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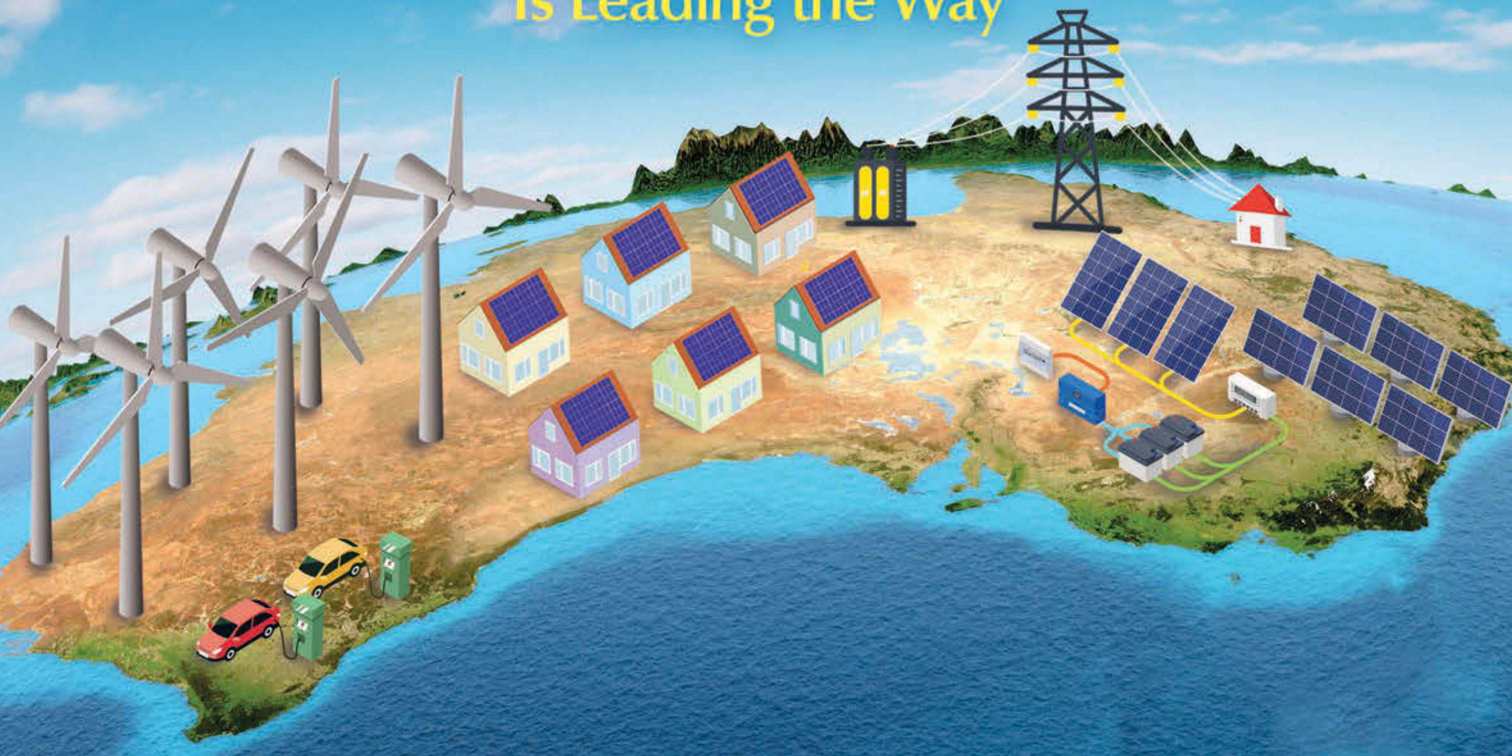
IEEE power&energy magazine

for electric power professionals

Renewables in Australia

How the Land Down Under Is Leading the Way



2021 Awards

Congratulations to All

Decarbonization

One Country's Journey

IEEE PES Power & Energy Society®

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IEEE
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IEEE POWER & ENERGY SOCIETY (PES)

The IEEE Power & Energy Society is an organization of IEEE members whose principal interest is the advancement of the science and practice of electric power generation, transmission, distribution, and utilization. All members of the IEEE are eligible for membership in the Society. **Mission Statement:** To be the leading provider of scientific and engineering information on electric power and energy for the betterment of society, and the preferred professional development source for our members.

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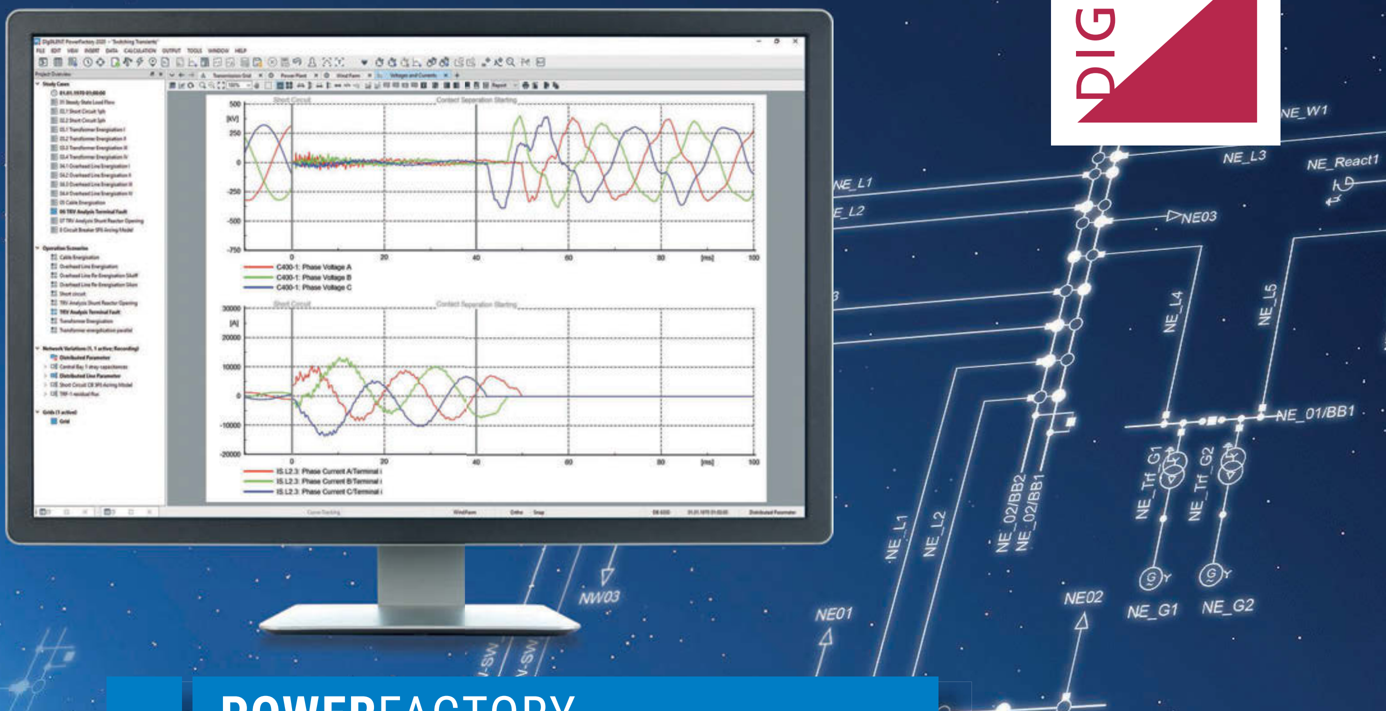

Barry Mather and Steve Widergren

insights

from the land down under

THE 1959 MOTION PICTURE, *ON the Beach*, starring Gregory Peck and Ava Gardner, tells the apocalyptic story of a submarine stationed in Australia. Due to its Southern Hemisphere remoteness, the continent is one of the few places left to succumb to the fallout from a catastrophic nuclear battle. The situation is bleak, and the tale gets bleaker. Mankind's character for hope and survival plays large in the story.

Like *On the Beach*, this issue of *IEEE Power & Energy Magazine* is set in Australia. Back then, the existential driver was the nuclear arms race and the possibility of planned or accidental annihilation. Although that threat remains, another is transforming the energy industry and electric power systems. The driver is climate change and the related efforts to reduce greenhouse gas emissions.

Significant investments in alternative generation sources are dramatically changing the dynamics of operating the Australian grids. Higher penetrations of variable renewable resources and inverter-based resources (IBRs), such as batteries, are necessary to reach the regional emission goals. The changes that Australia is experiencing, and their plans to further reduce emissions, resonate with the transformations occurring in other parts of the world.

What makes Australia unique is its large, electrically isolated area composed of two regionally controlled grids with local and overarching government policies. Although the issues are complex, Australia presents a microcosm for looking at a variety of dimensions where the energy transformation is occurring arguably more quickly. The diversity of issues covers the operation and planning of the power grids, their market coordination mechanisms, and the government policy and regulatory structures put in place to guide change and the interactions of the constituents.

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In This Issue

Six excellent articles, representing early successes, remaining challenges, and ongoing efforts, provide a broad perspective of Australia's power system transformation.

- "Achieving World-Leading Penetration of Renewables": This article addresses the primary question of how much wind and solar energy can be integrated into the current, large synchronous power system serving Australia's south and east coasts. Grid-operating conditions are presented for near-term future scenarios of ever-higher renewable generation, including significant growth in distributed solar beyond currently world-leading levels. The zones of operation leading to considerable system impact are determined.
- "Essential System Services Reform": The transition of the power system reopens discussion of the needs and acquisition of essential system services. This article comprehensively defines the essential system services requirements and presents the strategies for procuring them.
- "Power System Operation With a High Share of Inverter-Based Resources": The authors detail the challenges of decreasing system inertia and system strength as higher levels of IBRs enter the market. They discuss the current management techniques being used to mitigate contingency impacts and ensure grid frequency performance.
- "Renewable Energy Zones in Australia": This article presents the results of an analysis- and stakeholder-driven process to determine the locations within Australia where renewable energy can be most efficiently integrated. It details the impact these resource scenarios have on power system resilience and the benefit of the integrated system plan beyond traditional network upgrades.
- "From Security to Resilience": The authors tackle the challenge of addressing high-impact, low-probability events in low-carbon grids. The risk of such events, the uncertainties in system operating conditions (which make these events difficult to predict), and the impact of these events on system

resilience are detailed. Ideas are presented for new mechanisms to manage operating risks and realize increased resilience.

- ✔ "Distributed Energy Resources Roadmap": This article focuses on the operation of Australia's South West Interconnected System, given the continually higher levels of installed distributed energy resources. The article discusses technical operating issues and customer education efforts. The need for a broad and comprehensive "buy-in" by all stakeholders to successfully plan long-term grid transitions is emphasized. A use case for the community-level microgrid integration of distributed energy resources is also presented for one of Australia's many isolated grid systems.
- ✔ "In My View": This column provides a perspective of Australia's energy transition over the past five years. It presents five universal features for transitioning to a low-carbon power system.

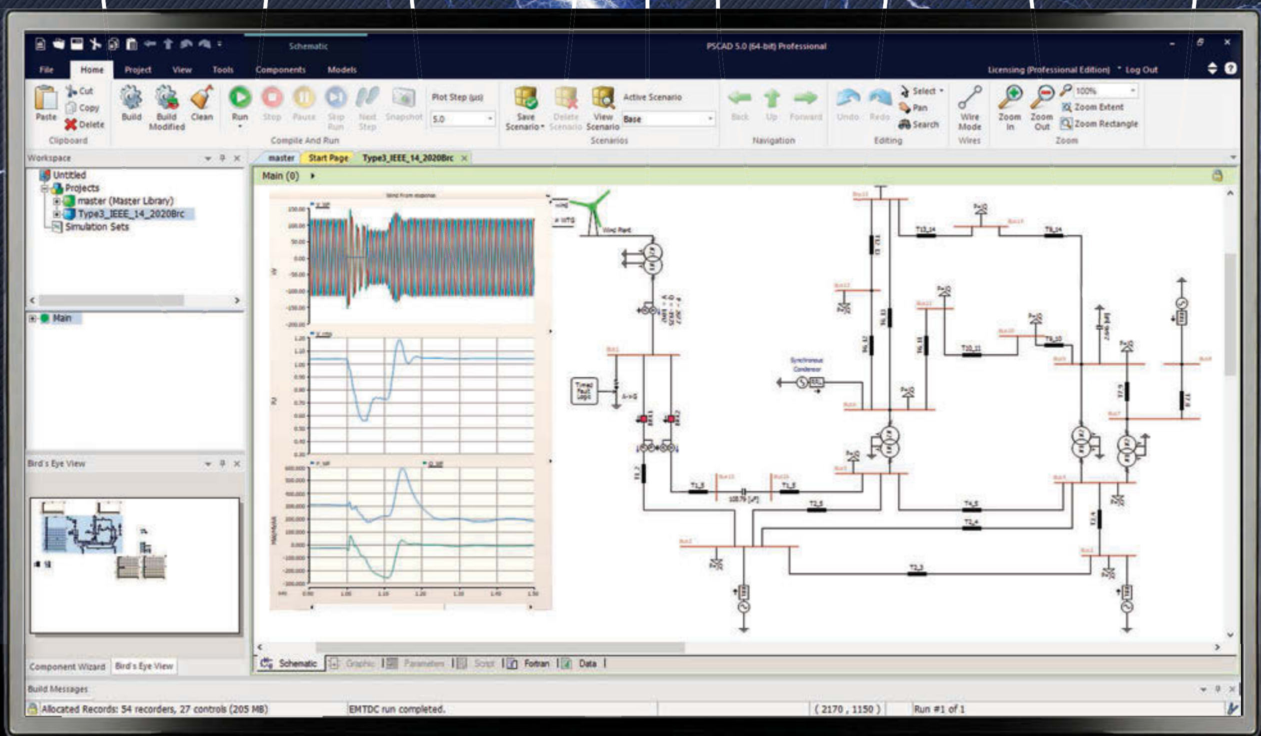
Homage

As the July/August issue of *IEEE Power & Energy Magazine* was being prepared for press, we learned of the death of Mike Henderson, my predecessor and mentor as editor-in-chief. Fellow editors and his longtime friends Mel Olken and John Paserba remember him in the "Society News" column.

Henderson and I were contemporaries in the power field. Coincidentally, we both started working at American Electric Power Service Corporation in Manhattan as entry-level engineers. New York memories would make for a common bond as we met at IEEE Power & Energy Society (PES) meetings and attended panels that the other chaired. He arranged his panels as performances: developing an interesting theme, assembling talented speakers, structuring complementary contributions, and communicating take-away messages. He brought the same focus-on-the-audience persona to the regional transmission planning sessions he chaired for ISO New England, and importantly, to this magazine. He left the stage too soon. Although he can no longer answer my calls, his voice reverberates.

Message From the PES Past President

A message from Saifur Rahman graces this issue's "Leader's Corner" column. The climate change issues that are



transforming the power and energy industry present not only challenges but opportunities to contribute ideas and seek solutions. PES provides a strong platform for communicating challenges and potential solutions. Opportunity calls to grow our diverse and talented membership and provide leadership in the discussion and shape of solutions.

Book Review

While we take a break from the "History" column in this issue, Editorial Board Member Brian Johnson provides a review of the textbook *Power Systems Modelling and Fault Analysis: Theory and Practice*, second edition, by Nasser Tleis. This technical area calls for a new look as the deployment of equipment and control techniques of IBRs grow and modern fault-analysis methodology and tools expand.

Cue the Spotlights

IEEE announced the 2021 award recipients. Those awards related to PES, including the IEEE Medal in Power Engineering, the PES-related technical field awards, and the Society-level awards, are presented in the "Awards" column. Please congratulate this year's awardees for their exceptional achievements.

The Ending

We applaud Guest Editor Dean Sharafi on his directorial debut of arranging the feature articles for this issue. We also thank the many authors who created the articles and interacted with our talented editorial staff, Associate Editor Barry Mather and Assistant Editor Susan O'Bryan, and who worked with Geri Krolin-Taylor and IEEE Publishing to develop the finished product in your hands.

Although this issue takes a slight departure from the magazine's regional diversity intentions by featuring stories and examples set in Australia, we believe the challenges, experiences, and conversations about the transformation underway in Australia's two main power grids have global ramifications.

The desired reaction of *On the Beach* was to startle the audience with the serious consequences from nuclear confrontation. In today's vernacular, one might say *woke*. Whether startled or woke, may the challenges and potential directions addressed in these articles bring hope to realizing an energy posture appropriate to the existential threat before us. Take heed, as the Salvation Army banner over the empty Melbourne city street at the film's end announces, "There Is Still Time..Brother."

Saifur Rahman

leadership opportunities

the role of PES in the global society

I WOULD LIKE TO SHARE WITH you some observations I have gathered from listening to our geographically diverse membership. Members have different priorities depending on whether they are students, academics, industry engineers, public sector employees, or retirees. But, they all have one thing in common: some level of interest in carbon neutrality, green energy, electric vehicles, and electrification.

All of these areas are in the IEEE Power & Energy Society (PES) field of interest. Our publications, conferences, standards-development activities, and tutorials reflect PES's engagement with these topics. Our members have a significant role to play in helping society achieve various targets policy makers have set up for their regions or countries. For example, 100 countries and 400 cities around the world have pledged to be carbon neutral by or before 2050.

The U.S. government is demanding U.S. power-sector greenhouse gas emissions (GHG) drop to 50% by 2030 and net-zero by 2050 and that the country as a whole be free from GHG emissions by 2050. In China, the plan is to generate more than half of electricity from renewable sources by 2030. India has an aggressive national program to significantly raise the country's renewable energy output. This is important because China, the United States, and India together are responsible for more than 50% of global carbon dioxide emissions today. Additional data shows that 20 countries in the world generate 81% of carbon dioxide globally.

To reduce their GHG emissions, several countries are promoting electrification in various ways. For example, in Norway, new car sales will be limited to only electric vehicles after 2025. In the United Kingdom, 85% of 29 million homes are heated with natural gas boilers. In Germany, that number is 47%. The current government policy in the United Kingdom stipulates that gas heating will stop for new homes by 2025, and the country will not allow the selling of gas home-heating equipment beyond 2030.

> All of these activities will result in steep increases in electrical demand in many countries of the world.

Universities are also becoming engaged in carbon-neutrality programs. Virginia Tech, a U.S. university, is making plans to make the campus carbon neutral by 2030. Over 90% of the current fuel mix for the electricity used on campus is fossil-fuel based.

All of these activities will result in steep increases in electrical demand in many countries of the world. For example, in the United States, due to the heavy emphasis on electrification, the electricity-generation capacity is expected to grow to 3,400 GW by 2050 from the current level of 1,200 GW. Similar growth in electrical demand is expected in most other countries around the world.

These challenges and opportunities will allow PES and its members to play increasingly important roles in the global society. PES is the only IEEE Society with "energy" in its name. With the active participation of our members from both industry and academia, we have grassroots connections to engage in this global challenge. Our conferences, publications, and tutorials/webinars on green energy at the local level are giving us more visibility and helping us to match societal needs with our members' interests and capabilities.

These offer tremendous opportunities for us to demonstrate our leadership from grassroots levels all the way to national, regional, and global levels. For example, we could organize industry-driven conferences in countries where such issues can be discussed in the context of local challenges and resources. PES can provide a platform for exchanging information among utilities, vendors, consultants, and regulators. If we are successful in organizing such conferences, PES can become the go-to place for regulators, policy makers, utility decision makers,

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manufacturers, and consultants to seek answers to the challenges they face as the industry evolves.

As electrification takes hold beyond industrialized countries, the paradigm is shifting. The model to build a national power grid and feed it from large central-station power plants may not be the most cost-effective and sustainable solution for many developing countries. What may work for India and China as they expand their national grids and build large power plants may not work for many smaller countries in Africa and Asia that may be better off with solar, wind, small-scale hydro, biomass, and microgrid types of energy.

Focusing on these challenges will help us find relevant and sustainable solutions for electrification and, at the same time, tap into different bases of professionals (such as development experts, entrepreneurs, consultants, and academics) who can be potential sources of PES members. As the second-largest IEEE Society, we have 40,000 members in 150 countries. By tapping into these new bases, we can significantly increase our membership and enrich our content.

PES is the IEEE leader in developing new programs to serve our members and attract new members, especially from industry. One example is the Corporate Engagement Program, which started with the signing of a memorandum of understanding with State Grid Corporation of China in November 2017. This program has now attracted many companies and universities from China, India, and the United States. The PES University, which was established in 2019, is a leader in the field of power engineering, providing access to knowledge and educational products that have credit-earning potential for PES members and nonmembers. To provide better communication among Chapters in various regions of the world, the PES Chapters Councils were set up in China, India, Africa, and Latin America during my presidency. PES Chapter chairs in these parts of the world now have a platform to be better organized, which helps them to start new activities locally with more relevance to the working technologists.

Finally, PES is leading IEEE in terms of gender diversity as well. We have three candidates for PES president-elect 2022–2023. I am happy to report that all three of them are female volunteer leaders in PES. Online voting started August this year. Please remember to vote at www.ieee.org/elections.

p&e

Dean Sharafi

Australia's power systems

enabling renewable energy integration & resilience

THIS ISSUE OF *IEEE POWER & ENERGY Magazine* is devoted to Australia. But why Australia? The answer is obvious from the perspective of industry folks who are facing the challenges of an abrupt energy transition, and I am hoping that by reading the articles in this issue it will be as obvious to our readers.

In Australia, the speed of the energy transition is faster than in any other country, and the impacts are more pronounced. In 10 years, Australia has transformed its power industry from the third-most carbon-intensive electricity sector to a system with a high penetration of variable renewable energy. In some regions, the renewable energy generated regularly reaches a level more than can locally be consumed. This transformation has brought about issues and challenges that are unprecedented.

The moment of deep reflection for the industry in Australia was in 2016 when the whole state of South Australia blacked out after a severe storm. The Australian government acted quickly and commissioned its chief scientist, Alan Finkle, to review the future security of the power system in the National Electricity Market (NEM), which serves five of the country's eastern and southern states. This later led to the establishment of the independent Energy Security Board to develop a long-term, fit-for-purpose electricity market framework that could be implemented in the NEM from the mid-2020s.

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In the separate state of Western Australia, which has a different electricity market, the state government formed the Energy Transformation Taskforce in 2019 to reform the market regulatory framework. This comprised a new essential system services [(ESSs), also known as ancillary services] framework expected to go live in 2022. The task force also created a distributed energy resources (DERs) road map to ensure the security of the grid, given the increasing participation of consumers in the electricity ecosystem.

After the South Australian blackout, we asked ourselves, "How much renewable energy can be added to a power system that is designed based on totally different concepts?" To answer this, my colleagues at the Australian Energy Market Operator (AEMO) embarked on an engineering quest that became known as the "Renewable Integration Study." The results of this study shed light on what could be expected at various phases of the penetration of renewables and how we can overcome the expected challenges to ensure that we continue to integrate low-cost clean power into our energy system.

In the first article, O'Connell et al. focus on this question and discuss the limits that affect how much wind and solar generation can operate at any one time, how close we are to these limits now, and how close they may be by 2025. The authors also present recommended actions that should be taken now to overcome the identified technical barriers and maximize the achievable levels of wind and solar penetration.

In the second article, "Essential System Services Reform," Lal et al. explore new technical, economic, and regulatory frameworks for the provision of ESSs in power systems dominated by variable inverter-based resources (IBRs).

Australia's two independent market design frameworks, the islanded Wholesale Electricity Market and the interconnected NEM, allow for a comparison of parallel regulatory and market settings in supporting system security and reliability. These two electrical grids have varying levels of system strength, inertia, and DERs. System strength, in simple terms, is the ability of the grid to maintain the proper voltage performance after contingencies. The article identifies the emerging challenges in defining, procuring, and providing system strength and its interactions with fault current, inertia, frequency control, and operating reserves.

The article reviews emerging energy systems' technological capabilities, including the provision of synthetic inertia and the rate of change of frequency, grid-forming inverters, and advanced DER aggregation in providing ESSs and system restart capabilities for secure, resilient, and islandable grids. Finally, the authors analyze the recent technical and financial successes of the world's largest battery, the Hornsdale Power Reserve in the South Australian region, and its ability to inform how future electricity market frameworks may incentivize and accommodate new technological capabilities.

In the third article, "Power System Operation With a High Share of Inverter-Based

Resources," Badrzadeh et al. discuss the challenges of operating a power system with a large penetration of IBRs and a high share of DERs. The novel approaches to this new mode of operation are presented for both systems, with a high concentration of IBRs in the islanded power systems as well as the areas of the grid far from the load and generation centers. The authors examine the challenges related to the impact of the reduced commitment of synchronous generators and what they mean from inertia and system-strength perspectives.

Many jurisdictions around the world, especially those that have recently undergone a rapid transformation of their energy systems, are appreciating the importance of planning at the power system level. Planning requires a whole-of-system view, with consideration for all the aspects of vast, integrated modern grids, including long-term security. In the current decade, renewable generation capacity is forecast to be driven by government policies and high-quality wind and solar resources in Australia. In the following decade, a strong investment in renewable energy is forecast to replace the energy from retiring coal-fired generation. The scene is setting up for a clean energy system dominated by renewables.

In the fourth article, Pack et al. discuss AEMO's Integrated System Plan, introducing the concept of renewable energy zones and the robust integration of these zones into the existing transmission network. They show how renewable energy zones can be optimally established to align investor interest with government policy and consumer value.

Often, as I listen to global experts debate the current transformation of power systems, policy and regulatory tardiness is highlighted as an issue when dealing with emerging challenges. Compounded by climatic changes and their effects on rapidly changing power systems, the concept of grid resiliency has been frequently discussed. In the fifth article, Eggleston et al. examine this topic, presenting a novel approach. They note how extreme events are increasingly affecting power systems worldwide, calling for new and effective ways to deal with these high-impact, low-probability events. They also observe how low-carbon grids are characterized by much higher operational uncertainty, with a risk profile that is correspondingly difficult to assess.

The article is focused on the NEM power system, which has experienced several extreme events, such as the severe storm that led to the South Australian "black system" in 2016. The authors note that although there is a general agreement in industry and research that new methodologies and tools are needed to improve power system resilience to extreme, high-impact, low-probability-type events, their practical implementation is still in its infancy. This includes the need to develop suitable regulatory frameworks capable of supporting adequate planning and operational (including market-driven) mechanisms and solutions while effectively assessing the full range of costs. The costs addressed here are those associated with both the consequences of these events and the mechanisms needed to manage them.

They discuss how the changing power system's risk, uncertainty, and resilience profiles are seeing increasing threats from "indistinct" events, that is, the distributed events that act on multiple generation and network assets in an affected area. Next, they outline a general "stronger-bigger-smarter" framework that better manages this uncertainty by enhancing power system resilience.

The authors also present ideas to systematically operationalize the proposed framework from a regulatory-design, system-dispatch, and market-operation perspectives. They discuss some of the issues that regulatory decision makers (including policy makers and system operators) may face. This includes making the decisions that enhance resilience under conditions of uncertainty and exploring the potential frameworks that help to improve flexibility at the lowest overall cost for consumers. Finally, they put forward the recommendations for how system operators might procure new solutions and take advantage of novel technologies to enhance power system resilience in low-carbon grids and make them operate more securely, even in the face of extreme events.

Given the two separate power systems and market designs in the east and west coasts of Australia, this tale would not have represented a complete picture of Australia's electricity sector's journey were it not for the cutting-edge work being performed in Western Australia. This peculiar grid, which is an island, has one of the highest shares of DERs in the world.

In the sixth article, "Distributed Energy Resources Roadmap," Hadingham et al. discuss their vision for the integration and management of DERs. The objective is to realize a future where DERs are integral to a safe, reliable, and efficient electricity system and where the full capabilities of DERs can provide benefits and value to all customers. The article also includes success stories about DER integration for smaller microgrids in the remote areas of Western Australia.

In this issue of *IEEE Power & Energy Magazine*, the story of these two power systems is told with a focus on what can be learned from a country that faces a rapid transformation and change in every aspect of planning, operation, market, policy, and regulatory design. Throughout the process of pulling this issue of the magazine together, I made new friends and worked with an incredible group of passionate and interested industry experts and academics. The objective of these professionals has been to answer the question of how we can go through this transformative journey while we continue to provide a safe, secure, reliable, and resilient power system. It has been an honor for me to work with them. I have enjoyed every moment of this interaction. May you enjoy reading about these Australian experiences and the insights they provide.

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Achieving World-Leading Penetration of Renewables

The Australian National Electricity Market

By Barry O'Connell, Chris Davies, Andrew Paver, Eloise Taylor, Taru Veijalainen, Rama Ganguli, and Christian Schaefer

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THE NATIONAL ELECTRICITY MARKET (NEM) POWER SYSTEM INTERCONNECTS five regions in eastern and southern Australia and delivers around 80% of the national electricity consumption. The NEM and its electrical regions exhibit unique characteristics compared to most other power systems. It has no interconnection to neighboring countries, covers large geographical distances, and contains world-class wind and solar resources.

World-leading levels of distributed energy resources have also increased the complexity of operating this power system. To provide context and a visual comparison, Figure 1 is taken from the Australian Energy Market Operator's (AEMO's) international review of power systems with high (>50%) instantaneous penetrations of wind and solar. It compares the geographical size of the NEM power system with those of some other power systems.

The NEM, like other power systems worldwide, is being transformed from a system with large thermal power stations connected to a high-voltage transmission network to a decentralized one with an increasing amount of variable inverter-based renewable resources (IBRs). According to AEMO, the NEM power system demand ranges from 16 to 35 GW, and it already had 22.2 GW of wind and solar capacity installed by the end of 2020. Subregions of the NEM such as South Australia have one of the highest penetrations of wind and solar in the world operating with a maximum instantaneous penetration of over 140%. South Australia also has one of the highest penetrations of rooftop solar PV anywhere in the world and operated with over 60% instantaneous penetration in 2019 (see Table 1).

By 2025, the NEM is expected to have transformed even further. AEMO's 2020 Integrated System Plan (ISP) forecasts a total installed capacity of wind and solar (including residential) of 27 and 36 GW for the studied "Central" or medium scenario and the "Step Change" or high scenario, respectively.

As outlined on AEMO's website, Figure 2 from its Renewable Integration Study (RIS) Stage 1 Report shows actual data of wind and solar penetration in 2019 in the NEM. The penetration represents NEM half-hourly wind and solar generation divided by the total electricity demand in the same period.

The 2025 projections indicate the potential instantaneous penetration by 2025 under the ISP's medium and high scenarios. The figure highlights significant forecast growth in the maximum potential instantaneous penetration of wind and solar from just under 50% in 2019 to more than 75% in the medium and 100% in the high scenario in 2025.

Many of the insights presented in this article are based on the findings of AEMO's 2020 RIS to identify limits that affect the maximum instantaneous penetration of wind and solar and also to determine how close the NEM is to these limits now and is expected to be by 2025. In addition, we will discuss actions that can overcome these barriers so the system can operate securely with higher penetrations of wind and solar generation in the future.

The article focuses on the RIS report's four core study areas:

- ✔ power system frequency stability
- ✔ system strength adequacy
- ✔ variability and uncertainty in the supply–demand balance
- ✔ managing of increasing volumes of distributed solar PVs (DPVs).

Power System Frequency Stability

Synchronous generation provides vital system services to the grid, one of which is synchronous inertia. Inertia provides a rapid and automatic injection of energy to limit the rate of change in grid frequency. It is required to stabilize the grid frequency when sudden imbalances between supply and demand occur. This inertial response was historically abundant in a grid dominated by synchronous generation.

However, inertia is declining as synchronous generators are being displaced during periods of high wind and solar penetration. This makes it more challenging to manage frequency stability at these times. Figure 3 shows the historic decline in the NEM mainland synchronous inertia levels and the 2025

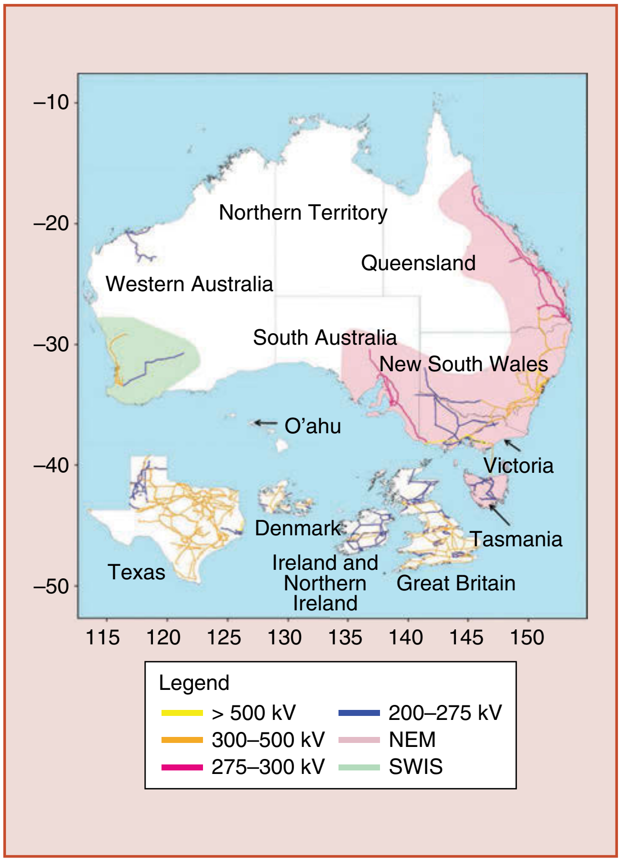

figure 1. A comparison of Australia's NEM with other power systems with a high share of wind and solar energy. (Source: AEMO; used with permission.)

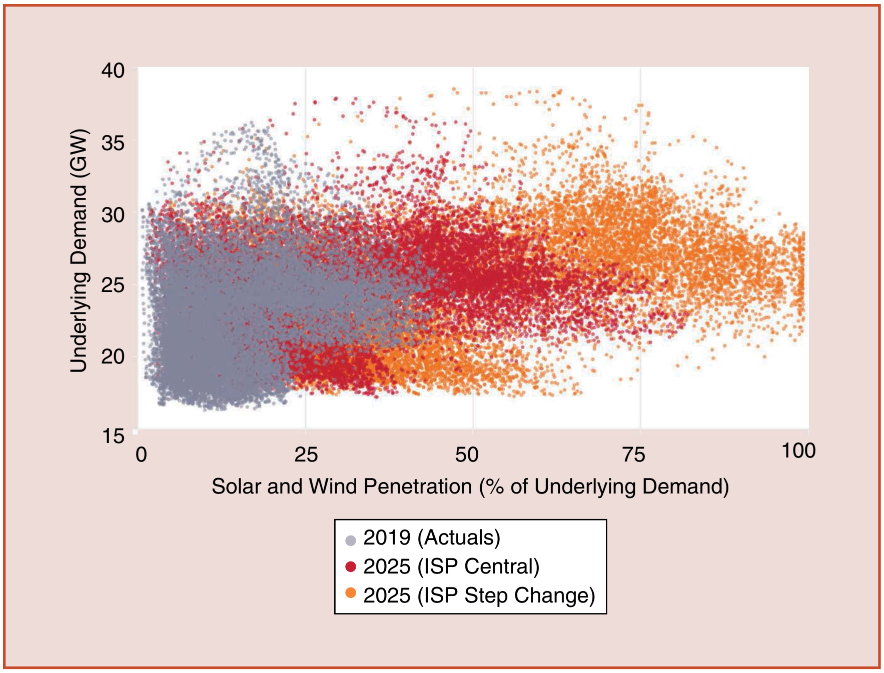

figure 2. The instantaneous penetration of wind and solar generation, actual in 2019 and forecast for 2025, under the ISP Central and Step Change generation builds. (Source: AEMO; used with permission.)

forecast range. The dotted red line is the inertia expected to be available as a by-product of the minimum synchronous units required to be online to maintain system strength.

As the system inertia decreases, the change in grid frequency accelerates for contingencies. Limiting the size of the largest contingency is an effective way of operating at lower inertia levels. But the the largest generation contingencies in the NEM can be set by renewable generation and future renewable generators could be even larger, which may limit the effectiveness of such a move.

Fast frequency response reserve helps arrest a faster frequency decline and is being considered by the Australian Energy Market Commission, the NEM rule-making body. The fastest reserve currently procured in the NEM to arrest frequency is evaluated across a 6-s time frame. The top curved line in Figure 4 shows the amount of reserve required to meet the required frequency performance for different system inertia levels with only a standard response over 6 s. This shows that, as the inertia level reduces, the 6-s reserve requirement increases significantly. The other curves show how increasing the volume of a fast-acting reserve reduces the total amount of reserve required to meet the required frequency performance, where the minimum amount of reserve procured is the static requirement or the size of the largest contingency.

Introducing a mechanism to reduce the size of the largest contingency and increasing the amount of enabled fast frequency response can allow the system to operate at lower inertia levels. But no large power system currently operates without synchronous inertia, and a minimum level of inertia is expected to be needed in the NEM for the foreseeable future. To move to system operation with lower levels of inertia, a staged approach will be needed to allow the system frequency control design to be adapted to the changing system with capacity built in advance of the requirement becoming evident on the system.

A promising development is synthetic inertia provided by grid-forming inverters. Some of the largest trials in the world (30 MW) are happening in Australia. These trials are demonstrating that inverters can provide synthetic inertia to the grid. While grid-forming inverters are promising, they are still in the early deployment phase. Further experience and analysis are needed to prove if we can replace large synchronous generators' inertia and safely enable multiple grid-forming inverters to work with the rest of the system under all conditions.

> Fast frequency response reserve helps arrest a faster frequency decline and is being considered by the Australian Energy Market Commission, the NEM rule-making body.

Another major positive change to frequency management in the NEM was the reinstatement of broad-based primary frequency control, also known as droop control, on all large-scale generators in 2020. This was introduced by the Australian Energy Market Commission in response to declining frequency performance. These rules were introduced with minimum specifications as to how the control parameters are set. Generating systems are not required to carry headroom (the ability to increase output) or foot room (the ability to decrease output) beyond what is available through normal operation or purchased in the reserve market.

This change has resulted in a significant improvement in the normal-band frequency performance. Figure 5 illustrates the following:

- ✔ The frequency distribution in the NEM in 2010 has a frequency performance tightly centered around 50 Hz.
- ✔ The primary frequency response declines after 2010 as generators withdraw primary frequency control outside of market enablement (what was enabled to comply with the market requirements), and the amount of renewable generation online increases, as seen in the September 2020 trace.
- ✔ There is a marked performance improvement in the normal operating band since October 2020 when the process of re-enabling primary frequency control on all generators began. This process is still currently underway.

What is not shown or quantified in this article is the improvement in system resilience. Enabling primary frequency control on all large generators increases the system's ability to survive more extreme events or larger system disturbances not covered by the market-purchased

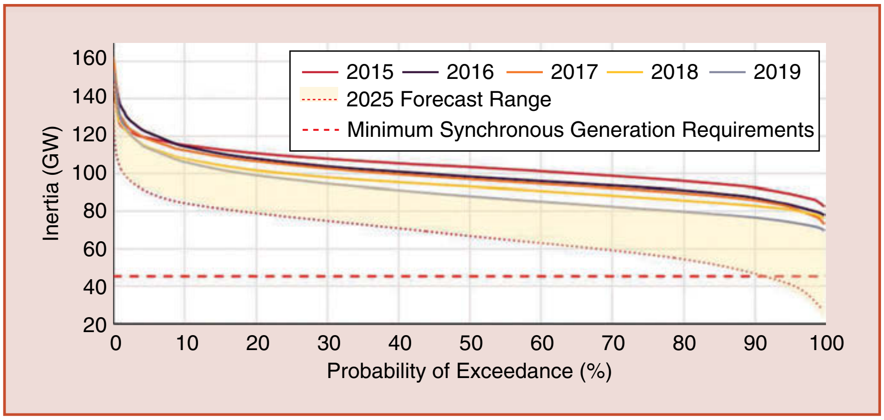

figure 3. The NEM historic mainland inertia and future forecast range. (Source: AEMO; used with permission.)

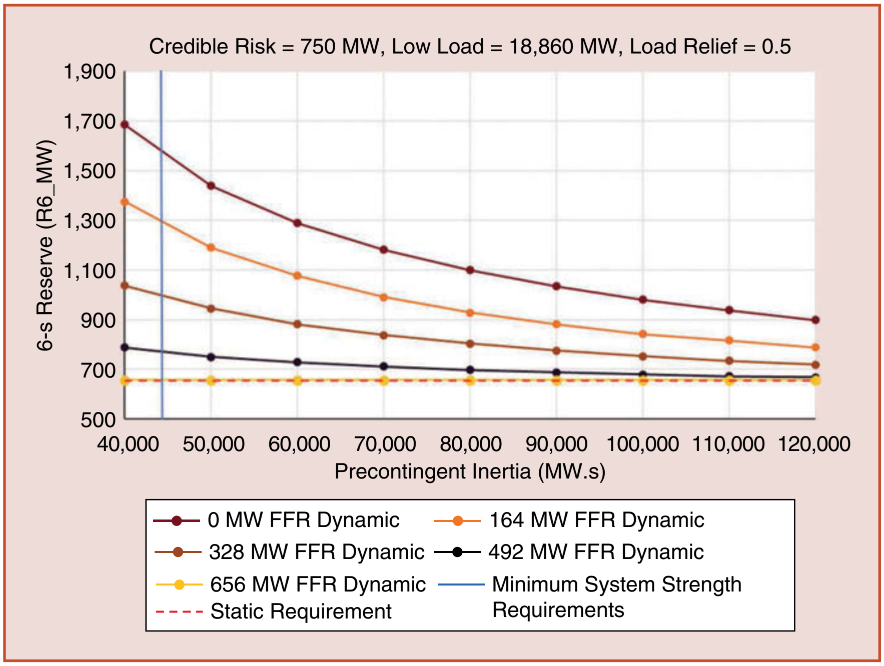

figure 4. The estimated 6-s reserve requirements plotted against the NEM system inertia precontingency for the largest credible risk of 750 MW. FFR: fast frequency response. (Source: AEMO; used with permission.)

Increased resilience is important as the power system transitions and the Australian power system pushes the operational boundaries with higher reliance on new energy sources.

reserve. Increased resilience is important as the power system transitions and the Australian power system pushes the operational boundaries with higher reliance on new energy sources. In this issue of *IEEE Power & Energy Magazine*, a separate article, "From Security to Resilience: Technical and Regulatory Options to Manage Extreme Events in Low-Carbon Grids," discusses in detail the need for increased system resiliency.

System Strength Adequacy

Due to the geographic size of the NEM power system, there are areas of the grid that are weakly interconnected to the rest of the network and electrically distant from the closest synchronous machine. This means they have low system strength. According to the literature published on the AEMO website, "system strength" is defined as the ability of the power system to maintain and control the voltage waveform at any given location in the power system during steady-state operation and following a disturbance.

Some of Australia's best renewable energy resources are in these weak areas, which has put the NEM at the international forefront of challenges in connecting wind and solar generation in areas with low system strength. New generator connections in these areas are obligated to not adversely impact stable system operation. Connecting generators, original equipment manufacturers, and network service providers are adapting to operating in these low system strength conditions. As such, Australia has been pioneering analytical techniques (i.e., electromagnetic transient modeling) to simulate the complex behavior of IBRs in these areas to solve these emerging challenges.

Figure 6 shows the current and projected impact of increased levels of online wind and solar generation relative to the number of large (>200 MVA as a proxy for high system strength sources)

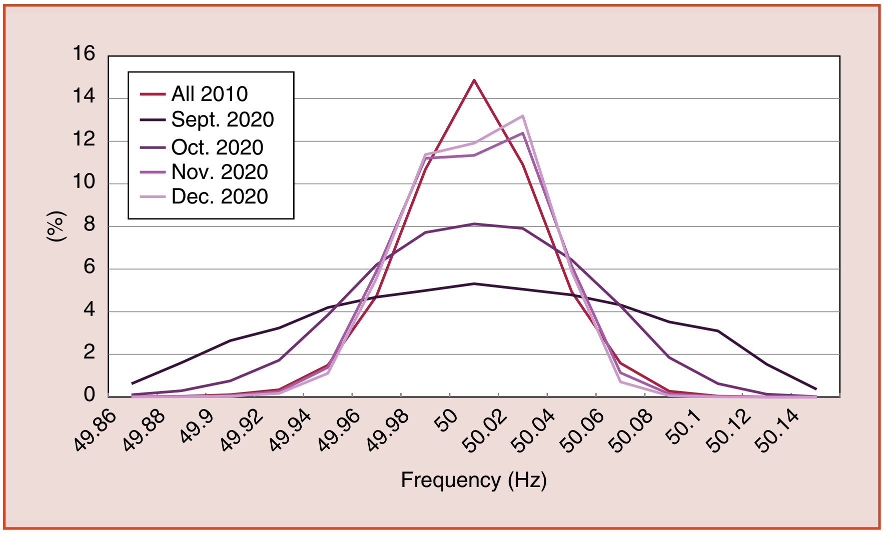

figure 5. The frequency distribution of the NEM mainland in 2010, 2019, and 2020. (Source: AEMO; used with permission.)

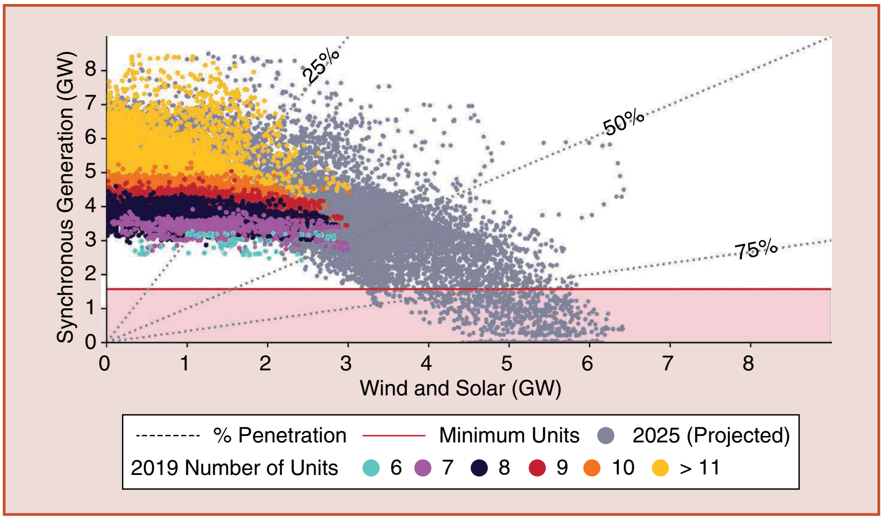

figure 6. The Victoria system operation showing synchronous generation and wind and solar output. The units count relates to units suitable to provide system strength services. (Source: AEMO; used with permission.)

> Connecting generators, original equipment manufacturers, and network service providers are adapting to operating in these low system strength conditions.

synchronous plants required to be online in the state of Victoria in the NEM. The figure shows synchronous generation plotted against the wind and solar PVs online for 2019 (colored dots) and 2025 (gray dots). The colors highlight the number of large synchronous generators online from the minimum combinations list. The projected generator dispatch outcomes for 2025 show an increasing likelihood of dispatch outcomes not delivering the required minimum combination of synchronous generators in the Victoria region.

AEMO is responsible for determining the minimum levels of system strength at critical locations in the transmission system. If these levels are forecast to be breached in the next five years, AEMO declares a system strength shortfall. The local utility is then required to procure system strength services to meet this gap.

A multifaceted approach is needed to manage the impacts of system strength with the needs of the power system likely to change as the generation mix changes. Opportunities arise for technology innovation to offer novel alternatives to traditional solutions.

In the NEM, consideration is being given to some combination of the following solutions:

- ✔ maintaining some minimum level of system strength at key network locations; this may be achieved by maintaining a minimum combination of synchronous generators and synchronous condensers online at all times
- ✔ actions to support stable operation of new connecting IBRs, such as
  - performance standards that ensure an ability to operate stably down to some defined level of system strength
  - improved control system tuning
  - network upgrades
  - scale-efficient system strength solutions to enable stable operation of defined IBR levels in nominated network locations
  - individual remediation of local system strength issues by new connecting IBRs to ensure stable system operation
- ✔ monitoring advancements in new technologies, such as inverter control systems, to enable stable system operation to be achieved more efficiently than with present solutions.

Many of these potential options need to be explored via electromagnetic transient studies to determine what actions must be taken. The complexity of studies required to enable transitioning to operation at lower levels of system strength should not be underestimated. These challenges are making power system operations in Australia interesting and exciting. In a separate article in this issue, "Power System Operation With a High Share of Inverter-Based Resources: The Australian Experience," the challenge of operation in locations with low system strength is discussed, and implemented measures have been highlighted.

Variability and Uncertainty in the Supply and Demand Balance

Increased reliance on wind and solar for energy will increase the variability and uncertainty in the energy supply. AEMO's statistical analysis of historical and 2025 projected ramps identified that hourly net demand ramps will be significantly larger in magnitude. Some are projected to exceed 5 GW/h beyond levels previously experienced in the NEM.

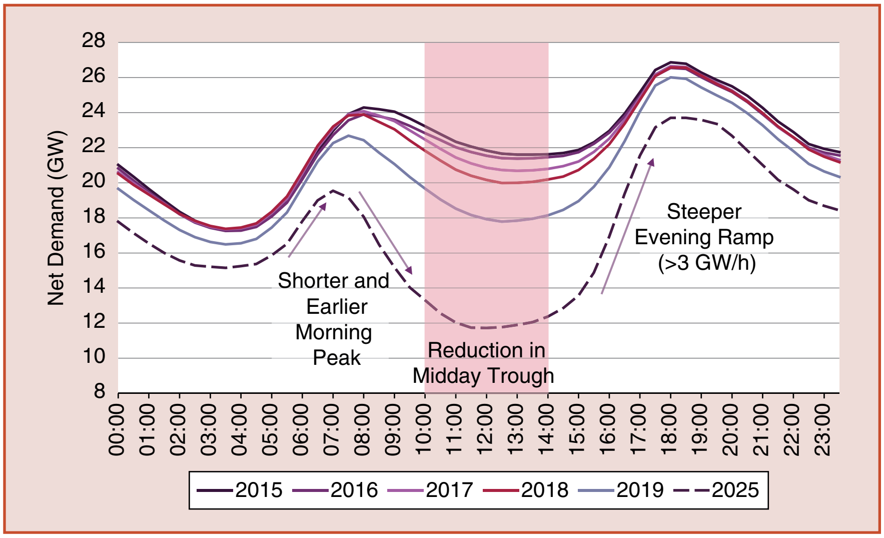

figure 7. The historical versus projected winter NEM average daily net demand profiles. (Source: AEMO; used with permission.)

> A multifaceted approach is needed to manage the impacts of system strength with the needs of the power system likely to change as the generation mix changes.

The largest net demand ramps are expected to occur on winter evenings when solar PVs ramp down during sunset coinciding with evening gross demand requirements ramping up. The average daily winter net demand profile shown in Figure 7 compares the projected "duck curve" to historical levels under the medium scenario build from the 2020 ISP.

AEMO reports that changes in wind or solar output (outside of sunrise and sunset) are challenging to forecast accurately over both short and longer forecasting horizons. Technological development and innovation have resulted in significant improvements in weather forecasting accuracy. However, the level of accuracy that is achievable even with best-practice weather forecasts can still lead to significant challenges in predicting wind and solar output and hence net demand variability in the power system. Consequently, ramps in the future are likely to be subject to more uncertainty. An accuracy analysis conducted on operational forecasts of wind and solar generation for 2018 found that recent wind and solar output gives a good indication of the level of future output (close to real time) but does not give a good indication of future variability.

Appropriate mechanisms must be in place to ensure that sufficient flexible resources are available to meet increasingly variable and uncertain system conditions. These resources can be sourced through grid augmentation and interconnection, new fast-start units with high ramping capabilities, demand response and energy storage, and retrofitted generators to improve characteristics such as minimum stable load, ramp rates, and the ability to cycle. A greater utilization of wind and solar resource flexibility should also be explored given their high ramp rates, short start-up times, and low minimum generating levels, subject to resource availability.

To manage the additional uncertainty associated with the emerging operating conditions in 2025, a suite of improvements is being investigated. These include operational improvements such as using a probabilistic forecast as input to the dispatch, which could help account for ramping uncertainty, and an improved weather observation infrastructure, which could enable weather forecasters to predict ramping events more accurately. Additional mechanisms to enable appropriate volumes of reserve in the market are also being explored, such as different approaches to an operating reserve market.

Managing Increasing Volumes of DPVs

AEMO outlines that parts of the NEM that have among the world's highest levels of DPVs, including one of the highest levels of residential solar PVs, a subset of DPVs. The majority of the DPV fleet is currently passive, meaning it is uncontrollable and invisible to the system operator (behind the meter and unmonitored in real time). The passivity is beginning to pose challenges to both the distribution network and bulk power system operation, especially in regions with higher DPV uptake relative to the local load.

AEMO's RIS international review identified a typical trajectory of system limits as the share of passive DPV increases. Limitations first arise within the distribution network as a result of concentration in localized areas. This eventually impacts the operation of the transmission system as the penetrations grow. As this growth continues, the inability to see and actively manage the distributed solar fleet affects almost all core duties of the bulk system operator in some way, including system balancing, system stability, recovery, and restoration following major events.

NEM regions are at different points along this growth trajectory and will continue progressing along this path as penetrations increase. Table 1 compares the maximum half-hourly penetrations of DPV generation by NEM region in 2019 against 2025 projections, showing projected regional levels as high as 85%.

table 1. The maximum DPV penetration as a percentage of demand.

	NEM	Queensland	New South Wales	Victoria	South Australia	Tasmania
2019 (actuals)	25%	30%	21%	31%	64%	12%
2025 Central scenario	41%	45%	33%	45%	68%	14%
2025 Step Change scenario	50%	57%	48%	66%	85%	21%

Impacts on the Bulk Power System

DPV are already impacting the ability to securely operate the South Australia region, and are beginning to affect operations in other NEM regions. The RIS investigated challenges for both distribution system and bulk power system operation. We present here the analysis of bulk power system challenges due to increased levels of DPVs.

> Appropriate mechanisms must be in place to ensure that sufficient flexible resources are available to meet increasingly variable and uncertain system conditions.

Figure 8 shows the South Australian system demand for each half-hour period plotted against DPV generation for 2019 and projected under the 2020 ISP Central and Step Change scenarios for 2025.

- ✔ *Zone A*: DPV generation begins to impact the system load profile, potentially resulting in challenges associated with
  - the effectiveness of emergency mechanisms (such as under-frequency load shedding and system restart) due to the reduced availability of stable load blocks in the daytime
  - transmission network voltage control due to reduced load in locations within the transmission network with large clusters of DPV generation
  - managing the net load variability associated with increasing ramps in DPV generation at the start and the end of the day, and cloud movements impacting significant PV clusters at the subregional level.
- ✔ *Zone B*: The potential mass disconnection of DPVs due to contingencies begins to impact the effectiveness of contingency management practices. Loss of DPV generation might exceed potential load disconnection following plausible transmission disturbances. If coincident with the loss of other generation, this could increase the largest credible risk in the region. Eventually, without action, as DPV penetration continues to increase, contingency sizes may become unmanageably large, especially for regions of the NEM that may operate as an island under some conditions.
- ✔ *Zone C*: System demand has reduced to such a point that there is an insufficient load to support minimum synchronous generation requirements for the provision of the system strength, inertia, frequency control, and voltage management services necessary for secure system operation under credible risk of separation or islanded conditions in 2025.

AEMO describes a range of measures to assist with the secure and efficient integration of increasing levels of DPV generation in the bulk power system. Figure 9 summarizes the mitigation approaches identified for these outlined different bulk system challenges with an indication of the relevant operating conditions under which they may be necessary.

Operating conditions span a range from normal daily operation to extreme abnormal system conditions. The power system is planned and operated so it can cope with the abnormal conditions from a single credible contingency event by procuring ancillary services and using constraints in the dispatch process. Extreme abnormal conditions represent system operation during exceedingly rare circumstances, such as unusual outage conditions, regions islanded from the NEM or at risk of separating, and system recovery and restoration following major noncredible events.

Measures have been categorized across the following dimensions:

- ✔ DPV systems, which include
  - local active management of DPV generation on a daily basis
  - in-built autonomous grid support and disturbance ride-through capability in the inverter
  - generation shedding capability during extreme abnormal system conditions
- ✔ load and storage, which include
  - active management to act as a "solar sink" on a daily basis
  - grid support during abnormal system conditions
  - the capability to offset DPV generation for system security required during extreme abnormal system conditions

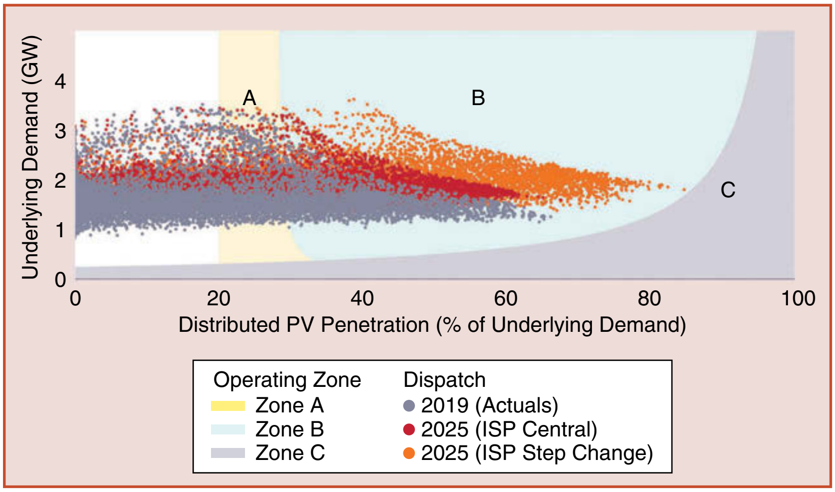

figure 8. The South Australia current and projected half-hourly distributed solar penetration and underlying demand. (Source: AEMO; used with permission.)

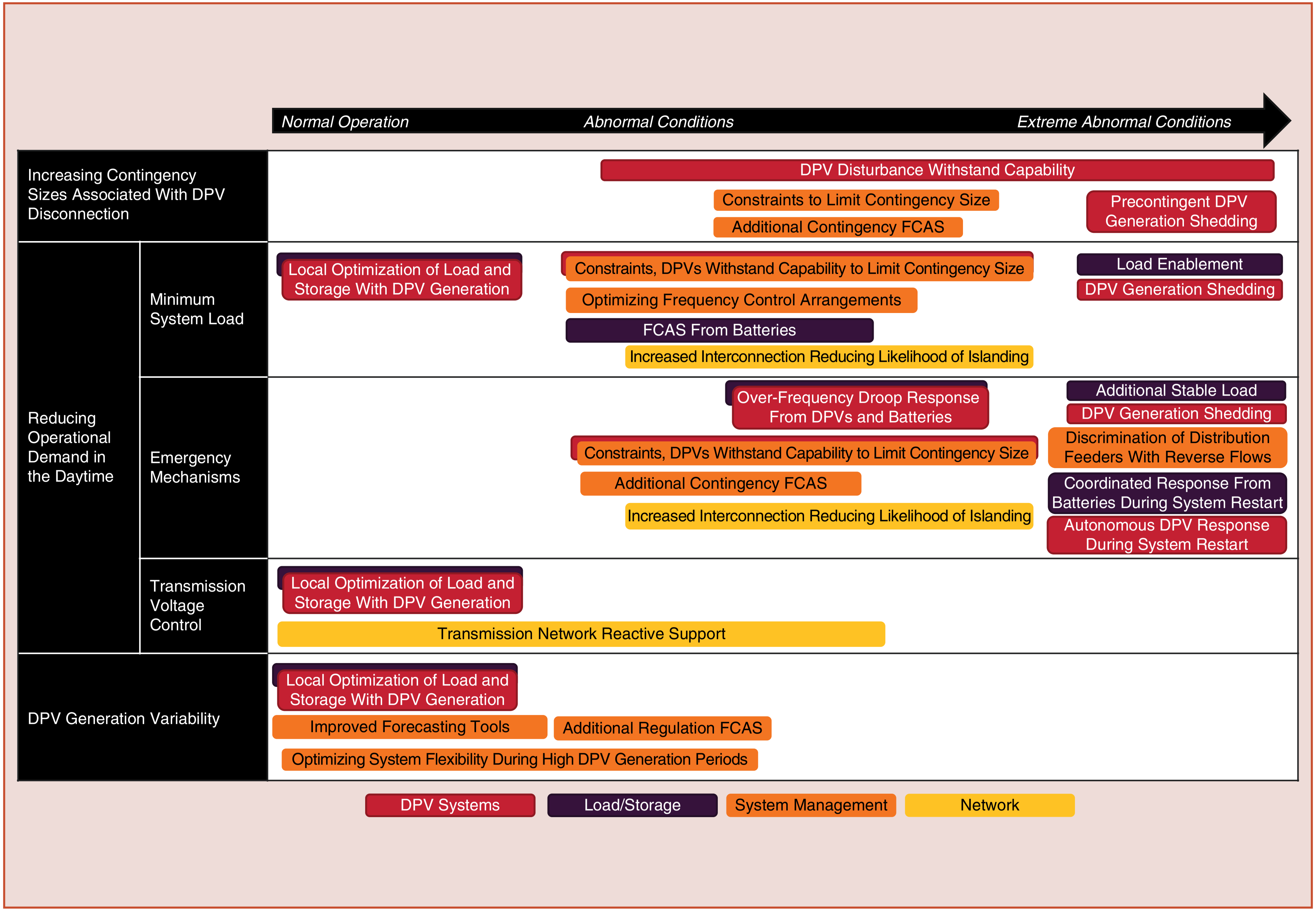

figure 9. Measures assisting with the integration of DPV generation in the bulk power system. FCAS: frequency control ancillary services. (Source: AEMO; used with permission.)

✔ system management, which includes
  - procurement of reserves
  - operational measures to ensure adequate system security services are available during periods with high levels of passive DPV generation online

✔ network development options helping to mitigate the consequences of high DPV generation in the daytime and reducing the likelihood of regions islanding from the NEM. This can include the likes of building new transmission lines or network resistor banks.

Looking to the Future

By 2025, the half-hourly generation from wind and solar PVs (including DPVs) is forecast to regularly exceed 50% throughout the NEM and at times reach much higher levels. If not addressed, system limits will present barriers to the amount of wind and solar generation that can securely operate at any one time.

Figure 10 shows the changing system conditions forecast in the NEM from 2019 to 2025 (as in Figure 2). These are overlaid with the system limits identified in the RIS Stage 1 study, which, if not addressed, will create barriers to the proportion of wind and solar PV generation that can securely operate at any one time. To read Figure 10,

✔ the gray dots show the actual instantaneous penetration of wind and solar generation in the NEM in 2019 and the red and orange dots show the forecast instantaneous penetration of wind and solar under the 2020 ISP Central and Step Change generation builds

✔ Zone A indicates where DPV integration challenges start to emerge

✔ Zone B indicates where managing variability and uncertainty will become increasingly challenging

✔ Zone C indicates where inertia and system strength limit impact secure operation

✔ Zone D is an aggregation of the current minimum online synchronous generation required to meet system strength requirements in each region.

Zone A represents where challenges with accommodating increasing penetrations of highly distributed PVs start to increase. The following measures stand out to the authors as low-regret enablers to be considered as early as possible in the regional uptake of DPVs:

✔ establishing suitable visibility of the distributed fleet (initially static visibility of what is installed and eventually some aggregated level of real-time visibility)

✔ DPV disturbance ride-through capability

✔ DPV capability to support grid frequency and distribution voltages

✔ the ability to curtail or shed DPV generation for use if extreme abnormal conditions (e.g., electrical islanding of regions) arise during high-DPV generation periods.

There is also a need for system operators to maintain the effectiveness of emergency under frequency load shedding and system restart capabilities as DPV uptake reduces the availability of easily forecasted and implemented load blocks during daytime hours.

Zone B highlights where weather variability and uncertainty characteristics start to push up against operational limits when balancing supply and demand. At the same time, system flexibility is changing and needs to be actively managed to ensure secure outcomes. Increases in system flexibility and improvements in forecasting to reduce uncertainty, along with operational improvements such as using a probabilistic forecast as input to the generation dispatch, will be required to manage the changing system.

To assess the ramping requirements and the system's capability to respond across different time frames, new operational tools and processes will be required. Appropriate regulatory frameworks should also be considered to ensure market signals align with this system need.

As the penetration further increases into Zone C, the system impinges on minimum inertia limits and the ability to securely manage frequency stability. To successfully manage frequency stability in the NEM in 2025, a minimum level of synchronous inertia will be needed. A staged approach to reducing online inertia is recommended to allow progressive adaptation of system frequency control design. In parallel, essential system

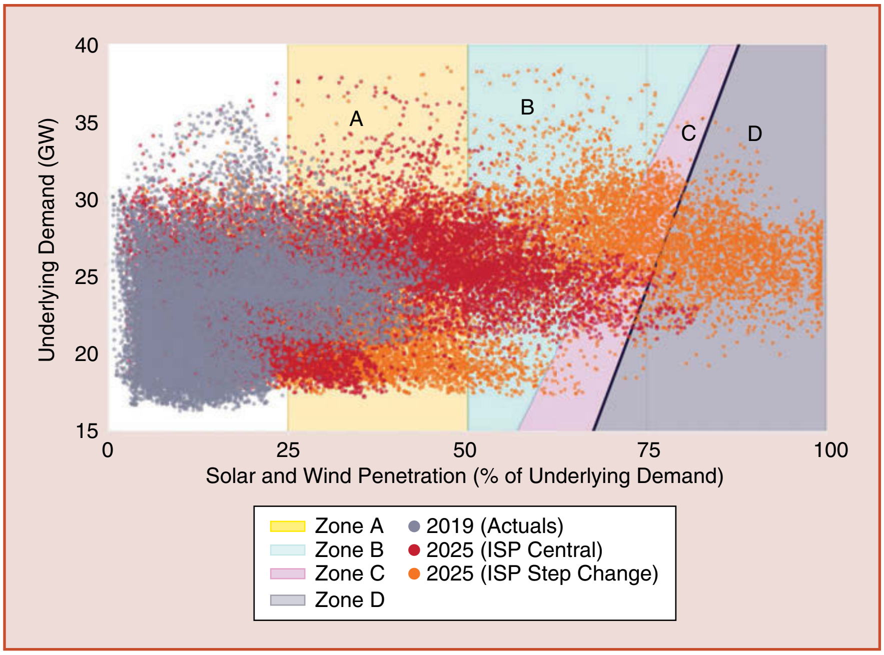

figure 10. Increasing penetrations of wind and solar and zones where system limits are likely to bind. (Source: AEMO; used with permission.)

> Improved generator control system tuning, network upgrades, and targeted placement of synchronous condensers are also important measures.

service requirements must be reviewed to ensure they are appropriate for lower inertia conditions. In a separate article in this issue, "Market Reform Initiatives in Australia: Essential System Services in Grids Dominated by Renewable Energy," market reform initiatives to provide appropriate levels of grid support services are discussed in detail.

Without timely action to address the regional and NEM-wide challenges identified in the RIS, operational limits will restrict the output of wind and solar resources. This would limit their maximum contribution at any given time in the NEM to between 50 and 60% of the total generation. The NEM could potentially be operated securely out to the beginning of Zone D by 2025 with up to 75% of total generation coming from wind and solar resources at any time. While a pathway has been mapped for achieving such an outcome within five years, the extent of work required to successfully adapt the NEM should not be underestimated and will require an all-of-industry effort.

As the penetration further increases into Zone D, the system strength is diminishing. Challenges are emerging for system operators to maintain both the stability of the bulk system and new generator connections to mitigate local system strength issues. The treatment of these issues will be through a combination of existing synchronous plants kept online with reduced minimum generation levels or operating generating units in synchronous condenser mode. Improved generator control system tuning, network upgrades, and targeted placement of synchronous condensers are also important measures. All of these solutions will need to be explored with advanced simulation techniques.

Operating a power system with 100% IBRs appears theoretically achievable in the future. However, successful operation under these dispatch conditions will require significant reengineering of the power system. Some world-leading evidence is coming from the Tasmanian islanded power system (size 1 GW demand), which has operated at times with more than 90% of its energy coming from IBRs.

Even with 100% of generation from IBRs for periods of the day in a system such as the NEM (with abundant gas and hydro resources), the generation mix could possibly swing to 100% synchronous generation within the same 24-h period. The challenge for system planners and operators, or anyone thinking about a high-renewable future, is not just how to progressively transition from today's operational experience. It also includes how to operate a future low-carbon power system on a generation technology base that is constantly shifting on an hourly basis.

For Further Reading

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Essential System Services Reform

Australian Market Design for Renewable-Dominated Grids

IN 1863, A SINGLE ARC LAMP ON OBSERVATORY Hill in Sydney, Australia, was lit to celebrate the marriage of Prince Albert of Wales and Princess Alexandra of Denmark. It was the first use of electricity anywhere in the country. It took 25 years until Australia established its first permanent 240-V electrical grid, in the small country town of Tamworth, New South Wales, in 1888. Two 18-kW, dc, coal-fired generators were supplied by the plentiful Gunnedah black coal basin nearby, and in the same year, on the other side of the continent, C.J. Otte supplied electricity to the Western Australian Government House with a small, 15-kW dynamo. By 1899, a full three-phase 240-V ac grid had been built on the east coast, establishing the foundation of the future power system across the country.

Then, as today, synchronous coal generators provided the majority of system services to maintain security and reliability. These services include the inertia to maintain stable frequency, system strength to maintain stable voltage waveforms, and energy reserves to maintain the balance of supply

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and demand, even with changing demand and unexpected contingency events. Under this arrangement, the provision of these services has been conveniently tied to the supply of electrical energy, with synchronous generators providing support simply by being synchronized with the electric grid. For more than a century, as the electricity infrastructure and trading systems grew, no separate mechanisms were developed to manage these "ancillary services" to the power system. Instead, grid connection standards implicitly regulated an equitable division of costs among facilities in rough proportion to their size. Operators could recover these "costs of doing business" as part of their energy revenue.

The generation mix around the globe is rapidly changing. In Australia, this is happening at a world-leading rate, from having the third-most carbon-intensive electricity generation in the world in 2010 to regularly receiving more than one-third of its power from renewables. One in five households has distributed photovoltaic (PV) systems (at an average of 600 W installed per person, growing at 250 W per person per year)—the highest rate of PV uptake anywhere. At times, more than 100% maximum instantaneous solar and wind penetration is achieved in some regions. Solar and wind generators connect to the ac grid via power electronics-based inverters, which do not provide traditional system services by default. This means that while inverter-based resources (IBRs) can replace the energy previously provided by synchronous coal and gas generation, the provision of system services is not replaced in proportion.

The remaining fleet of synchronous resources faces a growing burden of providing system support services, such as frequency and voltage control and spinning reserves, while revenues fall with electricity prices and reduced market share and energy generation. Left unchecked, this dynamic undermines the implicit stability that has historically supported the electricity system. In Australia's National Electricity Market (NEM), this has manifested in a 10-fold increase during the past five years in the number of occasions the system operator had to intervene outside normal market operations to maintain security and reliability [Figure 1(a)]. There has been a significant reduction in frequency control performance since 2007 [Figure 1(b)] due to the reduced provision of primary frequency control. Uncertainty and variability in net demand from increasing renewable penetration are expected to triple in the NEM through the coming five years [Figure 1(c)], as solar and wind are projected to regularly meet 100% of demand [Figure 1(d)].

As the generation mix has changed, a handful of events has catalyzed political interest and action. After a September 2016 statewide blackout in South Australia, the Australian government commissioned the report, "Review of the Future Security of the National Electricity Market," by the country's chief scientist, Alan Finkel. This led to the establishment of an overarching Energy Security Board (ESB) to implement a "long-term, fit-for-purpose market framework" to deliver a "secure, reliable, and lower-emissions electricity system at least cost" in the NEM. A key workstream of this reform program is to establish new markets and mechanisms for providing system support services. These were traditionally called *ancillary services* but are increasingly being referred to as *essential system services* (*ESSs*) in recognition of their changing value in grids with low levels of synchronous generation. There is a growing consensus that without market reform, the market operator's remit to "keep the lights on" will likely be accompanied by increased curtailment of renewables and greater complexity of operation. This trend is already being observed. In 2019–2020, renewables were curtailed, on average, 7% of the year in the NEM, due to ancillary service requirements, and operator interventions were in place more than 10% of the year.

This article presents the Australian approach to the challenge of providing ESSs in grids with a very high penetration of renewables, outlining first the physical and regulatory contexts of two comparative systems and markets—the NEM (with five regions across Australia's eastern and southern states) and Western Australia's wholesale electricity market (WEM)—and their concurrent programs of reform. The changing nature of ESSs in markets, principles of market design, the spectrum of opportunity for procurement of various new services, and the integration and congruency challenges of holistically addressing those services are discussed. Finally, we present the Australian pathway of reform and a vision for the future of ESSs, with the hope that it may prove helpful for other countries on similar decarbonization pathways (see "Essential System Services").

Context

Australia's electricity networks span vast distances across a continent roughly the area of the United States, but with less than one-tenth of the population. The energy industry, historically government owned, was deregulated in the 1990s to disaggregate the vertically integrated state utilities and support competition. This enabled cross-border electricity trading between states and territories. The NEM was established in 1998. The isolated nature of the Western Australia and Northern Territory electricity systems was a significant barrier to the continent-wide integration of infrastructure and policy. It was only in 2006 that Western Australia's WEM was established, covering the southwest region of the state and serviced by the South West Interconnected System, spanning an area roughly the size of the United Kingdom. The interconnected NEM power system is serviced by approximately 40,000 km of transmission network. The islanded South West system integrates approximately 7,800 km of transmission network.

The Australian Energy Markets

Arising from a period of widescale deregulation, the NEM was established with a strong commitment to market efficiency through real-time, 5-min dispatch intervals; no day-ahead capacity markets; and very high market price caps (currently AUD$–1,000–15,000/MWh). In 2021, the settlement time will reduce from 30 to 5 min to align with dispatch, further sharpening market efficiency in the continuous matching of electricity supply and demand. Along with providing efficient incentives for participants, real-time price mechanisms facilitate the possibility of contracts for difference and hedging to support long-term agreements and risk mitigation. This is extensively conducted in the NEM through hedging and swap contracts. NEM markets for system services were set up with a similar commitment to real-time pricing (for those services that were remunerated). The NEM has six frequency response markets (frequency control ancillary services): contingency frequency response raise and lower services for 6-s, 60-s, and 5-min response times and a causer-pays primary frequency response service. There are nonmarket services for network support and control, such as transient oscillation control, and system restarts.

Reflective of its smaller and more concentrated nature, the WEM balances market efficiency with greater structured procurement, including a capacity market (the reserve capacity mechanism), a day-ahead energy market, the short-term energy market, and a real-time energy market with 30-min dispatching (with lower market price caps, currently AUD$382–1,000/MWh). For system services, the WEM prioritizes structured procurement via a regulation market (load-following ancillary services) and other system services procured under contract, including frequency response (spinning reserve) and, like the NEM, similar nonmarket services for network control and system restarts.

The Post-2025 Program

In 2019, Australian federal and state and territory governments asked the ESB to advise on a long-term, fit-for-purpose market design for the NEM that could be applied starting in 2025 in response to the profound energy transformation occurring across the country. The initiative has

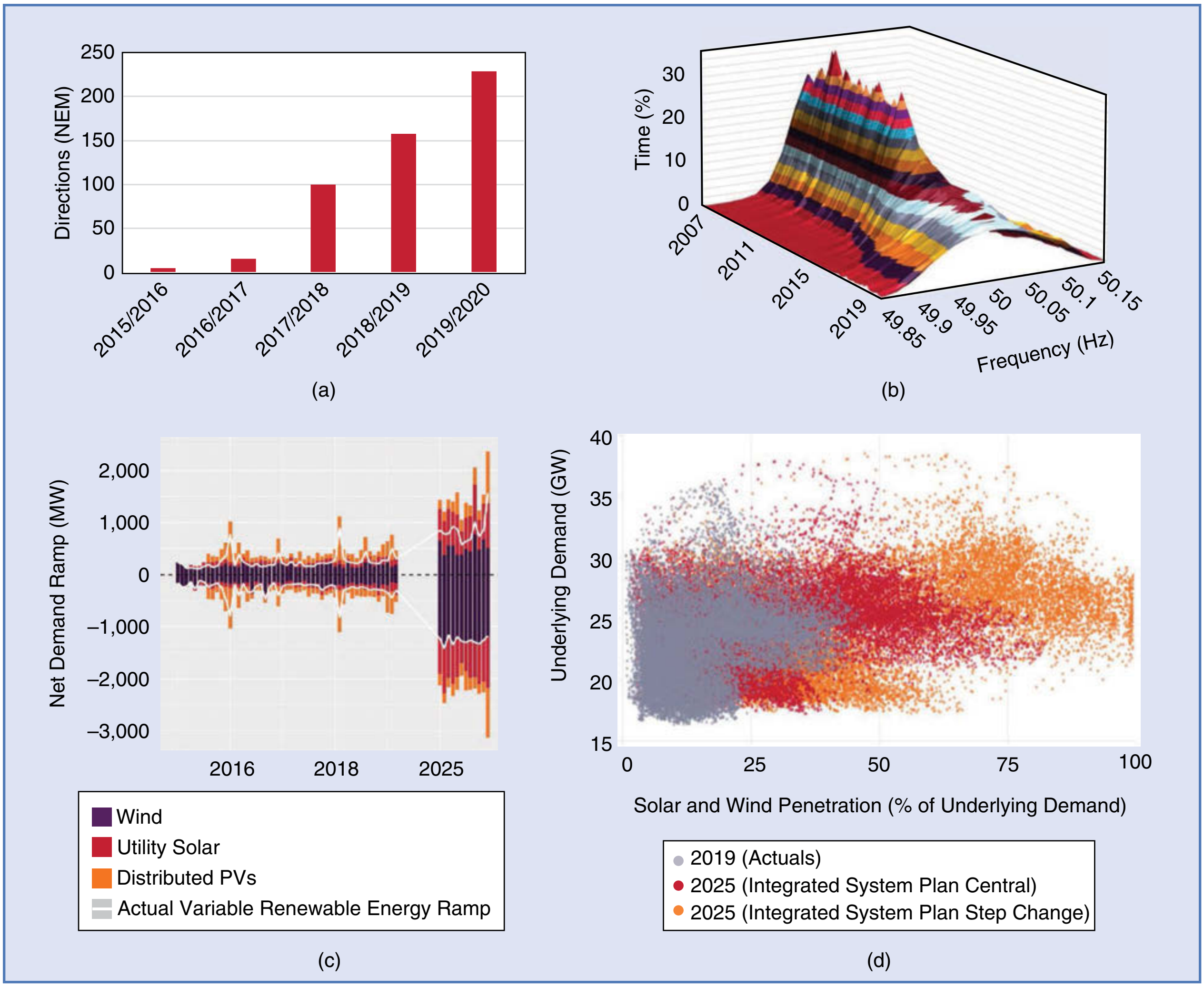

figure 1. (a) Operator directions in the NEM, showing that interventions are increasing. (b) A frequency distribution plot in the NEM to 2019, demonstrating frequency control declined as a result of reduced primary frequency control. (c) A butterfly plot of 5-min net demand ramps, historical and forecast (maximum 5-min ramp in 2025 > 1.5 GW, maximum 1-h ramp in 2025 > 6 GW), which shows that uncertainty is growing. (d) The forecast penetration of solar and wind as a percentage of underlying demand. They may meet 100% of Australia's power demand by 2025. [Source: Adapted with permission from Australian Energy Market Operator (AEMO) Renewable Integration Study, Stage 1, 2020, and AEMO Frequency and Time Monitoring Report, first quarter 2020.]

become known as the Post-2025 Market Design Project, focusing on the entire energy supply chain—from the wholesale energy market through transmission and distribution to behind-the-meter distributed energy resources. The ESB, resourced collaboratively by the Australian Energy Market Commission, Australian Energy Market Operator (AEMO) and Australian Energy Regulator, working with ESB staff, set up four workstreams to consider the issues and develop potential solutions, as in the following:

- ✔ resource adequacy through the transition
- ✔ ESSs and scheduling and ahead mechanisms
- ✔ demand-side participation
- ✔ access and transmission.

Industry and customer stakeholders have been extensively involved and consulted, and there is broad recognition that the individual workstreams are intrinsically interrelated and must be considered together for a coherent whole design. There is a wide range of views about each of the workstreams, but responses indicate that the reform of system service provision is the highest priority and most urgent. Such reform needs to occur before 2025 to address tighter frequency control, structured procurement for synchronous generation commitment (for system strength and inertia) potentially combined with an ahead mechanism to support scheduling, and the exploration of possible operating reserve and inertia spot markets.

The Western Australia 2022 Program

In 2019, the Western Australia government formed the energy transformation task force and charged it with making clear policy decisions through robust consultation to ensure coherent reform for a full overhaul of the market regulatory framework, to go live in 2022. The task force has an explicit focus on the assessment and redevelopment of a new ESS framework.

Principles for Procurement and Market Design

For the impending challenge of redesigning procurement frameworks for ESSs, it helps to first consider broad principles of market design alongside the intrinsic valuation of power system security. The objective of procurement frameworks should be to create efficient and effective economic mechanisms to deliver operational requirements. The operational requirements of power system security must focus on the management of the underlying physics of an electrical network, with sufficient redundancy and robustness in the face of uncertainty and risk.

Essential System Services

All power systems require a suite of system services, traditionally known as ancillary services but increasingly referred to as *essential system services* (*ESSs*), which are necessary for secure and reliable operation. Services can often perform the same function but vary in their names, implementation, competitiveness, and remuneration mechanisms across jurisdictions. Figure S1 and Table S1 summarize the various services that exist in Australia, with their wholesale electricity market and NEM implementations.

(Continued)

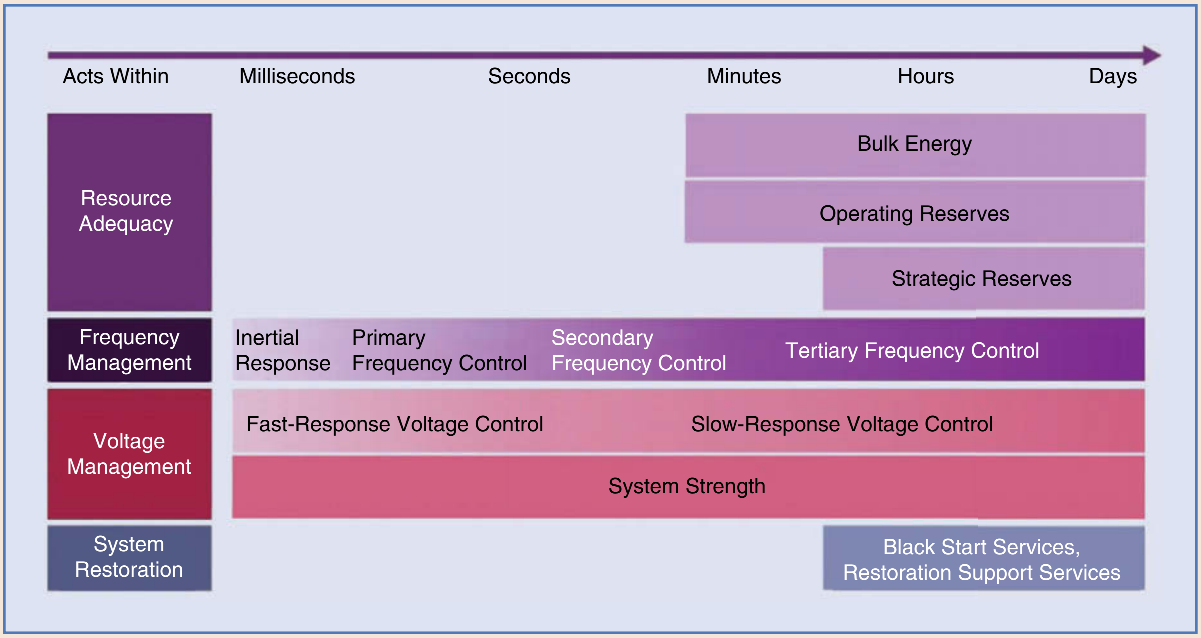

figure S1. Operation timescales and the categorization of certain ESSs. (Source: Australian Energy Market Operator Power System Requirements, 2020; used with permission.)

Market Design for ESSs

A recent report compiled by FTI Consulting for the ESB highlighted seven principles important to the design of effective procurement frameworks for ESSs (see Figure 2). These principles are fundamental in framing the design problem from a regulatory and market perspective. Alongside these principles is the recognition that any design process necessarily involves a compromise between elements to achieve an overall workable design. In particular, there is a natural tension between the idealized theoretical design of markets with assumptions of economically rational behavior and the physical reality of operation, which is complex, uncertain,

Essential System Services *(Continued)*

table S1. A summary of various ESSs in Australia and their implementations within the WEM and NEM.

Service	Description	NEM Equivalent	WEM Equivalent
Bulk energy	Power to meet demand (scheduled and unscheduled)	• Energy (5-m dispatch, 5-m settlement from 2021)	• Energy (30-min dispatch and settlement); moving to 5-min dispatch in 2022 and 5-min settlement in 2025
Regulation	Maintains frequency within the normal operating band, operating within seconds	• Regulation raise/lower	• Load-following ancillary service up/down market • Moving to co-optimized Regulation Service, 2022
Primary frequency response	Arrests and stabilizes frequency following an event that results in a sudden mismatch of demand and supply, operating within milliseconds	• Droop response and fast raise/lower (6 s) • Possible new fast-frequency response (<2 s) from 2022	• Droop response and spinning reserve • Moving to co-optimized contingency reserve real-time market in 2022
Secondary frequency response	Restores frequency to its normal operating band after an event, operating within seconds to minutes	• Slow raise/lower (60 s) and delayed raise/lower (5 m) • Possible combination of 6- and 60-s services from 2022	• Spinning reserve • Moving to co-optimized contingency reserve real-time market in 2022
Tertiary frequency response	Reschedules/unloads facilities that provide primary and secondary frequency response so that they are available to respond to new events	• Energy redispatch	• Energy redispatch and redispatch of government-owned energy assets • Moving to co-optimized contingency reserve real-time market in 2022
Inertia service	Physical inertia that reduces the rate of change of frequency (ROCOF) following a contingency event	• No existing service • Possible scheduling of synchronous resources through a unit commitment for security mechanism or synchronous services market • Possible future inertia spot market	• No existing service • Moving to a co-optimized ROCOF control service in 2022
Operating reserve	Balances the supply and demand of energy across a minute-to-hours horizon	• Possible new market for operating reserves and ramping availability from 2025	• No explicit service; managed by energy redispatch and self-commitment
System restart	Facility capability to restart a black system and to assist with reconstruction following a black system event	• System restart ancillary service	• System restart service • Provided as part of nonco-optimized essential systems services framework from 2022
Voltage support and system strength (discussed further in the text)	Stabilizes voltage in a location of a network	• Network support and control ancillary service • Possible scheduling of synchronous resources through a unit commitment for security mechanism or synchronous services market	• Network control service • Provided as part of nonco-optimized essential systems services framework from 2022
Capacity	Procurement of capacity (generation and demand-side management) to meet forecast peak demand on the yearly time horizon	• No explicit service except for reliability and emergency reserve trader function • Possible new market for operating reserves or ramping availability in the NEM	• Reserve capacity mechanism • Annually administered price mechanism for certified capacity

WEM: wholesale electricity market.

nonlinear, and failure prone. There are additional asymmetric costs of market efficiency and market failure. While designers may prefer complex, multilayered, and co-optimized markets, operators may desire conservative, expensive, and unoptimized solutions. Striking the right balance to develop efficient and robust economic solutions to technical challenges requires the rigorous and combined efforts of power system engineers and economists.

Policy makers have a variety of regulatory and market instruments available to them. Options include technical standards and licenses, operational directions and interventions, regulatory delegations (including network monopolies and other central agencies), individual contracts with providers, ESS auctions, and tenders and short-term spot markets. Regulated approaches can provide greater comfort in the technical provision, especially given complex security services (such as system strength). While market approaches provide the opportunity for greater efficiency, there is potential for financial innovation to outcompete technological innovation. Market solutions can also optimize against the technical specification of a service, creating a lack of resilience.

A case in point is the design of contingency frequency response markets in the NEM, where technical specifications guided by normal operating frequency bounds resulted in wide frequency governor dead bands. In the face of uncertainty, this led to poor frequency performance and system fragility, only recently corrected by the reimplementation of stringent mandatory primary frequency response requirements. By contrast, the WEM complements a spot market for regulation services with an obligatory droop requirement, which has led to improvements in frequency management.

Tradeoffs abound for investment considerations, given commercial risk appetite. While spot markets, if appropriately designed, can provide efficient scarcity price signals, investment decisions on long-duration assets are typically made in the context of longer-term revenue and cash flow visibility. In the design of ESSs, it is relevant to consider the following:

- ✔ Framework flexibility is needed in managing current principles of provision (such as from synchronous generators and synchronous condensers) while accommodating future innovation (inverters providing “synthetic inertia” and grid-forming capability).
- ✔ The locational nature of service provision must be taken into account. For example, fault current and system strength are highly locational relative to inertial frequency response, which is system wide.
- ✔ The complexity of co-optimization in the context of uncertainty needs to be understood.

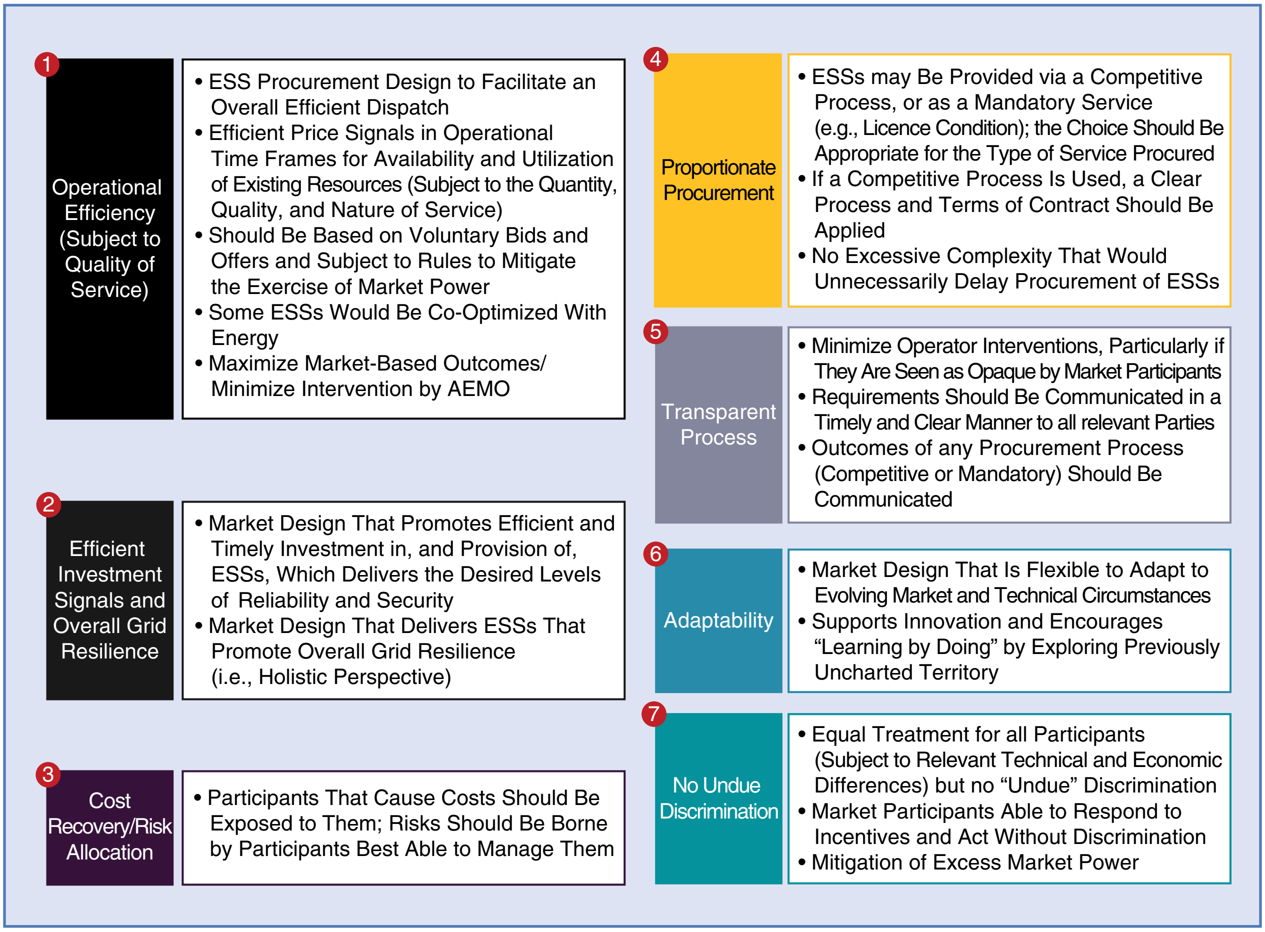

figure 2. Principles of market design for ESSs. (Source: Adapted from the 2020 FTI Consulting Report to the ESB.)

- ✔ The challenge of valuing ESSs and the consequent difficulty of allowing procurement quantities beyond minimum levels to provide additional robustness and resilience will have to be met.
- ✔ The tradeoffs of operational complexity and market sophistication are important: complex markets create more points of failure.

During this period of rapid change, adaptive governance and procurement approaches are helpful. For ESSs, a flexible contractual framework would support operators to mitigate fast-evolving system risks, potentially accompanied by an adaptive regulatory change process that supports participant decision making.

Other International Approaches

While Australia's power system finds itself in uncharted territory with the penetration of variable renewable energy (VRE) and distributed solar, there are pioneering advances in market design for system services being explored across the world. This section reviews some key developments in comparable systems in the United Kingdom and the United States. In the United Kingdom, electricity system operation and the procurement of system services are delegated to the National Grid Electricity System Operator (NGESO), a subsidiary of the for-profit, private National Grid UK, which also owns and operates the transmission network. This framework provides a comparatively high degree of flexibility in the approach to procurement, with the NGESO utilizing competitive tenders of varying duration and structure in procuring services.

Standardized system-wide frequency and reserve products have contributed to shorter-term, frequent contract auctions, while more individually tailored and longer-term contracts were used to secure requisite investment for services with locational requirements and smaller provider pools. A recent initiative is the stability pathfinder tender, which procures a combination of services, including fault levels and inertia. Reactive power, traditionally an obligatory service, is also increasingly obtained through competitive tender approaches.

The NGESO is subject to a unique financial incentive scheme with payments based on performance evaluated by the regulator Office of Gas and Electricity Markets through an annual scorecard assessment. The discretion provided to the Office of Gas and Electricity Markets has been particularly useful in a rapidly changing environment, providing flexibility to respond to evolving technical scarcities and to modify and adapt procurement on an ongoing basis. This has also left the NGESO to deal with the issue of supporting investment by initially procuring newer services via longer-term contracts (to underpin investment), moving toward shorter-term auctions as business models become established.

By contrast, regulatory regimes in the United States and Ontario, Canada, have delegated system services to independent system operators (ISOs), which are not-for-profit entities with relatively less discretion to make decisions about ESS procurement. Procurement approaches tend to be codified in regulations, with changes subject to detailed review, stakeholder engagement, market participant votes, and, in some cases, approval of the U.S. Federal Energy Regulatory Commission. Given the need for transparency, ESSs have tended to be obtained via either short-term spot markets (predominantly frequency and reserve products) or mandatory provision. Spot markets have provided transparency and price visibility, enabling financial markets to develop around services underpinning investment.

However, given regulatory structures, incentive mechanisms for U.S. ISOs have proven to be challenging due to narrow incentive thresholds and forecasted delivery targets. In practice, these obstacles, combined with the regulatory processes, have limited the ability of ISOs to develop new products expediently. While many jurisdictions are adapting technical standards for inverters, there has been less emphasis in international jurisdictions on service procurement concerning system strength. The meshed nature of North American grids means system strength and the provision of fault current is of less concern from a technical perspective, and as a result, it is not explicitly defined as a system service for many regions, including New York ISO, Midcontinent ISO, and Ontario Independent Electricity System Operator.

Australian market designs have strong parallels with security-constrained gross power pool models common across markets in North America, apart from procedures for centralized unit commitment and two-settlement market clearings, which are not part of the NEM. However, given the extent of VRE penetration and the unique operational phenomena observed in Australian grids, the networks will likely have to forge novel approaches to procure these complex and multifaceted technical services. These approaches will also have to work alongside the broader challenge of a 5-min spot market framework without ahead and capacity markets.

Spectrum of Opportunity

Procurement Frameworks

Having identified a case for change and reviewed the principles of market design for ESSs, the challenge progresses to canvasing the "spectrum of opportunity" in resolving the missing services that arise as IBRs replace synchronous generators. There are many options to procure ESSs, but frameworks can be broadly categorized along an axis of market efficiency, as follows (see Figure 3):

1) *market operator interventions and the self-provision of services* without market-based remuneration (currently used for system strength, inertia, and operating reserves)
2) *structured procurement* via nonspot market mechanisms (currently used for emergency out-of-market reserves, voltage control, and network support/control)
3) *spot market-based* provision of services (currently employed for energy, regulation, and contingency frequency control).

Although there is a preference for real-time signaling, not all system services are suited for market-based procurement. The market design assessment for each service includes

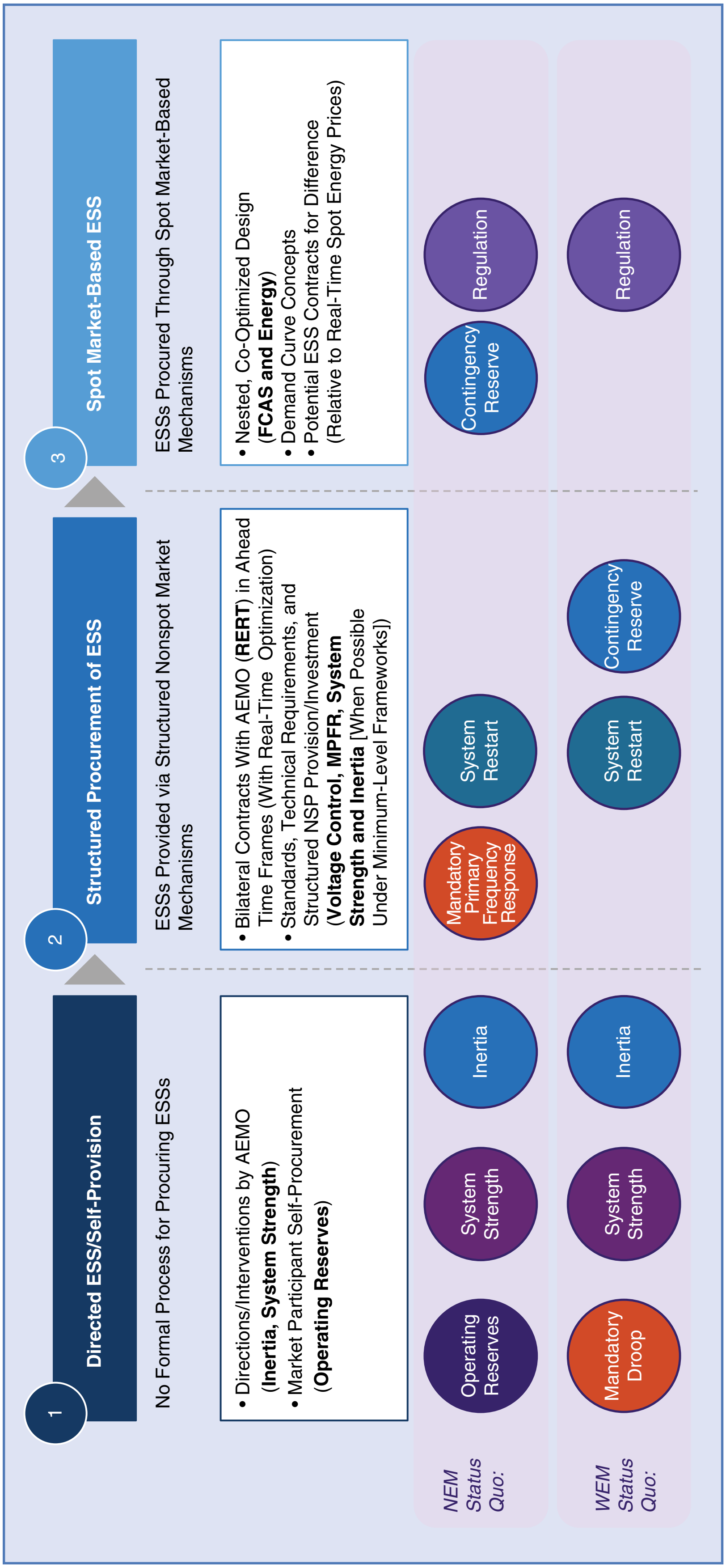

figure 3. The spectrum of opportunity for ESS in the NEM and the WEM, indicating the status of current ESS market mechanisms, with an implicit axis of "greater market efficiency" toward the right. RERT: reliability and emergency reserve trader; NSP: network service provider; MPFR: mandatory primary frequency response; FCAS: frequency control ancillary services. (Source: Adapted from the 2020 FTI Consulting Report to the ESB.)

factors such as the measurability/fungibility of a product, the competition and co-optimization scope, complexity and simplicity, and locationality. This section introduces various options for market designs for each ESS stream under consideration, namely, operating reserves, frequency management, synchronous services, and inertia.

Operating Reserves

Energy markets must maintain supply and demand in instantaneous balance with prices set through a spot market. Market participants often have separate contracts across their portfolios to manage the risk around the energy spot price. The market operator, however, typically does not see these contracts. Instead, it must rely on faith that participants will display economically rational behavior and take advantage of high prices at times of supply scarcity. This trust is increasingly being tested by the changing nature of generation, with the "invisibility" of behind-the-meter distributed PV generation and the variability and uncertainty of large-scale wind and solar [Figure 4(a)]. The likely result is the system operator managing the system more conservatively, leading to greater VRE curtailment as risk becomes excessively high. The possible design of an operating reserve or the ramping availability service that is under current consideration may help address this challenge in the NEM.

There are several market options to procure operating reserves, including 1) obtaining firm availability in the dispatch interval 30 min ahead [Figure 4(c)], 2) holding a certain level of spinning callable reserve to be triggered to dispatch as energy, and 3) securing operating reserve headroom in the coming 5 min to dispatch as energy. With each option, the use of a demand curve constructed from historical forecast errors may inform the efficient level of reserve and firm the availability to acquire it [Figure 4(b)]. These options are being developed for possible NEM implementation in the next two years. Decisions on a final preferable new market will be based on tradeoffs between operator confidence, market efficiencies, and potential adverse impacts on the energy spot market.

Frequency Management

This class of services encompasses the need to schedule reserves of energy capacity that respond to unexpected changes in the load–generation balance (in addition to synchronous inertia, which will be discussed). There are two broad categories to consider:

1) *regulation reserves*: responding to ongoing and smaller imbalances, primarily due to variations in demand and generation from intermittent sources
2) *contingency reserves*: responding to sudden and very large disturbances, such as the loss of a major generation unit.

Under assumptions of reasonable connectivity and system strength, frequency management can be sourced from any network location. Much like the case of standard energy supply, this global pool of resources lends itself to procurement via a centralized, co-optimized spot market (energy dispatch can be considered a very slow class of frequency control). However, the desire for a universal and highly optimized market design must be carefully weighed against the complexities and irregularities this can create in a physical system.

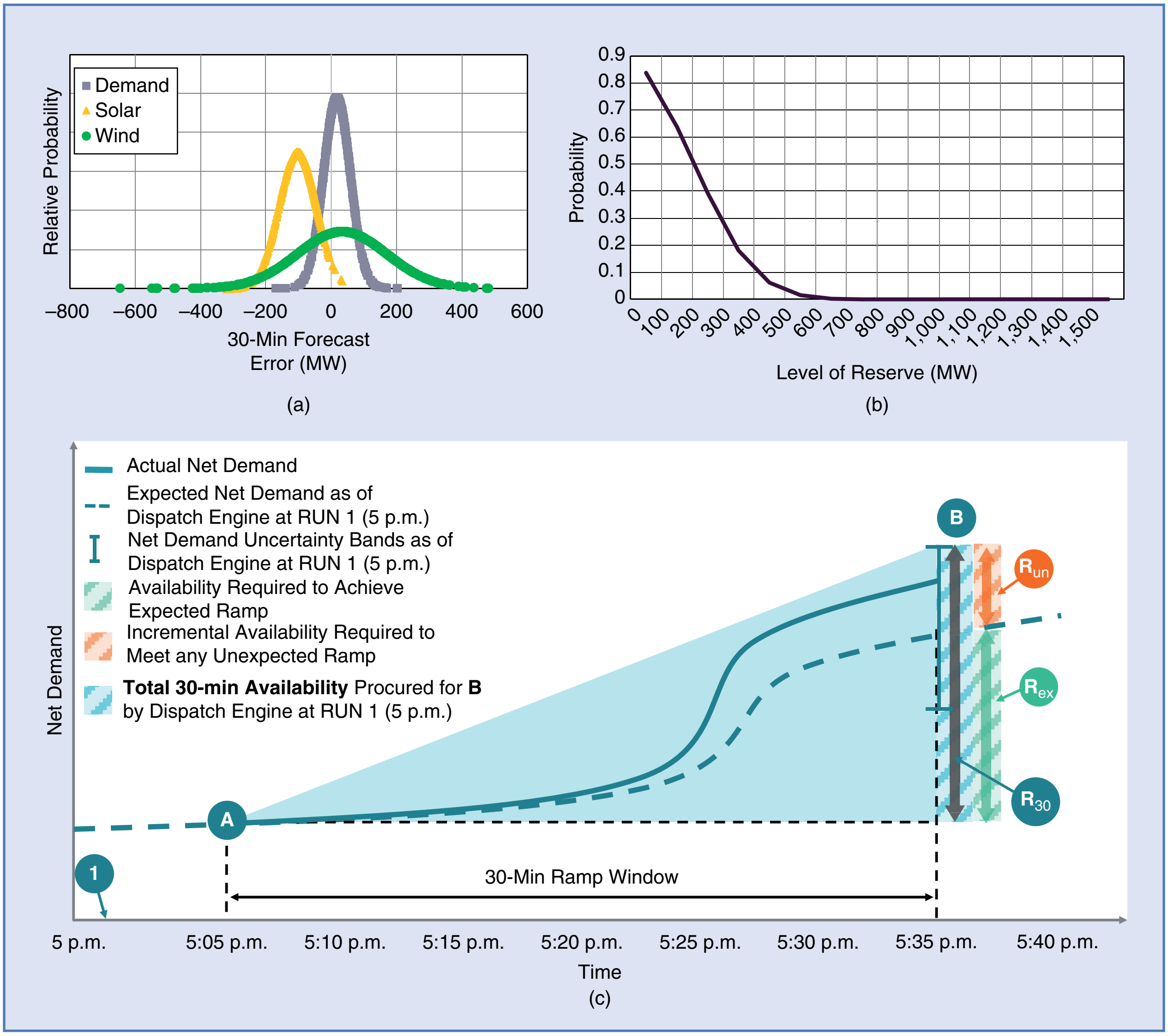

figure 4. (a) The probability distribution of 30-min forecast errors for South Australia, summer 2019–2020, 2–6 p.m. (b) The probability that the 30-min forecast error is higher than any particular reserve level, which may inform an efficient reserve demand curve. (c) An example 30-min ramping “availability” product to address unexpected ramps across a 30-min time horizon. (Source: adapted from Brattle Consulting Report to AEMO, 2020.)

Figure 5 illustrates this consideration through a system operations abstraction of frequency management for contingency response services. In this view, the physical response of the entire generation fleet is aggregated and considered according to different performance requirements for the deployment and sustainability of power output into inertial, primary, secondary, and tertiary response. These distinctions are not fundamental but reflect control structures formed around physical properties and useful tradeoffs optimized in the allocation of power system resources.

Three critical security limits must be managed following a generation contingency (Table 1). Exact operating limits vary due to jurisdictional norms and reliability standards. However, these standards ultimately reflect the physical tolerances of an electrical plant. Inverter-based facilities, for example, generally have a higher tolerance to the rate of change of frequency (ROCOF) than rotating machinery. The ideal procurement model also incorporates incentives to reward tolerances. It reduces overall service requirements in addition to the procurement of suppliers. The NEM reform program is reviewing the feasibility of including additional fast-frequency contingency response (with reaction times shorter than 1 s) alongside mechanisms to support the efficient provision of (currently mandated) primary frequency response within the normal operating frequency band.

Inertia and System Strength

The procurement of synchronous services, namely, system strength and inertia, is particularly complex to transition from the traditional provision as a by-product of generation from synchronous generators. Options to replace this include the network operator building additional synchronous resources (for example, synchronous condensers with flywheels) and creating incentives for the provision of services through advanced power electronics (see "Australia's Big Battery"). There is an opportunity to procure inertia as a separate service, an option being implemented as part of the market reform in Western Australia through the ROCOF Control Service (see "Western Australia Rate of Change of Frequency Control Service").

System strength is an emerging concept broadly defined as the strength of a power system's voltage waveform. It is closely associated with inertia and fault current levels but does not solely consist of either. The ability to maintain a stable waveform is decreasing as IBRs connect to the system. The appropriate procurement mix for system strength may incorporate elements of various frameworks, with challenges for

table 1. Frequency limits to be managed following a generation contingency.

Limit	Description	Management
ROCOF	Maximum ROCOF in the first 1–2 s	Synchronous inertia and potentially "virtual inertia" from power electronics resources
Nadir	Absolute minimum frequency, typically reached around 6 s	Primary response of local generation control systems
Settling frequency	A "quasi-steady-state" frequency maintained while the system is restored to normal operating conditions	Secondary response directed by central generation control schemes

Australia's Big Battery

Following an 8-h statewide system blackout in South Australia in 2016, there was an intense period of government effort to ensure ongoing security for the approaching summer. Following a series of tweets between billionaires Elon Musk, chief executive officer of Tesla, and Mike Cannon-Brooks, chief executive of Atlassian, Tesla offered to build a 100-MW battery within 100 days of signing a contract or the battery would be "free." The South Australian government accepted the offer, subsidizing the initial development cost, expediting planning approvals, and negotiating an ongoing contract for the government to use the battery as an emergency reserve, which French developer Neoen would own. In 2017, the Hornsdale Power Reserve (HPR) was commissioned and connected to the grid, becoming the world's largest grid-scale battery, at 100 MW/129 MWh. The battery has been a resounding commercial success for South Australia customers and Neoen, delivering an estimated AUD$150 million in electricity cost savings to consumers in its first two years—AUD$116 million alone from frequency control costs in a two-week period in 2019, when South Australia was islanded from the rest of the grid.

The facility has demonstrated the potential of future ESS provision through inverter-connected equipment. The precision with which batteries follow automatic generator control set points while providing frequency control ancillary services as compared to a traditional thermal generator is striking (see Figure S2). At present, there is no extra remuneration for facilities that exceed the market ancillary service specification in the NEM. The performance of the battery (typically subsecond) has provided an impetus for the consideration of a fast-frequency response service, which is critical for maintaining security in the power system as inertia levels continue to decrease.

In December 2019, HPR was expanded by 50 MW/64.5 MWh (to 150 MW/193.5 MWh) with grants and financial support from multiple state and federal initiatives.

policy and regulation in appropriately allocating risks, costs, and benefits to customers, system operators, and network service providers.

A possible approach to procurement is to mandate threshold levels at all nodes across the network (via the specification of a minimum fault current level and short circuit current ratios) and allocate maintaining these levels to the transmission network service provider. As regulated entities, there is some incentive for providers to procure capital equipment to include in their regulated asset base. This may discourage the provision of synchronous services from smaller, nimbler, and more efficient technologies in the medium to long term. Australia's NEM experienced the "gold plating" of its network during the first decade of the millennium, with overinvestment in capital infrastructure in network providers' regulated asset bases. There is caution toward enacting regulation to revisit this through the overprocurement of system strength and synchronous

The upgrade is being delivered by Neoen in collaboration with Tesla, the AEMO, and the network service provider ElectraNet to demonstrate the capability of inverter-connected generation to deliver a service equivalent to one from a synchronously connected generator, which is typically achieved by modeling and implementing the theoretical response of a synchronously connected generator at high speed to govern the response of the facility to power system conditions. Tesla expects to show a system functional inertial capability equivalent to 3,000 MW. Such a capacity has not been demonstrated at grid scale but may represent a pathway to displacing synchronous generation for the provision of these services in the future.

HPR enjoyed first-mover advantages as the initial grid-scale connected battery in Australia. At the time, it was expected to prevent support for additional (*n*th of a kind) battery investment, under the assumption that it had taken the majority of the available funding. This has not been the case. At the time of writing, 209 MW of grid-scale battery storage are operating. A further 900 MW are expected for delivery by 2024, and 7 GW are in the proposal phase in addition to several gigawatts of pumped-hydro investments slated across the country.

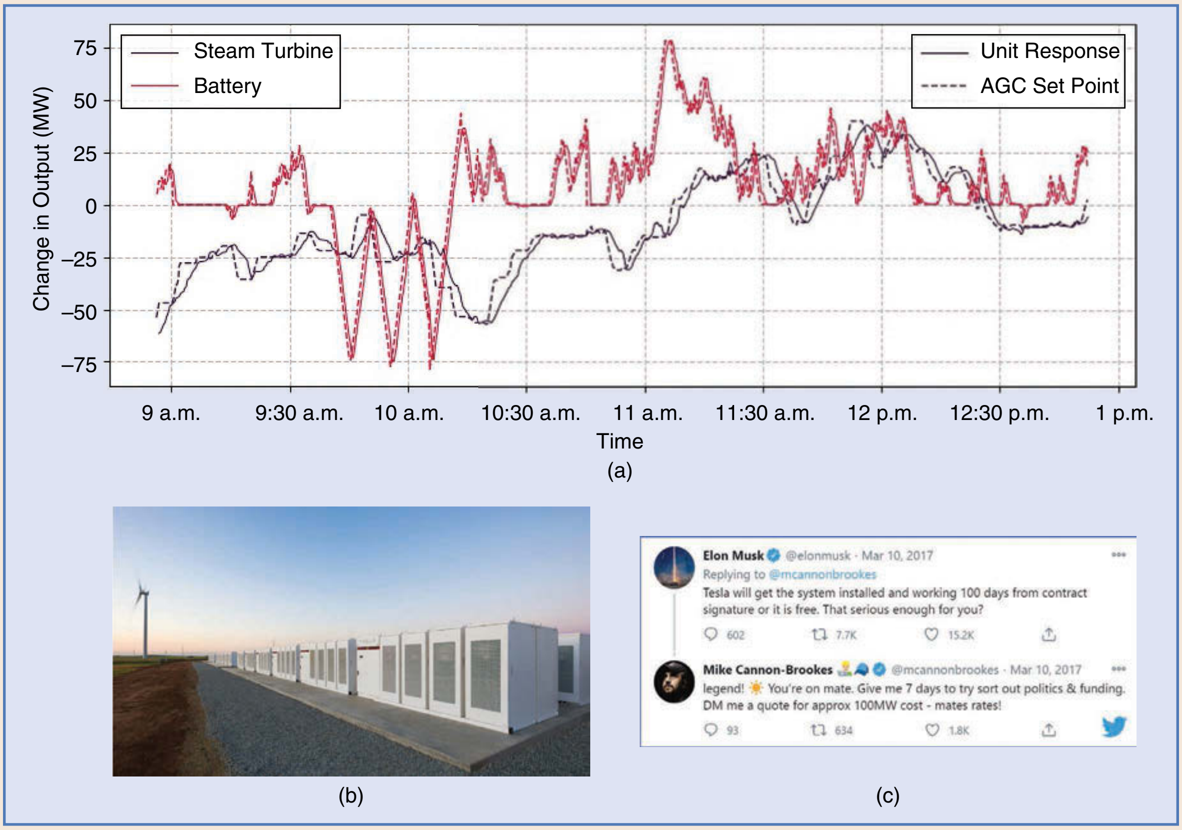

figure S2. (a) A comparison of the regulation frequency response capabilities of HPR compared to a steam turbine. (b) HPR. (c) An extract of the Twitter conversation between Mike Cannon-Brookes and Elon Musk that formed the genesis of the battery. AGC: automatic generation control. (Source: Twitter.)

services. The challenge will be in allocating risk and cost appropriately while enabling operator confidence and flexibility within the system to adapt without causing inefficient overprocurement.

A parallel option includes a unit commitment for security or synchronous services market mechanism that enables an operator to schedule synchronous units to minimum levels for safe operation. The mechanism could then support additional VRE penetration through competitive provision from uncontracted resources. This could also be potentially supported with a "nomogram" (a diagram that facilitates calculation through geometrical construction), a precursor of which is the example transfer limit advice table for strength in South Australia (Figure 6). While not exhaustive, this example indicates the various combination of synchronous (gas) units that support different levels of nonsynchronous (renewable) generation.

The computational complexity of modeling to construct a table such as this is significant. Additional difficulty arises from the inclusion of economic considerations to support efficient decisions in allowing or curtailing renewable energy. When this economic analysis can be combined with such a table, it may provide a pathway toward a complete nomogram to support the greater economic integration of renewables in the short to medium term. It is not clear how these various approaches may be married, nor is it evident how to manage the risks and costs of over- and underprocurement to customers via network service providers and the system operator. The emerging capabilities of grid-forming inverters (see "Australia's Big Battery") will likely play a part in any future mechanism, requiring review and revision during the transition.

Interdependencies

Thermal power stations (largely coal fueled) are forecast to retire at pace in the next two decades from the NEM and WEM (Figure 7). A key pillar of reform is the consideration of resource adequacy mechanisms to drive investment in capacity to ensure that the reliability standard is met through the transition. However, the power system will also need investment in resources capable of meeting its ESSs. If these requirements are not considered when investing in new generation (or demand-side) capacity, the overall cost of delivering secure and reliable energy to consumers is likely to be higher. Investment in system service capability may take the form of incremental capital expenditures to new entrant generation, retrofitting existing generators, and new stand-alone merchant resources with system service capabilities. A resource adequacy mechanism (e.g., a capacity market) could be extended to incorporate investment in system service capabilities by placing an obligation on consumers (or retailers) to procure additional capabilities.

These interdependencies present a significant challenge to the overall coordination of reform and market participation across investment horizons. Historically, grid-scale power systems have required large investments in equipment to be economical. In smaller systems and jurisdictions, this has meant that a single provider may be the most economically

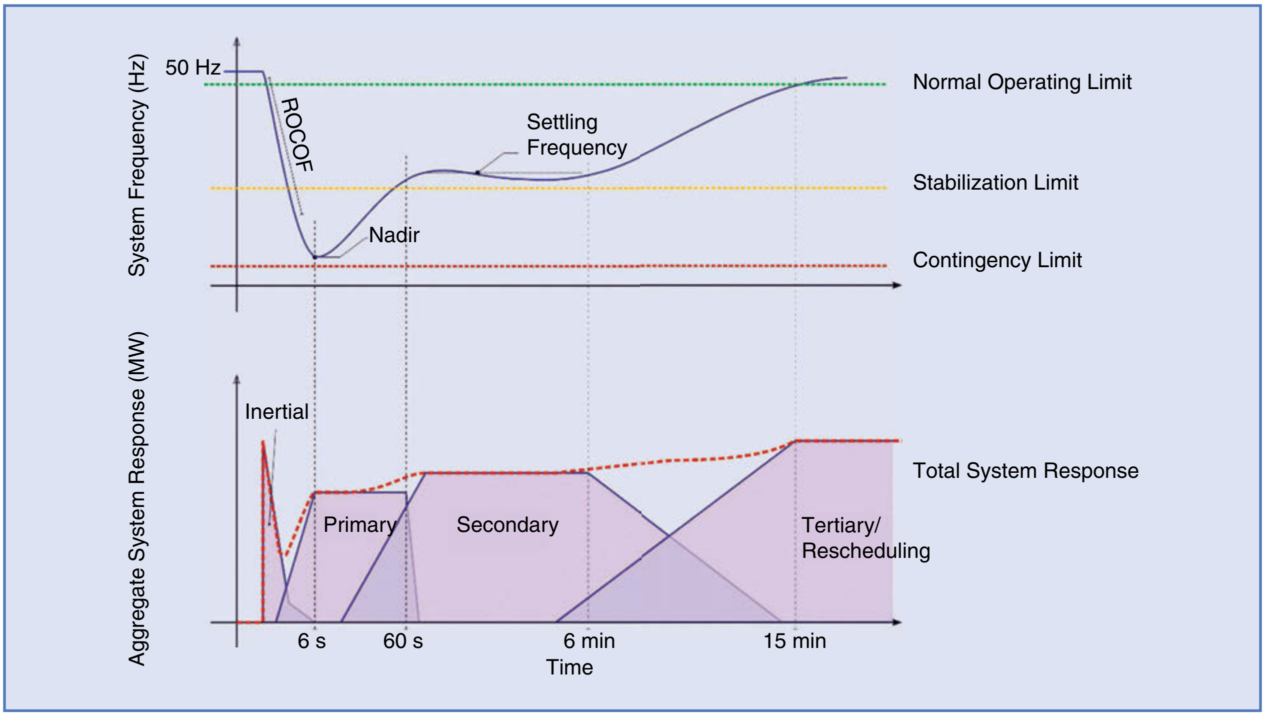

figure 5. (a) The system frequency appropriately managed after a contingency event. (b) Frequency management mechanisms to support the restoration of system frequency following a contingency event. ROCOF: rate of change of frequency.

Western Australia Rate of Change of Frequency Control Service

In August 2019, a Western Australia energy transformation task force found that a real-time co-optimization of all frequency control services, including inertia, was most appropriate for the future WEM, driven by a mixture of physical, operational, and market considerations. Historically, the WEM relied on an empirically derived rule of thumb: 70% of the largest generation contingency (in megawatts) was allocated as headroom across a set of designated facilities. An analysis and comparison of this approach identified that the combination of isolation and relatively small size resulted in the WEM being run close to its technical limits.

The transition to the greater penetration of renewables has necessitated a more sophisticated market design and led to a preference for a real-time spot market to optimize system inertia and primary response speed. In this context, initial design options focused on the correct balance of service definition "segmentation," for example, adding 1-, 2-, and 3-s services to complement the co-optimized 6- and 60-s markets, as done in the NEM. With system requirements abstracted to fundamental quantities (i.e., generic megawatt specifications), the optimal delivery of these services would be by market dynamics, irrespective of the underlying technology.

Unfortunately, investigations and analysis revealed issues with the multisegment approach from the following physical and market perspectives:

- Physical
  - Each segment adds complexity and increases the degree of "fantasy" space in which the commercial abstraction diverges from physical reality. In practice, there is no clean, linear separation of megawatts into convenient buckets.
  - Inertia is only superficially the same as primary response. True rotating machinery has a fundamentally instantaneous reaction, while power electronics suffer from an electronic detection delay on the same order (<1 s) of the critical ROCOF period.
- Market
  - Each segment adds complexity, resulting in additional infrastructure/systems overhead plus an opportunity to game/manipulate market systems.
  - Especially in a relatively "shallow" market (pool of suppliers), more complexity increases the chances of a participant effectively exercising power over a market.

The task force decided that a single segment was most appropriate. While multiple segments facilitate more service differentiation, in practice, such gains were marginal, while the downsides were guaranteed. The implementation of this direction required a fundamental change in the perspective of service definitions. Rather than split physical responses across multiple segments, the entire response profile is characterized in reference to a perfect exponential response (see Figure S3) chosen to approximate the output of a physical turbine. The response factor is then converted into a multiplier that incentivizes speed. Inertia is split from the primary response in recognition of the underlying physical differences, while inverter-based generation is credited through very high-performance multipliers. The task force, however, noted the ongoing research and development of inverter-based technology, and named the inertial service ROCOF Control in recognition that future developments may open this segment to power electronic devices.

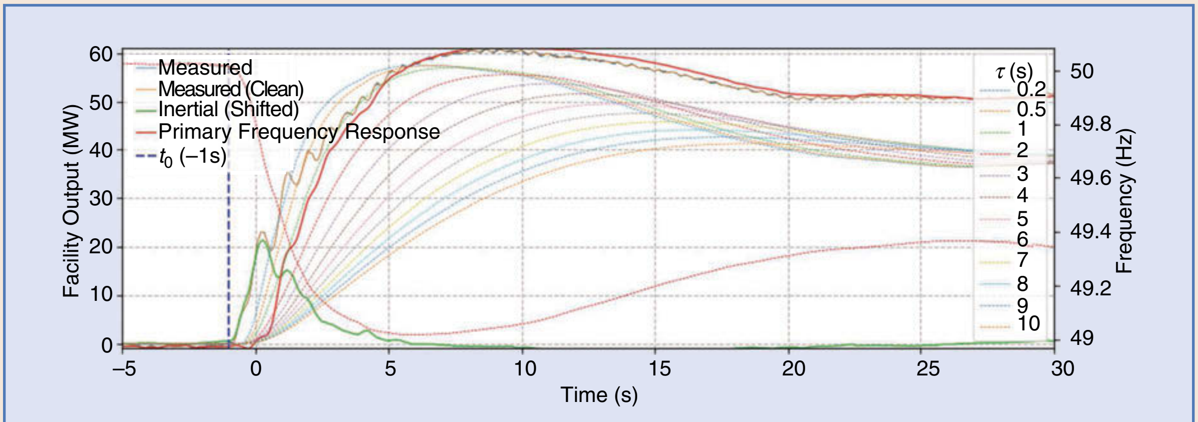

figure S3. The physical response of a gas turbine is measured and compared against an array of hypothetical "perfect exponential" responses of different speeds.

efficient approach for providing a certain service. Even with rapid distributed energy resource (DER) emergence, it may still hold that a single regulated ESS provider is a more economical solution than open-market provision. To facilitate investment, the markets for procuring services need to be stable and have clear participation requirements. In theory, markets with sufficient competitive tension will drive efficient investment and retirement decisions, ensuring that suitable

Combination	Nonsynchronous Generation Level	Torrens Island A				Torrens Island B				Pelican Point			Osborne		Quarantine or Dry Creek*
		Ax	Ax	Ax	Ax	Bx	Bx	Bx	Bx	GTx	GTx	ST18	GT	ST	
LOW_2	≤1,300 MW					■	■			■		■			
LOW_3	≤1,700 MW					■	■						■	■	■
LOW_4	≤1,450 MW									■		■	■	■	■
LOW_5B	≤1,700 MW	■	■			■	■	■							
LOW_6	≤1,700 MW					■				■	■	■			
LOW_7	≤1,700 MW	■	■							■		■			■
LOW_8	≤1,600 MW	■				■				■		■	■	■	
LOW_10	≤1,750 MW	■	■			■	■						■	■	
LOW_11	≤1,700 MW	■								■	■	■			
LOW_13	≤1,700 MW	■				■	■	■					■	■	
LOW_14	≤1,300 MW	■	■			■				■		■			
LOW_15	≤1,300 MW	■				■				■		■			■
LOW_18B	≤1,700 MW	■				■	■	■							■

figure 6. An excerpt of the AEMO's 2020 transfer limit advice for South Australia, indicating the combinations of synchronous units (green squares) at low levels of system strength that may support various levels of nonsynchronous (renewable) generation (column 2). Ax, Bx, and so on represent different generating units of the power stations.

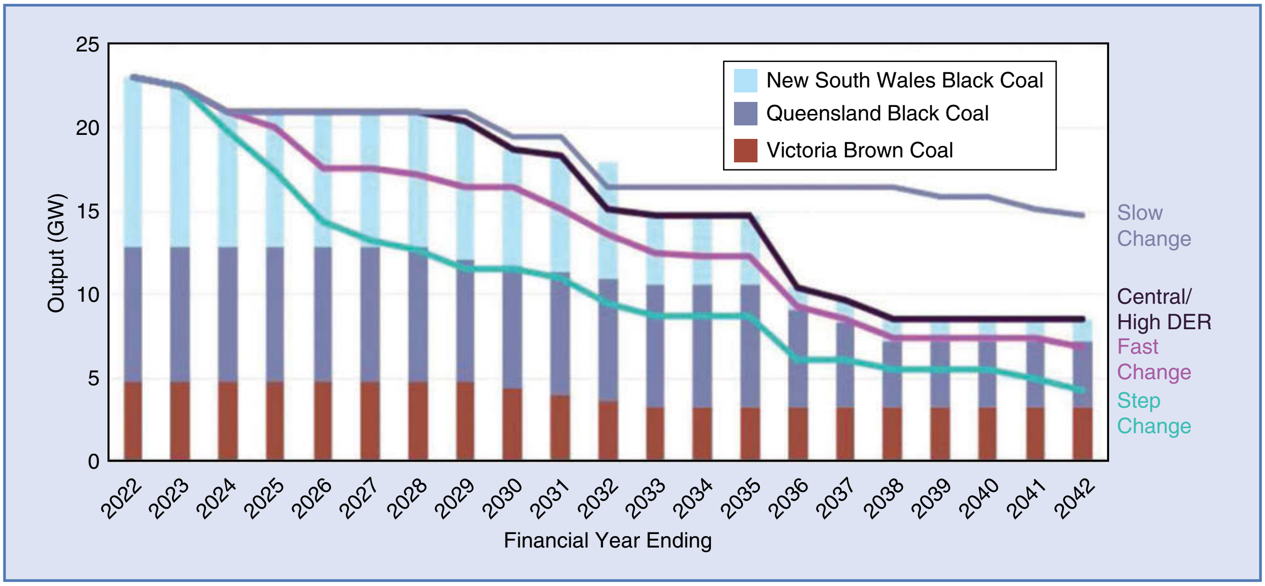

figure 7. A forecast for coal generation retirements in three Australian states. DER: distributed energy resource. (Source: 2020 AEMO integrated system plan.)

quantities of each ESS are available. For power systems that lack competitive tension due to either a small size or market concentration, a nonmarket procurement mechanism may be more appropriate. In either case, without appropriately defined services and compensation mechanisms, gaps are likely to appear in the market due to insufficient new investment. Such voids will not be filled without government or other external intervention.

In particular, DERs and demand-side management can likely provide ESSs on a cost-competitive basis with traditional and new grid-scale resources. DERs can be scaled in a more granular fashion than grid-scale resources once the appropriate rules and initial participation infrastructure are established. This may make them an effective option for augmenting the availability of ESSs on multiple time horizons. Thus, it is vital that, when revising market arrangements, DERs are designed to be part of the solution. If they are not explicitly designed for, there is a real risk that DERs will not be able to participate. The approach needs to balance the requirements of visibility for system operation, distribution-level operation requirements, and the implementation cost of any control and communications systems required to facilitate market access. Explicitly considering how DERs participate in ESSs will enable proponents to build a clear business case and "value stack" alongside other services to bring the required systems and solutions to market. Without such, mechanisms could drive separate capital investments to meet each of the power system requirements, increasing costs to consumers.

The Australian Approach and the Future of ESSs

Australia's electricity system is rapidly transitioning from a generation fleet dominated by coal and gas to accommodating the world's highest penetration of residential solar PVs (22% of all stand-alone houses), with the regular instantaneous provision of a 100% renewable supply likely within five years. This will occur on the east coast, with a grid covering more than three times the area of Texas and in southwestern Australia across an area the size of the United Kingdom. Catalyzed by the rapid pace of change and through a handful of significant system security events, Australian governments have instigated sweeping market reforms to support the transition to higher VRE penetration. A key focus is on ESSs, with the recognition of services once provided by synchronous generators as a byproduct of energy generation and not yet replaced by inverter-based technologies.

Although there are regulatory and physical differences between the west and east coast markets, the philosophical and economic principles established during the markets' conception have been maintained. Included are the importance of efficient price signals in operational time frames based on voluntary bids and offers, facilitating overall dispatching while maximizing market-based outcomes and minimizing interventions. Regarding the reform of specific system services, Figure 8 outlines a graphical road map indicating the pathways for reform in both markets. For the NEM, this involves the possible implementation of the following:

- ✔ a new operating reserve spot market likely based on a 5- or 30-min ramping availability product procuring either the total ramp or holding reserve out of the market through a separate call mechanism
- ✔ a new fast-frequency response market (sub-2s) to encourage and reward the provision of rapid frequency control from batteries and the refinement of the mandatory requirement for primary frequency control (recently enacted and already delivering market improvements to systemwide frequency performance)
- ✔ a new framework for system strength, where the system operator sets minimum/efficient levels (via a short circuit current ratio) at all nodes of the network, and the network service provider is obliged to maintain those levels. There will likely be a mechanism to schedule synchronous resources in operational time frames to provide inertia and system strength with support for the longer-term consideration of an inertia spot market.

For the WEM, the reform pathway includes the following:

- ✔ a new spot market for regulation frequency management and the transformation of the current contingency frequency control framework to spot markets similar to the NEM
- ✔ the implementation of a ROCOF control service spot market to pay for inertia in operational time frames—the first such market we are aware of anywhere in the world.

For all new services, there is an explicit awareness of the importance of setting technical requirements to support and encourage emerging technologies and, in particular, possible future DER capabilities and demand-side participation. Both the NEM and WEM reform programs are ongoing. Development to date has required robust collaboration across market operators, regulators, and government agencies and extensive engagement with market participants, including generators, retailers, DER aggregators, consumer representatives, and network operators.

The rapid pace of change has been catalyzed by legislated net-zero emission targets from states and territories toward 2050, although a national target has not yet been set. Australia is the world's largest exporter of coal and natural gas. Ensuring the impact of measures to address climate change generates significant political debate with extensive business lobbying. This may, in part, explain why Australia has struggled during the past two decades to navigate a middle path through the electricity transition with bipartisan support. But even with uncertain support at a federal level, and perhaps, in part, because of it, Australian households have embraced rooftop solar at world-leading levels, and industrial buildings are

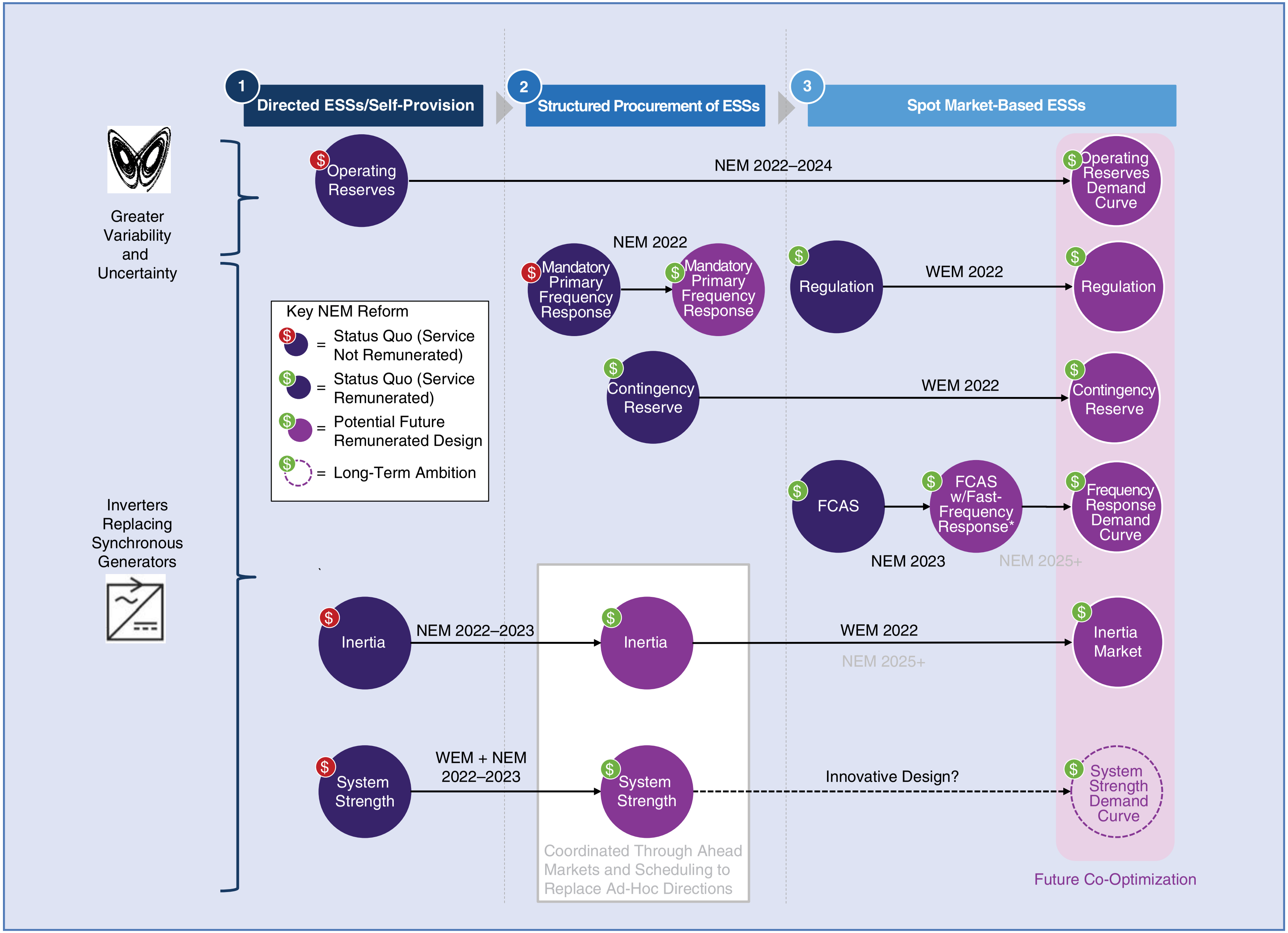

figure 8. A possible road map for ESSs in Australia (the NEM and WEM) to 2025 and beyond, indicating an evolution toward spot market-based mechanisms, where possible. (Source: adapted from FTI Consulting's 2020 Report to the ESB.)

now following. Spurred by broad political support at the state level for net-zero targets, state and territory governments are heavily investing in renewable generation through reverse auctions and power purchase agreements. They are making investments in transmission designs flagged by the system operator as essential to support emerging renewable energy zones. These zones are discussed in another article in this issue, "Planning at System Level, Renewable Energy Zones."

Reform programs are underway but with significant work still to be completed. For the NEM and the WEM, the detailed work of market design, technical qualification, compliance, and regulatory frameworks has yet to be finalized. Each will have a significant impact on market participant behavior and system outcomes, and there is a growing recognition of the value in allowing flexibility to those involved in the transition. Australia is likely to continue on its reform pathway for the coming decade, due to the rapid pace of change in both supply and demand.

The current reform of ESSs predominantly addresses challenges arising from the inverter-based replacement of synchronous generation, with early steps focusing on the emerging variability and uncertainty of supply. Future essential services will likely be needed to 1) mitigate minimum demand (already a pressing security concern for some regions, 2) provide individual components of system strength (where fungible), and 3) provide a broader provision of system restart services to support greater resilience and islandability in the event of bushfires and extreme weather events. All future reforms will need to interact fairly with DERs, recognizing that the advanced grid-forming technological capabilities of new battery technologies, such as the Hornsdale Power Reserve, will likely be eventually translated to the power electronics of smaller inverters at the household scale. To support customer participation and fairness, this may be facilitated through a broadly accepted "DER Bill of Rights" with principles that could include 1) the allowance of the near-unimpeded self-consumption of self-generated electricity (even if exports may be curtailed), 2) the fair imposition of technical requirements to support grid security, and 3) remuneration for energy and system services proportional to that received by large-scale resources.

As the electrification of transportation proceeds at pace alongside the increased sophistication of demand-side participation, there will likely be new system service needs and opportunities for provision from emerging resources, such as electric cars. This will need to be accompanied by a redefinition of roles for network service providers. As the energy transition gathers momentum through the millennium, Australia finds itself rapidly departing from the paradigm first enacted in 1899 of default system service provision from synchronous resources. It is moving toward new market frameworks that remunerate the provision of distinct services in real time from technology unimaginable 100 years ago. How Australia addresses this change has the potential to help inform the global energy transition in the coming century for the urgent decarbonization journeys all countries across the world are now navigating.

For Further Reading

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Power System Operation With a High Share of Inverter-Based Resources

The Australian Experience

By Babak Badrzadeh, Nilesh Modi, James Lindley, Ahvand Jalali, and Jingwei Lu

THE NATIONAL ELECTRICITY MARKET (NEM) of Australia, operated by the Australian Energy Market Operator (AEMO), comprises five regions on the eastern coast of Australia. Together, they exhibit unique characteristics compared to most other international power systems. This stems from world-class wind and solar resources and the absence of interconnection to neighboring countries.

The NEM power system has large geographical distances in the order of several hundred kilometers between load centers, areas of concentration of inverter-based resources (IBRs), and synchronous generation centers.

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World-leading levels of distributed energy resources have increased the complexity of operating this power system.

Operating the NEM power system has caused several unique operational challenges that require developing several first-of-their-kind solutions. Each NEM region has specific operational challenges, and a solution applied in one region may not necessarily work for another. This article discusses selected operational challenges experienced across the NEM and solutions implemented to manage power system security with increased penetration of IBRs.

In addition, this article discusses challenges related to the impact of the reduced commitment of synchronous generators and increased uptake of IBRs. These challenges could apply at any given time, including when the entire network is intact and all sources of generation are visible and controllable, or when part of the network is an island and a large share of generation from distributed IBRs is not visible and only partially controllable.

Increasing the commitment of synchronous generators above a certain level provides only a marginal benefit to the grid with a high share of IBRs, particularly in remote parts of the network, and there is a large electrical distance between IBRs and synchronous generators. Under these circumstances, localized solutions provide more benefits, and such solutions are discussed.

This article also outlines other factors that increase the complexity of power system operation. These include increasing uptake of distributed energy resources and, in particular, distributed photovoltaic (PV) systems and the NEM's recent experience of several contingency events involving the loss of multiple power system elements due to extreme weather-related events. This, combined with aging network and generation assets, has resulted in increased occurrences beyond the next credible contingency for which power systems are typically planned and operated.

Such events include multiple concurrent planned outages of network and generation assets, rapid forced withdrawal of several larger thermal units, and severe thunderstorms and tornados damaging several transmission towers. This article presents examples of complexities associated with multiple planned outages and sustained islanded operation of a normally interconnected system with a high share of IBRs.

Insufficient Synchronous Unit Commitment

Background

Historically, synchronous generators have been the primary source of electricity supply for meeting demand. They have also provided several inherent or controlled characteristics, such as system strength (as characterized by the ability to maintain stiff voltage magnitude and phase angle across the system), inertia, and frequency control.

Some characteristics have been defined as ancillary services under the umbrella of the ancillary services market, providing further revenue streams for the generator owner. However, such characteristics can only be provided when the generator is dispatched to supply the demand. The revenue from ancillary services is often not enough to bring a generator online that would otherwise opt out of bidding into the energy market due to the availability of cheaper sources of energy generation.

In the NEM, the dispatch of synchronous generators has been decreasing due to several factors, such as the growing share of transmission-connected IBRs (a cheaper source of energy), increased uptake of distributed PV systems reducing supply demand from transmission-connected generators, the retirement of synchronous generators, and reduced reliability of aging synchronous generator assets. This trend has been experienced in all five NEM regions but most notably in South Australia (SA). This is primarily due to the region's abundance of existing utility-scale IBRs and distributed energy resources, and its reliance in recent years on one type of fuel source (natural gas) for all synchronous generation.

In late 2016, SA was operated with one synchronous generator online because of natural market operation, which prompted actions and technical analysis to determine the absolute minimum requirements to be online. The studies determined the minimum number of synchronous generators, typically at least four, required to be online at any given time. Determining the number of synchronous generators required to maintain system security is a nontrivial task as it depends on many factors, including unit size, vicinity to other synchronous generators, and electrical distances between those generators and areas of IBR concentration. These synchronous generator combinations need to be predetermined based on detailed power system studies before they can be used operationally.

The remainder of this section outlines how AEMO first determined the minimum unit commitment for SA to maintain sufficient system strength and then applied the same methodology to other NEM regions, considering subtle differences between different regions and impact on unit commitment.

Determining Unit Commitment for SA

The SA power system has the highest penetration of IBRs, not just in Australia but varguably worldwide among systems of its size. The region covers an area 40% larger than Texas in the United States but with only 7% of that state's population. The power system's demand is highly variable, ranging between 300 and 3,300 MW, with a median demand of 1,400 MW. SA has one of the highest percentages of existing IBRs worldwide. It has 2,700 MW of grid-connected IBRs primarily located in a concentrated area referred to as North Area, as shown in Figure 1. Operationally, instantaneous IBR penetration has, at times, exceeded 150% of demand. SA also has another 1,400 MW of distributed PV systems, largely in the Adelaide metropolitan area where most of SA's demand and synchronous generators are located. As mentioned earlier, all of the region's existing large synchronous generators are gas fired with a relatively high fuel cost compared to IBRs.

Despite being interconnected with other NEM regions via a double-circuit ac line and a single-circuit dc link, SA's sheer size (approximately 1 million km^2 with a large part uninhabitable) makes for a relatively weak power system. Thus, a sizable portion of SA has no electrical infrastructure,

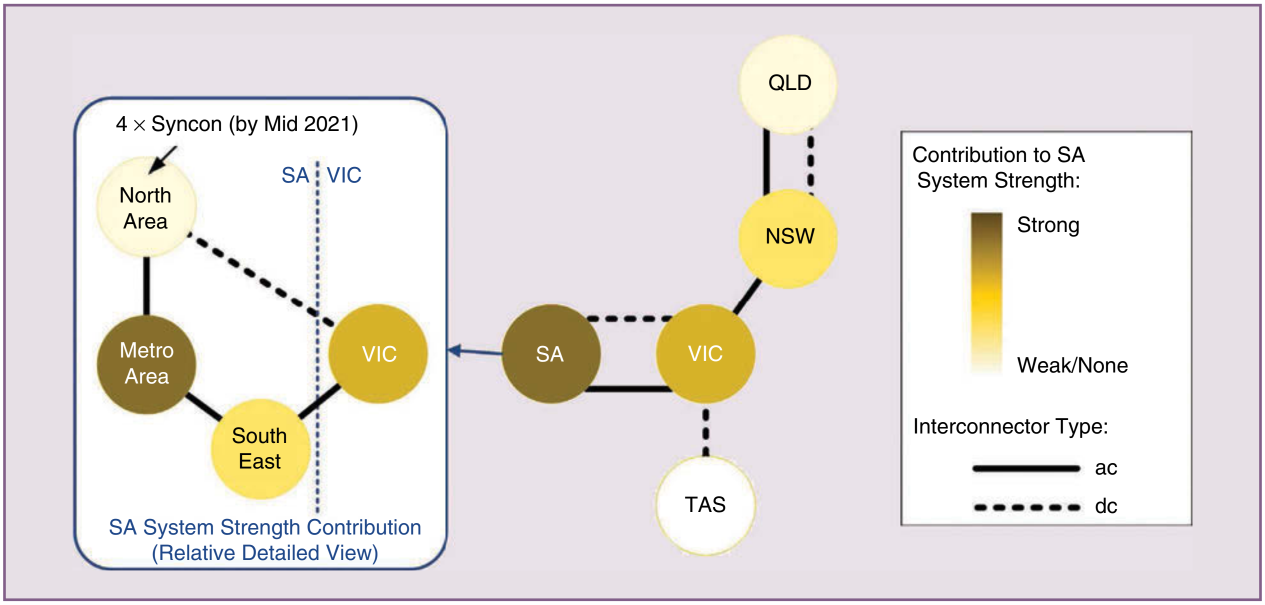

figure 1. The contribution of different NEM regions and subregions to SA system strength. QLD: Queensland; NSW: New South Wales; VIC: Victoria; TAS: Tasmania; SA: South Australia.

and the portions that do get limited system strength support from other regions, as Figure 1 highlights. The system's very large size, with several hundred kilometers between the IBR concentration areas and synchronous generators, creates a further challenge in the SA region.

To determine minimum unit commitment from a system security perspective, AEMO had to develop a wide-area electromagnetic transient (EMT) model of the SA region and surrounding areas and later apply the same approach for all other regions. Determining adequate system strength as a function of generation dispatch and operating conditions requires a thorough understanding of complex interactions between IBRs themselves and with the wider network, and these cannot be generally simulated with phasor-domain modeling.

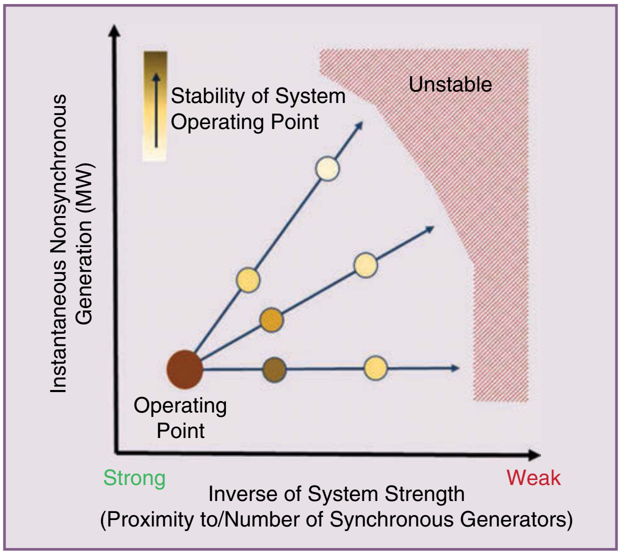

figure 2. Factors influencing system strength.

The combinations of synchronous generators for maintaining sufficient system strength correspond to a minimum baseline level of strength required for the system as a whole, regardless of dispatch pattern. The level of out-of-merit dispatch—referred to as "directions"—applied to meet this baseline level is not generally sufficient to ensure unrestricted operation of IBRs. Further directions to allow unrestricted IBR operation would lead to a significant residual cost, and in some instances, there may not be enough capable synchronous generators available. The total output of most IBRs collectively is, therefore, curtailed to a system-wide limit to ensure power system security is maintained for a given synchronous generating unit combination. This level is based on EMT studies and could differ depending on the exact combination of online synchronous generators.

Figure 2 summarizes key points from AEMO's several thousand simulation case studies to determine SA system strength requirements in operational timeframes. The color intensity illustrates the extent of system stability. Darker colors indicate a highly stable system, and paler colors show a system on the verge of instability. As Figure 2 indicates, the higher the penetration of IBRs, the lower the system strength will become unless it is compensated by additional synchronous generators. This implies that the higher the penetration of IBRs in the system, the greater the need for sources of system strength like synchronous machines. The figure also highlights that system strength can only be provided by synchronous machines that are sufficiently close.

Dealing With Synchronous Unit Scarcity in SA

Maintaining a sufficient number of synchronous generators at all times has been challenging in practice, especially during low-demand and low-price periods. Where the normal market predispatch mechanism has not forecast at least the required minimum synchronous unit commitment, AEMO has intervened in the market via directing synchronous generators online that would not otherwise be dispatched. As shown in Figure 3, AEMO has increasingly directed synchronous generators over the past three years, and up to more than 250 times in 2020, to maintain sufficient system strength in SA.

Intervention in the electricity market is not a cost-effective measure, and it is not in the long-term interest of consumers. To reduce and ideally eliminate the need for market interventions, AEMO required SA's transmission network service provider, ElectraNet, to consider other options.

The process to identify alternate solutions started when AEMO declared a fault-level shortfall (proxy for system strength) in SA in October 2017 as required by the recently introduced fault-level rules in the Australian NEM grid code (National Electricity Rules). ElectraNet, as the SA system strength service provider, was then required to develop cost-effective options and timeframes for meeting the declared shortfall. ElectraNet's economic analysis of viable options determined that the installation of synchronous condensers would be the most cost-effective solution. Installation was compared to AEMO's ongoing directions under the system security constraints and ElectraNet's contracting directly with synchronous generators capable of providing the required system strength.

Detailed power system studies confirmed that installing four large synchronous condensers on the transmission network would address the system strength shortfall declared by AEMO. These synchronous condensers are being installed progressively, and all will be operational by late 2021. Further studies will be required after the synchronous condensers are operational to determine whether the SA power system can be operated without any synchronous generators and, if not, the exact characteristic and services that must be provided by synchronous generators.

Synchronous Generators Unit Commitment for Other NEM Regions

Lessons learned from operating SA with a low number of synchronous generators prompted AEMO to determine predefined quantities and combinations for maintaining system strength in other NEM regions. In the Victoria region, unlike in SA, AEMO did not identify the need to constrain the aggregate IBR output at all times under system intact conditions, but it found critical prior outages could still result in severe constraints in IBR output. These predetermined combinations of synchronous generators are available to real time operational personnel to ensure at least one of the acceptable combinations of generator dispatch is available at any given time. Occasional periods where this could not be met have been experienced. However, the frequency and duration of directions have been far less than has been required in SA.

AEMO then determined all regional combinations based on detailed EMT studies as it did for SA. Any new combination of generation dispatch would need to undergo the same assessment before it can be used operationally. The only exception is the Tasmania region, the smallest in the NEM, and includes numerous hydro units of comparable sizes. Hundreds of valid synchronous generator combinations exist in Tasmania, so AEMO instead developed an automated fault-level calculation tool that is integrated into the suite of overall control room tools. This allows a real-time calculation of expected fault levels.

Results from these simple fault-level analyses have been benchmarked against a detailed EMT analysis, showing a good correlation. This approach will not work, however, in other NEM regions with larger (often much larger) area sizes, large distances between areas of concentration of IBRs and synchronous generators, and a variety of synchronous generator types, sizes, and owners. AEMO-fed lessons learned from these operational analyses into regulatory changes that went into effect in 2018. System strength and inertia requirements focus on a planning horizon of up to five years to assess and arrest any potential shortfall in the natural availability of sources of system strength and inertia support.

High Concentration of IBRs in Remote Areas

Background

Several areas in the NEM have seen an exponential uptake of IBRs over the past few years with the majority of IBRs being connected in remote and sparse areas. We earlier highlighted the need to maintain a sufficient number of online synchronous generators to maintain system strength. In remote areas with a high concentration of IBRs, however, the marginal impact of additional synchronous units is very limited. This results in limited system strength support from the wider power system, even when many synchronous generators are online, creating the potential for adverse IBR interactions and instabilities as IBR uptake increases.

One of the key manifestations of such instabilities in several NEM regions is the creation of sustained postdisturbance oscillations. These oscillations have a dominant frequency of 5–10 Hz and have historically occurred once in practice due to forced outage of a transmission line. Detailed simulation

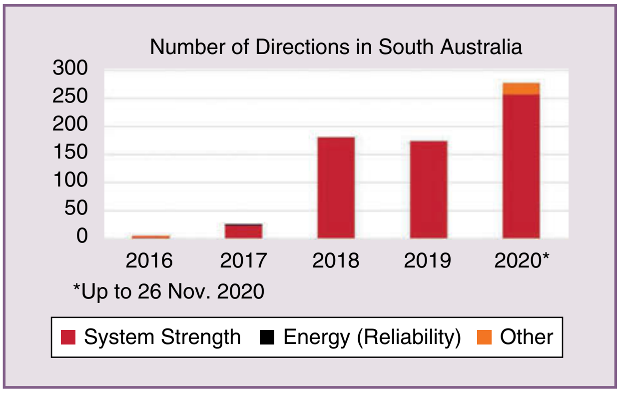

figure 3. The number of directions in SA.

studies carried out by AEMO have indicated the possibility of these oscillations in three of the five NEM regions.

One example is an area referred to as the West Murray Area, which encompasses the northwest of the Victoria region and the southwest of the New South Wales region, as shown in Figure 4. This area has many IBRs already connected, and many more are in the process of connection.

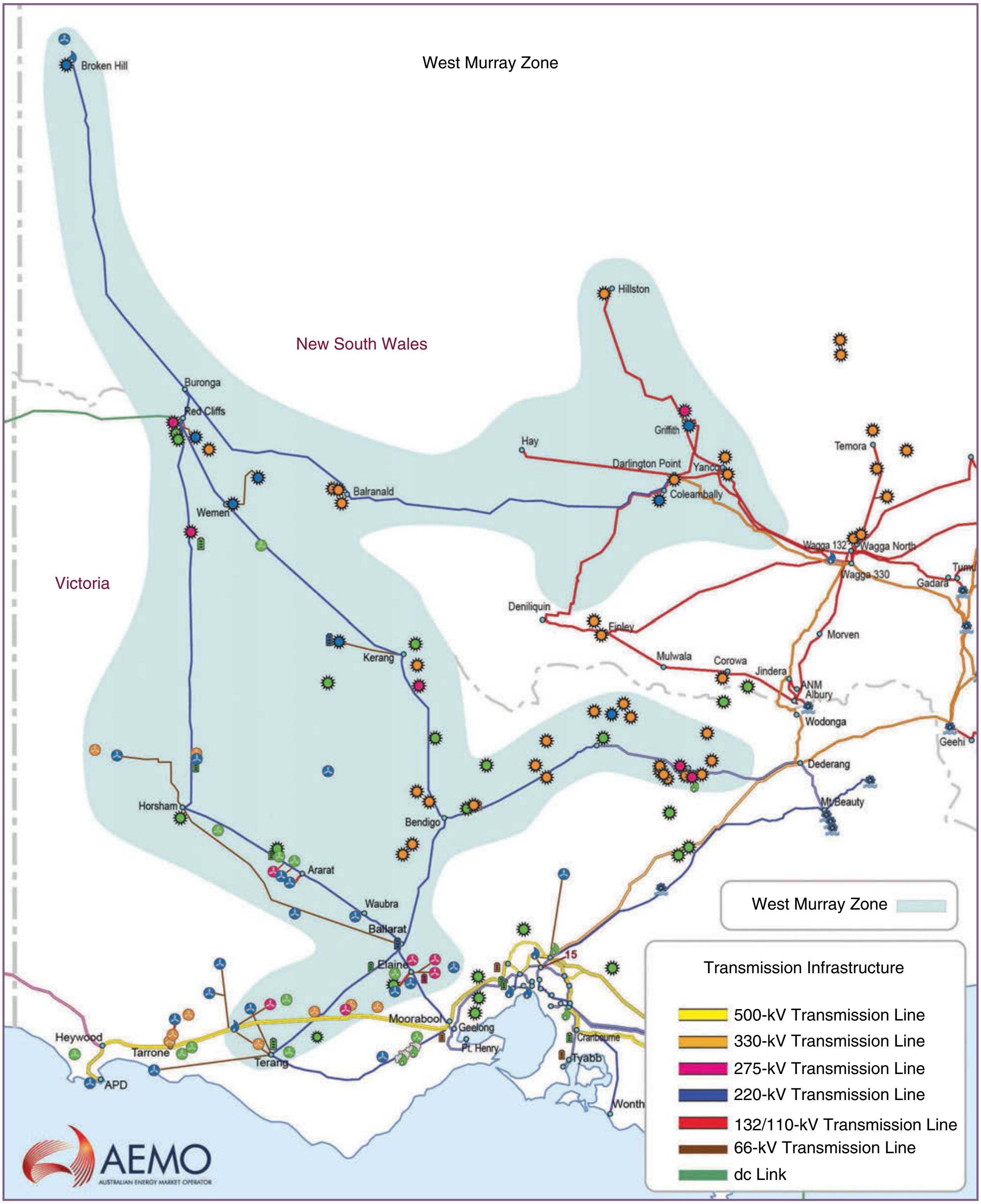

figure 4. The West Murray Area. (Source: AEMO; used with permssion.)

Practical Experience

Detailed simulation studies carried out for the zone indicated sustained postdisturbance oscillations following a loss of some critical transmission lines. Disconnecting these lines would further weaken the link between areas of concentration of synchronous generation in southeast Victoria and IBRs in the West Murray Area. Considering the high impact on overall power system security and commercial operation of impacted IBRs, AEMO decided it was crucial to categorically determine whether these oscillations are a true reflection of actual plant behavior or can be attributed to modeling artifacts.

AEMO conducted several staged system tests when actual system conditions were like the simulation condition that indicated sustained postdisturbance oscillations. Simulation studies confirmed that an unfaulted disconnection of some of the critical transmission lines would be adequate to cause those oscillations; hence, there was no need to apply an actual fault to the system during staged tests. Consistent with simulation studies, the actual staged tests indicated the presence of sustained low-frequency oscillations with a dominant frequency of 7 Hz, as shown in Figure 5, which depicts an example network voltage when switching out a transmission line. As the figure shows, the magnitude and frequency of oscillations are largely in alignment between simulation and field measurements.

Solutions Implemented

This section discusses key outcomes of detailed simulation studies conducted and different viable options implemented in practice for addressing the sustained low-frequency oscillations experienced.

Reduction in the Number of Online Inverters

AEMO found that a reduction in the total MW output of impacted IBRs would not have a significant impact on the magnitude of oscillations experienced. For example, constraining those IBRs to 0 MW while maintaining the same number of online inverters would only result in a marginal reduction in the level of oscillations.

Constraining the number of online inverters to 50% of the total installed inverters demonstrated a substantial reduction of oscillations. The result was that the system could be operated within its technical envelope in terms of stability and power quality criteria. Under this scenario, each IBR could be operated with up to 50% of its nominal power, subject to resource availability.

Installation of Synchronous Condensers

None of the IBRs with an adverse impact had their own synchronous condensers to enhance system strength for their stable operation. Furthermore, no electrically close synchronous generator was available in the area. However, a few other more recently connected IBRs were available in the West Murray Area with dedicated synchronous condensers. Studies confirmed that the synchronous condensers, in addition to facilitating the stable operation of associated IBRs, can help suppress low-frequency oscillations for those IBRs determined as key contributors to unacceptable voltage oscillations.

Figure 6 shows the impact of one and two synchronous condensers associated with IBRs without an adverse impact, highlighting that the addition of two synchronous condensers practically eliminates unacceptable oscillations on key contributing IBRs.

Inverter Control System Tuning

AEMO's analysis determined that the original tuning of an inverter control system for the key contributing IBRs was another key cause of low-frequency oscillations. The original tuning was developed without recognizing nearby IBRs and potential adverse interactions.

AEMO recently developed wide-area EMT models of all NEM regions and an integrated model combining all four mainland regions (excluding Tasmania). These models are extensively used for various purposes, including generator connection studies, long-term planning, operational decision

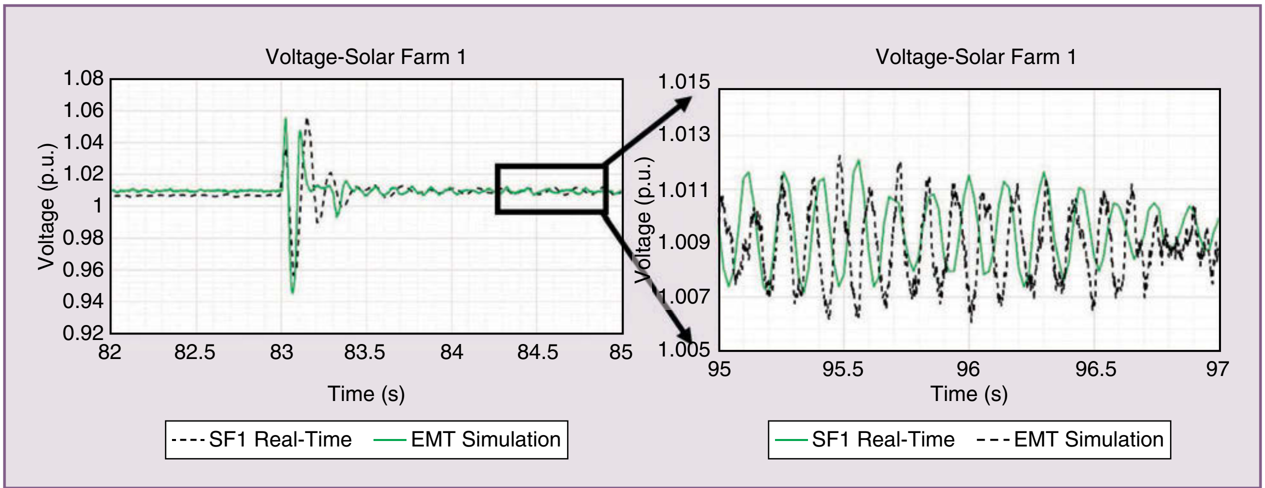

figure 5. A comparison of measured system responses against EMT simulation results for staged disconnection of a critical transmission line.

making, and event analysis. As provided for in the National Electricity Rules, these models can be provided to relevant network owners in each region. However, the legal framework does not facilitate the release of these models to generator owners and respective original equipment manufacturers, contributing to the challenge of accurately accounting for the response of other nearby IBRs when designing and tuning each IBR for the first time. Note that these complex interactions between multiple IBRs cannot be identified by conventional and more widely releasable phasor-domain power system models or by generic models that do not account for the exact response of the IBR type under low system strength conditions.

Recognizing that original equipment manufacturers have the best in-depth knowledge of control system parameters and their interrelationship, AEMO adopted a collaborative approach, working closely with IBR owners and equipment manufacturers to ensure that while the revised tuning mitigates adverse interactions between multiple IBRs, it will not compromise other aspects of each IBR's performance due to the sheer number of changes involved. Changes applied included modifications of inverter control system parameters, such as phase lock loop freeze and unfreeze state thresholds; the introduction of a counter oscillatory and fast active and reactive current compensator; and change in proportional gains of low voltage ride-through control loops, control limits, and rate limiters.

AEMO then evaluated the performance of the tuned IBRs (i.e., the dominant sources of oscillatory response in the original test) through several staged system tests, involving a trip and auto-reclosure of a critical transmission line with unconstrained (i.e., 100% inverters online) operation of affected IBRs. Figure 7 shows the impact of IBR tuning as demonstrated in reality and compares it against results obtained from wide-area EMT simulations, illustrating consistent results between the measurements and simulation.

Increasing Complexity of Outage Management

Planned outages of network elements, such as transmission lines, occur from time to time for reasons including line maintenance, replacement of insulators on some of the transmission towers, and reinforcement of tower footings. Other key elements, such as dynamic reactive support plant, can also undergo outages, for example, during control or firmware upgrades.

The increased uptake of IBRs in the NEM, often connected to less interconnected and meshed parts of the network, has made outage assessment significantly more complex, requiring more detailed assessment. In several circumstances, a line outage would cause a substantial reduction in the level of system strength available to the IBR to the extent that a stable postdisturbance response from IBRs can no longer be achieved.

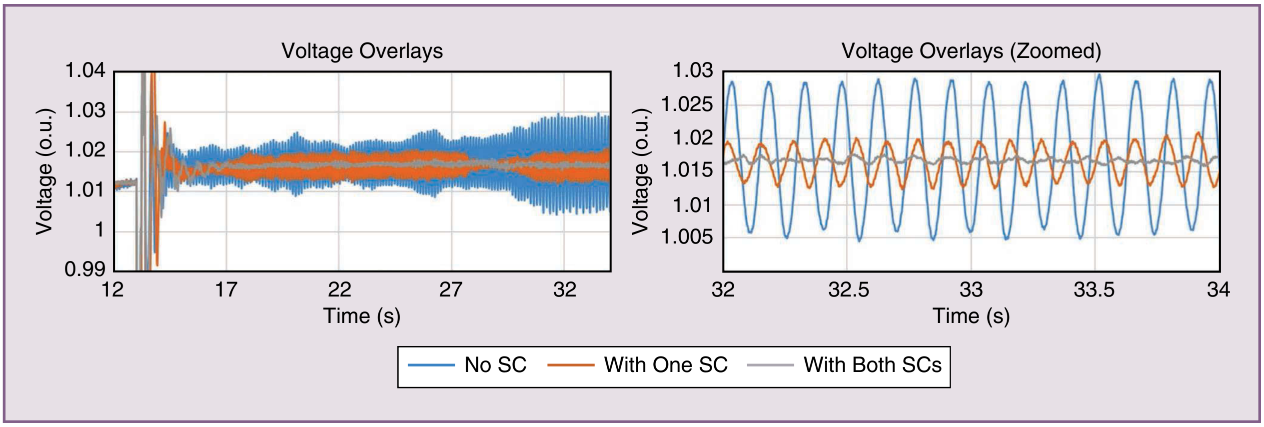

figure 6. The contribution of synchronous condensers on mitigating sustained postdisturbance oscillations.

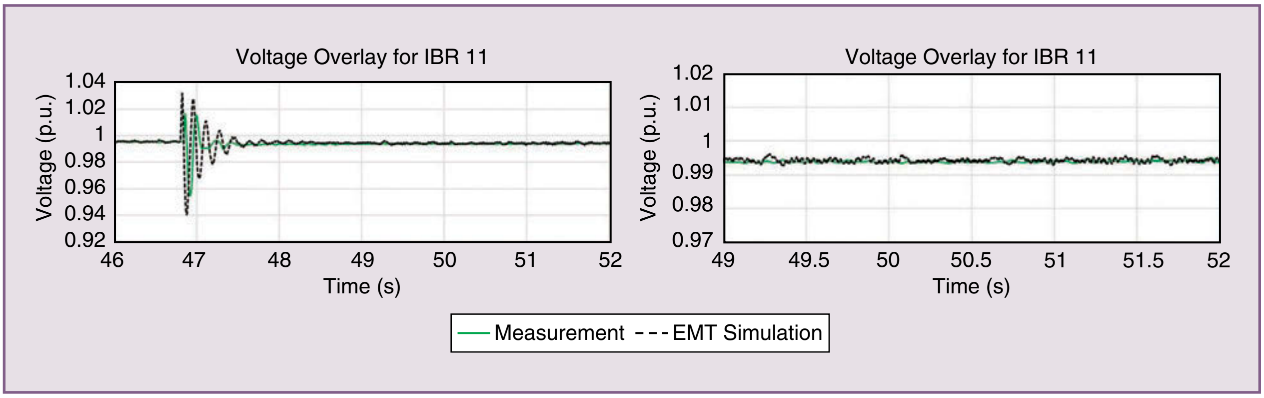

figure 7. Overlays of measured and simulated responses following IBR tuning.

For a few outages in various parts of the NEM, a combination of reduction in the IBR output and the number of online inverters has been applied. The level of constraint required is often more restrictive than typical constraints experienced in the system without outages. Outages of critical transmission lines could require a complete disconnection of some IBRs for the duration of the outage, typically ranging from a few hours to a few days.

There have also been examples where outages of critical dynamic reactive power support sources, such as static compensators, would require a constraint to the output power or the number of operating IBRs. The NEM has also seen increasing instances of multiple concurrent outages, most commonly involving concurrent outages of network and generation in the same part of the network. More complex recent outages have involved multiple network and generation owners. In one of the most complex experiences to date, an outage necessitated combinations of synchronous generators in two NEM regions concurrently to ensure a stable postcontingency overall system performance.

Increased Uptake of Distributed PVs

Distributed resources currently represent 20% of the NEM's installed generation capacity with most of this capacity being distributed PVs. The SA region has recently experienced times when 100% of demand was supplied by solar power, of which 80% came from distributed PVs. Distributed PV systems have been installed in the NEM for over a decade with very different standards and requirements, particularly from the standpoint of fault ride-through capability. A sizable proportion of distributed PVs have no ride-through standards at all, yet systems connected more recently have varied levels of fault ride-through capabilities. Inadvertent disconnection of distributed PVs during network fault events has been experienced several times in the course of power system operations.

This behavior has meant that in some NEM regions, particularly in SA, the size of the largest credible contingency for which the power system is planned and operated is determined by distributed PV responses during a fault rather than the loss of the largest synchronous generator. The largest credible contingency is often a loss of a large metropolitan synchronous generator resulting in the sympathetic disconnection of distributed PVs, also concentrated in metropolitan areas. In Australia's NEM, this is considered as a single credible contingency.

Another consequence of increased uptake of distributed PVs is a reduction in the system's total operational demand to be met by transmission-connected generators. Key concerns with low operational demand include the potential for high steady-state network voltages and ensuring that all minimum must-run synchronous generators are supplied with their minimum stabilizing load. Many of these units are large thermal plants with relatively high minimum loading requirements for their stable operation compared to other generation technologies.

Both of these challenges—the inadvertent disconnection of distributed PVs during faults and a reduction in the minimum load available for stable operation of synchronous generators collectively—will be exacerbated when a normally interconnected system operates as an island. Interconnections to other regions would not be available as an extra load for a stable operation of synchronous generators or capable of providing a range of desired system security attributes. Of these, the absence of frequency control support from other NEM regions would have the highest impact during islanding conditions.

Determining Secure Operating Envelope of a Normally Interconnected System When Operating as an Island

Background

On 31 January 2020, a multiple contingency event resulted in the formation of an electrical island comprising the whole SA power system and a small part of the network in the adjacent Victoria region. Islanding conditions lasted for 18 days.

AEMO had to develop novel solutions for the secure operation of this islanded system, which had a high share of IBRs. An islanded power system must source all essential system services such as frequency control, voltage control, inertia, and system strength from within the island without any support from the neighboring system(s). When the availability of these services is limited, it is important to effectively utilize them for the overall power system security of the islanded network.

System emergency frequency control schemes, such as the underfrequency load shedding scheme and overfrequency generation-shedding (OFGS) scheme, are the last line of defense against large frequency excursions and play a vital role in maintaining system security. The effective operation of underfrequency load shedding and OFGS requires a certain available amount of load and generation respectively to control large frequency excursions. It is also important to maintain sufficient inertia to reduce the rate of frequency changes following a disturbance and to allow the effective operation of these emergency frequency control schemes.

While this section focuses on one actual islanding experience, many of the lessons learned and actions taken would apply to any normally interconnected power system if it operated as an island with a high share of IBRs.

Minimum Unit Commitment Under Islanding Conditions

As discussed earlier in this article, minimum synchronous unit commitment is maintained in all five NEM regions. Under system intact conditions, the key factor determining the required number of synchronous generators is the need to maintain sufficient system strength. Operating a system as an island results in reduced available system strength, and it also means frequency-related characteristics, including frequency control and inertia, must be sourced from within the island. These factors collectively increase the minimum required number of synchronous generators under islanding conditions compared to those required for system intact conditions.

Relationship Between Physical Inertia and Fast Frequency Response

In a power system, inertia and frequency control are closely related. The amount of physical inertia is the key determining factor in arresting frequency rise or fall. However, this is not sufficient by itself to ensure frequency recovery within the necessary frequency range. The provision of local frequency control is another critical factor in maintaining system security under islanding conditions. The two attributes may be provided by the same device (e.g., synchronous generators). However, this is not essential as inertia-less IBRs can provide a faster frequency response than that of the turbine-governor of a synchronous generator. For example, a battery energy storage system has a typical frequency response on the order of a few hundred milliseconds as opposed to several seconds for a synchronous generator.

While a minimum level of physical inertia is always needed to arrest the frequency, this is not sufficient to maintain all aspects of system security. The additional inertia required can be sourced from synchronous generators or by fast frequency response (FFR) from the IBR. For example, if several synchronous generators are running, they could be utilized as the primary source of frequency control. However, operating under low-demand conditions with a lower number of synchronous generators would mean these generators likely need to be directed to come online. Maximizing the use of FFR would reduce the need for these synchronous generators and associated directions.

Figure 8 shows an example of the relationship between physical inertia and FFR for the SA power system under a specific operating condition. The relationship shown in Figure 8 changes based on the size of the contingency. The potential for inadvertent disconnection of distributed PVs would mean the occurrence of a larger credible contingency during daylight hours, indicating the need for a higher level of physical inertia and FFR during the daytime.

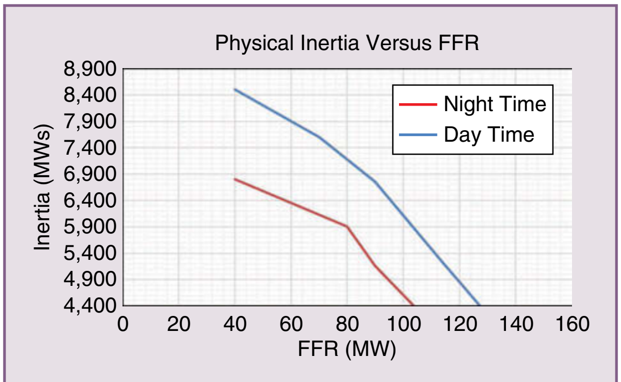

figure 8. The relationship between physical inertia and FFR.

Management of the Size of the Contingency

The largest size of a contingency an islanded power system can withstand without breaching its frequency operating standards depends on the frequency control capability of local generators. AEMO's power system studies for SA islanding conditions indicated the total frequency control capability provided by synchronous generators and IBRs would not always be sufficient to deal with the largest credible contingency if no preemptive measures were taken.

The maximum size of a contingency can often be controlled by the central dispatch process, where a constraint can be applied to the output of IBRs and synchronous generators to manage their credible disconnection. However, this is not true when a sympathetic trip of distributed PVs is involved because distributed generation is not controllable via the dispatch process.

To reduce the size of distributed PV disconnection and the contingency size, emergency manual intervention in the form of preemptive disconnection of distributed PVs would be required. This would also increase the available load required for the stable operation of large synchronous generators, allowing them to operate sufficiently far above their minimum stable load points to facilitate the provision of bidirectional frequency control. Such an emergency intervention would be achieved through coordination between transmission and distribution network service providers and AEMO as the power system operator.

Commitment Order for Grid-Connected IBRs

During low-demand periods, where there is more generation than demand, judicious decisions need to be made on the commitment order of controllable generators. Some IBRs in SA are enabled with the OFGS. AEMO needs to ensure sufficient OFGS capacity was available at all times to accommodate the loss of the largest loads and the dc interconnector in SA, so AEMO

- ✔ gives priority to all IBRs enabled with OFGS during low-demand periods where not IBRs can remain online
- ✔ applies further delineation in very-low-demand periods to give dispatch priority to those OFGS-enabled IBRs with a relatively lower frequency activation threshold.

These actions were implemented during the actual islanding event and would be implemented should a future islanding event occur.

We earlier discussed the relationship between physical inertia and FFR. Currently, a large amount of FFR is available from a transmission-connected battery energy storage system in SA. Operating a battery energy storage system close to zero generation would maximize FFR capability for any given contingency and either load or generation disconnection events. This would help operate an islanded SA power system with much lower physical inertia than would otherwise be required if no FFR was available, which results in a reduced need for synchronous unit directions.

During low-demand conditions when there is a need to reduce the amount of grid-connected generation, such a measure provides a twofold benefit. It allows a smaller number of synchronous units online while also maximizing the overall frequency control capability of a region.

The Need for Enhanced Modeling and System Testing

Secure power system operation requires the use of fit-for-purpose, accurate, and validated power system simulation models. The use of wide-area EMT modeling has become a necessity. Conventional power system models cannot accurately represent complex interactions and overall system response under scenarios with a high share of IBRs. All of the studies discussed in this article and the operational measures taken are based on the wide-area EMT models that AEMO has developed. While AEMO does not currently integrate EMT analysis into control room tools for real-time assessments, it does use these models extensively to determine the secure operating envelope of the power system with a high share of IBRs and power system limits under various system conditions.

Considering the novelty of some of the experienced phenomena and increased complexities in actual power systems and simulation models, it is important to validate these models to ensure they represent the actual behavior of the system and its elements. Field measurements recorded during system disturbances provide a good opportunity to validate the overall system model against network faults that may not otherwise be practicable.

Over the last few years, AEMO and relevant asset owners have carried out field tests in an area with a high share of IBRs. The aim is to observe the collective response of several IBRs and their interactions with the wider network and measure key quantities that can be later used for validating models. Examples of such tests were shown in Figures 5 and 7.

Summary

Operating a power system with a high share of IBRs has presented AEMO with several new and complex system security challenges. This has necessitated developing many novel solutions backed by detailed and fit-for-purpose power system modeling and simulation studies.

SA, one of five NEM regions, has the highest share of IBRs at both the transmission and distribution levels. For this reason, many actions currently implemented in the NEM were first operationalized in SA and then implemented in other regions (recognizing that other NEM regions experience unique phenomena). Actions discussed in this article are

- ✔ establishing minimum must-run synchronous units at all times during both system intact and islanded conditions
- ✔ installing strategically located synchronous condensers to reduce the need for the directed dispatch of synchronous generators, which otherwise naturally tend to be offline during high IBR periods, hence, reducing the cost of market interventions
- ✔ determining and managing the size of sympathetic disconnection of uncontrolled distributed PVs to avoid creating a larger contingency than would otherwise need to be accounted for
- ✔ identifying the value of FFR provided by IBRs, and its complementary value concerning physical inertia provided by synchronous generators, to securely operate a normally interconnected power system with high IBRs share as an island.

The article also presents an example of adverse control system interactions between multiple electrically close IBRs, all in remote parts of the network and far from large synchronous generators. Such phenomena have been experienced frequently in remote parts of the network with high IBR shares. Methods implemented in the short and long term to address the resulting low-frequency oscillations include a reduction in the number of online inverters, use of nearby synchronous condensers, and control system tuning for the impacted IBRs to operate stably under lower system strength conditions that would not be possible with the original control system.

For Further Reading

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Renewable Energy Zones in Australia

THE ENERGY LANDSCAPE IN AUSTRALIA IS UNDERgoing a rapid and disruptive change. An aging fleet of coal-fired power stations, coupled with the declining costs of renewable energy and storage, has culminated in strong investor interest in renewable resources. The establishment of renewable energy zones (REZs) and their robust integration into the existing transmission network have the potential to align this investor interest with government policy and consumer values. In this article, we show how REZs can be optimally established in Australia to maximize value across the energy supply chain.

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The Energy Transition

Historically, transmission and distribution systems in Australia were designed around a one-way flow of electricity from areas abundant with natural resources, such as coal or hydro, to the load areas. Typically, distances between generation production and ultimate consumption could exceed 300–500 km because of the low population density and the remoteness of fossil fuel deposits to major cities.

To facilitate the transmission of power from generation locations to load centers, a series of long and, at times, radially interconnected transmission and distribution lines is located along strategic easements to connect these long-utilized fuel sources. An assortment of public and private sector funding sources over numerous

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Integrated System Planning

By Eli Pack, Bianca Christison, Dane Winch, and Lars Narushevich

decades has made significant investments in transmission assets that primarily connect power stations near thermal coal and gas reserves to the major capital cities.

Transmission assets can have technical lives of more than 50 years with capital costs exceeding many hundreds of millions, if not billions, of dollars. It is imperative to continue to maximize the use of existing transmission assets while complementing them with network upgrades or expansions as generation sources evolve.

Although the overall grid consumption is being held somewhat constant by growth in distributed energy resources, new generation capacity is needed to replace retiring plants. To fill that gap, the Australian Energy Market Operator (AEMO) forecasts that Australia should invest in a further 26–50 GW of new, large-scale variable renewable energy (VRE) resources in the National Electricity Market (NEM) by 2040. This is comparable to the current total existing installed capacity of large-scale generation in the NEM today. The pace at which these coal-fired and gas-powered generators retire is expected to accelerate over the next 20 years. However, recent historical observations of retirements suggest that the rate of change could reasonably be higher (see Figure 1).

One of the key challenges in managing a smooth transition from incumbent to new entrant generation is the need to develop the generation production, storage, and transmission assets in a least-cost manner to consumers. With limited examples of large-scale transmission developments in Australia over the last decade, a robust regulatory framework is required to extract value from both existing and new transmission augmentations to facilitate this generational transition.

In October 2016, the Council of Australian Governments energy ministers agreed to an independent review of the NEM to evaluate security and reliability and provide advice to governments on a coordinated national reform blueprint. The review recommended an integrated grid plan that would inform investment decisions and ensure that security is preserved in the NEM as the generation mix evolves.

AEMO was ultimately entrusted to produce this grid plan, known as the Integrated System Plan (ISP), by developing a co-optimized blueprint for the NEM under a range of scenarios. The ISP was described as a plan to facilitate the efficient development and connection of REZs across the NEM.

REZs

The concept of a REZ has gained international traction over the past decade, and several projects have already been implemented, such as the competitive REZs formed in Texas between 2005 and 2014. At AEMO, we set out to learn from these experiences when creating a plan for the Australian grid. The starting point was to agree on a definition for a REZ. While several were already in use, they were often too specific for our purposes. We decided on a definition that would be flexible and future proof. A REZ is defined as "an area where clusters of large-scale renewable energy can be developed using economies of scale."

With a definition in mind, a selection of candidate REZs was needed. That is, where might these REZs be located? As outlined in the 2020 ISP, AEMO engaged the consultant DNV GL to provide information on the resource quality for potential REZs. A wind resource quality assessment was provided based on mesoscale wind-flow modeling at a height of 150 m above ground level (a typical wind turbine hub height). Global horizontal irradiance and direct normal irradiance data from Australia's Bureau of Meteorology were used to assess the solar resource quality.

The results of the initial resource quality investigations are shown in Figure 2. This analysis generally shows that solar resources are greatest toward northern and central Australia, and wind resources are highly locational. Based purely on this information, it would seem logical to locate a REZ in northern Queensland—at the top of the map—where solar and wind resources are both rich. However, as we quickly discovered, a successful REZ depends on many more variables than just resource quality.

With a wealth of resource quality information, AEMO hosted industry workshops to gather information about what could make a REZ successful. Through these workshops, 10 scoring criteria were identified to inform the candidate REZ selection. These criteria are specified (from AEMO's website) as

- ✔ *wind resource*: a measure of high wind speeds (above 6 m/s)
- ✔ *solar resource*: a measure of high solar irradiation (above 1,600 kW/m^2)
- ✔ *demand matching*: the degree to which the local resources correlate with demand
- ✔ *electrical network*: the distance to the nearest transmission line
- ✔ *cadastral parcel density*: an estimate of the average property size
- ✔ *land cover*: a measure of the vegetation, water bodies, and urbanization of areas
- ✔ *roads*: the distance to the nearest road
- ✔ *terrain complexity*: a measure of terrain slope
- ✔ *population density*: the population within the area
- ✔ *protected areas*: exclusion areas where development is restricted.

The results of this criteria-weighted resource scoring are shown in Figure 3. With wind and solar resource weightings reduced to just 35% and 30% of the total score for each map, the resulting graphic highlights new areas that could be ideal REZs. The results of this analysis and the weightings assigned to each criterion were benchmarked against active feasibility studies to ensure that a successful REZ would generally align with investor interests.

When conducting this analysis, we were limited to the data available for macroscale modeling. Notably, some important data remain unquantified, including social license, environmental impacts, native title, and alignment with government initiatives for regional growth. While it is paramount for these considerations to be assessed before committing to individual projects, it simply wasn't feasible at this early stage in the process. An individual candidate REZ might span tens or even hundreds of thousands of square kilometers, and there are limitless ways of realizing the infrastructure needed to unlock its potential.

Based on the 10 scoring criteria, 35 candidate REZs were defined geographically, as shown in Figure 4. The generation and storage icons in this figure broadly indicate the forms of developer interest that might be expected if a REZ were implemented. These initial candidate REZs were subject to revision and will continue to be evolved. They have already been adjusted several times based on consultation

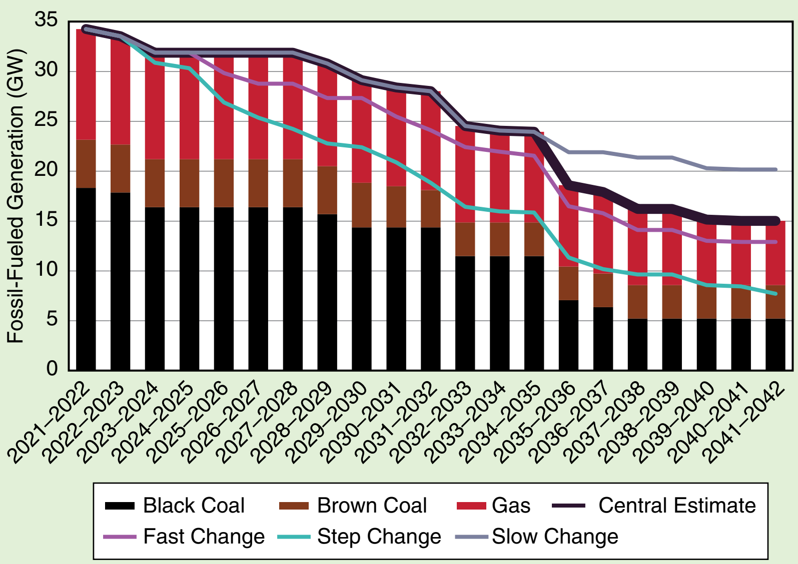

figure 1. The reduction in fossil-fueled generation capacity. (Source: AEMO; used with permission.)

feedback. In some instances, REZs have been added, removed, or combined, based primarily on feedback from generator developers, transmission companies, and governments.

Although this article focuses on solar and wind resources, other sources of energy and energy storage were also considered, including battery storage, hydroelectric power, pumped hydro, geothermal, gas-powered generation, and coal-fired generation. In particular, AEMO's modeling found that a combination of energy storage technologies and durations will help provide the necessary firming services to ensure that reliability standards are met.

For integrated system planning, which is essentially an optimization of investments, each REZ is reduced to a series of characteristics that enable a macroscale system-wide optimization. While there are many characteristics for each REZ, they can be broadly grouped into the following areas:

- ✔ resource quality and diversity
- ✔ availability of pumped hydro or other long-duration energy storage
- ✔ existing capacity of network to host VRE
- ✔ cost to increase VRE hosting capacity (often including distinct options that simultaneously increase network transfer capacity and hosting capacity)
- ✔ network losses (due to electrical distance to load centers)
- ✔ locational cost penalty factors (due to road access, remoteness from ports, and so on).

AEMO publishes scorecards in the ISP to summarize the positive and negative characteristics of each candidate REZ.

An Integrated Approach to System Modeling

AEMO's planning approach seeks to deliver the optimal mix of generation and transmission developments to meet security and reliability standards with the least cost to consumers. We begin with the development of a series of credible global economic and technological development scenarios that are designed to cover a wide range of potential and credible

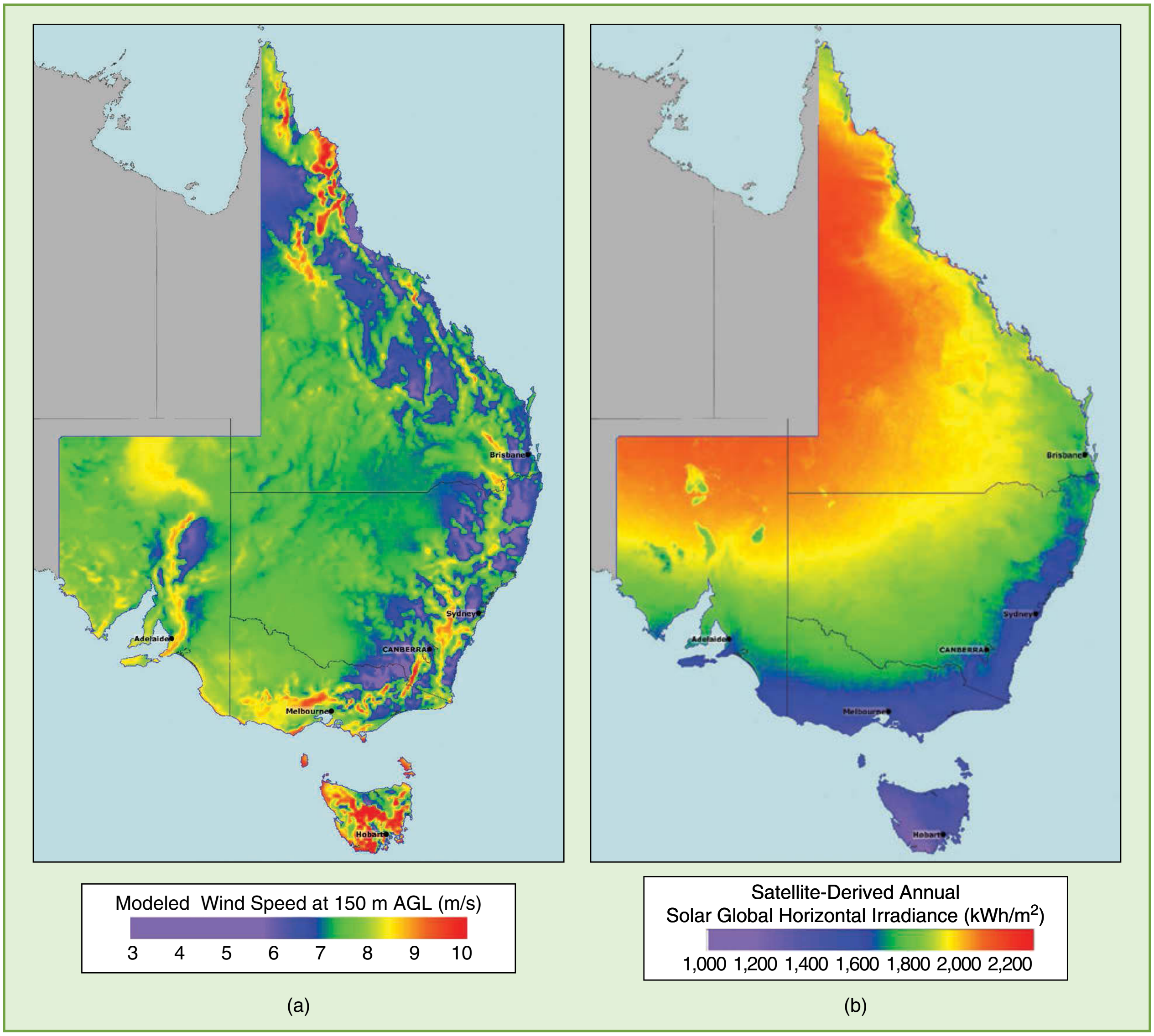

figure 2. Using (a) wind and (b) solar resource quality to inform potential REZ locations. (Source: DNV GL; used with permission.)

futures. Typically, we ensure that these scenarios vary across several key parameters, including demand, technology, policy, and environmental conditions.

For the 2020 ISP, we associated each scenario with a particular representative concentration pathway (RCP). These RCPs describe potential trajectories for greenhouse gases and their impact on temperature rise by the year 2100. The average temperature rise ranged from 1.4 °C (RCP 1.9) to > 4.5 °C (RCP 8.6). These trajectories are then aligned to Australian policy settings and used as an input that limits annual carbon emissions. More emission reduction is naturally associated with mild temperature rise scenarios.

In effect, these scenarios describe the potential environments in which Australia's energy networks may operate in the long term. Consequently, they determine the inputs to the modeling framework, which includes four main components:

- ✔ capacity outlook model
- ✔ time-sequential modeling
- ✔ gas supply model
- ✔ engineering assessment.

These four components are interlinked, so we take a multistage process with several feedback loops, as shown in Figure 5. We perform multiple iterations of modeling to converge on a reasonable view as to how the gas and electricity systems may develop under each scenario.

The Capacity Outlook Model

The first stage of the model is to determine the capacity outlook for both the gas and electricity infrastructures. The capacity outlook allows us to estimate the major investment decisions for both electricity generation and transmission and gas supply and transmission that result in the most cost-efficient

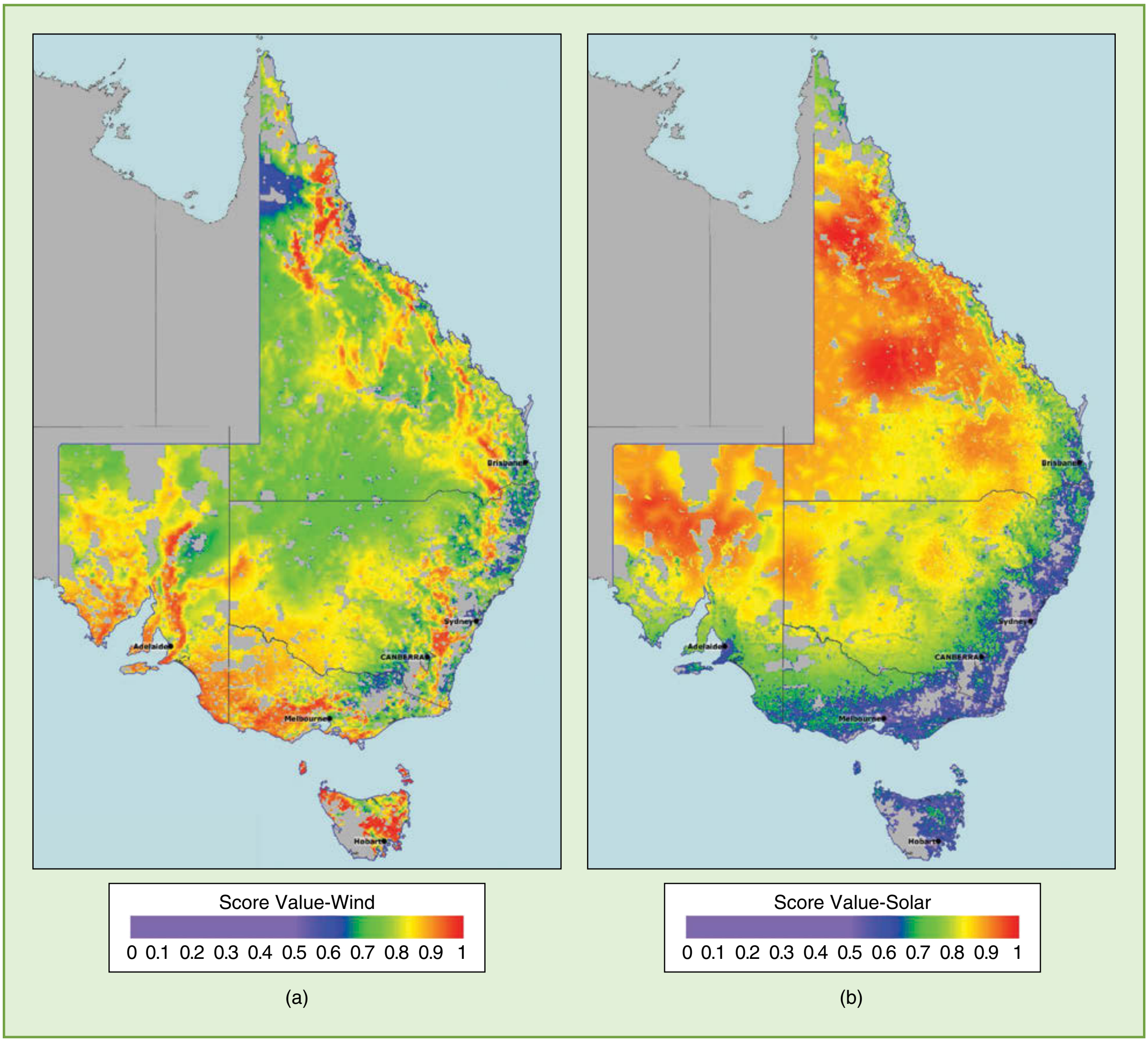

figure 3. The results from using 10 development criteria to inform potential REZ locations to connect (a) wind and (b) solar plants. (Source: DNV GL; used with permission.)

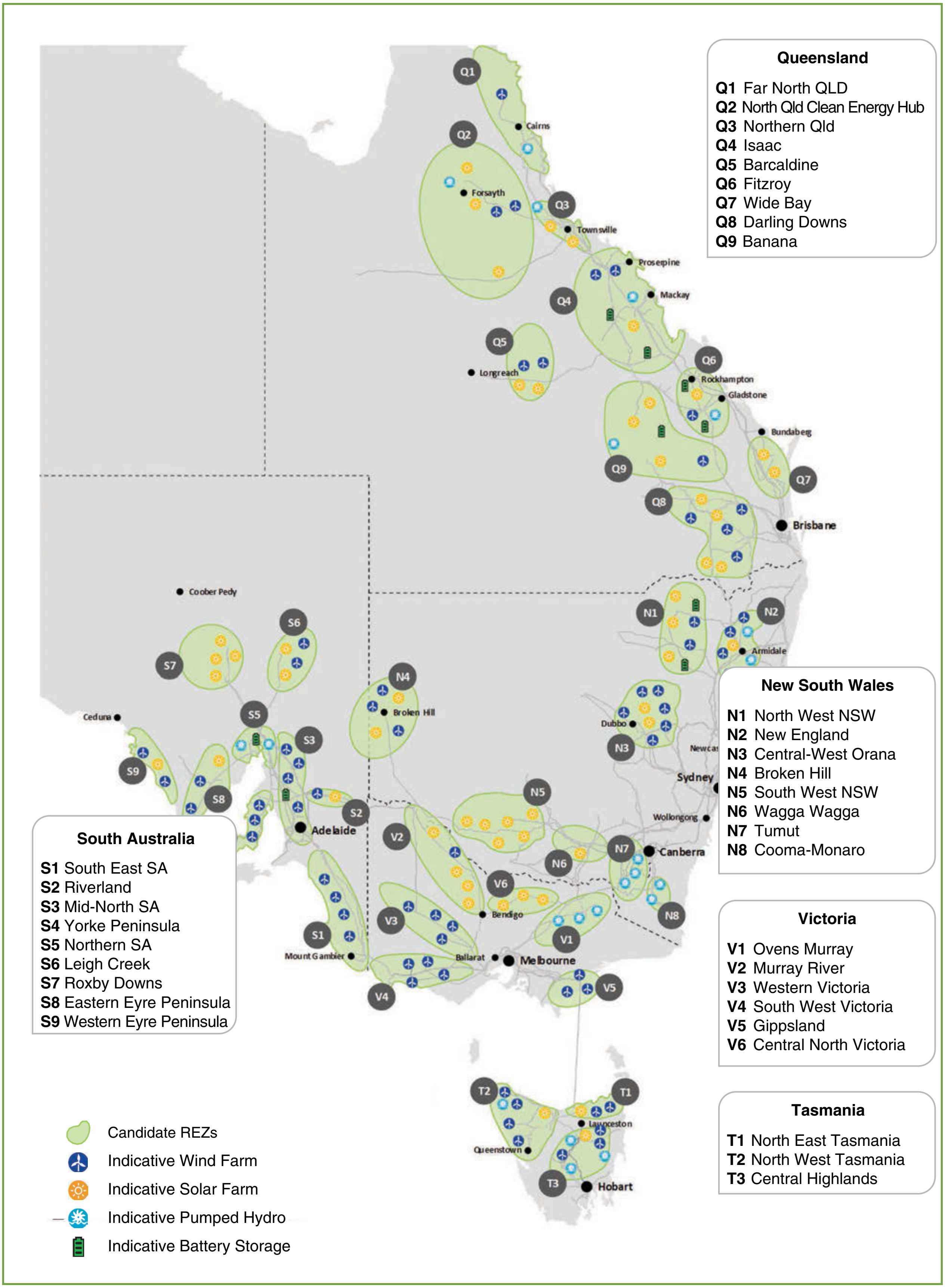

figure 4. The candidate REZs. (Source: AEMO; used with permission.)

power system that meets reliability standards. The capacity outlook is essentially solving an objective function, with the objective being to reliably (defined by Australia's reliability standards) meet the electricity demand for the NEM for the next 25 years while minimizing cost, subject to several constraints, such as the physical limitations of the existing generation and transmission plant and carbon budgets.

A suite of models is then used to explore the optimization problem through varying periods. This approach either focuses on the entire outlook period or an enhanced representation of the system at an intertemporal level. By taking this approach, we can explore a range of operational characteristics for each of the generation, storage, and demand response solutions for the respective scenarios.

In practice, a capacity outlook model is a two-stage approach. The first stage considers electricity and gas interdependencies with a long-time horizon but has a coarse representation of time. The second stage is a more granular model that provides chronological and detailed representations of the long-term electricity system by solving in multiple steps. Because this stage performs a more complex optimization over a shorter horizon, it relies on the foresight provided by the first-stage model.

To successfully run these models, we need to provide a capacity outlook model of several fixed parameters, such as electricity demand, new generator costs, or policy requirements. We also need to supply several "candidate options" for new generation and large transmission interconnection, which can be selected by the capacity outlook to meet the objective while addressing constraints.

Specifically, the capacity outlook contains parameters for all 35 REZs, as described previously, which ensures that the capacity outlook model is rich in detail when making decisions on REZ transmission and generation development. This ascertains that diversity among REZs is considered, which can reduce the need for higher cost generation, such as open-cycle gas turbines, to provide firming.

We generally found that new large interconnector candidates that increase the transfer capacity among the major load centers often have synergies with REZ network developments. That is, a new interconnector between the major cities often traverses or passes near multiple candidate REZs. We, therefore, include the additional network capacity provided to a REZ by interconnector expansion options in the capacity outlook model.

Finally, the outputs of the capacity outlook model are a set of generator, storage, and network investment decisions. Those decisions reflect the interdependencies between the gas and electricity systems to determine optimal thermal generation investments; retirements; and transmission expansion, gas field, and pipeline investment plans over the longest time horizon (25 years or beyond).

To complete the capacity outlook, the allocation of generation investments to specific locations in the network (typically a specific network connection point in the REZ) needs to occur (usually based on spare network capacity). We must do this because the capacity outlook model presents a simplified picture of the network topology, whereas the next stage of the model uses a far more detailed representation of that topology.

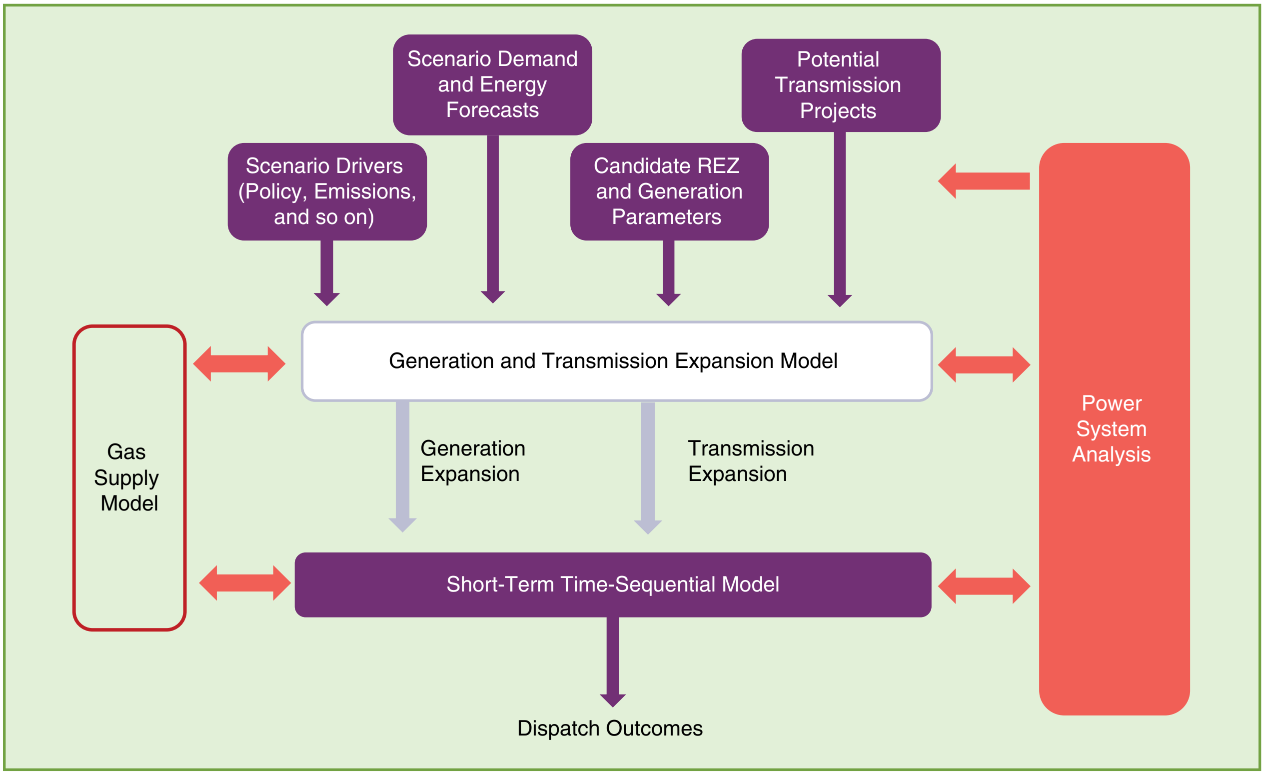

figure 5. An overview of AEMO's modeling framework. (Source: AEMO; used with permission.)

To meet reliability standards, any future with high wind and solar generation will require dispatchable resources to firm the renewable energy production. Energy storage located within a REZ can smooth the profile of electricity exported, which allows for optimal sizing of the network. When allocating generation, extra consideration is given to where the large-scale storage (both pumped hydro and battery energy storage) is placed, so that it can reduce or avoid network investment in a REZ as well as firm the VRE. Now that the major investment decisions have been made, the next stage of the modeling aims to optimize the dispatch outcomes for this given set of generation, storage, and network investments.

The Time-Sequential Model

The generation and transmission decisions made by the capacity outlook model are used as the basis for the time-sequential model. In essence, this model simulates dispatch outcomes for the given system and mimics the dispatch process used in real-time operations.

As the investment decisions are essentially locked in (for our modeling), the time-sequential model allows us to go into much greater detail in terms of portraying the physical complexities of the power system. The model introduces a detailed network topology and representation of the power system limit and a Monte Carlo simulation of generation outages as well as the supply bidding models and generation unit commitment.

The dispatch outcomes and resulting network-flow information from the time-sequential model allow us to explore a range of important considerations. As outlined on AEMO's website, these considerations include

- ✔ possible breaches of the reliability standard
- ✔ feasibility of the generation and transmission outlook when operating conditions and network limitations are modeled
- ✔ number of synchronous generators online
- ✔ generation mix and fuel offtake
- ✔ utilization of the network upgrades, including interconnection and REZ expansion
- ✔ impact of interregional demand diversity
- ✔ diversity between intermittent supply and demand
- ✔ the impact of unplanned generation outages.

AEMO uses these insights to modify inputs to the capacity outlook model, such as candidate transmission options, and validate its outcomes. With the outcomes from this capacity expansion model, we can investigate the impact of electricity sector investment decisions on the gas infrastructure.

The Gas Supply Model

The gas supply model is used primarily to assess gas reserves, production, and transmission capacity adequacy by complementing the capacity outlook models. This model forms part of the co-optimization of both electricity and gas sectors under the respective scenarios. The model performs gas network production and pipeline optimization at daily time intervals. With this capability, a range of technology solutions can be identified to reduce total system costs for both electricity and gas infrastructures.

With the dispatch outcomes from the time-sequential model and a capacity outlook validated in both electricity and gas systems, we can now conduct a more detailed engineering design and power system simulation in the engineering assessment stage. We do this by linking the dispatch outcomes for each interval in the time-sequential model to a load-flow model.

The Engineering Assessment

AEMO conducts an engineering assessment to investigate possible technical and operational challenges that may occur given the power system and dispatch outcomes from the capacity outlook and time-sequential models. These investigations include network capacity, system strength, and power system inertia. Initially, we perform network capacity studies to ensure that the design is robust to thermal, voltage, transient, and oscillatory stability limits across the network. We then explore system strength, particularly within REZs, which determines how well the power system maintains its voltage waveform. System strength is usually weaker where there are high penetrations of inverter-based resources that are electrically distant from synchronous machines. Finally, we investigate power system inertia requirements, which require an appropriate level of synchronous inertia or its equivalent in fast frequency response. Inertia is crucial for ensuring frequency stability and is particularly relevant as synchronous machines are replaced with VRE sources.

We develop solutions to these challenges to ensure a credible and robust power system and, where required, refine the inputs to previous models. The range of solutions investigated includes conventional network augmentations, the placement of synchronous machines (e.g., pumped hydro generators) and synchronous condensers, and modern inverter-based technologies. In practice, the engineering assessments are primarily performed using dynamic and steady-state studies.

The ultimate result of AEMO's four stages of modeling yields a comprehensive projection of future gas and electricity systems for a given scenario. This projection includes the technology, amount, and locations of new generation, generally in REZs, and the additional transmission infrastructure required to facilitate this new generation to supply the electricity load across the grid. It also includes the capability to investigate specific power system operation trends on a half-hourly basis.

Delivering Economic Efficiency with REZs

As outlined in AEMO's 2020 ISP, this modeling forecasts that more than 26 GW of new grid-scale VRE, supported by storage, gas-powered generation, and demand-side participation and transmission investments, will be required to replace power station retirements expected in the late 2020s and mid-2030s. To enable the expected rise in renewable energy, the ISP identifies strategic investments in transmission infrastructure, REZs, and low-cost firming resources.

In the current decade, renewable generation is forecast to be driven by government policies and high-quality wind and solar resources. In the next decade, a very strong investment in renewable energy is forecast to replace the energy from retiring coal-fired generation.

As long as network upgrades are delivered efficiently (e.g., through competitive tendering), strategically placed interconnectors and REZs, coupled with energy storage, will be the most cost-effective way to add firm capacity and balance variable resources across the whole NEM. Our modeling has shown that interconnector upgrades are required to strengthen the network and share resources among states. Strategically placing REZs on those interconnector corridors can enable single projects to increase overall system benefits by using the new network capacity provided by the upgrade for interconnection and VRE hosting. This is often the most cost-effective way of establishing a REZ, and it results in better use of assets and resource sharing across regions.

Providing the Technical Requirements of the Power System

As the power system continues to transition from large thermal power stations to inverter-based resources, the essential services required to satisfy system security requirements must be maintained. While the technology exists today to achieve this, continued innovation in this space will help to affordably transform a system that has previously relied on thermal synchronous generators to provide these services.

Because of the significant size of these new generation projects, network expansion and system strength remediation will be required. The concept of establishing REZs to coordinate this generation investment brings an opportunity to deliver robust essential system services. The system services already provided by new generators entering the system should be used to their full potential. The power system will, however, need to be augmented to ensure that there is sufficient system strength, inertia, frequency control, reactive power, and voltage control available across the network for its secure operation.

AEMO's system strength analysis for the ISP shows that a lower cost network design (before considering system strength needs) could lead to higher system strength requirements and overall costs. Compared to a project-by-project approach, a coordinated approach to network and system services for REZs can provide efficiencies of scale and lower costs for the required network and system security services. Also, further improving inverter control systems can significantly reduce system strength remediation costs.

If well located, REZs could materially reduce total system and transition costs. As outlined on AEMO's website, they can

- ✔ reduce the long-term transmission footprint in new areas by optimizing early investments
- ✔ reduce project connection costs and risks
- ✔ optimize the mix of generation, storage, and transmission investments
- ✔ colocate and optimize investments in network and system support infrastructure
- ✔ colocate and optimize weather observation stations to improve real-time forecasting
- ✔ realize benefits of capital scale in all those investments
- ✔ promote regional expertise and employment at scale.

AEMO's ISP modeling indicates that the ideal near-term REZ locations would take advantage of both attractive renewable resources and existing spare transmission capacity. They would be subject to land availability, regional policies, and consultation with local communities and indigenous groups. In those areas where the network is already relatively strong, development will be robust to issues such as network losses and system strength. VRE generation in these REZs will be cheaper than building the network infrastructure needed to unlock new REZs.

As the existing network reaches capacity, large-scale transmission infrastructure extensions into new regions with good diverse resource capacity will be required to connect the REZs. AEMO's ISP considers how to best develop future REZs in a way that optimizes transmission developments with generation and storage. Any new transmission network built to connect REZs should be cost-effective while providing reliability and security. A successful design will minimize the environmental impact, adhere to relevant design standards and regulatory requirements, and offer flexibility and expandability to address the future needs of the power system.

Without adequate investment in the transmission infrastructure, new VRE projects will be inefficient and struggle to connect. This could, in turn, lead to the private sector underinvesting in the new generation capacity needed ahead of the planned or unplanned retirement of existing generators.

REZ development identified in the ISP can be categorized into three key phases that reflect the timing and drivers. These phases are outlined in Figure 6. Even though REZ projects are geographically distant, they are highly interrelated. These projects must be centrally coordinated as a series of augmentations over time.

A Robust REZ Design Is Paramount

REZ designs must adhere to specific design standards and characteristics. Consideration of the technical requirements of the power system will ensure that the system operator has the required levers to operate the network securely and reliably. These requirements include system operability, thermal capacity, voltage and frequency management, resource adequacy, and system restart capability.

Staging and Interconnection

AEMO's ISP suggests that, where possible, the REZ design should leverage and contribute to the efficient and optimized design of the shared transmission network. REZs should be staged to increase the transmission capacity at appropriate levels to co-optimize investment in transmission and generation. For example, staging can be achieved by building a double-circuit tower but stringing a single circuit initially or through the early acquisition of strategic easements for later stages. The design can be enhanced by understanding long-term strategic transmission development in the area so that staging of the REZ development and costs can be optimized. Where REZs can form part of interconnectors, the design should take this into account to enable efficient interconnector development.

Number of Connections to the Main Grid and Route Diversity

When a REZ reaches a certain critical capacity, it should connect to the main transmission network with at least two connection points. This looping allows for additional network reliability and route diversity, which increases system resilience, for example, to climate impact and bushfire risks. In recent years, the Australian grid has been impacted by bushfires, resulting in multiple lines out of service and reduced transfer capacity to major load centers. Climate studies have demonstrated that extreme weather occurrences will increase over time. When developing REZs, risks such as these must be considered in the design.

The Network Design

AEMO's ISP highlighted that well-designed REZs should consider the structure of the network needed to avoid the application of constraints on generation to manage large contingency events. For example, if single-easement radial connections were applied to a large REZ, this would imply a large single critical contingency size (possibly in excess of the current largest single contingency size).

The contingency size is critical to the security of the power system and the management of frequency within operating standards. A looped or meshed integration of a REZ, if designed well, could reduce the potential contingency size and reduce or avoid potential operational limits that may otherwise need to be applied to generation in the REZ.

Sharing Connection Assets

AEMO's ISP demonstrated that coordinating generator connections at hubs, rather than connecting on a stand-alone basis along transmission lines, may provide a more reliable and cost-effective network connection. The hub connection reduces capital expenditures by minimizing the duplication of connection infrastructure. Adequate switching arrangements to allow for outage flexibility will also minimize the impact on the transmission network.

Adequate Network Capacity and Voltages

The long-term ultimate arrangement for transmission development in the area can inform appropriate sizing and voltage levels at relevant substations. In this way, costs can be optimized through gains in economies of scale when executing major construction projects. Most of the substation engineering, procurement, and construction work can happen at one time. This limits the exponential costs of retrofitting expansions that would otherwise be required in the future.

Through the ISP, AEMO identifies and refines REZ candidates and prioritizes REZ developments with staging. This approach results in a functional network design that integrates REZs with the shared network.

First Steps Toward Implementation

AEMO's ISP identifies strategic investments in transmission infrastructure and REZs, which, when coupled with low-cost firming resources, will be the most cost-effective way to add generation capacity and balance renewable resources. Since the inaugural ISP in 2018, several individual REZ projects have progressed through regulatory approval or been funded by state governments. The New South Wales, Victoria, and Queensland state governments have all committed to developing REZs that are components of AEMO's ISP.

Australia's first expansion of the shared transmission network to unlock a REZ is expected to be the Western Victoria Transmission Network Project. Originating in the 2018 ISP, this 190-km project was rigorously assessed and will deliver value to consumers by accessing high-quality wind resources. Wind plants developed in this area are expected to provide downward pressure on electricity costs by displacing brown coal generation. In early 2021, this project was undergoing environmental effects studies, planning approvals, and easement acquisition.

Taking a different regulatory approach, the Central West-Orana REZ Transmission Link project was recommended in the 2020 ISP. This project gained strong support from the New South Wales state government and local developers. State

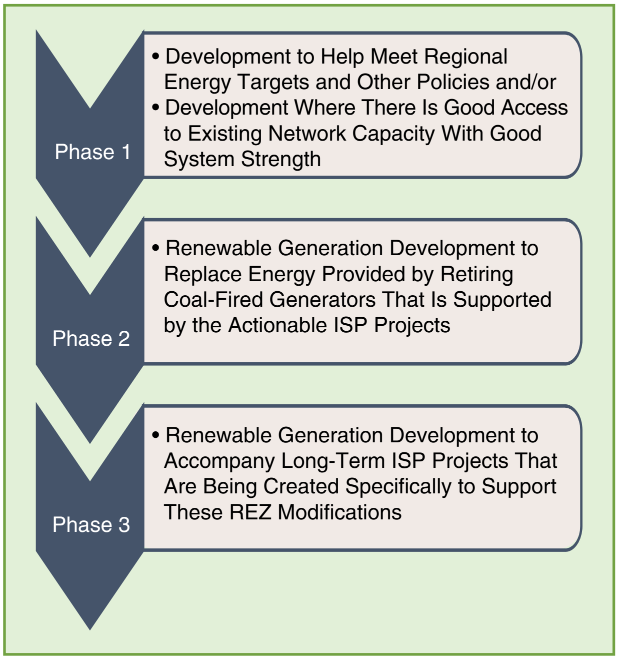

figure 6. The REZ development phases. (Source: AEMO; used with permission.)

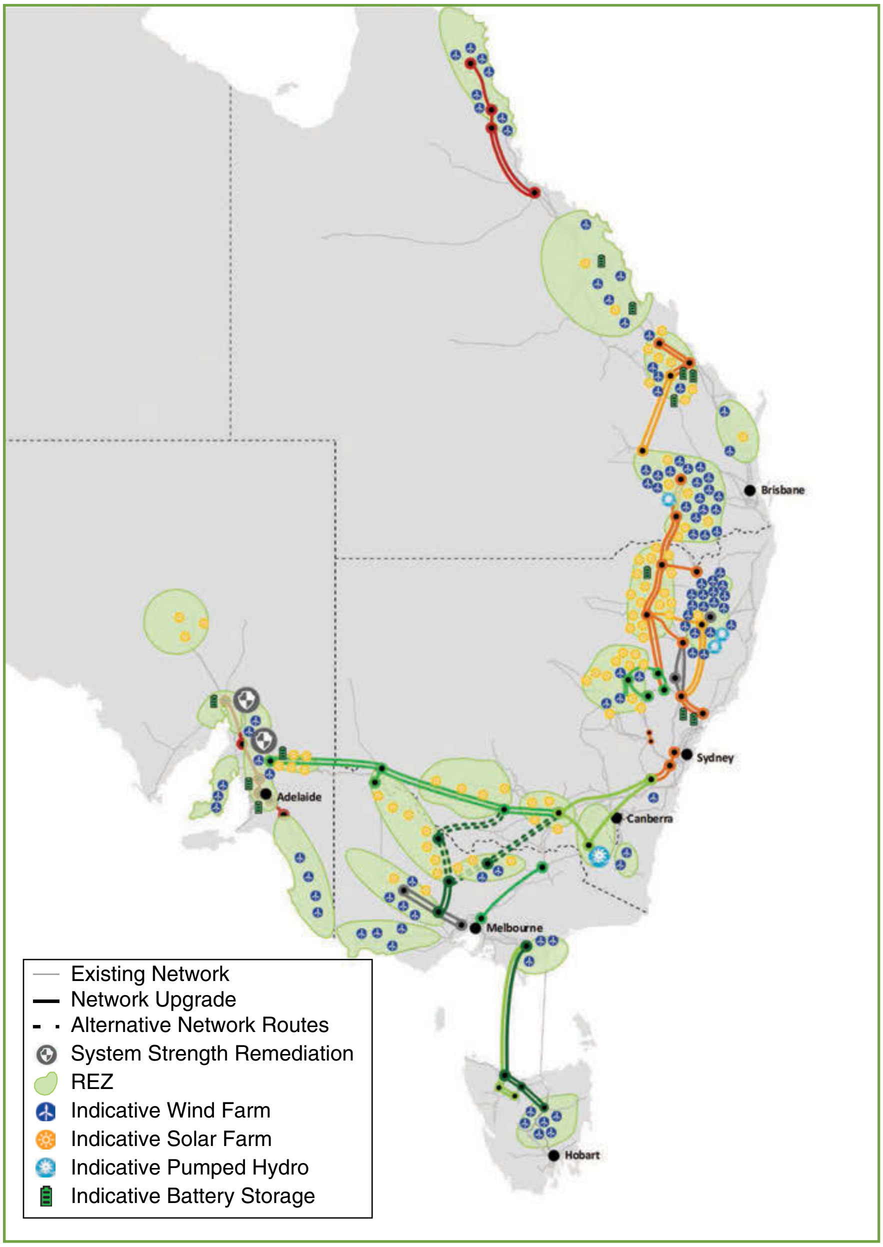

figure 7. An ISP that connects REZs. (Source: AEMO; used with permission.)

legislation was enacted to create a streamlined regulatory approach approving a transmission infrastructure that supports REZs in the state. This project is progressing quickly and is expected to unlock 3,000 MW of wind and solar capacity.

Figure 7 illustrates the key network and generation projects projected for the next 20 years. This road map will continue to advance with the evolution of the Australian energy system.

Summary

AEMO's ISP is a dynamic, whole of system plan that identifies the optimal road map for unlocking and interconnecting REZs across Australia. To implement it, multiple and well-coordinated efforts will be necessary to progress distributed energy resources, VRE, firming capability, transmission development, system security, gas development, and market reform. They will need to start now, given the long lead times for major projects, the scale of reform required, and the imminent end-of-life retirement of significant volumes of coal-fired generation.

For Further Reading

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From Security to Resilience

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Technical and Regulatory Options to Manage Extreme Events in Low-Carbon Grids

EXTREME EVENTS ARE INCREASINGLY AFFECTING power systems worldwide, calling for new and effective ways to deal with these so-called high-impact, low-probability (HILP) events. The situation is exacerbated by a transition to low-carbon grids. These systems are dominated by inverter-based resources, including different types of variable renewable energy (VRE) sources and distributed energy resources (DERs), and are characterized by higher operational uncertainty and a risk profile that is correspondingly difficult to assess.

By Julian Eggleston, Christiaan Zuur, and Pierluigi Mancarella

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New methodologies and tools are needed to improve power system resilience to extreme, HILP-type events, but their practical implementation is still in its infancy.

This has become evident in the power system of the National Electricity Market (NEM), a long, interconnected grid serving southeast Australia. The NEM grid is leading the world in the installed capacity of VRE sources and DER integration. In recent years, it has also experienced several extreme events, such as the severe storm system that led to the South Australia "black system" event of September 2016, where a major part of the NEM power system was disconnected for several hours.

New methodologies and tools are needed to improve power system resilience to extreme, HILP-type events, but their practical implementation is still in its infancy. This includes developing suitable regulatory frameworks to support adequate planning, operational mechanisms, and solutions. It also requires effectively assessing the full costs associated with both the consequence of these events and the mechanisms needed to manage them.

In this article, we present pioneering work developed in the context of the 2019 report, "Review of the South Australian Black System Event," that took place on 28 September 2016. The work was undertaken by the Australian Energy Market Commission (AEMC) and supported by the Melbourne Energy Institute at the University of Melbourne. This report covered technical and regulatory aspects aimed at evolving existing grid planning and operational frameworks to help address emerging challenges of integrating more inverter-based resources while facing severe weather events driven by climate change.

We specifically discuss how low-carbon grids evolving power system risks, uncertainties, and resilience profiles are increasingly threatened by so-called indistinct events. These are distributed and inherently uncertain events that act across multiple generation and network assets in an affected area over time. From a regulatory perspective, we discuss some of the issues that decision makers, including policy makers, regulators, and system operators, may face when making decisions to enhance resilience under conditions of uncertainty. We explore potential regulatory framework approaches to improve resilience at the lowest cost for consumers. Finally, we put forward some recommendations for how system operators might procure solutions to take advantage of new technologies to enhance power system resilience in low-carbon grids. We include practical examples from what has been proposed in Australia.

Security and Resilience of Low-Carbon Grids

Low-carbon grids based on VRE, DERs, and inverter-based resources face pressing operational challenges in terms of maintaining system security. In Australia, the South Australia "black system" event in 2016 prompted important questions and calls for urgent measures to improve the NEM power system's security as advocated by the 2017 Finkel Review of the NEM, led by the Chief Scientist of Australia Alan Finkel.

Besides enhancing the security of the power system, a crucial focus is on improving the power system's resilience to extreme events. While security is the operational component of reliability historically associated with the system's ability to respond to credible contingencies, resilience explores how power systems deal with rarer, more severe noncredible contingencies (e.g., simultaneous loss of multiple system components) associated with HILP events. For example, the IEEE Power & Energy Society Task Force on Definition and Quantification of Resilience 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."

For grids dominated by inverter-based resources, VRE technologies, and DERs, the increasing fragility of the system makes cascading outages more likely. In a low-carbon grid, security and resilience become more intertwined. Interesting examples refer to the assessment of frequency response and operating reserves to deal with "indistinct" events, which are intrinsically highly uncertain.

The more uncertain and variable operating profiles of low-carbon grids prompt our need to consciously and actively think about resilience. Many power systems have historically operated with classical N–1 or N–2 security criteria that ensure the system can keep supplying customers safely even after the loss of one or two major components. On the other hand, extreme events where multiple assets can fail due to cascading may be classified as N–X, with X much greater than two. It is not possible to economically run a power system to realize secure operation against such N–X contingencies and thus also provide resilience. New operational and planning approaches are therefore needed, as discussed later in this article for the Australian case.

The Power System Security Arrangements for Managing Risk to Its Operation

Power system security is concerned with managing the risk that a contingency event could pose to satisfactorily operating the grid with frequency, voltage, current, and plant operation within appropriate standards or ratings. Consequences include the risk of a cascading outage of power system

Interesting examples refer to the assessment of frequency response and operating reserves to deal with "indistinct" events, which are intrinsically highly uncertain.

elements, which can lead to a major supply disruption or even a black system event.

Contingency events that can potentially put the system at risk can be classified into the following elements:

- ✔ *credible contingencies*: events that the system operator [the Australian Energy Market Operator (AEMO) in Australia] considers are reasonably possible, such as the loss of a single network element or generating unit
- ✔ *non-credible contingencies*: events that are not considered as reasonably possible given prevailing conditions, such as the simultaneous failure of multiple generating units or transmission lines.

These contingency events have traditionally been defined as "distinct" or definable events on the power system. In the NEM, national electricity rules explicitly define these events by reference to specific, distinct events, such as the loss of a generating unit or a transmission line.

Arrangements for managing grid security are summarized in Figure 1.

AEMO is required to operate the power system in a secure state in the absence of a contingency event. This means that a credible contingency does not result in the loss of load and the grid remains in a satisfactory state. This is represented by the left-hand side of Figure 1.

To maintain the power system in a secure state, the system operator defines a "technical envelope" where the power system can operate. The envelope represents the operating limits for each power system element so that a satisfactory state, without load shedding, is achieved after a credible contingency event. The technical envelope is implemented through constraints applied to the grid as well as market operation. These constraints include interregional interconnector flows, intraregional transmission flows, and generator dispatch that reflects thermal, voltage, and transient stability limits in the power system. In addition to defining constraints in the technical envelope, the system operator also ensures that there are sufficient contingency capacity reserves of reactive and active power to maintain voltage and frequency within required limits.

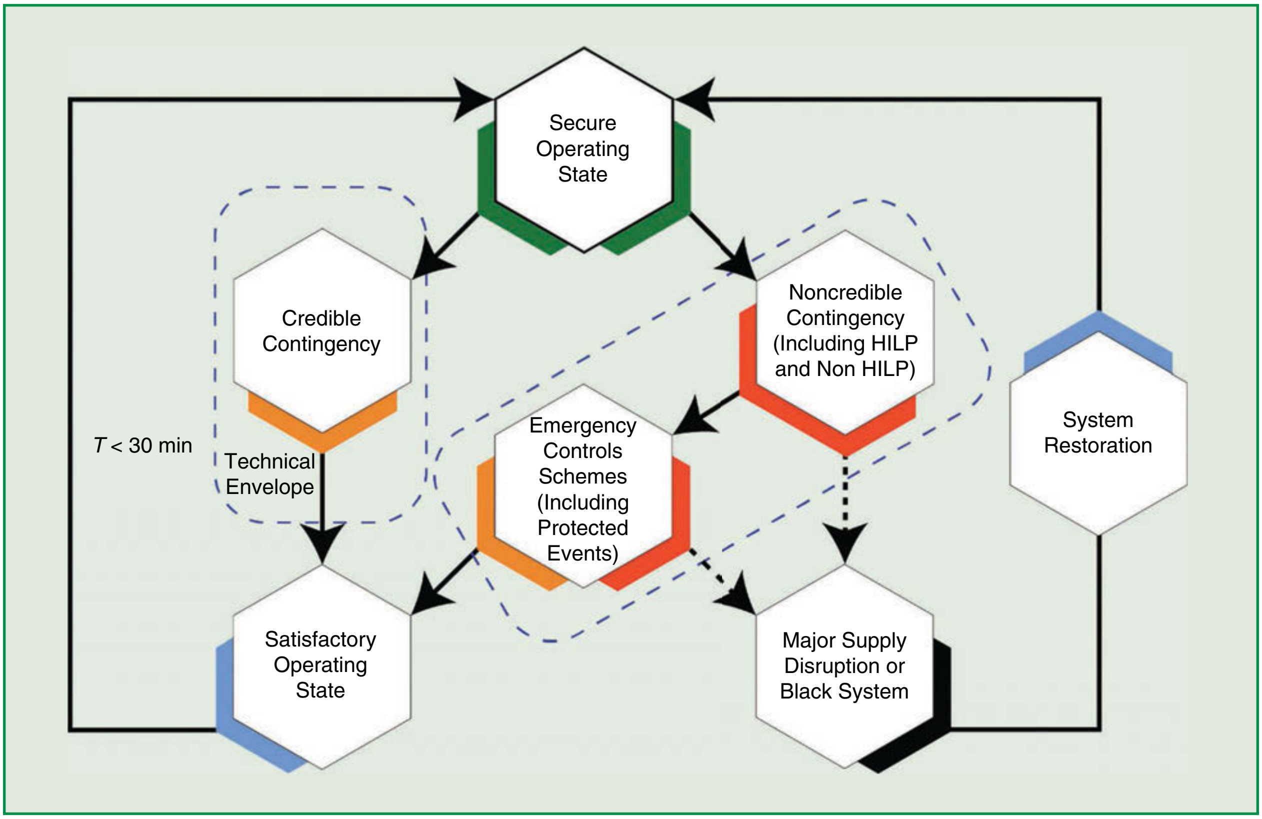

figure 1. Arrangements for a secure power system, with specific applications to the Australian NEM (courtesy of AEMC).

In addition to the reasonably possible (credible) contingencies, the power system can also be exposed to noncredible contingency events. While some of these can be more severe than credible events, their probability is considered low. A secure operating state does not mean the grid would necessarily remain so after a severe noncredible contingency event. In practice, this means that load shedding may occur to prevent the system from collapsing. Therefore, power system security arrangements require emergency control schemes, such as underfrequency load shedding (UFLS), as a last line of defense to prevent a cascading outage. This is represented in the middle of Figure 1.

Abnormal conditions, such as storms or bushfires, can increase risks to the power system by making otherwise noncredible contingency events more likely to occur. For example, the loss of double-circuit transmission lines, normally a rare contingency event, is classified as noncredible. Making the system secure for such an event would impose restrictions on grid operation, increasing the costs of supplying customers by constraining transmission network flows and dispatching more ancillary services. However, during approaching storms or bushfires, the likelihood of a double-circuit line loss is significantly increased and has historically been "reclassified" from noncredible to credible. In this way, the resilience of the power system can be increased for known abnormal conditions.

Resilience of the NEM power system can be further increased through the declaration of a "protected event." This is a noncredible contingency event that is somewhat possible and likely to lead to a cascading failure, such as the loss of a major double-circuit transmission line. To prevent a protected event from leading to a cascading failure, the system operator can take a portfolio approach that deploys a mix of ex-ante steps (e.g., installation of special protection schemes) and ex-post measures (e.g., procuring additional ancillary services and constraints on network flows). This is, for example, what AEMO employs to deal with situations when loss of major interconnections and separation events of some regions (e.g., South Australia from the rest of the NEM) may become plausible.

Should a very rare, yet severe, contingency event occurs, a cascading outage may not be arrested by emergency control schemes. Parts of the power system could therefore experience a black system event, like in South Australia in September 2016. Therefore, the system operator must ensure that sufficient system restart facilities are available to reenergize the system following a major supply disruption. This is represented on the right-hand side of Figure 1.

The decision of whether contingencies are treated as credible and noncredible crucially defines the technical envelope for power system operation. This implies a tradeoff between the ongoing costs to the market for maintaining the grid in a secure state and the benefits of potentially avoiding the loss of load following less severe events and the reduced risk of a major supply interruption.

The Changing Nature of the Risks to the Operation of the Power System

Current power system security arrangements largely reflect the risks to the systems prevalent when they were developed.

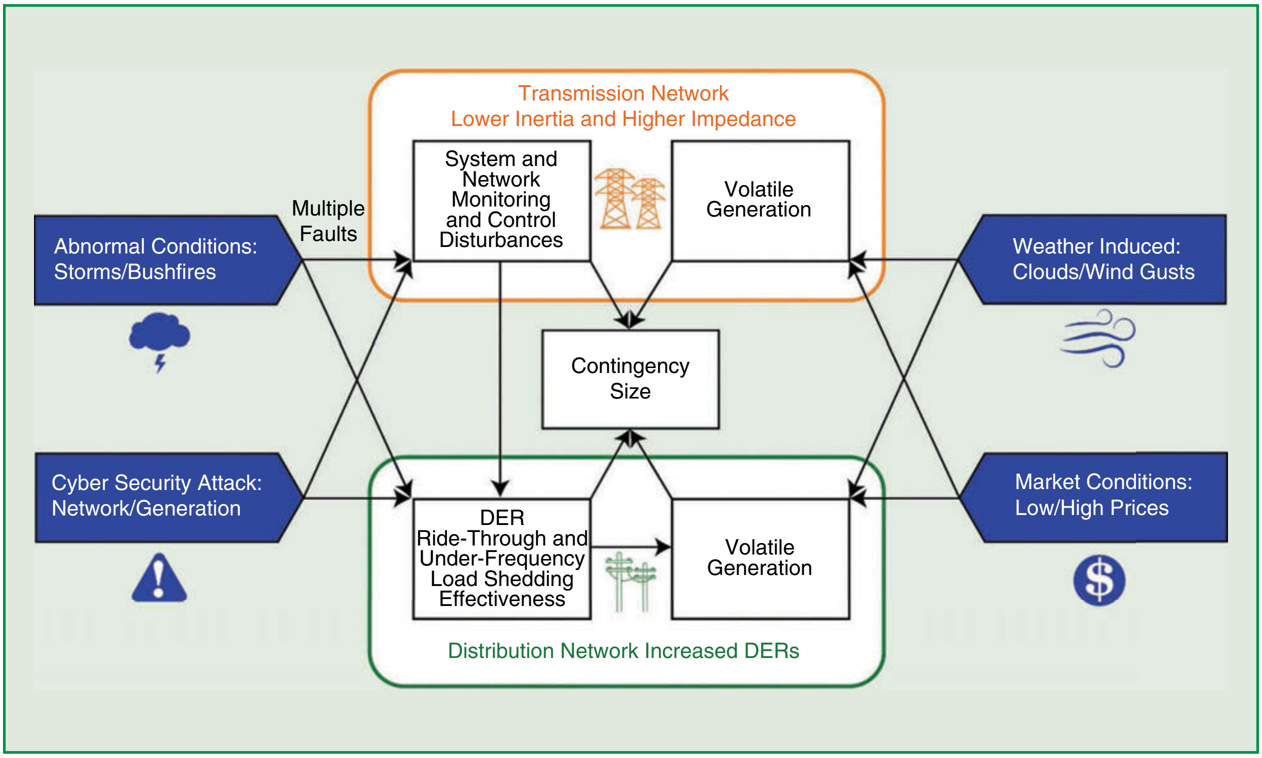

figure 2. Indistinct events due to uncertain interactions within the power system.

These arrangements were implemented when the generating mix was dominated by a limited number of large generation units. Most were located at generation hubs that were, in turn, often in highly meshed parts of the grid. Given this mix, dominant events causing risks to power system security typically involved the sudden failure or service removal of specific generating units or network elements. Such events are distinct and definable with the size of their impact being deterministic.

Australia's NEM generation mix has changed in recent years with the reduced operation, mothballing, or retirement of many large synchronous generating units. That is coupled with the rapid deployment of DERs, inverter-based resources, and intermittent generation at both the transmission and distribution levels.

Along with an increase in severe weather events, the changing generation mix has introduced a new class of risks to power system security. Risks are increasing due to the so-called indistinct events that can act on multiple generation and network assets in an affected area within minutes. The specific assets involved in the contingency event, and hence the size of the impact on the system, are not known before the event.

Figure 2 summarizes some examples of these emerging "indistinct" events. Further considerations and context about operational uncertainty and risk associated with different types of indistinct events and underlying issues and drivers are provided in "Three Types of Indistinct Events Affect Operational Uncertainty."

The NEM regulatory frameworks, which are set out in the national electricity rules, define how the system must be managed by the AEMO. These frameworks were designed around the management of traditional "discrete" risks, whereby the system operator should be able to describe the expected contingency, indicate which component may be at risk, and quantify the potential contingency size. As power system risk profiles changes, and with more and more emerging "indistinct" events that are difficult to characterize (in probabilistic terms, not to even mention deterministically), national electricity rules are being revised to ensure that AEMO has the correct tools at its disposal to manage these new risks.

Developing a Portfolio Approach to Resilience

As the power system changes and becomes more "fragile," policy makers and system operators are rethinking HILP event management. A wider range of coordinated resilience solutions is required to manage increasingly indistinct, and extreme, HILP events. The need for new resilience solutions is increased by the decline of innate resilience buffers that has occurred in many power systems, including the reduction of latent system inertia and system strength, as discussed

Three Types of Indistinct Events Affect Operational Uncertainty

Weather

There is increasing generation risk associated with weather changes, such as sunlight intensity or wind speeds, which are generally distributed and affect a significant number of units. While the associated generation changes can be forecast and assessed probabilistically, there is also associated uncertainty, particularly under abnormal weather conditions, such as high winds and storms. In parts of the NEM, the largest credible contingency could be an output change from a group of variable-generating units in an affected geographic area.

System Response

With more and more synchronous units retiring, the resulting lower levels of fault current and inertia are increasing significantly the uncertainty of a system's dynamic response to disturbances. This uncertain response is further compounded by the more complex response behavior of DERs. In particular, the size of a contingency, such as a single network fault or generator trip, can be significantly increased by an unexpected loss of generation. For example, this could be due to a portion of the nearby inverter-connected VRE generation (such as in the 2016 South Australia black system event) or distribution-connected DERs (such as in the August 2019 Great Britain load disconnection event) failing to ride-through the associated disturbance, including due to protection settings issues.

Emergency Control Schemes

There are emerging issues associated with the effectiveness of emergency control schemes and the associated uncertainty in the resulting system response. An important instance is UFLS schemes in the presence of large DER quantities. While the scheme is designed to shed load by disconnecting distribution feeders at predefined substations, this may also disconnect areas of net embedded generation, increasing the overall net loss of supply and therefore risk to the power system.

Again, there have been a few situations of this kind, including again in the August 2019 event in Great Britain. Other important considerations on operational uncertainty and risk that can be brought by emergency control schemes regard the interactions between different types of special protection schemes as generation mix and power system conditions change. This may require revising control algorithms and settings to prevent unintended interactions and cascading outages.

earlier. Technology innovations also offer significant opportunities to help address resilience concerns.

The findings from the analyses performed in reviewing the events that conducted to the black system events in South Australia in 2016 and other similar events in Australia and worldwide suggest that when developing an overall approach to procuring resilience solutions policy makers adopt a coordinated portfolio approach. Such a hybrid approach with different technologies and a mix of network and nonnetwork solutions will enhance overall resilience while also helping to reduce costs for consumers.

A portfolio approach reflects the characterization of resilience described earlier, as being about using a range of resilience solutions

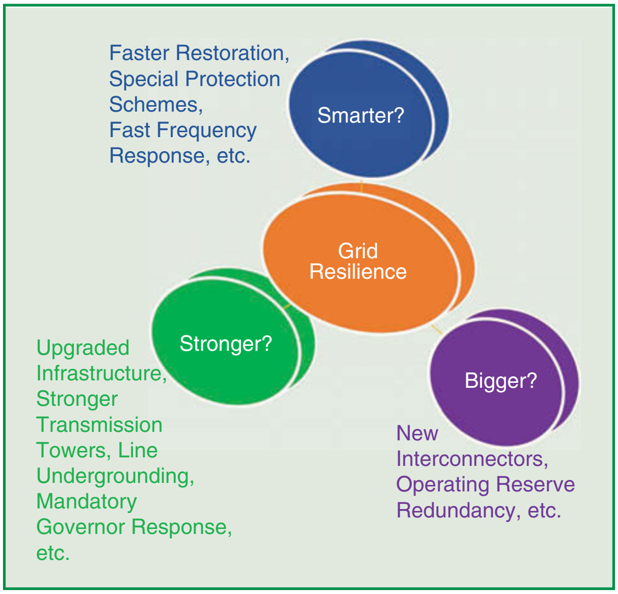

figure 3. A power system resilience enhancement framework (adapted from Panteli and Mancarella, 2015).

- ✔ to make the system stronger, bigger, and/or smarter
- ✔ to better *avoid*, *survive*, and *recover* from major disturbance events.

The "stronger-bigger-smarter" component of the framework (Figure 3) seeks optimal tradeoff solutions among asset redundancy, asset strengthening, and the use of more intelligent/flexible technologies and operation policies.

On the other hand, the "avoid, survive, recover, and learn" component of the framework looks into how different solutions can enhance resilience at the different stages of an extreme event.

This concept is further illustrated in Table 1, which identifies a range of resilience solutions that could improve overall resilience. These ideas are under consideration by the NEM. The general concept is that using a combination of solutions can help deliver an optimal resilience outcome at the lowest total system cost. This is based on the partial substitutability and complementarity of the various resilience solutions described.

Partial substitutability implies that it may be possible to use a single solution, or a combination, to achieve the same outcome at a lower overall cost. For example, a given level of overall resilience could be delivered in a region using a single solution, such as constraining interconnector flows into or out of the region (a bigger/avoid solution). However, such an approach can come at a material cost as the limitation of interregional flows may increase the total cost of wholesale energy in the region.

A system operator may, therefore, look to deliver the same level of resilience, but at a lower total cost, through a mixed approach based on the substitutability of resilience solutions. For example, the operator might relax interconnector constraints while procuring more ancillary services within the region (a bigger/survive solution). While recognizing that these two solutions are only partial substitutes, such an approach could, however, deliver similar outcomes while reducing total costs if the mixed solution costs less than the single solution.

table 1. Resilience solution matrix (adapted from AEMC, 2019).

	Avoid	Survive	Recover
Stronger	• Transmission fault/damage detection equipment • Doubling transmission circuits	• Increase tower strength to resist high winds • Increased strength of tower footing • Firmware improvements to resist cyberattacks	• Increased multiple fault ride-through and active power recovery capabilities
Bigger	• Conservative interconnector limits • Enhanced special protection schemes • Mandate technical standards for active and reactive power provision	• Use inertia and system strength services to manage for noncredible contingency • Regional frequency control ancillary services procurement	• Black start services • System restoration services • Batteries with grid-forming inverters to support load "islands" and enhance restoration
Smarter	• Improved generator and system modeling capabilities • Enhanced demand and generation forecasting • Protected events/protected operation	• Enhanced frequency load shedding functionality • Refinements to the operation of special protection schemes • Coordinated and appropriately tuned generator control responses	• More effective system restoration administrative and communication processes • Better modeling and physical testing of black start and restoration services

> Partial substitutability implies that it may be possible to use a single solution, or a combination, to achieve the same outcome at a lower overall cost.

Complementarity also implies that each solution described previously might reinforce each other, delivering a material increase in overall resilience. For example, while procuring significant additional volumes of regional ancillary services and constraining interconnector flows will increase resilience (a mixed bigger/avoid and bigger/survive solution), complementing this with additional black start and system restoration services that have been effectively modeled and tested (a mixed bigger/recover and smarter/recover solution) will result in a material increase in resilience. The presence of these last-resort services could mean the system can be recovered in hours rather than days after a HILP (assuming that the additional ancillary services/interconnector constraints failed to prevent a black system), significantly increasing overall resilience and improving customer outcomes.

In addition to these concepts, a portfolio approach to resilience should take into account that resilience solutions can be both targeted and general. Targeted measures might include specific physical assets (e.g., a special protection scheme) designed to manage specific risks (e.g., noncredible loss of a double-circuit transmission line). General measures might include changes applied across the system (e.g., mandating more comprehensive technical capabilities from all generators) designed to provide a general improvement in the resilience of the system to nonspecific risks.

Several technical studies suggest that adopting a mix of targeted and generalized solutions may provide an optimal resilience outcome based on managing both "known" unknowns and "unknown" unknowns. The existing "protected events" process in the NEM is a good example of an existing regulatory framework that reflects these general principles. Introduced in 2017, this process allows AEMO to identify specific noncredible contingencies for management and then propose mixed solutions at the lowest overall cost. Examples of mixed solutions have included operational actions (e.g., curtailing power transfer between regions during abnormal conditions) coupled with investment actions (e.g., procuring additional fast active power response services from a battery and upgrading UFLS schemes).

Finally, resilience solutions can also provide system support for credible events, which should be accounted for in the relevant cost-benefit analysis. One of the challenges, therefore, is to adopt a consistent framework for both security and resilience solutions. In this respect, significant work is needed to truly understand the role of new technologies in providing security and resilience while displacing conventional technologies. For example, frequency response from batteries or hydrogen electrolyzers might be a substitute for primary frequency response from conventional generators in the case of credible events. However, the fast response of new technologies may be much more beneficial to the system in the case of HILP events, especially under low-inertia conditions. Capturing this kind of behavior from a technical perspective, and then from a regulatory and market view, is a work in progress in Australia and worldwide.

New Mechanisms Being Discussed and Developed to Further Support Resilience

Power system operators need new mechanisms and tools to manage resilience that look and feel very different from those they originally learned how to operate. This is a significant challenge for policy makers and system operators mainly due to the increasing uncertainties surrounding HILP events and the related complexity of assessing associated costs.

In this regard, the NEM is going through a significant reform process for transition to a power system based increasingly around inverter-based, variable, and decentralized renewable generation. The work of the Energy Security Board and various market bodies focuses on managing the rapid transition of the generation fleet, growth in DERs, and an increasingly active demand-side. This work in progress will help strengthen the power system and deliver resilience benefits. AEMC is also progressing several pieces of work specifically targeted at enhancing system resilience. This includes working with other market bodies to develop frameworks to manage "indistinct" events.

As discussed earlier, power system risk profiles are changing with new classes of "indistinct risk" becoming more predominant. Unlike a distinct contingency event, indistinct events require consideration of multiple potential assets that will be affected and the response of the system. Therefore, indistinct events require an assessment that recognizes the uncertainty inherent in the event itself as well as the uncertainty of the power system's resulting response. Existing frameworks that only consider the probability of a distinct event are likely to be inappropriate for managing indistinct events.

AEMC is considering a new regulatory framework to better manage these indistinct events. This would allow AEMO to take actions in addition to those needed to manage a distinct, credible contingency event when external conditions mean the power system is likely to face increased indistinct risks.

> The system's resilience is provided in different ways to manage the risks of most possible noncredible distinct events with only the most severe events likely to have a black system event risk.

For example, to manage increased risk from a major storm system crossing a region, AEMO might elect to apply more constraints on dispatch or procure additional ancillary services.

Figure 4 summarizes the NEM's current arrangements for distinct events and operating strategies for indistinct events in the future. As discussed earlier, the power system is kept in a secure state to manage the risks of discrete credible contingency events. The system's resilience is provided in different ways to manage the risks of most possible noncredible distinct events with only the most severe events likely to have a black system event risk. For example, this is achieved through the protected events framework where specific noncredible distinct events are managed through mixed solutions. Resilience is also delivered through AEMO's ability to reclassify distinct noncredible contingencies to credible during abnormal conditions.

Possible new regulatory arrangements for managing indistinct event risks are also summarized in Figure 4. At the time of writing (May 2021), some of these arrangements are being investigated by AEMC through the "indistinct events rule change request."

Defining the size and characteristics of indistinct events regarded as reasonably possible and credible using probabilistic methods.

The top left-hand box of Figure 4 describes AEMO's current approach to the management of credible distinct events. These contingencies are considered reasonably possible in the surrounding conditions, and AEMO takes action to manage them by constraining dispatch and procuring additional ancillary services.

The bottom left-hand box represents the logical extension to indistinct events. In this area, the system operator would take action to operate the power system so that the system is secure for credible indistinct events. For example, as mentioned earlier transmission-level contingencies can induce DER and VRE tripping or drop in outputs due to protection relay settings and specific control strategies. This may particularly occur in areas with reduced system strength and inertia due to the large-scale penetration of inverter-based technologies and renewables. However, in these cases the potential size and exact location of output impacts from loss from VRE and DER are uncertain.

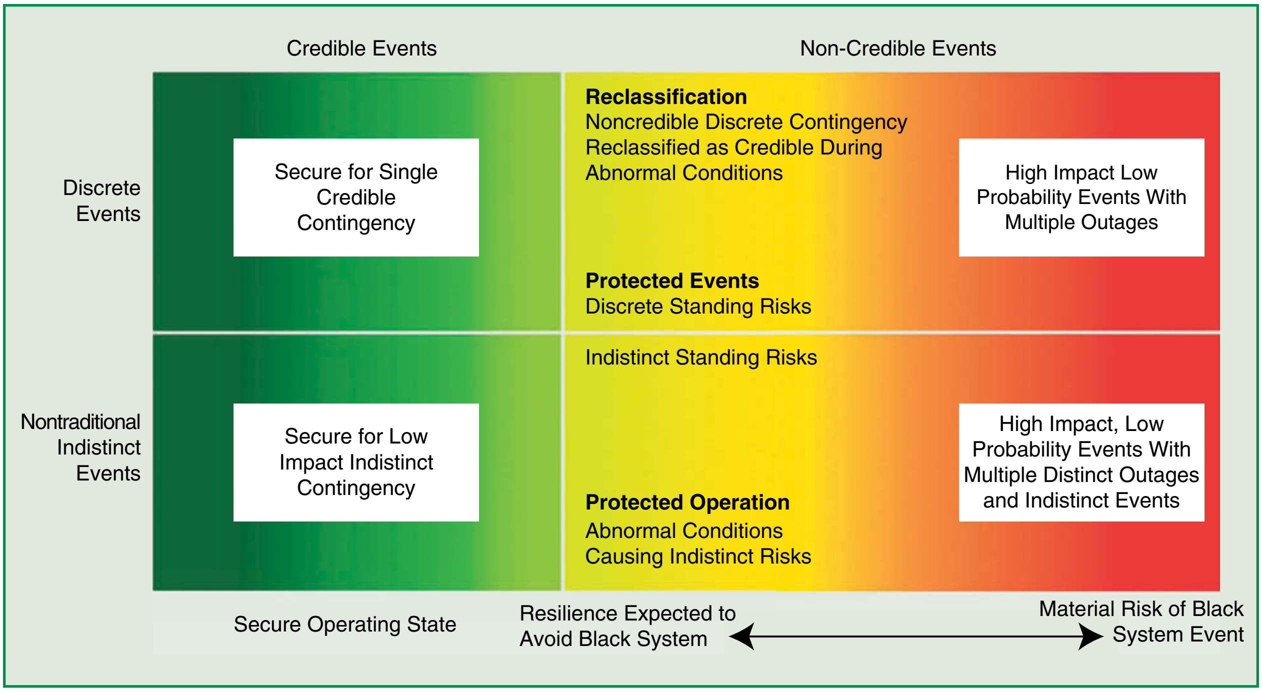

figure 4. Power system operating strategies to manage credible and noncredible events, including HILP events and different types of indistinct events (courtesy of AEMC).

Therefore, a new operational mechanism that has been discussed is the so-called $N-(X+)$ operation. The "+" indicates augmentation of the classical $N-X$ criterion with the "size" of the indistinct contingency considered. This theoretical approach would likely involve data-driven analysis to determine what indistinct events might be considered reasonably possible in the surrounding circumstances. A similar approach has already been adopted by National Grid in Great Britain.

While at present the $N-(X+)$ security criterion is not being explicitly considered as a potential amendment to the NEM regulatory frameworks, at least in the context of resilience and indistinct events, AEMO is already adopting data-driven probabilistic approaches to deal with operating reserves to guarantee reliability.

Extending Protected Events Arrangements

The focus of AEMC's current work is to consider noncredible indistinct risks, which may include HILP-type events. These events can take several forms, including those dependent on external abnormal conditions (condition-dependent) and those independent of external conditions (condition-independent).

Noncondition-dependent indistinct risks that can be considered are "standing" risks since the risk does not change by reference to external abnormal conditions. An example could include a cyberattack. This type of risk is indistinct in that it may affect multiple undefinable assets on the system, and it is described as "standing" since the threat is not necessarily dependent on identifiable external conditions. However, it is noted that, in the case of an attack warning, the risk might be considered "condition-dependent," and other approaches could be used. This type of indistinct risk is being investigated by AEMC. It may be that the standing nature means the protected event framework could form the basis of a regulatory approach for managing standing indistinct risks, too.

Implementing New Operational Measures

Condition-dependent indistinct risks are the other area of focus in AEMC's work program. These are indistinct noncredible risks, the magnitude of which changes depending on external abnormal conditions. Examples of such conditions could include a large storm crossing a region of the power system. AEMC is considering new frameworks to allow AEMO to take necessary operational actions to manage these kinds of risks. Steps may include restricting power flows on interconnectors, procuring additional ancillary services, and directing additional synchronous generating units to be online to increase system inertia, fault levels, and dynamic active and reactive power capability.

The framework being considered by AEMC through the "indistinct events rule change" aims to establish processes that would provide the system operator with the flexibility to effectively manage the power system's rapidly changing risk profile. In devising such a framework, it will be important to consider how the risks can be managed given the associated extreme uncertainty. It will also be necessary to consider how governance frameworks can ensure the full suite of costs is identified. For example, transparency and openness will likely be important to allow all affected parties to have a say and that all learnings from past events are captured and inform the operational frameworks.

Acknowledgment

The authors appreciate the support of AEMC while acknowledging that the views expressed in this article are those of the authors only.

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Distributed Energy Resources Roadmap

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THE TRANSITION TO DISTRIBUTED energy resources (DERs) is happening rapidly in Western Australia, presenting serious and pressing risks to the safe and efficient operation of its main electricity grid, the South West Interconnected System (SWIS). DERs are smaller-scale devices that can either use, generate, or store electricity and form a part of the local distribution system serving homes and businesses.

How the State of Western Australia Is Leading in Integration

In 2020, the Western Australia government released the report “DER Roadmap” to guide DER integration and management to realize a future where it is integral to a safe, reliable, and efficient electricity system, and where its full capabilities can provide benefits and value to all customers.

The Southwest Interconnected System

SWIS is a unique power system serving a small, dispersed population of approximately 2 million people spread over approximately 250,000 km^2 an area larger than the United Kingdom. It is both geographically isolated and electrically islanded with no interconnection to the large National Electricity Market that serves most of Australia’s population on the country’s south and east coasts. In SWIS, fewer than 100 power stations serve 1.15 million customer connection points. About 900,000 are in the Perth metropolitan region. Outside SWIS, there is one other interconnected grid and 34 isolated microgrids in regional and remote Western Australia. The Northwest Interconnected System links Port Hedland, Karratha, and other key towns and mining centers in the state’s Pilbara region (Figure 1).

The SWIS network operator, Western Power, is owned by the Western Australia state government and acts as the primary distribution and transmission network service provider. Western Power is regulated by an independent economic regulator, which approves prudent and efficient expenditure and revenue recovery from network customers.

The largest generator and retail energy business, Synergy, is also state owned and accounts for more than half of the electricity sold in SWIS. Importantly, almost all residential customers in SWIS are “noncontestable,” meaning that they can only purchase electricity from Synergy under tariffs approved by the state government.

The power system and the wholesale electricity market are managed and operated by the independent Australian Energy Market Operator (AEMO). With no interconnection to other energy markets, arrangements for a unique reserve capacity mechanism are in place to ensure sufficient capacity is available during peak demand periods.

SWIS was designed around a small number of transmission-connected, large-capacity power stations. These include

gas-fired generation facilities (45% of installed capacity) and a few large coal-fired generation facilities (21%) located near coal-mining operations in the southwest of SWIS. These facilities combined accounted for almost 90% of large-scale energy generation supplied to the grid in 2019–2020. The remaining generation was primarily provided by utility-scale wind generation located in the north of SWIS.

Recent additions of large wind farms and the growing contribution and impacts from rooftop solar are rapidly changing the generation mix. Scenario modeling in 2020 indicates renewable generation will outstrip growth in other generation types over a 20-year modeling horizon.

Small, distributed rooftop solar represents about 18% of total generation capacity and is estimated to contribute around 10% of total energy supply. This is difficult to measure accurately as it is masked by serving behind-the-meter and distribution level loads, reducing the total required from large transmission-connected generators.

The contribution of energy generated by rooftop solar photovoltaic (PVs) is leading to low customer demand from the grid in the middle of the day and a steep ramp-up to the daily evening peak. If current trends continue, AEMO has forecast midday low-load conditions will pose a significant risk to the power system as soon as 2022.

DERs in Western Australia

DERs cover a wide range of technologies and services that can deliver value across different parts of the electricity supply chain, including renewable generation such as solar PVs, energy storage, electric vehicles, and technologies that residential consumers can use to manage their electricity demand (e.g., air conditioners, hot water systems, pool pumps, or smart appliances). DERs can be located within a customer's premises (i.e., behind-the-meter) or connected directly to the distribution network.

Australia is a global leader in distributed solar uptake rates with Western Australia being among the highest Australian jurisdictions. Unlike other countries where solar has primarily been associated with utility or large commercial installations, uptake in Australia has been largely driven by small household installations. Almost one in three homes in SWIS has solar PVs, with more than 3,000 households adding a solar PVs system each month. AEMO estimates that 50% of households will have solar PVs in the next 10 years.

The popularity of rooftop solar PVs in Western Australia is driven by a favorable climate and solar resource, high levels of homeownership and suitable housing, installer competition, and financial incentives, including beneficial tariff structures and government subsidy programs.

Rooftop solar PVs are ideally suited to the Western Australian climate. SWIS experiences an annualized average of 8.8 h of sunlight a day, and Perth has the highest number of cloud-free days of all Australian capital cities.

Over 75% of all dwellings in Western Australia are free-standing houses, with medium- and high-density dwellings accounting for 21% of the housing in 2016. Residential lot sizes are also larger than the Australian average, leading to larger roof areas ideal for rooftop solar PVs.

At the same time, uniform flat tariffs, technology cost reductions, and subsidies have provided a strong price signal incentivizing solar PVs. The household retail tariff, comprised of a relatively small, fixed charge of AUD$1.05 per day and a flat rate of AUD$0.29/kWh at all times, disproportionately recovers fixed costs through variable charges. This structure encourages the installation of DER generation as self-generation allows households to avoid buying electricity from the grid and therefore paying for fixed system costs over that period.

Synergy is also required to offer a solar feed-in tariff for residential customers. Before November 2020, the default Renewable Energy Buyback Scheme offered AUD$0.071/kWh for all customer solar PV exports. Federal government financial incentives (known as the Small-Scale Renewable Energy Scheme) and declining technology costs, combined with competitive pricing from economies of scale within the local industry, have also contributed to the uptake. The combination of these factors means the payback period for a new rooftop solar PV system is close to three years on average, making it an attractive investment proposition for households. Indeed, Western Australian customers are installing rooftop solar PVs at an accelerating rate (Figure 2).

The uptake of other DERs is relatively weak but is expected to increase as costs decline over time, particularly for technologies (such as household batteries and electric vehicles) that complement solar PV investments. Household

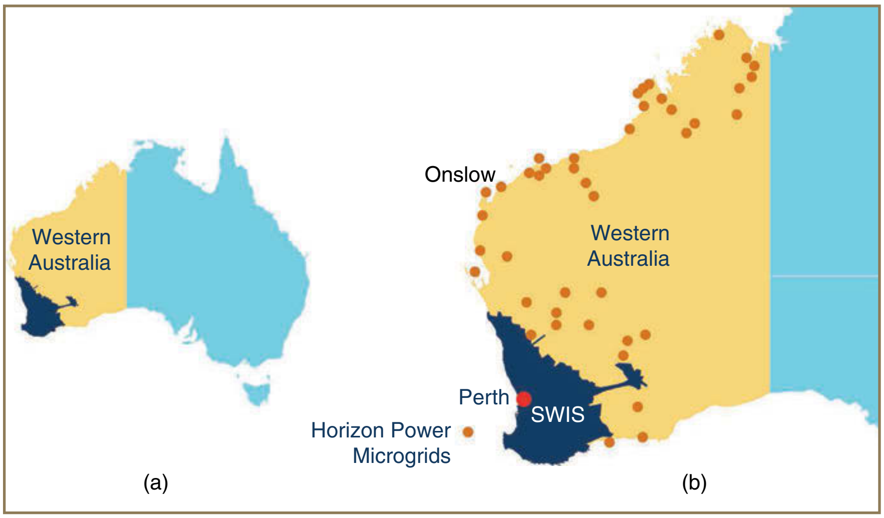

figure 1. (a) Western Australia and (b) the SWIS and Horizon Power microgrids.

appliances, such as air conditioners and pool pumps, are also highly represented in Western Australian households and offer the potential for load management. For instance, in 2014, an estimated 88.5% of homes had at least one air conditioner.

The Challenge

The isolation of SWIS and the rapid increase in uncontrolled rooftop solar PVs means that the challenge of integrating renewable energy is being experienced ahead of most other electricity systems around the world. Rooftop solar can already supply nearly 50% of instantaneous underlying demand at times. Unlike other grids, SWIS is unable to rely on interconnections for system support services to maintain voltage and frequency when there is a large contribution from nonsynchronous intermittent generation.

The impact of rooftop solar PVs and other DERs is amplified in the islanded microgrids throughout Horizon Power's service area (i.e., outside SWIS). Currently, PV hosting capacity limits have been introduced in several microgrids, leading Horizon Power to explore ways to increase hosting capacity through actively managing this resource in the Onslow microgrid (see "Onslow DERMS: DER Integration in Action in Western Australia").

The SWIS daily load profile, which represents the energy drawn from the grid by customers, has evolved in recent years to resemble a typical "duck curve" (Figure 3). Energy generated by rooftop solar PVs is leading to low grid-supplied electricity demand in the middle of the day and a steep ramp-up in demand for the daily evening peak as PV system production decreases at sunset.

In March 2019, AEMO released a report, "Integrating Utility-Scale Renewables and DERs in the SWIS," that identified forecast trends in midday low-load conditions as a significant problem with market efficiency and system stability. As highlighted earlier, AEMO forecasts that the critical minimum demand at which technical limits are breached (around 700 MW) could potentially be reached as soon as 2022. As well as presenting risks to the overall energy system, the unrestrained flow of solar energy onto local distribution systems, which were originally built for single-direction energy flows, is increasingly causing network operator issues on the distribution network.

Also, increased output variability caused by cloud bands can cause rapid changes in output from rooftop solar PVs, which results in the need for other generators to respond. As the size of the rooftop PVs and the proportion of instantaneous load it serves grow, there is an increasing need for fast response support that can represent more than 25% of underlying demand within very short periods.

The DER Roadmap

The Western Australia government responded to this rapidly approaching challenge by launching the Energy Transformation Strategy. This also addressed the opportunities presented by the transition to renewable and distributed energy technologies. The strategy contains three interlinked pieces of work:

- ✔ *a new market design*, to respond to the need to integrate high levels of renewables
- ✔ *the Whole of System Plan*, to identify through scenario modeling the least-cost investment required in large-scale generation, transmission, and energy storage and to identify emerging challenges for SWIS over a 20-year horizon
- ✔ *the DER Roadmap*, to safely and reliably integrate customer DERs in SWIS.

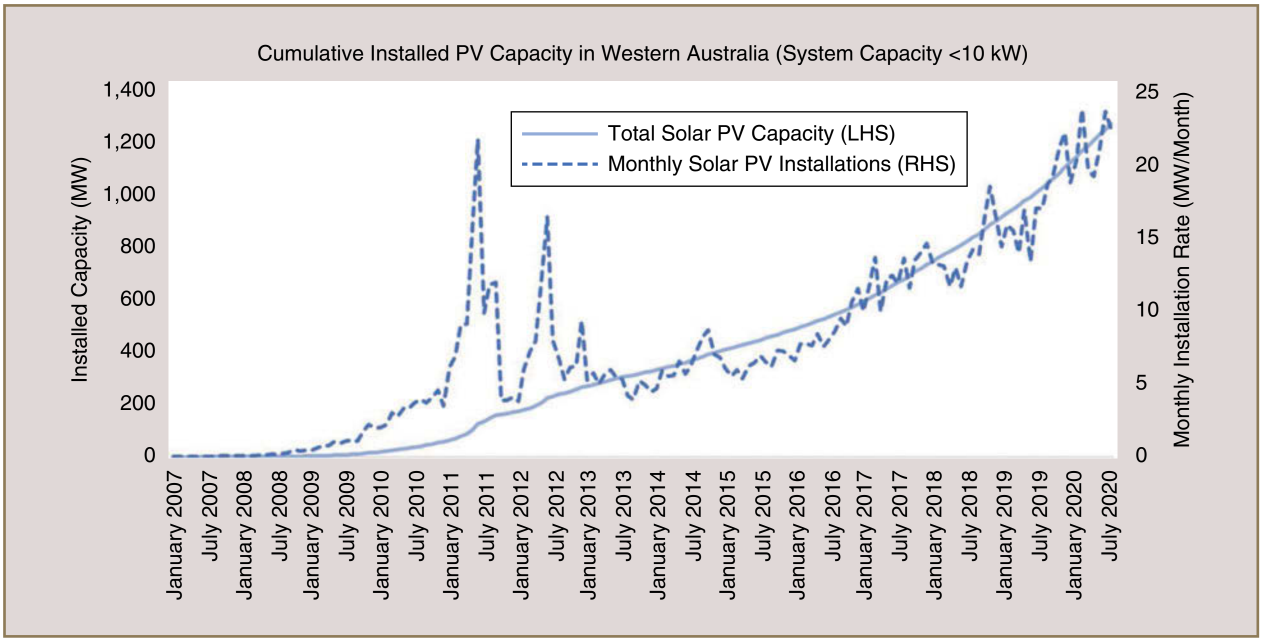

figure 2. Installed solar PV capacity in Western Australia. (Source: Australian PV Institute Solar Map, funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au on 8 December 2020.)

Onslow DERMS: DER Integration in Action in Western Australia

Challenges in Horizon Power Area: Hosting Capacity, Desire to Add More Renewables

Horizon Power is responsible for providing safe and reliable electricity to more than 100,000 customers by operating the North West Interconnected System and 34 isolated microgrids throughout remote regions of Western Australia.

The well-documented technical challenges, such as reverse power flow along with the intermittent nature of solar generation causing power quality and reliability issues, means there are physics-based technical limits to how much solar can be connected to an electricity system. Since 2009, Horizon Power has carefully managed these technical challenges, which are exacerbated in smaller isolated microgrids, and currently has implemented renewable energy hosting capacity limits across 15 of its microgrids.

Horizon Power considers hosting capacity limits to be a necessary, but temporary, measure. Over the past few years, it has been working on several DER "orchestration" trials as the key to overcoming the technical barriers to connecting higher levels of rooftop solar.

DER orchestration is achieved through the visibility and control of all DER connected to the network and includes communication with rooftop solar inverters, battery storage inverters, and large household loads (e.g., air conditioning) using the IEEE 2030.5 Standard for Smart Energy Application Protocol.

Passive customer assets are effectively integrated into the planning and operation of the Onslow microgrid in a way that enables greater customer choice and access to the greater benefits of renewables. At the same time, it unlocks the value of aggregated rooftop solar as the cheapest future source of energy and uses DERs to reduce or avoid the need for costly generation or network solutions to meet future energy demand.

While Horizon Power has successfully delivered DER orchestration projects in Carnarvon and Broome over the past few years, it is the Onslow DER project that applies DER orchestration at a scale of an entire town. This is a potentially transferable solution to removing hosting capacity limits and enabling greater participation and value from DERs across its entire service area.

Onslow Context

Onslow is a small coastal town located in the Pilbara region of Western Australia with a relatively transient population of fewer than 1,000 residents. In 2016, there was a need to renew Onslow's power network assets to meet the growing needs of this natural gas and mining region.

Project Outline

Horizon Power initiated the Onslow DER project to validate the forecast that lower cost energy could be achieved by more than just utility-owned and -operated assets, that is, supplemented by the aggregation of customer rooftop solar. This required a solution that could safely and reliably integrate high levels of customer-owned rooftop solar to deliver a clean energy future that delivers value to customers.

The main objectives of the project were to

- safely integrate customer and network DERs to supply > 50% of Onslow's annual energy
- design, build, and operate a functional energy resources management system to economically integrate high levels of DERs, much of which would be customer-owned in tandem with a centralized gas generation power station
- partner with customers to incentivize the uptake of *controllable* DERs.

The technical rooftop solar hosting capacity in Onslow is ~850 kW, beyond which power quality is compromised, and more rooftop solar cannot be accommodated. To achieve > 50% of annual energy being met by renewable energy, the project set a target of achieving uptake of 2 MW of highly distributed rooftop solar and up to 1 MWh of small-scale customer battery energy storage systems (BESS) by local households and businesses.

The resulting time-varying power flows would need to be "orchestrated" along with the in-place utility-owned 1-MW solar farm, two utility-owned 1-MWh BESS, and all in tandem with the centralized gas-fired Onslow power station.

Customer and Community Participation

Active customer and community participation in the Onslow DER project would be critical to its success. To achieve the target of 2 MW of rooftop solar, Horizon Power provided an upfront incentive of 50–75% discounts to Onslow customers on the purchase of a 3- or 5-kW system. This meant over 50% of households and small businesses would need to participate, most of which were renters or living in corporate or government housing.

As such, the project focused on the principles of "better engagement" through placing customers, key community stakeholders, and "local champions" at the center of the project. This was achieved via ongoing engagement and education of the project, power system, challenges, and opportunities for customers and community.

Rooftop solar and BESS were launched in the community in March 2019 and had signed up 2.1 MW (inverter capacity) of rooftop solar and over 500 kWh of energy storage by the close of the incentive in December 2019.

Technical: Architecture and IEEE 2030.5

Horizon Power made an early decision to adopt the IEEE 2030.5 Standard for Smart Energy Application Protocol to securely manage distributed generation, storage, and demand response systems. Horizon Power's partners on the project included PXiSE Energy Solutions, which supplied the centralized distributed energy resources management system (DERMS). With a central DERMS in place, Horizon Power also partnered with SwitchDin to provide the edge or "secure gateway device" installed at each home as the translator of IEEE 2030.5 commands from the DERMS into the appropriate control signal to the real inverter hardware (Figure S1).

Project Outcomes

Customers connected 2.1 MW of discounted solar (far exceeding the network's 850 kW limit without coordination) while accepting the need for "generation management" to protect the network from power quality and reliability issues from reverse power flow and intermittency of solar generation. This included providing concessions to low-income households with solar installed on every home in the Onslow Bindi Aboriginal community.

Network and customer DERs are now capable of providing up to 50% of Onslow's annual energy volume as managed by Horizon Power's centralized DERMS.

Horizon Power's DERMS is currently "orchestrating" the following in tandem with the central gas and diesel power station:

- 2.1 MW of customer rooftop solar
- 1-MW solar farm
- 500 kWh of customer energy storage including "smoothing"
- 1-MW/1-MWh BESS
- 1-MW/500-kWh BESS (utilized at power station as grid-forming device when testing gas and diesel off/renewable generation only).

(Continued)

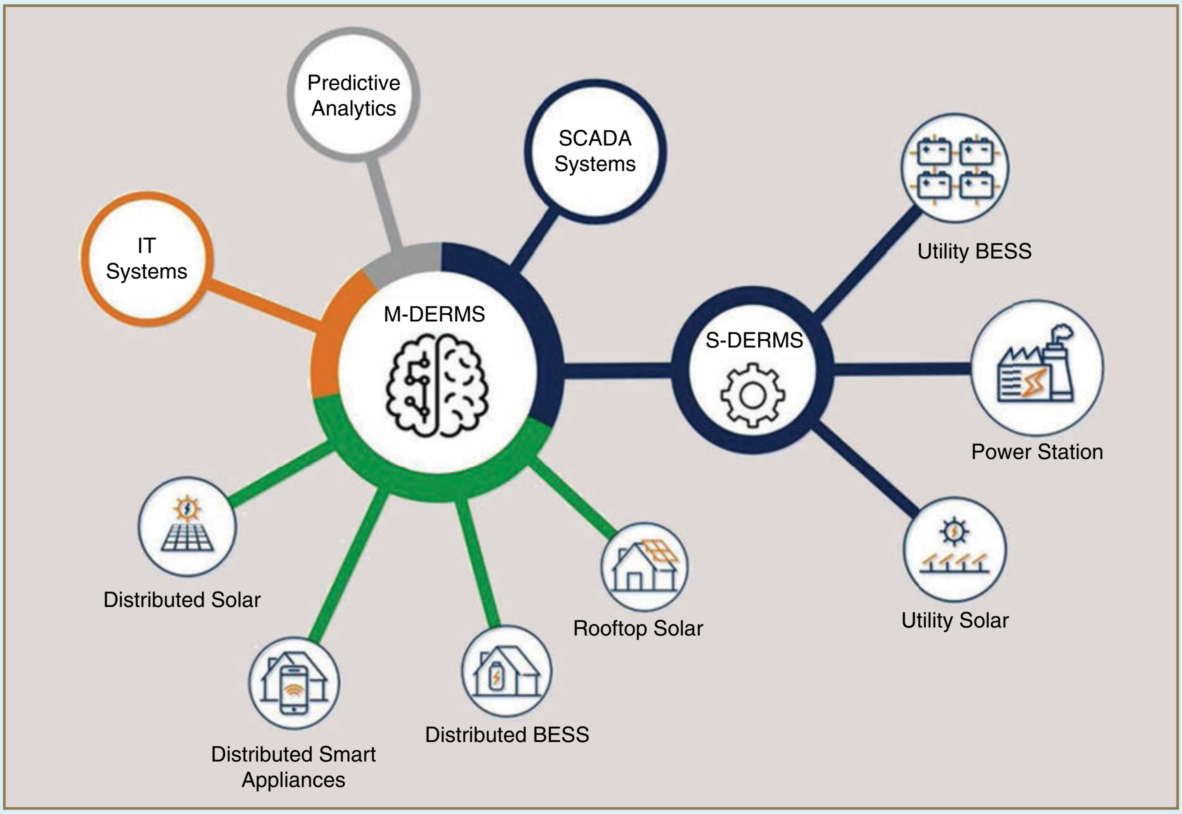

figure S1. Horizon Power DERMS high-level architecture. M-DERMS: master-DERMS; SCADA: supervisory control and data acquisition; S-DERMS: system-DERMS.

Onslow DERMS: DER Integration in Action in Western Australia *(Continued)*

figure S2. Onslow project: the (a) 1-MW PV system and (b) substation with energy storage system.

The DERMS incorporated weather data to proactively smooth intermittency and prevent excess reverse power flows breaching generator minimum loading at the central power station. During August 2020, for example, the daily median solar penetration at peak was approaching 90% with customer systems being curtailed 9% on average.

Key Lessons

- Customer involvement:
  - Conduct early, collaborative engagement to understand customer needs, wants, and expectations *ahead* of setting project targets.
  - Timely and transparent communication on the need and amount of "generation management" is required to highlight the whole of community benefits, such as more customers being able to connect and benefit from solar while mitigating any sense of "loss aversion."
  - Raising customer understanding regarding power system fundamentals is a challenge that goes beyond a single project.
- A functional DERMS is technically complex and time-consuming:
  - It is critical to partner with vendors that have direct, demonstrated experience as well as a shared approach to development and operation.
  - Develop use cases and provide sufficient time for development and testing activity.

Overall, the improved outcome for networks is visibility and control of high DERs in tandem with traditional infrastructure while continuing to provide customers with choice and greater benefit.

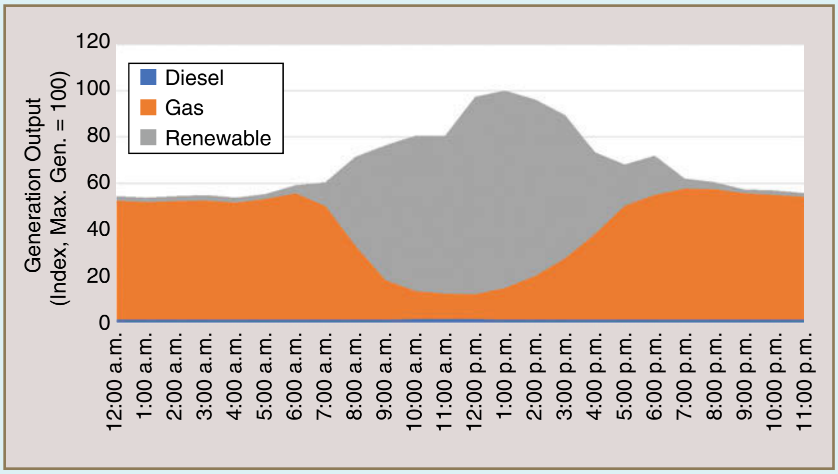

figure S3. Energy generation by type in Onslow—August 2020.

Next Steps

Horizon Power recently set the strategic goal of achieving "zero refusals when connecting rooftop solar by 2025." With the capability now in place in Onslow, it is building a transferable model for the most viable DER management solutions in each of its microgrids (Figures S2 and S3).

The Vision

The overall vision underpinning the DER Roadmap is a future where DERs are integral to a safe, reliable, and efficient electricity system and where their full capabilities can provide benefits and value to all customers. The approach is to manage risks from minimum demand in a way that considers legacy DERs, optimizes potential DER resources, and creates downward pressure on total power system costs. Other options for dealing with this challenge are significant and costly network augmentation or constraining the connection of DERs to the network. They were discounted at the outset.

The process for developing the roadmap was pragmatic and practical. Reflecting the urgency of the looming challenge, the roadmap was developed and released in under a year. The development process involved significant industry and stakeholder input through workshops and one-on-one consultations. From a shared understanding of the problem and vision, stakeholders worked with the Energy Transformation Taskforce to develop the actions that would realize this vision. The DER Roadmap team also worked closely with AEMO and the local transmission and distribution network operator, which provided key technical input and feedback.

Similarly, the approach to the roadmap's implementation involves working closely with implementation partners (e.g., Energy Policy WA, Western Power, Synergy, AEMO, and the broader energy sector) to refine and improve detailed action plans and regulatory amendments.

Released in April 2020, the DER Roadmap outlines 37 actions to ensure Western Australians can continue to install and enjoy the benefits of rooftop solar and new energy technologies in SWIS, unlocking greater value from these devices for the benefit of the power system. In the next section, we discuss the four key themes in the roadmap (Figure 4).

DER Roadmap: Technology Integration

There is a range of actions in the roadmap related to the technical capability of DER devices and the ability of the network and system operators to observe and respond to the impacts of DERs.

The increasing penetration of embedded generation and the subsequent high level of daytime exports are

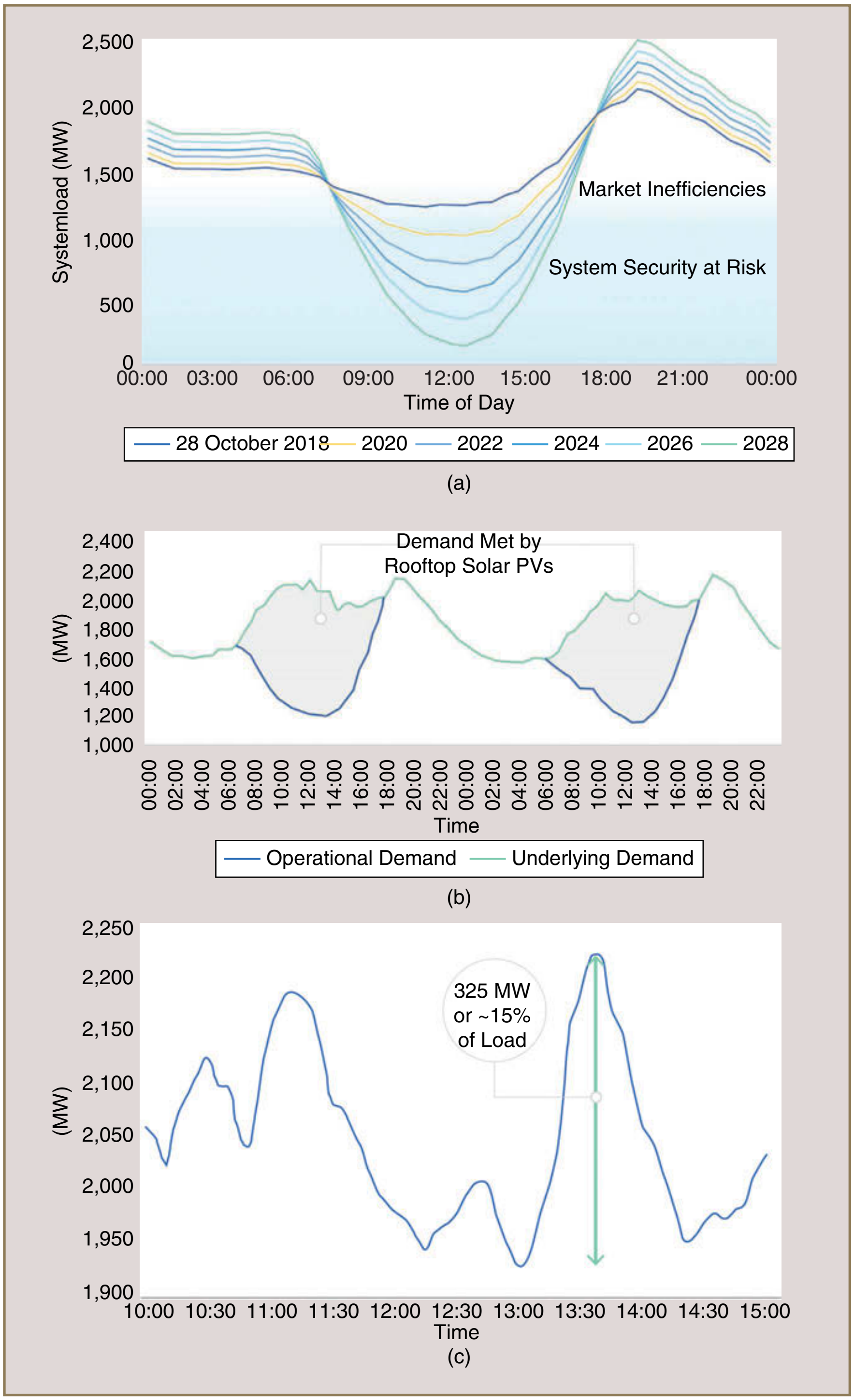

figure 3. (a) Forecast operational demand levels in SWIS, (b) operational versus underlying demand, 12–13 October 2019, and (c) system load fluctuations due to solar PV volatility as observed by AEMO on 18 October 2019.

manifesting in voltage rises on the distribution network. These rises present serious issues for network management when the physical thermal limits of network infrastructure are reached. The severity and rate of voltage rises have increased concurrently with the rapidly growing installation of rooftop solar PVs.

Under existing network connection arrangements, Western Power sets a default limit for residential customers that confines the export capacity of solar PV systems to 5 kW (Western Australia has a mix of single-phase and three-phase connections for residential properties). The limited communications capabilities of existing inverters (to send information and receive signals remotely) restrict the management of customer DERs in response to network conditions. Consequently, as installed DER generation capacity increases, Western Power would be required to undertake significant network augmentation or limit rooftop solar installation applications.

Customers, too, are impacted by power quality fluctuations resulting from two-way power flows on the distribution network. These fluctuations can trip the self-protection settings of inverters, decreasing output and limiting the financial benefits expected by customers.

Further, system security is put at risk by the inconsistent performance of inverters during system disturbances that can exacerbate fluctuations. These issues are all worsened by a large legacy fleet, size, and location of which the network and system operators have extremely limited visibility. The degree of compliance of these inverters with the existing mandatory settings is largely unknown, and their performance during events is unpredictable.

Last, the pressing concerns of low daytime demand and high evening peak may be addressed in part through increased battery storage. However, uptake in SWIS at the behind-the-meter, distribution, and transmission levels is currently low.

To address these issues, the roadmap recommends a range of technology-related actions to improve DER performance, the visibility and capability of the network and system operators, and the use of storage.

Inverter Standards

Inverter performance is central to managing the impacts of DERs, and in the near term, improvements to inverter standards are essential to managing power quality on the distribution network. The electrical standard applicable in SWIS is Australian Standard 4777.2:2015—*Grid Connection of Energy Systems via Inverter Requirements* (AS/NZS4777).

In 2019, Western Power made volt-var response settings a mandatory requirement of connection in its Network Integration Guidelines, which set out guidance for the installation of DER generation. These settings now require devices to act as a reactive power sink for grid voltages above 235 V (and a var source at voltages below 220 V). However, the DER Roadmap identified the need for further improvements to inverter performance in SWIS and recommended these be progressed through an uplift to AS/NZS4777, which came into effect in 2020. This change results in inverters automatically reducing output as voltage rises rather than tripping off at high voltages, reducing the risk of large numbers tripping off on mild days with low-load and high-solar generation.

Included in these improvements are enhanced autonomous inverter functions, including a frequency response triggered outside of a narrower band (with a threshold of 50.025 Hz now compared to the existing 50.25 Hz). This will more closely

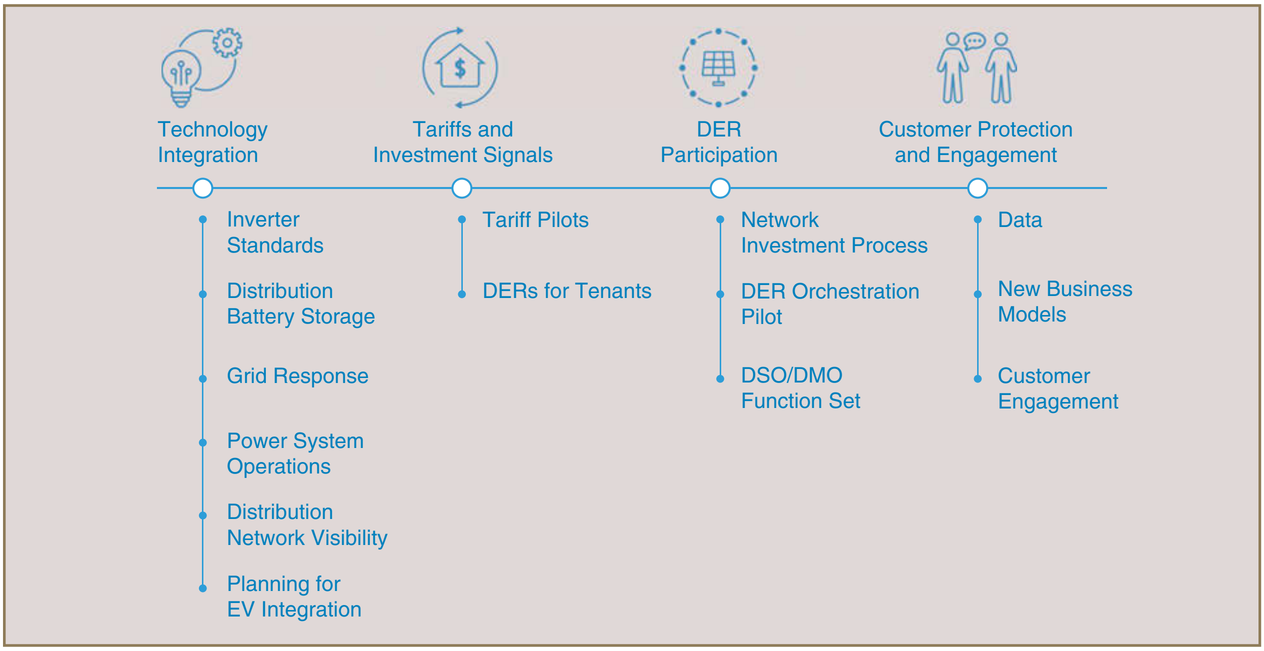

figure 4. DER Roadmap themes.

align inverters with the required frequency settings of large generation facilities in SWIS. It will ensure consistency across all generators in response to frequency excursions. Inverter capabilities to ride through short voltage disturbances are also under review for inclusion in the standard revisions.

Other changes include an improvement to communications functionalities. These are critical and foundational technical requirements that will facilitate the future participation of DERs by enabling the integration of aggregated DERs. The roadmap looks to understand the net benefit of updating the settings in the legacy inverter fleet (approximately 33% of the installed inverters). Many existing inverters can perform in line with updated standards, but they may require a firmware upgrade accomplished either remotely or by an on-site electrical contractor. The opportunity to target these inverters (particularly in network locations where issues are emerging more rapidly) is to be assessed by the distribution network operator weighed against the cost of such upgrades.

Last, AEMO and other national Australian energy agencies identified that as much as 40% of grid-connected inverters for solar PV systems across Australia do not fully comply with AS/NZS4777 and relevant distribution network service provider connection agreements. The roadmap recommends that a monitoring and compliance regime be further explored for SWIS to ensure inverters are compliant with requirements and can be upgraded as these requirements change.

Distribution Battery Storage

Storage is viewed as an essential component to ensure power system stability and security in a high-DER environment. Uptake of behind-the-meter storage is currently low in SWIS as high technology costs and a flat tariff structure have prevented storage systems from providing an attractive economic proposition for households.

However, the use of front-of-the-meter battery storage in the distribution grid provides an opportunity to unlock the full capability of storage across the electricity service value chain. They offer economies of scale for technology and installation costs while presenting a chance for more efficient coordination of storage capacity to provide broader benefits.

A distribution-connected battery can be located in areas to provide localized network benefits. For example, batteries can be operated to store energy generated by local solar PVs and exported later during the evening peak. This can help distribution feeders that are under thermal stress and defer the need for costly network augmentation by reducing energy flows across low-and medium-voltage distribution transformers at these times. At sufficient numbers and capacity, several distribution-connected batteries can be coordinated to respond to broader system requirements and deliver market services.

In SWIS, these benefits are not currently available to customers who install behind-the-meter storage. Similar opportunities are contemplated as part of the DER participation theme discussed here.

Under PowerBank trials recommended in the roadmap, customers can share these benefits through "virtual" storage products that allocate a share of excess solar generation storage in a community battery for a daily fee. This provides a cost-effective alternative to expensive behind-the-meter storage while allowing customers access to value streams they might otherwise be unable to access.

The roadmap recommends installing PowerBank batteries to address localized network constraints with an attached customer virtual storage product where possible, plus a range of regulatory changes to facilitate the broader use of distribution storage where efficient. As per the roadmap, 10 PowerBanks (each 116 kW/464 kWh) were installed in 2020 to provide network support. Consistent with the DER Roadmap, Western Power has also released the "Distribution Storage Opportunities" information paper to advise the industry on future storage opportunities to provide services to the network operator.

Grid Response and Power System Operations

High levels of DERs present challenges across the power system. The physical limits of the low-voltage distribution network infrastructure are being tested more frequently by voltage fluctuations, which may require significant augmentation and additional costs. The distribution network is also constrained by a narrow voltage standard defined in Western Australia legislation—a nominal voltage of 240 V ±6% for 100% of the time. This differs from all other Australian jurisdictions, which specify a nominal voltage of 230 V with a wider tolerance of +10%/-6% for 98% of the time.

The increasing DER penetration causes suburban distribution feeders to act as a net energy exporter at certain times. This adds complexity to the management of the power system. Increases in the variability of generation compound the problem. Without adequate consideration of the magnitude and direction of power flows at the distribution level, the system operator is faced with significant risks during system events.

To improve the ability of Western Power to manage voltage, the roadmap recommends the urgent installation of reactive power compensation (enacted by Western Power in 2020), and the amendment of the voltage standard in Western Australia legislation to align with the Australian standard.

The roadmap also recommends the system operator's dynamic modeling systems be enhanced to adequately incorporate DERs. This is to be complemented by a review of existing underfrequency load-shedding arrangements to ensure they can maintain system stability on low demand days, and revision of system restart arrangements.

Network Visibility

To manage the greater complexity for distribution network operation, Western Power requires better visibility of local power quality, flows, network constraints, and real-time DER capabilities. To facilitate this capability, the roadmap recommends Western Power assess its existing visibility capability, leading to an investment plan for deploying equipment to enhance network visibility.

In the National Electricity Market, a DER register was established to capture a range of metadata for installed and newly installed DER devices. The roadmap recommends a similar register be created for SWIS to enable AEMO to refine its forecasting and efficiently manage its system and market operations. AEMO and Western Power have overseen the addition of data for approximately 90% of DERs installed in SWIS. The ongoing DER register was expected to "go live" in early 2021.

Electric Vehicle Integration

Electric vehicle (EV) uptake has been exceptionally slow in Western Australia, and it is not expected to have an impact on SWIS before 2025. However, the future cost of technologies, customer sentiment, and local or national government policies remain uncertain. The capacity of EV batteries is significantly larger than storage systems currently being installed in SWIS. Their operation will likely have a sizeable impact on SWIS. The timing and location of charging infrastructure for EVs also present significant risks and opportunities.

The roadmap recommends that Western Power begin planning work for the integration of EVs in the grid. This work is to consider the location of household and larger fast-charge infrastructure and trials to test and understand the capabilities of vehicle-to-grid technology.

DER Roadmap: Tariffs and Investment Signals

As noted previously, current tariff structures in Western Australia do not provide appropriate signals for grid-efficient behavior. Residential customers in the SWIS pay a fixed charge per connection (of AUD$1.05/day) and a flat rate (of AUD$0.29/kWh) (pricing as of 2020–2021). Additionally, at the time of writing the roadmap, buyback payments for energy exports were offered under the Renewable Energy Buyback Scheme (REBS) at a flat AUD$0.07/kWh. This rate is above the weighted average wholesale energy cost in the middle of the day (which, in recent years, has been around AUD$0.03/kWh and could decline further with energy prices in the Western Australian Wholesale Energy Market recording negative values with increasing regularity at this time of day).

Tariff Pilots

The roadmap finds that current tariff structures are incompatible with a high DER energy system and result in significant cross subsidies benefiting those with rooftop solar PVs. The roadmap recommends tariff pilots to encourage customers to consume energy in a way that supports the grid. The pilots will help policy makers understand how alternative tariffs can play a role in promoting efficient investment in and the use of DERs, including batteries, and to share the benefits of efficient behavior with customers.

A time-of-use tariff that provides a strong incentive to shift consumption to between 9 a.m. and 3 p.m. with a variable rate of AUD$0.08/kWh during the middle of the day is currently under trial. This tariff provides customers with a willingness to shift load with a clear price signal to do so either through behavior change or some form of automation.

In August 2020, REBS was superseded by the Distributed Energy Buyback Scheme (DEBS) for households with new or upgraded solar PV systems. DEBS introduces time-of-export pricing for household energy exports and offers buyback to exports from battery and electric vehicles for the first time. Instead of a flat AUD$0.07/kWh, households were offered AUD$0.10/kWh for exports between 3 p.m. and 9 p.m. and AUD$0.03/kWh at all other times. This change provides customers with a further incentive to shift consumption to the middle of the day (to increase self-consumption) and a price signal to install west-facing rooftop PV panels to maximize generation during peak load periods.

While DEBS represents a modest reduction to total buyback payments for a typical system, it was generally well received by customers and industry and across the sector. At the time of writing this article, it has not affected household PV installation rates. As well as more efficient investment in DERs, DEBS has played a role in raising awareness and educating households about the different values of energy at different times of the day.

DER Roadmap: DER Participation

The theme's objective is to build a future where customers with solar, storage (including EVs), and other small-scale devices can be active participants in the power system. It is envisaged that this will be done by aggregating many small devices to provide electricity services and act as a "virtual power plant."

While there have been many trials that test DER aggregation on a small scale, the DER Roadmap envisages that most DERs will need to be managed or directed, at least in a basic way, to ensure that the future power system can be managed securely and safely. Few, if any, jurisdictions are operating with DERs as a central participant in power systems and markets.

Existing regulatory and market structures that are built around single-direction energy flows do not conceive of DERs as a participant in the same way as utility-scale generators or large facility demand-side participation. A change in thinking in operational rules, practices, and procedures is needed to enable a true transition to two-way power flows.

To achieve this for SWIS, the DER Roadmap recommends a DER orchestration pilot to serve as a crucial test of DER aggregation capability. This will enable customers' devices to provide services to the network operator and participate in the wholesale energy market, including the provision of essential system services where the DERs have the capability.

An end-to-end virtual power plant pilot (Project Symphony) will demonstrate DERs' ability to support the power system. This includes helping solve local network issues and participating in local markets, including testing the ability to replace system support services traditionally performed by large generators. The pilot is based in metropolitan Perth's outer southeast, an area with recent rapid expansion in residential construction. The location was selected for its high PV penetration (around 50%), and local distribution system that experiences high voltages during midday and high thermal load during evening demand peaks.

The pilot seeks to test the value to the network operator realized by managing DERs as an alternative to network augmentation.

As well as testing the technical parameters to enable and orchestrate DER participation, Project Symphony will be important in setting customer norms and developing acceptance of DER orchestration. Testing customer service offerings that manage DER generation will provide valuable learnings to support aggregation beyond the trial.

Following the pilot, capabilities will be expanded across SWIS in a managed way to integrate virtual power plants at scale into SWIS. The DER Roadmap proposes that aggregated DERs will begin participating in the local wholesale energy market, including the provision of essential system services where capable, by 2023.

DER Roadmap: Customer Engagement and Protections

Consumer engagement and customer protection under emerging business models make up the final theme of the roadmap.

Consumer Engagement

Central to the roadmap approach is delivering the best outcomes for consumers. Figure 5 outlines the current and future opportunities for households regarding DERs. The DER Roadmap actions will open up future technologies and choices, avoid expensive upgrades to the network, and enable everyone to share in the benefits of PVs and other forms of DERs. But the current level of community understanding of some energy concepts, such as minimum demand issues and the need to make changes to integrate DERs into the power system, is low.

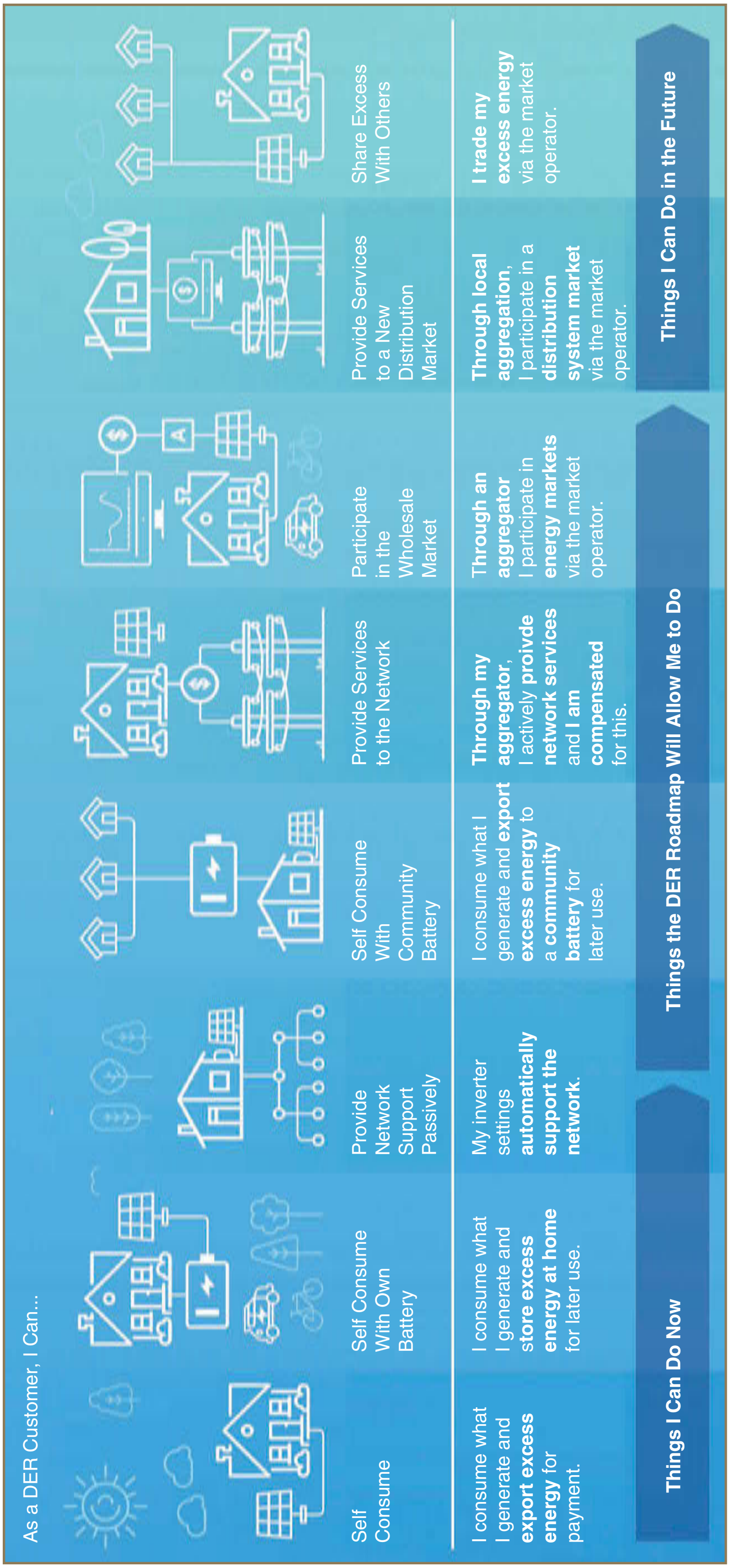

figure 5. The DER customer journey.

Customers' acceptance of their DERs becoming part of a smart and integrated energy system is central to maximizing its potential. Customers need to be part of the journey that takes DERs from being passive to becoming active participants in the electricity system.

The need to start a conversation with consumers has also been considered in materials developed to sit alongside the technical roadmap publication. A video and a consumer-facing website have been developed to explain this complex challenge. The government-owned energy entities and Energy Policy WA are working together to find the best way to bring consumers along for the ride. Early actions include broad messaging through mainstream media channels about the transition to a future energy system that involves more renewable energy and new ways of integrating DERs into the power system and engaging with households. Utility campaigns highlight new energy pilots and products, such as community batteries. Energy Policy WA has started engaging with interested consumers to slowly build community knowledge and energy literacy.

Customer Protections

Energy Policy WA is undertaking a licensing framework review to ensure a customer protection framework evolves with the development of new business models and energy service offerings in a high-DER future. This review aims to ensure that consumers of behind-the-meter electricity services are covered by robust customer protection arrangements. In the first instance, it is proposed that a code of practice will be developed for behind-the-meter generation and storage service providers. It could be expanded in the future to cover other emerging business models.

The management of customer data was also identified as an important issue. On 26 November 2017, the Australian government introduced the Consumer Data Right that gives consumers greater access to and control over their data. This is expected to apply to customer energy data in other parts of Australia from late 2021. Western Australia will assess the regulatory and policy arrangements for the Consumer Data Right for the energy sector once current reforms in the sector are substantively completed. This will ensure it is fit for purpose and considers the specific ways in which consumers with DERs engage with Western Australia's energy systems in the future.

Conclusion

Western Australia has moved quickly to put an action plan in place to support the transition of SWIS and regional microgrids to a high-DER future. The state government's ownership of major industry players for the residential sector has facilitated this fast response. The isolated nature of SWIS and the many microgrids has focused attention on the problem.

Developing an action plan is only the first step. Successful implementation will depend on getting the technology right as well as bringing customers along for the journey. Consumer understanding of the end goal (e.g., integrating more renewable energy at low cost) will help to build acceptance of changes in how their DER is managed and how it engages with the electricity system over time. This will enable consumers to continue to install DERs while keeping the electricity system reliable, secure, and affordable.

The need to closely engage customers has also been born out in the Onslow DERMS project, which found that generation management can gain customer acceptance if there is a shared vision that has broad-base support.

For Further Reading

"Energy transformation taskforce, distributed energy roadmap," Energy Policy WA, Perth, Western Australia, Dec. 2019. [Online]. Available: https://www.wa.gov.au/government/distributed-energy-resources-roadmap

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"Integrating utility-scale renewables and distributed energy resources in the SWIS," Australian Energy Market Operator, Perth, Western Australia, Mar. 2019. [Online]. Available: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Integrating-Utility-scale-Renewables-and-DER-in-the-SWIS.pdf

Biographies

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by Mel Olken and John Paserba

in memoriam

Michael Henderson

MICHAEL HENDERSON PASSED away after a year-long courageous battle with illness on Saturday, 22 May 2021, in Longmeadow, Massachusetts, United States. Mike served as the editor-in-chief (EIC) of *IEEE Power & Energy Magazine* from 2016 to 2020 and was on the magazine's editorial board since its inception in 2003, contributing to multiple issues as a guest editor and author. His mission was to make the magazine accessible to a broad audience, and he led the editorial board with that passion.

Mike was a proud native son of Brooklyn, New York, United States. He received two master of engineering degrees: one in electrical power engineering in 1977 and one in electrical engineering (M.E.E.) in 1976—both from Rensselaer Polytechnic Institute. In 1975, he earned a B.S. degree in electrical engineering from the Polytechnic Institute of New York (now New York University), where he served as an adjunct lecturer from 1993 through 1999. From July 1999 until he retired in 2020, he was the director of Regional Planning and Coordination at ISO New England.

Previously, he worked at the New York Power Authority (NYPA) (1983–1999), Long Island Lighting Company (1980–1983), and American Electric Power (AEP) (1977–1980). Mike often shared memories of his time at AEP, which was a supportive and stimulating work environment for young engineers and a source of lifelong friends and colleagues.

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Michael Henderson

Mike was a registered Professional Engineer in the state of New York. He was a longtime contributor to the IEEE Power & Energy Society (PES) and other organizations, including CIGRE and the Electric Power Research Institute.

PES was Mike's second family, where he cultivated friendships all over the world. Mike was involved in numerous PES technical activities, taking leadership roles in the Transmission and Distribution (T&D), Power System Dynamic Performance, and Power System Operation, Planning, and Economics Committees. He made significant contributions within the T&D Committee's High-Voltage dc (HVdc) and Flexible ac Transmission Systems (FACTS) Subcommittee.

PES was Mike's second family, where he cultivated friendships all over the world.

Mike organized and presented technical seminars and dozens of panels and technical papers at IEEE and other forums. His sessions often drew large crowds when he chaired or spoke, imparting his Brooklyn charm and sense of humor. He had fun and loved bringing fun to others. His passion for discovering practical applications of cutting-edge technologies (especially FACTS and HVdc) contributed to addressing operational challenges in the real world of deregulated markets. Mike was elected IEEE Fellow in 2016 with the citation, "For contributions to the application of high-voltage dc and flexible ac transmission systems."

He is survived by his wife Dorita, son Robert, and daughter Gabby. The family asks those wishing to honor Mike's memory to continue his commitment to the engineering profession by donating to the IEEE PES Scholarship Plus Initiative. (See the details later.)

A Natural for EIC

Some 40+ years ago, a bright-eyed recent M.E.E. graduate was assigned as a trainee to the Electrical Generation Section at AEP in New York City that I headed, and that is how my and Michael's friendship commenced. Mike proved himself to be a very competent engineer with extraordinary technical knowledge while remaining humble and very willing to listen to the realities of experienced elders. AEP's acquisition of the Columbus and Southern utility led to the relocation of AEP to Columbus, Ohio, and the scattering of many, including Mike, who did not wish to leave the New York area.

Michael and I went our separate ways, but our associations with IEEE PES enabled our reunification. During my time as the executive director of PES and with Mike's involvement with our Society, we were able to reconnect. After my retirement as PES executive director and installation as the founding EIC of our newly created *IEEE Power & Energy Magazine*, Mike and I spoke. He made a strong, impressive argument for association with the editorial aspects of this publication. Without hesitation, I accepted his offer and invited him to join the magazine's editorial board, where he quickly became a truly valuable asset as a talented author as well as a superb guest editor whose contributions were always highly regarded.

When the time came for me to step down and lead the search for a replacement, I knew that I need not look too hard because Michael was my prime candidate. He was totally familiar with the routines that had been established and understood the criteria that governed the publication and what was required to meet the needs of potential authors. He also understood the role of IEEE Publications in the process and was familiar with the staff. The only drawback was his hesitation to undertake the challenge, which would be in addition to the workload at ISO New England. I cannot convey my pleasure when I finally learned that he would accept.

Mike's five-year tenure as the EIC was an unqualified success. I admired each issue, noting both the timely theme as well as the quality of the selected articles. I was aware of the editorial support that his son Robert contributed and how proud that made Mike feel.

Mike and I were in touch during his five years as editor and through all of the travails of this past year. I marvel as I think of his attitude as his condition went through a sinusoidal curve toward the inevitable ending. During that year, he spoke of the love for his family that I know was totally reciprocated. My thoughts today are not only of Mike, but also of Dorita, Robert, and Gabby, and I can only offer my sincerest condolences. Rest in peace, my friend!

—Mel Olken, IEEE Power & Energy Magazine EIC, 2003–2016

The family asks those wishing to honor Mike's memory to continue his commitment to the engineering profession by donating to the IEEE PES Scholarship Plus Initiative.

Beyond the Technical

I met Mike when he was at NYPA and I was at General Electric. We both changed jobs in the 1998–1999 time frame but continued to work on several IEEE PES committees together over the years and were both members of *IEEE Power & Energy Magazine's* editorial board.

We bonded over baseball and the New York Yankees. Mike would say, "When I was a kid, I had to become a Yankees fan because the devil himself, Walter O'Malley, moved the Brooklyn Dodgers to some far-away place named Los Angeles, California." I became a Yankees fan while living near the Yankees AA farm team in upstate New York, where I watched the young kids who eventually became four-time World Series winners from 1996 to 2000.

One favorite memory I have is attending a Tampa Ray's game with a colleague while at the 2007 PES General Meeting. Mike was also on his way to the game, so we shared a cab to the stadium. We split up at the entrance since we had our tickets while Mike headed to the ticket line. Soon after settling into our seats, Mike walked down the aisle and sat down next to us. We wondered how he obtained his ticket right next to where we were sitting. Amazing what that man with Brooklyn sensibilities could arrange with a ticket agent! We went to a game again at the next General Meeting, where I had the pleasure to meet his son, Robert.

I sadly remember a phone call I got from Mike in April 2020. In privacy, he shared about his illness and his planned course of treatment. He asked if I could help with the upcoming issues of *IEEE Power & Energy Magazine* beyond my role of associate editor, History. I immediately said yes. The arrangement came with unlimited support from Robert to assist with the remaining 2020 issues. Mike contributed as much as his treatment schedule allowed throughout the remainder of 2020.

We will all miss a great man, a power and energy professional, a husband to Dorita, a father to Robert and Gabby, a dedicated EIC, and a dear friend.

—John Paserba, IEEE Power & Energy Interim EIC, 2020

To Donate in Mike's Honor

Please go to the "IEEE Tribute Giving" webpage (https://www.ieeefoundation.org/how-to-give/tribute-giving) and provide all relevant information. Below "Donation Information," click the dropdown arrow right of "Designation" and select "IEEE PES Scholarship Plus Fund." Next, below "Tribute Information," enter "Mike Henderson." To the right of "Type," select "In Memory of." Click "Donate Now" to finish.

IEEE & PES awards

accolades to the 2021 recipients

IEEE AND THE IEEE POWER & ENergy Society (PES) recently announced the 2021 IEEE medals, technical field awards, and Society-level award recipients. The honorees are selected through a comprehensive nomination and evaluation process. Please join us in congratulating this year's honorees for their exceptional achievements.

IEEE Awards

2021 IEEE Medal in Power Engineering

The IEEE Medal in Power Engineering was established in 2008. It is presented to an individual for outstanding contributions to the technology associated with the generation, transmission, distribution, application, and utilization of electric power for the betterment of society. The award consists of a gold medal, bronze replica, certificate, and honorarium. The medal is sponsored by the IEEE Industry Applications Society (IAS), IEEE Industrial Electronics Sociey, IEEE Power Electronics Society, and PES. The 2021 IEEE Medal in Power Engineering was awarded to Praveen K. Jain for contributions to the theory and practice of high-frequency power-conversion systems.

Praveen K. Jain

Praveen K. Jain revolutionized many aspects of high-frequency power-conversion technology with innovations that found application in the space, telecommunications, computer, induction melting, and renewable energy industries. He was one of the first researchers to solve problems in the starting of thyristorized series-tuned induction melting power supply systems. He also developed new power converter topologies and control techniques for photovoltaic microinverters.

He is an IEEE Fellow, recipient of the 2017 IEEE Canada Power Medal, and the founding director of the Center for Energy and Power Electronics Research (ePOWER) at Queen's University in Kingston, Ontario, Canada.

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IEEE Technical Field Awards With PES Affiliation

IEEE Technical Field Awards are bestowed for contributions or leadership in specific fields of interest of the IEEE. The following IEEE Technical Field Awards are either cosponsored by PES or the awardee has named their affiliation with PES.

IEEE Herman Halperin Electric Transmission and Distribution Award

The IEEE Herman Halperin Electric Transmission and Distribution Award recognizes outstanding contributions to electric transmission and distribution. This was presented to Brian Stott for contributions to the development and application of power flow and optimal power flow analysis.

IEEE Charles Proteus Steinmetz Award

The IEEE Charles Proteus Steinmetz Award recognizes exceptional contributions to the development and/or advancement of standards in electrical and electronics engineering. Haran Karmaker, is the recipient of this award, for leadership in and contributions to the development of standards for electrical machines.

IEEE Richard Harold Kaufmann Award

The IEEE Richard Harold Kaufmann Award recognizes outstanding contributions in industrial systems engineering. Stephen McArthur received this award for innovative contributions to the advancement of intelligent systems for power engineering applications.

IEEE Nikola Tesla Award

The IEEE Nikola Tesla Award recognizes outstanding contributions to the generation and utilization of electric power. Zi-Qiang Zhu received this for contributions to the design, modeling, control, and application of ac permanent magnet machines and drives.

IEEE Technical Field Awardees


Brian Stott


Haran Karmaker


Stephen McArthur


Zi-Qiang Zhu


Philip T. Krein

IEEE Transportation Technologies Award

The IEEE Transportation Technologies Award recognizes advances in technologies within the fields of interest to the IEEE as applied in transportation systems. Philip T. Krein was presented with this award, for contributions to electric vehicle battery management and hybrid system optimization.

PES Awards

The following awards are presented by PES to recognize the achievements of deserving PES members.

IEEE PES Award for Excellence in Power Distribution Engineering

- ✔ Thomas E. McDermott, for contributions to simulation techniques for power distribution systems, including integration of distributed energy resources and modeling lightning transients.

IEEE PES CSEE Yu-Hsiu Ku Electrical Engineering Award

- ✔ He Renmu, for contributions in measurement-based load modeling of power systems.

IEEE PES Cyril Veinott Electromechanical Energy Award

- ✔ Bulent Sarlioglu, for contributions to the design, development, and manufacturing of electric motors and drives for industrial and aerospace applications.

IEEE PES IAS A.P. Seethapathy Rural Electrification Excellence Award

- ✔ Satish Chaparala, for significant contributions to understanding and addressing electrical safety issues in developing countries.

IEEE PES Leadership in Power Award

- ✔ Mark Carpenter, for supporting the development of engineering resources to advance power systems solutions, sponsoring mentoring programs, and promoting industry professionals' collaboration.

IEEE PES Nari Hingorani Custom Power Award

- ✔ Ambrish Chandra, for contributing to the improvement of power quality and grid integration of renewable energy sources.

IEEE PES Nari Hingorani FACTS Award

- ✔ Rajiv K. Varma, for advancing FACTS controllers application in education, research, and professional society, and for developing an innovative STATCOM technology utilizing PV solar farms.

IEEE PES Outstanding Power Engineering Educator Award

- ✔ Shmuel S. Oren, for contributions to mentorship and education on the design and operation of electricity markets.

IEEE PES Outstanding Young Engineer Award

- ✔ Daniel Kenneth Molzahn, for contributions to the theory and practical application of nonlinear optimization algorithms for electric power systems.

IEEE PES Prabha S. Kundur Power System Dynamics and Control Award

- ✔ David J. Hill, for contributions to the power network modeling, theory, analysis, and control.

IEEE PES Ramakumar Family Renewable Energy Excellence Award

- ✔ Mukesh Nagpal, for protection solutions facilitating the grid integration of renewable energy resources.

IEEE PES Roy Billinton Power System Reliability Award

- ✔ Chongqing Kang, for contribution to power system reliability analysis and enhancement under high renewable energy penetration.

IEEE PES Uno Lamm High Voltage Direct Current Award

- ✔ Hans Bjorklund, for outstanding contributions and visionary leadership to the development of advanced control and protection systems for HVDC.

IEEE PES Wanda Reder Pioneer in Power Award

- ✔ Marianela Herrera Guerrero, for outstanding contributions and leadership in efficient and reliable operation of public utilities, inclusiveness and diversity of power marketing, and the transformation of the energy structure.

(continued on p. 96)

fault analysis theory

an updated edition

THIS ISSUE'S "BOOK REVIEW" column discusses *Power Systems Modelling and Fault Analysis: Theory and Practice,* second edition, written by Nasser Tleis. The reviewer writes, "This book is suitable for graduate level power engineering students as well as upper division undergraduate students who have had a first course in power engineering."

Power Systems Modelling and Fault Analysis: Theory and Practice

By Nasser Tleis

This new resource by Dr. Nasser Tleis provides a valuable update to the first edition of *Power Systems Modeling and Fault Analysis.* He is the vice president of Power Transmission Planning at Dubai Electricity and Water Authority. He has a Ph.D. degree from the University of Manchester Institute of Technology. Tleis has more than three decades of experience working in the utility industry.

Power Systems Modeling and Fault Analysis focuses on fault analysis, providing the theory behind the modeling and solution approaches used in industry practice. This edition builds on the solid foundation of fault-analysis techniques from the first edition with updates to the presentations of the fundamentals for apparatus modeling and fault-analysis techniques. Like the first edition, the second includes a discussion on international standards for short circuit analysis. The text includes several numerical examples to help the reader learn how to apply the techniques.

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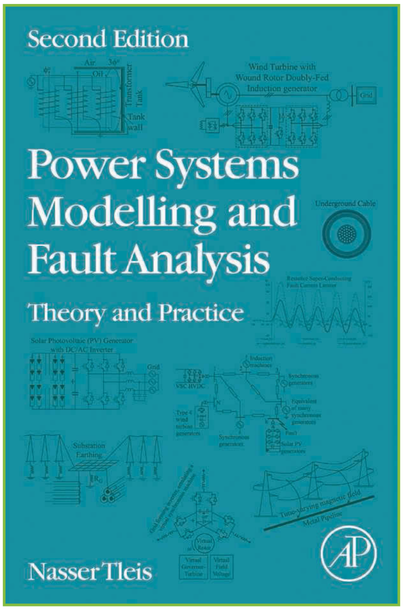

As was the case with the first edition, this edition first introduces power systems' faults and the application of symmetrical components for fault analysis. Next, the book provides in-depth coverage of modeling techniques for power apparatus, including overhead lines, underground cables, rotating machines, and inverter-based power sources.

This edition has additions to the section on modeling underground cables and major updates related to modeling the fault behavior of wind turbines, photovoltaic generation, and other inverter-based resources. The section on the short circuit behavior of inverter-based resources includes a discussion of grid codes related to the behavior of generation resources. The book also introduces the emerging topic of grid-forming inverters, starting with a thorough discussion of different control objectives, such as droop control and virtual synchronous machines, and follows up with a discussion of their fault responses.

The presentation on fault-analysis techniques now includes techniques for performing fault analysis for large systems with fault-current sources that behave as voltage sources, such as synchronous generators, alongside inverter-based resources that behave as current sources. This addition is a valuable resource for both practicing engineers and students learning fault-analysis techniques. The book includes a discussion on developing network equivalents along with practical approaches for dealing with model data uncertainties. There is a brief discussion of risk assessment and safety considerations.

The second edition includes an updated presentation on approaches to control short circuit current levels, both from an operational viewpoint and from a power-system-planning and design viewpoint. The chapter includes a discussion on different types of fault-current limiters including superconducting fault-current limiters.

This book is suitable for graduate-level power engineering students and upper-division undergraduate students who have had a first course in power engineering. The book will also be of interest to practicing engineers seeking a better understanding of modern fault-modeling and analysis techniques, especially for systems with a high penetration of inverter-based generation sources.

—Brian K. Johnson

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awards *(continued from p. 94)*

IEEE PES Prize Paper Awards

- ✔ Nadew Adisu Belda, Cornelis Arie Plet, and Rene Peter Paul Smeets, "Full-Power Test of HVDC Circuit-Breakers With AC Short-Circuit Generators Operated at Low Power Frequency," *IEEE Trans. Power Del.*, vol. 34, no. 5, pp. 1843–1852, Oct. 2019.
- ✔ Swaroop S. Guggilam, Changhong Zhao, Emiliano Dall'Anese, Christine Chen and Sairaj V. Dhople, "Optimizing DER Participation in Inertial and Primary-Frequency Response," *IEEE Trans. Power Syst.*, vol. 33, no. 5, pp. 5194–5205, Sept. 2018.

IEEE PES Working Group Recognition Award—Outstanding Standard or Guide

- ✔ Jim McDowall, Committee Working Group chair, Mike Nispel, Working Group vice-chair, "IEEE 1679, Recommended Practice for the Characterization and Evaluation of Energy Storage Technologies in Stationary Applications." IEEE PES Energy Storage and Stationary Battery Committee.

IEEE PES Working Group Recognition Award—Outstanding Technical Report

- ✔ Nenad Uzelac, Working Group chair, "PES-TR64, Impact of Alternate Gases on Existing IEEE Standards," IEEE PES Switchgear Committee.

IEEE PES Outstanding Chapter Awards—Small Chapter

- ✔ Pune Chapter, Chapter Chair Surekha Deshmukh.

IEEE PES Outstanding Chapter Awards—Large Chapter

- ✔ Malaysia Chapter, Chapter Chair Hazlie Bin Mokhlis.

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PES meetings

for more information, www.ieee-pes.org

THE IEEE POWER & ENERGY Society's (PES's) website (http://www.ieee-pes.org) features a meetings section, which includes calls for papers and additional information about each of the PES-sponsored meetings. Please check the conference website for the most current information.

September 2021

IEEE PES GT&D International Conference and Exposition, Istanbul (GTD 2021), postponed until Spring 2023, Istanbul, Turkey, contact Omer Usta, usta@ieee.org, https://ieee-gtd.org/

IEEE International Smart Cities Conference (ICS2), 7–10 September, virtual event, contact Soufiene Djahel, s.djahel@mmu.ac.uk, https://attend.ieee.org/isc2-2021

IEEE PES Innovative Smart Grid Technologies Latin America (ISGT LA 2021), 15–17 September, virtual event, contact Jorge Lafitte, dr.jorge.lafitte@ieee.org, https://www.isgt2021.org/

October 2021

IEEE Electronic Power Grid (eGRID 2021), 4–6 October, virtual event, contact Chan Wong, chan.wong@gmail.com

IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe 2021), 18–21 October, virtual event, contact Pourakbari Kasmaei Mahdi, mahdi.pourakbari@aalto.fi, https://ieee-isgt-europe.org/

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Fifth International Conference on Energy Internet and Energy System Integration (EI2 2021), 22–24 October, Taiyuan, China, hybrid event, contact Wenping Qin, qinwenping1027@163.com, https://attend.ieee.org/ei2-2021

November 2021

IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC 2021), 21–23 November, virtual event, contact Boby Philip, boby.philip@ieee.org, https://ieee-appeec.org/

IEEE Sustainable Power and Energy Conference (iSPEC 2021), 25–27 November, Nanjing, China, contact Hui Yang, huiyang@seu.edu.cn, http://ieee-spec.csee.org.cn/2021

December 2021

IEEE PES Innovative Smart Grid Technologies Asia (ISGT Asia 2021), 5–8 December, Brisbane, Australia, hybrid event, contact Tapan Saha, saha@itee.uq.edu.au, https://ieee-isgt-asia.org/

February 2022

IEEE PES Innovative Smart Grid Technologies (ISGT 2022), 21–24 February, Washington, D.C., United States, contact Kathy Heilman, kathy.heilman@ieee.org, https://ieee-isgt.org, https://ieee-isgt.org

April 2022

IEEE PES Transmission and Distribution Conference and Exposition (T&D 2022), 25–28 April, New Orleans, Louisiana, United States, Carl Segneri, carlsegner@sbcglobal.net, http://www.ieeet-d.org

July 2022

IEEE PES General Meeting (GM 2022), 17–21 July, Denver, Colorado, United States, contact Roseanne Jones, roseanne.jones@ieee.org

For more information on additional technical committee meetings, webinars, and events, please visit our IEEE PES calendar: https://www.ieee-pes.org/meetings-and-conferences/conference-calendar.

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when minimum demand emerges as an issue due to abundant rooftop solar? The tools used to secure grid visibility, analyze decisions, and manage data are still in their infancy.

Although the topology of the Australian system has unique characteristics, we know from our colleagues in other jurisdictions that the operational challenges and new analytic requirements we are experiencing are not unique. The transmission owners and system operators around the world recognize that to navigate successfully to a low-carbon renewable power system, the technical challenges must be understood and addressed. I am proud of the work AEMO and others in the Australian power sector are doing to tackle these issues and contribute to an international understanding of efforts to decarbonize the power system.

Along with increased technical complexities, transitioning to a low-carbon system is bringing new challenges to public policy, the socioeconomic framework, and business model conventions that collectively define the power industry. The business models designed for an era when there was a clear difference between supply and demand do not work as well in a system that must accommodate increasing consumer investments in solar generation and storage. The grid's future is being driven by the decisions that occur across dining room tables and is no longer the exclusive domain of boardrooms and regulatory commissions.

In this issue, my colleagues discuss how AEMO and others in Australia are going about solving technical challenges. We also touch on the reforms that are occurring and how we must change our markets and regulations to address the very different energy future that we are creating. After all, this is an essential service that, with decarbonization, is even more critical to the health of our economies.

I highlight what I believe are five universal features of the transition to be addressed, regardless of jurisdiction, if the creation of a sector-coupled, low-carbon power system is to be successful:

1) *The transition is a technology-driven, socioeconomic change in the power system*: Like parenting and aging, this transition is not for the fainthearted. The power industry is characterized by long-lived assets, powerful incumbents, and well-honed regulatory and market conventions. It serves a critical public interest for affordable and reliable electricity, and, for all these reasons, there is a strong incentive to take things incrementally. The scope and scale of this change mean that tepid and small steps are no longer pragmatic or feasible. We need to be prepared to envision a different future and take the necessary steps to achieve it. We must also acknowledge that the rules and practices we are putting in place support a transition. They may be temporary, revised, or replaced in the future.
2) *Independent, proactive system-wide planning with government support will benefit consumers and developers*: I entered the power industry in the United States in the late 1980s when the system was reluctantly transitioning from one that was dominated by vertically integrated utilities to one that supported independent generation and development. As a result, there was a move to either transparent, independent planning by utilities or regional planning by independent operators to level the playing field among new generators. Where additional transmission infrastructure was required, this focused on connecting discrete renewable developments. In these circumstances, traditional planning and regulatory conventions work.

This is not the case for the type of transition we are confronting now. The national transmission asset base will need to triple over the next several decades to accommodate the level of additional renewable generation required to replace retiring fossil resources. We know that just building out the transmission network is insufficient; we need to identify the complementary investments that will be necessary for the system to remain affordable, secure, and reliable. We must also be mindful of the social license issues associated with land usage and economic development.

The transition is about more than the rapid investment by individuals in distributed resources. There is the expected growth of electric transportation and the electrification of other elements of the economy. The green and blue hydrogen economy will develop. There is a need for greater resiliency to address climate change (bushfires and harsher storms). Together, it becomes clear that the nature of system planning involves broad socioeconomic issues. Processes are needed to integrate sound engineering and government policy and support. The process must be open, consultative, and allow for innovation as well as a close coordination of transmission development and the construction of supply.

Given the level of investment required and the societal and economic risk if we do not get it right, we cannot just hope that the system will work in the end: we will need to make it so. To ensure that this happens in the NEM, AEMO is expanding the planning capabilities of its Integrated System Plan to take into account all of the potential system effects. The aim is that, with the support of governments and utilities, the necessary network investments will be in place before the coal retirements and ahead of new generation.

In Western Australia, AEMO is supporting the state government, which is taking on a larger decision-making role. We are also working with governments throughout the country to define and support the development of renewable energy zones and avoid issues if new supply is developed haphazardly. Although some in the industry were concerned about what they termed a return to *central planning*, this view is changing with wider acknowledgment of the level and nature of investment required.

3) *Access to information must be as universal as access to electricity*: The corollary of more transparent and collaborative planning is the ability to share information about both the planned and the real-time power grid. I grew up in the industry at a time when there were three universal truths:
   - First, that electricity was an essential service and that in modern society this meant that the goal should be to provide universal access to affordable and reliable electricity, which, on a personal note, I hope is attained in my lifetime.
   - Second, that there are aspects of the provision of electricity at a scale that make it a natural monopoly, and hence, it should be regulated as such.
   - And third, with a nod to my revered predecessors Alfred Kahn and Peter Bradford at the New York Public Service Commission, as a regulated monopoly operating in a sphere of complex engineering, the regulated utility will always have more information than the regulator. Accordingly, there is a need for a set of incentives in the form of a regulatory compact to promote efficient investment.

Although I think that all three of these attributes will remain for the foreseeable future, one aspect is changing: the sharing of information. As I think over my last years at AEMO, one of our greatest risks as a system operator was caused by our lack of visibility into the system. This limited how we communicated to others what we were seeing and comprehending. The power system, with its multiple individual asset owners operating in a coordinated way in real time, is an engineering marvel. As we redesign the system around weather and climate as our primary fuel source, governments, industry, developers, investors, and even individual homeowners have a stake in real-time, planning-level information. Governments and regulators may well want to consider how universal access and individual information are included in the fundamental changes of the transition. Some are labeling this the *democratization of data*.

In Australia, AEMO and governments are pursuing these efforts through statutes that entitle consumers to quick access to their data. The creation of a digital twin will let AEMO model and share grid information to support better decision making. Without question, however, in an era where electricity is clearly regarded as a service and not a commodity, we need to consider the ability to generate and supply data access as the new fuel for the industry.

4) *The integrated power system will be multidirectional, distributed, and more resilient*: Information and new approaches to sharing systems are so integral to a successful transition because the participants that make up the power system, both new and existing, are changing. Their roles also are evolving. The application of load shaping and demand response as a resource to manage an efficient power market is well established. Equally clear is the importance of storage as a critical resource for grid flexibility, reliability, and resiliency for a system to withstand more frequent and harsher weather events.

   One significant implication of the changes underway is a blurring and blending of the business and operating models of industry participants and energy consumers. The differences drawn between customers, networks, generators, and retailers become less relevant in a world where storage can neatly fit into a service supplied by any of these players. We are seeing this happen in real time in Australia as networks, retailers, renewable developers, and commercial and residential consumers invest in storage and other forms of system support. The challenge is how to do it in the most efficient way.

   More rooftop solar, batteries, and electric vehicles will cause an increasing demand on distribution networks to host these investments at a low cost. The bulk power system will also be expected to optimize these capabilities across the whole of the system. This will not occur unless we orchestrate the capabilities of these systems in a manner that drives efficiency, reliability, and security rather than compromising them, supporting vertically seamless system operations.

5) *Organizational culture will transform to become collaborative, innovative, and less risk averse.* How we function as organizations will fundamentally change. Our experience at AEMO is that because of the complexity and novelty of the issues, we could not wait for all the answers before we acted. This gave us a better understanding of risks, recognizing that in this business, we need to reconfigure and redesign the airplane while we are flying it.

   For the industry to take on this transitional challenge, executives, managers, regulators, policy makers, and board members will need to rethink their approach to risks and risk management. This includes consultation, transparency, and a more sophisticated approach to measuring failure and success. Indeed, as my colleague Clare Savage, chair of the Australian Energy Regulator, succinctly put it as she saw the challenge, it is how we can convert our thinking from "No, because …" to "Yes, and how … ."

In my view, it is these three words that we all need to take to heart.

Audrey Zibelman

decarbonization

Australia's journey of energy transition

THE ARTICLES IN THIS ISSUE OF *IEEE Power & Energy Magazine* are a testament to the scale and scope of the transformational changes of the Australian power system and the enormous capabilities of my former organization, the Australia Energy Market Operator (AEMO). The closure of coal plants due to aging and poor economic outlooks, and the government initiatives related to the decarbonization of the power sector, is occurring in one of the world's most favorable natural environments for zero-carbon wind, solar, and hydro resources. This is leading Australia toward a future where AEMO expects that up to 100% of our power at times may be able to be drawn from renewable resources by 2025.

As we all know, although there may be differences in policies and system topologies, the power system, governed by the laws of physics, operates in the same way worldwide. Roughly five years ago, Australia and AEMO suffered their most difficult year since AEMO was formed in 2009. On 28 September 2016, a storm caused a system blackout in South Australia. The following summer, excessive heat led to load-shedding events in South Australia and New South Wales. This was on top of AEMO's loss when its beloved Chief Executive Officer Matt Zema unexpectedly passed away in July 2016.

When I arrived at the Melbourne airport to take on the chief executive officer job at AEMO in March 2017, the TV monitors were reporting a very public disagreement between Jay Weatherill, then the premier of South Australia, and Federal Energy Minister Josh Frydenberg, over South Australia's renewable energy program. As an American, where having local coverage of energy issues is a major feat, I learned immediately that energy politics and the interest in energy in Australia were going to be different from what I was used to.

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I arrived in Australia from my position as the chair of the New York Public Service Commission where, under Governor Andrew Cuomo, we designed and put in place a series of reforms. They were known collectively as the "New York Renewing the Energy Vision" to reinvent the industry and better address policies to integrate clean energy, provide affordable and reliable power, and resolve resiliency concerns in the wake of Hurricane "Superstorm" Sandy. I discovered that in Australia, despite the continuing policy debates, the reforms planned for in New York were already occurring at a breathtaking speed for an industry accustomed to changes that occurred in decades, not in years or months.

By any measure, the Australian statistics are impressive. Over the last several years, the increased pace of residential rooftop solar means that a new installation is added every 6 min. Today, in the National Electricity Market (NEM), which covers five Australian regions and the majority of the nation's supply and demand, the current 9 GW of distributed solar capacity represents approximately 26% of the total peak system demand of 35 GW. We are modeling scenarios for the distributed photovoltaics to reach up to 21 GW by 2025.

On the grid scale, AEMO registered 2.1 GW of wind projects and 2 GW of solar projects in the NEM in 2020 alone. The scope for new capacity far exceeds the capability of our current modeling systems and power grid for timely integration. Following the commissioning of the world-leading 100-MW/129-MWh Hornsdale battery in South Australia in 2017, we now have five grid-scale battery projects in the NEM, totaling 260 MW/334 MWh of storage, with more to come.

More strikingly, AEMO's long-term economic and system modeling confirms that when the aging coal plants retire, Australia will transition to an affordable and secure power system comprising variable renewable resources supported by storage, hydro, natural gas, and a more interconnected, two-way network.

Achieving these outcomes will not be easy. The increased demand for flexibility when we heavily rely on variable renewable energy is well known; less well understood are the challenges. The increases in renewables can lead to difficulties in managing voltage and frequency due to the loss of inertia and system strength. The same also applies to predicting when increases in these types of resources create oscillation challenges. Furthermore, what are the right set of policies and approaches

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