PERSPECTIVES

Rethinking Energy Reliability with Modern Power Systems

Our perspectives feature the viewpoints of our subject matter experts on current topics and emerging trends.

INTRODUCTION

Utility-scale wind, solar, and battery resources are challenging the way we assess and value system reliability as part of the ongoing Energy Transition process.

On November 17, 2022, the Federal Energy Regulatory Commission (FERC) issued two orders and published a Notice of Proposed Rulemaking related to concerns over reliability gaps associated with inverter-based resources (IBR).[1] FERC recognizes that IBRs[2], in the form of utility-scale wind, solar, and battery resources connected to the bulk power system, have direct reliability impacts to the overall Bulk Power System (BPS).[3] [4] The North American Electric Reliability Corporation (NERC) has investigated a series of "disturbances" that involve the widespread reduction (i.e., loss of generation) of IBRs to identify systemic reliability issues.[5] The 2022 Odessa Disturbance Joint NERC and Texas RE Staff Report highlighted the significant risk to BPS reliability, issued immediate calls to action to enhance NERC standards for IBRs, and pushed NERC Reliability Standard enforcement.[6]

North America is fortunate to have strong leadership through the Electric Reliability Organization (ERO) Enterprise composed of NERC and six Regional Entities to ensure a highly reliable, resilient, and secure power supply for over 400 million people throughout the United States and Canada. As mentioned above, NERC and its partners actively track and evaluate system risk. This paper addresses one of several risks NERC has identified—as energy transition to IBRs occurs, reliability risk increases and requires additional investment to mitigate that risk. This paper evaluates issues including: what measures must be put in place to mitigate the risk? What are the costs associated with those efforts? How does the power generation industry appropriately budget for the necessary efforts to ensure reliability?

NERC is the regulatory authority overseeing reliability for the bulk power systems that provide electricity across continental United States, Canada, and the northern portion of Baja California, Mexico, and is subject to oversight by FERC and governmental authorities in Canada. NERC's mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Decarbonized Fleet Challenges

"As the MISO region rapidly transitions to a decarbonized fleet, the system will become more interconnected and interdependent," said Jordan Bakke, MISO's director – strategic insights and assessments. "The task of resource planning is becoming more complex and having a shared understanding of future trends and risks is necessary to ensure reliability."

2022 MISO Regional Resource Assessment Media Report, November 30, 2022.

To do that, NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel.[7] The NERC Reliability Standards define the reliability requirements for planning and operating the North American bulk power system. Those requirements apply to IBRs, and through the proposed rulemaking, will reach further downstream to increasingly smaller power generation facilities.

[1] 181 FERC ¶ 61,124, 181 FERC ¶ 61,125 and 181 FERC ¶ 61, 126

[2] 181 FERC ¶ 61,124 used the term IBRs "to include all generating facilities that connect to the electric power system using power electronic devices that change direct current (DC) power produced by a resource to alternating current (AC) power compatible with distribution and transmission systems. This order does not address IBRs connected to the distribution system." The Notice of Proposed Rulemaking (NOPR) used similar language.

[3] The Bulk-Power System is defined in the Federal Power Act (FPA) as facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. 16 U.S.C. 824o(a)(1).

[4] 181 FERC ¶ 61,124 at ¶5.

[5] 181 FERC ¶ 61,125, FN 12. NERC disturbance reports for IBRs (1) the Blue Cut Fire (August 16, 2016); (2) the Canyon 2 Fire (October 9, 2017); (3) Angeles Forest (April 20, 2018); (4) Palmdale Roost (May 11, 2018); (5) San Fernando (July 7, 2020); (6) the first Odessa, Texas event (May 9, 2021); (7) the second Odessa, Texas event (June 26, 2021); (8) Victorville (June 24, 2021); (9) Tumbleweed (July 4, 2021); (10) Windhub (July 28, 2021); (11) Lytle Creek (August 26, 2021), and (12) Panhandle Wind Disturbance (March 22, 2022).

[6] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf, last visited December 8, 2022.

[7] https://www.nerc.com/AboutNERC/Pages/default.aspx, last visited December 8, 2022.

ENERGY RESILIENCE AND RELIABILITY

Electrical system grid resilience is the ability of a system to withstand adverse events and its ability to adapt to such events without suffering operational compromise. Simply put, resilience for an electrical system is its ability to withstand adverse events without sustained interruptions of service to customers. Resilience is largely about what does not happen to the grid or electric consumers. Reliability, on the other hand, is a measure of behavior once resilience is broken. FERC defines resilience as, "the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[8] The start of a sustained interruption is the transition point from the domain of resilience to the domain of reliability.[9] Some may argue with these definitions, and, in fact, some of the arguments may be valid, but for the sake of this paper we will consider these definitions for resilience and reliability as appropriate.[10]

The challenge of energy transition continues to be maintaining the correct mix of fuel-based generation with IBRs that will have both the capacity as well as the duration to meet load requirements throughout various demand scenarios. There are several system challenges associated with this transition process, but a couple of the primary impacts are 1) loss of system inertia or momentum as large, conventional prime movers such as turbine driven generators that are being retired and removed from the grid and 2) the reactive power, also known as Volt Ampere Reactive (VAR) that is necessary for grid operations.

System inertia supports sudden changes in system frequency driven by fluctuations in electrical demand. In the U.S. that frequency is 60 Hz, and small deviations in both BPS voltage and frequency can potentially lead to significant system impacts. Inertia behaves a bit like the shock absorbers in a car's suspension, which dampen the effect of a sudden bump in the road and keep the car stable and moving forward.[11]

With regard to reactive power, alternating current power systems rely on magnetic fields to work. A transformer, motor, or generator cannot work without magnetic fields. The principle of operation of these devices is totally dependent on those magnetic fields. These magnetic fields come from current flow. Apparent power typically referred to as Megavolt Amperes (MVA) includes both real power and reactive power. Since the voltage is the same for both, we can focus on the current. A portion of the total current is for the megawatts. The additional current is the current required to create the magnetic fields (VARs). The VARs are also delivered by the generators. When reactive power drops, voltage drops, which can cause a circuit to fail.

All of these effects can be especially difficult for system operators to address during extreme weather events, and those impacts affect both system reliability as well as resilience.[12]

The Lawrence Berkeley National Laboratory prepared a paper titled "Utility Investments in Resilience of Electric Systems"[13] which takes contribution from the Organization of MISO States, the National Rural Electric Cooperative Association, Edison Electric Institute, and the National Association of State Utility Consumer Advocates. The paper suggests that resilience has been a consideration within reliability for a long time and credits three recent developments as drivers for the "unbundling" of reliability and resilience:

1. Our society's reliance on high-quality, dependable electrical service has increased.

2. The United States has experienced several high-impact, low-frequency events (HILF events) with serious impacts to the electric system.

3. New threats are emerging that could have devastating effects on the nation's electric system (e.g., cyberterrorism and the potential for geomagnetic disturbances, or "GMDs").[14]

These high-impact, low-frequency events, also described as "Black Sky Events," are at the far end of the power generation spectrum – a complete and lasting disruption in service.

[8] FERC Grid Resilience Order, supra note 22, at P 13. FERC does seek comment on the definition.
[9] JD Taft, PhD, Electric Grid Resilience and Reliability for Grid Architecture (November 2017).
[10] JS Held, Dulude, J.C., White Paper, Energy Storage and Its Potential Impact on Business Risks, 2022.
[11] https://www.nationalgrideso.com/electricity-explained/how-do-we-balance-grid/what-inertia
[12] VARs Explained in 300 Words, Without Equations or Vector Analysis | Fossil Consulting Services, Inc.
[13] https://eta-publications.lbl.gov/sites/default/files/feur_11_resilience_final_20190401v2.pdf
[14] Id. at 6.

***Figure 1** - Reliability versus Black Sky events.*[15]

However, there is evidence that events historically categorized as low frequency events are now also becoming more common. The Electric Power Research Institute (EPRI) produced a Technical Update in January 2021 titled "Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy"[16] that found among other points:

- Effective load carrying capability calculations generally do not consider weather correlated deviations from standard profiles for variable energy resource (VER) output that might result in large fleet-wide variations in the output of both existing resources and incremental units.
- The availability and output of renewable sources being correlated with weather requires other resources and/or demand to rapidly respond to significant changes in renewable energy production.
- It is acknowledged that natural gas-based generation is a critical supply technology needed to maintain reliable service to consumers; it is generally assumed to be an "available resource" even though both operational and regulatory issues can and do lead to that capacity being unavailable.
- The industry's methodologies for calculating resource adequacy assume that outages and reductions in output are independent and uncorrelated. Increased dependence on renewable technologies combined with a recognition of common mode events that affect multiple generators makes it clear that the assumption of independence may no longer be valid.[17]

EPRI's findings support the work now being undertaken by FERC. As the reliability-resilience continuum becomes more formalized, separate metrics and methodologies for reliability and resilience may become available. Those developments are needed and must include the Black Sky Events mentioned above.

WHAT IS LOAD SHEDDING & WHY IS IT USED?

System instability may occur, for example, when load demand exceeds available supply and correction is not available, i.e., a power shortage exists. This can trigger a cascading process initially composed of frequency fluctuations and power surges, which escalates to unpredictable tripping or damage to equipment including generation and transmission assets, and finally cumulates in widespread blackouts.[18] To avoid blackouts, it is necessary to reduce system load in an orderly manner; this is known as "load shedding." Load shedding is, for all practical purposes, organized power outage to protect the Bulk Electric System (BES or, for this paper, "grid") through reducing electrical demand by removing customers in an overall effort to protect the system from physical damage and protect it from complete system failure.

Load shedding consists of two types of reductions in electrical load. Voluntary reductions in electrical demand for certain customers based on pre-scheduled or on-demand basis is commonly referred to as interruptible load. Users that sign up for interruptible power do so to receive a reduced electrical rate or payment for doing so. The other type of electrical load reduction is referred to as involuntary load shedding. This is when a utility electrical provider lowers or stops electricity distribution across the coverage area for a short period of time; this type of load shedding is commonly referred to as a rolling blackout.[19]

[15] Id. at 7
[16] Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy. EPRI, Palo Alto, CA: 2021. 3002019300.
[17] Id. at vii-viii.
[18] NERC was created in response to the 1965 Northeast Blackout. On Tuesday, November 9, 1965, at 5:16 p.m. Eastern, a major cascading system disturbance resulted in the loss of 20,000 MW of load, affecting 30 million people. This outage lasted for 13 hours and was the most significant disruption in the supply of electricity at that point in the history of the electric industry, affecting parts of Ontario in Canada as well as Connecticut, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Pennsylvania, and Vermont in the United States. The 1965 Northeast Blackout was caused by a backup protective relay on one of five lines between an Ontario power plant the Toronto. The power redistribution to the remaining four lines caused the same "tripping" which then cascaded across Ontario and the northeast United States. Essentially each of the tripping events was to prevent physical damage to various components on the power grid.
[19] https://www.techtarget.com/searchdatacenter/definition/load-shedding#:~:text=Load%20shedding%20(loadshedding)%20is%20a,primary%20power%20source%20can%20supply.

When an involuntary load shed is ordered by the Regional Transmission Organization (RTO) or the Independent System Operator (ISO), it is done as a last resort to protect the BES from a complete and catastrophic failure. Once the order is given, the various electrical transmission and distribution suppliers have a pre-determined list of circuits that have been identified as critical, i.e., ones connected to hospitals, first responders, etc., that are not included in the rolling blackout. These rolling blackouts generally exclude large transmission customers and other critical facilities directly associated with fuel supply. All remaining circuits are subsequently included in the rolling blackout process. Normally, these circuits are interrupted and rotated for periods of 15 minutes to an hour until such time that the overall BES is normalized. In the case of Winter Storm Uri in Texas, the extreme temperatures and the duration of the storm led to interruptions lasting days rather than hours.

System operators design procedures to disconnect load and apportion energy curtailment among customers as part of load shedding. Public utility commissions or boards are the regulatory authorities that approve the design of these systems and take into consideration many factors including contractual rights to interrupt, voluntary curtailments, and voltage and frequency disruptions. Ultimately, while technical considerations inform the decision-making process, load shedding is policy driven.

An example of the type of data analysis utilized by system operators and regulatory authorities is based on Loss-of-Load Probability (LOLP) models. The LOLP model represents the likelihood that the system load will exceed the power generating capacity in a given time period, e.g., an hour. For any given hour, LOLP represents a probability that there would be insufficient power to meet the electrical load in that hour, and therefore reduction in load, either via voluntary or involuntary interruption, to balance the system in that hour. As there is some chance for the system to be "short" any given hour, hourly LOLPs are aggregated annually to produce a Loss-of-Load Estimate (LOLE) measure that could be easily compared across different power systems.

Through resource planning and regulatory processes, most Western countries mandate calibration of their power market LOLEs to 0.1 days per year (or 1 day in 10 years). This is a small amount of expected downtime, but it reflects the gravity and seriousness with which electricity reliability is treated and how much modern society depends upon it. LOLE is only one of the commonly used reliability measures in resource adequacy, as there are many other factors and measures taken into consideration when analyzing power system reliability.

When determining the required power to be produced from a given system, capacity, the amount of generation that can be produced in full production, is a critical consideration. Capacity of a power plant is commonly described as nameplate generation capacity, which is the amount of power the manufacturer states the plant can produce. Other measurements of electrical capacity include net summer and net winter generating capacity.[20] Various constraints impact capacity and decrease the actual capacity in relation to the nameplate capacity. The capacity factor for any given generating unit is the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period. Capacity factor can be thought of as how frequently a plant is running at its maximum power. The U.S. Energy Information Administration (EIA) provided capacity factors by energy source for 2021 as shown below.

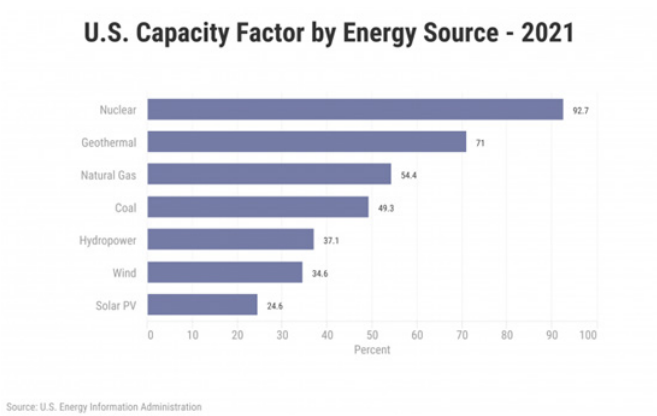

***Figure 2** - U.S. capacity factor by energy source, 2021 (Source: U.S. Energy Information Administration).*

As energy transition occurs and IBRs become more prevalent, the NERC Reliability Standards need to be reevaluated.

[20] https://www.energy.gov/ne/articles/what-generation-capacity, last visited December 8, 2022.

GRID RELIABILITY AND HOW TO DEFINE ACCEPTABLE RISK OF SYSTEM FAILURE

The main question when evaluating grid reliability is, "What is an acceptable risk of system failure?" When it comes to BES reliability, how should reliability be defined, what is "acceptable," and how is that revised standard achieved? Designers, operators, and regulatory agencies each have internal assumptions based on their individual backgrounds in making these determinations. Location of the generating asset, historical information about weather, and other data points all figure into the analysis. As the inputs into the analysis are constantly evolving, there is a significant need to develop a dynamic system of analysis that considers the changing nature of generation, the location of generation, storage capability and capacity, and many other factors.

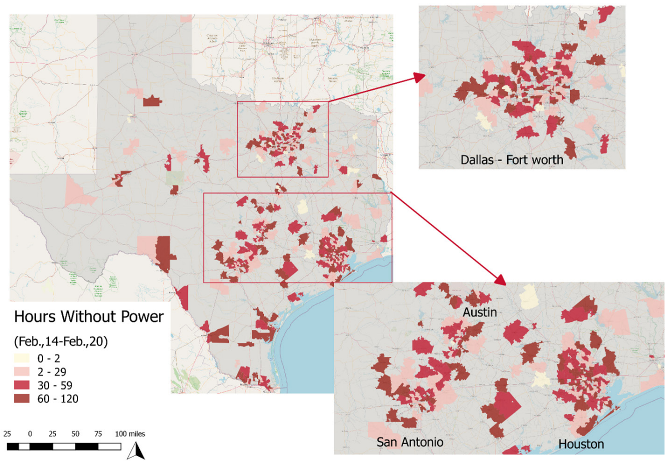

Figure 3 *- Map of areas of Texas affected by loss of power from February 14 to February 20, 2021 during Winter Storm Uri.*

Despite these lengthy events, reliability is generally evaluated in minutes or hours as reflected in the National Renewable Energy Laboratory graphic below.[21]

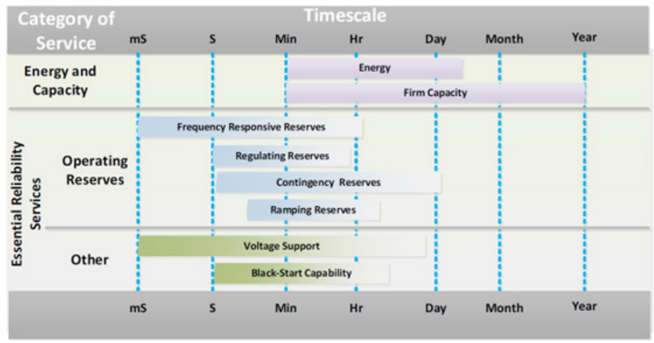

Figure 4 *- Reliability is generally evaluated in minutes or hours (Source: National Renewable Energy Laboratory).*

Resource adequacy and portfolio planning are becoming front page issues in our decarbonizing society. A recent report by the Energy Systems Integration Group suggests moving beyond the current approach to resource adequacy/portfolio planning.[22] According to that report, "rapidly increasing levels of wind, solar, storage, and load flexibility require the industry to rethink reliability planning and resource adequacy methods for modern power systems. Periods with a risk of shortfall often no longer coincide with peak demand—reliability risks are less about peak load and more about the daily setting of the sun, extended cloud cover, wind speeds, cold snaps, and heat waves."[23] In the past, weather primarily affected demand which in turn impacted resource adequacy. With IBRs primarily driven by atmospheric elements, weather extremes now impact both the demand and generation availability (i.e., intermittent resources).

[21] National Renewable Energy Laboratory (NREL) Technical Report, NREL/TP-6A20-72578, January 2019.
[22] https://www.esig.energy/resource-adequacy-for-modern-power-systems/
[23] Energy Systems Integration Group. 2021. Redefining Resource Adequacy for Modern Power Systems. A Report of the Redefining Resource Adequacy Task Force. Reston, VA.

UPDATING CONSIDERATIONS FOR GRID PLANNING WITH MODERN POWER SYSTEMS

Consequently, as resource adequacy and planning procedures continue to evolve amid decarbonization, it will still be paramount to maintain the three pillars of power system planning: affordability, sustainability, and reliability.[24] Affordability was once straightforward—what does the customer pay for the power supplied as decided by the state public utility regulatory body, taking into account traditional inputs? Today, affordability is part of the evolving decarbonization discussion and still includes the traditional inputs, but now must also account for a variety of newly injected factors, some caused by IBRs, to determine the ultimate cost to the consumer.

NERC defines reliability for the grid as:

- Adequacy, or the ability of the electric system to supply the aggregate electrical demand and energy requirements to the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Operating reliability (formerly titled Security), or the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.[25]

Because of the issues discussed here, NERC and FERC are actively working to address reliability and resilience. Through its Reliability Issues Steering Committee, NERC has developed a Resilience Framework focused on robustness, resourcefulness, rapid recovery, and adaptability.[26]

The risk of shortage of generation can be offset by increasing the investment in generation, i.e., adding more megawatts (MWs). However, the increased investment translates to increased cost to the consumer or simply affordability. This occurs because risk, in the form of expected unserved energy, which occurs at the outer margin of generation demand, must be planned for in the form of generation not at risk. In the case of solar and wind, risk is related to intermittent performance and needs to be offset with high performance certainty (energy availability in the form of fuel storage), i.e., coal, geothermal, hydropower, or nuclear.

The acceptability of a reliance metric depends not on the day-to-day demands of the system but rather on the system's ability to maintain connectivity throughout an extreme event such as the multi-day events referenced above. An important aspect of system reliability, in addition

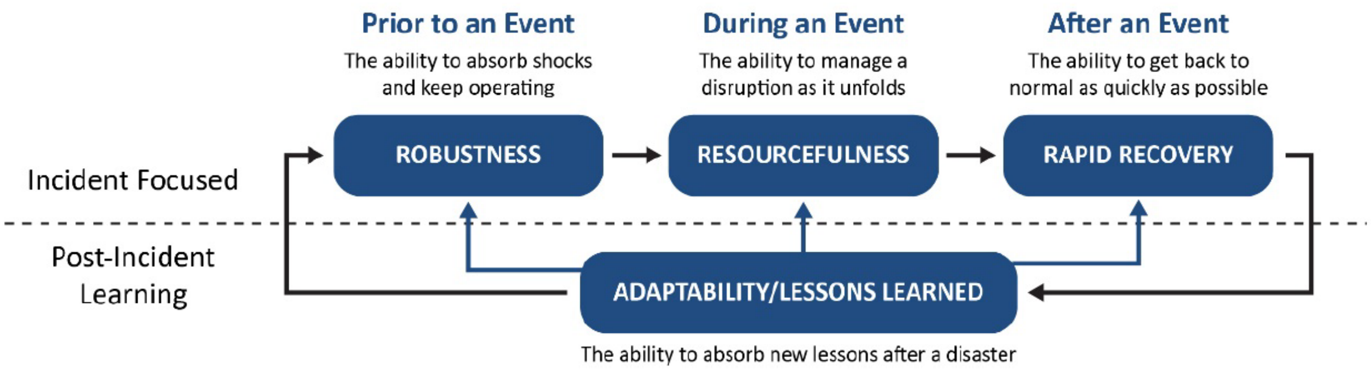

Figure 5 *- NERC's Resilience Framework.*

[24] Id, P.1.
[25] https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20Resilience%20Report_Approved_RISC_Committee_November_8_2018_Board_Accepted.pdf
[26] Id.

to operating throughout an extreme event, is the ability to rebound from that event, and this is generally referred to as resilience of the system.

An acceptable reliability outcome for the bulk electrical systems is the ability to bend but not break—resilience is the capability of the system to return to normal operations. What became evident from Winter Storm Uri was that the impact of system performance in terms of temperature was significantly magnified by the duration of the event. That combination of magnitude and duration substantially impacted reliability and, as the impacts multiplied, the ability of the system to rebound came into question, ultimately narrowly avoiding failure through substantial load shedding.

LOOKING AT THE TEXAS POWER GRID FAILURE

It is evident that ongoing energy transition for generation that depends on atmospheric elements—solar and wind—is significantly affecting and skewing the analytics for reliability. Texas currently has more than 35,000 MWs of wind generation. If it was a separate country, it would lead the world in wind power. That amount represents roughly a third of their total electrical generating capability. That also means that a full third of their capacity may not be available to support the electrical load demand during an extreme weather event as was the case with Winter Storm Uri. There are 4.5 million Texans, roughly 17% of ERCOT's entire customer

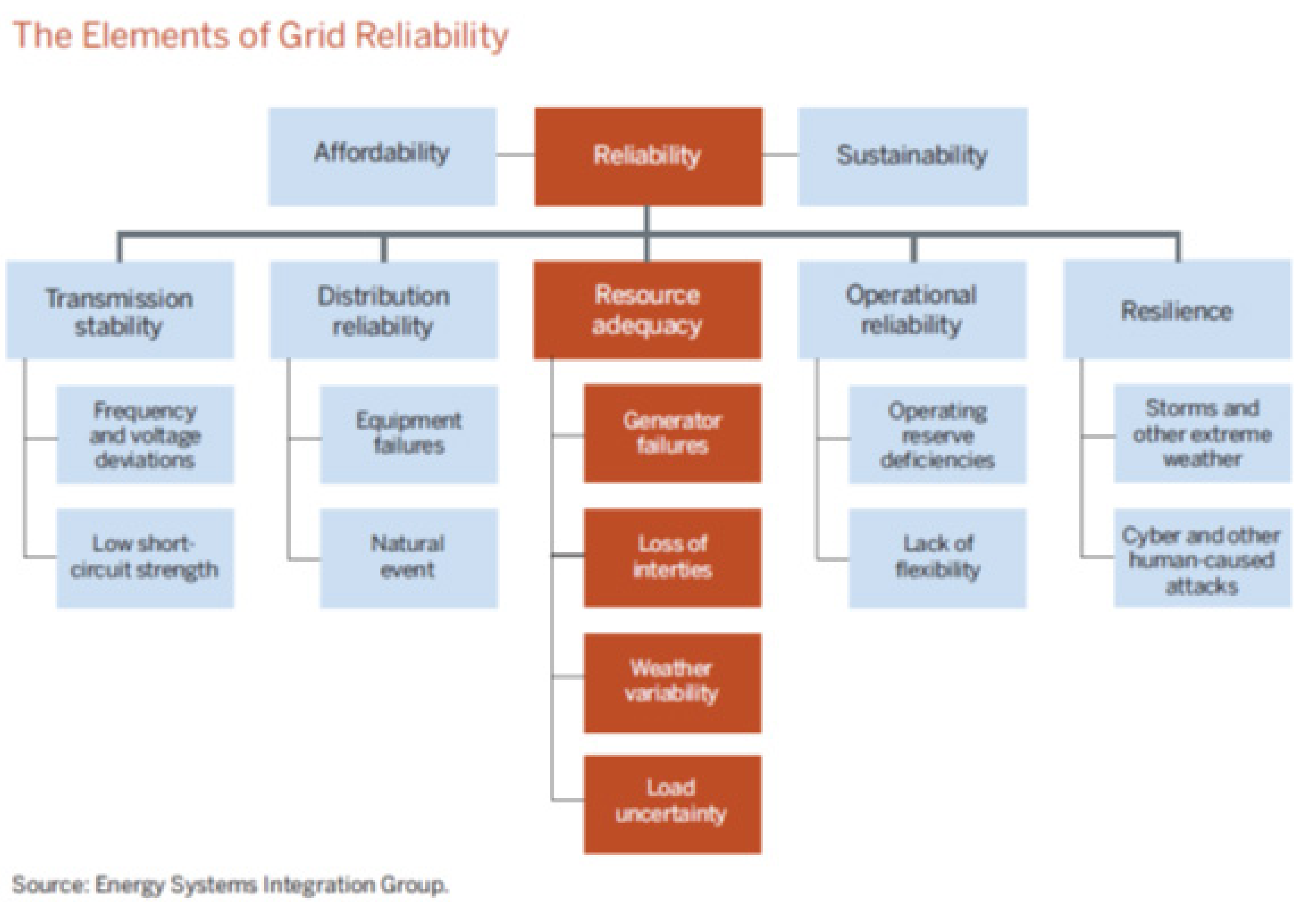

Figure 6 *- Elements of grid reliability (Source: Energy Systems Integration Group).*

base, with firsthand knowledge of actual impacts that support prioritizing how reliability is assessed and how it is priced to assure performance during those extreme times.

In the case of Electric Reliability Council of Texas (ERCOT), the potential for a system-wide black out was averted during Winter Storm Uri with only 4 minutes and 37 seconds to spare but the data clearly shows that once temperatures increased, generation immediately increased as well—resilience and rebound. When a system exceeds its reliability boundary the only alternative is forced load-shedding to avoid total system collapse. The impacts of a total system collapse versus the inconveniences of rolling blackouts – significant as they were for this winter storm, would be catastrophic. The re-establishment of the grid after a total collapse could take significantly more time, and the resultant impacts and costs for extended periods of millions of consumers without electricity would be disastrous. Recent forensic reviews of what occurred during Winter Storm Uri indicate that even though Texas has good diversity of generating asset types, much of the system relies on two primary forms of generation that were significantly impacted by weather: wind and natural gas. Wind generation was adversely affected and directly impacted when equipment froze, which resulted in loss of generation. Natural gas production facilities were impacted not just when equipment froze but by shortage of fuel. Freezing at the production well heads caused significant reductions in available natural gas. The reduction in fuel produced derates and outages in generating assets that subsequently led to loss of electrical support for natural gas production equipment, thus creating additional loss of fuel capacity which produced a negative feedback loop on generation capacity which continued to exacerbate the problem. As witnessed by this event, the inextricable connection between the two energy sources compounded the effects upon the reliability of either to produce and support their respective infrastructure. This phenomenon is not captured in any of the scenarios considered or evaluated by ERCOT because typical or current reliability assessment and resource adequacy planning looks at demand peaks rather than chronological operations as well as coincident and correlated impacts as seen in the recent Texas event.

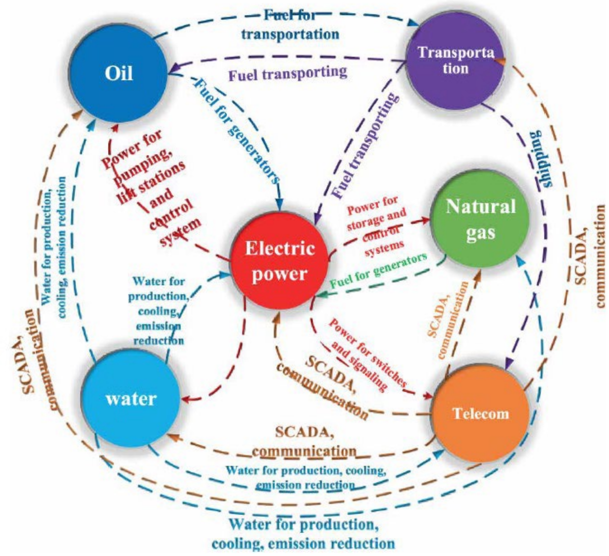

Figure 7 *- (Source: IEEE 2020 PES-TR83 – Resilience Framework, Methods, and Metrics for the Electricity Sector).*

Wind and natural gas fueled generation could be considered to represent two different generation extremes of the current policy spectrum. Wind fueled generation represents zero-carbon, low impact, intermittent, and, in many cases during weather extremes when performance is essential, non-dispatchable. Natural gas fueled generation represents a carbon source even while considered clean burning and identified as a "bridge fuel" in a net-zero carbon world, which may serve as a base load that normally can be counted on to anchor electrical demand as well as serve as a form of peaking generation. In the aftermath of Winter Storm Uri, both received significant criticism concerning their part in the generation shortfall. Yet, two of the questions that remain are at play here. Was it the technology that failed, or was it the current approach to evaluating and pricing reliability? How does ongoing energy transformation affect it? We will address these issues in another article.

What approach is appropriate to establishing the correct and reasonable assumption as to the time period for operational extremes? PJM Interconnection L.L.C. (PJM), an RTO, evaluates and assigns LOLE. According to training material associated with PJM's Reliability Pricing Model, the reliability criterion is based on LOLE not exceeding one occurrence in 10 years and the resource requirement to meet the reliability criterion is expressed as the Installed Reserve Margin (IRM) as a percentage of forecast peak load.[27] When compared to

[27] RPM 101 Overview of Reliability Pricing Model, PJM State & Member Training Dept., Undated, Slide 12.

what occurred in Texas during Winter Storm Uri, a one in 10 return frequency would appear to be reasonable since a similar occurrence happened in Texas in 2011. Statistically, that is coincidental in terms of return period but regardless, the facts remain: the statistics do not account for the multiple day event or significance of the event, i.e., a Black Sky Event.

ERCOT's approach to evaluating reliability is to essentially assign a fixed percentage of the overall forecasted peak load to establish its forecasted reserve margin. ERCOT and other RTOs and ISOs deal with marginal increases in electrical generation to meet the assigned projected demand in completely divergent ways. Where PJM has a capacity market which prices additional capacity such that it incentivizes the ancillary requirements for increased generation reserve, ERCOT does not. ERCOT historically utilized an energy-only market pricing mechanism to incentivize additional generation to enter the market. ERCOT does not utilize a capacity market. What this has potentially shown is that, while this type of market arrangement typically works for day-to-day energy delivery, it appears to be challenged at the margins during extreme weather hot or cold weather events, but a full examination of market adequacy and performance comparison is outside the scope of this paper. Additionally, ERCOT is changing to "promote the supply of dispatchable generation and develop a backstop reliability service."[28]

CONCLUSION: WHAT NEEDS TO CHANGE TO IMPROVE ENERGY RELIABILITY AND RESILIENCE?

So how do these issues factor into actual reliability performance at the Bulk Electrical System level, and how is that reliability correctly valued? Why would the current state of technology and understanding of electrical system behavior allow for a 20,000 MW load shed—one of the largest (if not the largest) in U.S. history—that lasted for days on end? How could it occur in a state that leads the nation in total installed electrical generation capacity and leave more than 4.5 million people without essential electrical service during an extreme weather event?

The answer may lie in how system reliability risk is established and what is determined as acceptable. Regardless of how ISOs and RTOs have historically defined acceptable risk, an actual event determines for us the current metric. For Texas, a week of sub-freezing temperatures inducing a multiple day load shed reaching a peak of 20,000 MW is the de facto current risk level for reliability. What needs to be asked as a follow-up to the event is whether that is still acceptable. Also, what has changed? Perhaps more importantly, why has it changed?

As the rate of energy transition increases exponentially from carbon based electrical energy sources to non-carbon based ones, the need to re-evaluate and re-price reliability is imperative. Today the analysis around reliability reflects a different set of circumstances, essentially a carry-over from years gone by. Reliability principles were developed when planning involved less dynamic change—the coal fired power plant was located in the general area of the industry that required substantial supply and the associated transmissions lines were planned based on the necessary link between the two. Today, IBRs are located where the wind blows and the sun shines. The carried over reliability principles do not account for the fact that the new generation is not located the same way as it once was. It is the equivalent of laying out roads to nonexistent towns or relying on the same roads from 50 years ago. Jonathan Schneider and Jonathan Trotta suggested in their paper entitled "What We Talk About When We Talk About Resilience," that, "the diffusion of responsibility over the electric grid, and the dramatically different challenges faced in each region of the country call for a multi-faceted and nuanced response to the resilience challenge, recognizing the varied jurisdictions in play, the different nature of the challenge in different regions and substantial scope and limitations of each of the potentially relevant authorities."[29] Summarizing their point, federal, state, and local regulatory entities must unite in their efforts to maintain adequate electrical system reliability and resilience.

Much has been learned from Winter Storm Uri and similar force majeure events. We learned that the Bulk Electrical System reliability risks include a constellation of considerations including unanticipated impacts on fuel availability, the appropriateness of the reliability timescale, and fuel diversity, among many other variables. As we saw with the effects on natural gas production, the impacts related to fuel availability for the local grid were multiplied. Today we need a dynamic planning approach that changes to reflect the ever changing inputs to the reliability matrix.

[28] https://interchange.puc.texas.gov/Documents/52373_336_1180125.PDF
[29] Schneider, J., and Trotta, J., What we Talk About When We Talk About Resilience, The Energy Bar Association, Nov. 14, 2018.

Finally, how does energy transition's potential impact on reliability affect those services that manage risks associated with the aftermath of a storm? First responders? Underwriters and insurers? Qualitatively, those impacts are significant and need to be part of the assessment on reliability. How we define acceptable risk when it comes to grid reliability needs to transition at the same pace as the systems themselves, and it will require a review of both the metrics and how those metric results are priced in the market. We will continue to monitor the marketplace and report on reliability in the decarbonizing world.

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