may be prudent for studies with a short horizon, long-term studies can benefit from including technologies that are not yet commercialized.

These reasons provide insight into potential milestones that might trigger a deeper exploration by electric companies. In some cases, hydrogen is included as an option but not selected in the underlying capacity expansion model. These models use many assumptions and simplifications, making it difficult draw conclusions on whether hydrogen was not selected due to the cost of electricity, the capital cost or conversion efficiency. Rather, the model outcomes might not represent the full picture of possibilities. In other cases, hydrogen is excluded from the candidate technology options completely.

POWER SYSTEM MOTIVATIONS

Regardless of modeling sophistication, electric company resource plans that mention hydrogen often consider it as a replacement for coal or natural gas facilities. While the terminology varies between plans, these electricity companies are motivated to identify resources that can reduce carbon emissions while also ensuring there are sufficient dispatchable resources available to support system reliability under many operating conditions.

Of 115 U.S. IRPs that were reviewed, 33 are planning for or considered hydrogen-capable generators. Twelve of these IRPs specified that these hydrogen facilities could replace coal-fired or natural-gas-fired generators, by providing similar capabilities while also satisfying policy goals.

The potential for this application is bolstered by case studies that have found that hydrogen facilities can cost-effectively reduce emissions by providing the flexibility otherwise provided by natural gas-fired generation [3]. This flexibility can be achieved by (1) behaving like a flexible demand, where hydrogen production responds to price signals or instructions from an electric system operator; or (2) behaving like a generator, where stored hydrogen is used to generate electricity to inject into the power grid. When choosing an approach, electricity companies may consider potential trade-offs. The latter option may be appealing to companies that desire direct control of facilities. This appeal may be tempered by the amount of energy losses in the power-to-hydrogen-to-power pathway today. Ten of the reviewed IRPs plan to increase the number of gas units in their systems; however, they assume that any new gas units are hydrogen capable, allowing these units to fueled by a hydrogen-natural gas blend or be retrofitted to 100% hydrogen.

IRPs described the use cases for production of and generation using hydrogen using a variety of terms including fuel diversity, long-duration energy storage, resilience, baseload, and load following. In many cases, the discussion of hydrogen was coupled with other supply-side technologies such as small modular nuclear reactors and alternative long-duration energy storage. In many cases, IRPs acknowledge that there is uncertainty about which of these potential emerging zero-carbon technologies will ultimately be deployed. In such cases, these electricity companies signaled their intent to study these technologies and maintain optionality for the future.

EMERGENCE OF DEMONSTRATION PROJECTS

Florida Power & Light Company (FPL) has proposed that with some modification, its existing natural gas generating units may be fully fueled by hydrogen, renewable natural gas or both. To evaluate this assumption, FPL is embarking on a pilot project starting in 2023 to test blending natural gas and electrolytic hydrogen at an existing combined cycle natural gas unit [9]. Similarly, Georgia Power and Duke Energy have announced demonstration projects related to hydrogen

Some electric companies are considering hydrogen in their resource plans as part of a broader strategic interest. For example, according to Puget Sound Energy's (PSE's) 2023 Electric Progress Report (which provides updates to the 2021 IRP that considered 2022 to 2045), leading in the region's hydrogen hub infrastructure is a near-term priority. Beyond 2030, PSE is interested in hydrogen providing clean peaking capacity, with the potential to blend with natural gas starting in 2030 and increasing to 100% hydrogen by 2045, using both new and retrofitted facilities [10].

Modeling Approaches

THREE PRIMARY MODELING APPROACHES

In the plans that modeled hydrogen, all acknowledged that simplifying assumptions were made. Three general approaches were observed: (1) Incorporating it as a standard dispatchable resource; (2) Incorporating it as a storage resource; and (3) Modeling it using integrated or Power-to-X software capabilities.

Hydrogen as an energy carrier can have multiple end-uses, not only in the power sector but also in mobility and industry. As such, there are numerous configurations of hydrogen facilities that impact its use case for the power system. A green hydrogen production facility whose production is used by a different sector can provide load flexibility benefits to the electricity sector. If the facility is coupled with a generator, creating a power-to-hydrogen-to-power pathway, it may prioritize serving the electricity sector by providing peaking or flexibility services. If the electricity sector isn't its main priority or if the facility is subject to dual price signals from both hydrogen and electricity markets, it might operate with a different capacity factor and choose to only provide electricity through self-scheduling or in response to a scarcity event, similar to many combined heat and power facilities. Finally, if the facility has significant storage capability, it may provide long-duration or seasonal storage to the power sector.

The modeling choices differ for each of the above modes of operation. Electric companies may also initially consider whether they would own the production of hydrogen or have a contract for the fuel, how hydrogen is stored, whether storage size constrains the availability of hydrogen and any transportation constraints. These decisions can impact the round-trip efficiency of hydrogen systems, potential energy limitations, and the flexibility/responsiveness of the unit.

Standard Dispatchable Resource

This is the most common and simplest approach. It uses existing model capabilities for natural gas facilities and modifies the fuel source. One benefit is that this approach can be used to model facilities that blend hydrogen with natural gas or those that use only hydrogen.

A common implicit assumption with this approach is that the hydrogen is produced by a separate entity. The costs, therefore, are reduced to the capital cost of the turbine and the operating costs (which may be some combination of the cost of electricity, an assumed levelized cost of hydrogen, or a price adder relative to the cost of other fuels).

Puget Sound Energy chose this approach, informed by its assumption that the company will likely have an off-take agreement from a fuel supplier. PSE also included a constraint to represent the expansion of hydrogen pipelines by limiting when existing generators can access hydrogen[10].

Storage Resource

This approach treats hydrogen as a long-duration energy storage resource. There is limited information available on how electricity companies factor in the size and types of storage. While not observed in today's U.S.-based IRP modeling inputs, incorporating storage-related parameters, like compression levels, storage losses, and storage medium can inform whether to compress and store hydrogen as a gas or as a liquid as can each impact overall efficiency and total losses. Alternately, if the storage medium (whether it is a tank or a geological storage formation) is known, planners can better assess the consequences of the amount of gas, or "cushion" that must remain in the storage system to maintain pressure, as well as the amount of hydrogen that can be stored.

Integrated Resource (Power to X)

This is the most complex approach to model, as it requires inputs related to the entire conversion, storage, and reconversion pathway that are ignored in other modeling methods. This more integrated approach may allow electric companies to better compare the trade-offs of different use cases, estimate future load profiles, and inform decisions around plant design. It may also be used to understand the impacts of sector coupling, recognizing the needs of other sectors from the same facility and the impacts of dual market price signals from electricity and hydrogen markets. Companies that use this approach typically assume that they are responsible for hydrogen production. In such cases, there is a greater interest in understanding the limitations to how much hydrogen could be available and the trade-offs between using electricity to produce hydrogen compared to serving other electrical loads. In the case of green hydrogen, this modeling aims to optimize the size of storage facilities and electrolyser, the speed at which storage can be filled (including impacts of compression), and the amount of additional electricity required to produce hydrogen. This approach has the potential to integrate the dynamics of the hydrogen facility, by factoring the timescales of operation from the electrolysers and the balance of the plant with the timescales used to operate the grid. Development of these methods is ongoing and are focused especially on the potential flexibility services hydrogen facilities can provide to the power grid.

Common Modeling Limitations

A common modeling assumption is the operating parameters of a hydrogen facility are the same as existing gas turbines, which is not necessarily the case given the different chemistries of methane and hydrogen. Two such considerations that have not been described in IRP methodologies are:

- Flame Speed: Hydrogen has a faster flame speed than methane. At very high levels of hydrogen (exceeding 95%), this can narrow the operating range of a turbine [11].
- Volumetric Energy Density: Hydrogen has a lower volumetric energy density than methane. To maintain the same power output, system components like fuel supply lines will require resizing [11]. Therefore, potential costs like resizing could be incorporated into the model to align with this assumption.

Environmental considerations are another example of model constraints that are not yet discussed in IRP modeling. For example, because hydrogen burns at a higher temperature than methane, nitrogen oxides (NOx) emissions at the site may potentially increase. Not only could this potentially increase the degradation of materials and coatings [11], but at some sites, environmental limitations may, as a result, constrain the operation and utilization of hydrogen.

A common modeling assumption is that hydrogen fuel is always available on demand. However, hydrogen may act like a 'just-in-time' resource, where physical constraints in the form of transportation limitations can also create scarcity conditions. Potential conditions that may be considered include volume and type of storage facility, pipeline constraints related to line pack or compression, and/or coincident demand for hydrogen from other sectors [12]. Financial and contractual realities may also impact the availability of hydrogen fuel, whereby offtake agreements for hydrogen may affect when and how hydrogen is produced and used.

3 POTENTIAL BENEFITS OF INCORPORATING HYDROGEN INTO LONG-TERM PLANNING

Many studies have indicated that low-carbon technologies, such as hydrogen, may be needed to achieve deep decarbonization of the power sector. Because these studies typically describe only the total energy produced using hydrogen, other additional use cases may be understated or not fully quantified.

Reduce Costs

The Inflation Reduction Act (IRA) is expected to have a significant impact on costs and opportunities relating to hydrogen in the U.S. Firstly, the incentives provided by the IRA can help reduce the price of hydrogen, making it more likely to be selected as a resource in a long-term resource plan. Further, the price impacts vary by technology type. For example, recent EPRI analyses suggest that incentives for zero-carbon electrolysis in the IRA may provide a potential pathway for lower costs than natural gas reforming [13]. The introduction of the IRA and its impacts on IRPs was also recognized by electric companies. For example, Pacificorp's 2023 IRP update specifically mentions that the passage of the IRA provides tax incentives that significantly reduce the cost of hydrogen production and accordingly, hydrogen was modeled as a new non-emitting peaking resource in its 2023 plan [14].

Ensure Reliability

Ongoing EPRI research has highlighted the importance of grid services like flexibility (both for balancing and seasonal variability) and other ancillary services, particularly considering retiring fossil capacity [15]. Existing pathway studies typically do not include a high level of operational detail and may therefore underestimate the ways hydrogen might be able to provide reliability services that are otherwise unavailable in a deeply decarbonized system. Hydrogen facilities could provide operational flexibility, either as a flexible load that reduces hydrogen production or as a generator, by using hydrogen as a fuel to generate electricity in response to power system signals. Alternatively, hydrogen facilities could provide seasonable flexibility, as a form of long-duration energy storage, ensuring reliability when other resources are not available (e.g., during droughts or dark doldrums) for a sustained period [16].

Reduce Emissions

Where hydrogen is used to displace energy from fossil resources, it has the potential to reduce total emissions. This may be achieved through blending hydrogen with natural gas or producing 100% clean hydrogen to generate power. There are numerous drivers for electric companies to prioritize emissions reductions, including environmental policies, state targets, and environmental social and governance goals.

Respond to Stakeholders

Electricity companies have many stakeholders, with varied knowledge and expectations. In some cases, stakeholders may have an interest in understanding the implications of resource plans that limit resource options. In such cases, including hydrogen as a candidate resource may be crucial for ensuring ongoing reliability. Other stakeholders may have hesitation on emerging technologies. Capturing uncertainties and incorporating additional constraints when modeling may respond to these stakeholder concerns. Electricity companies may also choose to compare multiple configurations in response to stakeholders. In Pacificorp's 2023 IRP process, they received recommendations to investigate the potential to replace retiring coal plants with 100% green hydrogen and to assess the impacts of large, flexible loads such as hydrogen electrolysis [14].

Maintain Optionality and Improve Fuel Diversity

Maintaining optionality, particularly by considering the role of emerging resources, is a widespread practice employed by electric companies to fully assess the value of potential investments and ensure that decisions are robust over time. This strategy is sometimes expected by regulators to ensure that all options have been tested [17].

EPRI studied pathways to economy-wide net zero by 2050, demonstrating the need for new clean energy technologies past 2030, including green hydrogen, advanced nuclear, and carbon capture utilization and storage [5]. Hydrogen can play a role in enabling electrification and in replacing existing technologies to facilitate deep decarbonization of the grid.

4 POTENTIAL CHALLENGES WHEN INCORPORATING HYDROGEN INTO LONG-TERM PLANNING

Several challenges have been identified in terms of modeling and incorporating hydrogen into long-term plans. These were identified through interviews with electric companies, resource planners, and U.S. IRP documents.

Timing Uncertainties

Incorporating a resource into a long-range plan entails having confidence that the technology and associated fuel will be available when needed. In many cases, electric companies´ plans rely on estimates of technology maturity to understand when a resource can reliably reach commercial operation and therefore contribute to its resource plan. While the challenges technology learning curves is not unique to hydrogen, the challenge may be amplified by complexities around whether additional essential infrastructure is available to support hydrogen at scale [18].

KEY CHALLENGES

The comprehensiveness, or level of detail, to model when considering hydrogen is uncertain. While various approaches have been proposed in academia and are used in commercial models for integrated resource plans, there is not yet an accepted 'industry-standard' method. This challenge is amplified because the desire to model details must be balanced with convergence time and tractability.

Through interviews and an in-depth review of IRPs, two significant uncertainties were identified as key challenges when modeling and relying on hydrogen in IRPs: (1) the timing of when hydrogen will be available and (2) the total cost of developing hydrogen facilities for use by the power sector.

Development of hydrogen-enabled turbines is accelerating rapidly. These developments have given manufacturers and other electricity companies a high degree of confidence in current estimates that 100% hydrogen-enabled turbines may be ready by 2030. While promising, there are additional degrees of complexities beyond turbine capability. Low-carbon hydrogen is not available at scale today. Making it available at a scale appropriate for power generation would require advancements to develop a broader energy economy that not only entails advancements in electrolyser technologies, the balance of plant and infrastructure outside of the plant. This infrastructure includes pipelines for delivery of hydrogen, storage facilities, water infrastructure to feed the electrolytic process, transmission infrastructure to deliver electricity to hydrogen production facilities, and potentially additional generation resource expansion to ensure additional electricity can supply production facilities [19].

Given the numerous infrastructure developments needed and interest in building hydrogen infrastructure to support several industries and end uses, many electric companies have identified that understanding supply chain considerations and incorporating these considerations into timing estimations is a primary challenge.

Outside of demonstration or pilot programs, of the reviewed IRPs that consider hydrogen as a candidate resource, all assume availability no sooner than 2030. Some consider longer lead times, particularly given the development of transportation and storage infrastructure, with hydrogen available for the power sector around 2035.

Cost Uncertainties

The objective of most capacity expansion models is to minimize costs, meaning that having realistic, accurate cost forecasts is a very important element of integrated resource planning.

Many IRPs that incorporate hydrogen today include an estimate of the cost of hydrogen as a fuel. The DoE Hydrogen Shot program aims to reduce the price of clean hydrogen to $1 USD per kilogram [20]. While this price is mentioned often in IRPs that model hydrogen, electric companies acknowledged that it is not certain whether and when the price of hydrogen will reach this point by 2031.

In addition to uncertainty in fuel price, capital costs may also be uncertain. For example, to retrofit a gas turbine to use hydrogen, there are potential changes to combustion, fuel, and plant safety systems [23]. However, with very few examples of conversion today, the costs for this expenditure are uncertain. Beyond the conversion of hydrogen to power, one may also factor in the cost of building new hydrogen production facilities and the costs to transport and store hydrogen as a fuel.

Comprehensiveness

It is vitally important for IRPs to comprehensively and accurately model resources with sufficient detail so that their costs, benefits, and impacts on the power system can be well understood. Because hydrogen has the potential to provide services across many time scales, valuing all its uses using a single model could impose the addition of many details. The addition of these details, in addition to typical generator details like location, failure rates, maintenance schedules, and degradation rates, can greatly increase the complexity and convergence time of models.

Multiple models may be required to have sufficient spatial and temporal granularity [21, 17]. For example, to value the operational flexibility of hydrogen, modelers may choose to incorporate sub-hourly forecasts and operational characteristics of the hydrogen facility. At the same time, the efficiency of a hydrogen facility may also depend on the capacity factor of the electrolyser and/or the energy expended to compress hydrogen for storage. The availability of hydrogen fuel to supply electricity demand (e.g., fuel assurance) may be impacted by transportation networks or the availability and speed of access to storage hubs. For investment planning decisions, modelers may choose to compare various modes of operation—such as coupling with another end use, having onsite electricity generation, making use of new or additional pipelines, or blending in the gas network.

Understanding all the potential benefits and limitations can aid electricity companies in proactively respond to stakeholder concerns and identifying risk factors and adaptations that might be required when implementing an IRP.

Ultimately, valuing all the benefits of hydrogen and its ability to provide multiple grid services could increase financial assurance – making it clear to resource planners and their regulators whether an investment can recover its costs. For those that participate in markets, the pace of change in market constructs and uncertainties about compensation from future energy markets may add additional modeling challenges.

Load Forecasts and Additionality

Producing hydrogen through electrolysis requires about 55 MWh of electrical energy per ton of hydrogen [6], which can significantly increase electrical system demand. This effect, often termed "additionality" may be an important consideration for IRPs. Considering additionality allows planners to not only model the power generation benefits but also account for increased load and ensure that any additional electricity resources, including both generation and transmission, are optimized. The absence of credible forecasts of increased electrical demand due to hydrogen production in an IRP restricts the ability of electricity companies to plan for use cases and programs for load flexibility. Consideration of additionality may support electrification goals for the broader economy, such as the building, industry, and transport sectors, and help to manage periods of excess renewable generation [2]. British Columbia, Canada has already seen very large load requests for hydrogen production and as a result, Fortis BC considered it as a significant load driver in some of the scenarios used in its 2021 Long-Term Electric Resource Plan [22].

5 PRIORITIES AND EMERGING LESSONS FOR STUDYING HYDROGEN IN IRPS

The approaches for modeling hydrogen are advancing quickly, as can be seen in the development and improvement of Power-to-X modeling capabilities in commercial capacity expansion software in recent years. At the same time, the desire to model hydrogen in resource plans is also advancing. Good practices are starting to form that may help steer resource planners forward as their modeling matures.

GOOD PRACTICES ARE EMERGING

Despite limited experiences with modeling hydrogen in IRPs, good practices and considerations are forming.

Lesson 1: Incorporate or Evaluate All the Use Cases of Hydrogen

Hydrogen is a very versatile energy carrier, with many applications. Particularly under deep decarbonization scenarios that look beyond 2040, hydrogen may provide grid services like seasonal storage, balancing, load flexibility or regulation, in addition to peaking capacity. Capturing the full range of use cases to the system can help resource planners identify the value of hydrogen. The potential benefits of hydrogen are not always quantified in IRPs. Improvements to capacity expansion models or the use of multiple models may be warranted to represent operational detail and fully capture the value of multiple use cases.

In addition to electricity sector use cases, hydrogen has a significant role to play for other sectors. Consideration of sector coupling may inform synergies like demand flexibility or partnerships to enable cost sharing, and tradeoffs like supply chain implications, coincident high demand for hydrogen, and scarcity conditions.

Lesson 2: Recognize Uncertainties

The role of hydrogen in the power sector is highly uncertain. While some of this uncertainty can be attributed to its technological maturity, questions about whether a larger hydrogen economy and the role that hydrogen might play in decarbonizing other sectors abound. Developing a prudent and implementable IRP calls on resource planners to employ methods that account for long-range uncertainties and benefits. Scenario analysis or stochastic methods are two approaches that can address stakeholder concerns and maintain optionality in a resource plan.

Lesson 3: Factor Hydrogen Production into Load Forecasts

Interest in hydrogen is not limited to the power sector. Electrolytic hydrogen increases electricity demand and may be used for the broader economy, as part of decarbonization goals. Monitoring the development of hydrogen production and incorporating it into load forecasts can not only improve the accuracy of IRP inputs but can also inform resource planners of potential synergies and challenges.

Lesson 4: Improve Transparency of Modeling Assumptions

Efforts to develop industry consensus on modeling techniques may be improved when there is greater transparency and detail provided publicly by electric companies. This may allow resource planners to learn from one another. Industry forums, conferences, and publications (including appendices of IRPs) are ways to improve transparency. This challenge appears to exist across energy models. While this technical brief has focused on IRPs, other landscape reviews have similarly found that detailed information on underlying models and their assumptions is not publicly available [4].

Lesson 5: Understand the Motivators for Including Hydrogen

There are many good reasons for incorporating hydrogen into a resource plan today, including maintaining optionality and demonstrating responsiveness to stakeholders. Current and future policy or stringent emissions targets may increase the urgency or desire to model hydrogen. Understanding power system requirements, especially in deep decarbonization scenarios, as well as financial incentives can not only motivate modeling of hydrogen in an IRP but can also inform the modeling approach(es) used.

Lesson 6: Commit to Learning and Evolving

Where electricity companies model hydrogen as a candidate resource in their expansion plans, simplified techniques have been used as a starting point, with the aim to increase comprehensiveness over time. In parallel, researchers are developing techniques and comparative analyses that can inform the development of, and create consensus on, best practices when modeling hydrogen.

6 SUMMARY OF FINDINGS

Several studies suggest that hydrogen may be a critical resource for ensuring emissions and reliability goals in the power sector. Although interest in hydrogen was limited in prior planning cycles, IRPs in the last three years have started to consider a role for hydrogen. In some cases, hydrogen was not modeled or was not selected by a capacity expansion tool. When modeled, the amount of information disclosed in an IRP is limited. The broad number of potential power system use cases from hydrogen coupled with the individual needs of electric companies suggests that the modeling approach used for hydrogen may vary between IRPs. Some models may prioritize the operational flexibility of hydrogen, where it is modeled similarly to a gas generator, whereas other models might prioritize its storage capability and potential to provide energy arbitrage.

IRPs that do not currently consider hydrogen may observe benefits when incorporating hydrogen, including improving fuel diversity, reducing system costs, ensuring reliability, reducing emissions, and responding to stakeholders.

Electric companies that do consider hydrogen in their resource plans acknowledge and are monitoring uncertainties on the cost of hydrogen fuel and infrastructure, as well as the timing of when hydrogen infrastructure would be available for use by the power sector.

Areas of future research may consider techniques to improve models that support IRPs. This research may aim to understand the potential for hydrogen to provide multiple grid services, reduce run times in capacity expansion, assess the need for additional resources to support hydrogen production, and/or address key uncertainties surrounding the deployment of hydrogen.

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