21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

CIGRE US National Committee
2023 Grid of the Future Symposium

Electric Utility Executive Perspectives on Modern Grid: Opportunities and Challenges

Chris ROOT*, Damir NOVOSEL, David ELIZONDO
Quanta Technology, LLC
USA

Alfonso MUGUETA
Avangrid
USA

SUMMARY

This paper summarizes electric utility executive perspectives on modern grid challenges and opportunities. The perspectives were obtained via workshops that Avangrid initiated, and Quanta Technology executed. The following utilities were involved: Avangrid, Hawaiian Electric (HECO), San Diego Gas & Electric (SDGE), Southern California Edison (SCE), Oncor Electric, Eversource, and National Grid (NGRID). The paper concludes with key observations and recommendations based on utilities' perspectives.

KEYWORDS

Renewable Energy Integration, Electric Grid Changes, Electric Load Increases

croot@quanta-technology.com

INTRODUCTION

While the electrical power industry offers key solutions to achieve society's decarbonization targets, many electrical utilities face significant challenges. This paper addresses the challenges of integrating renewables with aging infrastructure while addressing reliability, resilience, safety, and energy justice needs and requirements. During this integration, two key questions must be investigated: 1) how can utilities best upgrade the power system, and 2) how can utilities change the way they plan the system to more efficiently deploy investments, which would add value to electricity users and satisfy society goals for renewable energy and electrification targets.

In order to address these and related questions, Quanta Technology, with Avangrid's support, organized two workshops involving utility executives. Such an approach is imperative because sharing best practices and benchmarking utility companies against comparable utility peers is a key step toward addressing challenges and identifying optimal solutions for grid modernization. Participating utilities included Avangrid, Hawaiian Electric (HECO), San Diego Gas & Electric (SDGE), Southern California Edison (SCE), Oncor Electric, Eversource, and National Grid (NGRID). The workshops included a series of questions and discussions and the report summarizing the key findings and recommendations that can be drawn from both workshops individually and collectively.

This paper summarizes the key findings of these workshops and is divided into three sections: "Observations," "Recommendations based on Utility Discussions," and "Conclusions." These sections relate to regulations; transmission and distribution (T&D) system needs; overhead vs. underground construction; overall system planning with new loads; renewable integration and transportation electrification; and balancing reliability and resilience priorities.

OBSERVATIONS

The discussions with utility executives covered major industry topics. Key observations are presented below. They are divided into the following subsections/subtopics: federal and state regulations; transmission and distribution; system planning and new loads; renewable integration; electric transportation; and reliability and resilience.

Federal and State Regulations

1. Federal and state regulations are critical factors that drive utility behavior in transmission infrastructure development and operations.
    a. This is a complex process in the United States, where fifty-two regulatory bodies consider the fifty state public utility commissions, along with the two main federal agencies (Federal Energy Regulatory Commission [FERC] and the North American Electric Reliability Corporation [NERC]).
    b. This leads to different priorities and political influences, and even differences among the various ISOs/RTOs drive different behaviors among transmission owners and other stakeholders.
2. In California, New York, and Texas, the ISO/RTO or governing body is only responsible for one state, compared to regions where ISOs/RTOs operate in multiple states (i.e., PJM and ISO-NE).
3. This changes the dynamics between state and federal policies that influence electric transmission functions. The regulatory environment for distribution regulations is

predominantly state based, but that is changing with some recent FERC orders that begin to touch assets in the traditional distribution operating space.

4. Collaboration on sharing best practices and energy policy initiatives is achieved among some utilities, but increased sharing and awareness of successes can only help the entire industry.

Transmission and Distribution Upgrades

1. Aging infrastructure and asset management projects need to be incorporated into new improvements for needed upgrades for renewable generation interconnections.
2. As more photovoltaic projects are in less populated areas, the interconnection projects are becoming more expensive. Massachusetts seems more progressive in developing a plan to split some improvements between the developers and the utility.
3. Transmission additions and asset condition programs are funded in New England through the ISO process, and regional rates are regulated at FERC, which has worked well. Many programs exist for replacing old structures and sometimes wires based on asset condition. In New York, where the transmission and distribution programs are under state regulators, increasing spending beyond traditional spending levels is difficult.
4. Some state regulators are reluctant to approve spending above historical levels, due to concerns around rate increases and affordability. Additionally, in some parts of the country, the focus has moved away from resiliency and toward renewable generation interconnections and electrification. In some jurisdictions, regulators prefer non-wire alternatives (NWAs) over capital spending because many regulators believe NWA's 1) are easier to approve and 2) are a more cost-efficient solution than the traditional wired solution. But many techniques do not offer long-term solutions or address asset condition issues.

   Moreover, some state distribution regulators have backward-looking rates, which means the utility must spend the money first and then request to have it put into rates after the fact. This situation can be troublesome if the utility must increase spending outside historical patterns and justify it afterward. A more forward-looking approach from the state regulators could create more predictable environments for utilities' investments.
5. Another issue is the design standard that a project upgrade must meet. Some utilities use standard wire and circuit ratings, with projected growth built into the design. The amount of load growth expected in the future is increasingly difficult to predict. For instance, a state committee sets the companies' load growth predictions in California. In other areas, the company sets the growth rate, or sometimes, as in Vermont, the growth rate is established in collaboration with multiple stakeholders.
6. Large new loads are being proposed for transmission connections in different areas of the country. New data centers can be as large as 100–200 MW per building, with gigawatt campuses now being discussed among the major players in the data center industry. Also, clusters of transportation warehousing and trucking firms (usually near major highways) could present a situation of large demand increases (one area in Southern California estimated it could be as high as 200 MW) as some of these facilities convert to electric transportation.

System Planning and New Loads

1. System studies at the transmission and distribution level are becoming more complicated and impactful to prudent decision-making.

a. Electrical utilities are doing studies to identify upgrades required to incorporate renewable energy projects. These studies are becoming increasingly complex to ensure reliability, and usually result in other potential customer impacts and potential interactions with other generators.

b. Transmission studies take the longest and are often coordinated with the ISOs/RTOs, while distribution and sub transmission studies can be slightly shorter. The large number of interconnection requests has many utilities struggling to perform these studies, and developers frequently complain to the regulators and RTOs in many areas of the country.

2. There is often a gap between regulators and utilities on the impact of load growth from electrification efforts.

   a. Most states have climate change goals but the impact of these goals is not always recognized in the load growth the utilities can use in their projections. There is a concern for stranded investment as electrification propensity, particularly at the localized level, is not clear. The need and time required for utilities to do grid upgrades may not be understood.

   b. EV charging remains an open issue regarding when charging will occur and how, who, and whether an entity will manage charging loads to manage feeder demand.

Renewable Integration

1. Studies in New England have examined the impacts of clustered renewable energy projects. These can be from multiple developers and are studied together to develop an optimum solution that could be financed by many of the projects. These projects can aggregate to large impacts on sub-transmission and transmission systems. Determining who pays and how much can be a major stumbling block.
2. With high levels of renewable energy on all state agendas, the regulatory agencies and developers focus on building these projects to achieve the state's climate objectives. In many cases, the developers trying to build these projects complain to high government officials that the utilities are not working fast enough to perform the required studies to approve the projects. The process in many cases requires detail design specifications of inverters to perform the studies which the developer may not have yet as they have not selected an inverter vendor. This leads to additional delays in the studies and discussions with the developers.
3. Some utilities have developed GIS-based maps identifying areas with available capacity for new renewables. This development has been very effective as a screening tool for developers as they are looking for land for their projects, which will be on the distribution system.
4. It is difficult to tell developers they cannot connect in a particular area due to the interconnection's condition, configuration, and cost. To address this problem, one utility is thinking of developing a base or standard circuit rating. If there is a surplus, it would be available on a first-come, first-serve basis.
5. The new IEEE Standard 15471 and IEEE Standard 28002 will help integrate the new inverter-based generators into the system. Most regulators have adopted these standards.

[1] IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. https://standards.ieee.org/ieee/1547/5915/.

[2] IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems. https://standards.ieee.org/ieee/2800/10453/.

6. The modeling of transmission systems is performed similarly across the industry by the utilities and ISOs/RTOs in the case of transmission connections. Most utilities and ISOs/RTOs use similar tools, although several want more integrated planning tools. Some utilities use scenario planning. Additionally, detailed modeling of inverter behaviors under different operating conditions is a challenge because, in the study phase, the models are not available from the developers.
7. Besides modeling new renewable generators to identify potential problems, determining who bears the cost of the upgrades continues to be an issue throughout the country. In particular, regulators are dealing with the following problem: if the developers do not pay for most system upgrades that may be needed to incorporate additional renewable energy projects, how will that impact customer rates?

Electric Transportation

1. Although states generally have aggressive EV targets and electric heat pump targets, there needs to be a reconciliation with load growth in various areas that will be hit hardest as the load grows. Traditionally, utilities waited until the load happened and then mitigated it. In the future, the load could increase so fast that the amount of work needed could not be done in time, which could impact reliability. Few states are recognizing the load growth impacts and are comfortable recognizing this future electrical growth will happen and recognizing that utilities must start preparing the electrical grid for additional needed capacity.
2. Most utilities do not control electric car chargers. These are significant loads and will impact residential transformers and substation loads.
3. There is a need for utilities to get in front of the regulators to provide practical scenarios on a more granular level at the substation or feeder level to ensure that proper investments are made in a timely fashion.

Reliability and Resilience

1. Most utilities have some issues with the accuracy of distribution systems' detailed data and GIS (graphic information systems), which they use, for example, to verify which secondary feeder is connected to which transformer. To address this problem, several utilities have developed techniques to monitor transformer overloads through billing or smart meter information and phase balancing and Volt Var Optimization (VVO) solutions.
2. Regulators have not recognized that the increased workload on renewable interconnections may impact the utilities' ability to dedicate resources and capital to these issues.
3. Although the state regulators' focus is still primarily on reliability and affordability, resilience can quickly come into focus after a large event such as a weather-based widespread outage.

RECOMMENDATIONS BASED ON UTILITY DISCUSSIONS

Based on the observations in the previous section, the following recommendations are made for each section.

Federal and State Regulations

1. Utilities should develop a structured approach to share experiences and best practices, as well as to develop a common message to regulators. This action would benefit the industry by enabling it to more effectively reach decarbonization, reliability, resilience, safety, and energy justice goals.
2. The state regulators' focus is still primarily on reliability and affordability, not resilience. However, as there is a need to develop investment prioritization processes to address reliability and resilience in the context of affordability, it is recommended utilities to perform an analysis to communicate needs to the regulators.
3. Utilities must build relationships with respective state regulatory technical staff to educate and inform decision-makers on critical issues in transmission and distribution. The approach should leverage asset condition work and asset management plans and share the results and documentation of the work needed for a reliable and resilient system. Discussions should include the need to not only replace assets in kind but to increase the system's capacity to meet the state's climate goals. This may be a long-term objective and require some regulatory rulings but giving utilities some certainty or investment guidance would be very helpful.

Transmission and Distribution Upgrades

1. Develop an integrated roadmap to prioritize programs that will accomplish multiple objectives the regulators are interested in, such as asset condition, load growth, and renewable connections.
2. Share asset management plans with regulators outside of the rate-making process to educate them on the grid's state.
3. Consider using non-wire alternative (NWA) solutions to bridge capacity shortfalls in constrained areas until permanent upgrades can be permitted and constructed.

Overhead vs. Underground Construction

1. In communities planning beautification projects or new developments, work with the cities, towns, or developers to consider these improvement projects to pay for undergrounding existing facilities.
2. Identify all the costs and benefits of the two types of construction via a cost-benefit study. Such studies should consider local geography, system configuration, and underground conditions. Additionally, studies should include societal benefits. These studies will have different answers based on all these factors.

System Planning and New Loads

1. Develop and further enhance the planning tools, models, and strategies to speed the interconnection process and address inverter-based resources. To aid in this development and enhancement, take into consideration how the process works in the different states and utilities.
2. The industry must continue to develop integrated resource and T&D planning tools, including scenario planning. Utilities are at different levels in the process based on

geographical and regulatory requirements. There is a gap between integrated T&D tools, models, and processes.

3. Investigate areas with smart meters where data mining could provide distribution planning efficiencies.
4. Stay connected with technical associations like IEEE's PES and CIGRE, where technical innovations are presented. This recommendation would be particularly beneficial for addressing issues regarding renewable generation and electric vehicle impacts on the system. Also, consider participating in the Association of Edison Illuminating Companies (AEIC) and Edison Electric Institute (EEI), organizations that share common utility issues. EEI is also an organization that deals with national issues and has various membership committees for sharing information.
5. All transmission-owning entities should be involved in the North American Transmission Forum (NATF). Approximately 90% of transmission owners in North America are members. The NATF focuses on sharing best practices and compliance with NERC reliability standards. The NATF also provides no-cost reviews of utility practices by industry member experts and makes recommendations. The NATF holds quarterly members' meetings and has several subcommittees. Membership is limited to transmission-owning entities.

Renewable Generation

1. Review the interconnection study process to expedite study time frames, data quality, and study scopes.
2. Identify areas where interconnections will be less of an issue.

Electric Transportation

1. Identify potential areas where larger charging stations may be sited (for example, at FedEx/UPS/postal offices) to understand the potential impact of electrifying these facilities. Similarly, areas such as along major highways (at rest areas). Focused studies in these areas may be needed to identify system upgrades in the future.
2. Develop strategies for the following: managing electric chargers, including individual Level 2 and group charging stations for residential and fast charging for medium- and heavy-duty vehicles.
    a. Address the grid impact based on the significant load. Provide more granular practical scenarios to the regulators and emphasize the need for investments in a timely fashion.
    b. Address mitigation solutions, including grid upgrades, grid reconfiguration, managed charging and demand-side management (DSM) options, and DERs and storage technologies.

Reliability and Resilience

1. State regulators' focus is still primarily on reliability and affordability, not resilience. Develop investment prioritization processes to address reliability and resilience in the context of affordability to better communicate the need to the regulators.
2. Consider targeted standard improvements in areas for reliability and resilience. For example, consider slightly different construction standards near the coast or heavily treed areas to improve reliability and resilience.

3. Continue to develop a formal asset management program related to aging infrastructure, asset management, and replacement. Link such programs to resilience, reliability, affordability, and risk management.
4. Develop an asset ranking system based on age, condition, load growth potential, system criticality, and future renewable generation connections. Then, use this information to develop some level of capital upgrades.

CONCLUSIONS

A modern electric grid is necessary to achieve a clean energy future. A structured, coordinated approach among utilities to share experiences and best practices, is beneficial to move the industry and society forward to realize reliable, resilient, affordable, and safe electrical energy delivery that fulfills decarbonization and energy justice needs. Being able to discuss these issues with regulators is important.

Results from sharing experiences at the electrical utility executives' workshops described in this paper are one step toward reaching that goal. The list below summarizes the key recommendations:

1. Build a relationship with your respective state regulatory technical staff members to educate and inform decision-makers on critical issues. Develop a regulatory strategy that explains issues and the magnitude of the challenges, including different scenarios to state regulators, to get input before a rate case.
2. Develop investment prioritization processes to address reliability and resilience in the context of affordability to better communicate the need to regulators.
3. Address the increasing need for integrated resource and T&D planning, including scenario planning.
4. Develop and further enhance the planning tools, models, and strategies to speed the interconnection process and address inverter-based resources. To aid in this development and enhancement, take into consideration how the process works in the different states and utilities.
5. Continue developing a formal program and standards related to aging infrastructure and replacement, and link programs to reliability, resilience, affordability, and risk management. Additionally, address load and renewable growth potential.
6. NWAs could bridge capacity shortfalls in constrained areas until permanent upgrades can be permitted and constructed, although it is considered a short-term solution that may require another upgrade in the near future, which will challenge the investment from the customer's point of view.
7. Complete a cost-benefit analysis (including societal benefits, local geography, system conditions, and configuration) to address undergrounding vs. overhead construction.
8. Develop strategies for managing electric charging for light-, medium- and heavy-duty electrical vehicles, addressing grid impact and mitigation solutions (e.g., grid upgrades, grid reconfiguration, managed charging and DSM, and Distributed Energy Resources (DER) and storage).
9. Develop methodologies to leverage data and data analytics tools/expertise for operational and cost improvements and incorporate operational experience and knowledge into these methodologies.
10. Stay connected with technical associations—like CIGRE, IEEE, and AEIC—and increase involvement in the NATF.

11. Review distribution design standards to determine whether there should be different options in areas of different weather climates such as along the coast, or in micro-climates or in other areas which may be impacted by climate changes may make sense instead of only having one standard design for a large utility footprint.
12. Investigate areas with smart meters where data mining could provide distribution planning efficiencies and continue to develop data analytic tools.

ACKNOWLEDGMENTS

The authors would like to thank and acknowledge Kevin Geraghty, COO SDGE; Erik Takayesu, SVP SCE; Colton Ching, SVP HECO; Mark Carpenter SVP Oncor, Aftab Khan, SVP Eversource; Carol A. Sedewitz, VP National Grid; and Jamie Willett, Manager Central Maine Power, for invaluable contributions, as well as support by Quanta Technology participants Kevin Curtis, EVP; Wayne Bishop, VP; and Carl Segneri, VP.