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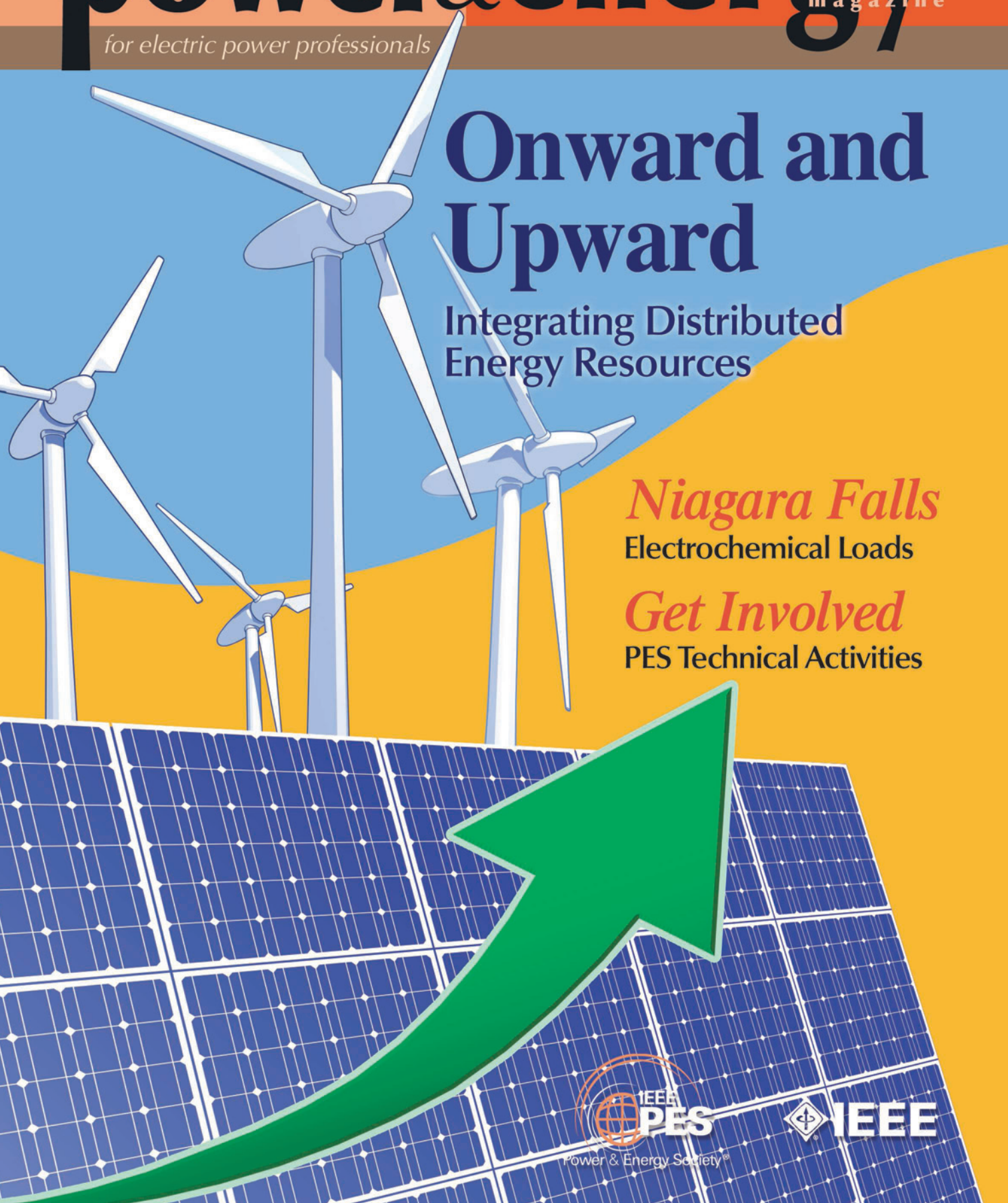
for electric power professionals
Volume 18 • Number 6 • November/December 2020



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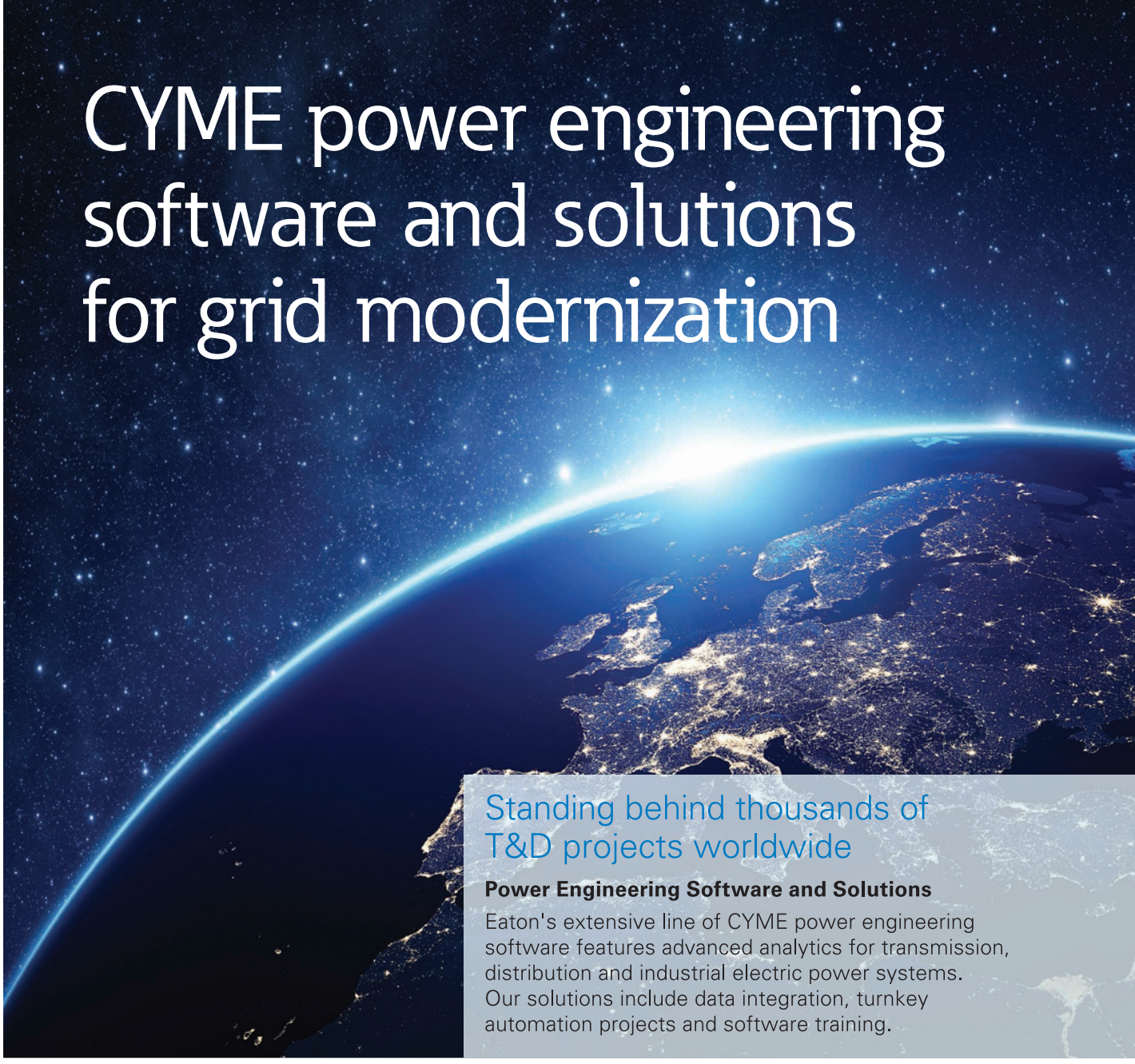

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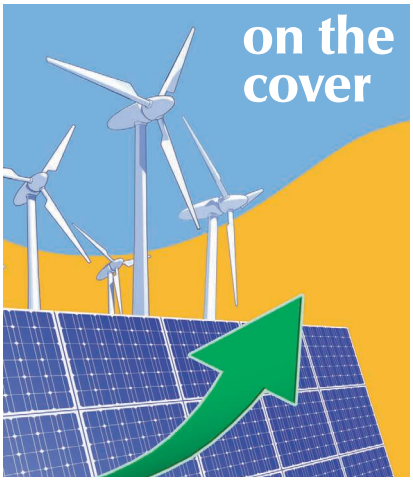

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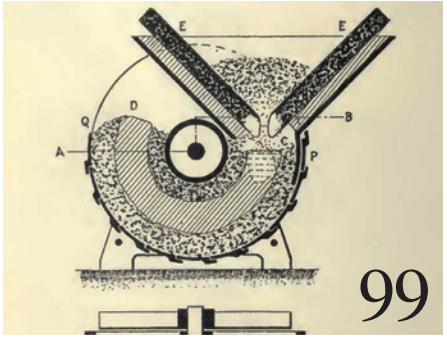

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AS I REFLECT ON THE YEAR 2020 for this final issue of *IEEE Power & Energy Magazine*, I am quickly reminded of a lyric from a song by an American rock band: "Lately, it occurs to me what a long, strange trip it's been." As I write this column, it occurs to me that we are not yet at our final destination on this long, strange trip called COVID-19. As we started the year, COVID-19 was just entering our lexicon. And now, at the end of 2020, the ways we do business, educate, travel, hold meetings and conferences, and interact with each other have changed—all due to COVID-19.

We have not yet achieved an understanding of what the "new normal" will be. Many jobs remain out of the office and at home locations; numerous universities continue with remote education; social distancing continues to be an active practice in our communities, factories, and field work spaces; utility load profiles have changed; and many global travel restrictions persist. Please continue to make wise choices and be safe as we migrate through this long, strange trip during the COVID-19 era.

In This Issue

The overall theme of this issue is the integration of distributed energy resources (DERs). We have tackled this topic in *IEEE Power & Energy Magazine* through the years, and this latest issue represents the next progression in this important area affecting our industry. We have five articles that represent authors and DER topics from around the globe discussing the following topics:

- ✔ the challenges being addressed as Australia integrates very high levels of distributed photovoltaic (PV) systems
- ✔ an autonomous energy grid concept for the control and operation of grids with high levels of DERs of all types
- ✔ a detailed view from Japan of grid operation challenges related to high levels of DERs in the form of distributed PV and wind energy
- ✔ the challenges of reaching a 100% renewable energy target by 2040 in the Canary Islands
- ✔ system protection impacts resulting from the integration of inverter-based DERs.

Along with these articles on DERs, we have one more article to this issue:

- ✔ "Predictive-Maintenance Practices," by Richard Fioravanti, Kiran Kumar, Shinobu Nakata, Babu Chalamala, and Yuliya Preger, addresses current safety practices in battery energy storage system development, provides examples of predictive maintenance approaches in other industries, notes the key components of an effective approach, and describes methodologies to identify leading fault indicators.

The "In My View" column provides a perspective on grid services from DERs.

History

We have explored a number of interesting aspects of electrical power associated with the Niagara Falls area through the years in the pages of the "History" column. In this issue, Robert D. Barnett presents a view of the "loads" consumed by customers of the early hydroelectric generation plants near Niagara Falls. The article concentrates on early electrochemical factories and the distribution methods to serve those loads.

Leader's Corner

In the "Leader's Corner" column, Vijay Vittal, IEEE Power & Energy Society (PES) vice president (VP) of Technical Activities, shares his thoughts on PES technical activities. As a VP on the PES Governing Board, he also serves as chair of the PES Technical Council,

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which is made up of the chairs of the PES's 17 technical and four coordinating committees. He describes the organization along with some of the key work, output, and impacts of PES technical and coordinating committees.

Book Review

In this issue, we provide a book review of *Power System Modeling, Computation, and Control* by Joe H. Chow and Juan J. Sanchez-Gasca. This 2020 edition, published by Wiley in conjunction with IEEE Press, is aimed at making the advanced topics of modeling, computation, and control more accessible to graduate students, power engineers, and control design professionals. The review says that this book is a welcome addition to the body of literature covering power system modeling, computation, and control and that it will prove valuable in academic settings and for practitioners.

PES Meetings

I am pleased to report that the pivot of the IEEE PES General Meeting (GM) from an on-site event to a virtual one due to COVID-19 was a success. I participated as an attendee by watching the live simulcast activities and the on-demand events and downloading and reviewing the proceedings, which included the papers presented at the virtual conference. At the end of the event, Frank Lambert, 2020 PES president, and Wayne Bishop, PES VP of Meetings and Conferences, sent an email to the PES membership, which made the following points concerning the virtual 2020 GM:

- ✔ There were more than 2,200 registered attendees from 69 countries around the world. For comparison, at the 2019 in-person conference, we had attendees from 61 countries.
- ✔ The on-demand conference had 137 panel sessions, 644 accepted conference papers, 170 accepted transaction papers, 37 poster sessions, 16 paper forums, and four best paper sessions.
- ✔ More than 300 individuals served as session chairs to ensure that 1,200-plus video presentations could be included in the program.
- ✔ More than 1,000 people have watched the plenary session, which included a keynote talk from David Murray, chief information officer at Hydro-Quebec and president of Hydro-Quebec Productions.
- ✔ The events included 215 sessions with an average attendance of 51.

There were many people involved in this pivot to make the event the success that it was. It is amazing to think that, while many conferences are scheduled years in advance and have organizing committees in place, this event was able to pivot from on site to virtual within just 100 days. Congratulations to all involved, including the PES executive office, our contractors, the Montreal Local Organizing Committee, the GM Steering Committee, the session chairs, the presenters for all session types, the authors and panelists, and our conference registrants and attendees.

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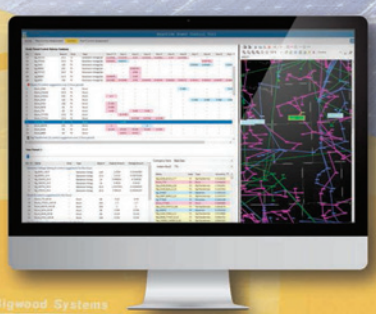

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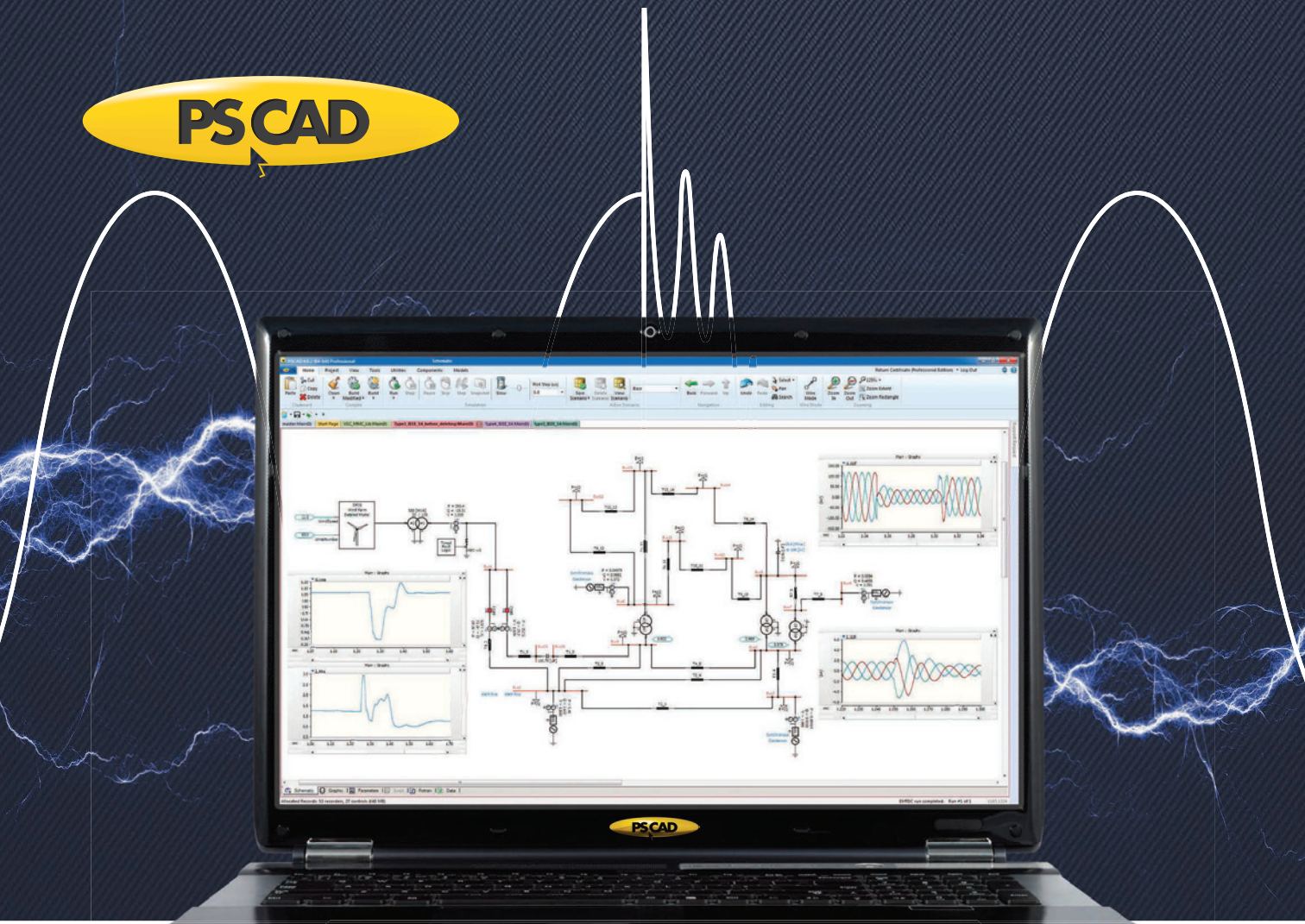

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Unfortunately, the IEEE PES Transmission and Distribution (T&D) Conference and Exposition that was originally planned for Chicago in April 2020 and then rescheduled to October was finally canceled due to the COVID-19 pandemic. The conference papers were presented virtually in October and will be available on IEEE *Xplore*. We will see you in New Orleans, Louisiana, for T&D 2022 in April 2022.

PES sponsored and cosponsored meetings and conferences are listed in the "Calendar" column in this issue. The sponsored and cosponsored meetings are listed as virtual or canceled (in some cases, there have been no announced changes to the original on-site plans), and they may change as this issue goes to publication.

PES Awards

With the transition of the 2020 PES GM to a virtual event, this year's PES Awards Ceremony was also virtual. The virtual ceremony included videos to honor this year's PES award recipients and was e-hosted by Alfredo Vaccaro, PES Awards and Recognition Committee chair. There are also two IEEE-level award recipients by PES members included in the video lineup. Access to the videos is open to anyone and not just GM registrants. Share in the reaction of our 2020 award recipients by watching these videos; they can be accessed from the PES home page at www.ieee-pes.org or directly at https://ieeetv.ieee.org/event-showcase/2020-awards-IEEE-Power-Energy-Society.

Society News

We are saddened to report the passing of Patrick Ryan, PES executive director, on Tuesday, 8 September 2020. In "Society News," we remember Pat's family, his career, and his accomplishments.

Thank You

This issue represents my second and final one serving as interim editor-in-chief (EIC) during this period of transition. I want to thank the guest editors, Barry Mather and Guohui Yuan, for their respective efforts with the five articles and two columns on the topic of DERs, as well as Ben Kroposki for his early input on planning this issue. I would also like to thank all the authors of the articles, columns, and features in this issue.

Once again, Robert Henderson went above and beyond the call of duty in assisting with the editing of this issue, and I thank him for his extensive efforts. As a novice interim EIC, I appreciate the guidance of Geri Krolin-Taylor, senior managing editor, and Maria Proetto, Shanon Nason, and Roseanne Jones, of the IEEE PES Executive Office, for their friendly advice and help on the PES content. I would also like to thank Mike Henderson (immediate past EIC) and Steve Widergren (incoming EIC) for their input and guidance. I ask you all to support Steve in his new role. I look forward to continuing to serve as associate editor of History on the *IEEE Power & Energy Magazine* Editorial Board.





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Vijay Vittal

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THE TECHNICAL ACTIVITIES OF the IEEE Power & Energy Society (PES) are coordinated by the PES Technical Council. The current officers of the PES Technical Council are Vijay Vittal, chair; Hong Chen, vice chair; Diane Watkins, secretary; and Farnoosh Rahmatian, past chair. The chair of the PES Technical Council also serves as the PES vice president for Technical Activities. The PES Technical Council coordinates the activities of 17 technical committees (TCs) and four coordinating committees:

- ✔ Analytic Methods for Power Systems Committee—Kevin Schneider, chair
- ✔ Electric Machinery Committee (EMC)—John Yagielski, chair
- ✔ Energy Development and Power Generation (EDPG) Committee—John B. Yale, chair
- ✔ Energy Storage and Stationary Battery Committee—Curtis Ashton, chair
- ✔ Insulated Conductors Committee—Henk Geene, chair
- ✔ Nuclear Power Engineering Committee—Daryl Harmon, chair
- ✔ Power System Communications and Cybersecurity Committee—Ken Fodero, chair
- ✔ Power System Dynamic Performance (PSDP) Committee—Costas Vournas, chair
- ✔ Power System Instrumentation and Measurements Committee—Jim McBride, chair
- ✔ Power System Operation, Planning, and Economics Committee—Fran Li, chair
- ✔ Power System Relaying and Control (PSRC) Committee—Russ Patterson, chair
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- ✔ Surge Protective Devices Committee—Steven Hensley, chair
- ✔ Switchgear Committee—Keith Flowers, chair
- ✔ Transformers Committee—Bruce Forsyth, chair
- ✔ Transmission and Distribution (T&D) Committee—Gary Chang, chair
- ✔ Energy Internet Coordinating Committee—Hongbin Sun, chair
- ✔ Intelligent Grid and Emerging Technologies Coordinating Committee—Doug Houseman, chair
- ✔ Marine Systems Coordinating Committee—Dwight Alexander, chair
- ✔ Renewable Systems Integration Coordinating Committee—Andrew Leon, chair.

These committees, which were reorganized in July 2016, are responsible for the technical activities in each of their subdisciplines within the broad power and energy discipline. They conduct technical activities including the development of standards, technical reports, and technical sessions for various PES technical meetings—paper, poster, panel, and super sessions—and identify, explore, and provide solutions to emerging topics of interest within their subdisciplines. TCs conduct various technical activities through subcommittees, working groups, and task forces.

A detailed description of the various TCs and their activities can be viewed by navigating to each committee's website from the PES Technical Council website, https://www.ieee-pes.org/technical-activities. These websites clearly state the scope of each committee's activities and include a flyer that provides a succinct description of the activities of each TC. Many of the committees have meetings during the PES General Meeting, the PES T&D Conference and Exposition, and the Joint Technical Committee Meeting. Additionally, many hold multiple meetings during the year to conduct their activities. The PES Technical Council website provides updated information on committee meetings held outside the PES General Meeting and other conferences.

An important responsibility of the PES Technical Council is the design and planning of the technical program for the annual PES General Meeting. This includes planning the super sessions and technical paper and poster sessions. The TCs coordinate the conference paper reviews and plan the panel sessions.

The IEEE Industry Technical Support Leadership Committee (ITSLC), formed by the governing board, provides support to and cooperates with governments, regulators, and other industry organizations globally on technical issues related to power, energy, and policy

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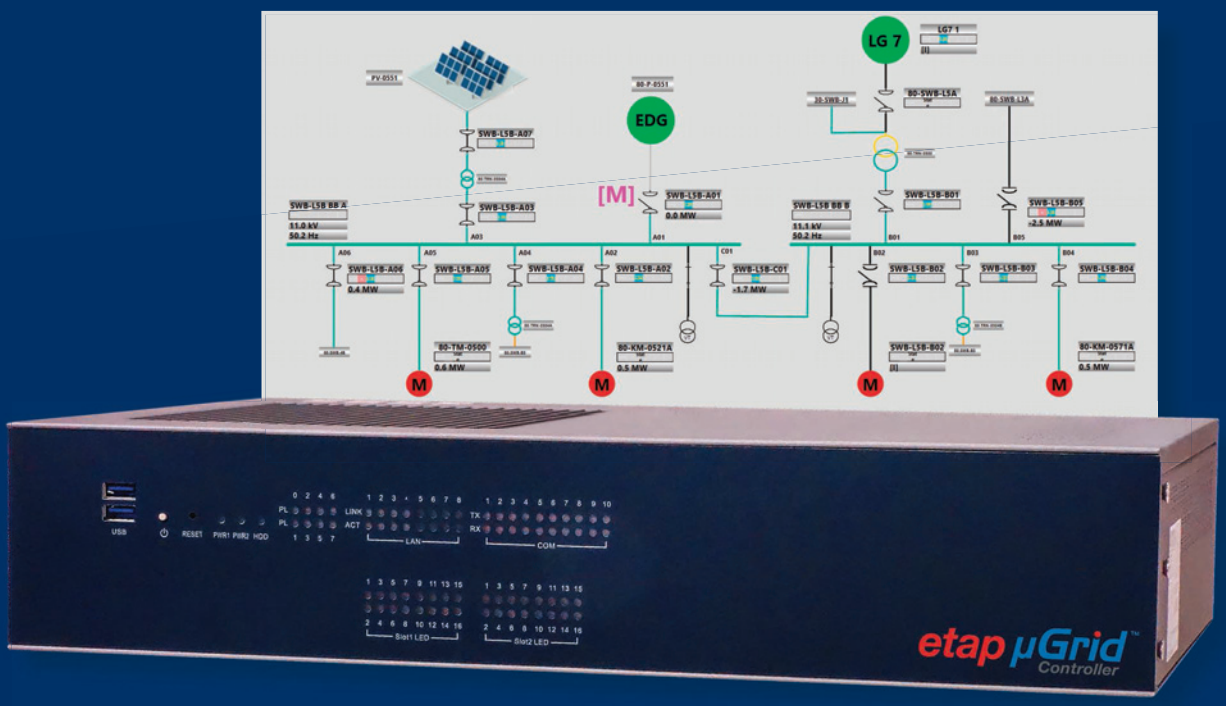

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topics. The ITSLC has worked with representatives from the various TCs to develop its technical content. In response to the COVID-19 pandemic, the ITSLC, in collaboration with several TCs, developed a worldwide survey of utility experiences and practices in response to the pandemic. A white paper based on the responses to the survey was developed and is available free of cost at https://resourcecenter.ieee-pes.org/technical-publications/white-paper/PES_TP_COVID19_050120.html. The ITSLC also conducted two webinars based on the white paper, which have been recorded and are available for viewing at the IEEE PES Resource Center (see the "Technical Resources" section).

Getting Involved in Technical Activities

PES members can get involved in TC activities through several different avenues. The meetings for TCs and their associated subcommittees, task forces, and working groups are generally open. Individuals interested in the technical topic could attend the meetings associated with these entities as guests. If the technical topic is of interest, then they can then volunteer to contribute and become members. It is important to examine each TC's operations and procedures manual (available on its website) to find out more about becoming a member of a task force, working group, subcommittee, or committee. PES members can also volunteer to chair technical paper sessions at PES conferences and the General Meeting. This can be done by contacting the appropriate TC program chair. (The officers for each TC are listed under the "Officers" tab on the TC website.)

An important TC activity is the review of papers for the five PES transactions. The reviews are conducted by the editor-in-chief and the various editors of each publication. Reviewers play an important role in this peer-review process. Subject matter experts can volunteer to become reviewers by providing the requisite information and following the steps provided at https://www.ieee-pes.org/images/files/pdf/invitetoreviewers.pdf.

Technical Resources

The PES Resource Center (https://resourcecenter.ieee-pes.org/) is an excellent resource for the power and energy professional. For a PES member, it has a plethora of technical material that can be downloaded free of cost. This includes conference papers from various PES conferences, presentations from panel sessions, open access journal articles, and technical reports produced by the TCs. The Resource Center also includes a large collection of tutorial products, some of which are free and some that can be downloaded for a nominal fee.

IEEE standards, PES transactions articles, and conference papers can be downloaded from IEEE *Xplore*. Not all items on IEEE *Xplore* are free, and a subscription to a particular publication

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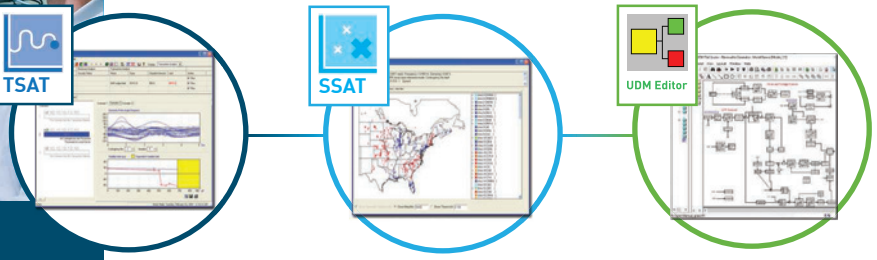

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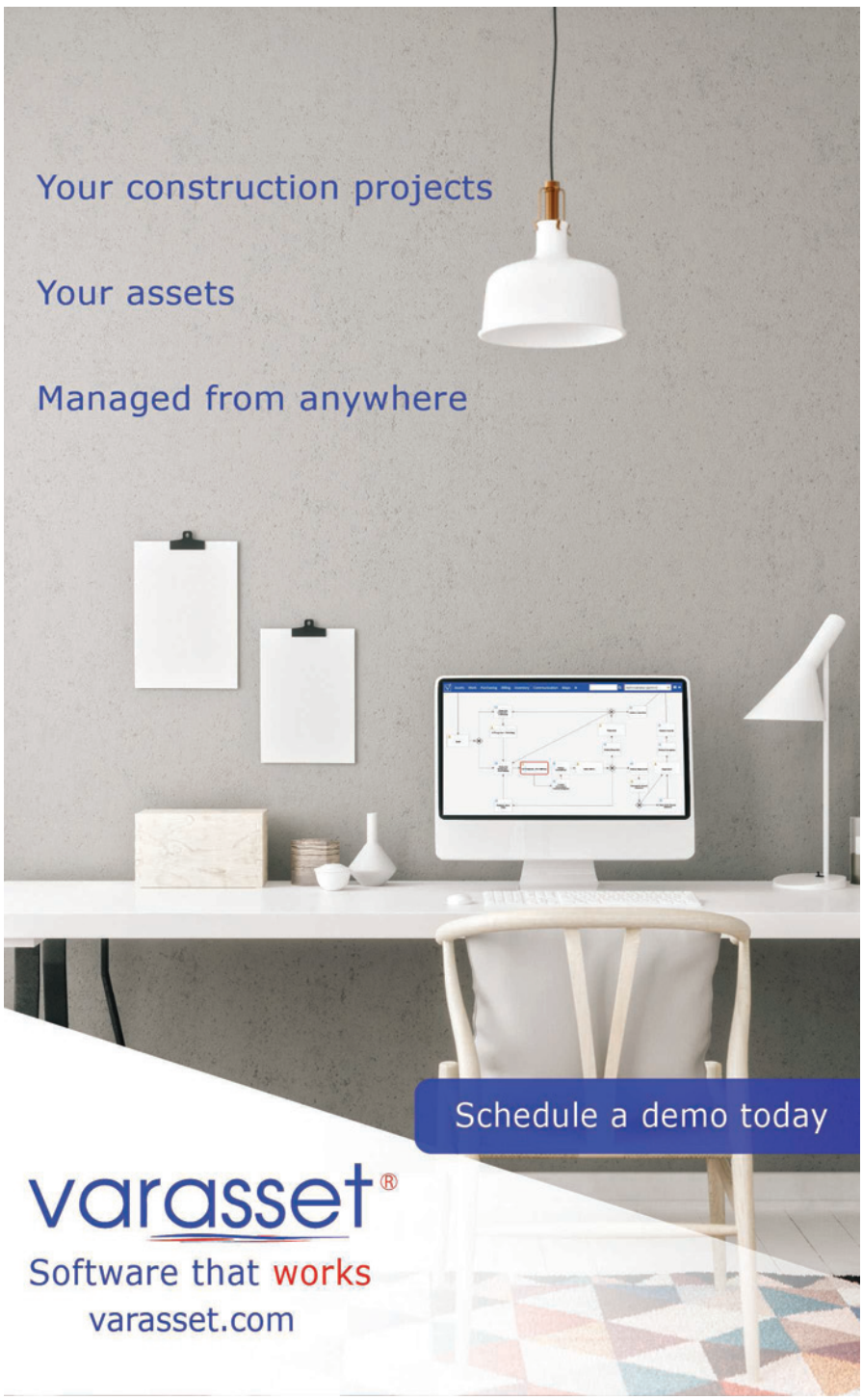
(through the annual IEEE membership renewal process) or institutional access may be required.

The Resource Center also contains several technical reports prepared by various TCs on topics of contemporary interest and relevance. PES members can download these reports at no cost using their IEEE login credentials. Revenue is earned when these reports and documents are downloaded by non-PES members. Some of the more recent reports have had a significant number of downloads. A summary of the downloads through the end of June 2020 is shown in Table 1.

The COVID-19 pandemic and its resulting consequences, coupled with the evolving explosion of renewable resources in the grid, have produced unique technical challenges that have generated a significant interest in technical inquiries to produce solutions that will guarantee the expected reliability and economy of the electricity infrastructure around the world. The PES Technical Council and its TCs are well positioned to tackle these challenges and welcome participation from power and energy professionals around the world.

table 1. A summary of PES Resource Center downloads.

Rank	TC
	TCs With the Most Products
1	PSRC: 49
2	T&D: 46
3	EDPG: 44
4	Power System Analysis, Computing, and Economics: 27
5	PSDP: 25
	TCs With the Most Product Downloads
1	ITSLC: 6,931
2	PSDP: 4,740
3	T&D: 3,320
4	PSRC: 2,446
5	EDPG: 1,155
	TCs With the Most Revenue
1	T&D: US$1,962
2	ITSLC: US$1,726
3	PSDP: US$1,366
4	PSRC: US$1,296
5	EMC: US$790
	Products With the Most Downloads
1	"Impact of IEEE 1547 Standard on Smart Inverters" (ITSLC): 1,439
2	"Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance" (ITSLC): 1,277
3	"Microgrid Stability Definitions, Analysis, and Modeling" (PSDP): 1,219
4	"The Definition and Quantification of Resilience" (ITSLC): 1,059
5	Tutorial course: Transient Analysis of Power Systems: Solution Techniques, Tools, and Applications (T&D): 1029





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guest editorial

Barry Mather and Guohui Yuan

onward and upward

distributed energy resource integration

WHEN THIS COLUMN WAS WRITTEN, it is fair to say that most IEEE Power & Energy Society members have experienced, or continue to experience, a significant level of disruption to their normal work practices. Yet, during this extended period of wide-scale work-from-home reality that many of us are experiencing, the continued availability of critical services has been impressive. Most impressive has been the reliable supply of power to our homes-turned-offices. The integration of high levels of distributed energy resources (DERs) into our power systems, the focus of this issue, is perhaps even more topical in our current working environment, where our working style is decentralized—just like DERs compared to centralized generators—and overall power system reliability and resilience is more impactful.

With the continued installation of approximately 100 GW per year globally, the role of grid-connected photovoltaics (PVs) in the power system continues to increase. In the United States, more than half of the grid-connected PV capacity is interconnected at the distribution level. Although other countries have different penetration levels of DERs, all are generally experiencing higher levels of DER interest and deployment. A common international theme is the rapid growth of DERs driven by customer demand once the capability to interconnect generation on the distribution level is realized, followed by sustained deployment until existing technical limits are met. Given the obvious need for highly reliable and resilient power delivery and the changing landscape of not only the "type" of generation but also where it is located in the overall power system, how can we effectively plan and operate the power system with ever higher levels of DERs? Luckily, there is strong support for high-quality research focused on integrating distributed PVs and other DERs into the electric grid worldwide.

For instance, in the United States, the U.S. Department of Energy (DOE) has been supporting research in integrating distributed PVs and other DERs into the electric grid with millions of dollars invested each year. These research programs address system-level issues in DER integration to meet customer needs while maintaining grid reliability, resilience, and security. These activities are also organized through DOE initiatives such as the Grid Modernization Initiative and the Energy Storage Grand Challenge. The DOE collaborates with 14 national laboratories and more than 100 industry partners to develop the knowledge base and technical capabilities needed to modernize the U.S. electric infrastructure. This research has helped to accelerate the development and application of DER technologies that advance the modernization of energy systems in the United States.

There are more than 2.3 million solar generators on the U.S. distribution system today, with steady growth expected in the future. The integration of electric vehicle (EV) charging stations, energy storage devices, and energy-efficient buildings is also increasing steadily. Managing many small resources embedded in the power system is a fundamental challenge compared to managing the traditionally centralized grid. Additional challenges with DERs are the variability and uncertainty in generation and load due to unforeseen and uncontrolled events. But DERs can also offer many benefits to power systems: they are more scalable, the generation is closer to the load, and they are more adaptive. As the power system relies more and more on networked communications and digital technologies and natural disasters such as hurricanes, flooding, and wildfires increase in severity and frequency, the exposure to cyberattacks and physical hazards also increases. Localized DER technologies can help the power system be more resilient when a disruption does occur. During hazards, the power system can be reconfigured into independent secure segments that each contain load and generation. This can enhance grid resilience to keep critical services online and restore service faster with help from the fast-responding power electronics in solar generation and energy storage systems.

This is the seventh issue of *IEEE Power & Energy Magazine*, since 2009, that has now focused on the challenges of integrating DERs into the power system at scale. Each of the five theme articles included in this issue focus on multiple elements of DER integration, where the DER-centric technology, planning, operating methods, and so on play

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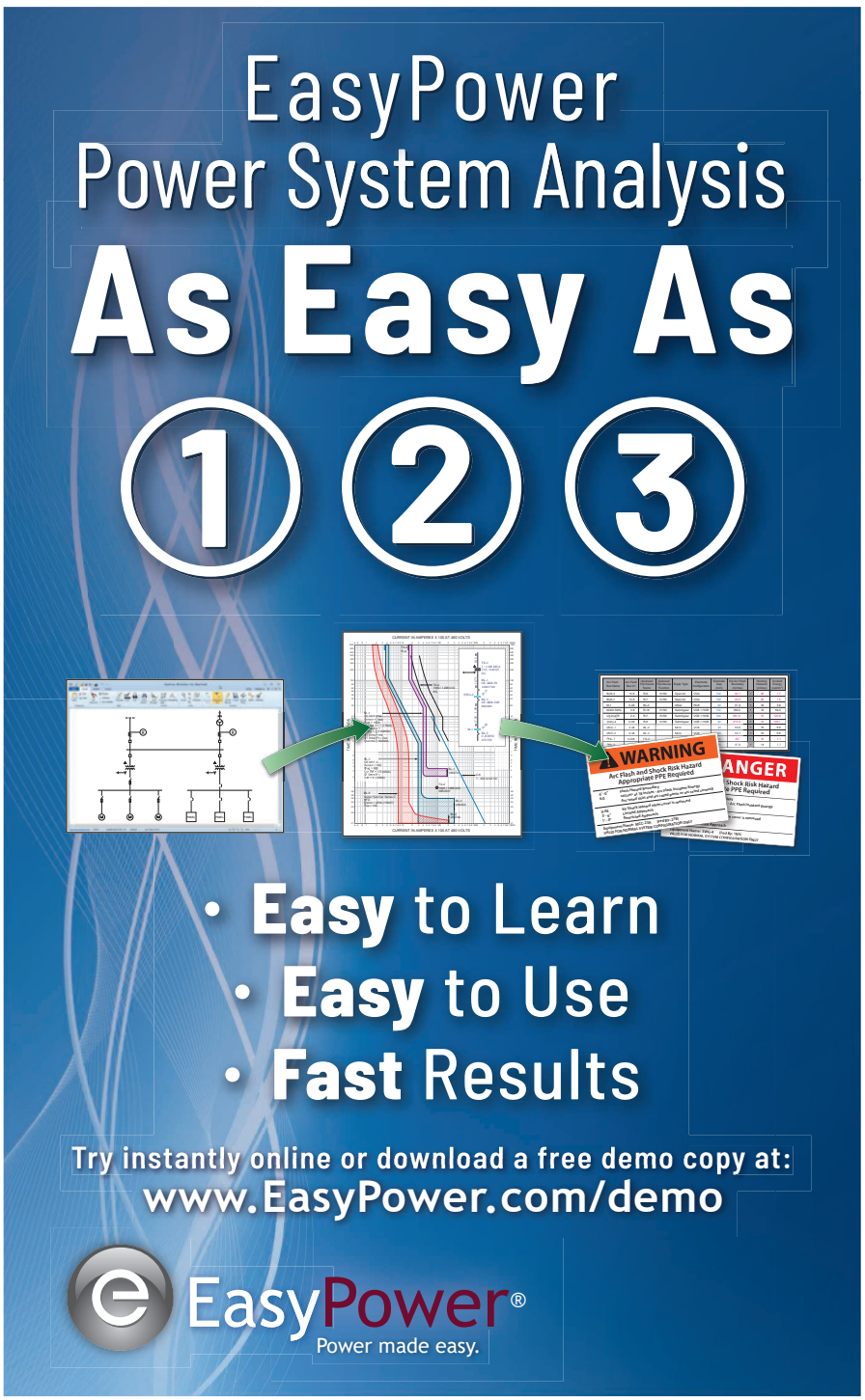
increasingly important roles. As DERs become prolific, they will need to provide more grid services/functionalities, which have typically been supplied via other means. Likewise, as DERs are deployed in greater numbers, the planning and operation of such systems becomes more critical for the proper operation of the interconnected power system. The findings and perspectives of the articles in this issue provide a snapshot of ongoing research and efforts to ensure the continued ability to integrate increasingly higher levels of capable DERs into the world's electric power systems.

The evolution of DERs, dominated by distribution-connected PV systems, has been chronicled over the years. Although many challenges remain, it is interesting to observe how the most critical concerns of industry and the highest focus by researchers have morphed as most utilities gained experience with DER integration firsthand. Without a doubt, issues such as voltage regulation on the distribution circuit are critical requirements for interconnected DERs, but other issues have also become critical as DERs have increased to be a sizeable generation source and are impactful to system operations. Recently, several studies were completed that focused on the impact of DERs on the transmission system, both during normal operation (e.g., the role of PV forecasting in generation scheduling) and during contingencies (e.g., the possibility of wide-scale inverter-based DER tripping during regional voltage and frequency events). As you peruse the articles in this issue, we hope that you marvel at the comprehensiveness of the integration of DERs and their respective studies but also identify new areas of R&D to continue the integration of DERs at higher levels.

The first article, "Consumer-Led Transition: Australia's World-Leading Distributed Energy Resource Integration Efforts," was prepared by a team of authors from across many power system domains. Naomi Stringer, from the University of New South Wales, and her coauthors present a comprehensive view of the challenges being addressed as Australia integrates very high levels of distributed PV systems. Notably, Australia leads the world in distributed PV penetration for small, mostly residential, rooftop systems. Such systems provide little visibility to system operators, creating considerable challenges. This article also covers pioneering work on the validation of distributed PV system ride-through functionality/settings via the postevent analysis of bulk system disturbances. The very high levels of DER integration in Australia's major interconnections can serve as an example of what is possible in other systems worldwide.

The second article, led by Benjamin Kroposki at the National Renewable Energy Laboratory, is "Autonomous Energy Grids: Controlling the Future Grid With



Large Amounts of Distributed Energy Resources." It describes a new concept for the control and operation of grids with high levels of DERs of all types. The autonomous energy grid concept realizes a cellular structure for the grid, with multilayer distributed control implemented to enable highly flexible, resilient, and reliable operation of the grid cells in an optimal manner. Required control coordination between the grid cells is structured to reduce communications requirements while still seeking to realize optimal operation of the entire power system. The scalability of the proposed concept is discussed in detail, and examples of large-scale, lab-based, and real-world implementations are presented.

Kazuhiko Ogimoto and Hiroshi Wani from the University of Tokyo and Kyushu Electric Power Company, respectively, offer "Making Renewables Work: Operational Practices and Future Challenges for Renewable Energy as a Major Power Source in Japan," which provides a detailed view of grid operation challenges related to the high levels of DERs in the form of distributed PVs and wind. The article focuses specifically on the island of Kyushu, which has experienced significantly higher levels of renewable penetration compared to load than much of the rest of Japan. A detailed view of operating practices, both new and old, is provided, along with an account of how those practices, combined with large forecasting errors, led to an emergency operating condition in March 2019. Lessons learned from this event are expertly presented, and new operating methods, now employed, are described in detail. Furthermore, a view of future improvements in power system operation with high levels of renewables is given via a discussion of grid constraints and the potential for additional flexibility from virtual power plants and managed EV charging.

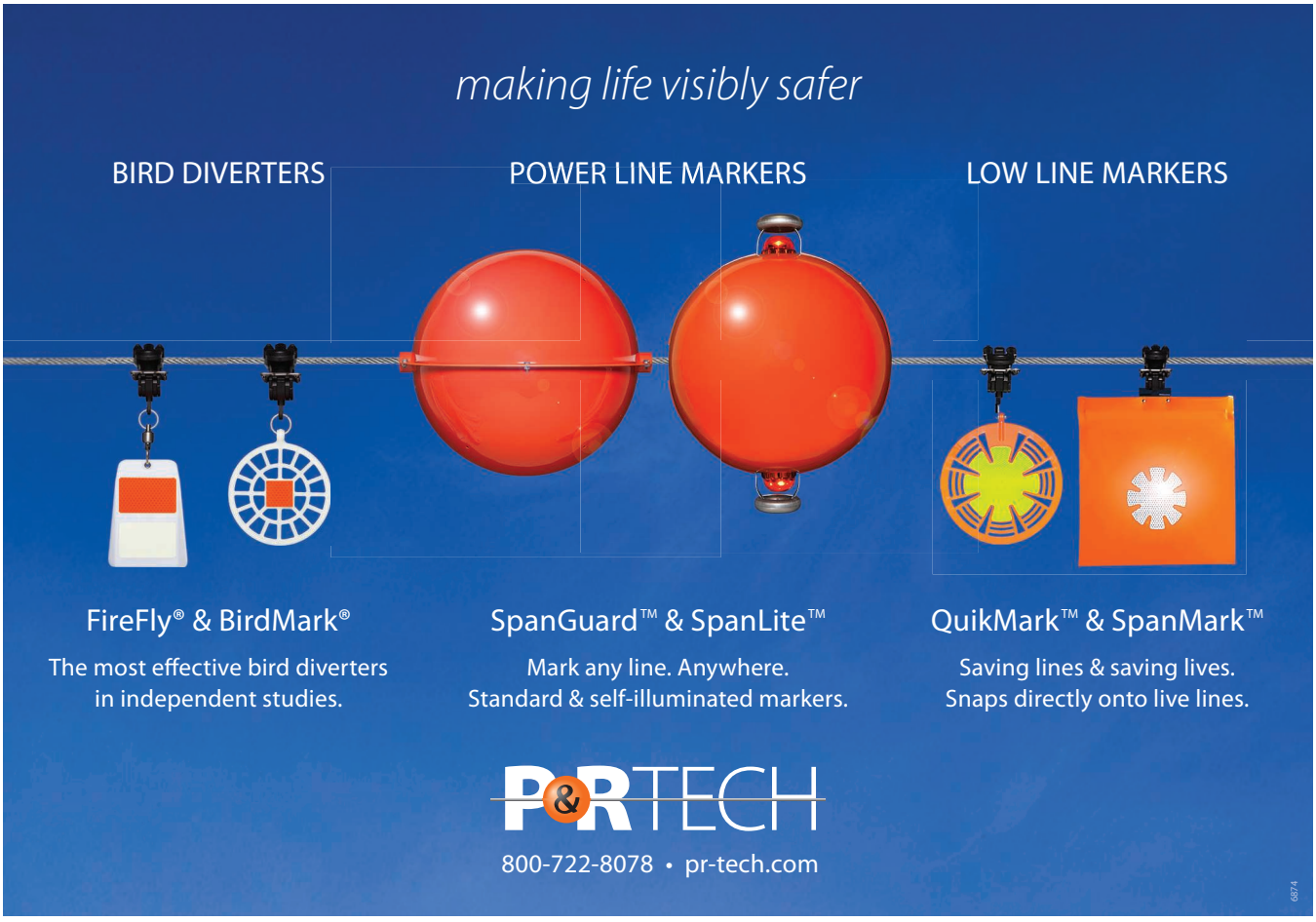
Continuing the theme of islands with high levels of distributed PVs, the fourth article, "Back in the Race: Achieving 100% Renewable Energy in the Canary Islands," by Ricardo Guerrero Lemus from the Universidad de La Laguna, Spain, describes the challenges of reaching a 100% renewable energy target by 2040. The article starts with a comprehensive overview of the current state of many types of renewable generation across the Canary Islands. Specific operational challenges are highlighted, such as a highly seasonal, tourist-driven load profile and relatively deep channels between islands, which make the interconnection of island systems difficult. Additionally, the article provides a more detailed discussion of the operational challenges and the amazingly high renewable operating levels realized on both the El Hierro and Tenerife islands. The integration of a major pumped-storage hydropower system on El Hierro and the lack of any significant amount of storage on Tenerife provides a good comparison of how system operation requirements can differ, even within the same region.



The fifth and final theme article is "On Good Behavior: Inverter-Grid Protections for Integrating Distributed Photovoltaics" and was authored by a broad team, including Tom Key of the Electric Power Research Institute, Gefei "Derek" Kou of Dominion Energy, and Michael Jensen of Pacific Gas and Electric Company. This expert team takes on the difficult topic of system-protection impacts resulting from the integration of inverter-based DERs. The article starts with a description of the types of impacts and the resulting protection concerns that can occur, particularly at high penetration levels. Through the presentation of example protection impacts and utility surveys focused on protection concerns, the article addresses issues such as an open phase on a three-phase line, direct-transfer trip requirements, and preferred interconnection transformer construction. Further, the solutions for many of these concerns are also given, including an example of a currently implemented utility solution that increases the visibility of protection-related issues and communications-enabled control to support the appropriate mitigation.

The "In My View" column, "Distributed Generation: Leveraging for Grid Services," authored by Tom Bialek from San Diego Gas and Electric Company, rounds out this DER issue. Bialek provides an excellent perspective on the often-discussed and researched, but not often-realized, provision of grid services from DERs. Starting with observed grid challenges, implementation difficulties, DER adoption history in California, and the recognition of the tremendous effort already exerted for effective DER integration, the argument is made that much more work is needed.

Without the support of many people, this issue simply would not have been possible. Thanks first to Michael Henderson and John Paserba for their encouragement, advice, direction, and editorial prowess while pulling this issue together. The final development of this issue occurred during the transition of *IEEE Power & Energy Magazine* editor-in-chief leadership, which was efficient and seamless. Thanks to Robert Henderson for his excellent review of the feature articles. Thanks also to the entire *IEEE Power & Energy Magazine* editorial board for their continued support of this DER issue. Additional thanks are due to the 23 authors from 13 organizations in four countries who supplied articles for this issue. Their hard work preparing the articles to provide a clear and understandable picture of their research is evidence of their professionalism and dedication to properly integrating DERs. Finally, thanks to the readers of *IEEE Power & Energy Magazine*. We hope you find this issue enjoyable, informative, and thought-provoking.



Consumer-Led Transition

Australia's World-Leading Distributed Energy Resource Integration Efforts



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IT'S A SUNNY SPRING DAY in South Australia. A light breeze is cooling the coastal state capital of Adelaide as approximately 260,000 distributed solar photovoltaic (D-PV) systems on residential and business rooftops generate electricity, setting a new state record for the lowest minimum electrical demand for the third time this season. All looks peaceful throughout the suburbs. D-PVs form an irregular yet persistent patchwork across one-third of the houses in the state. Most consumers are going about their day without a glance at the D-PV panels on these roofs. However, the mild temperature and bountiful sunshine lead the D-PV generation to climb, causing the voltage to creep higher and power to flow in reverse across large swathes of the distribution network. Some D-PVs are tripping off, unbeknownst to their owners and the local network operator.

The Australian Energy Market Operator (AEMO) is tracking falling demand and monitoring the proportion of synchronous generation in the South Australian interconnected region. Engineering teams are assessing the potential power system security implications of D-PV behavior during possible contingency events. The state's distribution network operator is observing and managing the changing voltages and flows through the system. Other teams continue their work on developing innovative planning and operational

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approaches—from new interconnection standards and flexible export limits to virtual power plants (VPPs)—for managing the ever-growing penetration of D-PVs and, increasingly, home battery energy storage systems (BESSs) and electric vehicles (EVs). Meanwhile, consumers across the state are contemplating their most recent power bill and their growing climate concerns, looking up at their empty roof space, and considering investing in D-PV themselves.

State of Play

The Australian National Electricity Market (NEM) serves approximately 90% of the population through one of the longest interconnected power systems in the world (Figure 1). The electricity sector was restructured during the late 1990s and features a regional wholesale spot market and retail competition. Transmission network service providers and distribution network service providers (DNSPs) are regulated monopoly businesses, separate from the generators and suppliers that purchase electricity from the spot market and sell power to consumers through deregulated retail market arrangements. AEMO is both the independent system operator and the market operator across the east and west coasts of Australia.



D-PV Uptake

Low PV system prices, excellent solar resources, and a significant proportion of stand-alone housing in Australia, coupled with high retail electricity prices, have led to a notable D-PV uptake during the past decade. Australia now has the highest proportion of houses with D-PVs worldwide, with approximately one in every four houses (all dwellings excluding apartments) having installed D-PV equipment and more than 2.2 million systems in total. The state of Queensland has the highest penetration of D-PVs, closely followed by South Australia (Figure 1). However, the relative contribution of D-PVs to demand is much greater in South Australia compared to Queensland, given South Australia's smaller industrial load and mild climate. The South Australian DNSP is SA Power Networks (SAPN). In Queensland, there are two DNSPs. Energex serves the metropolitan southeast, and Ergon Energy Network serves the more rural northern and western consumers; both are part of the Energy Queensland Group.

While the majority of D-PV systems in Australia are small (with capacities of lower than 30 kW ac), there is an emerging market in the 30–200-kW range for commercial and industrial sites. Between 2018 and 2019, the number of new D-PV applications approved in South Australia alone increased by 50%, and the high D-PV uptake is widely expected to continue. Across NEM, AEMO has forecast D-PV generation to more than double by 2039–2040 in all NEM market regions under a central uptake scenario and to at least triple under a high-uptake scenario. While D-PVs are the most common of the distributed energy resources (DERs) in Australia, other forms of DERs, including BESSs, are also increasingly prevalent. However, there remains a limited visibility of D-PV operation and minimal, if any, remote interoperability.

Contributions to Meeting NEM Demand

D-PV generation is making increasing contributions to meeting demand, particularly during mild autumn and spring conditions. At certain times of day, D-PVs, in aggregate, represent the largest single generator in NEM, reaching an estimated maximum of 6 GW of instantaneous generation in 2019 (or 23%

By Naomi Stringer, Anna Bruce, Iain MacGill, Navid Haghdadi, Peter Kilby, Jacqui Mills, Taru Veijalainen, Matt Armitage, and Nigel Wilmot

of the underlying demand). During spring 2019, the D-PV contribution exceeded 50% of the generation in South Australia for 6 h on the minimum "net" system demand day (Figure 2). Through the past decade, SAPN has observed a progressive reduction in the minimum demand each year across the distribution system (Figure 3), and the rate of the reduction has accelerated, with the minimum demand falling by ~200 MW between October 2018 and October 2019. As result, the entire distribution network is expected to be a net source of power during minimum demand periods as early as spring 2020 (September–November), while AEMO is projecting periods of zero net demand across all of South Australia by 2024–2025 in some scenarios. This has implications for distribution system operation as well as for maintaining system security, considering that South Australia often obtains inertia, frequency control ancillary services, and system strength support through its ac interconnection with Victoria. System security challenges are considered in the following, and additional details can be found in "Renewable Integration Study Stage 1—Appendix A: High Penetrations of Distributed Solar PV" in the "For Further Reading" section.

The Evolution of DER Impacts

Significant volumes of DERs present challenges and opportunities across the grid, requiring changes to forecasting,

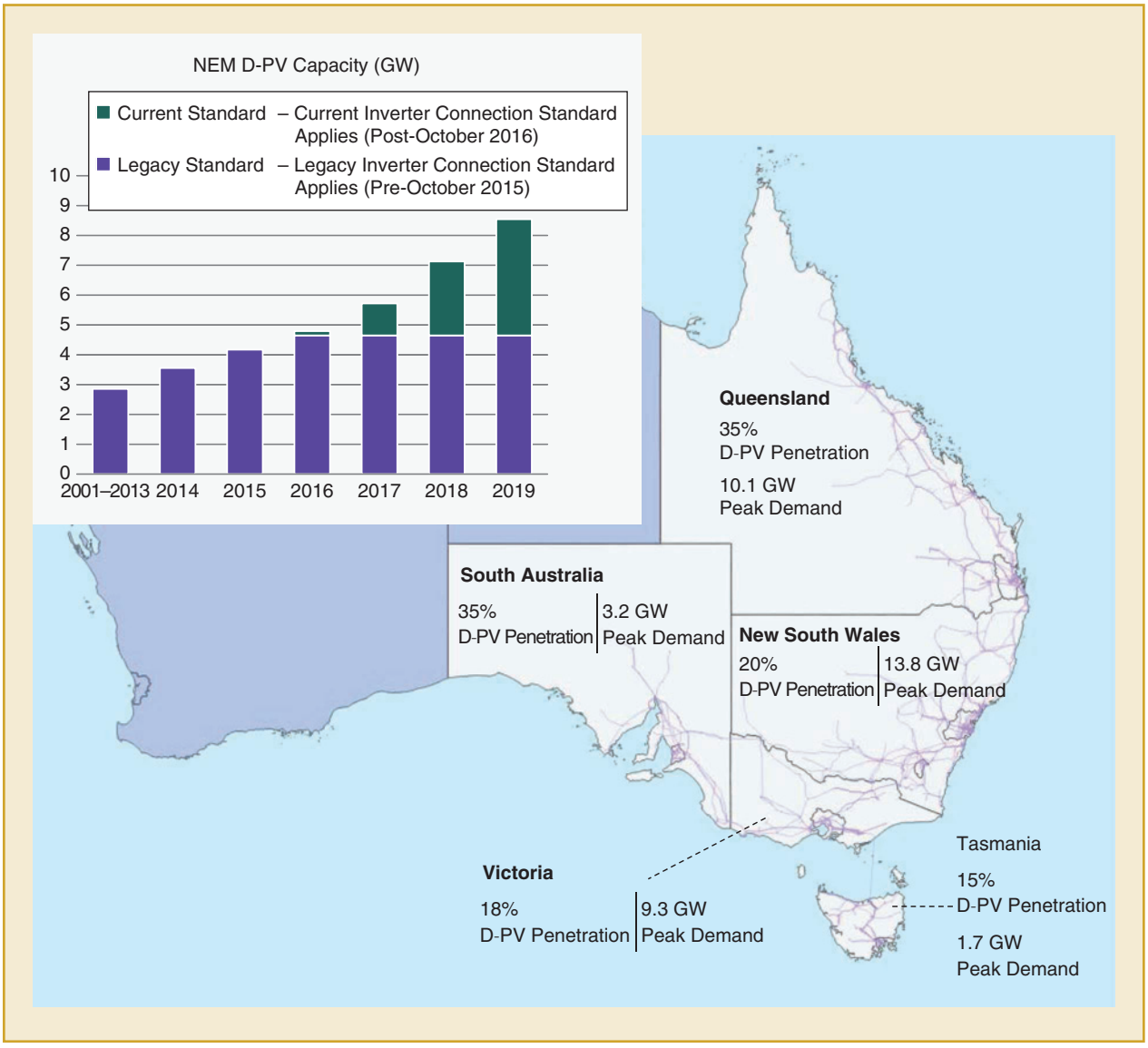

figure 1. The Australian NEM regions. The penetration percentages indicate the proportion of stand-alone households with D-PV generation. The graph shows the D-PV uptake and the installed generation volume according to "legacy" (pre-2015) and "current" (post-2016) inverter interconnection standards across NEM. Note that Australian and New Zealand Standard AS/NZS4777.2:2015 for inverters is currently under review.

planning, and operation. Figure 4 illustrates the increased scope and depth of planning for DNSPs. In addition to considering the peak demand, network planners and operators now need to estimate the minimum and underlying demands (without D-PV generation). However, there remains very limited visibility of DERs and, indeed, the low-voltage (LV) network. Trials provide much needed insight into actual operational conditions and illustrate key challenges. For instance, SAPN's Salisbury VPP trial connected 100 BESSs coupled with D-PVs at residential premises in suburban Adelaide. Operational data from the trial demonstrates the evolution of DER integration challenges in the distribution network. VPP implications for system operation are considered in a later section.

Historically, the primary concern for planners and operators has been ensuring that network thermal limits are not breached during peak demand load days (ⓐ in Figure 5). High levels of D-PV generation make voltage

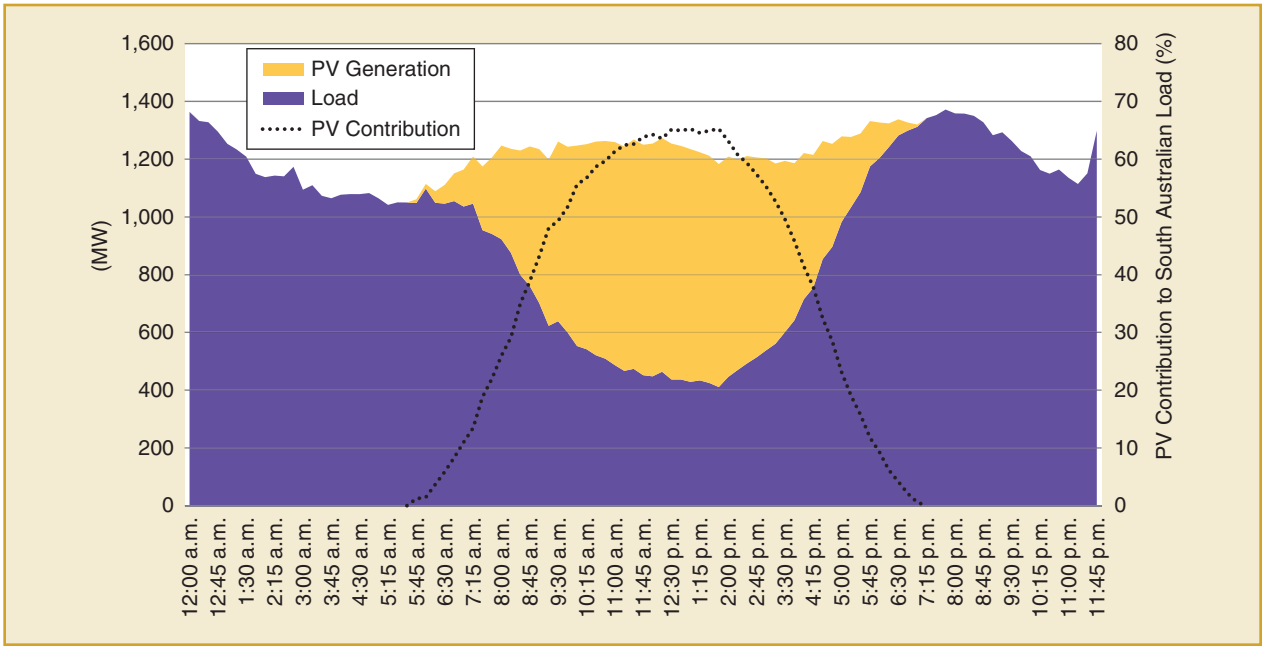

figure 2. The D-PV contribution to the minimum net load in South Australia on 10 November 2019.

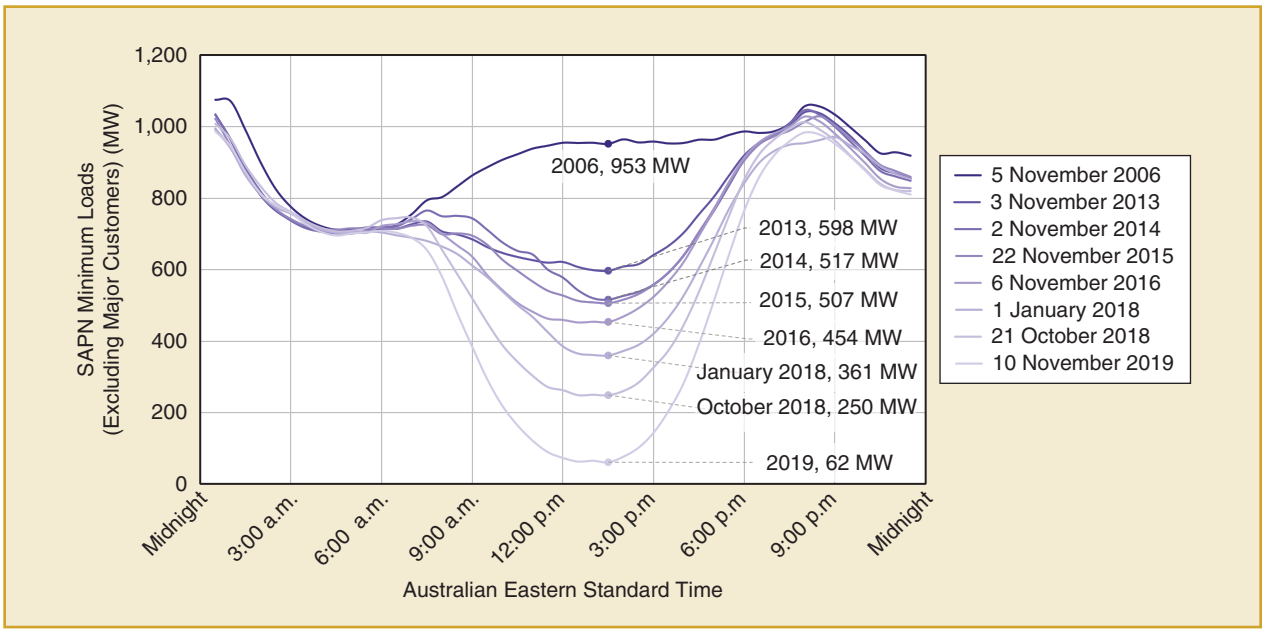

figure 3. The SAPN minimum load days. Major customers are excluded, while major generation is included. D-PVs are netted off as a negative load.

management a key challenge, as indicated by ⓑ in Figure 5. In this instance, the VPP export is likely to be large enough to cause the voltage to rise outside the allowed range. The Salisbury trial highlighted that the orchestration of DERs also poses new challenges. The trial showed that VPP operation can cause extreme peaks in demand that significantly exceed the normal summer maximum load, e.g., when all batteries were instructed to charge in anticipation of a storm front (© in Figure 5) Conversely, should a VPP be instructed to discharge in the middle of the solar day during a high-price event or to provide frequency control and ancillary services (FCASs), then voltage and thermal limits may be breached due to reverse power flows (ⓓ in Figure 5).

This article focuses on increased voltage ranges, reverse flows, and D-PV implications for system security, with each section outlining challenges and solutions. However, further difficulties and opportunities are emerging, including implications for designing protection for the distribution and transmission system, reactive power management, underfrequency load shedding, and system black-start capabilities.

Increasing Voltage Range

Challenges

Voltage management is growing more challenging in Australian distribution networks as extreme summer temperatures drive air-conditioning demand and the D-PV uptake continues. The net effect is a broader range of voltage conditions that can rapidly change during relatively short periods on a single network feeder. Visibility in the LV system generally remains limited; however, some monitoring exists, and new techniques for data visualization and analysis are emerging.

Existing Voltage Conditions

To comply with Australian Standard AS61000.3.100-2011, the 99th voltage percentile (V99%) at a customer's point of

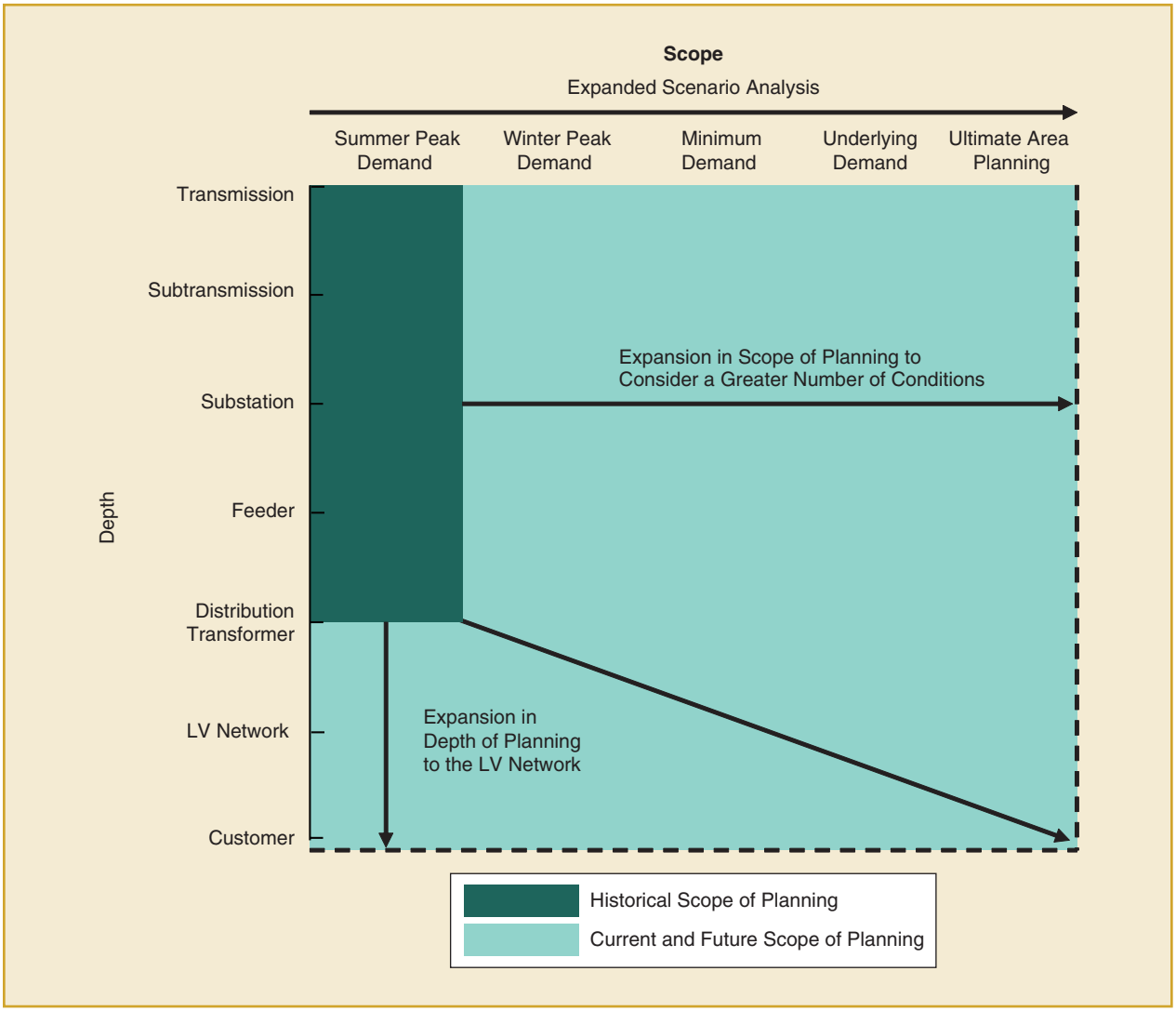

figure 4. SAPN's initiative to increase the depth and scope of network planning activities. For further details, please refer to "Future Network Strategy" in the "For Further Reading" section. LV: low voltage.

connection must be no greater than 253 V, and the first-percentile voltage (V1%) must be no lower than 216 V. Data from approximately 25,000 monitors across Queensland show that the distribution of the V1% measured at the distribution transformers appears quite high compared with the lower limit of 216 V. This margin is required to enable voltage drops to customers at the end of the LV network. Voltage data from a significantly smaller quantity of roughly 4,000 LV monitors, typically installed near the end of LV circuits (Figure 6), demonstrate a much lower V1% for customers that are distant from the distribution transformer. The average customer's voltage distribution in Queensland is likely to sit in a narrower range than the one shown in Figure 6, which is illustrative of points at the end of the LV network. Given the limited LV network visibility, the samples in Figures 6 and 7 are not representative of population-wide voltage conditions.

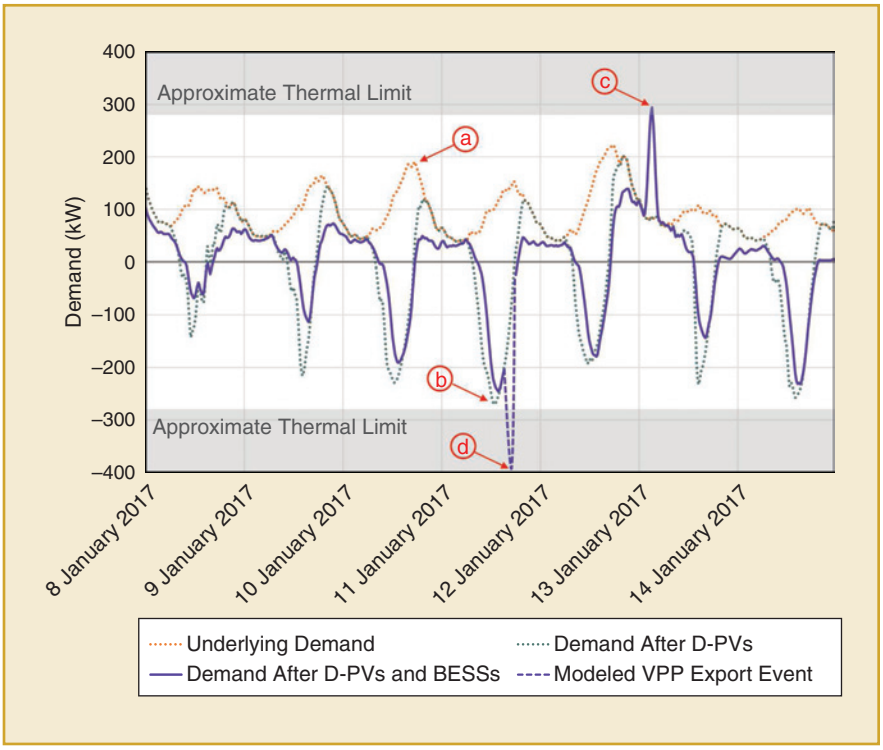

figure 5. The South Australian Salisbury battery trial. ⓐ The existing thermal limit challenges during peak demand (orange). ⓑ The existing voltage challenges, with high D-PV exports (green). ⓒ The reduced peak demand, with batteries, and the observed peak during a VPP charging event (purple). ⓓ The modeled emerging VPP-driven thermal limit challenges during VPP export events (dashed). For further details, please refer to "Low-Voltage Management Business Case" in the "For Further Reading" section.

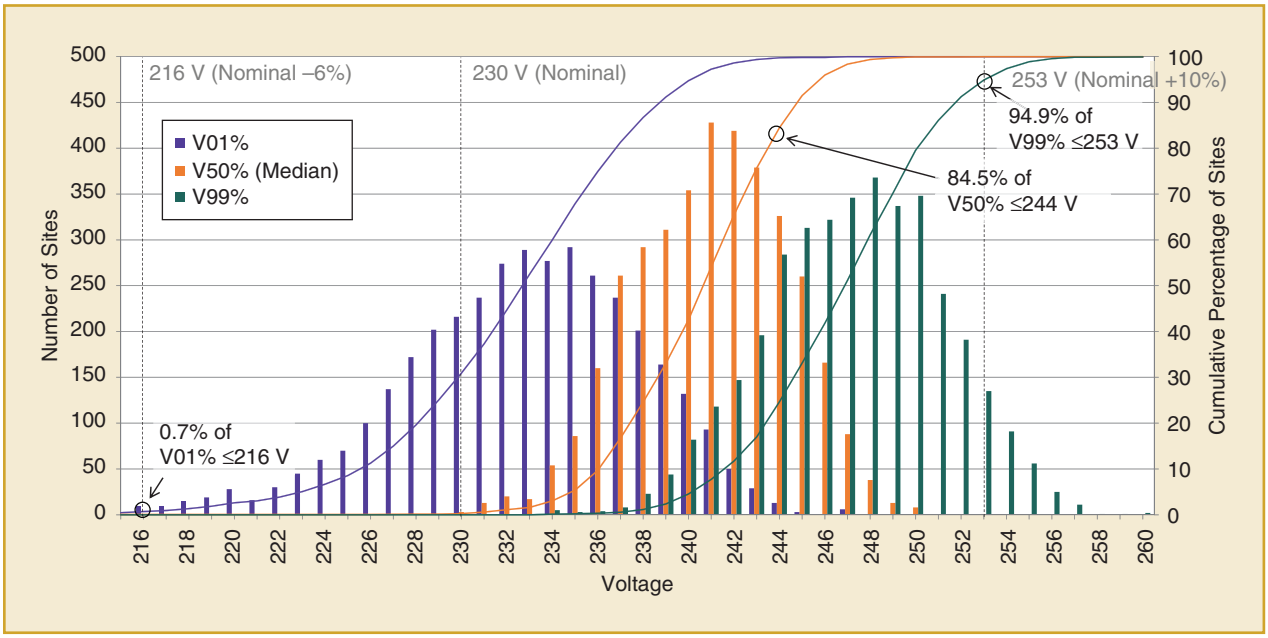

figure 6. Voltage measurements for the LV monitoring of Energex networks in spring (November) 2019. The data are from ~4,000 LV monitors (out of approximately 150,000 LV networks in Queensland). For further details, please refer to "Distribution Annual Planning Report" in the "For Further Reading" section. V50%: 50th voltage percentile.

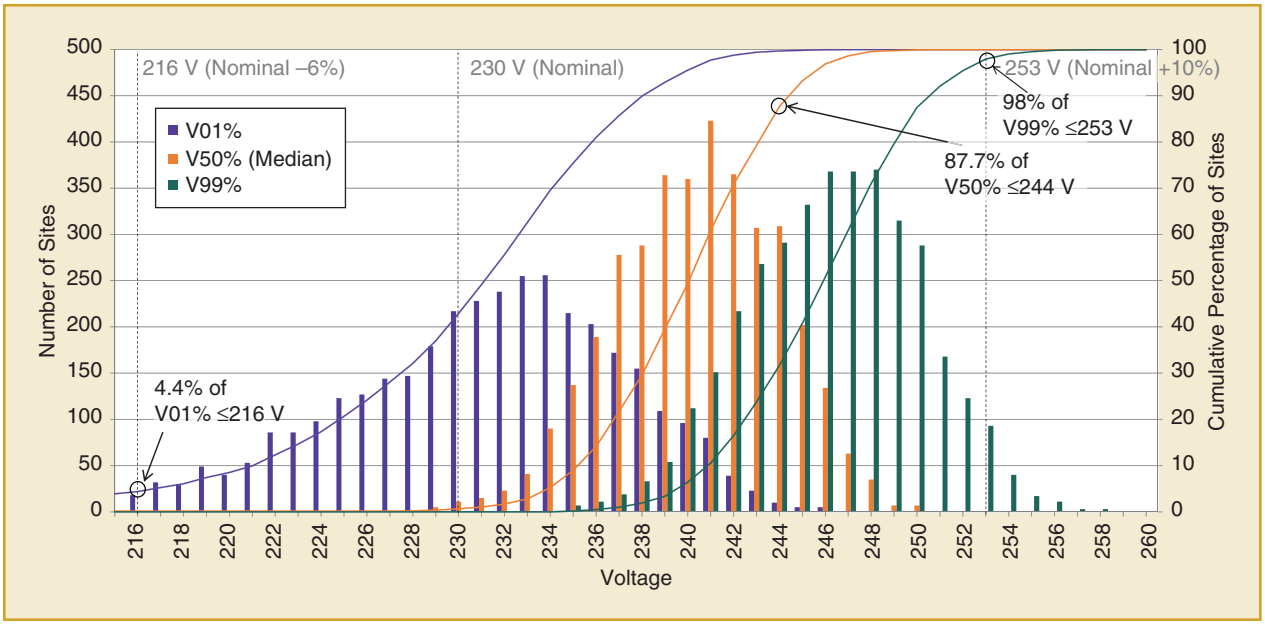

figure 7. Voltage measurements for the LV monitoring of Energex networks during the summer peak week in February 2020. The data are from ~4,000 LV monitors (out of approximately 150,000 LV networks in Queensland). For further details, please refer to "Distribution Annual Planning Report" in the "For Further Reading" section.

Customers at the ends of LV circuits are exposed only to the lowest voltages on a few days each year, when peak loads happen. DNSPs are responsible for maintaining voltage compliance during peak periods, when maximum demand occurs, just as they must maintain compliance during the spring and autumn months, when loads are modest and the reasonable solar irradiance results in minimum demand, events that are likely to be observed significantly more frequently. Figure 7 indicates that during the weeks when maximum demand occurs, there is very limited room for further widescale reductions in voltage levels.

Estimating PV Curtailment

The curtailment of distributed PV generation due to high voltages in the distribution system has received considerable interest due to the potential lost revenue for consumers with PV equipment. In addition, overvoltage curtailment may limit opportunities for DER participation in the broader power system, for instance, through VPPs. Typically, curtailment occurs when local network voltages exceed inverter overvoltage set points, causing the inverter to "trip" and curtail to zero power output, even when there is a behind-the-meter load (Figure 8). During recent years, Australian DNSPs have moved to mandate that volt–var and volt–watt response modes are enabled for new D-PVs, which facilitates a more progressive reduction in the inverter output as the voltage rises, rather than relying on overvoltage trip settings. Legacy D-PVs installed under the previous inverter interconnection standard tend to have higher overvoltage set points. Regions with high penetrations of legacy D-PVs can therefore produce higher voltages and trigger greater levels of curtailment than areas with significant numbers of nonlegacy D-PVs. The same standard also applies to BESSs and can prevent the systems from operating, even when they are attempting to charge, which would otherwise assist with alleviating overvoltage conditions.

An analysis of more than 1,300 South Australian sites observed by a solar-monitoring company, Solar Analytics,

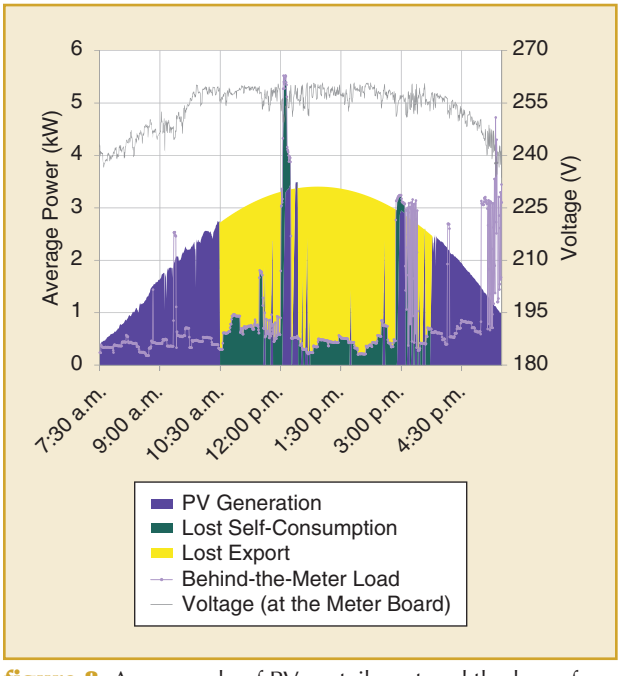

figure 8. An example of PV curtailment and the loss of self-consumption at a single site in South Australia on 5 March 2017.

is presented here. This analysis examines 24 clear-sky days and is therefore expected to capture high curtailment conditions. Its findings indicate that the overall levels of PV curtailment due to overvoltage tripping are currently low, with an average of just 1% of generation being curtailed per site, overall. However, these impacts are not evenly distributed, and some sites are badly affected, losing up to 45–95% during a particular day (Figure 9), with clear equity implications. The most extreme curtailment is observed during spring (September–November), when mild temperatures coupled with strong solar resources appear to result in local network voltage rises (Figure 10). Customer inquiries in the SAPN area relating to PVs and overvoltages also display a seasonal pattern and peak during spring (Figure 11).

Solutions

Evolution of Voltage Management Techniques

Australian DNSPs are pursuing a number of voltage management techniques as D-PV penetration increases. One traditional method of mitigating end-of-line voltage spread on medium-voltage (MV) feeders with similar load profiles is with line drop compensation (LDC). By boosting the voltage with an on-load tap changer as the load increases, LDC mitigates the peak load voltage drop at the end of the feeder and thus the worst-case voltage spread. LDC can also be applied during reverse flows to lower voltages. The result is an increased voltage spread at the start of the feeder, with higher voltages when there is maximum demand and lower voltages during reverse flows, in exchange for a reduction in the voltage spread at the end of the feeder. The implication is that on voltage-constrained parts of the network (typically toward the end of longer MV feeders), a falling minimum demand can cause an increased voltage spread and breached voltage constraints just as easily as rising maximum demand. Thus, voltage constraints associated with reverse flows can be planned for using minimum demand forecasts in a proactive manner, much as maximum demand forecasts have been used to plan for growth in peak loads.

Most Australian distribution networks have a topology more like European networks than those of the United States, with 400-$V_{p\text{-}p}$, LV-nominal, larger three-phase distribution (MV/LV) transformers that supply roughly from 10 to several hundred customers and LV secondary circuits that can be hundreds of meters long. In rural areas with much lower customer densities, single-phase feeders (including single-wire earth return) and smaller single-customer distribution transformers are more common. In addition, most Australian distribution transformers have offload tap changers that

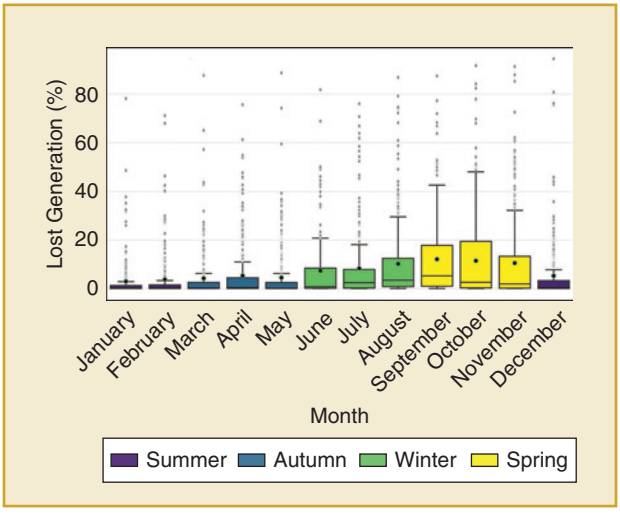

figure 10. The D-PV generation that was lost during one year (impacted consumers only) The center line indicates the median, box edges designate the 25th and 75th quartiles, whiskers denote a 1.5× interquartile range, black dots represent averages, and gray diamonds show outliers.

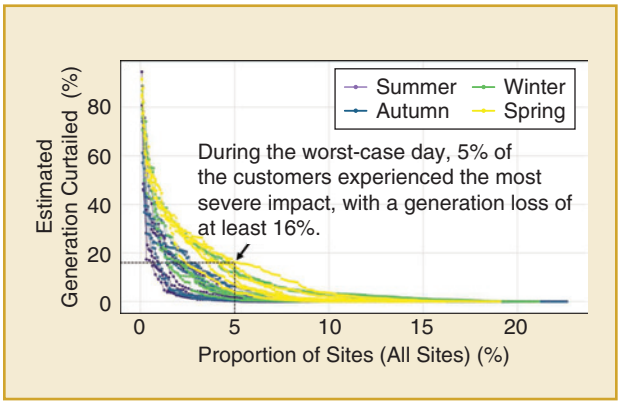

figure 9. A PV curtailment distribution, where each data point indicates an individual site that experienced curtailment in South Australia during 24 clear-sky days in 2018 (there are 1,851 distinct sites in the data set, and 983 of them experienced curtailment).

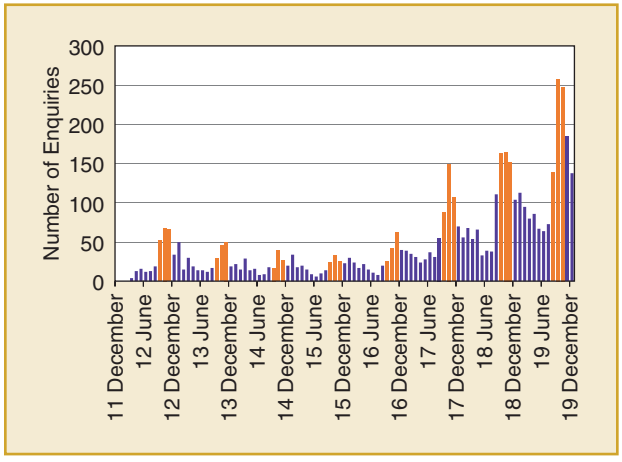

figure 11. SAPN high-voltage/D-PV-related customer enquiries per month. Spring is indicated in orange; all other seasons are in purple. For further details, please refer to "Low-Voltage Management Business Case" in the "For Further Reading" section.

require manual adjustments by field personnel. As a result, while offload tap chargers can permanently alter the maximum and minimum voltages on a supplied LV network, they provide no reduction of the voltage spread.

Tap reductions and the phase balancing of loads and PV systems are the first and least-cost options for managing voltage where feasible. Otherwise, excessive voltage spreading (whether the result of maximum demand growth or minimum demand reduction) can be reduced in four distinct ways:

1) reducing the network impedance, by using either lower-impedance (generally bigger) conductors or higher-rating transformers
2) reducing the magnitude of real power flows, either traditionally by splitting feeders, with demand response to shift demand, or with energy storage technologies, such as BESSs
3) adjusting reactive power flows, either traditionally with capacitor banks and behind-the-meter power factor correction or with modern devices, such as static synchronous compensators (STATCOMs) and behind-the-meter smart inverter reactive power compensation
4) using a regulating technology, such as an MV regulator, an LV regulator, and a voltage-regulating distribution transformer.

A summary of current and potential voltage management measures is provided in Figure 12. As the DER uptake continues and visibility in the distribution network improves, it is possible that voltage management challenges may be most economically addressed through MV solutions, that is, initiatives that impact large regions of the network, rather than localized and largely reactionary measures in the LV network.

Reverse Flows

Challenges

When considered collectively, D-PV sources are, by far, the largest generator in NEM. The next-largest plant is the Bayswater black-coal plant, at 2.6 GW. Substantial reverse power flows are already being observed in the distribution system across South Australia and metropolitan Queensland. In the SAPN region, 42% of the zone substations have already been observed in reverse flow conditions, with a further 32% nearing reverse flows. In some cases, reverse flows are sufficiently large to exceed subtransmission substation reverse power limits (which are often constrained by legacy tap changer designs). While reverse flows are being felt most acutely in the LV network, their impacts are rapidly extending to the subtransmission and transmission systems as well as raising system security concerns for AEMO. The reduced efficacy of underfrequency load-shedding schemes is a major concern, along with reactive power management, which are both exacerbated by the low levels of visibility and control. It is therefore critical that adopted strategies consider impacts across the entire power system.

Solutions

Incentivizing Load

Moving hot water demand to coincide with peak solar generation times presents one option, but there are challenges to this approach; in South Australia, this usually requires a site visit to manually reprogram the time clock or meter in each customer's meter box. In addition, the amount of available load is likely to be sufficient only to defer, rather than resolve, the minimum demand issue. Another approach being pursued in South Australia is the introduction of a new time-of-use "solar soak" network tariff from July 2020 that includes a low-cost, off-peak rate during the middle of the day to encourage customers to shift their load into the solar trough. The effectiveness of this will depend, in part, on the extent to which energy providers choose to pass on this price signal in their retail tariffs.

Flexible Export Limits

Currently, all embedded generating units with an export limit at or below 5 kW are automatically approved for connection in the SAPN network. An analysis by SAPN and EA Technology indicates that this approach is unsustainable, even with a volt–var mode mandated for all new installations. Figure 13 shows the approximate amount of D-PV generation in terms of kilowatts per consumer that can be accommodated in the SAPN network before voltage and thermal limits are exceeded across different network types, and it includes the present and forecast levels of D-PV penetration. The modeling shows that voltage limits are typically breached ahead of thermal limits across all network types, and, indeed, voltages are already exceeding allowable levels in some cases.

Due to the increasing volume of large generator connections of more than 30 kW and the subsequent effect of breaching connecting substation reverse N–1 limits, SAPN generator interconnection standards require a supervisory control and data acquisition (SCADA) runback scheme carried out by generators at the constrained substation to prevent any distribution and transmission asset overload and damage to equipment. Here, N–1 refers to the total capacity of the connecting substation with one major item of plant out of service (a "single contingent event"). In this case, it is the resultant capacity due to a single transformer outage from either a zone substation or the transmission connection point substation.

Without remedial action, the projected 2025 uptake of D-PV generation is expected to result in widespread voltage breaches, and the distribution network may become a bottleneck, limiting the benefits that can be captured from DERs. Additionally, VPPs present a concern where simultaneous charging and discharging, even at low battery penetrations, could exceed thermal limits. In response, SAPN has considered three options:

1) It could continue to apply a static connection limit of 5 kW and increase the network hosting capacity

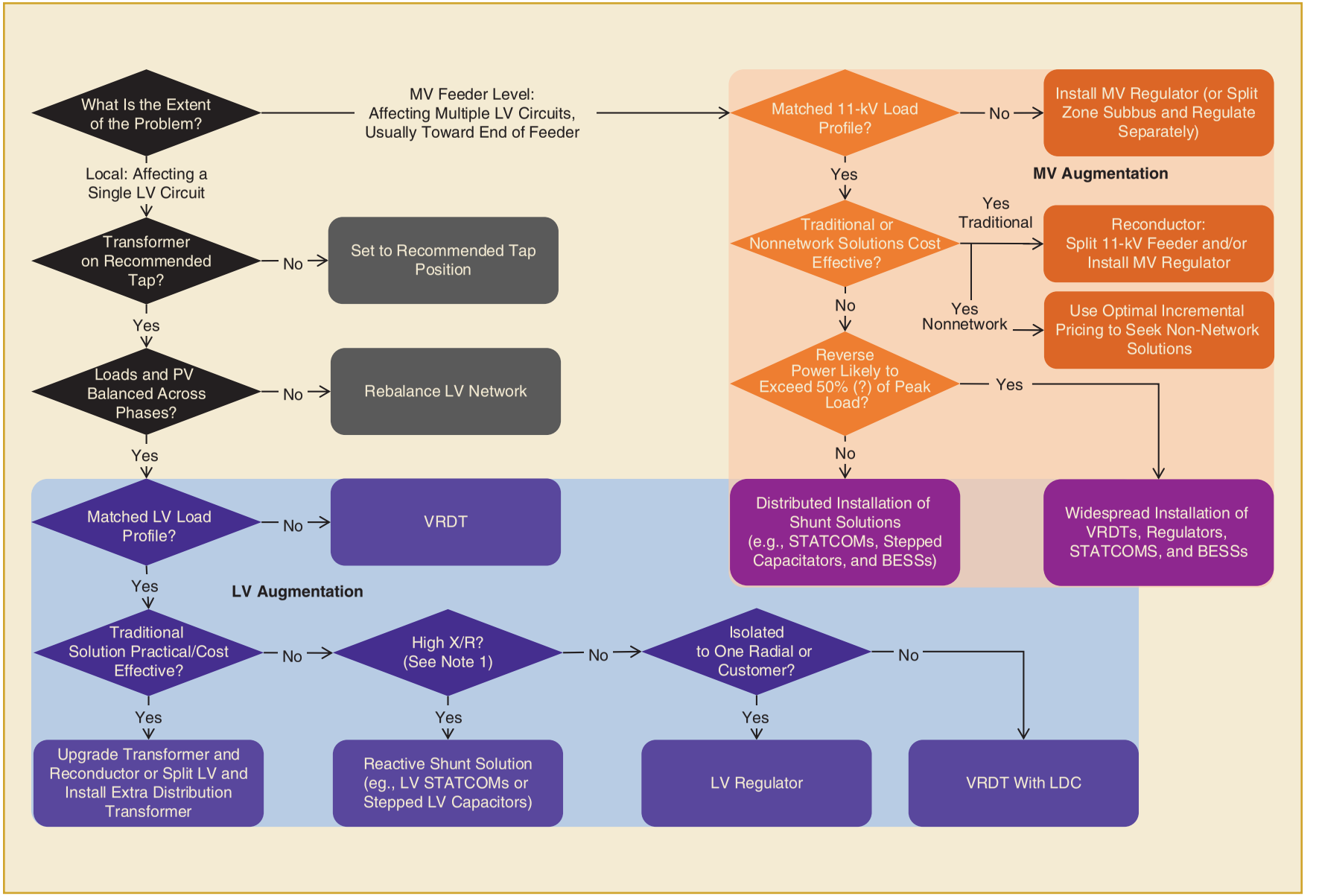

figure 12. Current and potential voltage management options framework. Note: X/R is the ratio of the source reactance to the source resistance. VRDT: voltage-regulation distribution transformer.

to accommodate all additional DERs. This could be achieved through a combination of network augmentation (such as investment in voltage regulators) and non-network solutions, such as demand management.

2) It could start applying static connection limits to new DERs, which might result in "zero-export limits" for DERs in parts of the network that are at their technical capacity (i.e., no exporting is allowed).
3) It could apply dynamic export limits ("flexible export connections"), meaning that DER export limits could vary depending on actual conditions when there are periods of export below the current 5-kW limit and potentially during periods when the export exceeds this threshold.

A techno-economic analysis indicated that enabling dynamic export limits would provide the greatest net economic benefit to all consumers, and hence this is SAPN's proposed approach. The application is currently under review by the Australian Energy Regulator as part of the revenue determination process conducted every five years (it is also referred to as a general rate case in some regions). If dynamic export limits are approved, SAPN plans to implement flexible export connections for all small and medium DERs by 2023.

A key component of this solution lies in the establishment of a standard web interface to communicate dynamic export limits to smart inverters, aggregators, and VPPs. SAPN is already undertaking preliminary trials in this area in conjunction with VPP operators in South Australia and planning a larger pilot to extend this capability to smart solar inverters in 2021. This will be undertaken in collaboration with another DNSP, leading inverter manufacturers, and a gateway vendor. SAPN is planning to adopt *Standard for Smart Energy Profile Application Protocol*, IEEE Standard 2030.5, which is also being applied in California as part of Rule 21. SAPN has leveraged the work undertaken by the standard-setting organization SunSpec Alliance and is identifying which aspects of IEEE Standard 2030.5 should be applied in the South Australian context. A 24-h forecast series of export limits is expected to be communicated to solar inverters, VPPs, and aggregators every 5 min on a rolling basis, with the technical architecture appearing in Figure 14.

System Security

Challenges

A growing body of evidence indicates that D-PV generation poses significant system security challenges in NEM, due to the response of inverters en masse during major power system disturbances and the continued "hollowing out" of the daytime system load. This section focuses on the D-PV disturbance response. However, it is important to note that reduced system load profiles have begun to impact operations in South Australia due to the region's high share of D-PV generation relative to the local underlying demand and weak transmission interconnection with neighboring regions, making the state more susceptible to islanding from NEM. For further details, please refer to "Renewable Integration Study

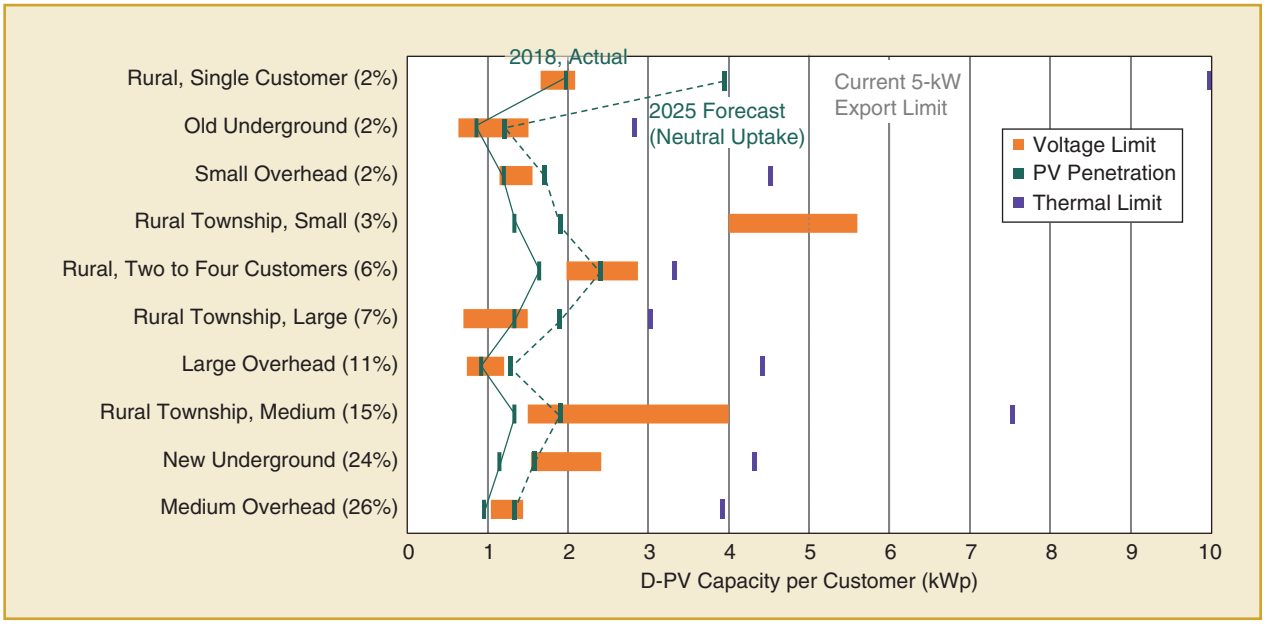

figure 13. The modeling outputs for the SAPN hosting capacity. The orange bars indicate the D-PV capacity per customer that networks of each type can accommodate before voltage limits are exceeded. The length of the bar reflects the statistical variability between individual networks of a given type. The purple bars represent the amount of D-PV generation per customer before thermal limits are reached due to a reverse current flow. The green bars show 1) the average level of D-PV penetration in 2018 and 2) the forecast level of penetration in 2025. For further details, please refer to "Low-Voltage Management Business Case" in the "For Further Reading" section. kWp: kilowatts peak.

Stage 1—Appendix A: High Penetrations of Distributed Solar PV" in the "For Further Reading" section.

Frequency Disturbance Case Study

The current inverter interconnection standard requires an overfrequency droop, or frequency–watt (F–W), response. At the time the standard was published, in 2015, this was a world-leading requirement, as the F–W response was generally not mandatory for small-scale systems. An analysis of real-world operational data from more than 3,000 D-PV systems during a major system disturbance on 25 August 2018 has provided unique insight into the inverter performance of this F–W function. D-PVs installed under the current standard ("post-2016" systems) appear to have performed the F–W response adequately, in aggregate (Figures 15 and 16), providing evidence of D-PVs acting rapidly, autonomously, and in concert to aid with maintaining power system security. This sort of useful DER response is becoming more important in regions, such as South Australia, where there is limited interconnection with neighboring areas and demand is increasingly met by D-PVs during some periods. However, the separation event on 25 August 2018 also uncovered concerns regarding inverter compliance. An examination of individual D-PVs (rather than in aggregate) found that at least 15% of the systems in Queensland and 30% of those in South Australia did not appear to perform an F–W response. High noncompliance rates raise concerns as to whether inverters can and will perform key functions, such as underfrequency ride-through, when required.

Voltage Disturbance Case Study

D-PV responses to major system voltage disturbances also pose substantial risks. A 30–40% reduction in the aggregate D-PV generation has been observed following major voltage disturbances in NEM, including an event in South Australia on 3 March 2017 following the loss of the Torrens Island gas generator (steam subcritical, nameplate capacity: 1,280 MW). During this event, the voltage fell to 0.1 per unit for one phase in the Torrens Island area, which is in proximity to the main load center of Adelaide. It is worth noting that the conditions during the disturbance were similar to those experienced prior to the 2016 South Australia system blackout event and that D-PV losses exacerbated the situation, with the most extreme D-PV response close to the disturbance source (Figure 17). A further analysis undertaken by AEMO in its renewable integration study (RIS) supports a number of necessary actions. The RIS notes that, in the absence of these actions, AEMO may require a moratorium on D-PV installations or the expensive retrofitting of existing D-PV equipment.

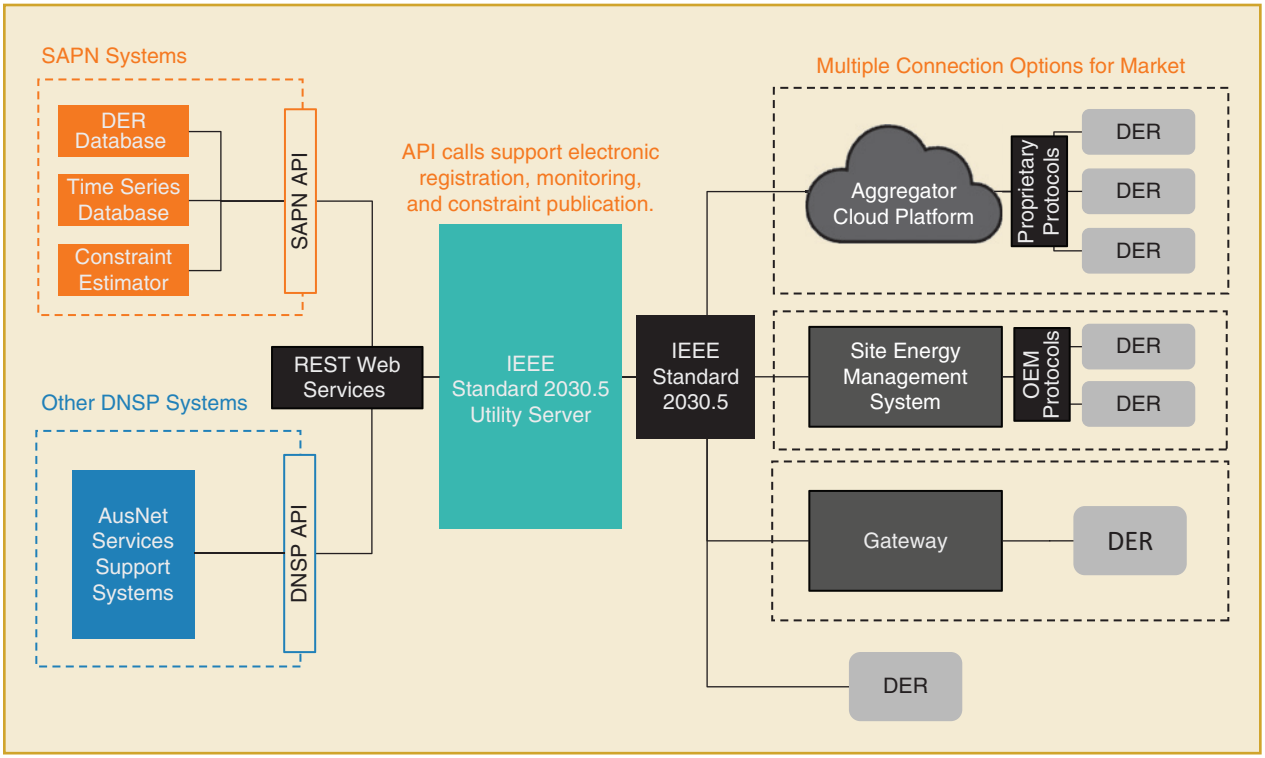

figure 14. The SAPN technical architecture for flexible export limit communication. Communication between the DNSP and the server uses a Representational State Transfer (REST) software architecture, while exchanges between the server and the DERs or the DER controllers employ IEEE Standard 2030.5. API: application programming interface; OEM: original equipment manufacturer.

Solutions

Interconnection Standards

In Australia, DERs are predominantly small systems connected to the LV grid through inverter energy systems, with requirements for their function and performance specified in *Standard for Grid Connection of Energy Systems via Inverters—Part 2: Inverter Requirements*, AS/NZS4777.2:2015. In June 2019, AEMO submitted a proposal to review AS/NZS4777.2 to address the key challenges resulting from the increasing penetration of D-PVs by aligning the aggregate behavior requirements for these systems with wider power system security objectives as well as distribution-level protection, power quality, and safety requirements. The proposed changes align with recent developments in international standards, such as IEEE 1547-2018 and Association of Electrical Engineering 4105 (Germany), which have implemented "smart" inverter functionality to support system security. As of July 2020, a revision of AS/NZS 4777.2 is out for public consultation, with expected publication in early 2021. This revision was developed through close collaboration between AEMO, DNSPs, inverter manufacturers, and other key stakeholders. In addition, AEMO is seeking to mandate minimum device-level curtailability requirements for new D-PV installations in South Australia to aid in managing extreme abnormal system conditions during periods of high D-PV contribution.

Disturbance Withstand Capabilities

As previously described, an analysis of recent system disturbances in NEM has highlighted the increasingly significant and unpredictable behavior of D-PVs during these events. The analysis shows that some of the currently installed inverters behaved in unexpected ways. Potential noncompliance with the expected operation under the current standard could have caused unforeseen reductions and losses of generation, thus increasing the event severity. With increasing DER levels, the unpredictable and potentially damaging behavior of D-PVs creates a growing risk and uncertainty that (in the absence of improved DER capabilities) will drive a need for AEMO to take increasingly conservative actions in managing the power system. Under the most extreme DER generation levels, AEMO might otherwise lose the ability to maintain line flows and restore operational stability. To continue to securely manage the power system as the penetration of inverter-connected DERs continues to grow, disturbance-withstanding requirements are being clarified and defined in AS/NZS4777.2. The proposed changes seek to define

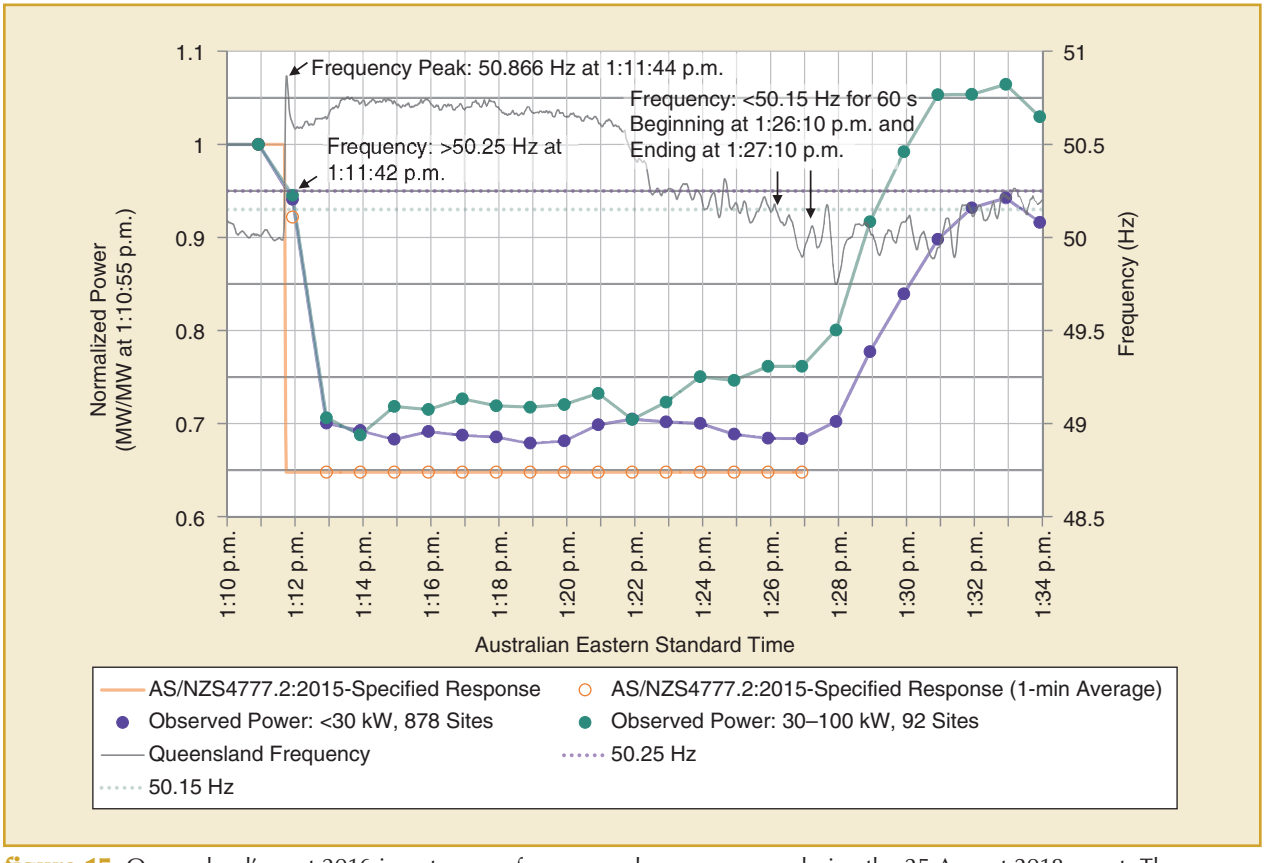

figure 15. Queensland's post-2016 inverter-over-frequency-droop response during the 25 August 2018 event. The average aggregate power is compared with the specified profile. For further details, please refer to "Technical Integration of Distributed Energy Resources" in the "For Further Reading" section.

operational performance requirements for disturbances to the voltage (including multiple events) and the frequency.

Power Quality Modes

Although AS/NZS4777.2:2015 already addresses the power quality response, at the time of its adoption, many of the functionalities were novel and not widespread and thus implemented only in an optional capacity. With the increasing DER penetration of the distribution grids, DNSPs are now requiring the implementation of functions, such as volt–var and volt–watt response modes, for new D-PVs, which facilitates a more progressive reduction of the inverter output as the voltage rises. Otherwise, the system relies on overvoltage trip settings to manage local system operations and increase feeders' DER-hosting capacities.

Protection and Control Functionality

The unpredictable behavior of D-PVs following disturbances has been identified as potentially resulting from the lack of clear guidelines for performance, measurement, and response during events that cause voltage waveform distortions. For the revised AS/NZS4777.2, the Standards Australia review is considering the inclusion of clearer specifications for the expected accuracy, including the ability to withstand associated voltage waveform disturbances, and performance for various system conditions, such as a capability to withstand frequency rates of change and voltage phase angle jumps.

Next Steps

The suggested changes in this revision of AS/NZS4777.2 are a first step toward a high-DER future by improving the autonomous behavior of associated systems. Further requirements will be considered by AEMO through a staged approach, such as active optimization through interoperability, resulting in a need for cybersecurity measures and increased coverage beyond the LV network.

Larger Systems

According to the SAPN generator interconnection standards, it is a requirement for every generating system that is net exporting more than 200 kW to the distribution network to implement a cost-effective SCADA solution that has the ability to carry out a control signal issued by SAPN and, at times, under the direction of AEMO to manage system security. This may include curtailing the output of large asynchronous generation during periods of low minimum demand combined with large D-PV outputs and during noncredible

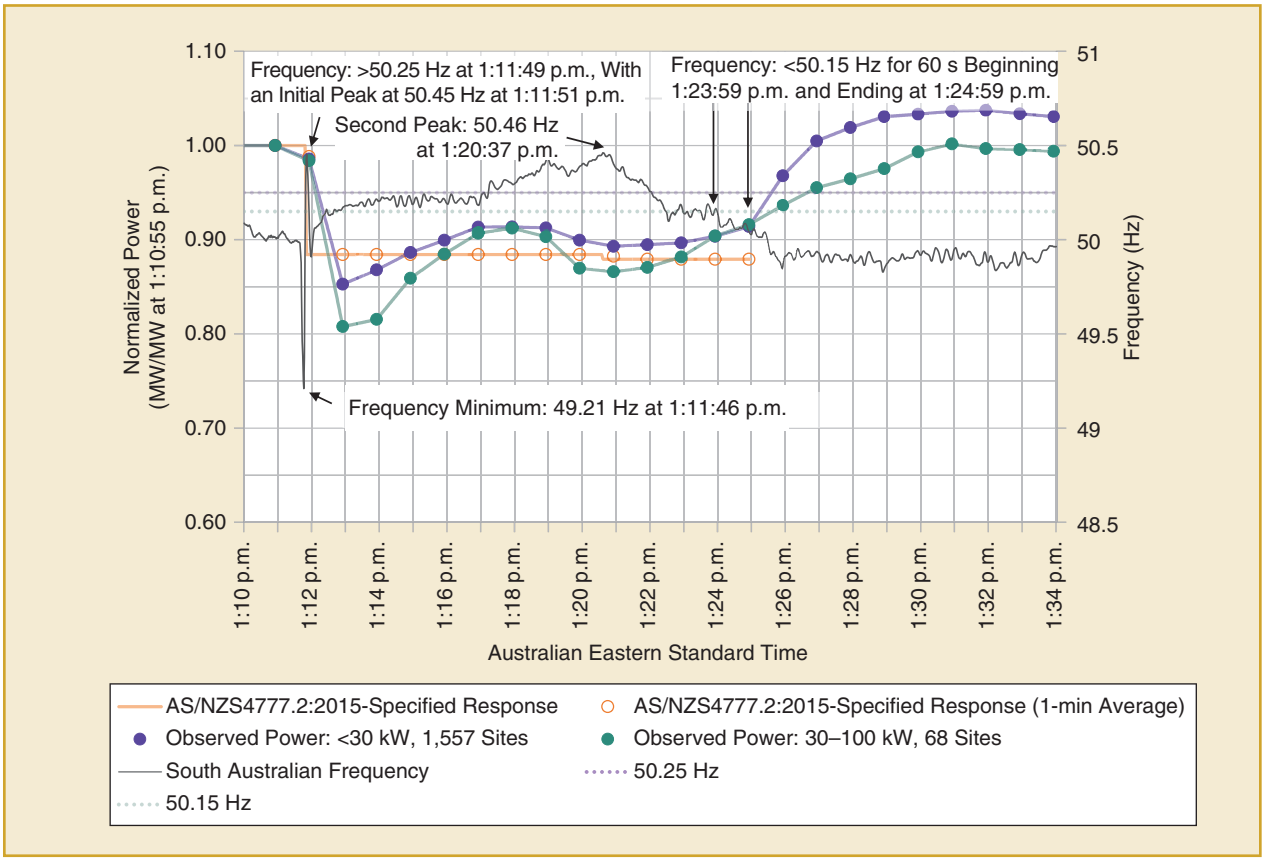

figure 16. South Australia's post-2016 inverter-over-frequency-droop response during the 25 August 2018 event. The average aggregate power is compared with a specified profile. For further details, please refer to "Technical Integration of Distributed Energy Resources" in the "For Further Reading" section.

contingency events. A recent example of such a contingency event occurred when the interconnector between Victoria and South Australia separated on 31 January 2020.

VPP Demonstrations

Given the potential scale of DER installations during the next decade, AEMO has established a dedicated program to integrate the resources into the power system safely, securely, and in a way that maximizes their benefits for all consumers, not just those who own them. For example, appropriate frameworks can incentivize DERs to deliver value for all electricity consumers by providing grid services that make the power system more efficient.

In 2019, AEMO launched VPP demonstrations to explore the capability of aggregated DERs to deliver FCASs and develop the organization's understanding of how VPPs respond to energy market price signals. A *VPP* broadly refers to an aggregation of resources (such as decentralized generation, storage, and controllable loads) that are coordinated to deliver services for power system operation and electricity markets. As of January 2020, there are two participants in the program, and two further VPPs are going through the enrollment process. Although there is a small pool of data to draw from, the knowledge that has been gleaned to date indicates that VPPs can respond effectively to power system events and price signals. This includes responding to frequency excursions beyond the normal operating range (49.85–50.15 Hz) and precharging (or discharging) to cater to future high-price (or low-price) events, respectively. Two VPP responses to contingency FCASs and energy events in South Australia are analyzed in the following.

10 December 2019 Response to Underfrequency Event

On 10 December 2019, NEM experienced both high (>50.15 Hz) and low (<49.85 Hz) frequency events within 45 min of each other. The South Australia VPP responded immediately, in both cases, to first charge its batteries to lower the system frequency and then discharge the batteries to raise the system frequency, shown in Figure 18.

9–15 January 2020 Response to Energy Spot Prices

Observing VPPs' actions during the course of a week provides evidence that VPPs do respond to energy market signals. This is clear in Figure 19, where precharging in anticipation

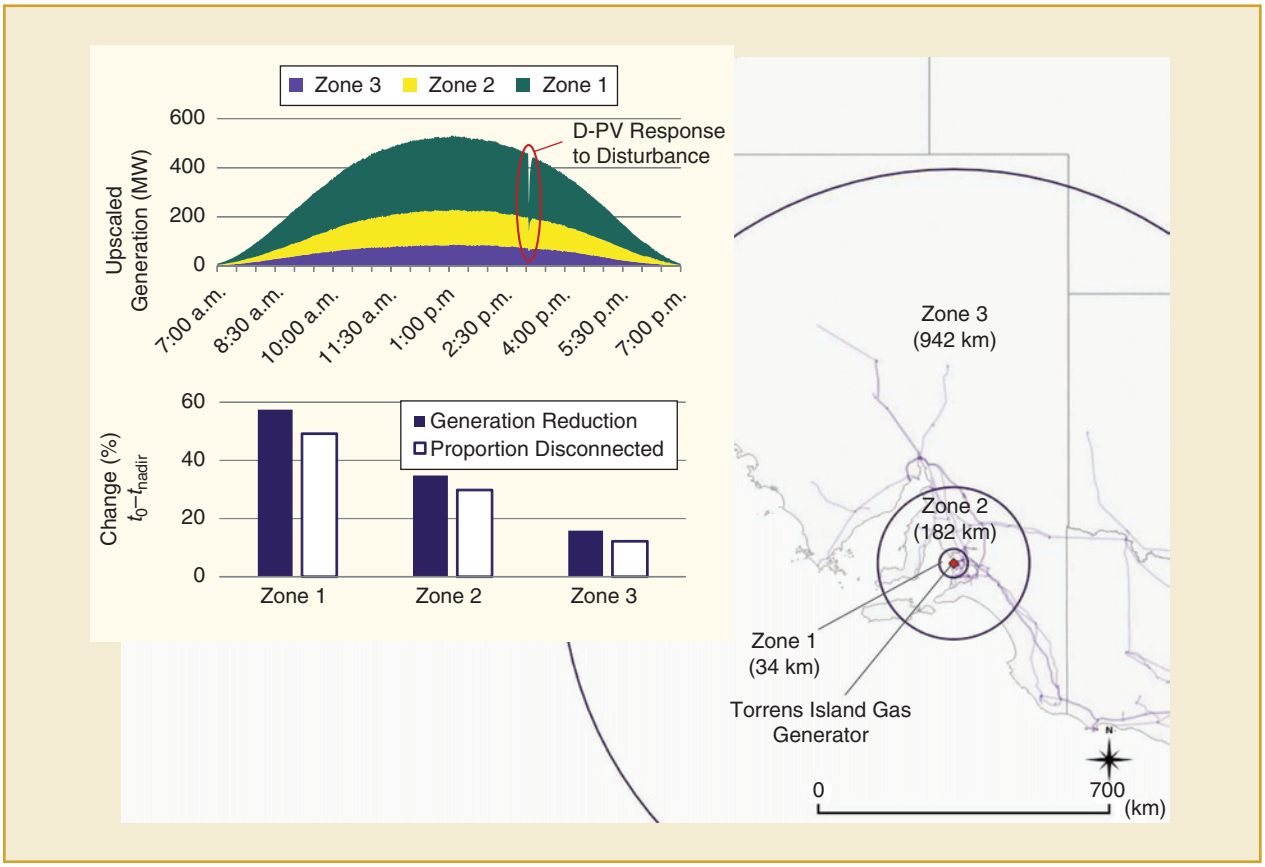

figure 17. A South Australian voltage disturbance event map and D-PV response profile for 3 March 2017 (*upscaled generation* indicates the estimated performance across the South Australian D-PV fleet, based on operational data). For further details, please refer to Stringer et al. in the "For Further Reading" section.

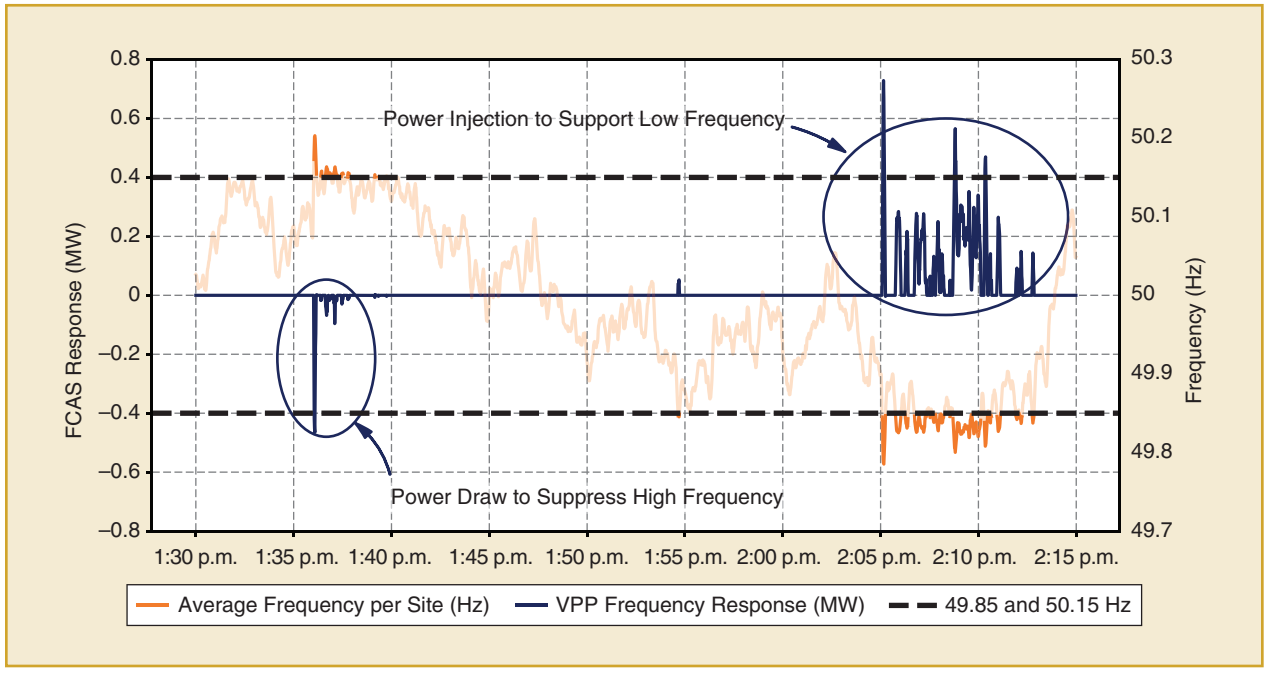

figure 18. The FCAS response for South Australia's VPPs on 10 December 2019, with Victoria and South Australia regional separation. For further details, please refer to "Virtual Power Plant Demonstration: Knowledge Sharing Report No. 1" in the "For Further Reading" section.

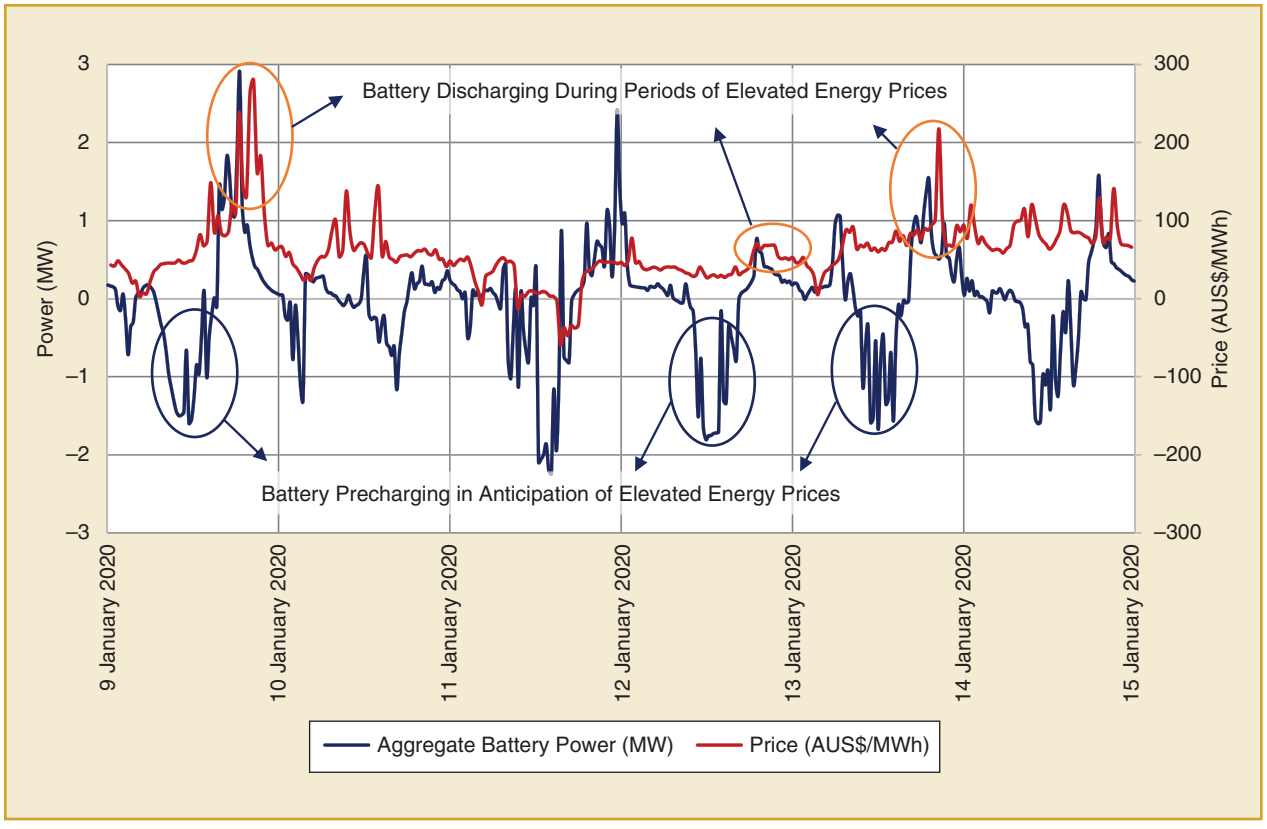

figure 19. The energy response for South Australia's VPPs on 9–15 January 2020, showing behavior during one week and the price-versus-battery dispatch. For further details, please refer to "Virtual Power Plant Demonstration: Knowledge Sharing Report No. 1" in the "For Further Reading" section.

of elevated prices and discharging when prices are high can be observed. As a result, the power system is supported by the provision of additional energy when needed. These events show that VPPs can benefit the following groups:

- ✔ participating consumers, by sharing the value earned through participation in FCASs and responding to energy market prices
- ✔ all other consumers, by creating more competition to reduce prices and, if VPPs scale up enough, potentially deferring/displacing the need for large-scale generation assets.

Next Steps

Australia's demonstrations will continue to provide knowledge regarding the effectiveness of VPPs for adding value to the power system. The addition of other participants will enrich the current data set and enable more analysis to be carried out and a deeper understanding to be gained. Conclusions will then be drawn to inform other DER-related trials and future market reform recommendations.

Looking Forward

Cast your mind forward to a bright spring day during the 2030s. D-PV generation is likely to be an even more familiar sight across most major Australian cities, accompanied by BESSs and a fleet of EVs. Perhaps Adelaide, the South Australian coastal capital, no longer has a monopoly on breaking minimum electricity demand records. As solar noon approaches, distribution systems across the country become net exporters, and reverse flows are rife. However, the grid is humming along nicely, and the system remains stable and secure. Dynamic distribution network limits are being broadcast, and the voltage is managed as DERs act to support the grid. Consumers are gaining rewards for the role their DERs perform, VPPs are responding to power system needs, and the benefits are being shared across the population. Very occasionally, a fault sends the voltage or the frequency wobbling; however, the system quickly responds and predictably brings operations back into kilter. Consumers again go about their business, rarely registering the new and evolving systems that are in place as the grid of the future slides seamlessly into the fabric of daily life. Perhaps this world is even closer than expected, with Australia at the pointy end of DER integration and with the impacts that are already being felt across the entire power system. As an eventful Australian summer comes to a close, the challenges and opportunities afforded by DERs are undiminished, and the collaborations across the industry are as important as ever.

Acknowledgment

We would like to gratefully acknowledge contributions from the SAPN team, which provided valuable input, guidance, and feedback during the development of this article.

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Autonomous Energy Grids

Controlling the Future Grid With Large Amounts of Distributed Energy Resources



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THE DRASTIC PRICE REDUCTION in variable renewable energy, such as wind and solar, coupled with the ease of use of smart technologies at the consumer level, is driving dramatic changes to the power system that will significantly transform how power is made, delivered, and used. Distributed energy resources (DERs)—which can include solar photovoltaic (PV), fuel cells, microturbines, gensets, distributed energy storage (e.g., batteries and ice storage), and new loads [e.g., electric vehicles (EVs), LED lighting, smart appliances, and electric heat pumps]—are being added to electric grids and causing bidirectional power flows and voltage fluctuations that can impact optimal control and system operation. Residential solar installations are expected to increase approximately 8% annually through 2050. Customer battery systems are anticipated to reach almost 1.9 GW by 2024, and current forecasts project that approximately 18.7 million EVs will be on U.S. roads in 2030. With numbers like these, it is not unreasonable to imagine a residential electricity customer having at least five controllable DERs. In future

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electric grids, as more DERs are integrated, the number of active control points will be too much for current control approaches to effectively manage.

Imagine, for example, the San Francisco Bay Area, which has a large distribution system with approximately 4.5 million customers. Figure 1 illustrates synthetic distribution systems of the Bay Area made from actual data that have been created to replicate properties of the actual systems, including various voltage levels and both wye and delta connected circuits. What if each customer had a PV system, a battery energy storage system, an EV, a smart thermostat, and controllable lighting loads? This would amount to approximately 10–20 million controllable devices capable of producing, storing, and consuming electricity. Currently, there are no control systems capable of ingesting 20 million data streams and making real-time operation decisions.

In current large-scale grids, such as the Eastern Interconnection in the United States, central station power plants provide power to loads and have on the order of 10,000 points of control. Current control systems work well when there are a limited number of active control points in the system, but to deal with the massive amounts of new DER technologies and the availability of grid measurements, a new control framework needs to be developed. The framework needs to monitor, control, and optimize large-scale grids with significantly high penetration levels of variable generation and DERs; it needs to process the deluge of data from pervasive metering; and it needs to implement a variety of new market mechanisms, including multilevel ancillary services. To handle this highly distributed energy future, we propose the concept of autonomous energy grids (AEGs).

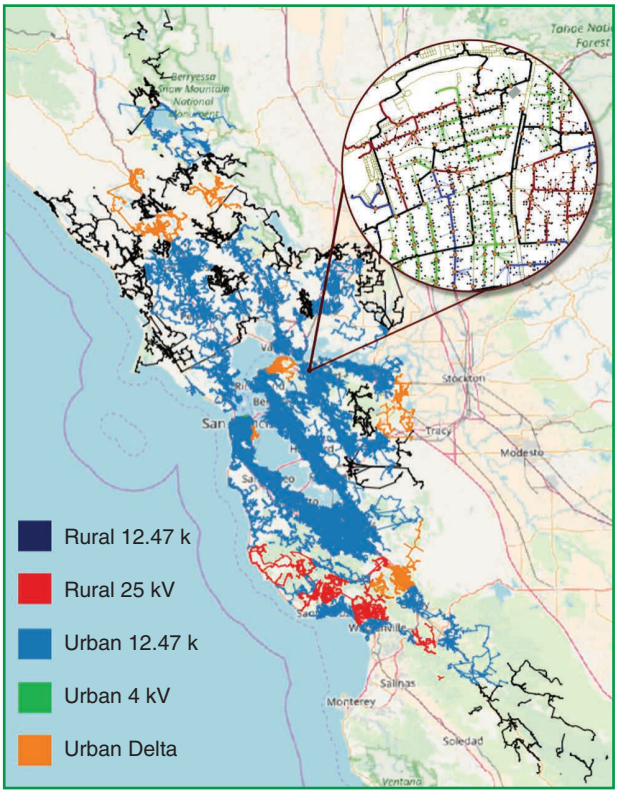

figure 1. This is the San Francisco Bay Area synthetic distribution system, developed under the ARPA-E GRID DATA program. Line configurations are mostly wye with a small amount of delta. (Source: grid data: NREL; map: OpenStreetMap.org.)

Autonomous Energy Grids: The Concept

AEGs are multilayer, or hierarchical, cellular-structured electric grid and control systems that enable resilient, reliable, and economic optimization. Supported by a scalable, reconfigurable, and self-organizing information and control infrastructure, AEGs are extremely secure and resilient, and they can operate in real time to ensure economic and reliable performance while systematically integrating energy in all forms. AEGs rely on cellular building blocks that can both self-optimize when isolated from a larger grid and participate in optimal operation when interconnected to a larger grid. Figure 2 shows how a scalable approach to control can be built from the lowest level of individual controllable technologies (renewable energy, conventional generation, EVs, storage, and loads) and used to control hundreds of millions of devices through hierarchical cells. In the figure, the bottom level consists of individual technologies that are aggregated into small cells. Then, each upper level represents a collection of cells until the entire grid is covered. Within each layer, distributed controls are used to optimize energy production and meet system requirements. There is minimal information passed between layers, and this hierarchical approach enables the control of hundreds of millions of devices.

To make this idea a reality, control algorithms for AEGs will need to be developed and implemented with the following characteristics:

- ✔ *Operate in real time*: Control algorithms must operate fast enough to ensure real-time operations in electric grids that balance load and generation every second.
- ✔ *Handle asynchronous data and control actions*: Data need to be used from a variety of asynchronous measurements and sources, whereas distributed decision making leads to asynchronous control actions.
- ✔ *Robustness*: This covers both reliability and resilience, where reliability is fault tolerance, and resilience is the ability to come back from a failed state. These control systems also must be robust to communications failures, prolonged communications outages, and large-scale disturbances.
- ✔ *Scalable*: Control algorithms must operate in a scalable fashion to ensure control of hundreds of millions of devices.

We will discuss these characteristics in detail in the following sections.

Operate in Real Time

One key challenge with AEGs is the development and implementation of real-time optimization and control methods. We use the term *real time* to indicate that power set points of the DERs are updated within each cell on a *second or subsecond* timescale. Electric grids must maintain energy balance at every time instance. This is required to maximize the operational and economic objectives while coping with the variability of ambient conditions and noncontrollable energy assets and achieving intercell coordination to ensure reliable systemwide operation. Solving optimization problems to convergence every second or every few seconds, however, has been impractical because of the following challenges:

- ✔ *Complexity and convergence analysis.* For large-scale grids, the computational complexity of a centrally defined system could prevent the solution of optimization problems at the required timescales. When an optimization problem is solved in a distributed and/or hierarchical fashion (e.g., with device-to-device or cell-to-cell communications as well as intracellular message passing), multiple communications rounds are necessary to converge to (possibly optimal) solutions. Note that the optimization tasks related to AEGs are markedly different from traditional settings in which energy systems are optimized at the wholesale level using economic- and market-based objectives. In the traditional operation of bulk systems, a few large-scale generators are dispatched, and the noncontrollable net load varies slowly. Such operation is incompatible with AEGs that include a massive integration of DERs or whose optimization models require accurate representations of ac power flows within the DERs' controllability region. In traditional bulk systems, optimization problems are nonconvex, nondeterministic, and polynomial-time hard (NP-hard); therefore, they may be infeasible to solve at the envisioned timescale with hundreds of millions of control points. To address these challenges and facilitate the development of provably stable and optimal distributed solution methods for AEGs, a first step is to develop convex relaxations and linear approximations of pertinent nonconvex problems.
- ✔ *Model inaccuracy.* Approximate linear models or convex relaxation methods might be leveraged to derive convex problems that facilitate the design of computationally affordable solutions. However, approximate/relaxed convex problems might involve only an approximate representation of a system's physics and constraints; therefore, the optimal solutions of the convex problem might not be feasible for the original problem. To begin to address this issue, distributed optimization algorithms have been developed to use measurement information directly, which is known as online optimization with feedback. Measurement-based (or feedback-based) algorithms address the feasibility issue, and they can be distributed or centralized. The design of a distributed version is certainly more challenging than the centralized one, but the distributed version can be implemented on a more flexible communications architecture, which can enhance cyber robustness.

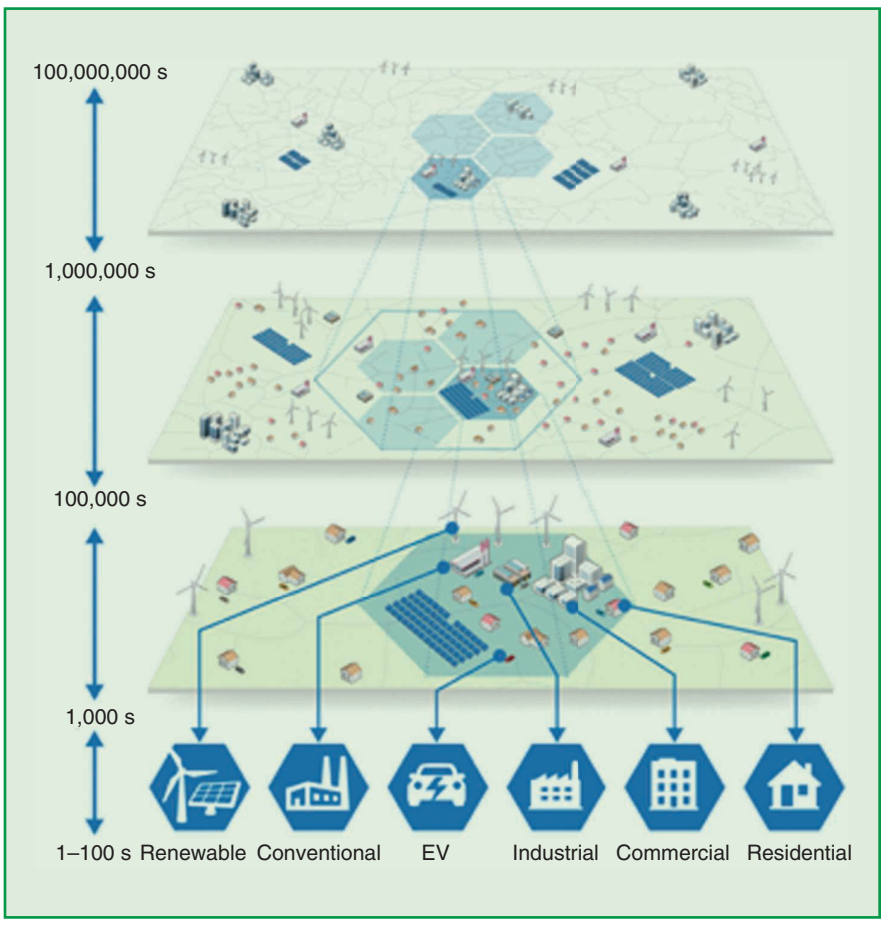

figure 2. The AEGs form a distributed hierarchical control system that integrates individual technologies in a cellular structure to the bulk power system. The scale on the side indicates the number of controllable technologies seen along the bottom level. The lowest level depicts the locations of various generation, storage, and loads.

- ✔ *Pervasive metering.* Solving optimization problems using relaxations/linearizations of the ac optimal power flow (OPF) requires pervasive metering to collect measurements of the noncontrollable loads at all locations in real time, which might be impractical. One way to address this problem in the large-scale grid of the future is to develop and implement distributed state estimation algorithms that can provide insight into the state of the system without having to explicitly measure every point of interest.

To address these challenges within the AEG cells, a real-time optimization framework has been developed at the National Renewable Energy Laboratory (NREL) under the Network Optimized Distributed Energy Systems (NODES) program within the U.S. Department of Energy's Advanced Research Project Agency-Energy (ARPA-E). The framework can model well-defined objectives and constraints of DERs located within each cell as well as consistency constraints for electrical quantities that pertain to the cell-to-cell connections. By using measurements in the system as a feedback mechanism and tracking optimal solution trajectories, the resultant feedback-based online optimization methods can cope with inaccuracies in the representation of the ac power flow and avoid having to measure all the noncontrollable resources. Figure 3 demonstrates how voltage and current measurements are used as feedback to better track the optimal trajectory of a large-scale system by sending a price signal that embeds cost functions, reliability functions, and system constraints.

The algorithm enables DERs to track given performance objectives while adjusting their power [the real power (P) and reactive power (Q) set points] to respond to services requested by grid operators and maintain electrical quantities within engineering limits. The design of the algorithm leverages primal-dual gradient methods that improve the convergence rate of the optimization problem, allowing the algorithms to take advantage of the structure of the problem and be solved in real time. The gradient governs which direction and how fast to search for the next iteration in the optimization, and it can be suitably modified to accommodate appropriate measurements from the distribution network and the DERs. Primal-dual gradient methods can be implemented in real time because every gradient iteration is computationally cheap (very fast to compute); however, this method usually has a fast convergence rate when referred to the number of iterations required for the algorithm to converge. The resulting algorithm can cope with inaccuracies in the distribution system modeling; moreover, it avoids pervasive metering to gather the state of noncontrollable resources, and it naturally lends itself to a distributed implementation. Analytic stability and the convergence of optimally tracking the solutions of the formulated time-varying optimization problem is established. Figure 4 depicts how the real-time algorithm uses active and reactive power set points for a single DER (blue line) to track an optimal trajectory (red line).

Hierarchical Communications and Asynchronous Data

To enable the real-time optimization of AEGs with millions of controllable devices, a hierarchical communications architecture that includes cell-to-cell and cell-to-customer message passing can be formulated to manage these devices. Mathematically, to obtain consistency among cells, constraints are added to the optimization problem to ensure that adjacent cells agree on the power flows from one cell to another. This is known as consensus-based optimization. Overall, the resultant feedback-based online optimization methods need to provably track the solution of the convex optimization problems by modeling well-defined objectives and constraints for each cell as well as the consistency constraints for electrical quantities that pertain to the cell-to-cell connections. The feedback-based method also works for nonconvex problems; however, analytic proof of convergence for the feedback-based method is very tricky and not well established. These cell connections can be geographically

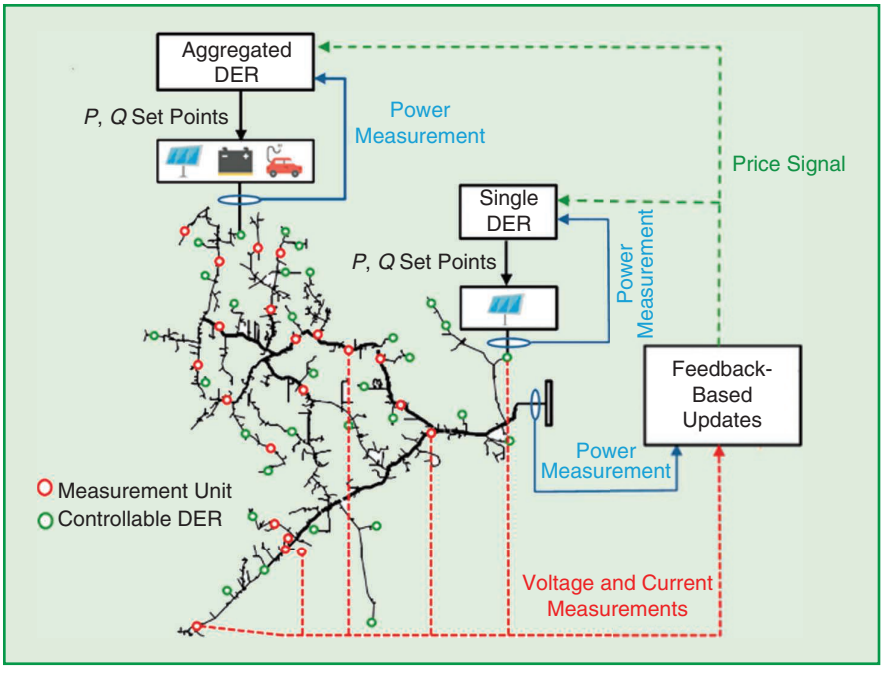

figure 3. These measurements are used as a feedback mechanism for DER control. Real (P) and reactive (Q) power are used to optimize conditions on the distribution circuit.

colocated or based on aggregators, such as smart-home aggregators. In this sense, it is worth emphasizing that the design of the distributed algorithm as well as the overall communications strategy will depend on the types of actors participating in the real-time optimization process (e.g., end customers, cell controllers, or aggregators).

In addition to the influx of DERs, the installation of new sensing and measurement technologies (e.g., smart meters and distribution-level phasor measurement units) will drastically improve the observability of grid conditions at the distribution level. To take advantage of all the available measurements, algorithms must be able to operate in an asynchronous way to account for different communications latencies and for devices that can be controlled at different timescales (e.g., inverter-interfaced devices are controlled at fast timescales, whereas thermostatically controlled loads are controlled every few minutes). Analytic proof of convergence can be tedious, but it is widely accepted that gradient-based algorithms can be implemented asynchronously.

Robustness

In the context of AEGs, robustness includes both reliability and resilience. Reliability is the property to be tolerant to faults, and resilience is the ability to come back from a failure to an operational state. For reliable operation, stability analysis can be used at multiple timescales. Resilience to communications drops and asynchronous operation should be analytically established through pertinent input-to-state stability and tracking results. In other words, the AEGs should be able to continue operating even in the presence of these faults/errors. Mathematically, iterative optimization algorithms have been developed to operate with errors in their estimated parameters, such as gradients. In fact, it can be shown that a packet loss leads to the computation of primal or dual gradient steps with outdated information. Thus, cells that can switch from an islanded mode to a larger grid-connected mode may continue operating amid faults and/or threats to the grid. These properties can be modeled as time-varying constraints in the underlying optimization problem. Similarly, flexible operation, in which a cell (or a portion of a cell) switches to an autonomous control setting during a prolonged communications outage, should be enabled.

Scalability

Figure 5 illustrates an architecture in which communications among cells occur when performing distributed and/or hierarchical control. As mentioned previously, distributed and hierarchical control algorithms are scalable and allow for the control of millions of devices in real time. When using distributed/hierarchical controls, the problem is broken up into smaller "cells," and the interactions among cells can be reconciled using consensus to ensure consistency constraints for electrical quantities that pertain to the cell-to-cell connections. For example, adjacent cells must agree on the real and reactive power exchanges at the points of interconnection or overlap.

Real and reactive power set points from the optimization are sent between levels in the hierarchy. Intracellular communications (on the same level) can be used to ensure that the set points of the DERs are computed to maximize the given operational objectives while ensuring that electrical limits are satisfied within the cell. Communications also

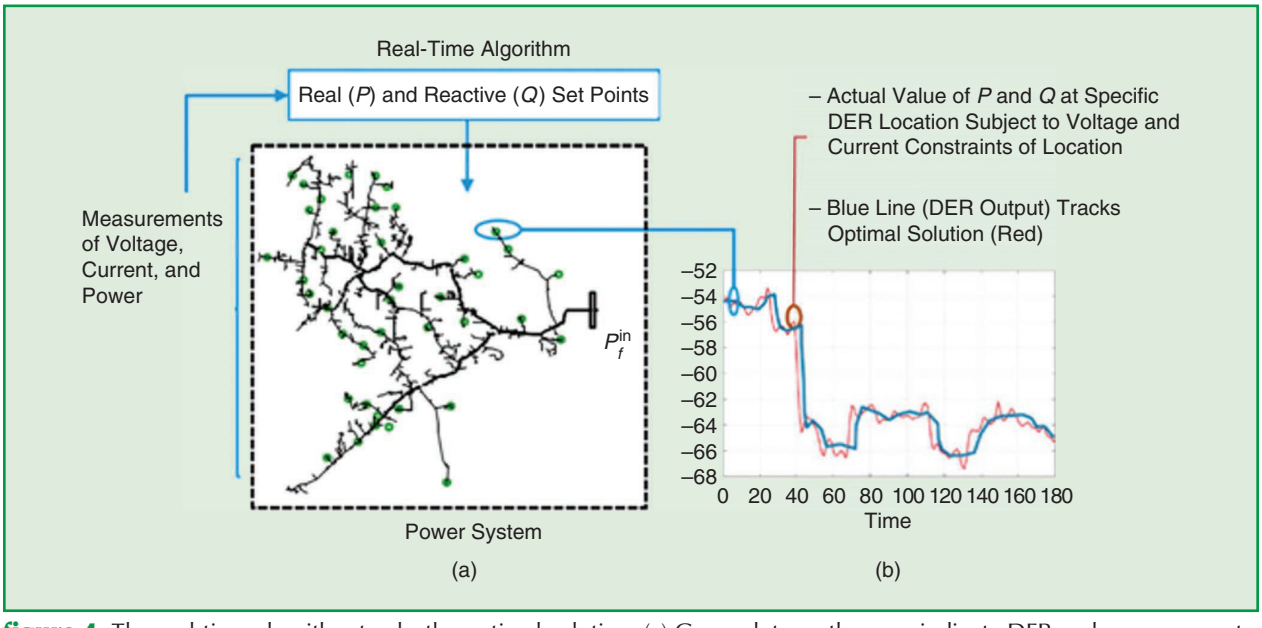

figure 4. The real-time algorithm tracks the optimal solution. (a) Green dots on the map indicate DER and measurement locations. (b) The graph shows only the real power (P) set point in red and the actual DER power output in blue for one DER location.

take place between a cell-level control platform and individual customers; these are necessary to optimize customer-level objectives while respecting electrical limits within a cell. Message passing among cells to optimize the flow of power is based on economic and reliability targets. These levels of hierarchy allow for scalable distributed optimization algorithms to be designed and implemented in AEGs.

Figure 5 presents three levels of hierarchy. The top level, level 3, aggregates neighborhoods to achieve an optimization objective, such as voltage regulation or power balancing. This level communicates to level 2 (e.g., a single neighborhood) about the aggregated power designated for that neighborhood. This information is passed from the neighborhood level down to the homeowner, level 1, as a power set point to track. The homeowners might accordingly coordinate their own distributed wind or solar, smart-home devices, and EVs to optimally balance the grid needs and their own usage preferences. Communications run in both directions, as indicated in Figure 5. For example, if homeowners are unable to meet their power set points, information is passed back up to level 2 (e.g., via monitoring the aggregate power of the neighborhood) to indicate this, and the optimization is repeated until each agent in the cell has reached a feasible solution that achieves the global objective as well as individual satisfaction.

After demonstrating that distributed control concepts can work on a single distribution circuit, the goal is to implement a hierarchical control scheme that would allow true scalability. This work considered a potentially large distribution network controlled cooperatively by several networked AEGs. Figure 6 is an illustration of this work. A regional coordinator communicates with all the dispatchable nodes within each AEG cell, and a central coordinator communicates with all the regional coordinators. Each regional coordinator knows only the topology and line parameters of the cell that it controls, and the central coordinator knows only the topology and line parameters of the reduced network, which treats each cell as a node and connects all the cells. Given such information availability, we explored the topological structure of the linearized power flow model to derive a hierarchical, distributed implementation of the primal-dual gradient optimization algorithm that solves an OPF problem. The OPF problem minimizes the total cost of all the controllable DERs and a cost associated with the total network load subject to voltage regulation constraints. The proposed implementation significantly reduced the computational burden compared with the centrally coordinated implementation of the primal-dual algorithm, which requires a central coordinator for the whole network.

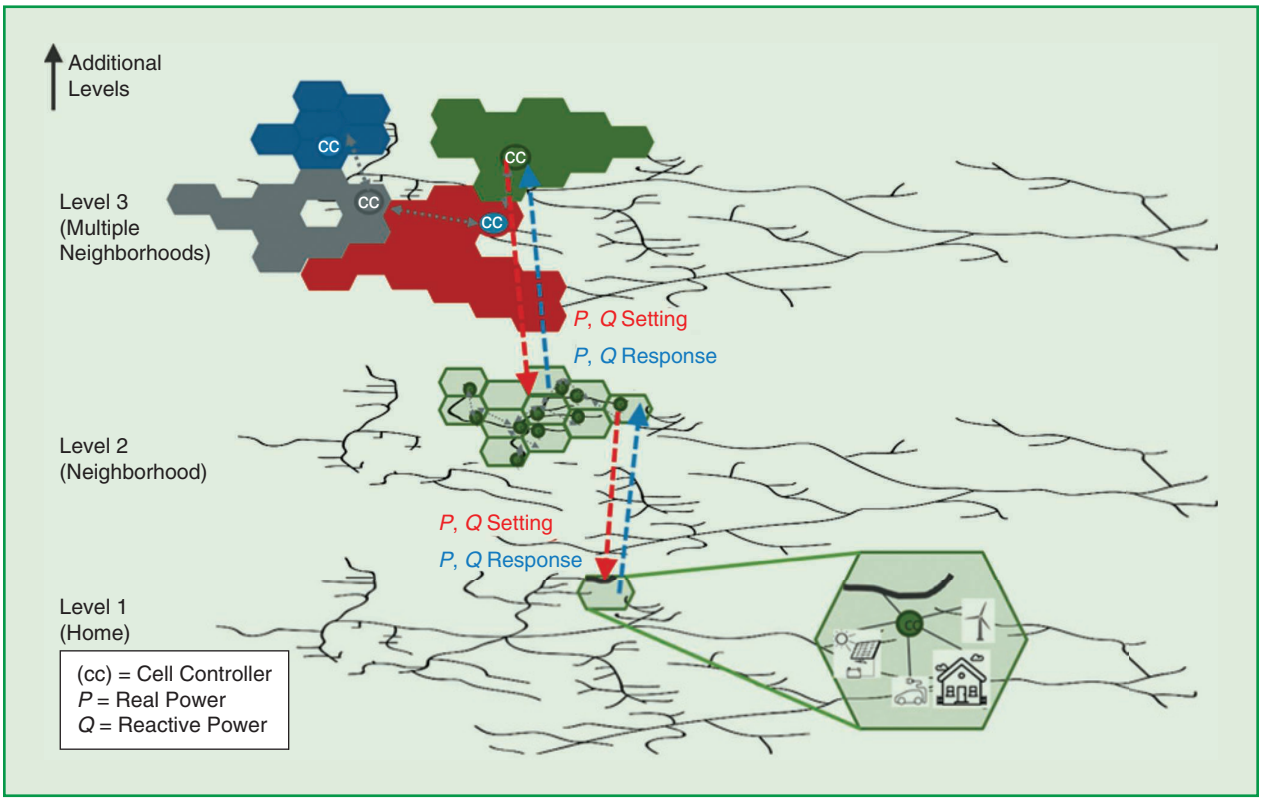

figure 5. The communications architecture for distributed and real-time optimization of AEGs. In the figure, Level 1 would be at a home or business, Level 2 would be at a neighborhood, and Level 3 would be multiple neighborhoods, all on a single distribution circuit.

In this example, a three-phase, unbalanced, 11,000-node test feeder was constructed by connecting the IEEE 8,500-node test feeder with a modified Electric Power Research Institute (EPRI) Circuit 7. In this example, a node is an electrical node where all voltages are equivalent. Figure 6 depicts the single-line diagram of the feeder, where the line width is proportional to the nominal power flow on it, so a thicker blue line has more power flowing through it. The primary side of the feeder was modeled in detail, whereas the loads on the secondary side (which is an aggregation of several loads in this system) are lumped into corresponding distribution transformers, resulting in a 4,521-node network with 1,335 aggregated loads. We grouped the nodes into four large cells (dotted circles) that were physically colocated and into a collection of other scattered nodes not inside these cells, as illustrated in Figure 6. Cell 1 contains 357 nodes with controllable loads, cell 2 contains 222, cell 3 contains 310, and cell 4 contains 154. Cell 4 represents the EPRI test circuit. We fixed the remaining loads on all 292 nodes not included in the four large cells.

To evaluate how well voltage regulation was enabled by the control algorithms, the three-phase, nonlinear power flow model was simulated using OpenDSS, a power flow solver. Figure 7 illustrates the output of the simulations under different voltage controls (voltage without control in blue, voltage with a default local controller in orange, and voltage with the OPF controller in green). The voltage without control (blue) demonstrates a large variation in voltage control between 0.8 and 1.0 p.u. The local controller (orange) demonstrated several locations of undervoltage (lower than 0.95 p.u.). In contrast, the OPF control (green) was able to maintain the voltage magnitudes of all the nodes within the bound from 0.95 to 1.05 p.u. by incorporating global information. In contrast, the default control of the regulators and capacitors could not guarantee that all the voltages were within this bound. Of note in Figure 7 are the nodes located on the right, which present a tight grouping for comparison. These points represent the EPRI circuit and did not have significant voltage changes because their initial conditions were within the normal operating parameters.

The simulation results showed that an improvement of more than 10-fold in the speed of convergence can be achieved by the hierarchical distributed method compared with the centrally coordinated implementation, without losing any optimality. This significant improvement in convergence speed makes real-time grid optimization and control, as well as fast recovery from blackout conditions, possible for large distribution systems.

These results demonstrate how the hierarchical distributed implementation of the primal-dual gradient algorithm to solve an OPF problem achieves the objective to minimize both the total cost over all the controllable DERs and the cost associated with the total network load, subject to voltage regulation constraints. The proposed implementation is scalable to large distribution feeders comprising networked devices, and it reduces the computational burden compared with the centrally coordinated primal-dual algorithm by using the information structure of the AEGs. To the best of our knowledge, this simulation demonstrates the largest optimization-based control of a power system to date, but we are working on even larger simulations.

Large-Scale Simulations

There is a significant challenge to integrate multiple technologies into seamless and resilient operating energy systems with large numbers (10^8) of controllable devices. One of the biggest obstacles to understanding how these systems will function at scale is to create and test a computational framework that enables the design and analysis of optimization and control approaches for these highly distributed energy systems. To enable this vision of AEGs of the future, advanced computational techniques—such as artificial intelligence,

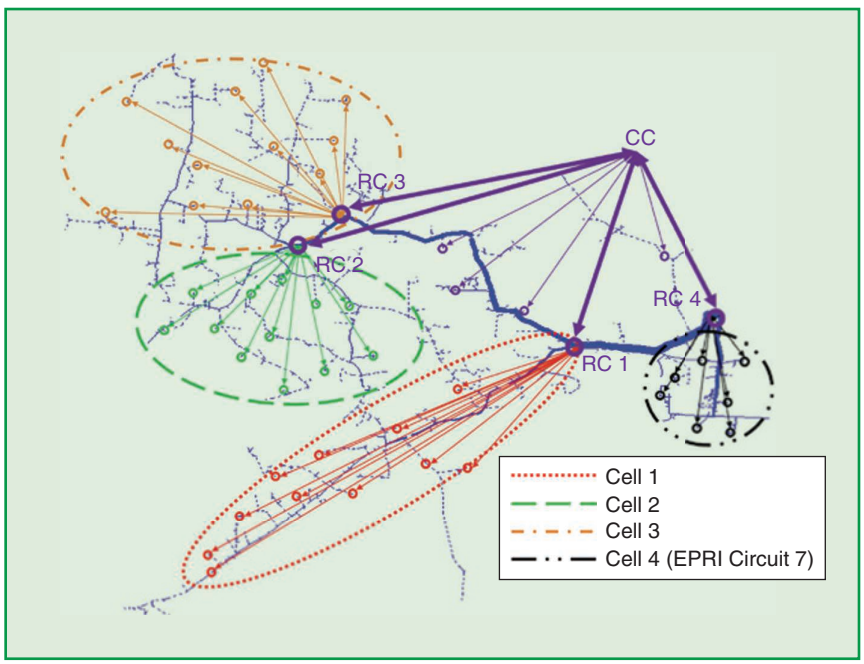

figure 6. The 11,000-node test feeder constructed from the IEEE 8,500-node test feeder and a modified EPRI Circuit 7 (Cell 4). Four AEG cells were formed for this experiment. The higher level cell controller (CC) passes information (purple lines) to the regional cell (RC) controller and to individual nodes that are not located within a cell. The blue lines illustrate the physical layout of the distribution feeder, and the thickness of the line indicates the amount of power flowing through the line.

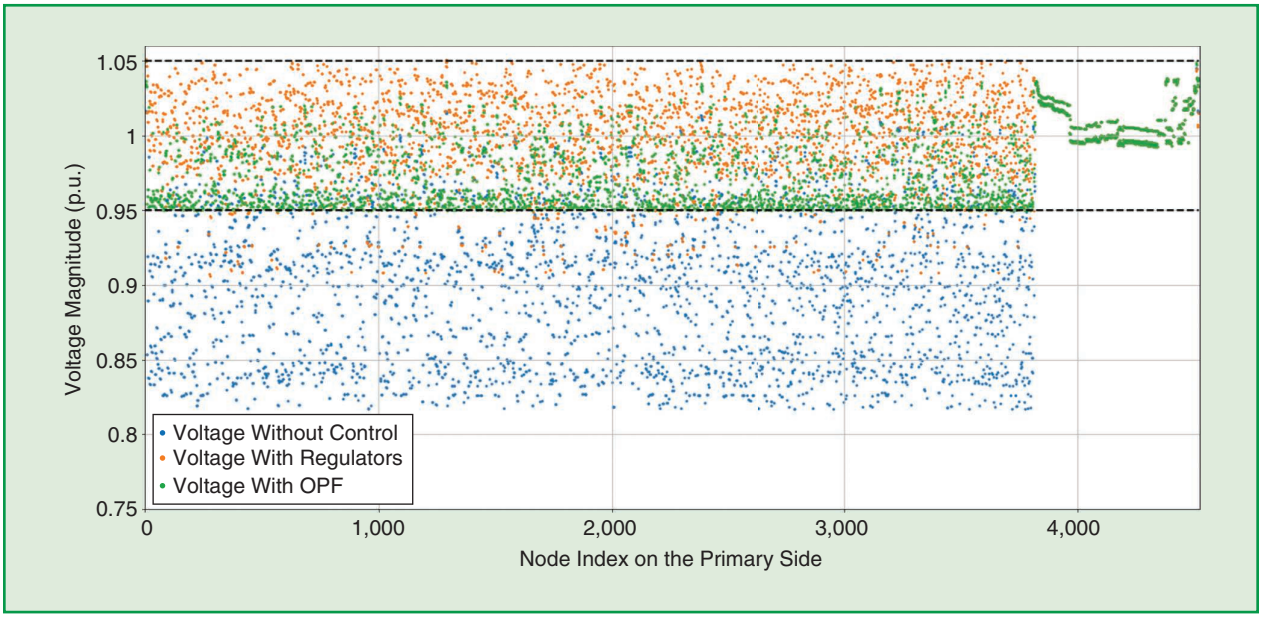

figure 7. The voltages are controlled within 0.95–1.05 p.u. by the OPF algorithm (green dots).



figure 8. A fleet of EVs under distributed control in the NODES experiment at NREL's Energy Systems Integration Facility. (Source: NREL; used with permission.)

machine learning, scalable simulations, and data analytics—are being employed to develop and evaluate these new control and optimization algorithms at large scales to operate millions to hundreds of millions of controllable devices on the grid in real time.

Innovative, secure, scalable, hierarchical, real-time control strategies that are autonomous and make the best use of big and real-time streaming data will be explored to ensure that these complex systems function properly under a wide range of possible conditions. Evaluating deployments through coordinated simulations of 10^8 devices, including high-fidelity models of the system, each component (e.g., residential/commercial buildings, autonomous EVs, solar, wind), and autonomous controllers in both normal and abnormal operations will be carried out to characterize and validate these approaches.

Currently, it takes approximately 1.5 h to run a simulation of feeders with 12,000 DER devices and optimization-based distributed controllers, including high-fidelity solutions of ac power flows for evaluating 24 h at 1-min resolution. This equates to about 23 days of simulation to run an entire year. Scaling to tens of millions of devices will require much more for an annual simulation. In many cases, simulations of critical days and weeks are sufficient; however, this highlights the need for advanced computational resources to fully evaluate these control and optimization approaches for the AEGs of the future. Luckily, in the future, once the algorithms are developed and verified, simulations of their outcomes will not be needed to run in real time on the grid.

Evaluations in the NREL Energy Systems Integration Facility

To evaluate if the software algorithms would work when integrating many real controllable devices, we set up a large experiment at NREL's Energy Systems Integration Facility. NREL's work on the ARPA-E NODES program helped develop the first implementation of the algorithms in hardware and successfully demonstrate the real-time optimization of a single AEG cell. The experiment included simulation of a real distribution feeder from California with 366 single-phase connection points, more than 100 controllable assets at power (inverters, EVs, and batteries; see Figures 8 and 9), and hundreds of simulated devices. The distributed algorithms were implemented in cost-effective microcontrollers that self-optimize and communicate to the central coordinator to attain systemwide goals (voltage regulation and frequency response).

Real-World Applications

We have now started to move out of the laboratory to demonstrate the deployment of AEGs in the real world. The team has been working with Holy Cross Energy (HCE), a utility cooperative near Aspen, Colorado, to deploy the AEG technology in a group of smart homes in Basalt, Colorado. The smart homes in Basalt Vista (Figure 10) are a pilot for an altogether new approach to the grid. These homes optimize energy for residents and their neighbors, but the principles behind Basalt Vista go much further. Within homes, each new connected device or energy resource, such as a residential battery, water heater, or solar PV system, can be controlled for unprecedented energy efficiency. At a larger scale, entire communities could rapidly share power, creating reliable energy for everyone.

HCE had been searching for a solution to managing new devices on its system. This has included a mix of customer energy technologies and bulk generation resources since the decreasing costs of connected customer-owned devices have made these systems much more affordable. HCE's grid has seen 10–15 rooftop solar installations per week, and it has been increasing its solar base for years, planning for a 150-MW summer peaking system through 2030.

In another real-world experiment, we used our real-time optimization algorithms to coordinate assets in the Stone Edge Farm Estate Vineyards & Winery in Sonoma Valley, California (Figure 11). The winery is a microgrid with tens of DERs, including PV systems, batteries, a hydrogen electrolyzer, a gas turbine, and controllable loads. The experiment, conducted in collaboration with the Massachusetts Institute of Technology-born startup company Heila Technologies, showed how our approach can help self-optimize a cell within the future AEG vision, achieving voltage regulation and allowing the microgrid to become a virtual power plant that can provide services to the distribution system.

Conclusion

AEGs of the future will need to control and optimize millions of controllable devices in real time. A traditional central optimization approach to this problem is infeasible because of the computational cost. Therefore, robust, scalable, and predictive hierarchical and distributed control algorithms with provable convergence are needed to optimize the grid in real time. NREL has developed these scalable algorithms to enable the proliferation of DERs on a massive scale.

A fundamental underpinning of AEGs is the ability to accurately model the cellular building blocks and their interactions with the rest of the systems so that control, optimization, and forecasting methods might be applied in operation. NREL is also building computational tools that can cosimulate multiple technologies on the grid to design and evaluate these scalable, distributed control and optimization algorithms using high-performance computing. In addition, NREL has taken the preliminary steps of demonstrating these algorithms in real time for real-world devices in the laboratory and now in smart homes. Additional work will be needed in controls, optimization, data analytics, complex systems, and cybersecurity to implement the AEG across the entire U.S. grid.

Building on the distributed optimization techniques that have been developed, additional thought needs to be given to the design of future market mechanisms to systematically account for payment/rewards to exchange energy and the provision of ancillary services among autonomous cells and devices. The ideas of transactive energy will need to be considerably



figure 9. The inverters under test in the ARPA-E NODES experiment. (Source: NREL; used with permission.)



figure 10. The smart homes in Basalt, Colorado. (Source: NREL; used with permission.)

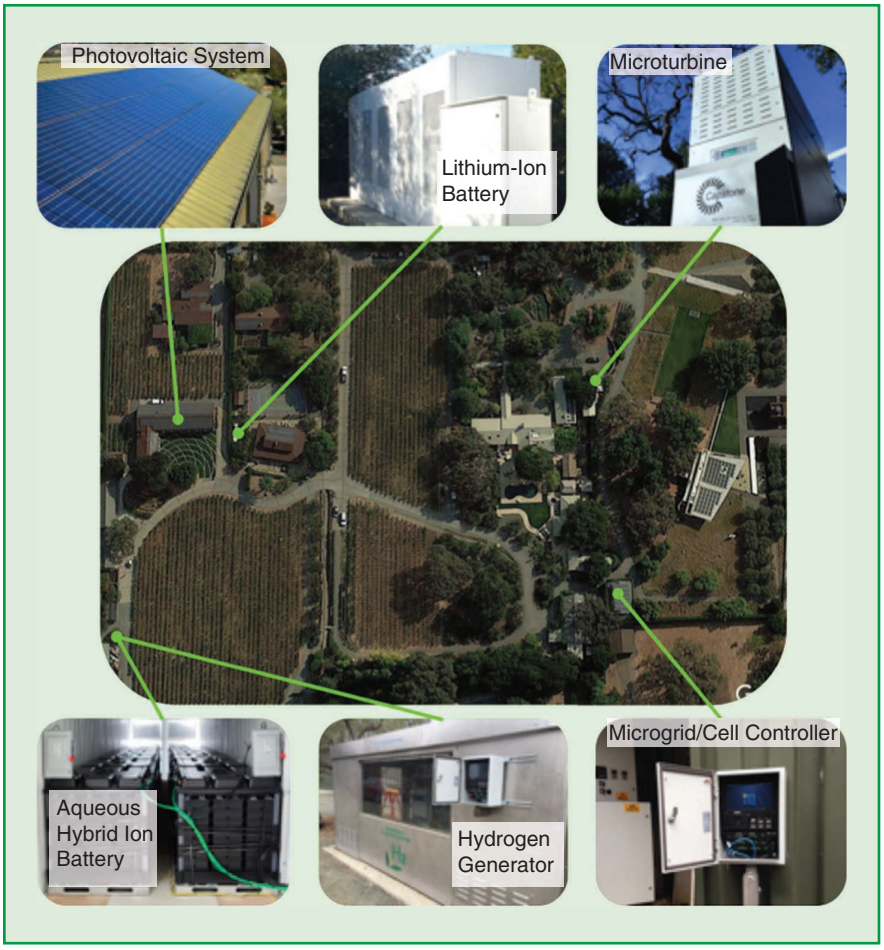

figure 11. The Stone Edge Farm microgrid, Sonoma Valley, California. (Source: Stone Edge Farm; used with permission.)

broadened to accommodate the proposed architecture with millions of controllable devices on the system and to enable rigorous mathematical analysis of system stability and optimality.

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For Further Reading

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Operational Practices and Future Challenges for Renewable Energy as a Major Power Source in Japan

Making Renewables Work

By Kazuhiko Ogimoto and Hiroshi Wani

JAPAN HAS BEEN EXPERIENCING A RAPID DEPLOYMENT OF PHOtovoltaics (PVs) since the Feed-In Tariff (FIT) Scheme for Renewable Energy was launched in July 2012. The increasing penetration levels of variable renewable generation, especially PVs and wind, have been affecting power system operations in each of Japan's 10 balancing areas. To accommodate this rapid growth in variable generation, the government established the Working Group on Grid Connection of Renewable Energy in 2014 to continually discuss and make timely decisions about these operational issues, including capacity connections, operation enhancement and asset improvement in each balancing area, and inevitable curtailment procedures for renewable generation.

The operation of a power system can be enhanced by the sophisticated dispatch operation of thermal power plants, energy storage plants, and interconnection,

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which requires various kinds of system flexibility, including balancing the active power in different time domains. Power imbalances are traditionally caused by shortages of supply capacity, demand fluctuation, and the disconnection of service. Under high penetration levels of variable generation, however, the inconsistency and uncertainty of variable generation, i.e., errors in generation forecasts because of weather changes, are emerging causes of power imbalances. These forecast errors are difficult to remove completely, and extreme forecast errors have strong negative impacts on the operation of power systems that have a high penetration of variable generation. On the other hand, additional sources of flexibility are emerging and expected. Examples include the flexible operation of traditional generation plants, such as thermal, hydropower, and pumped-storage hydropower (PSH); the advanced management and control of distributed generation, such as PVs and wind; and, in the future, manageable demand, such as heat pump water heaters (HPWHs), electric vehicle (EV) charging, and distributed storage.

This article discusses the difficulties encountered during, and the enhancement of, the power system operations of the Kyushu Electric Power Company (EPCO), which has increasing penetrations of PV and wind generation, by presenting the latest status of renewable energy deployment in Japan in general and specifically on the island of Kyushu. It details the challenges that have been faced and the countermeasures adopted in Kyushu at the transmission and distribution levels. Additionally, it describes the challenges and technical possibilities of a national renewable energy deployment strategy and delivers our conclusions.

Renewable Energy Deployment in Japan

In 2012, the year following the East Japan Great Earthquake and the subsequent nuclear disaster, the government launched the FIT program to accelerate renewable energy deployment. In 2014, the government revised the national basic energy plan, which announced the mass deployment of renewable energy as a national strategic target. This plan and the 2015 long-term energy demand and supply outlook both projected that the demand and supply balance of energy and electricity in Japan in 2030 will include annual shares of renewable generation ranging from 22 to 24%. As shown in Table 1, which was sourced from the Ministry of Economy, Trade, and Industry (METI), the current PV capacity is nearly 80% of the expected total of 64 GW in 2030. In the meantime, several committees have been working to establish a strategy for a future energy system, including making improvements and essential revisions to the FIT program and related institutional rules. Considering that the applied capacities in the FIT program, including those that have not been deployed yet, are 82.3 GW for PVs and 10.8 GW for wind, respectively, the proposed renewable generation share of 22–24% can be realized.

Many applications and implementations of PV generation, however, are concentrated in small balancing areas where land prices are lower. As shown in Figure 1, PV generation occupies the largest share of new installations of renewable energy systems under the FIT program. Such an uneven deployment of PV sources has created many concerns about Japan's future energy and social systems. Examples of those concerns include issues regarding the increased FIT surcharge levied on consumers, the challenges confronting power system operations as a result of one-sided PV deployment, impacts on deregulated wholesale power market operation, environmental ramifications for local communities, and issues regarding the treatment of decommissioning waste from future PV systems.

The Current Situation in Kyushu

The power system in Kyushu, the southernmost of the four main islands of Japan (as illustrated in Figure 2) has been the most severely affected by the rapid and heavy PV generation penetration. In the Kyushu area, which is interconnected with Honshu, the largest island, by the Kanmon interconnection line, the peak load is 16 GW during the summer and the winter, and the minimum daytime load is 8 GW. The supply capacities are 4.2 GW from four nuclear power plants and 2.3 GW from PSH. Figure 3 graphs the recent PV deployment in Kyushu. PV generation in Kyushu expanded by seven times in only six years after the launch of FIT in 2012. By the end of March 2018, the PV capacity had reached 8.53 GW, which is comparable to the minimum daytime load. Figure 4 compares the PV

table 1. The progress toward renewable energy capacity deployment before and after FIT, as of March 2019.

	Before FIT (June 2012)	After FIT (A) (as of March 2019)	Target (B) (Fiscal Year 2030)	Percentage of Target in Operation (A)/(B)
Geothermal	0.5 GW	0.6 GW	1.44–1.6 GW	37
Bioenergy	2.3 GW	4 GW	6–7.3 GW	60
Wind	2.6 GW	3.7 GW	10 GW	37
Solar PV	5.6 GW	50.2 GW	64 GW	78
Hydro (medium and small)	9.6 GW	9.7 GW	10.9–11.7 GW	86

The targets accord to the 2015 long-term energy demand and supply outlook. (Source: METI; used with permission.) When the target is a range rather than a specific value, the percentage of the target for the operation is based on the middle of the range.

capacity deployment share with other share indexes in Kyushu. The figure shows that Kyushu, which has approximately 10% of the total land area, population, and power demand in Japan, has roughly 20% of the country's PV/wind generation. The reasons for such large shares of PV generation in Kyushu are the suitable conditions of lower land prices and a relatively greater solar irradiance than other areas in Japan.

System Operation Challenges in Kyushu

Renewable Energy Curtailment

In Japan, the FIT program enforces priority dispatching of renewable generation in all balancing areas; however, to maintain the quality and stability of power system operations in each balancing area, when the supply and demand balance is in danger, the generation of renewable energy can be curtailed. Renewable generation can be curtailed in a balancing area only after all the thermal generation, PSH plants, and interconnections have been dispatched to minimize the restriction under stability and quality constraints. Among the renewable energy systems, PVs and wind can be curtailed only after a reduction of biomass energy generation because biomass fuel is regarded as energy that can be stored.

On 13 October 2018, Kyushu's transmission operator made the first renewable generation curtailment in Japan. As shown in Figure 5, 0.93 GW of PV and wind generation were restricted under the following conditions at 12 p.m.: 7.3 GW of power demand, 4.5 GW of baseload generation,

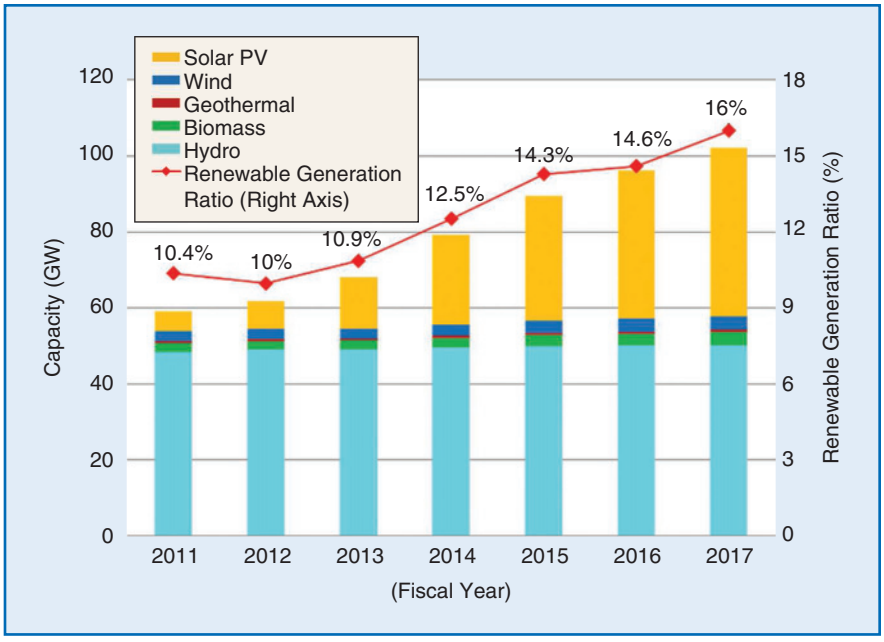

figure 1. Renewable generation deployment in Japan. (Source: METI; used with permission.)

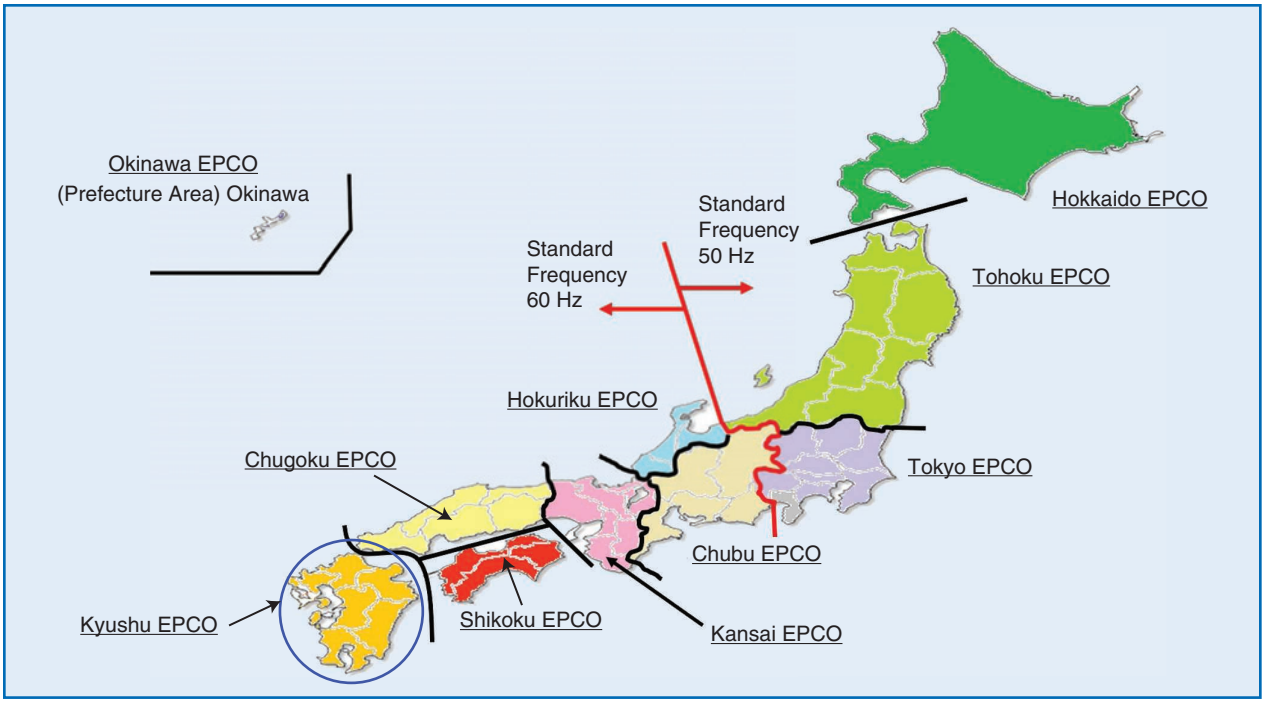

figure 2. The 10 balancing areas in Japan. Kyushu EPCO (circled) is the focus of this article.

2 GW of thermal generation, 1.8 GW of energy storage by PSH plants, and 1.9 GW of power export via an interconnection line to a nearby balancing area. Table 2 describes the results of the renewable generation curtailment operation. From the first renewable generation curtailment in Kyushu through June 2019, there were 56 renewable generation restriction operations. From March to May, when demand is low because of the minimum air-conditioning loads and maximum irradiation, there were more frequent renewable generation curtailments, with a maximum of 2.57 GW.

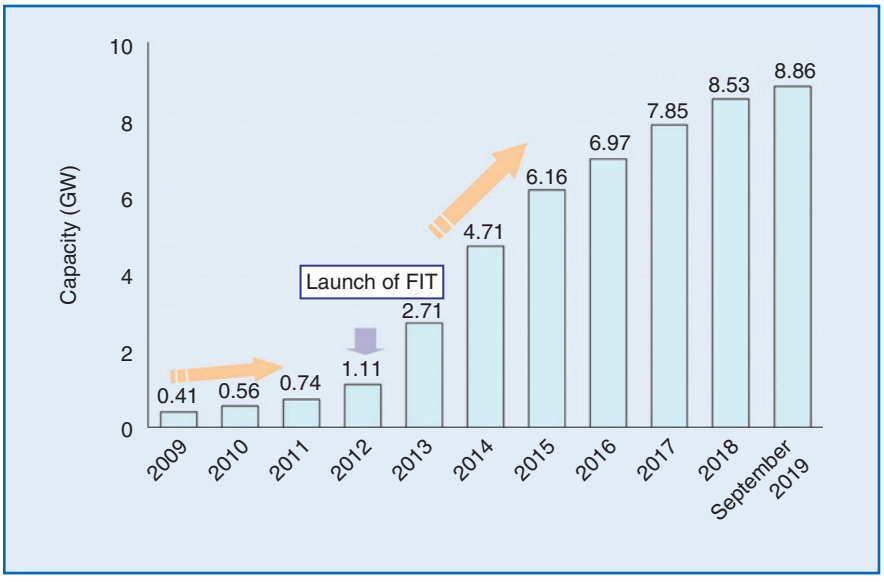

figure 3. PV deployment in Kyushu. (Source: Kyushu EPCO; used with permission.)

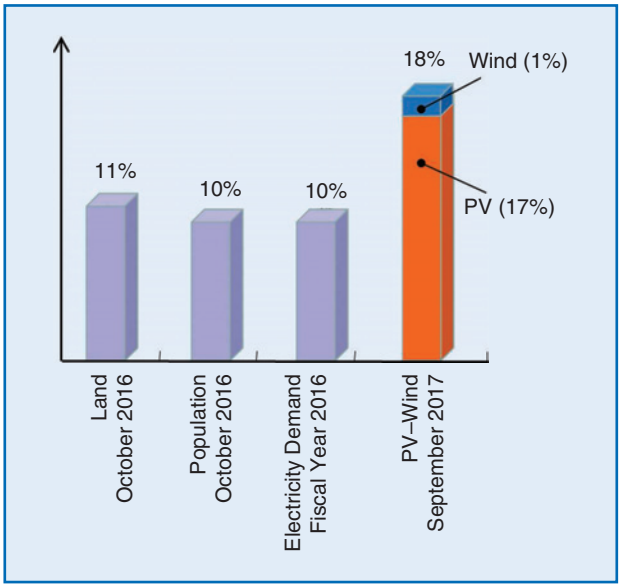

figure 4. A comparison of Kyushu's PV deployment and related factors as percentages of Japan's total. Note the significant difference between Kyushu's share of the total electricity demand (10%) and the total PV and wind generation (18%). (Source: Kyushu EPCO; used with permission.)

System Operation

Generation forecasting of PV and wind generation is beginning to be used to enhance system operations. A PV generation forecast uses irradiance data from eight sites to predict the PV output. Since January 2018, however, the number of sites collecting irradiance data has increased to 47, greatly improving the accuracy of the PV output predictions (Figure 6). PV output predictions are carried out using three models, each with its strengths and weaknesses, depending on the weather pattern. Predictions of their performance have been continuously evaluated. During real operations, when satellite data are matched with historical insolation patterns, three predictions are weighted to yield an average forecast for a 3-h horizon, as in Figure 7. The satellite data are fit with historical patterns to yield weights for each forecast model. The 3-h prediction is given by the weighted average of the three forecast models.

Figure 8 gives an example of a flexible thermal plant operation to meet the ramp-up of residual demand during the evening. In addition to the flexible operation of pumped-storage units (300 MW × 6; 250 MW × 2), four combined-cycle gas turbine (CCGT) axes, which are composed of one combustion turbine and one steam turbine that have shorter start-up times, are synchronized in a short interval of roughly 15 min. Each axis, receiving a dispatch order 2 h before the target time, is paralleled in every 15 min.

To accommodate more PV and wind generation, an effective option was to increase the operational capacity of the ac interconnection with Honshu via the Kanmon line, with a thermal capacity of 2.5 GW. A grid stabilization system was installed to immediately and selectively trip multiple major generation plants in case of a failure of the line (Figure 9). Recently, in Kyushu and some other balancing areas, utility-scale battery energy storage systems (BESSs) are also being deployed. They provide a small but fast system frequency regulation service. Figure 10 depicts a 50-MW, 6-h NaS BESS in Kyushu. The system consists of two battery banks with 63 800-kW subunits. With a capacity of 300 MWh installed at one site, the system is one of the world's largest energy storage facilities.

Renewable Energy Generation Curtailment Procedures

Online curtailment is key for the efficiency and security of renewable generation restriction procedures, the reduction of the required amount of renewable generation limitation, and

the security of the power supply. The government of Japan, Kyushu EPCO, and renewable generation operators collaborated to install an online curtailment system for renewable generation systems. Kyushu EPCO incorporated online control devices for the renewable generation curtailment of 22 PV systems (394 MW in total) to demonstrate the system's effectiveness on the electric grid throughout the year (Table 3). Table 4 delineates Kyushu's PV capacity of 8.7 GW through the categories of online/offline control and connection voltages. Units totaling 4.8 GW—approximately 60% of the total PV output, as shown by the pink zones—are currently subject to renewable generation curtailment. Among this 4.8 GW of PV, a total of 1.7 GW can be controlled remotely, whereas approximately 2,000 units equaling a total of 3.1 GW cannot.

Figures 11 and 12 show the renewable generation management system and its process. This arrangement provides the system operator with the required curtailment capacity based on real-time data for the demand and supply balance, including renewable generation output. The system also provides renewable generation curtailment orders to generators in all voltage classes while maintaining fairness in terms of the number of

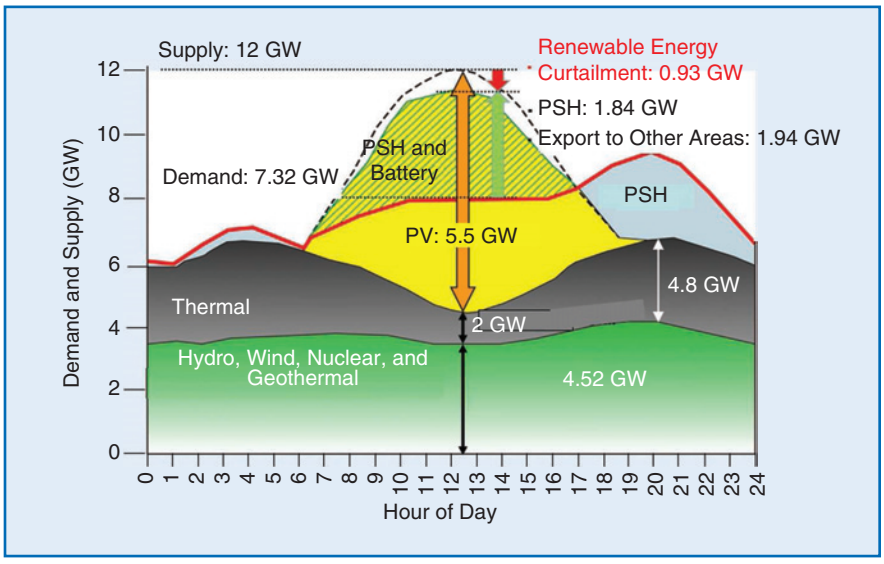

figure 5. The demand and supply operation on 21 October 2018. (Source: Kyushu EPCO; used with permission.)

table 2. The Kyushu renewable generation curtailment operation.

	2018			2019					
	October	November	December	January	February	March	April	May	June
Number of operations	4	44	0	1	1	16	20	10	0
Maximum curtailment (GW)	0.93	0.93	—	0.35	0.44	1.8	2.57	1.9	—
Curtailments per unit			5–6					8–9	

(Source: Kyushu EPCO; used with permission.)

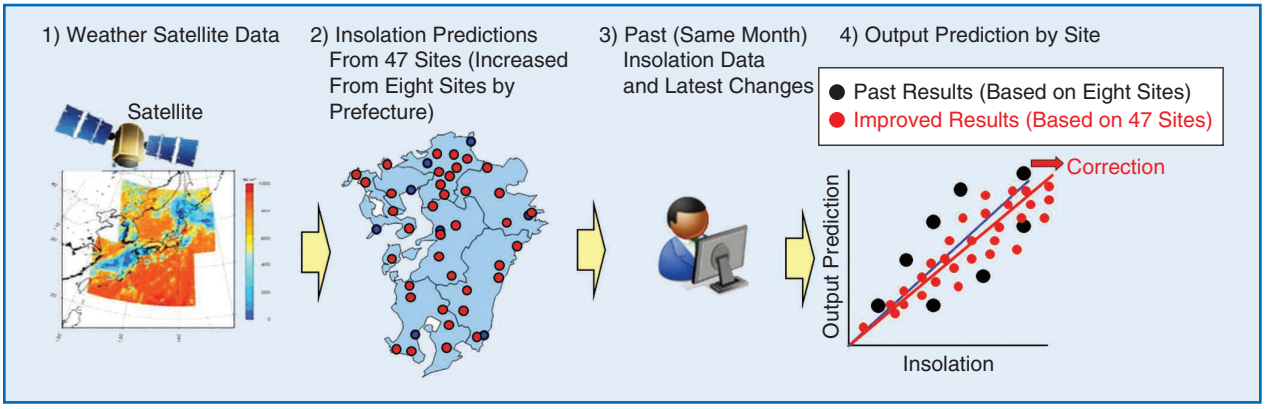

figure 6. An improved PV generation output prediction. (Source: Kyushu EPCO; used with permission.)

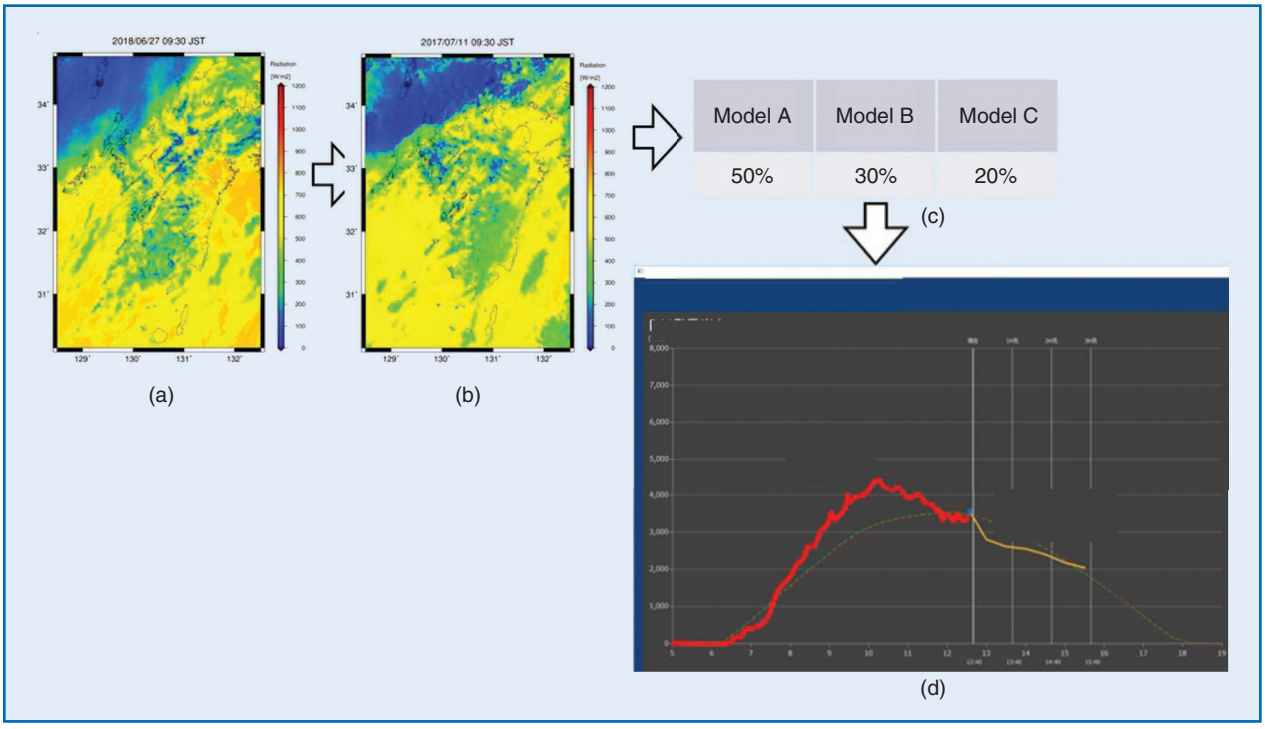

figure 7. An improvement of the PV generation forecast. (a) Satellite insulation data. (b) Historical pattern matching. (c) The weights for each model. (d) The historical (red line) and 3-h (yellow line) predictions. JST: Japan Standard Time. (Source: Kyushu EPCO; used with permission.)

times/days that restrictions are imposed on each unit. When automated, the limitation orders are sent to on-site PV control systems, or the systems download published curtailment schedules. If the control of a PV unit is not automated, the curtailment orders and schedules are sent to an on-site system manager who is responsible for the oversight of the PV unit, according to the law.

Curtailment by System Operation Using the Average Forecast Error

Since autumn 2019, the renewable generation curtailment procedures have been improved (Figure 13). The target amount of curtailment, which was previously calculated based on the historical maximum forecast error for the same month, is now determined based on the historical average forecast error for the same month. Offline units are issued limitation orders 1 day in advance, whereas the online units, to make the best use of the online-controlled PV units, are given restriction directives 2 h beforehand and only when necessary, using the latest available intraday forecast. Through the improvement, in terms of economy, the expected amount of curtailment decreases by the reduction of the target restriction. In terms of security, potential undercurtailment, as a result of the day-ahead orders, is treated, if necessary, by the

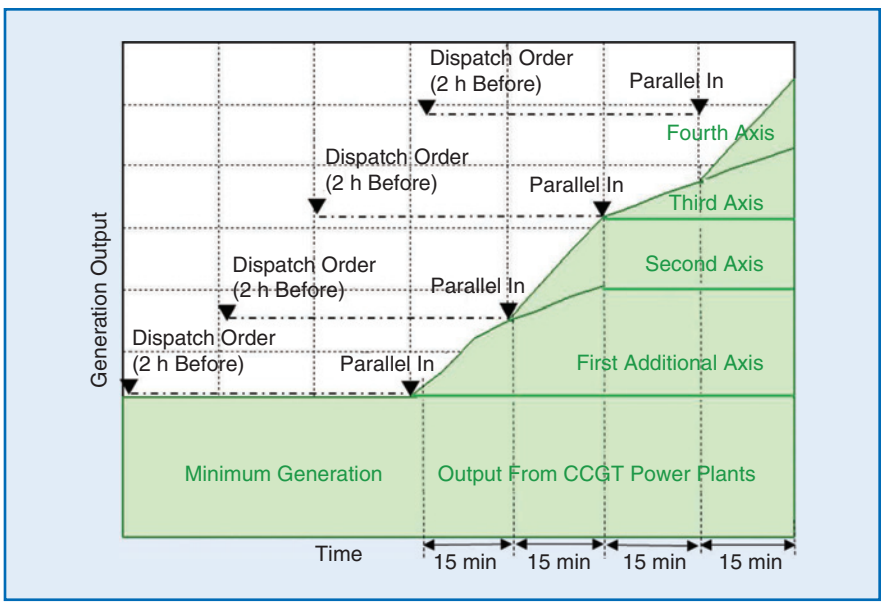

figure 8. Starting combined-cycle gas turbine (CCGT) axes during a ramp-up of the residual demand during the evening of 30 April 2018. (Source: Kyushu EPCO; used with permission.)

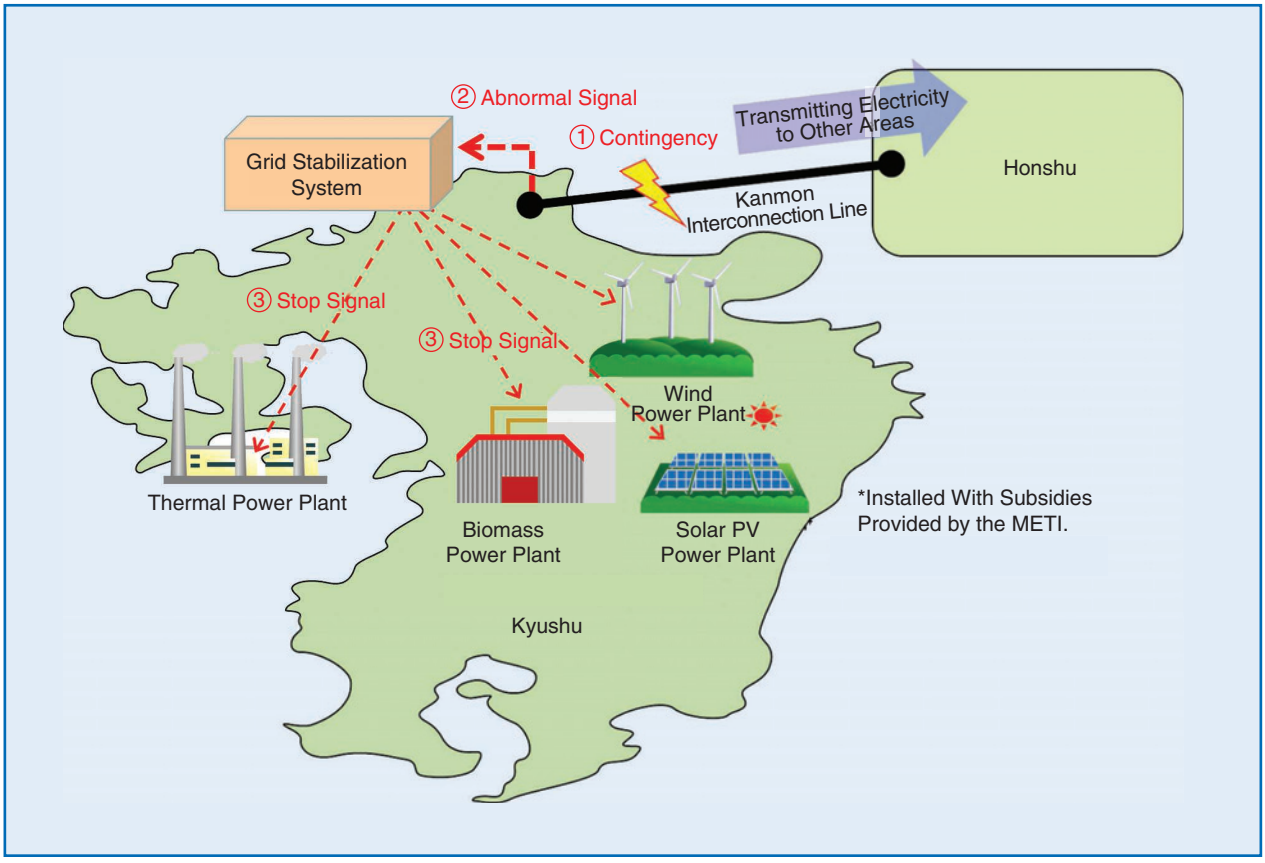

figure 9. The grid stabilization system that guards against failures of the Kanmon interconnection line. (Source: Kyushu EPCO; used with permission.)

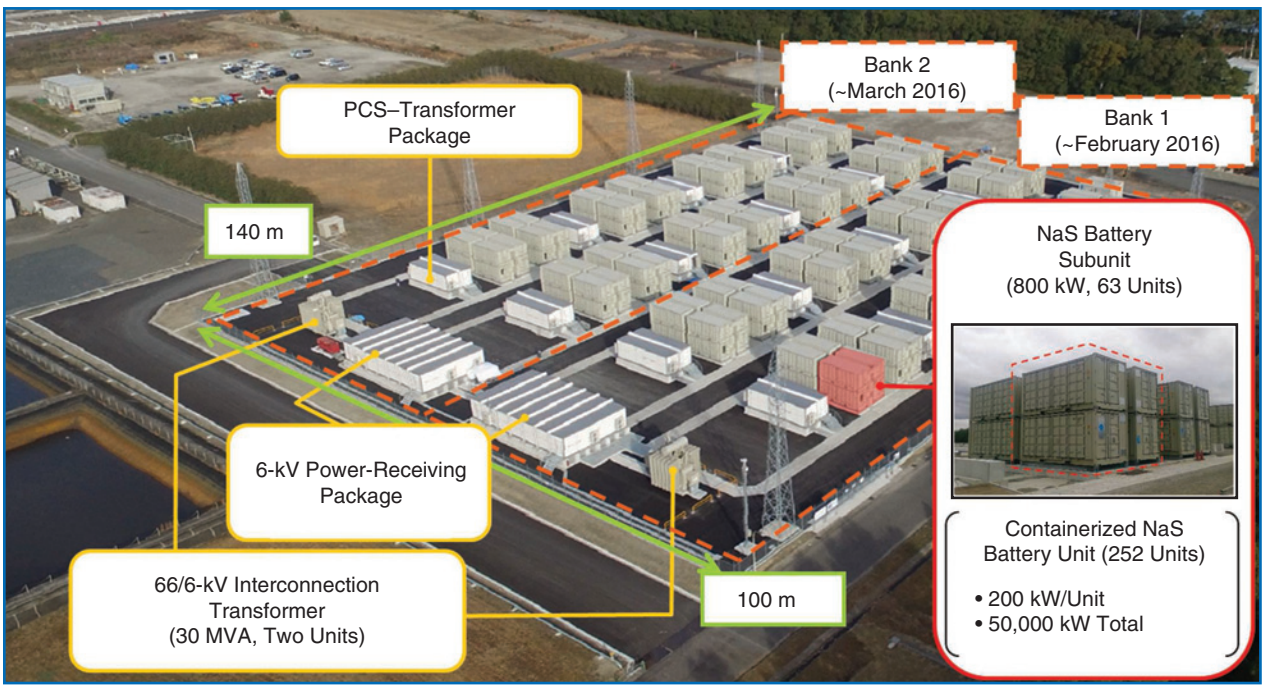

figure 10. The utility-scale BESS in Kyushu (50 MW, 300 MWh). PCS: power conversion system; NaS: sodium–sulfur. (Source: Kyushu EPCO; used with permission.)

table 3. The PV units and the number of systems with online renewable generation curtailment for demonstration.

Category	Target Capacity	Installations in Fiscal Year 2015	Installations in Fiscal Year 2016	Installations in Fiscal Year 2017	Capacity Accumulated in March 2017
66 kV or fewer	390 (20)	72 (2)	110 (3)	204 (14)	386 (19)
Fewer than 66 kV	10 (1)	3 (2)	0 (0)	5 (1)	8 (3)
Total	400 (21)	75 (4)	110 (3)	209 (15)	394 (22)

The table entries show megawatts, with the number of systems in parentheses. (Source: Kyushu EPCO; used with permission.)

table 4. The PV systems in Kyushu.

		Offline Manual Control (Old-Rule Units)		Online Automatic Control (New-Rule Units)	
66 kV and above		47 units	730 MW	26* units	470* MW
Medium voltage	≥500 kW	2,000 units	2,340 MW	312 units	340 MW
	<500 KW	2,000 units	400 MW	402 units	90 MW
Low voltage	≥10 kW	6,300 units	1,750 MW	25,000 units	840 MW
	<10 kW	29,700 units	1,330 MW	74,000 units	410 MW

The pink zones show targets for renewable generation curtailment, as of June 2019. (Source: Kyushu EPCO; used with permission.)
*These figures include 19 units of 400 MW under the old rule.

2-h-ahead restriction of additional online units. This improvement is expected to reduce the maximum capacity of each curtailment operation by 9%.

Impact of a Large Forecast Error

On 2 March 2019, the Kyushu area experienced an extreme PV forecast error (overgeneration). As depicted in Figure 14, the actual PV generation was 3.5 GW lower than had been forecast at 10 a.m. the previous day, whereas the demand was 0.9 GW higher than what was expected. To cope with the total 4.4-GW gap between demand and supply that resulted from the forecast error, at 9 a.m. on the day of the event, when the system operation revised the schedule, 0.81 GW of the scheduled PV curtailment and 2.26 GW of the scheduled PSH operation were canceled. Instead, 1.5 GW of PSH generation was scheduled. Moreover, 1 GW of thermal generation was requested by the operator.

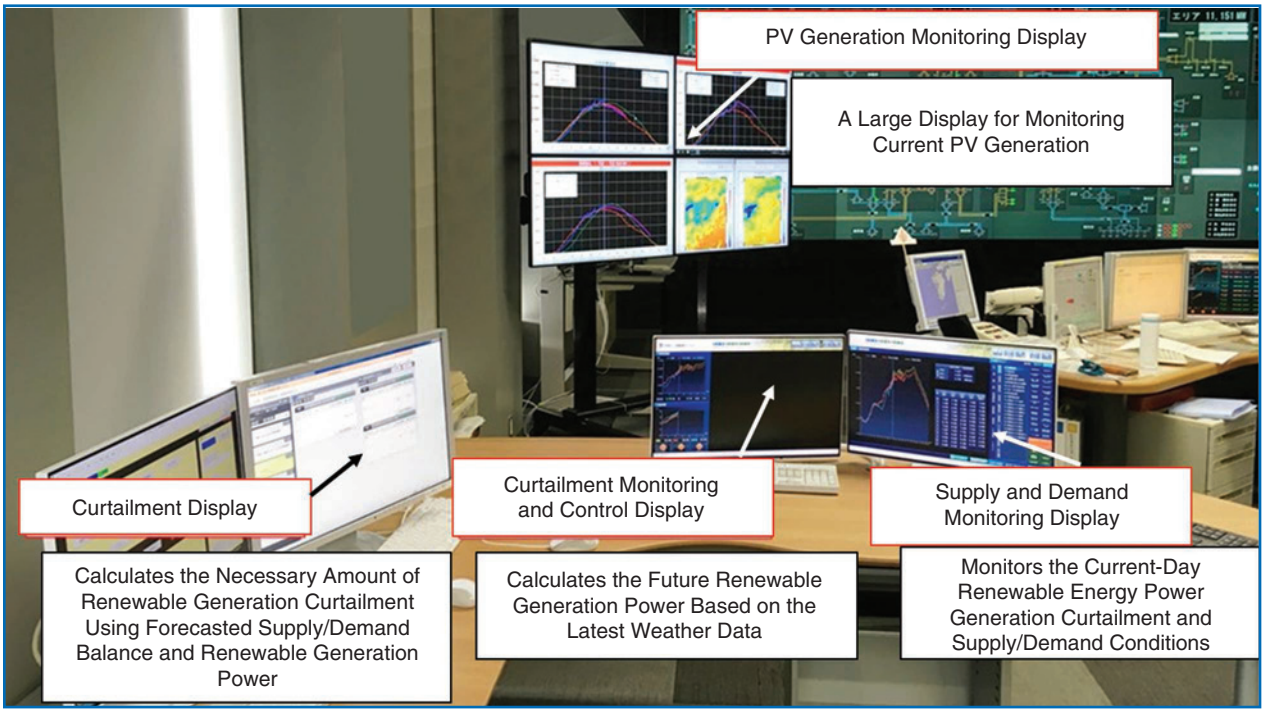

figure 11. The renewable generation management system in the load-dispatching room. (Source: Kyushu EPCO; used with permission.)

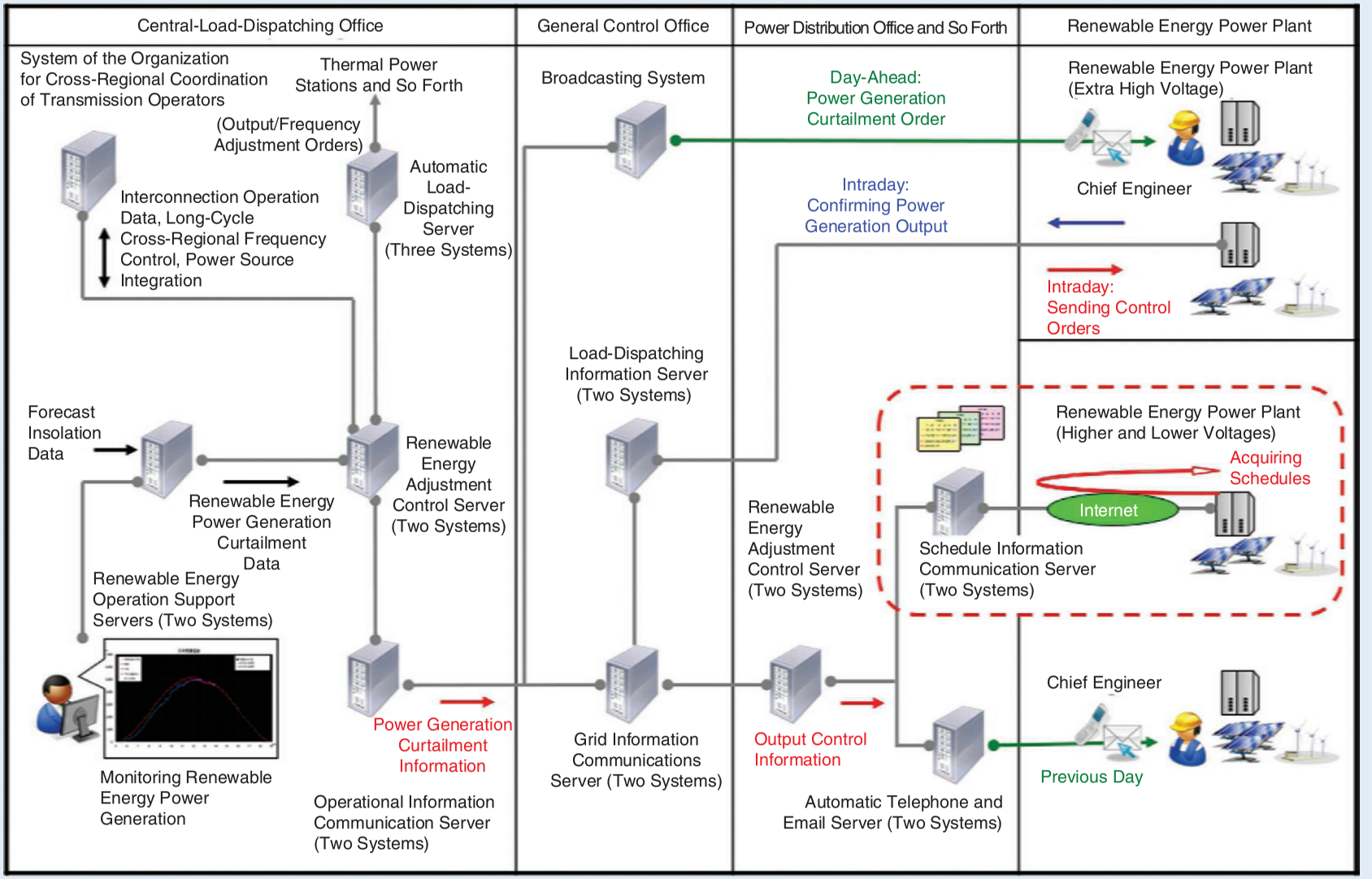

figure 12. The renewable energy management system. (Source: Kyushu EPCO; used with permission.)

During the afternoon, a 0.7-GW gas plant was synchronized 3 h after the operator's order. During the evening, there was almost no remaining energy stored in PSH.

It is crucial to understand that a reduction in PV generation often coincides with increased demand during winter and early spring because of a common root cause: increasing cloud cover resulting in a lower atmospheric temperature and less irradiation. To modify the system operation during the intraday and in near real time when there are PV output forecast errors, PSH plants with a minimal start-up time of several minutes and thermal plants that have relatively short start-up times are useful; however, when the PV capacity increases, the storage level of PSH plants should be carefully monitored and managed.

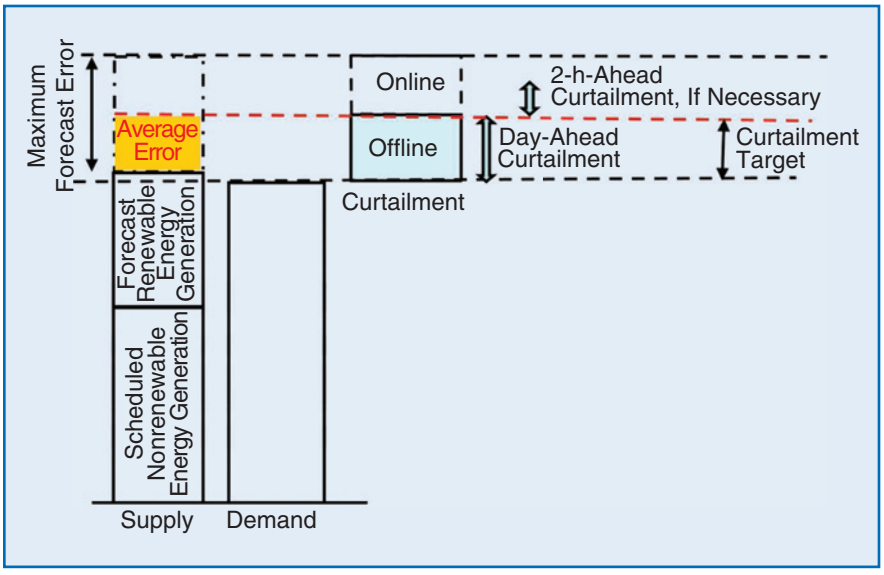

figure 13. Improvement in curtailment operation by using the average forecast error. (Source: METI; used with permission.)

Operation of Distribution System

As the share of renewable generation increases and the power supply from traditional, large-scale, centralized power plants decreases, the power flow in a distribution grid—which has been traditionally one directional from the transmission grid to the load—becomes bidirectional and dependent on the balance between local loads and local generation. In this situation, voltage management in a distribution system becomes more complicated because the voltage profile of a feeder line varies largely with and without the power flow accompanying a renewable energy connection, as shown in Figure 15. When

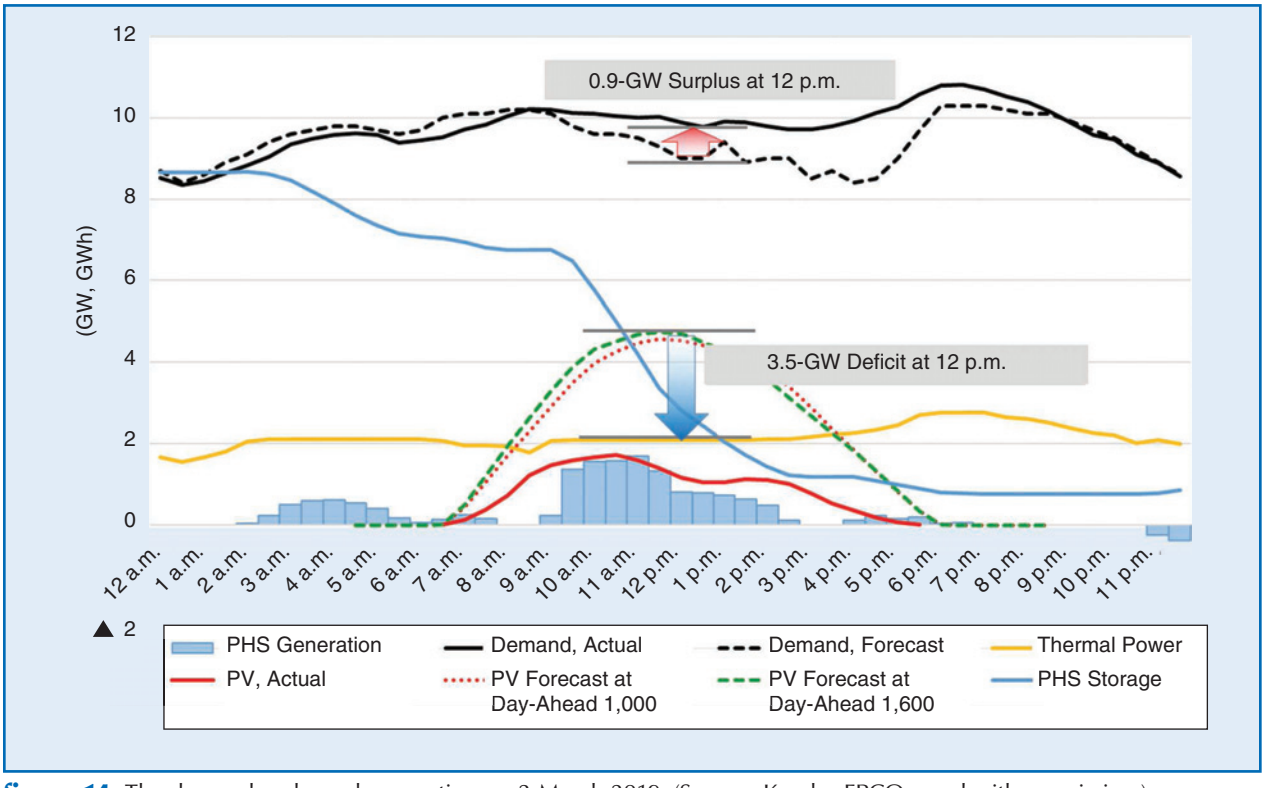

figure 14. The demand and supply operation on 2 March 2019. (Source: Kyushu EPCO; used with permission.)

the grid voltage deviates from the specified range because of a power injection from PV and other power plants, the connection code requires generation units to limit their output.

For residential and other generation units connected to a low-voltage distribution grid, the grid connection code (revised in March 2017) requires a standard power factor of 95% to avoid a voltage increase caused by a power injection. If grid voltages still fluctuate out of the operational range as a result of variation in local generation, other countermeasures are installed, such as a static var compensator (SVC). However, the additional reactive power flow reduces the voltage at the connecting point within the operational range and tends to reduce the voltage between the feeder head and the distributed energy resource, as in Figure 16. The figure shows a case for accommodating approximately 5 MW of PV generation on a 15-km span of feeder A of

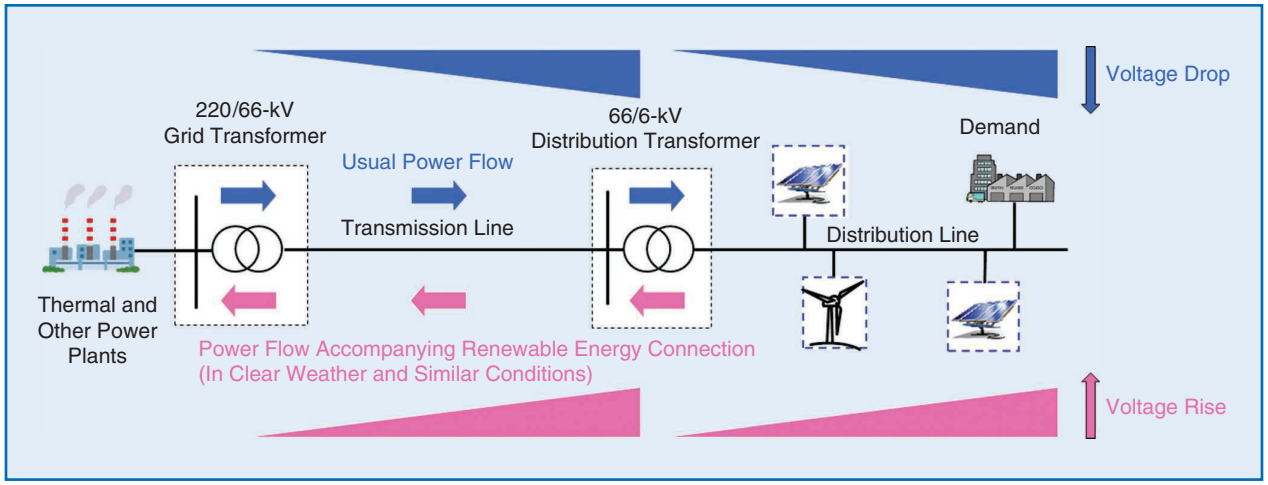

figure 15. The difficulty of voltage management in a distribution grid. (Source: Kyushu EPCO; used with permission.)

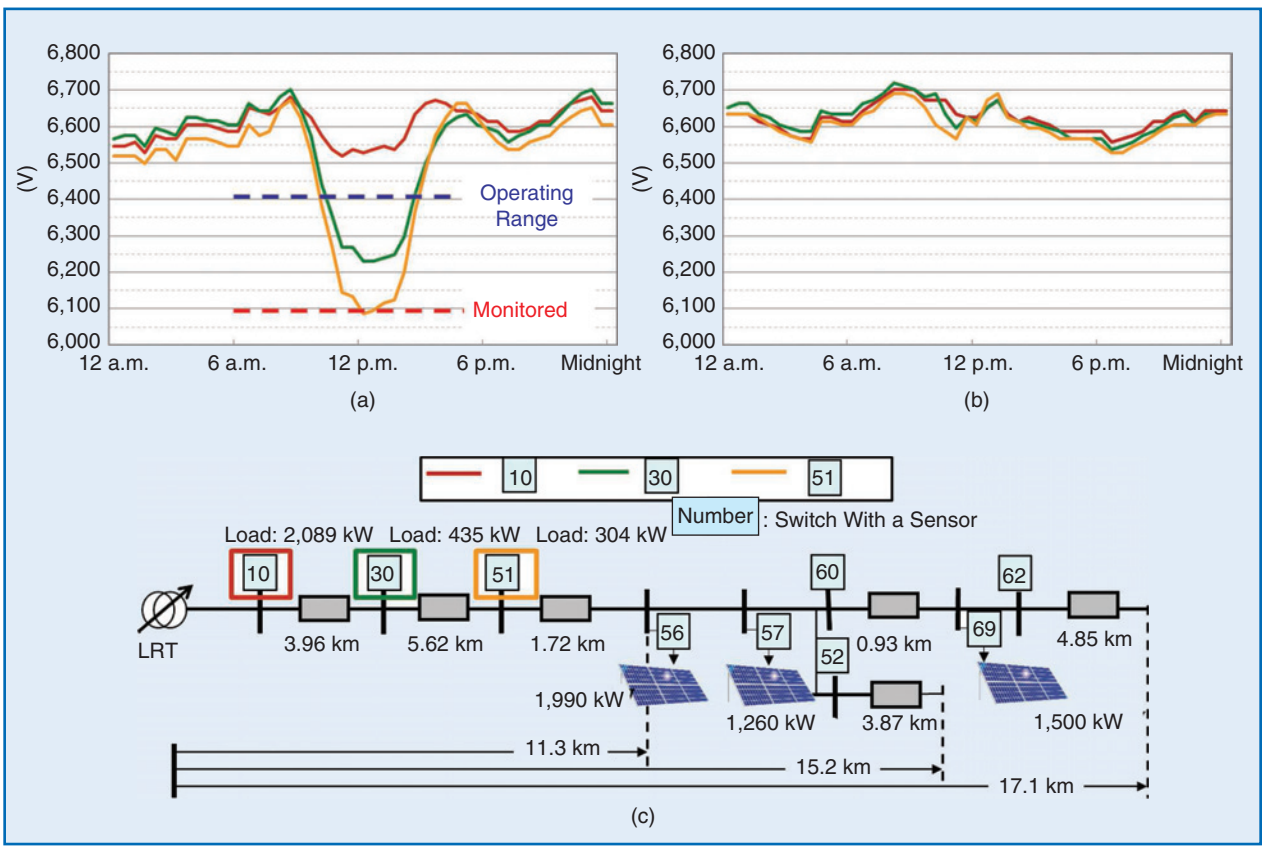

figure 16. The voltage deviation in a distribution system. (a) A sunny day with significant PV generation. (b) A rainy day with little PV generation. (c) The line diagram. LRT: load ratio control transformer. (Source: Kyushu EPCO; used with permission.)

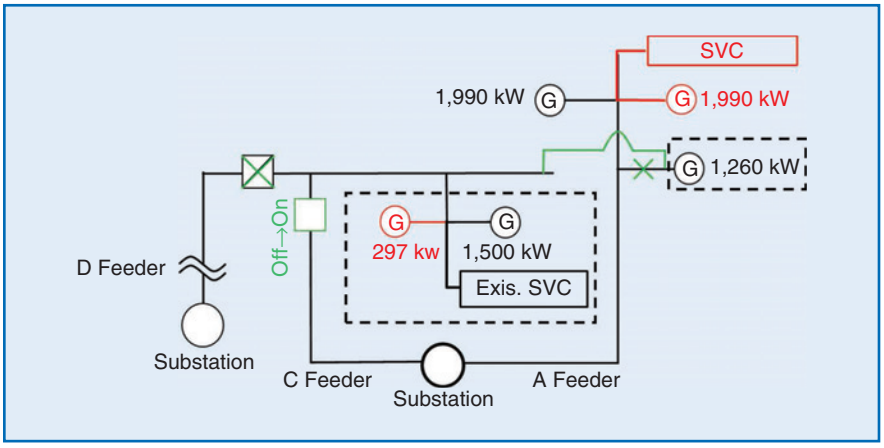

figure 17. Example countermeasures for voltage management in a distribution system. Red and green letters show new implementations and network connection changes, respectively. Exis.: existing. (Source: Kyushu EPCO; used with permission.)

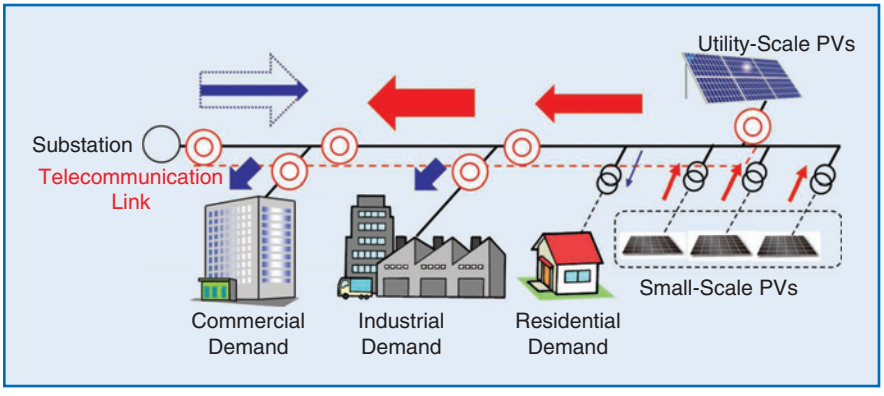

figure 18. Enhancing the system monitoring by using sensor-latching pole gas switches. The ◎ symbol represents a distribution switch with sensors, while ⊖ shows a pole transformer. (Source: Kyushu EPCO; used with permission.)

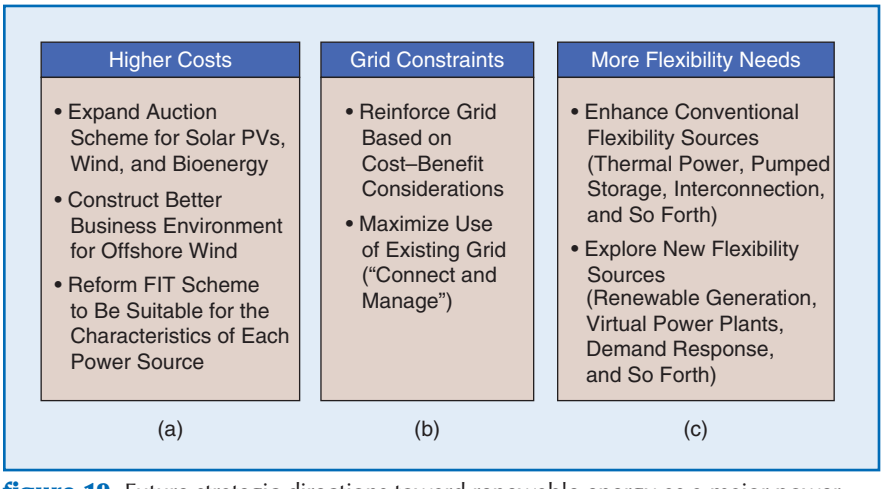

figure 19. Future strategic directions toward renewable energy as a major power source. Actions related to (a) expenses, (b) constraints, and (c) flexibility.

6.6 kV. On a fine day, the voltages at nodes 30 and 51 between the substation and the PV connecting points are reduced to below the operational range, whereas the voltage at the PV site is managed within the range.

Figure 17 depicts two measures that are taken to manage the voltage profile in the 6.6-kV feeder to accommodate new PV generation of 1,900 kW and 297 kW, shown in red: 1) an SVC is deployed near the 1,990 kW of PV power at the end of feeder A, and 2) the connection point of the existing 1,260 kW of PV energy is moved from feeder A to feeder C via the connection shown in green.

The voltage management and control in a distribution system are supported by a new voltage-monitoring system that uses sensor-latching pole gas switches (Figure 18), which were additionally deployed under the penetration of PV energy in distribution systems. The enhanced voltage monitoring, which examines synchronized voltages at different points, not only provides voltages but also estimates of PV unit generation and loads at distribution points.

National Strategy and Further Challenges

The rapid and mass penetration of renewable generation, in conjunction with other technical and institutional changes in the energy industry, have posed issues of affordability and supply security. Japan's national energy strategy and policies are being adjusted to address these issues. The guidelines address three strategic matters: higher costs, transmission/distribution system congestion (grid constraints), and the need for increased operational flexibility in power system operation (Figure 19).

Higher Costs

Higher costs are caused by various factors. One reason for higher

capital and operational expenses is the relatively small capacity of solar PV and wind power plants as a result of the limited availability of land in Japan. Figure 20 presents the increase of the total FIT cost recovered from the wholesale market and the surcharge on retail prices. The surcharge on a retail electricity bill is calculated from the surplus of FIT tariffs across the hourly wholesale market price in each area. The total surcharge, which was ¥2.1 trillion in 2017 for the 6% growth in the annual renewable energy generation share, further rose to ¥2.4 trillion in 2019, although the government has declared a cap on the total surcharges at ¥3.1 trillion, with an 8% increase in the annual renewable generation share.

The straightforward reasons for the increase in surcharges are the historically expensive FIT tariffs. Figure 21 shows the decline in FIT tariffs and future "price targets" through the categories of renewable generation. The FIT tariffs on PV generation that is lower than 10 kW and greater than or equal to 10 kW, which began at ¥42 and ¥40/kWh respectively, are now ¥24 and ¥14/kWh (in 2019). On the other hand, many 10-year contracts for installed rooftop PV reached their termination limit in October 2019. Sustainably managing renewable energy deployment after the current FIT program is replaced by a new renewable energy deployment program is a major focus area of Japan's energy policy. The affordability and economy of renewable energy are closely related to grid constraints and the increased need for generation curtailment/flexibility through infrastructure investment costs and the curtailment of renewable energy generation.

Grid Constraints

Grid constraints often come from the fact that PV plants are primarily located in areas with low land prices, whereas wind power plants are situated in areas that have significant wind resources, and they have less land price sensitivity. Transmission and distribution lines are congested with a large and variable power flow from new and remote renewable generation plants that feed into the system. When certain transmission and distribution lines are overburdened, and the generation from renewable energy plants is not manageable, the only solution is to invest in expanding and strengthening the grid, which might be expensive and take many years.

In Japan, where the rights-of-way of utility lines are limited, the Japanese Connect and Manage process has been implemented. This includes three steps for nonwire solutions to make the best use of existing line capacity without the difficulties of finding rights-of-way to accommodate new generation, including renewable energy. As shown in Figure 22, after deducting capacity for emergencies, an operational line capacity is supposed to accommodate the sum of each maximum generation, as with the previous grid operation in the figure. In step 1, the operational capacity for generation is probabilistically evaluated, reflecting the actual generation variation. In step 2, the emergency capacity use is reduced, with the condition that instantaneous generation tripping must occur during an N–1 contingency. In step 3, the operating capacity is cut through managing and curtailing wind and solar PV generation when necessary. Steps 1 and 2 have been implemented since 2018 to create, according to a trial calculation, an additional 46 GW of connecting capacity in Japan. Step 3 is now in preparation.

Flexibility

The increased need for flexibility comes not only from the variability of PV and wind generation but the reduced operational capacity of thermal units, which traditionally provided the operating reserves in different time domains. The

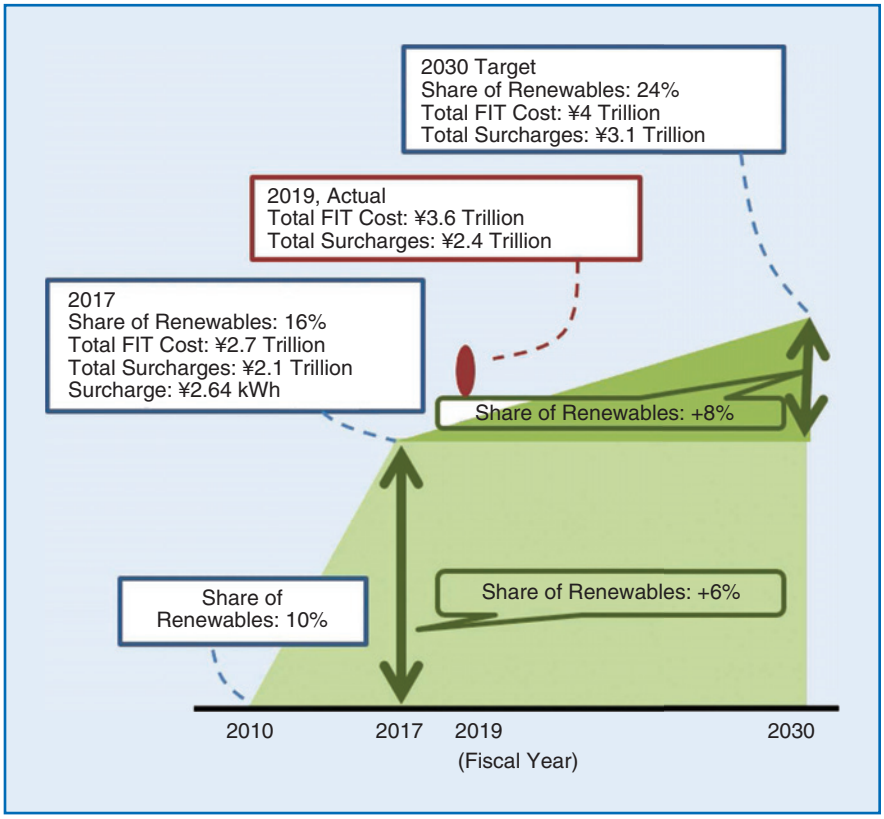

figure 20. Past and predicted increases in FIT cost in Japan (US$1 = ¥11). (Source: METI; used with permission.)

extreme forecast errors for the residual demand resulting from the prediction errors for the correlated PV generation and the power demand in Kyushu creates an emerging risk to the supply security and a growing need for additional reliable and affordable flexibility.

In extreme forecast error situations, the maximum use of distributed resources, including PV generation, wind power plants, and demand response, is expected to provide additional flexibility in the form of virtual power plants. A virtual power plant, which is a subset of the distributed resources, can control its output, such as active and reactive power, as if it were a single power plant. (Figure 23). Time-shifting demand can also provide a combination of upward and downward changes. In addition, within the range accepted in advance by customers, the curtailment of electricity demand whose production is storable, such as EV chargers and HPWHs, might provide a good system service resource to protect against inevitable extreme forecast errors.

We made an 8,760-h production cost analysis to predict the effectiveness of smart charging by 8.86 million EVs in 10 balancing areas of Japan in 2030, according to the 2015 long-term demand and supply outlook. EVs were categorized into five clusters based on their usage patterns. Figure 24 gives the results of the demand and supply analysis to minimize operational costs for smart charging

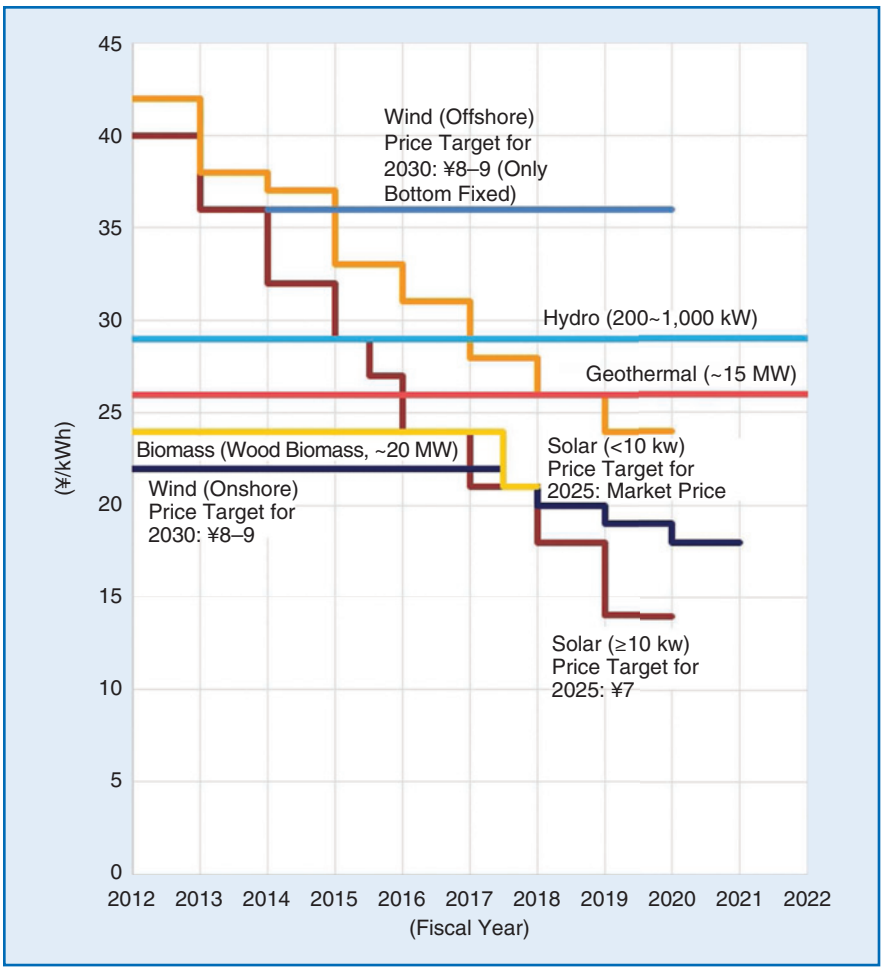

figure 21. The historical reduction of renewable energy FIT tariffs (US$1 = ¥107). (Source: METI; used with permission.)

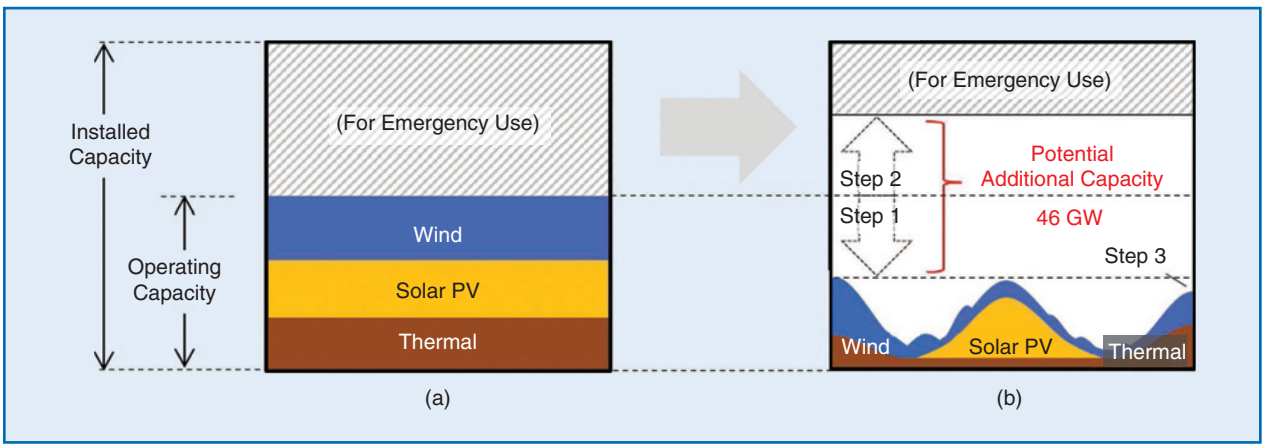

figure 22. The line capacity allocation under the Japanese Connect and Manage process. (a) The previous grid operation. (b) The new grid operation. Step 1: Perform a probabilistic evaluation of each generator. Step 2: Release the capacity through intertripping in emergency conditions. Step 3: Obtain grid access without grid enhancement through the conditions of curtailment. (Source: METI; used with permission.)

by comparing cases of uncontrolled charging and smart charging/discharging. The figure shows nationwide charging and discharging patterns in CL1–CL5 and the change in the net demand for each case on 1 April. It is apparent that the net demand is substantially bottomed up by the optimized charging and discharging of EVs.

As shown by the demand and supply operation on 2 March 2019 in Figure 14, an extreme over/under PV generation forecast error is a genuine threat to the Kyushu power system. It is not economical to use thermal plants to maintain upward and downward flexibility against the rare forecast error. PVs and wind can supply downward generation flexibility without losing significant production opportunities, and they can supply upward generation flexibility if the production is reduced in advance. In the future, there will be substantial possibilities for demand-side distributed resources. To evaluate the different flexibility requirements and provisions during optimum system operation, we need to enhance our production cost model to granularize the total operational flexibility into two directions—up and down—and different time domains.

Among the different kinds of flexibility, an upward tertiary–slow flexibility, which can be activated within 30 min, is assumed to treat extreme forecast errors for residual demand. Figure 25 offers an example of a demand and supply balance of tertiary–slow flexibility: the requirements for the upward and downward flexibility (request up and request down) are 6 and 2 GW, respectively. They are met through a combination of traditional power plants and distributed resources, such as PV and wind generation, EVs, and electric HPWHs. The reduced flexibility requirement for thermal plants means a substantial reduction of operational cost during standby.

In the distribution area, it is necessary to manage the power flow and voltage. Figure 26 demonstrates a possible future arrangement in which a new voltage management server centrally controls step voltage regulators (SVRs), static synchronous compensators, smart inverters of utility-scale PVs, SVCs, and batteries to manage the voltage profile of a distribution system. By managing and controlling resources on both the system side and the customer side, investment and operation costs are expected to be deferred and reduced.

Institutional Issues

Through the process of deregulation, various institutional arrangements for the design of wholesale and retail markets and regulatory frameworks are to be adapted to the penetration of renewable generation, especially PVs and wind power. Using generators as flexibility sources is an appropriate technical requirement not only for conventional but also renewable generators, especially PV and wind sources. In Japan, the grid connection code has not yet matured compared to the requirement for generators in the network codes developed by the European Network of Transmission System Operators. The connection code under revision is to prescribe frequency services for thermal units that are greater than or equal to 100 MW, whereas the existing grid connection codes specify limited functions for wind power plants, such as output deviation limit control, storm control, and generation droop control, under the existing institutional structure. For PVs, the Japan PV Energy Association and Japan Electrical Manufacturers' Association have begun to work together to develop new requirements for the grid connection code.

Conclusion

In Japan, the geographically imbalanced and heavy deployment of renewable energy, especially PVs in Kyushu, has posed various challenges for power system operations. System operators have rapidly been developing and implementing new procedures to secure a stable power

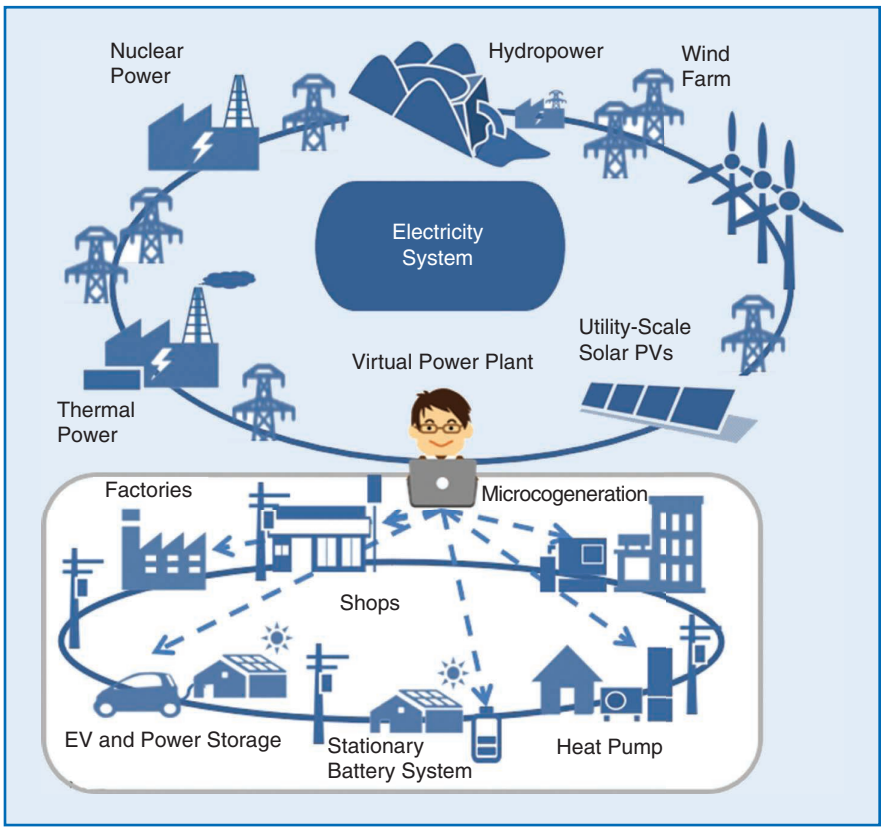

figure 23. The additional supply flexibility provided by virtual power plants. (Source: METI; used with permission.)

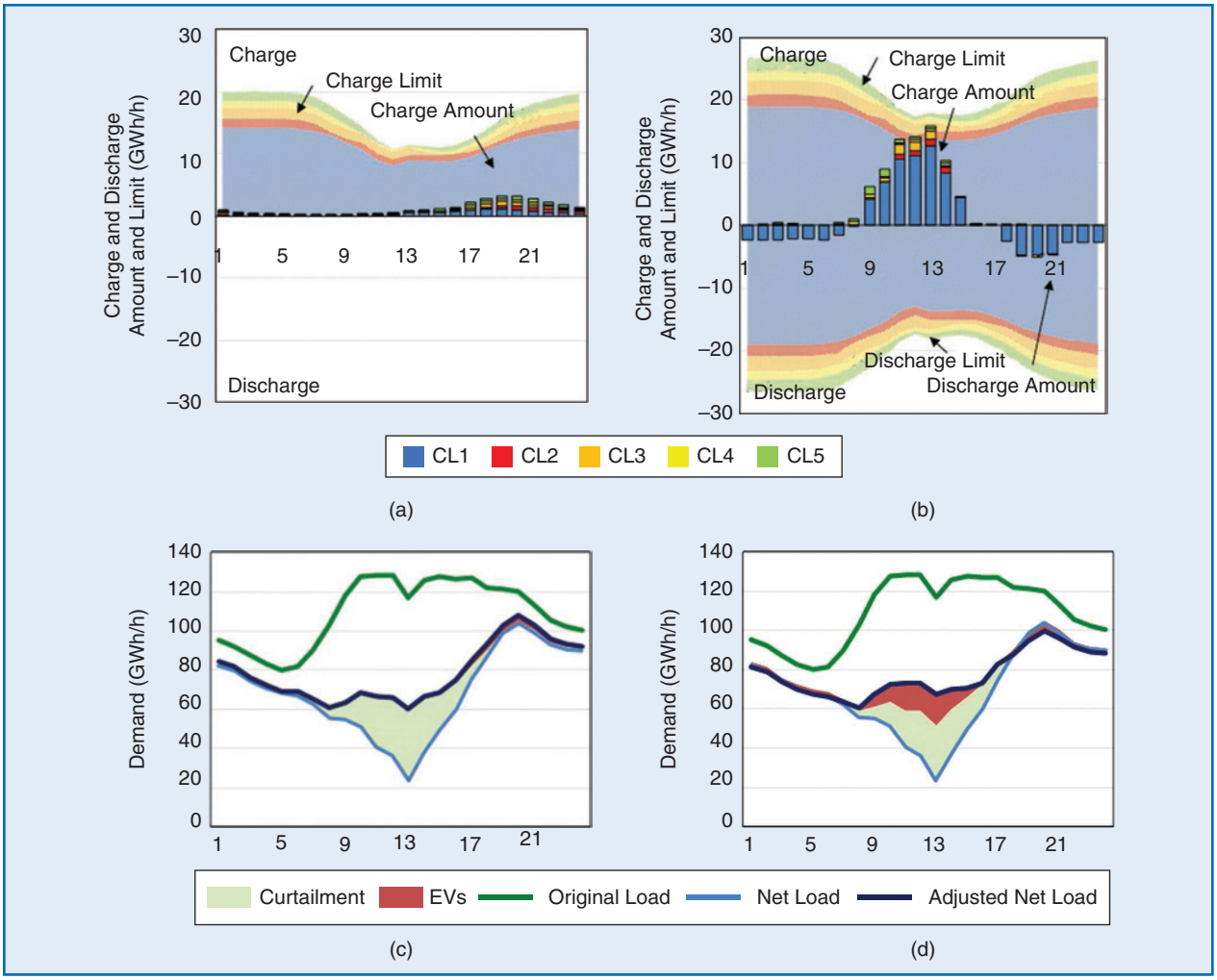

figure 24. The flexibility provided by the smart charging/discharging of EVs (1 April, 10 balancing areas in Japan). (a) Charge and discharge of uncontrolled charging. (b) Charge and discharge of controlled charging and discharging in homes and offices. (c) Load and curtailment of uncontrolled charging. (d) Load and curtailment of controlled charging and discharging in homes and offices. Clusters (CLs) 1–5: The charge and discharge capacity limits of five EV clusters according to usage patterns.

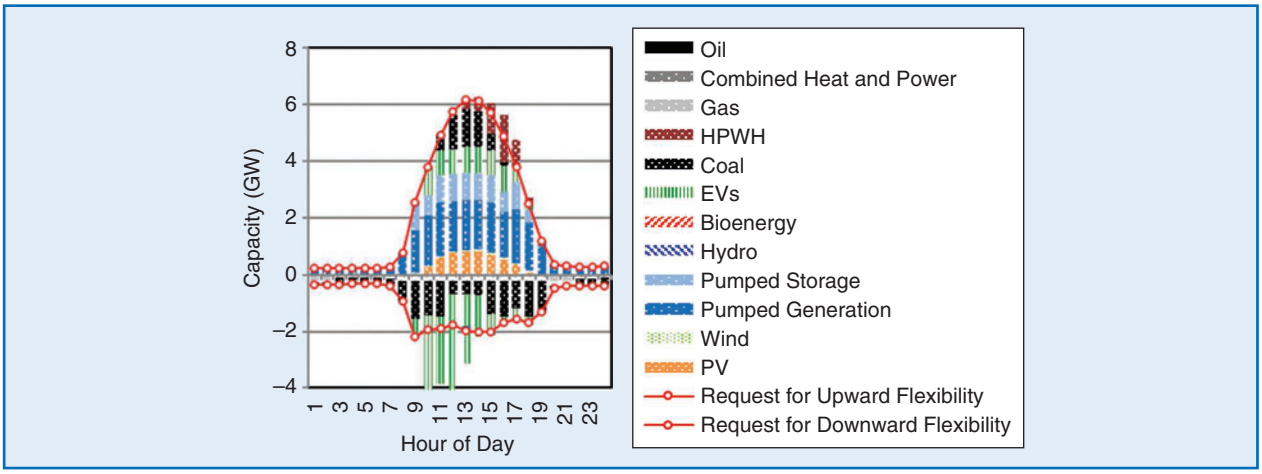

figure 25. An example of an optimum demand and supply analysis, including a balance of tertiary–slow flexibility against an extreme forecast error in Kyushu in April.

System operators have rapidly been developing and implementing new procedures to secure a stable power supply.

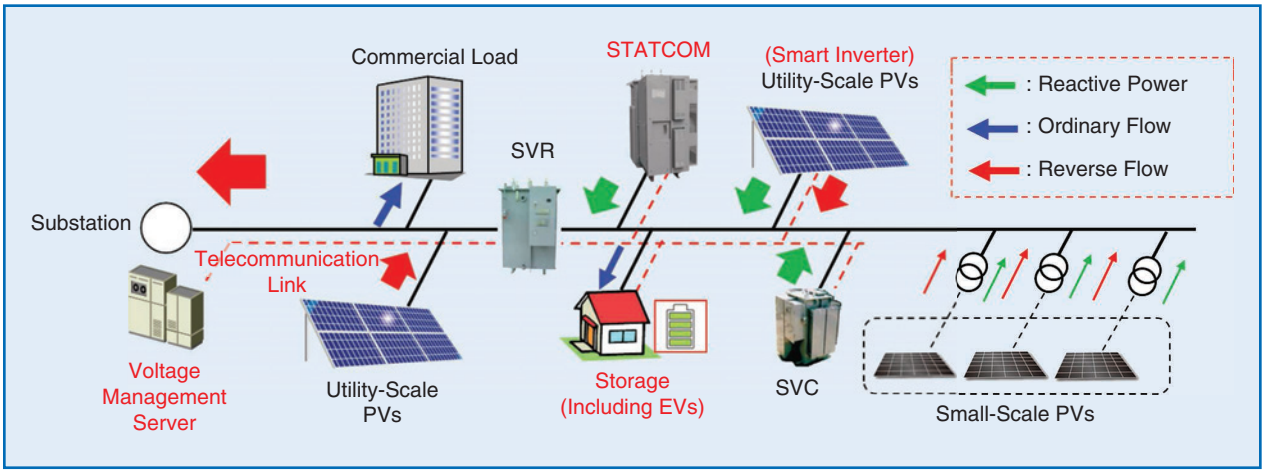

figure 26. A next-generation distribution system. (Source: Kyushu EPCO; used with permission.)

supply. Areas of innovation include renewable generation forecasting, renewable generation management, demand and supply operations, distribution operations, online PV control, and staff training. Although the issue was not described much in this article, under the progressing deregulation of the business structure of the power industry, the penetration of renewable generation is also causing many institutional challenges, including frequent ¥0 prices in the wholesale market. The increasing penetration levels of renewable generation also bring new issues regarding the reduced operation of synchronous machines and exacerbate the problems related to supply adequacy. We need to make every effort to realize a stable, affordable, sustainable, and safe future energy system through efficient planning, investment, and operation by enhancing technologies and institutions.

Acknowledgments

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Back in the Race



THE CANARY ISLANDS ARE AN ARCHIPELAGO of 7,447 km^2 and 2,127,685 inhabitants (2018), situated to the northwest of Africa (Figure 1). The islands are an autonomous community of Spain. There are eight inhabited islands and six isolated power grids, as Fuerteventura, Lanzarote, and La Graciosa are an interconnected system. The available amount of solar energy is quite high, reaching values of approximately 1,900 kWh/kilowatt peak (kw_p)/year in favorable locations. Wind is also an important renewable resource, mostly during summer.

In 2018, the electricity generated in the Canaries reached 8,841 GWh, with a peak power demand of 1,403.6 MW. Of the electricity generated, 10.5% was renewable, a 32.2% increase from the value in 2017. Of the 3,007 MW of capacity installed in the Canaries, 168 MW are from photovoltaics (PVs), 429 MW are from wind, and 13 MW are from hydro. Conventional power plants are mostly combined-cycle units (865 MW), but there are also steam turbines (483 MW), diesel engines (487 MW), and gas turbines (557 MW). These units are fueled with diesel and heavy oil. Natural gas was approved to be introduced in the islands in 1989, but it is opposed by many residents. Further, the only refinery located in the Canaries definitively stopped production in 2018, mainly for compliance with European Union (EU) environmental regulations.

The Canaries are a very important tourist destination for many Europeans and others. In fact, the Canaries hosted more than 15.6 million visitors in 2018. The tourism industry accounts for up to 35% of the electricity consumption in the Canaries' insular power systems (Figure 1). In contrast to other popular tourism islands in the EU (e.g., the Balearic and Greek islands), visitors to the Canaries are well dispersed throughout the year. Thus, the load profile is relatively flat, and conventional generation is generally constant year round, showing working-day hourly power peaks between 1,170 and 1,400 MW in 2018 (Figure 2).

The average wholesale price of the electricity generated by the conventional power units greatly depends on the size of the insular system (Table 1). This price includes a fixed cost, which is related to the availability of each unit to supply electricity during the time considered (the firm capacity), and the variable cost, which is mostly related to the price of

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Achieving 100% Renewable Energy in the Canary Islands

fuel. The fixed cost includes the financial return on investment at the generating unit, which had been 6.503% since 2014 but was revised by the National Commission for Markets and Competence (CNMC) and reduced to 5.58% for six years beginning in 2020. This reduction is mostly attributed to the expected long-term low money rate of interest in the market.

Of course, the reference cost that wind and solar energy must compete against is the variable cost of electricity since renewable generation is considered to offer no firm capacity to the system. The wind-hydropower plant El Hierro (described in the "El Hierro: The Highest Penetration of Renewable Electricity in the Canary Islands" section) is considered, but it does not offer firm capacity to the system throughout the year because of seasonality, and, consequently, it has a fixed-cost compensation that differs from that of the thermal units. To check the real cost for each unit, Red Eléctrica de España (REE), the national system operator and the owner of the transmission grid, periodically audits the facilities in situ to adjust the curve that relates the thermal content of the fuel consumed to the power produced. Moreover, any company that manages conventional power units must hold public auctions for the acquisition of the fuel, and the purchasing invoices must be submitted to the CNMC for monthly liquidations of the generating costs. Indeed, the price of the diesel and the heavy oil used to produce conventional megawatt hours is known and varies depending on the island (Table 2).

To plan the conventional power units serving electricity to the grid, REE gives daily dispatch orders to the different thermal units, based on a specific regulation that prioritizes the economic merits and through which each insular power grid acts as a unique node. A secondary dispatch directive considers security aspects for injecting renewable energy up to the integration limit. Finally, a tertiary dispatch instruction evaluates restrictions. All these dispatch orders can be adjusted, if necessary. Moreover, some Spanish grid codes have been adapted to the Canaries' insular power grids. One important code to be cited is P.O. 12.2, which discusses installations connected to the transmission grid and generating equipment. The code also establishes the operating range within which the grid operator must maintain the power system (Table 3). Because the total cost of electricity produced by the conventional units in the Canaries (163.51 €/MWh in 2018) is much higher than in mainland Spain (64.4 €/MWh in 2018), the difference is 50% financed

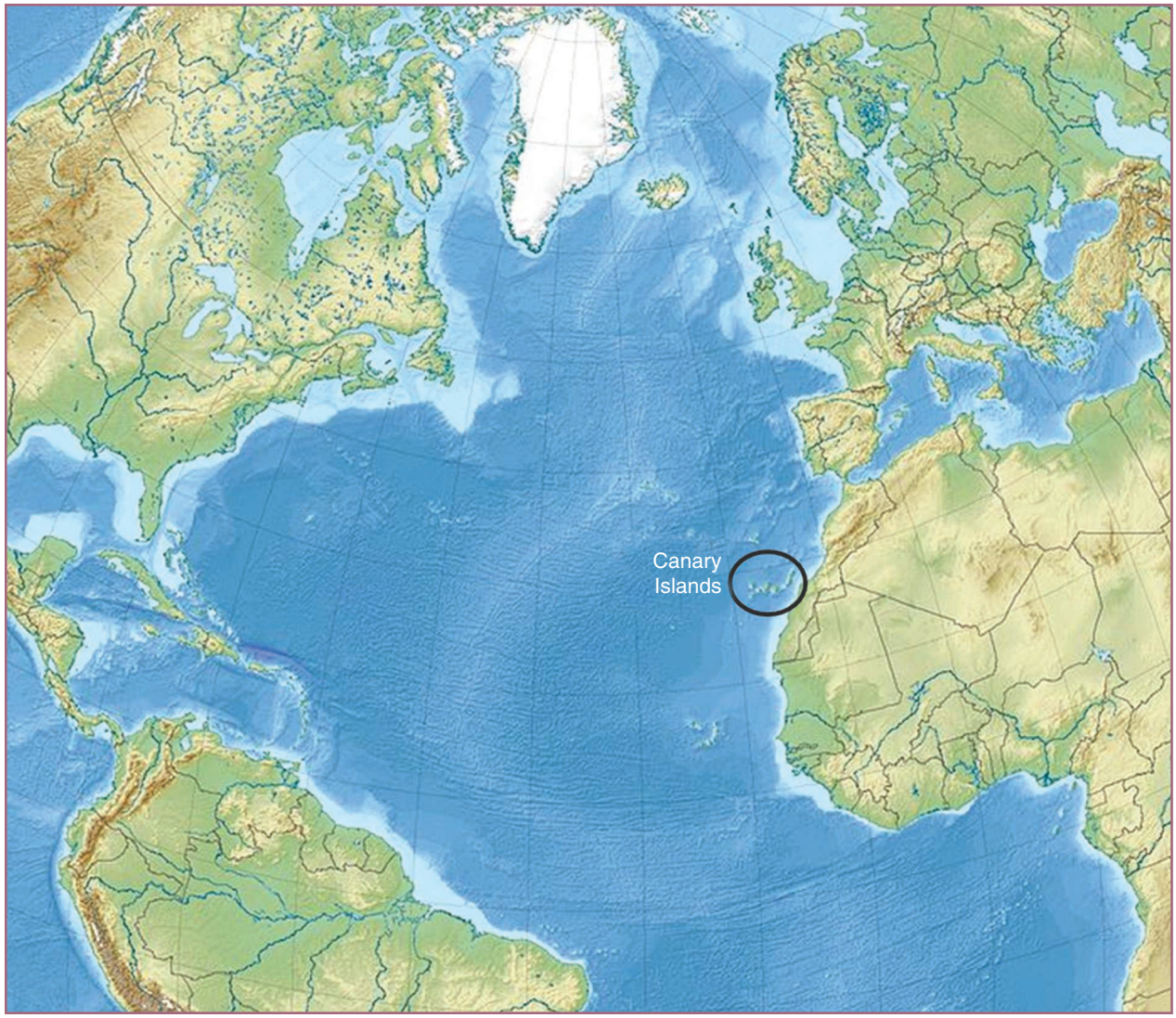


figure 1. The Canary Islands are located in the Atlantic Ocean. (Source: Uwe Dedering, https://es.m.wikipedia.org/wiki/Archivo:North_Atlantic_Ocean_laea_relief_location_map.jpg.)

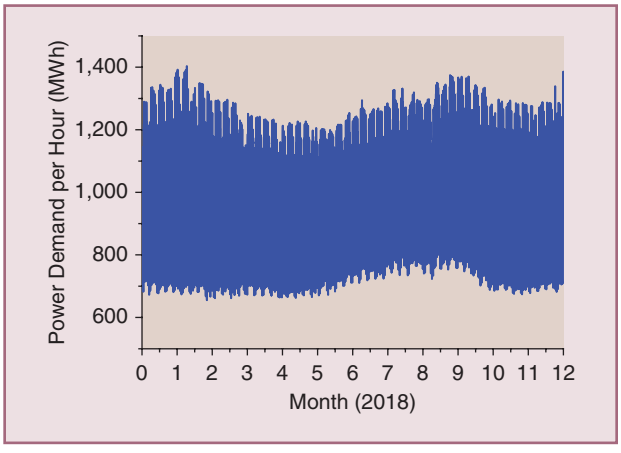


figure 2. The electricity produced in the Canary Islands in 2018, in hourly intervals. (Source: REE; author's elaboration.)

table 1. The 2018 generation expenses for the different power systems in the Canary Islands.

Power System	Variable Cost (€/MWh)	Fixed Cost (€/MWh)	Total Cost (€/MWh)
Tenerife	135.73	26.15	161.88
Gran Canaria	135.07	29.37	164.45
Fuerteventura–Lanzarote	123.6	26.51	150.11
La Palma	133.06	78.18	211.24
La Gomera	172.79	56.13	228.92
El Hierro	88	208.3	296.31

Source: Red Eléctrica de España (REE).

by all Spanish electricity customers and 50% subsidized by the Spanish government.

The demand price of electricity for retailers, direct consumers, and ancillary generation services is indexed to the Spanish price for the same actors but partially corrected on a daily basis. Indeed, the average price of the electricity demand in Spain during the day is modulated in terms of the hourly power requirements in each insular power system. This procedure is designed to offer a similar price in the Canaries but somewhat discourages electricity consumption during times of peak demand that are specific to the islands; however, it does not solve the problem of electricity production decoupled from renewable resources in mainland Spain and in the Canaries. In fact, wind energy generation is usually low in mainland Spain during summer, when it reaches the highest values in the Canaries. Also, the mix of renewable technologies is very different, not only between mainland Spain and the Canaries but among the islands (Figure 3).

As in any other region in Spain, consumers in the Canaries can bilaterally fix the cost of electricity with a retailer, and they can request the voluntary price for small consumers (PVPC) when the contracted power capacity is equal to or lower than 10 kW and has an access point that is lower than 1 kV. The PVPC for electricity in 2018 ranged from 108 to 138.6 €/MWh, adding 3.32 €/kW/month for the contracted power, the electricity tax (approximately 6%), and the value-added tax (6.5% in the Canaries, compared to 21% for consumers in mainland Spain). The determination of the PVPC is approved by the Spanish government and has a complex structure. All these rules make the power system in the Canaries quite transparent. In August 2019, the Canary Islands government approved a climate emergency declaration that aims to decarbonize the Canaries' economy by 2040 or, if possible, by 2035 (see "Declaration of Climate Emergency in the Canary Islands" in the "For Further Reading" section). Since this declaration, an energy decarbonization plan has been in preparation.

Evolution of Renewable Energy

Wind and PVs

The development of renewable energy in the Canaries has traditionally been based on feed-in tariffs. Wind energy was the first renewable resource to reduce the generating cost of electricity to a level compatible with low feed-in tariffs, and Spain developed a wind industry that has strong international activity. Wind energy was also the first technology to be deployed at significant values in the Canaries. REE originally gained experience by managing wind energy at its Control Center for Renewable Energies, in Madrid, Spain, and it was the first system operator to request telemetry for wind power plant integration into the national power system. That helped to lead to a favorable technical consideration of this technology by the Spanish government. PVs came later to Spain—they were expensive and expanded massively from 2005 to 2008—because of a high feed-in tariff that was offered without any limitation on the total capacity to be installed in the country, a situation that changed in September 2008. At that time, the lack of a defined plan for the development of PVs resulted in a sharp decline in new PV system connections and, consequently, a severe contraction of industries with activities in this area.

At this point, it is important to mention that before Tropical Storm Delta hit Tenerife at the end of November 2005, the Canary Islands power grid was vertically integrated, and Endesa, the utility, was in charge of the power supply. This meteorological event produced a partial but severe blackout on the island, and the recovery took approximately one week. Because the main cause of the blackout was the fall of some transmission grid towers, the Canary Islands' leaders persuaded the Spanish government to approve a regulation that gave REE the operation of the six power systems and, after negotiations with Endesa, ownership of all transmission infrastructure at a voltage equal to and greater than 66 kV as well as any large power generator that injected into the grid (2011), as in mainland Spain. This new scenario helps REE

table 2. The fuel prices (in euros per ton) published by the Spanish government on 12 October 2018.

Location	Heavy Oil (1% Sulphur)	Heavy Oil (0.73% Sulphur)	Standard Diesel	Diesel (0.1% Sulphur)
Tenerife	350.07	387.62	—	541.21
Gran Canaria	345.73	383.28	—	530.61
Fuerteventura	—	387.62	—	544.47
Lanzarote	—	387.62	—	544.47
La Palma	362.59	—	—	—
La Gomera	—	—	530.43	—
El Hierro	—	—	530.43	—

Fuel for producing electricity is exempt from taxation. Source: Dirección General de Política Energética y Minas.

table 3. The ranges within which grid operators must maintain the Canary Islands power systems (P.O. 12.2).

Voltage dip	90–1%: 10 ms–1 min
Voltage stability	0.85–0.9 per unit: 1 h
	0.9–1.118 per unit: unlimited
	1.118–1.15 per unit: 1 h
Frequency	47–47.5 Hz: 3 s
	47.5–48 Hz: 1 h
	48–51 Hz: unlimited
	51–52 Hz: 1 h

to be proactive in building new substations and repowering many transmission lines and substations to inject multimegawatt renewable generation into the grid.

The bulk of the PV capacity was very much concentrated in defined areas, having avoided development in parallel with distributed generation in urban areas because large PV power plants are more attractive to major investors looking for inexpensive land (of which there is a significant amount in semiarid areas in the southeast of each island) and since, at the time (2005–2008), it was not economically attractive to build new grid lines. In fact, Tenerife has the highest PV penetration, and most of the 106 MW of installed capacity is centered at two 66/20-kV substations connected to a preexisting 66-kV line.

Some PV investors are public entities because they regulate the available land and understand that wind and other renewables can offer high returns on public investments when the technologies start to be subsidized. The market has been evolving rapidly, however, after the Spanish government's approval of Royal Decree 244/2019 regarding self-consumption (including net metering and selling surplus energy to the power system) and EU Regulation 943/2019 and Directive 944/2019 concerning the electricity market. These instruments have regulated individual and collective self-consumption with and without surpluses, net metering, and selling excess electricity directly to the grid. At present, Spain is installing, on average, 1 MW of PVs daily for self-consumption, and the market is growing. This dynamic is also reaching the Canaries.

Geothermal Energy

There is a long-standing discussion about the opportunity to introduce geothermal energy to produce electricity on the islands, and preliminary studies have been conducted since the 1970s; however, the lack of active volcanos in the Canaries and the high cost of drilling makes the necessary exploratory activity very risky. There are some volcanic areas showing geochemical activity that can be compatible with

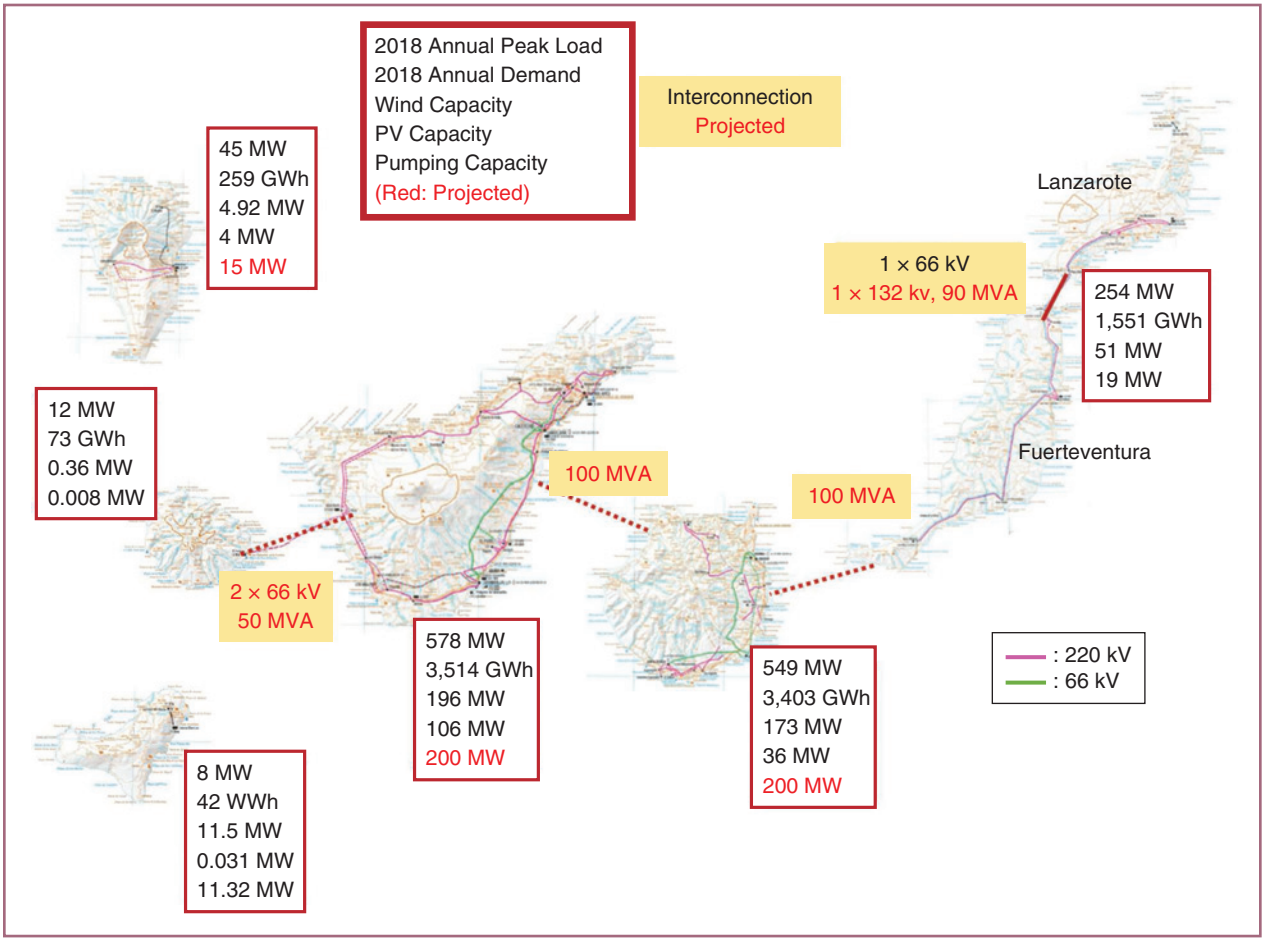


figure 3. The transmission circuits and main parameters of the Canaries' power grids. The box with the dark-red outline is the key to the information conveyed by the boxes with light-red borders; the red text indicates pumping systems that are being studied. The yellow boxes give the main parameters of interconnections that are in service or under review. Only the repowering of the interconnection between Fuerteventura and Lanzarote is expected during the short term. (Source: REE and the Spanish government; author's elaboration.)

an available geothermal resource; however, no hydrothermal resources for feeding high-enthalpy geothermal plants have been localized. An Australian company that specializes in developing geothermal power plants around the globe has unsuccessfully tried to start activities in the Canaries to search for a local public–private partnership to share the risks of exploratory drilling in some defined areas. Thus, at present, geothermal activity in the Canaries is studied primarily for geochemical and seismic research rather than possible power plant development.

Hydropower

Hydropower was the first source of electricity in the Canaries. It was promoted by visionary local investors on La Palma (a minor island), producing power for the first time on 31 December 1893. The first hydropower units used natural streams and were mostly in Tenerife, with some in La Palma. As the population and agricultural activities grew, however, two types of systems developed for capturing groundwater: drilling horizontal galleries at high and medium altitudes and drilling wells close to sea level. These activities produced water shortages for hydropower production. The power grid started to grow from the port areas instead, where conventional generating units were placed for an easy supply of fossil fuels (beginning with coal, which was gradually replaced by oil). Conventional power plants came to be located in the capitals of the islands, and, from there, the grids grew to the principal towns in the islands' interiors. Today, hydropower is again being considered but mostly for pumping and regulating the power grid. It is quite difficult to find places to locate the necessary reservoirs and grid infrastructure to connect and transport the energy because the islands are environmentally protected.

Biomass

The beginning of electrification in some rural areas of the Canaries was associated with agricultural activities but only for consumption. Indeed, sugarcane in the Canaries was replaced by other crops before the introduction of electricity. There are a few small biomass furnaces that supply heat to public pools and resorts; however, the biomass comes from other European countries since the forested areas in the Canaries are fragmented and occupy a small overall surface area. Also, the amount of residue from agriculture is minimal and heterogeneous. There was an attempt in 2014 by the largest Spanish company producing electricity from biomass, Energía & Cellulosa, to install two 70-MW power plants in the port areas of Gran Canaria; however, the regional government's Department of Health published a negative report warning about the pollutants that these plants could spread to the surrounding urban areas, and in June 2016, the company decided to abandon the projects because they would not receive any feed-in tariffs to make the investment attractive.

Future of Renewable Energy in the Canaries

Government Planning

As mentioned previously, the Canary Islands government aims for total decarbonization by 2040 or, if possible, 2035. The government previously used an approved energy plan, the Canary Islands Energy Plan (PECAN) (see "Canary Islands Energy Plan" in the "For Further Reading" section); however, arranging the electric system is an exclusive competency of the Spanish government, with the participation of Spanish regions and informed by the CNMC. After the last PECAN was approved in 2007 and two annual follow-up reports were published in 2008 and 2009, no new scheme has been authorized. Only a draft strategy, Canary Islands Energy Strategy (EECAN) 2025 was published; it highlighted the main PV and wind capacity indicators expected for 2025 (Figure 4) but did not include any legal reinforcement (see "Canary Islands Energy Strategy 2015–2025" in the "For Further Reading" section).

The share of renewable energy in the Canaries has discontinuously expanded, including the rapid growth of wind energy at the end of the 1990s to approximately 137 MW; public auctions for new wind power plants that were challenged in court from 2004 to 2014; a PV boom from 2005 to 2008, bringing the total renewable generation to 160 MW; and a new wind energy surge from 2017 to 2018, which raised the total to approximately 435 MW after a public auction in 2017. Moreover, new wind power plants (183.3 MW) are expected before 2022. Offshore wind receives special consideration in the EECAN, which projects that 300 MW of offshore wind power plants will be installed by 2025, since offshore wind generation is viewed as an opportunity for the industrial sector in the Canaries. Indeed, some prototypes are being financed by the EU and tested in Gran Canaria, in addition to marine energy devices. The coastal areas of the Canaries are strictly protected, however, and the water is deep near the shore of most of the islands (Figure 5), so floating wind turbines might be required.

As of September 2019, REE had given permits for access (after checking that there is enough spare capacity at the node) and connections (after reviewing the technical content of the project) to the transmission grid, and Edistribucion (Endesa) to the distribution grid, for up to 806 MW of PV and wind power plants. Endesa issued permits for up to 806 MW of PV and wind energy to access the distribution grid. Another 2,126 MW of PV and wind projects have permission only to access the grid (connection permits are still pending), while 413 MW are in the process of obtaining access and connection authorizations, and requests for 590 MW have been rejected because of technical problems (i.e., requests for connection to a substation that is saturated or does not yet exist). It cannot be assumed that all the PV and wind capacity with permits for access and connection

to the grid will be in service soon. Speculative activities are being detected, not only in the Canaries but in all Spanish regions. The Spanish government has approved new rules to prohibit such practices, asking for guarantees from all promoters and invoking the assurances if new PV and wind power plants do not reach specific milestones or connect to the grid by a certain time.

The main electricity planning document approved by the Spanish government for the Canary Islands and all other Spanish regions is "Development of Electricity Transmission Networks 2015–2020" (see the "For Further Reading" section). It includes studies for a new interconnection between Tenerife and La Gomera, repowering the interconnection between Fuerteventura and Lanzarote, and installing a pumped-storage system in Gran Canaria (Figure 3). The document also lists new conventional power units proposed by the utility (including an entirely new power station in Fuerteventura) and the capacity limits for any power unit (conventional or renewable) to be located in each insular power system.

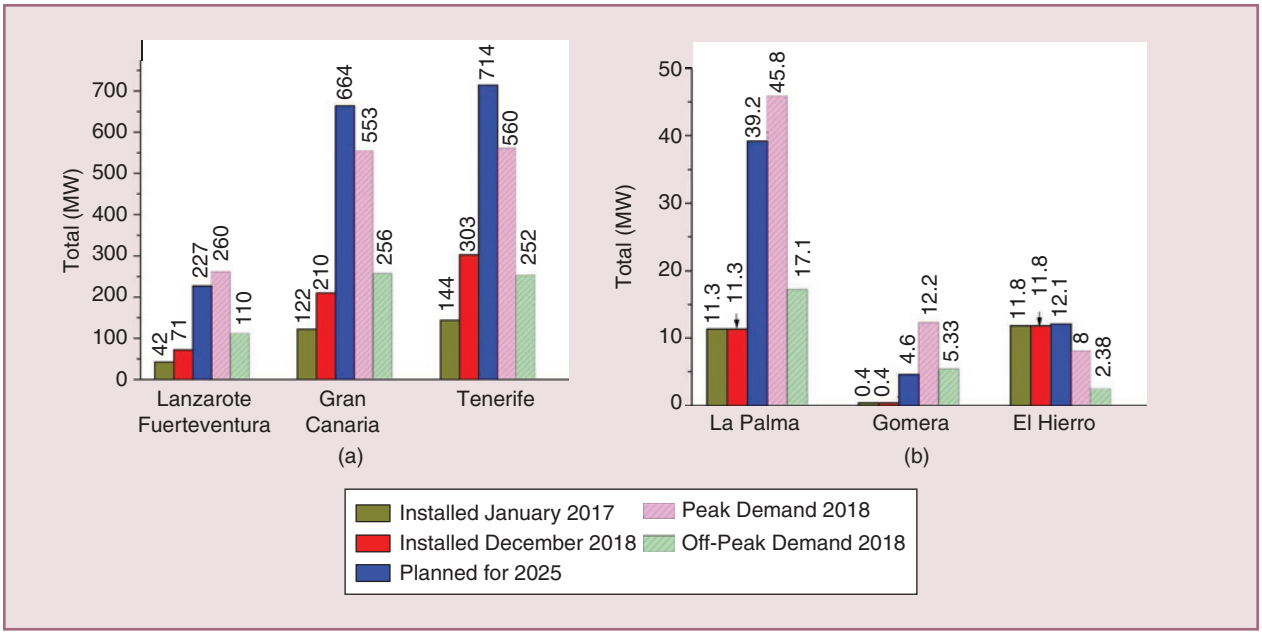


figure 4. The main PV and wind capacity indicators for the power systems in (a) Lanzarote, Fuerteventura, Gran Canaria, and Tenerife and (b) La Palma, Gomera, and El Hierro. (Source: REE and the Canary Islands government; author's elaboration.)

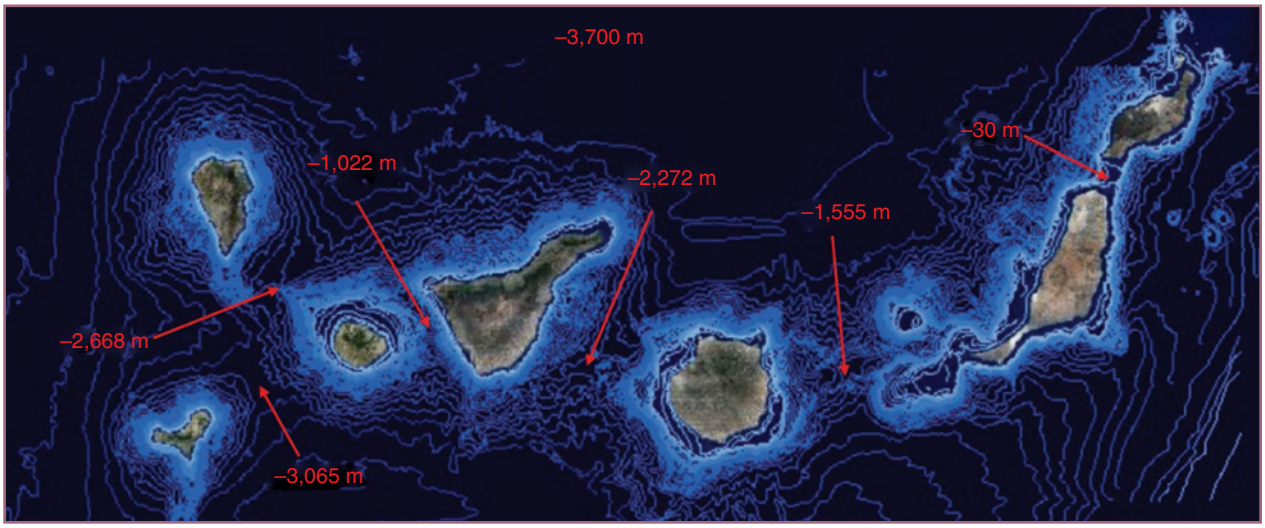


figure 5. A bathymetric map of the Canary Islands, including the minimum depth between islands. (Source: Canary Islands government.)

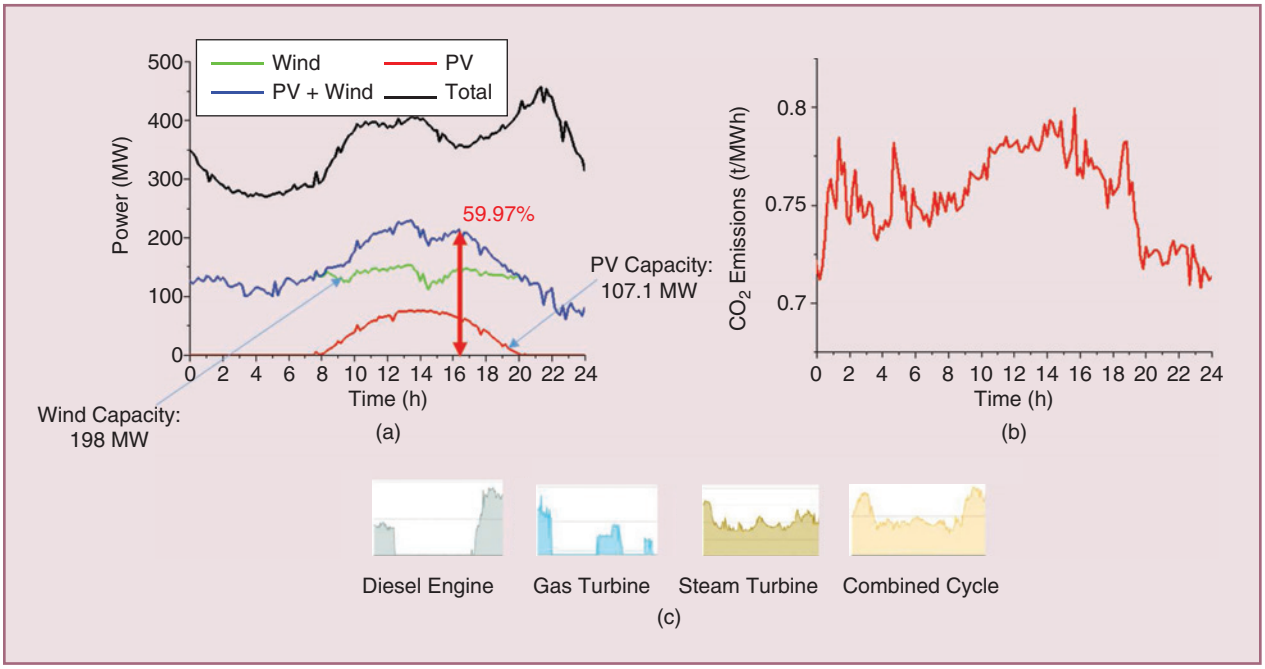


figure 6. (a) Generating curves for wind, PV, and total energy produced on 19 May 2019 (record instanteous generation at 4:20 p.m.); (b) evolution of carbon emissions per MWh produced; and (c) detail of the generating curves for each conventional power technology on 19 May 2019.

Tenerife: The Record for Renewable Electricity Injected Into the System

As of October 2019, Tenerife held the record for the highest instantaneous penetration of renewable energy (59.97%) for a power system without any storage capacity (no pumping, batteries, or any other storage system serving the power grid) in the Canaries. This was recorded on 19 May 2019 at 4:20 p.m. (Figure 6). As expected, the CO_2 emissions per megawatt hour generated by conventional power units increase when the renewable supply reaches its highest values, but they grow by only a few percentage points compared to other time intervals when the generating activity is mostly supported by conventional power units. That is partly because of the time intervals required by conventional generating units to reach hot starts and ramp-ups (Table 4). Lower CO_2 emissions per kilowatt hour produced can be expected if new dispatchable power units with faster starts and ramps replace the current conventional power units. In fact, EU Directive 2010/75, which covers industrial emissions, limits the operating hours of many important conventional power units. Some of these are retrofitted, but others will be decommissioned and replaced by new firm capacity.

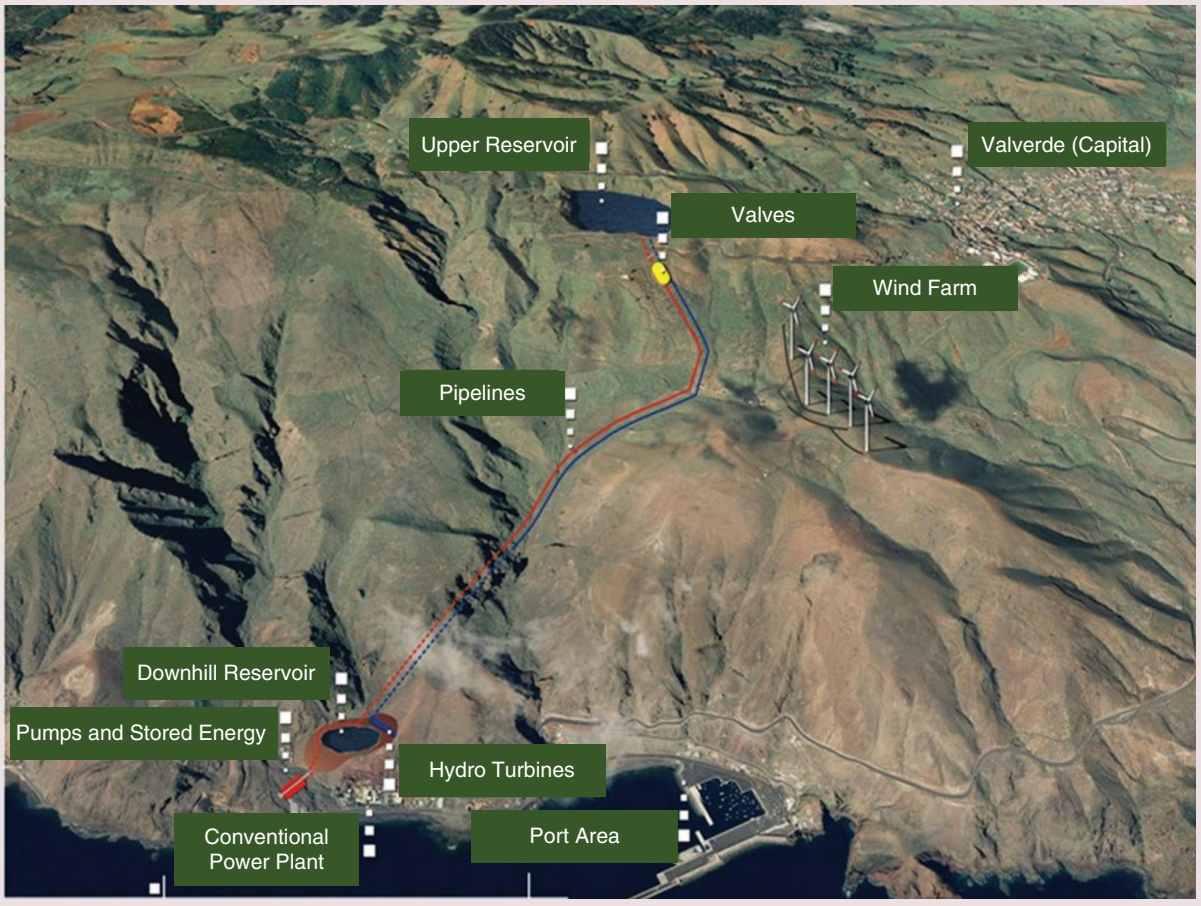
In addition, the future of renewable energy in the Canary Islands will be connected to the development of Royal Decree 244/2019 about energy self-consumption (including net metering and selling surplus energy to the power system). This regulation covers all of Spain, but it is particularly important for the Canary Islands, which constitute the Spanish region with the greatest solar irradiation rates and the highest cost of electricity. The decree includes individual and community self-consumption, and the connection between production and consumption sites can be used in an internal grid as well as the distribution grid, considering some very innovative rules about the distance between feeders and consumption locations. The regulation is very simple for distributed generation that has a nameplate capacity in kilowatts peak of fewer than 10, 15, or 100.

table 4. The conventional power units' average flexibility in Tenerife.

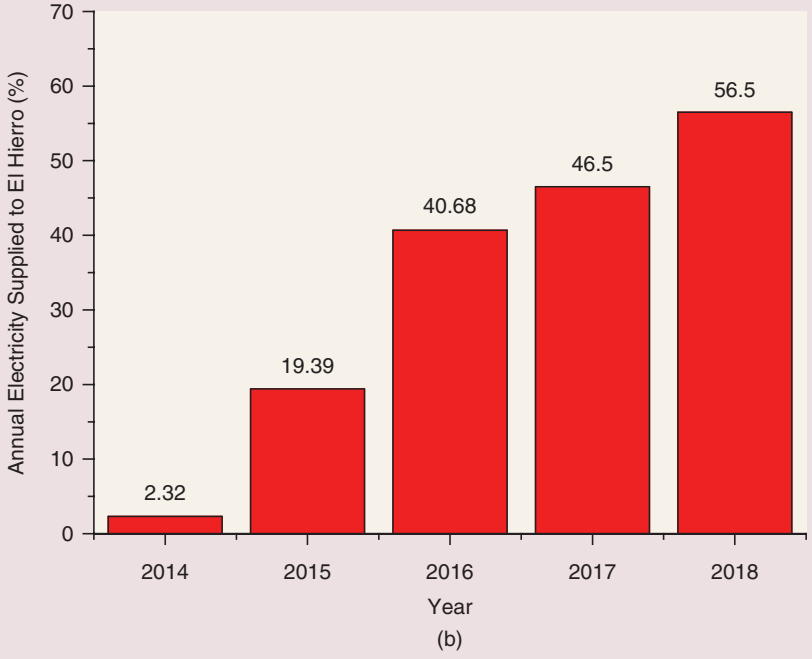
Technology	Hot Start (min)	Ramp-Up to Full Load (min)
Steam turbine	285	46
Diesel engine	23–68	4–11
Combined cycle	330	66
Gas turbine	24	9

El Hierro: The Highest Penetration of Renewable Electricity in the Canary Islands

There is general consensus in the Canary Islands that large amounts of storage capacity are needed to increase the share of renewable energy and reach a 100% renewable power system. At this time, however, there is discussion about the introduction of pumping systems and/or batteries (stationary and those used by electric vehicles). The Gorona del Viento hydro-pumping system on El Hierro island, which has been operating since mid-2014 (Figure 7), plays a central role for the first option. The system includes five wind



(a)



(b)

figure 7. (a) The Gorona del Viento power plant at El Hierro. (b) The percentage of electricity produced by Gorona del Viento per year. (Source: Gorona del Viento.)

turbines (11.5 MW), four Pelton hydro turbines (11.32 MW), a head of 655 m, eight pumping systems (6.24 MW), an upper reservoir (380,000 m^3), a downhill reservoir (149,000 m^3), and a pipeline of 2.3 km. This configuration offers approximately 2 days of hydropower autonomy to the island (~230 MWh), without the withdrawal of fresh water to the sea. The annual penetration level of renewable energy from Gorona del Viento reached 56.5% in 2018 [Figure 7(b)]. In July 2019, El Hierro reached a record 24 consecutive days with energy exclusively supplied from this power plant.

The efficiency of the system is approximately 50% because the main task is not to produce as much electricity as possible but, rather, properly integrate the energy from the wind power plant into the El Hierro network. In a noninterconnected system and for a small island, the primary concern for the power grid is integrating the power ramps produced by wind and solar energy because those sources produce frequency variations that are out of range in the grid. When the frequency variations are out of range, a substantial part of the wind energy reaching the wind power plant is curtailed because of the severe gusts experienced at the location during certain periods. The frequency of the power system in El Hierro has been out of range (Δf >250 mHz) more often than that of any of the other Canary Islands (81 h in 2017); thus, it was necessary to further reduce the average efficiency of the wind-hydropower system to limit the out-of-range hours (20.6 h in January–August 2019).

Additional strategies are being tested to further increase the share of wind in the power mix and reduce the periods when the frequency of the system is out of range. One strategy was to act on the primary frequency control of the hydropower turbine units (speed governors) and pump frequency converters, but this was not enough. A second effort consisted of reducing the pumped-unit shedding and revising the speed of the governor logic of the hydropower turbine generator units (i.e., by using a damper to mitigate the pressure waves in the turbine penstock, which causes oscillations in both the water pressure and mechanical power in the hydropower turbine units because the higher the nozzle rate of the opening, the larger the oscillation). Also, the procedure for processing the wind plant's active power settings was revised (each wind turbine receives a specific active power setting value; the minor power setting is between a 5-min moving average value calculated from a statistical method of regression and a consigned active power value) for power-frequency control. The next steps are to transition the hydropower turbines from generator mode to synchronous compensator mode, review the active power settings for each wind turbine, and enforce the wind power plant control capabilities (active power-frequency control and inertia emulation capability; see Marrero at al. in the "For Further Reading" section) to provide plenty of frequency response and regulation when operating.

There has been controversy about the cost of electricity generation in the El Hierro power system since Gorona del Viento began service. The El Hierro power system is the smallest in the Canaries, and it usually had the highest cost per kilowatt hour of all six energy networks. Also, the cost increases sharply when Gorona del Viento and the conventional power plant are both operating, so to lower expenses, it is necessary to shut down the conventional power plant (which includes only diesel engines) when Gorona del Viento has enough stored energy. Much of the extra cost can be attributed to the fact that the return on investment in Gorona del Viento was accelerated by the CNMC because of the delays for the plant's entry into service and the repayment of loans to the banks financing the venture. All this happened in parallel with an intense economic crisis. Finally, the loans were repaid in 2018, and currently the recognized price for the generated electricity is €15.57/MWh (which is revised every three years).

REE is planning to replicate Gorona del Viento in Gran Canaria by using the existing reservoirs of Chira (5.6 million m^3) and Soria (32.3 million m^3) and commissioning a 200-MW/3.82-GWh storage system. The project, which is valued at €391 million, began in 2007, with a scheduled completion in 65 months. There is some public opposition to the project, however, because of the potential environmental impact to the area. Also, there is a discussion about the ownership of this power plant, if it eventually enters service, given the simultaneous role of REE as the system operator and a producer. REE justifies its position by arguing that the pumping system will serve only as a regulation device for the power grid.

It is obvious that to reach 100% renewable energy in insular power systems, storing energy in pumping systems, batteries, and thermal units for tertiary regulation can be a key strategy. Also, gas-to-power storage systems could play a central role because the land available in the islands is scarce and expensive, the time for receiving the administrative permits required for occupying large areas is long, and the energy density of the hydrogen and methane per unit of occupied surface is much higher than that of batteries and, of course, pumping systems. In primary and secondary regulation, however, there is another interesting option to keep the frequency of the grid in the permitted range: short-term forecasting technology. In this area, satellites and (mostly) all-sky imagers can play a fundamental role. The attractiveness of satellites for island forecasting is limited because of the spatial resolution and the time range between served images, but the information that is provided can be helpful.

All-sky imagers give more localized information with a higher resolution. The accuracy of the sky imagers for forecasting PV power is limited, but the technology can play a role as a warning system for the utility. Low-cost (fewer than US$500 each) sky imagers have been placed on two of the Canary Islands in areas where more PV systems are located (Figure 8), and they were installed as pairs to calculate the height of the cloud base at the lowest cost compared to other technologies. Forecasts are made with images obtained every 10 s, and the algorithm learns by comparing the PV energy recorded in the substations where the multimegawatt PV plants inject into the grid. The goal is to offer warning services instead of



figure 8. The location of two all-sky imagers and (b) the substation in the southeast of Tenerife. The monitored multimegawatt PV plants are circled in red, the all-sky imagers are indicated by red arrows, and the substation is circled in purple. (Source of map image: Canary Islands government, www.idecanarias.es.)

precise PV forecasting since it is very difficult to obtain low error rates on partly cloudy days but easy to serve cautionary information, including quantitative analyses, to conventional power units, which is helpful for saving fuel costs.

Conclusions

The Canary Islands are back in the race to reach 100% renewable energy because solar and wind resources are abundant. The new government plans to reach the total decarbonization of the economy by 2040. The most important challenge—a robust regional energy plan backed by the Spanish government that describes the necessary steps to reach this goal—is being confronted. Important questions about the optimal ratio of distributed-versus-utility-scale generation, how to guarantee a 24/7 energy supply, how to store energy in the different islands, where to place new energy infrastructure, how to modify the current regulations to accelerate the permit processes, how to attract private investment, and how to create permanent local technology and business sectors that support this transition and expand it to neighboring countries in Africa will be answered shortly.

For Further Reading

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Biography

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On Good Behavior

Inverter-Grid Protections for Integrating Distributed Photovoltaics

THE INTEGRATION OF INCREASING NUMBERS OF larger photovoltaic (PV) power plants brings several challenges to traditional distribution system protection. Two major considerations are managing back-feed and coordinating the inverter response to abnormal conditions.

With the 2018 updates to IEEE Standard 1547, distributed energy resources (DERs) must be able to support the electric grid during both steady-state and abnormal conditions. The need to continue operating during voltage and frequency events has focused attention on protection coordination. In this article, we address several practical protection issues with inverter-connected PV plants, including temporary overvoltage, fault contribution and arc flash, response to feeder open-phase events, and islanding-prevention and reclosing practices.

We draw on field experiences to identify typical circumstances and issues as well as suggest practices to avoid some problems and options to mitigate others. In addition, we discuss DER power monitoring and data collection both for visibility and as modeling input to predict performance. We also identify the need for analytic tools to screen islanding risk, verify settings/responses, and evaluate grounding.

Overvoltage and PV Plants

When islanded from the primary system ground, DERs can contribute to a ground fault overvoltage (GFO) on unfaulted

By Tom Key, Gefei "Derek" Kou, and Michael Jensen

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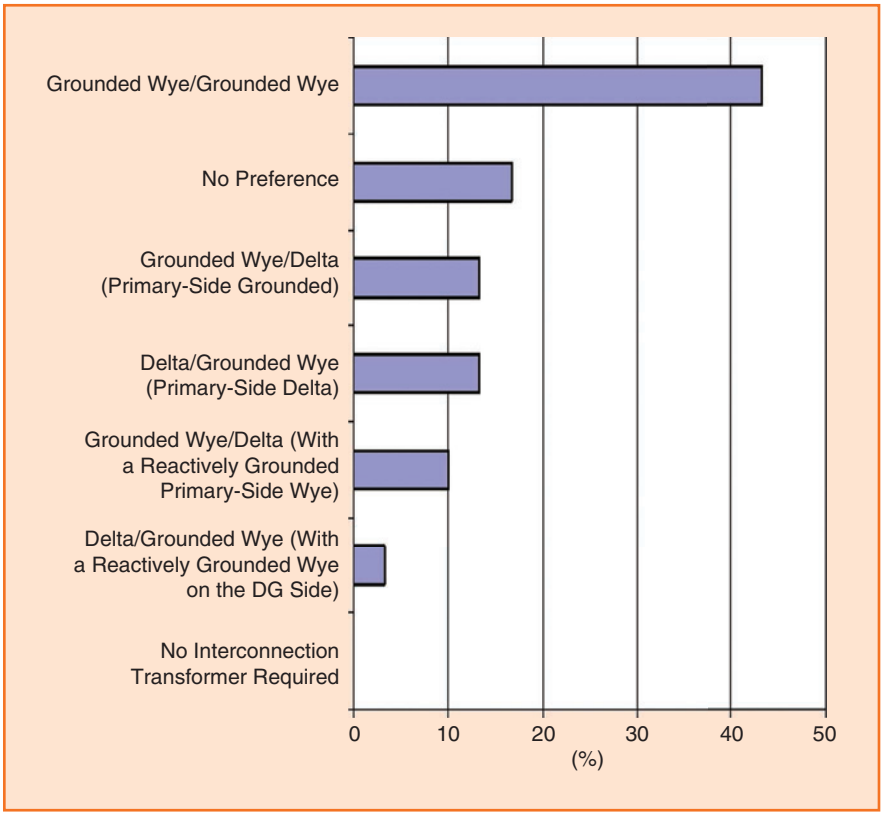

figure 1. The preferred transformer connections for inverter-based systems. (Source: EPRI 3002001277.)

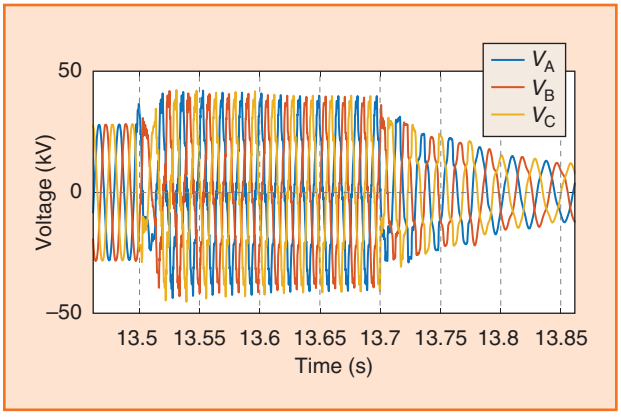

figure 2. The LRO measured at a utility-scale solar power plant. Grid disconnection happened at 13.5 s.

phases in a four-wire system. Effective grounding is intended to limit the line-to-ground overvoltage to 0.8 V_{l-l}. Maintaining this coefficient of grounding is a classic design objective in three-phase power systems and defined in IEEE/ANSI Standard C62.92.

For distributed generation (DG), the concern for GFO is a key factor in selecting the grid connection transformer. In the case of synchronous machine DERs, connections are normally required to provide supplemental system grounding. For inverter-connected DERs, the need is less clear because of significantly different fault behavior. When supplemental grounding is required, it is via the interconnection or a special grounding transformer (GT). A reactor may also be required in the transformer neutral for protection coordination.

Figure 1 shows the results of a 2013 Electric Power Research Institute (EPRI) survey identifying the Yg–Yg transformer configuration as the most common DER connection. A 2020 EPRI survey provided similar results. Given that the Yg–Yg connection does not provide effective grounding, the question of supplemental requirements for PV plants is raised. The current landscape is mixed, as some utilities require grounding and some do not. If required, details on how to achieve effective grounding vary for differences in distribution systems but also for differences in opinions and traditional practices.

In the most recent 2020 survey, EPRI interviewed 20 large utilities regarding system grounding practices and PV plants. There was a 50/50 split on requiring supplemental grounding for inverter-based DERs. Three of 10 utilities that now require DER supplemental grounding may consider grounded load as effective for inverters in the future. This inverter consideration is proposed in IEEE/ANSI Standard C62.92-6 and IEEE Power & Energy Society Technical Report 21. This new face on an old issue is expected to continue evolving with more inverter-interfaced PV and energy storage.

Another overvoltage concern for inverters is their response to a sudden loss of load. Load-rejection overvoltage (LRO) happens when a grid-following inverter is disconnected, e.g., due to breaker operation. Overvoltages occur because there is a temporary surplus of generation. A recent study by Dominion Energy on utility-scale solar power plants recorded elevated voltage levels upon the sudden disconnection of PV plants.

Figure 2 shows an example captured at a typical utility-scale, 5-MW plant at 34.5 kV. The transient overvoltage at this plant reached 159% of the nominal voltage and lasted 12 cycles. Such a phenomenon is not uncommon with rapid load rejection. Among 1,128 load-rejection events captured, 12% exhibited root mean square voltage magnitudes above 140% of the nominal, and most events lasted between one and six cycles.

Overvoltages exceeding equipment withstand capability could lead to medium-voltage (MV) arrester and instrument transformer failures as well as load equipment damage.

Overvoltages exceeding equipment withstand capability could lead to medium-voltage arrester and instrument transformer failures as well as load equipment damage.

Equipment failure incidents associated with PV plant LRO have been reported, and choosing plant interconnection equipment capable of handling transient overvoltages is a recommended practice. For example, heavy-duty-rated surge arresters and potential transformers with higher basic insulation levels are more likely to tolerate LRO.

In the meantime, inverter overvoltage limits were applied in Hawaii and have been added to IEEE Standard 1547-2018. These were confirmed by National Renewable Energy Laboratory and Southern California Edison lab testing of inverters. EPRI is also conducting research for the New York State Energy Research and Development Authority to better understand how LRO combines with GFO during unbalanced faults. This work included the role of island load and MV surge arresters.

Looking ahead, inverter LRO and GFO are expected to be largely mitigated with the application of the new IEEE Standard 1547-2018. An inverter certified under the standard "shall not cause fundamental frequency line-to-ground voltage to exceed 138% for a duration exceeding one cycle."

Fault and Arc-Flash Contributions

PV plants have limited fault current but may extend fault-clearing time. Supplemental grounding can add to fault current and arc flash. A closer look is needed to inform lineworker practices.

PV Plant Fault Contribution

An accurate short circuit representation is key to protection coordination and relay settings. Unlike synchronous generators, solar inverters act as a positive-sequence source and, depending on design, have insignificant negative- and zero-sequence fault current. Figure 3 shows a single-phase-to-ground fault near a 20-MW solar PV power plant. The faulted phase dropped to 35% of the nominal voltage. In response, the inverters contributed to the location fault current.

Figure 3 shows the symmetrical component fault currents from the solar inverters. It is noted that the fault current was dominated by a positive-sequence current (I_1). Negative and zero-sequence components (I_2 and I_0) are less than 5% of the rated current. The point-of-interconnection (POI) recloser opened eventually and eliminated the inverters' contribution. Throughout the event, the inverters' fault-current magnitude did not significantly increase, and limited by sunlight, the inverters' fault current reached only 80% of the rated current.

The observed solar inverter fault contributions are relatively low and very different from those of synchronous generators for all three sequence components. This illustrates why inverters need to be treated differently in any short circuit modeling and simulation platform.

The collective efforts of the industry have greatly improved the modeling techniques of inverter-based generation. Currently, most short circuit simulation platforms—including ASPEN, CAPE, and ETAP—provide for inverter modeling. Solar inverters are modeled as a voltage-controlled current source. By populating a table listing fault-current magnitude and angles at various terminal voltages, fault characteristics are incorporated into the analysis.

Still, precautions are required for solar inverter modeling. In addition to inherent current limits, solar inverters respond to faults by preprogrammed control modes. For example, unity power factor control mode will behave differently than reactive support control mode. Therefore, it is recommended that utilities verify inverter settings during the commissioning process and validate model performance through ongoing field measurements.

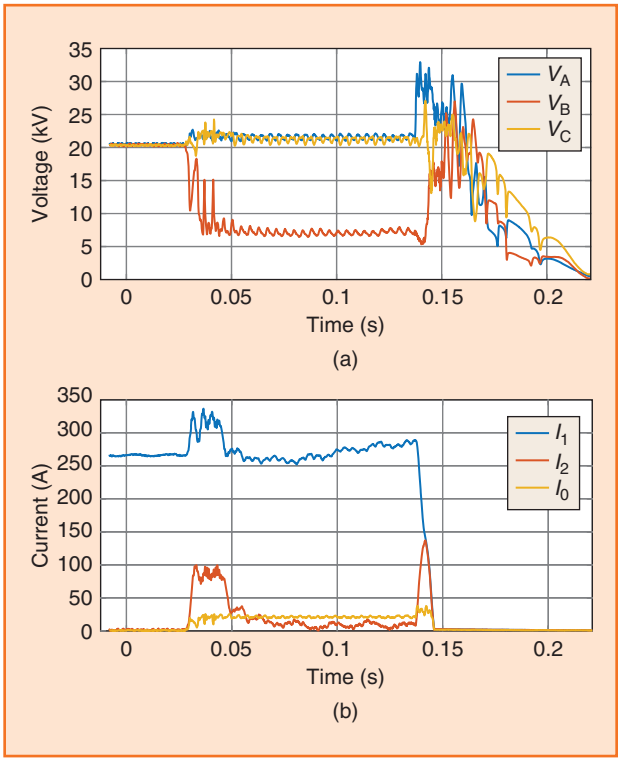

figure 3. The solar inverter fault (a) phase voltage and (b) symmetrical component current contribution.

PV Plant Arc-Flash Incident Energy

When field crews work on energized distribution feeders, there is concern about accidental faults and arc flash (see Figure 4). The danger is measured by flash incident energy in kilocalories per square centimeter. Arc flash correlates with line voltage, fault-current magnitude, and fault-clearing time. DERs can contribute to arc flash. Industry practice is to calculate arc-flash incident energy on a case-by-case basis so that field personnel are provided adequate flame-resistant safety clothing.



figure 4. A field crew working on energized lines at a Dominion Energy training facility. (Source: Dominion Energy.)

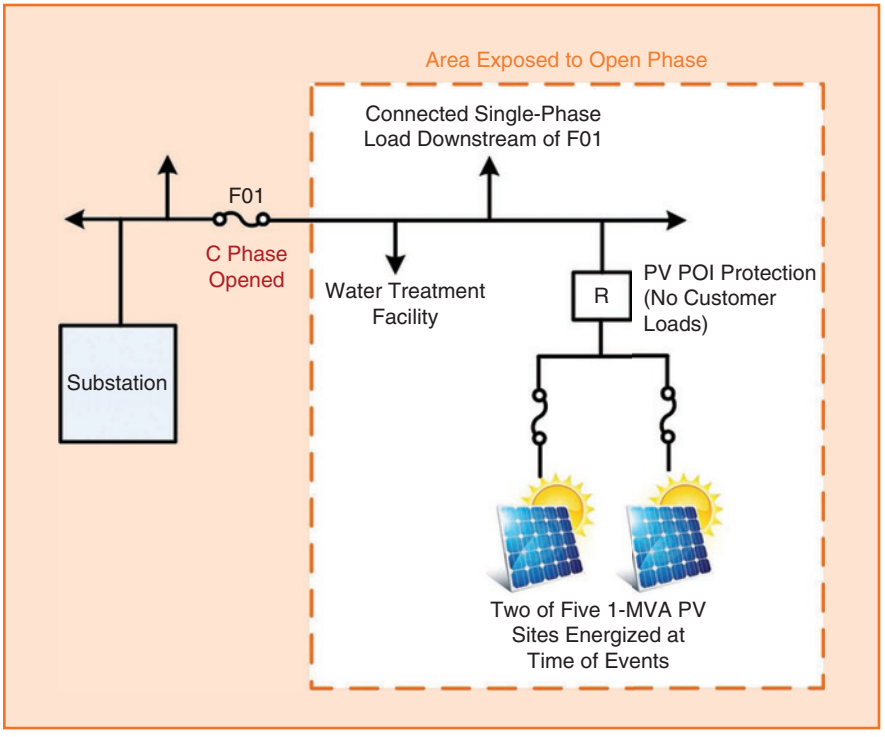

figure 5. An example of an open-phase event upstream from a PV plant. F01: phase C line fuse opened; R: site recloser.

DERs can increase arc-flash incident energy in two major ways. First, the step-up transformer windings, such MV wye-grounded and delta connection to the DER, provide a zero-sequence source. This setup can reduce ground current from the substation and delay fault clearing in the upstream protective device. Second, after loss of the grid source and prior to plant tripping, DERs can back-feed into the fault. This portion of arc-flash incident energy is correlated to the plant's run-on time before tripping.

PV plant mitigations for arc fault include neutral grounding resistors and recloser relay settings installed at the POI. Many utilities also enable high-speed fault clearing in feeder relays when crews are working on a line. Instantaneous clearing will largely reduce the fault-clearing time and the grid's contribution to arc-flash exposure.

Large PV plants integrated into the distribution system will often require protection coordination studies to determine both the feeder and plant relay settings. Design reviews and a commissioning process are also necessary to ensure that the solar power plant configurations meet protection requirements.

Single-Phasing Happens

Given three-phase feeders, what role will DERs play? Incidents of open phase (or single phasing on three-phase distribution circuits) can happen. This brings several concerns for PV plants. Depending on the transformer configuration and DER output to load, voltage on the open phase might be regenerated. During the open-phase incident, this leads to poor regulation or elevated voltages and can potentially expose the public to a live downed conductor.

These events are not rare in a distribution system with independent phase protection, such as single-phase reclosers. They can happen in a single-phase fault clearing if a single switch or fuse is open or when a conductor is broken. Figure 5 shows the case of a blown fuse.

The Role of DERs in Open-Phase Events

Although open-phase incidents are a concern without DERs, the addition of three-phase PV plants has led to an increase in reported incidents. One explanation is the increased number of fuses and plant-scale generation sources. Plant design, control of back-feed, and transformer connections all play a role. Behaviors vary among underground cables, different transformer windings, and the addition of supplemental grounding.

IEEE Standard 1547-2018 prohibits DERs from back-feeding into abnormal grid conditions, including open-phase events; however, detecting a plant high-side, open-phase event from the DER terminals can be challenging. Depending on the interconnection transformer windings (Δ, Y, or Yg), DER terminal voltage might remain within the normal operating range. Utilities have reported plant commissioning delays as a result of failures of open-phase field tests.

Table 1 shows field experience results from the commissioning of PV plants reported in EPRI 3002015949 in April 2019. These plants were built prior to the new IEEE 1547 standard. Typical solutions are the addition of primary-side, negative-sequence relays or inverter firmware changes. The referenced section of IEEE Standard 1547 requires DERs to "cease to energize and trip" immediately upon detection. A trip requires a 5-min delay time after voltage is restored.

Feeder open-phase incidents are problematic for PV plants, with or without DER back-feed. A voltage on the open phase can be recreated via plant transformer windings and in the case of cable capacitance. Figure 6 illustrates a plant layout where voltage on the open phase reached 1.2 per unit (p.u.) when inverters ceased to energize, leaving the ac filter connected. This is not unusual for installations requiring GTs and where MV cables add capacitance to the open circuit.

Modeling with GTs and cable capacitance indicates that steady-state, open-phase voltage reached 1.1–1.2 p.u. Without the cable capacitance and grounding, voltage on the open phase is typically lower, approximately 0.5–1 p.u. Table 2 summarizes the expected primary and secondary voltages for four common interconnection transformer winding and core types, assuming no load. The table shows the results both with and without GTs, without inverter and cable capacitance.

- ✔ *Yg primary/Yg secondary case*: With a local GT, steady voltage might appear on the open phase. The level depends on circuit capacitance and GT reactance. Without a GT and at low load, cable capacitance and no-load conditions can create a nonlinear resonance (ferroresonance).
- ✔ *Yg primary/Y secondary case*: Ferroresonance can be eliminated with an MV side GT.
- ✔ *Yg primary/Δ secondary case*: Effective grounding recreates 1-p.u. voltage on the open phase.
- ✔ *Δ primary/Yg secondary case*: Ferroresonance is more likely and severe.

table 1. A summary of open-phase test results showing 34 failures at 82 large PV plant sites.

Reasons for Failures	Ceased but restarted in <5 min	Did not cease to generate	Cease delayed >2 s	Open-phase voltage >1.1 per unit	Other reasons
Number of Failures	1	2	16	3	12
IEEE Standard 1547 Section	4.10.3[5]	6.2.2[6]			—

(Source: Xcel Energy; used with permission.)

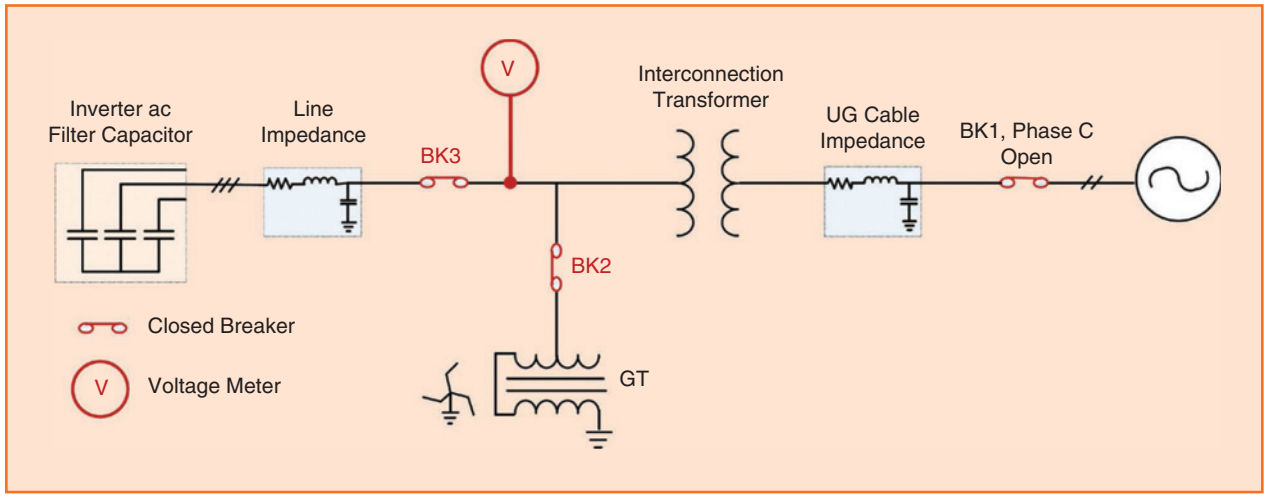

figure 6. A plant layout, from the feeder main line on the right to the PV plant on the left, with its protection devices (BK) and underground (UG) cable connection.

Detection Opportunity

Inverter-connected DERs can detect primary-side, open-phase events using negative-sequence components. EPRI has shown that such inverter detection methods are effective depending on the plant transformer connection and relative generation to load levels. Inverter detection may alert system operators for follow-up corrective measures if communication is added, as shown in Figure 7.

So far, with proper design, there can be no conflict between DER ride-through and open-phase detection; however, a delayed response may be needed to allow ride-through during unbalanced events. This delay, lasting up to 5 min, needs to be allowed during DER commissioning tests. Both passive and active detection methods are depicted in Figure 8. The relative effect of the interconnection transformer configuration is shown in Table 3.

Islanding-Prevention and Site Reclosing Practices

Should we let go of direct-transfer trip (DTT)? With deployment levels exceeding minimum loading in many locations, utilities must consider the effects of reverse power and the risk of unintended DER islanding when a grid connection is lost. Unintended islanding has been a long-standing concern in the United States, beginning with the U.S. Public Utility Regulatory Policies Act (PURPA) in 1978. Although interconnection rules for qualifying facilities have come a long way, the idea of unsupervised DER operation is still a key consideration for grid safety and reliability.

Since PURPA and, for the most part, still today, utility-grade relaying and communications have been required for synchronous machine-based and large PV plants. Conventional relay protections passively detect island conditions

table 2. The open-phase voltage with inverter ceases to energize.

Open-Phase Voltage	Transformer Type	Yg/Yg (5 leg)	Yg/Y (5 leg)	Yg/Δ	Δ/Yg
With GT and capacitance	Primary/secondary	1.2/1.18 p.u.	1.11/1.08 pu	N/A	1.38/1.21 pu
Without GT and with capacitance	Primary/secondary	Ferroresonance	Ferroresonance	~1 p.u.	Ferroresonance
Without GT and capacitance	Primary/secondary	0.6 p.u.	0.7 p.u.	1 p.u.	0.4 pu

N/A: not applicable.

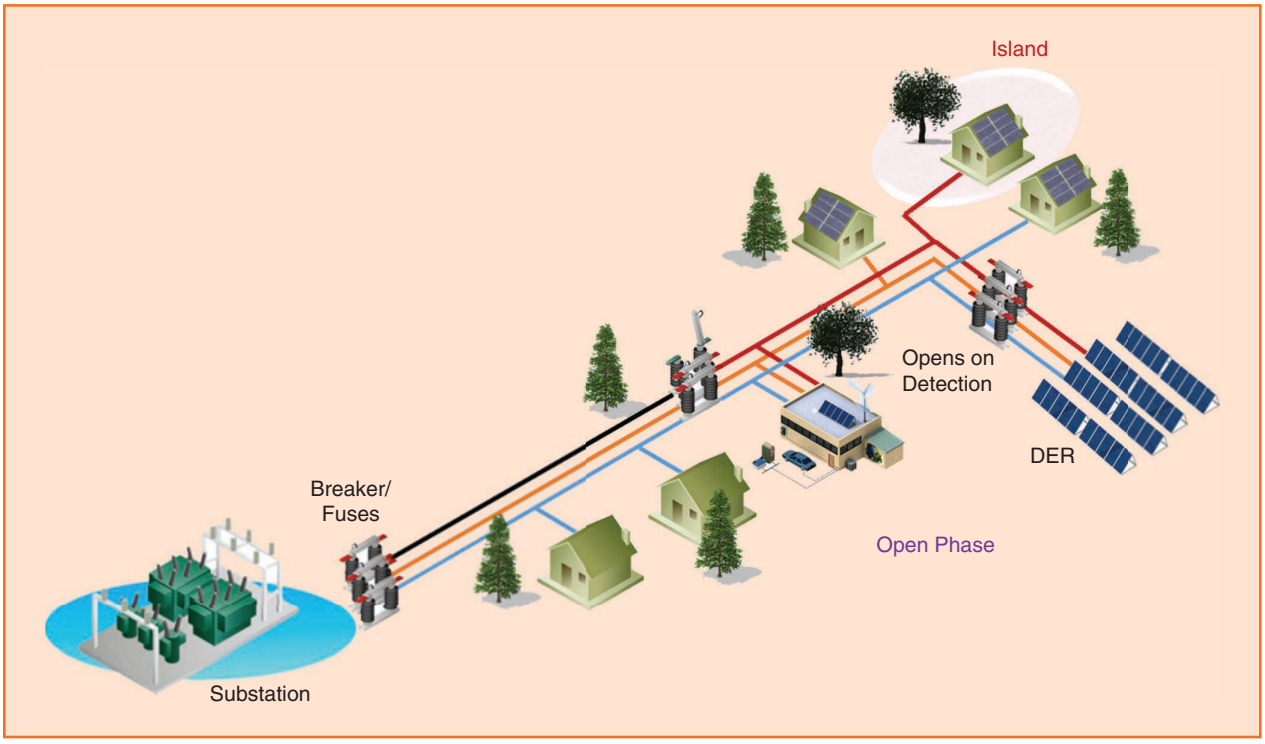

figure 7. An open-phase incident (midfeeder) detected by the downstream PV plant. (Source: EPRI.)

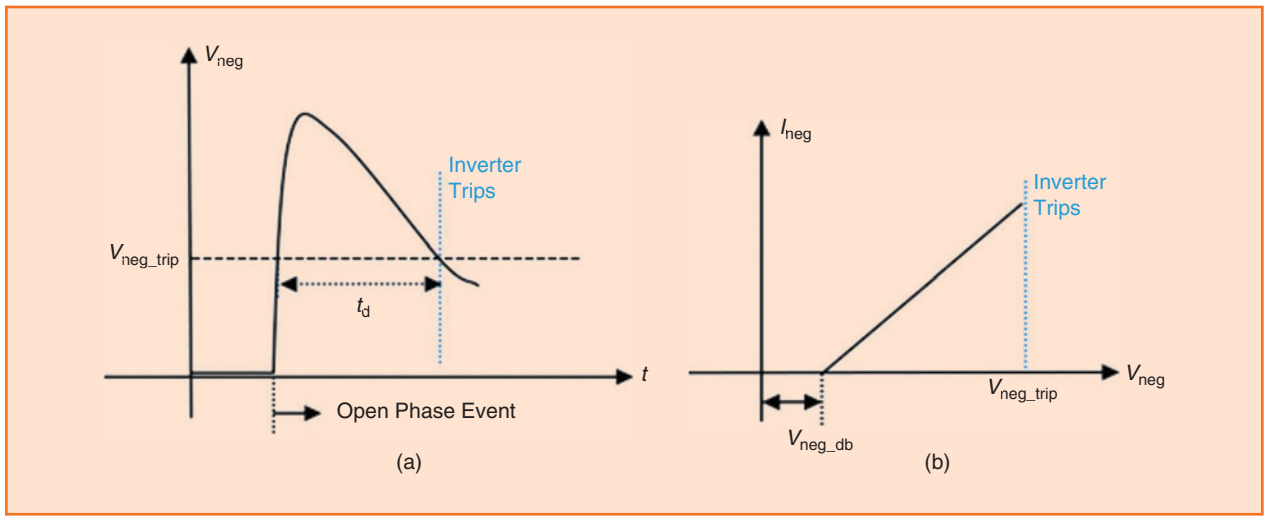

figure 8. Open-phase passive detection by (a) monitoring the reduction in negative-sequence voltage or (b) actively injecting negative-sequence current.

and are limited to voltage and/or frequency measurements without positive feedback.

Island-Prevention Practices

The common practice has been to augment local detection with DTT when an upstream protective device opens. DTT (or transfer-trip) systems are used to quickly disconnect DERs when a feeder breaker opens, usually at the substation; see Figure 9.

Island prevention using utility-controlled DTT is reliable and effective, but it is typically expensive for individual sites. It can be seriously impractical for high numbers of DER sites. Communications alternatives to copper and fiber are being considered, such as power line carrier and cellular. Also, practices extending the time for reclosing a main-line device are used in some areas with high DER penetration. Current practices to address DER islanding risk vary among utilities, as shown in Figure 10.

Pacific Gas and Electric Company (PG&E) and Dominion Energy participated in the survey, and the authors provided these additional details on their practices.

- ✔ In California, all investor-owned utilities follow California's Rule 21 for screening islanding concerns, even though risk varies among utilities, plant types, and feeder characteristics. For PG&E, supervisory control and data acquisition (SCADA) system-controlled reclosers have been used in cases of larger individual PV plants connected to a 12.5-kV distribution system. Although this approach is slower than conventional DTT, it provides cost-effective telemetry and plant disconnection for islanding. Reclosing is delayed for 10 s to coordinate with the SCADA system and reduce the risk of an out-of-phase connection. In addition, voltage reclose blocking might be applied on some devices. In this case, the line-voltage magnitude is checked to verify that it is de-energized, and the auto-reclosing is blocked if the voltage is ≥15% of the nominal voltage during the auto-reclosing attempt.

table 3. The effectiveness before and after IEEE Standard 1547-2018 depends on the transformer.

Open-Phase Voltage Cases	Transformer Type	Yg/Yg 5 leg	Yg/Y 5 leg	Yg/Δ	Δ/Yg
Passive detection	IEEE 1547A-2014	Good	Good	Poor	Good
	IEEE 1547-2018	Poor	Poor	Poor	Poor
Active detection	IEEE 1547A-2014	Better	Better	Good	Better
	IEEE 1547-2018	Good	Good	Good	Good

PG&E also evaluates aggregate DERs at substations and transmission line sections to ensure that the total does not present an islanding risk. This has been a primary concern because of high aggregate DER penetration and back-feeding into the transmission system (with related GFO concerns). DTT is normally required for all synchronous machines. These are common to power plants in the San Joaquin Valley and small hydropower units in the Sierra Nevada. For PV plants with onboard islanding-detection systems and certified to UL 1741SA, DTT is not required in most cases. These criteria may be updated based on ongoing review efforts as described in the Working Group 4 Final Report (see "For Further Reading").

- ✔ In U.S. states Virginia and North Carolina, Dominion Energy has experienced the deployment of many large PV plant connections on its 34.5-kV distribution feeder system. Islanding prevention is a high priority,

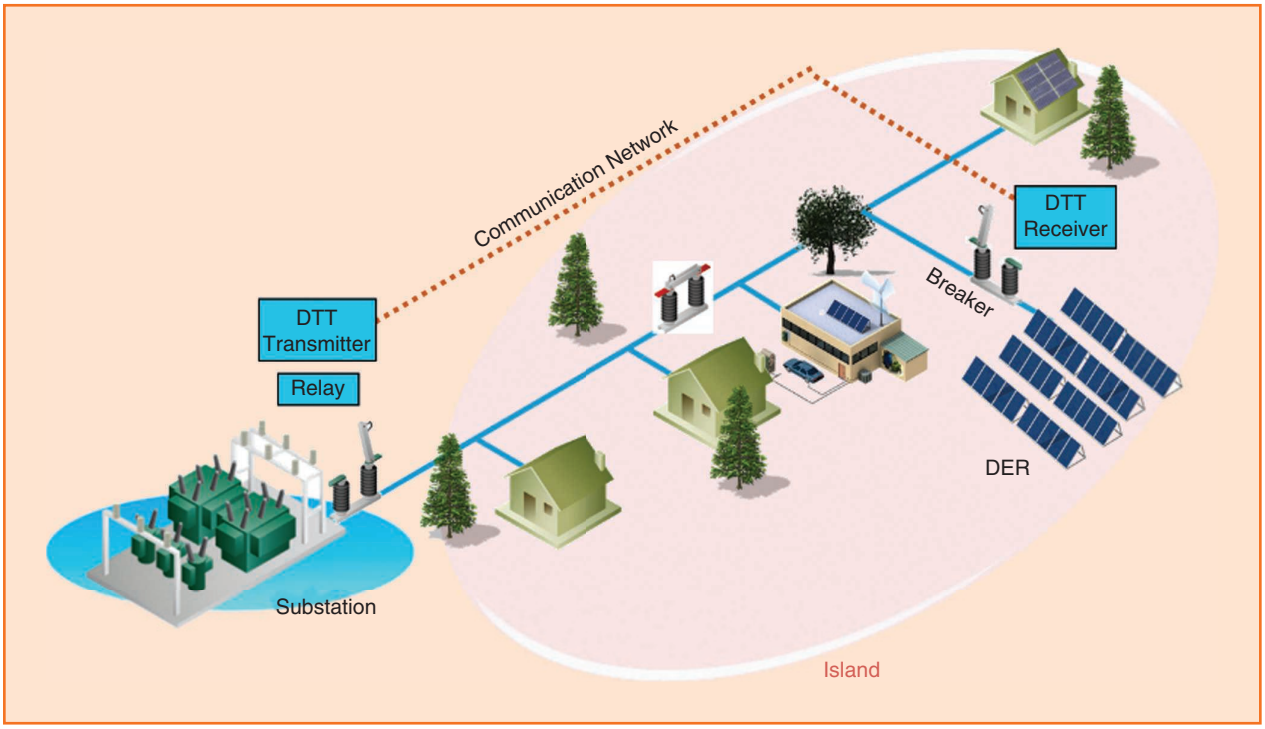

figure 9. The basic components of a DTT scheme. (Source: EPRI.)

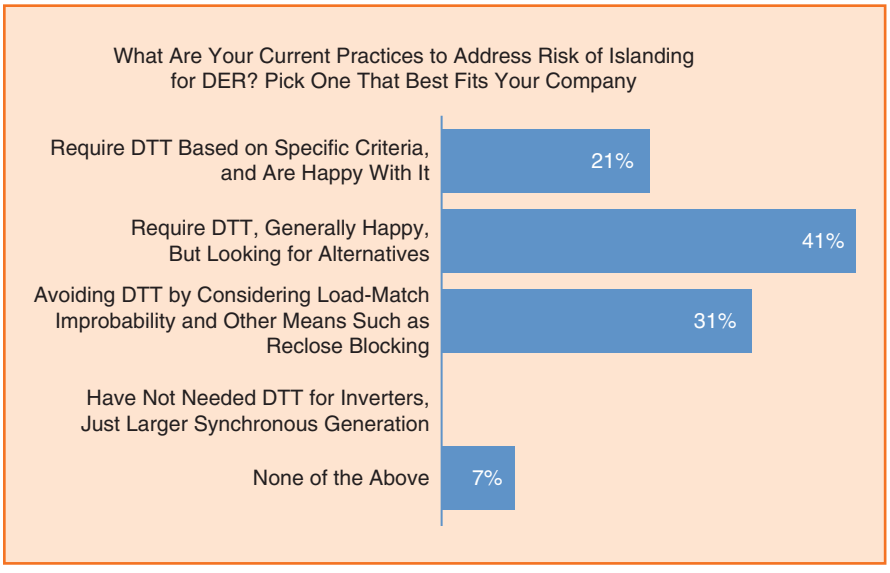

figure 10. A recent EPRI survey of 76 utilities regarding the application of DTT.

and practices are well established. When aggregate DER exceeds one-third of the minimum load on a line section, DTT is required. This DTT uses a permissive signal that fails to open if communications are lost for any reason. When certified PV plant aggregate DERs are less than one-third of the minimum load, the inverters' built-in protection for unintended islanding is relied upon. Automatic reclosing of the main-line sectionalizing device is allowed only when the POI recloser opening is caused by a fault (identified by the detection of abnormal low voltage or a momentary voltage sag). Reconnection of the DER plants is delayed until approximately 5 min after healthy voltage is detected.

Dominion Energy installs multifunction relays with reclosers including both revenue and power-quality (PQ) monitoring at the POI for sites larger than 1 MW. The two relays and meters are located on separate poles. These provide event oscillography for 1–2 s at 128 points per cycle. Setting the trigger properly offers excellent visibility. The investment in these multifunction relays provides the data necessary for forensic studies and has proven to be valuable. When any anomalies are detected, the PQ group installs sophisticated PQ meters for further investigation.

Updating Inverter Onboard Detection

Onboard active islanding detection is an important alternative for inverter-based DERs. Since IEEE Standard 1547-2003, it has been a requirement for the certification of DERs; however, the methods are often treated as proprietary information, and they are not well defined in specifications. Recent studies by EPRI and Sandia National

Unlike synchronous generators, solar inverters act as a positive-sequence source and, depending on design, have insignificant negative- and zero-sequence fault current.

Laboratories (United States) have considered IEEE Standard 1547-2018 grid support functions and fault ride-through requirements.

These studies found that some detection methods work better than others. The key outcomes were the definitions of generic islanding-detection methods. The studies addressed the performance evaluation of each method, including sensitivity to DER mix, system loading, and feeder characteristics. Ride-through and grid support functions were found to have a limited impact on the performance of active islanding detection methods.

Ride-through requirements have made previously developed Sandia guidelines for the assessment of unintended islanding risk less applicable with increasing DER penetration levels. In the past, 67% of generation/load and 1% var (reactive power) unbalance were reasonable criteria. With IEEE 1547-2018 category III ride-through, simple screening would require a conservative 25% of generation/load and 7% var unbalance criteria.

This work indicates that two things need to happen for the acceptance of onboard protection as an alternative to DTT. The first is for inverter manufacturers to identify which generic detection methods they are using. The second is for utilities to update island risk-assessment methods to account for new ride-through requirements. Certification is necessary but not sufficient. Assessments need to consider plant location and DER type, load/generation balance, number and type of grid loss events, and detection method details.

Coordination of Plant Site Recloser Practices

Directly related to DTT and DER ride-through, there is the need to coordinate relays that control plant-to-grid interconnection reclosers. Plant site multifunction relays installed with reclosers have the full range of protection setting options. Typically, these reclosers are required for operational on/off control of larger DER facilities. We found that, in many cases, they are also used as the disconnection means for a protection-grade DTT scheme. It is important that relays are set to respect DER plant ride-through requirements.

In another recent survey, we asked for current practices/relay settings at the DER plants. As shown in Figure 11, there were two main responses.

- ✔ The recloser is used for overvoltage/undervoltage and frequency trips, disconnection for momentary power loss, monitoring plant status, and ensuring time delay for re-energizing (48%).
- ✔ There is limited use of the recloser, mainly for on/off by the operator, not tripping in the case of grid momentary events or power loss, and to allow for immediate energization with the restoration of grid voltage (30%).

A good example of coordinating site recloser relays with DER site intertie protection functions is provided in Figure 12, courtesy of Southern Company Service. Tie-line reclosers are required by Southern for any plant of 1 MW or more (a very common threshold). When the DERs are connected via a low-side delta transformer or a zigzag GT, the DTT might also be integrated with the site recloser. For all cases, the settings allow for overvoltage/undervoltage and frequency ride-through.

Finally, when DERs are placed into grid service, they become a functioning part of the grid. This implies that the utility system depends on the DERs. The accuracy and

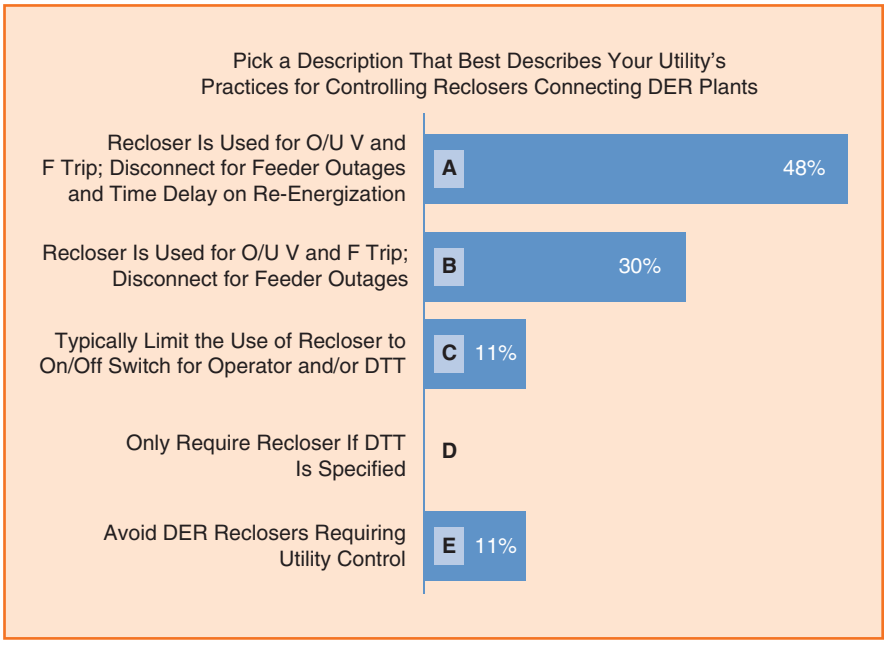

figure 11. The practices applied to DER site reclosers, with 76 utilities responding.

reliability of protective relays are essential; thus, most utilities require some form of commissioning/witness testing before connection to the system. Documentation of settings, one-line diagrams, and test reports need to be submitted to the utility for approval.

The Evolving Need for DER Analytics: New Challenges Require New Tools

Increasing PV and battery penetration levels will need the support of analysis tools. Just as DER planning tools have evolved (see Smith et al. in the "For Further Reading" section) there is a growing need for DER interconnection and operational tools. Here, we address several protection issues that would benefit from a handy analytic tool. Several evolving tools will support the assessment of DER short circuit coordination, arc flash, effective grounding, and risk of islanding.

Dominion Energy's Solar Monitoring Tool

DERs are integrated into the distribution circuits, where, historically, utilities have had the least amount of visibility. SCADA systems typically cover only distribution substations, and the time resolution of 2–4 s is inadequate for capturing transient dynamics. Additionally, solar power plants are usually located in remote areas (partially because of the inexpensive land), which makes onsite data collection a time-consuming task for field personnel. Meanwhile, as noted, it is of great interest to utilities to closely monitor DER performance and ensure safe and reliable operation. With the increasing size of solar power plants, there is a need for monitoring and data analytics infrastructure.

To improve the visibility of solar power plants, Dominion Energy developed a solar monitoring tool to collect disturbance event oscillography from measurement units located at POIs. Shown in Figure 13, the system takes advantage of cellular networks to transmit high-resolution waveform data from solar power plants to the utility's central server. The system provides real-time alerts for system operators so that timely actions can be taken to identify root causes and restore outages. The monitoring system also stores data and provides data analytics applications for

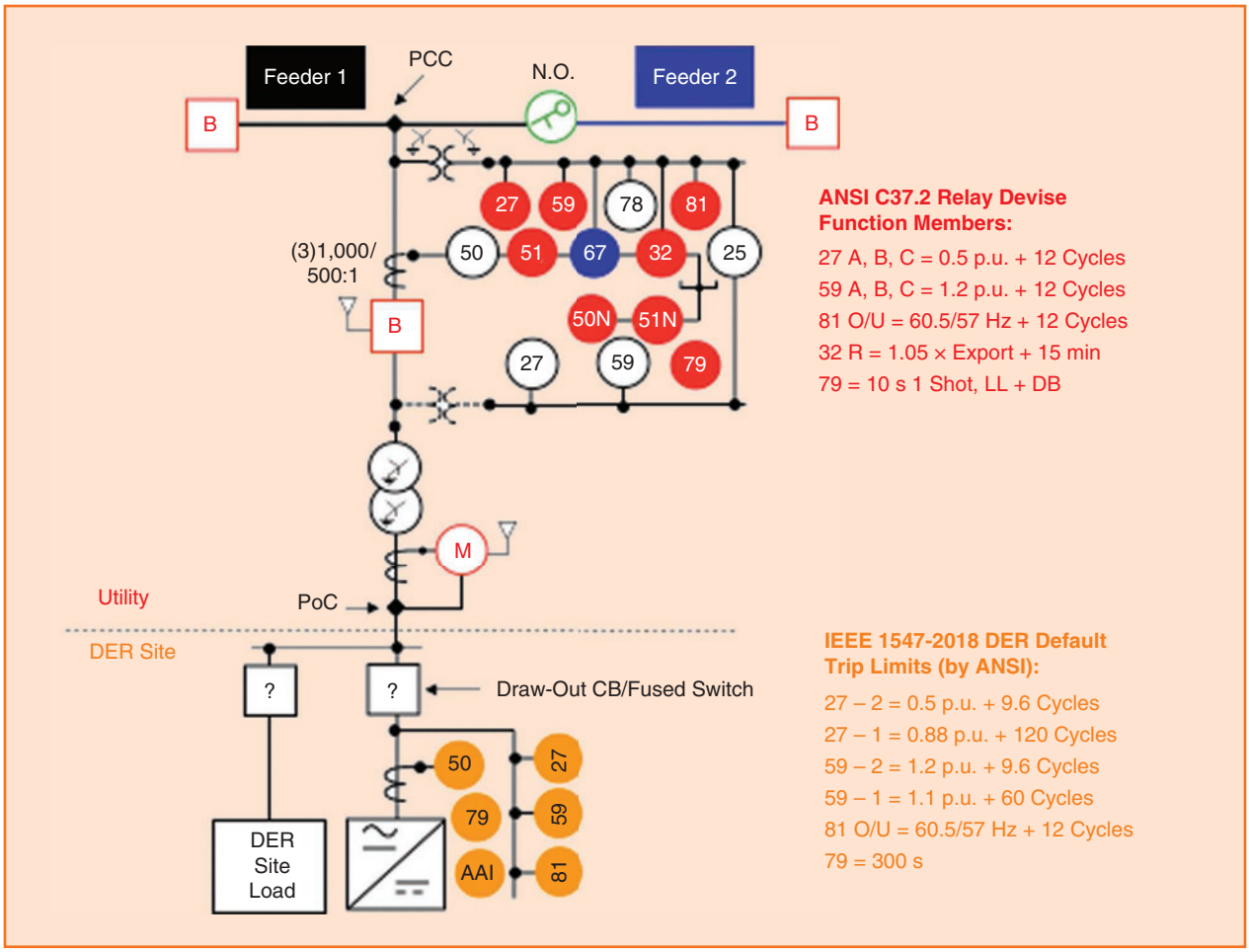

figure 12. The relays per ANSI Standard C37.2. Note that site relays might be integrated in inverter DERs. (Source: Southern Company Services.) AAI: active anti-islanding; PCC: point of common coupling with utility feeder; PoC: point of DER connection; N.O.: normally open; M: meter; CB: circuit breaker; O/U: over/under; LL: live line; DB: dead bus; B: breaker.

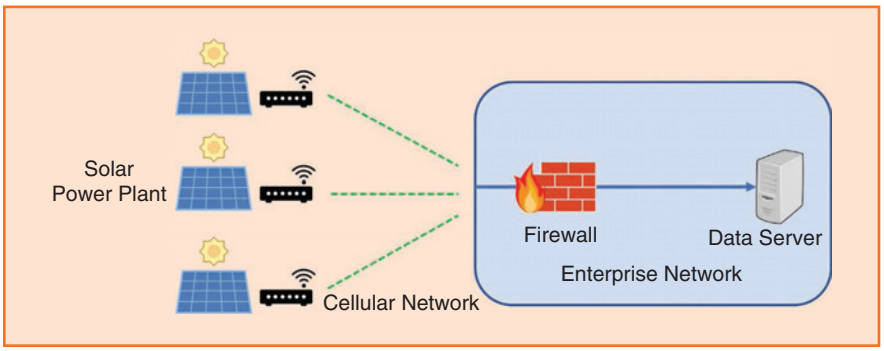

figure 13. The solar monitoring system developed by Dominion Energy.

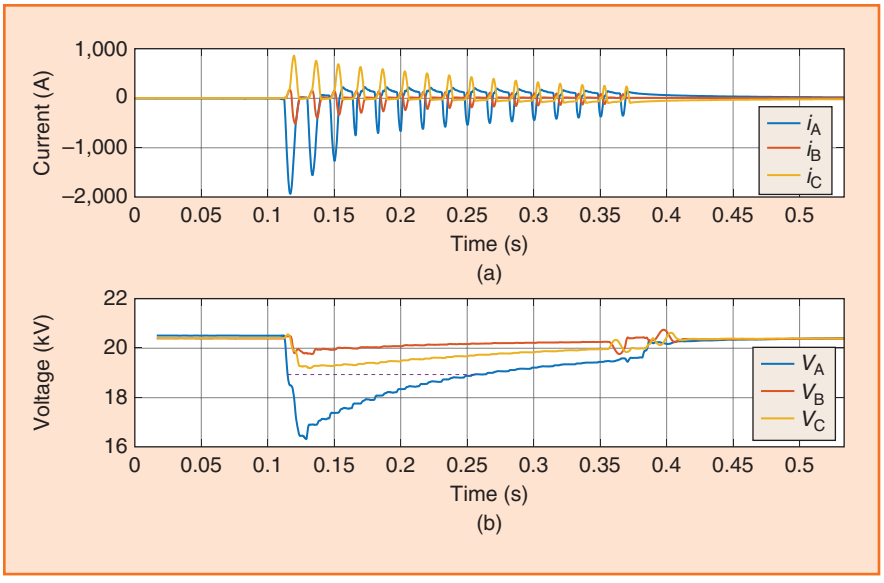

figure 14. Energizing the DER transformers induces inrush current and voltage sag.

engineers to take an in-depth look into solar generation's performance.

With regard to monitoring the PQ of solar power plants, energizing DER transformers creates inrush current that can momentarily depress circuit voltage. Such behaviors are not desirable because the induced voltage sag can affect the industrial and residential customers near the solar power plant. The transient is momentary in nature, with an average duration of six cycles, but it could reduce voltage to 70% of the nominal level. The SCADA system turned out to be incapable of monitoring such fast transients.

Unlike the SCADA system, the solar monitoring system is capable of collecting event oscillography from PQ meters with a reporting rate higher than 80 data points per cycle. This makes the fast transient phenomenon (see Figure 14) visible to utility engineers, and corrective actions can then be taken. Mitigation options include reducing energization events and installing preinsertion switches at the POI to alleviate inrush impact. The solar monitoring tool greatly improves the utility's situational awareness on its solar fleet to ensure successful solar integration.

For Further Reading

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Predictive-Maintenance Practices

By Richard Fioravanti, Kiran Kumar, Shinobu Nakata, Babu Chalamala, and Yuliya Preger



CHANGES IN THE DEMAND PROFILE and a growing role for renewable and distributed generation are leading to rapid evolution in the electric grid. These changes are beginning to considerably strain the transmission and distribution infrastructure. Utilities are increasingly recognizing that the integration of energy storage in the grid infrastructure will help manage intermittency and improve grid reliability. This recognition, coupled with the proliferation of state-level renewable portfolio standards and rapidly declining lithium-ion (Li-ion) battery costs, has led to a surge in the deployment of battery energy storage systems (BESSs). Although BESSs represented less than 1% of grid-scale energy storage in the United States in 2019, they are the preferred technology to meet growing demand because they are modular, scalable, and easy to deploy across diverse use cases and geographic locations.

As the number of BESS installations has increased, system integrators, utilities, government bodies, and professional organizations have put considerable effort into developing safety standards and best practices for engineering and commissioning. However, some recent safety incidents in the field have

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For Operational Safety of Battery Energy Storage Systems

led to total BESS destruction and posed risks to first responders. Despite the efforts of the energy storage industry to improve system safety, recent incidents show the need for a greater recognition of the limitations of current practices. For example, much of the effort has focused on improving safety at the cell and battery pack level. Additionally, risks that manifest during operation and the catastrophic failures arising from operator error or component failures have not received as much attention as the initial factory testing and commissioning of BESSs.

This article advocates the use of predictive maintenance of operational BESSs as the next step in safely managing ESSs. Predictive maintenance involves monitoring the components of a system for changes in operating parameters, which may be indicative of a pending fault. These changes signal the need for maintenance while the fault is still recoverable. Many industries, including utilities, use this maintenance approach for assets such as power plants, wind turbines, oil pipelines, and photovoltaic (PV) systems. However, this approach has yet to be fully explored and utilized for BESSs. Predictive monitoring is complementary to and should not replace safer system designs, which are essential for the real-time mitigation of catastrophic failures. However, when applied to BESSs, predictive monitoring can initiate actions that potentially prevent catastrophic failures from occurring. This article reviews current safety practices in BESS development, provides examples of predictive maintenance approaches in other industries, notes the key components of an effective approach, and describes the methodologies used to identify leading fault indicators.



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Current Recommendations and Standards for Energy Storage Safety

Between 2011 and 2013, several major grid energy storage installations experienced fires (see Figure 1). As a result, leading energy storage industry experts recognized that technologies and installations were beginning to outpace existing standards. In addition, although several energy storage technologies were available in the marketplace, Li-ion-based storage systems made up an increasing number of the installations. Of even greater importance was that the deployments were beginning to grow faster, especially in behind-the-meter residential and commercial applications. As such, a stronger focus on the safety of Li-ion-based storage systems took hold due to the fire potential of the batteries.

In 2014, the U.S. Department of Energy (DOE), in collaboration with utilities and first responders, created the Energy Storage Safety Initiative. The focus of the initiative included "coordinating DOE Energy Storage Systems Safety Working Groups with over 150 stakeholders from industries such as electric utilities, standards organizations, and manufacturing companies." These working groups

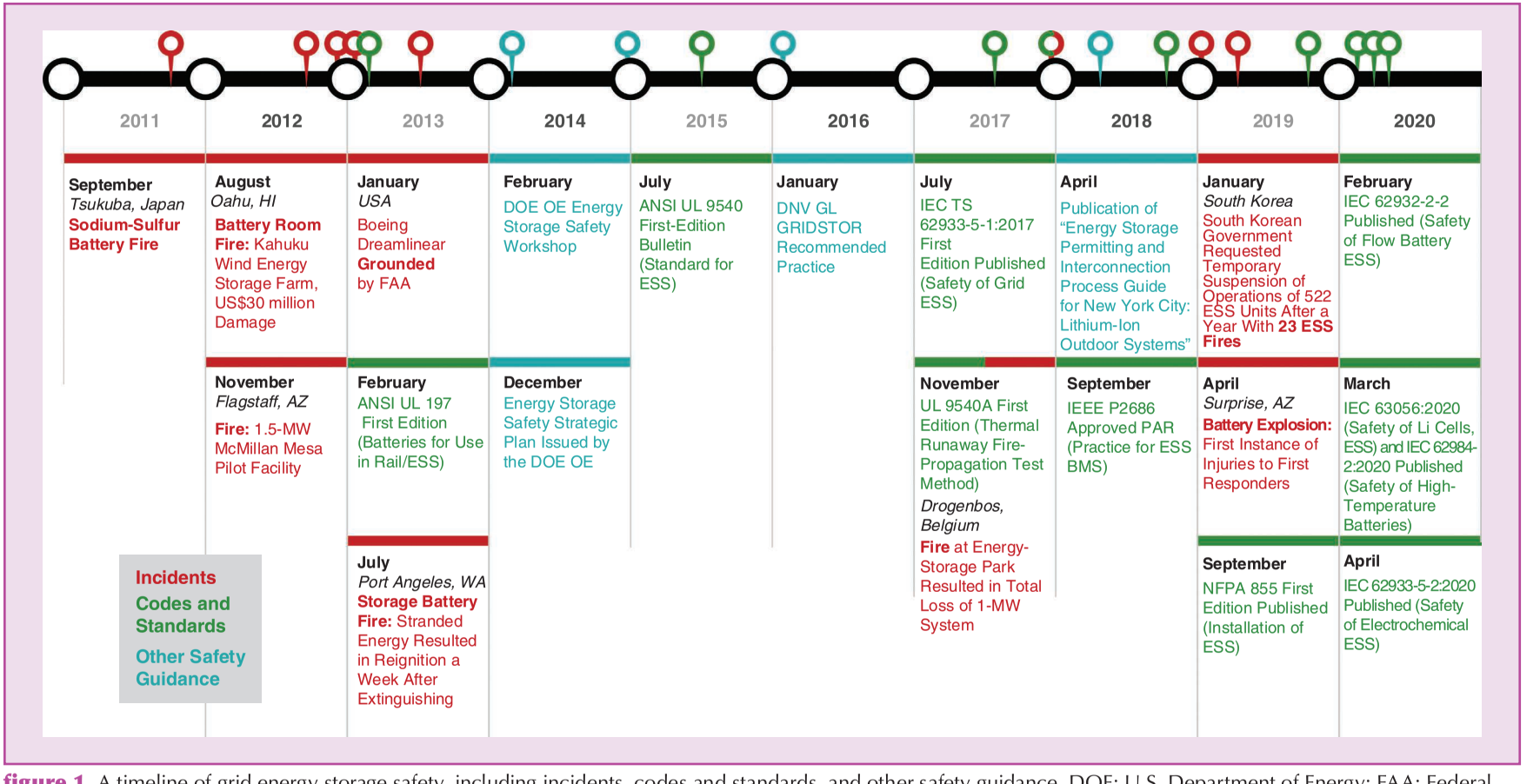


figure 1. A timeline of grid energy storage safety, including incidents, codes and standards, and other safety guidance. DOE: U.S. Department of Energy; FAA: Federal Aviation Administration; OE: Office of Electricity; PAR: project authorization request; NFPA: National Fire Protection Association.

"explored gaps in safety R&D; enabled the development of codes, standards, and regulations (CSR); and educated first responders on energy storage system safety." This was an initial attempt at bringing safety agencies and first responders together to understand how best to address ESS safety. In 2016, Det Norske Veritas (Norway) and Germanischer Lloyd (DNV GL) published the GRIDSTOR Recommended Practice on "Safety, Operation and Performance of Grid-Connected Energy Storage Systems." Other efforts included a collaboration between the New York State Energy Research and Development Authority, SmartDG Hub (led by the City University of New York), and the city of New York (with technical assistance from DNV GL, a testing and consulting company) which, in 2018, produced a process guidebook for BESSs: "Permitting and Interconnection Process Guide for New York City Lithium-Ion Outdoor Systems."

At the same time, many organizations were also developing or improving codes and standards to guide the design and installation of ESSs. Tables 1 and 2 categorize these standards into five groups: components, integrated systems, installation and commissioning, operations and maintenance, and incident preparedness. Despite the breadth of these standards, none provide significant guidance on whole-system preventive and predictive maintenance. Two of the most notable standards in the United States are UL 9540 (*Standard for Energy Storage Systems and Equipment*) and National Fire Protection

Association (NFPA) 855 (*Standard for the Installation of Stationary Energy Storage Systems*).

UL 9540 (first edition published with the American National Standards Institute in 2015) covers the safety of electrochemical, chemical, mechanical, and thermal ESSs. The document also incorporates ESS equipment for control, protection, power conversion, communication, and fire detection and suppression. UL 9540A (first edition in 2017) created a test method for evaluating thermal runaway fire propagation in BESSs.

The effort to develop NFPA 855 began in 2016 as ESS technology usage began to increase due to consumer, business, and government interest. The National Fire Protection Association received more than 600 public inputs and 800 public comments during the development process for the document, and the first edition was published in 2019. NFPA 855 focuses on mitigating risk by examining where ESSs are located, how installations are separated, and the suppression systems in place. The document considers ventilation, detection, signage, listings, and the emergency operations associated with ESSs and provides extensive requirements for ESS fire safety.

A working group of the International Electrotechnical Commission, Technical Committee 120/Working Group 5 Electrical Energy Storage Systems/Safety Considerations, has also developed two standards for integrated systems. IEC TS 62393-5-1:2017 specifies the safety considerations (e.g., hazards identification and risk assessment and mitigation) applicable to any grid-integrated ESS. The recently published IEC 62933-5-2:2020 focuses specifically on electrochemical ESSs—especially safety

table 1. Preinstallation codes and standards.

Components	
Secondary Cells and Batteries Containing Alkaline or Other Non-Acid Electrolytes—Safety Requirements for Secondary Lithium Cells and Batteries for Use in Electrical Energy Storage Systems	IEC 63056:2020
High-Temperature Secondary Batteries—Part 2: Safety Requirements and Tests	IEC 62984-2:2020
**Recommended Practice for Battery Management Systems in Energy Storage Applications*	IEEE P2686 and CSA C22.2 No. 340
**Standard Communication Between Energy Storage System Components*	MESA-Device Specifications/ SunSpec Energy Storage Model
Molded-Case Circuit Breakers, Molded-Case Switches, and Circuit-Breaker Enclosures	UL 489
Standard for Electrochemical Capacitors	UL 810A
Standard for Lithium Batteries	UL 1642
Inverters, Converters, Controllers, and Interconnection System Equipment for Use With Distributed Energy Resources	UL 1741
ANSI/CAN/UL Standard for Batteries for Use in Stationary, Vehicle Auxiliary Power, and Light Electric Rail (LER) Applications	UL 1973
Integrated Systems	
Electrical Energy Storage (EES) Systems—Part 5-1: Safety Considerations For Grid-Integrated EES Systems—General Specification	IEC TS 62933-5-1:2017
Electrical Energy Storage (EES) Systems—Part 5-2: Safety Requirements For Grid-Integrated EES Systems— Electrochemical-Based Systems	IEC 62933-5-2:2020
Flow Battery Energy Systems for Stationary Applications—Part 2-2: Safety Requirements	IEC 62932-2-2
IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems	IEEE 519
Standard for Interconnection and Interoperability of Distributed Energy Resources With Associated Electric Power Systems Interfaces	IEEE 1547
**Standard Communications Specification for Utility-Scale Energy Storage System*	MESA-ESS
Standard on Explosion Protection by Deflagration Venting	NFPA 68
Standard on Explosion Prevention Systems	NFPA 69
ANSI/CAN/UL Standard for Energy Storage Systems and Equipment	UL 9540
Test Method for Evaluating Thermal Runaway Fire Propagation in Battery Energy Storage Systems	UL 9540A

MESA: modular energy storage architecture.
*Under development.

measures—to mitigate hazards such as fire, explosion, and the retention of toxic gases and liquids.

Efficient safety testing and evaluation of grid-scale BESSs in accordance with the aforementioned standards is a key part of the development process for new systems. Typically, test facilities are outfitted for battery module or rack-level propagation studies. Figure 2 shows an example of a unique indoor test facility for a complete system at the National Laboratory

table 2. Installation and postinstallation codes and standards.

Installation and Commissioning	
Standard for the Installation of Stationary Energy Storage Systems	NFPA 855
Transportation Testing for Lithium Batteries	UN 38.3
Safety of Primary and Secondary Lithium Cells and Batteries During Transport	IEC 62281
Standard for Competency of Third-Party Field Evaluation Bodies	NFPA 790
Standards for Securing Power System Communications	IEC 62351
Fire suppression	NFPA 1, NFPA 13, NFPA 15, NFPA 101, NFPA 850, NFPA 851, NFPA 853, NFPA 5000, International Building Code (IBC), IFC, and state and local codes
Ventilation and thermal management of batteries for stationary applications	IEEE/ASHRAE 1635, IMC, UMC, and state and local codes
Egress/access/illumination (operating and emergency), physical security, fire department access, fire and smoke detection/containment	NFPA 1, NFPA 101, NFPA 5000, IBC, IFC, and state and local codes
Buildings, enclosures, and protection from the elements	IEC 60529, UL 96A, NFPA 5000, IBC, and state and local codes
Signage	ANSI Z535, IEEE C-2, NFPA 1, NFPA 70E, NFPA 101, NFPA 5000, IBC, IFC, and state and local codes
Emergency shutoff	IEEE C-2, NFPA 1, NFPA 101, NFPA 5000, IBC, IFC, and state and local codes
Spill containment, neutralization, and disposal	NFPA 1, IPC, UPC, IFC, IEEE 1578, and state and local codes
Electrical safety	IEEE C-2 (National Electrical Safety Code), NFPA 70E, FM Global DS 5-10, DS 5-1, and DC 5-19
Communication Networks and Systems for Power Utility Automation	IEC 61850
Seismic requirements, design, and testing	IBC, California Building Code, IEEE 693, ACI 318-05, and ACSE 7-10
Standard for Commissioning of Fire Protection and Life Safety Systems	NFPA 3
Standard for Commissioning	ICC 1000
Operations and Maintenance	
Standard for Electrical Safety in the Workplace	NFPA 70E
Recommended Practice for Electrical Equipment Maintenance	NFPA 70B
Hazardous Materials Code	NFPA 400
Incident Preparedness	
IEEE Guide for Substation Fire Protection	IEEE 979
Guide to the Fire Safety Concepts Tree	NFPA 550
Standard System for the Identification of the Hazards of Materials for Emergency Response	NFPA 704
Guide for Fire and Explosion Investigations	NPFA 921

IFC: International Fire Code; IMC: International Mechanical Code; UMC: Uniform Mechanical Code; ASHRAE: American Society of Heating, Refrigerating and Air-Conditioning Engineers; ICC: International Code Council.

> Predictive monitoring is complementary to and should not replace safety system designs, which are essential for real-time mitigation of catastrophic failures.

for Advanced Energy Storage Technologies (NLAB) of the National Institute of Technology and Evaluation in Japan. This NLAB Large Chamber is used to test containers up to 53 ft (16 m) in length under controlled thermal and wind velocity conditions (the first facility in the world to do so).

The guidelines under development include IEEE Standard P2686, *Recommended Practice for Battery Management Systems in Energy Storage Applications* (set for balloting in 2022). This recommended practice includes information on the design, installation, and configuration of battery management systems (BMSs) in stationary applications. The document also covers battery management hardware (e.g., grounding and isolation), software (e.g., algorithms for optimal control), and configuration. More recently, the Modular Energy Storage Architecture (MESA) Standards Alliance, consisting of electric utilities and energy storage technology providers, has worked to encourage the use of communication standards and advanced interoperability as well as the reduction of the engineering effort required to integrate an ESS into a utility. MESA is developing two standards: one that defines the communication between ESS components and another that defines the communication requirements for utility-scale ESSs. These standards include parameters for inverters, meters, general ESSs, BESSs, and Li-ion BESSs under various operations.

Gaps in the Current Approaches to Safety

Despite the depth of these collective efforts to understand and mitigate the causes of BESS failure, catastrophic failures continue to occur in the field. In 2019, South Korea initiated a study to determine the leading causes of 23 BESS fires that had occurred since April 2017. The country's Ministry of Industry formed an investigation committee of academics, research institutions, laboratories, and ESS industry experts. In the initial cases examined, cells or battery modules were not believed to be the root cause of the failure. As reported in the press at the time, the investigation identified four main causes of failure:

1) *A lack of battery protective systems for electric shock*: Systems were not able to properly protect dc contactors from the electrical hazards arising from overvoltage or overcurrent.
2) *Insufficient management of the operating environment*: Most of the installations were in mountainous or coastal areas. These environments exposed the BESSs to harsh conditions, including large temperature swings and high humidity, that could damage insulation and cause fires.
3) *Faulty installations*: Human error during installation could have led to system faults, resulting in ESS fires.
4) *A lack of ESS integrated control and protection systems*: Gaps in the integration of the BMS and energy management system (EMS) may have caused the fires.

The conclusions of the investigation raise the following question: When it comes to the next stage of failure analysis for ESSs, how can the industry further improve operations to reduce incidents in the field? Some of the issues noted in the South Korea investigation were not captured by standards, and there was no mechanism for identifying and fixing problems or design issues after the installation.

Currently, the industry certifies ESSs based on defined sets of codes and standards. This certification focuses on the overall design review of the core ESS, testing for adherence to standards before shipment, and commissioning once the unit is installed in the field. Ideally, the certification process ensures that the overall system design is sound, the factory testing makes certain that the unit was constructed correctly, and the commissioning test confirms that there were no faults created or discovered immediately after the unit was installed at the site. Nevertheless, gaps remain in maintaining the unit after installation and identifying potential failures that may occur in the longer term. In short, there is not much guidance on what to do on day 2 after a project is completed.



figure 2. An example of a full-scale ESS testing facility, the National Laboratory for Advanced Energy Storage Technologies' (NLAB) "Large Chamber," operated by the National Institute of Technology and Evaluation, Japan.

Continuous monitoring of the system post-installation is needed to facilitate maintenance and ensure that problems are identified and addressed before they can lead to cascading failures.

Continuous monitoring of the system post-installation is needed to facilitate maintenance and ensure that problems are identified and addressed before they can lead to cascading failures. Systems can be monitored by a BMS, but designs are not standardized, and owners/operators may not have ready access to critical information. Also, the inability of management systems to "connect the dots" among large quantities of data may cause systems to fail. IEEE P2686 may address some of these gaps. Still, current failure-response mechanisms usually lead to total BESS destruction. ESS hazard-mitigation techniques are primarily designed to protect human safety, which certainly needs to be the focus. These responses (e.g., water quenching) will often render the system unrecoverable, making the mitigation just as catastrophic (in a technical sense) as the initial event. Thus, we advocate the development of a framework for the predictive maintenance of operational BESSs as the next critical step in the safe deployment of ESSs.

Improving Operations Through Predictive Maintenance

Preventive and predictive maintenance are mature concepts for operational systems in industry. Operators complete preventive maintenance on a routine or timed schedule (weekly, monthly, annually, and so forth) based on the average or expected lifetime statistics for equipment. By contrast, predictive maintenance is carried out when needed based on the actual condition of the equipment. Components are monitored for changes in the operating parameters that may be indicative of a pending fault, and these changes prompt intervention.

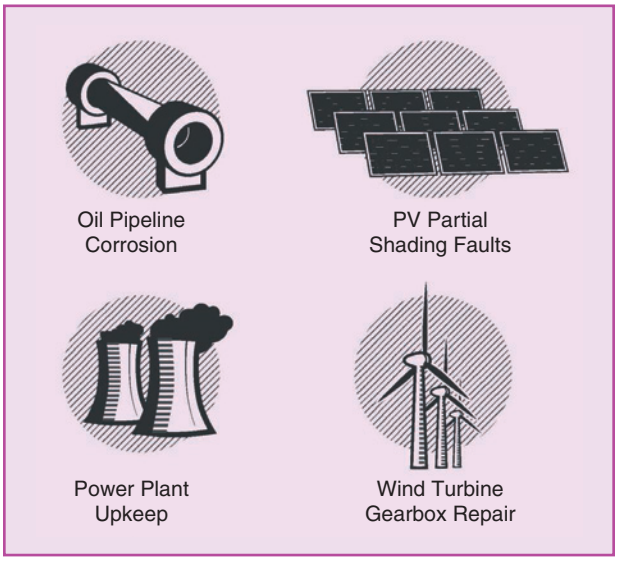


figure 3. Applications of predictive maintenance for other systems.

Some organizations have offered general guidance on preventive maintenance for BESSs. For example, an Energy Storage Safety 101 presentation during a May 2020 meeting of the California Energy Storage Alliance recommended semiannual steps such as visually inspecting the overall system; examining heating, ventilation, and air conditioning (cooling); and checking ESS software control and communications. An annual process similar to commissioning was also proposed. A 2019 *Energy Storage News* report on operations and maintenance noted that the Smarter Network Storage Project, a 6-MW/10-MWh battery system, receives a six-month checkup to ensure optimal performance (including identifying battery degradation levels, pushing software upgrades, and inspecting the power conversion system). In the same report, a representative from an ESS integrator noted that much of their maintenance involved software updates. BMSs implement safety functions and controls that depend on algorithms, sensor data, and system parameters. Furthermore, BMSs and inverters must communicate to coordinate control actions and responses to faults and warnings. Therefore, any software or firmware update glitches in either of those components can impact the effectiveness of safety features, leading to potential BMS malfunction and damage to batteries. Periodic software patching also ensures that systems are protected from known cybersecurity vulnerabilities.

Although helpful, preventive maintenance may be an oversimplification of what is required for maintaining complex systems and preventing failures. Here we define a *complex system* as one with many interacting components where it is difficult to comprehensively model all of the behaviors due to the dependencies, relationships, and all other interactions between these components. In complex systems, faults are less apparent and may not be visually identified or fixed by a routine procedure. Hence, complex operations for other systems (see Figure 3) often rely on predictive techniques, which are yet to be fully explored for BESSs.

Predictive analysis involves understanding how all of the components in a system fail and then actively monitoring the components for failure criteria. A 2019 report by GlobalData, "Predictive Maintenance in Power," noted several successful implementations of this approach in the utilities sector.

The nascent state of the industry also means reduced data on fault patterns, especially due to limited public knowledge exchange, making data analytics more difficult.

- ✔ The monitoring and diagnostics center at American Electric Power identified warning signs of failure and initiated repair work of a gas turbine blade before breakdown, resulting in savings of approximately US$19 million.
- ✔ Duke Energy used predictive analytics for the early detection of a crack in a turbine rotor. This resulted in savings of over US$7.5 million.
- ✔ Southern Company applied predictive analytics to power station models to decrease unexpected maintenance and maintain data quality reliability, resulting in savings of approximately US$4.5 million.
- ✔ Many wind turbine operators now use predictive analytics to monitor the health of gearboxes. The cost of gearbox failure can be upward of US$350,000 per incident.

Despite these and other successes, both business and technical challenges hinder a broader adoption of predictive maintenance in BESSs. From a business perspective, the energy storage industry is relatively young. Thus, business priorities and budgets do not always motivate investment in "soft" engineering methods such as data analytics and artificial intelligence-based services. The nascent state of the industry also means reduced data on fault patterns, especially due to limited public knowledge exchange, making data analytics more difficult. Furthermore, the pressure to keep the cost per kilowatt hour as low as possible means less investment in the sensors and infrastructure needed to process large volumes of data.

In terms of technical challenges, predictive maintenance techniques tend to be used for mechanical systems where factors such as "wear and tear" can be readily measured and monitored. For electronic systems, predictive practices may be more difficult to apply. Rather than wear out, electronic components are more likely to have a binary failure profile. An issue with one component may manifest itself downstream and result in the failure of another component, requiring data collection from multiple points to identify a pending failure.

Implementing predictive monitoring in conventional BESS hardware is also difficult due to limitations in communication channel availability and the processing power of battery/energy management devices. In a BESS, predictive monitoring would involve processing data from battery racks and the overall system to identify failure indicators. Ideally, the BMS of an energy storage device should have the ability to assist in this area; however, not all current BMSs are designed to recognize faults occurring outside of the immediate impacts on the battery itself (e.g., cells and modules) and may not have the throughput to process all the data. Predictive analysis must also depend on data from the EMS to understand the system's behavior. Current EMSs are often intended for dispatching/controlling multiple grid resources and do not include the necessary monitoring and safety functions to manage single or multiple BESSs. EMSs often lack direct communication with BMSs, and any fault detection by the BMS may not get communicated to the EMS, limiting preventive actions from system operators. Current standards have not addressed this issue.

A properly designed monitoring approach for operational ESSs will create indicators that can provide characteristics such as those listed in Table 3. The overall goal is clear: identify the indicators of potential faults and preemptively intervene on an operational ESS without making the intervention itself a problem. However, the links and causal relationships between faults and indicators and the potential of those early faults to lead to larger faults are not readily apparent at this early stage of the BESS industry. Ultimately, stakeholders must establish a methodology for identifying the indicator-fault relationships that can be tracked and monitored in these systems.

Creating a Predictive Maintenance Approach for BESSs

The sophistication of approaches for identifying useful "flags" or fault indicators has evolved substantially. In the most basic, reactive approach, these indicators are based on near misses reported by employees. All data are significant

table 3. The key characteristics of indicators for predictive monitoring.

Element	Description
Time element	• Days of warning rather than minutes or hours • Not all faults will have long lead times, but anything that can extend the timeframe can minimize destructive failures
Actionable warnings	• Point to the components that need to be replaced • Allow time for the examination of areas causing the warning to occur
Recoverable actions	• Safety measures intended to prevent catastrophic failure and threats to human safety can ultimately destroy the unit (unrecoverable) • Recoverable action must have minimal impact on the system

During the design phase, system integrators develop the product based on institutional or historical knowledge; however, the use cases the system encounters in the field could lead to new fault indicators.

and can be useful in preventing future failures. Hence, we recommend a culture where the reporting of near misses is encouraged. More rigorous approaches involve 1) leveraging indicator-fault links established during the system-design phase and 2) combining with additional indicator-fault links from the analysis of operational data on fielded systems. The identification of these links is an iterative process. During the design phase, system integrators develop the product based on institutional or historical knowledge; however, the use cases the system encounters in the field could lead to new fault indicators. Thus, the predictive maintenance approach should be scalable to adapt to new "patterns" with minimal impact on the overall system cost and availability. The following section elaborates on this two-layer approach for identifying indicator-fault relationships during the design phase and based on the data analytics for fielded systems.

Identifying Indicator-Fault Relationships During the Design Phase

It is expensive to retrofit a fielded system. Thus, the first step during the design phase is to make a deliberate decision to sense critical information and obtain as much data as possible to provide insight into various failure modes. Next, the process requires

1) the creation of a comprehensive listing of recoverable battery system faults and the linking of faults to leading indicators. This begins with thoughtful engineering consideration of the system design; however, the designer should complement this consideration with a collection of historical data from key developers, operators, and manufacturers.
2) the determination of whether indicators are already being tracked through current BMSs, EMSs, or any plant controllers.
3) the finalization of a list of indicators and criteria to be monitored to reduce the field failures of BESS equipment.

This is a beneficial process to leverage, although there may be gaps when new failure modes are identified or the process does not account for the design errors or field/environmental degradation that could lead to failures.

The industry has many well-established processes for system design, including various probabilistic risk assessment (PRA) approaches (e.g., failure modes and effects analysis, fault tree analysis, and so on) and systems-theoretic process analysis (STPA). It is important to note the nuances from processes created from a system-safety perspective. These processes are rooted in historical data, where the mechanism of a past failure is identified to improve designs and prevent a similar failure from occurring in the future. To contribute substantially to predictive maintenance, however, the system-design process also needs to establish the monitoring criteria that can be used in maintaining device operation.

PRA, built from a foundation of risk management, is the most widely used safety engineering method. A PRA approach identifies hazards, their deterministic causes and consequences, and provides a method of describing uncertainty. The process enables the calculation of *expected risk* (defined as the probability of an event multiplied by the relative severity of its consequences) so that a developer can compare different design options. PRA uses fault and event tree analysis to break a complicated system into subsystems and components when there is insufficient data to directly predict behavior. Risk is then increased or decreased based on how failures in components and subsystems operate together to generate accidents.

Additionally, failure modes and effects analysis (FMEA) is a systematic procedure for assessing reliability and how component failures can impact system safety. Developers begin an FMEA by compiling a list of each component or type of component in a system. Then they calculate the probability of each component failing in a variety of ways based on historical data. Table 4 shows a brief list of typical FMEA calculations for a BESS (adapted from an Electric Power Research Institute report on ESS safety). The probability and severity each receive a score of 1–10, with 10 corresponding to a more probable or severe event. Each failure mode is linked to a hazard effect, consequence, method of prevention, and method of detection. The identification of the detection method lays the foundation for predictive maintenance. It is apparent, however, that this conventional FMEA approaches system design from a safety perspective (preventing catastrophic failure) rather than detecting faults while they are still recoverable. The process creates a probability but does not provide the leading indicators necessary to flag pending failures of the areas. Still, these processes are beneficial in understanding what areas to focus on when creating indicator-fault relationships.

A more recently developed design tool, STPA, views a system as a collection of interacting control loops. Accidents happen when the component interactions in these loops violate safety constraints. Unlike PRA-based tools, it does not rely on any component failure rate data. Thus, this

methodology is valuable in the development of new, complex systems. STPA is conducted in four parts:

1) Identify the accidents and hazards to be prevented in the system.
2) Draw all the control structures in the system.
3) Determine unsafe control actions.
4) Identify causal scenarios, i.e., linkages, between faults.

This fourth step can lead to the relevant indicators for predictive maintenance. Rosewater and Williams in the "For Further Reading" section provide a more detailed explanation of this process.

Different companies prefer different methodologies during the system-design phase. In the previous section, we provided a few examples rather than recommending a specific approach. Many methodologies are rooted in the (appropriate) foundation of protecting human safety, with hazard-mitigation responses that tend to render the system unrecoverable. Predictive monitoring accepts that faults may occur through degradation due to long-term operation or from the impact of an external issue that may damage a component. Predictive maintenance requires identifying the cascading chain of faults that leads to failure and specifying which faults are recoverable.

Identifying Indicator-Fault Relationships Using Data Analytics on Fielded Systems

The second layer of identifying indicator-fault relationships for predictive maintenance involves using field data. During the design phase, developers evaluate the system based on institutional or historical knowledge; however, they may not be aware of everything they need to consider. With data analytics, the goal is to process field data and examine them from different perspectives to identify new relationships. The original system design may not have coverage of all the necessary signals, so a developer may need to integrate different data sets to understand what is going wrong. Once a developer identifies a new indicator-fault relationship from the postprocessing of field data, it becomes another signal to respond to in real time.

Figure 4 offers a case study for developing such a predictive maintenance approach from system integrator NEC Energy Solutions. The company first used FMEA during the system-design phase to identify critical components and failure pathways and determine data needs. Their cloud infrastructure enables data collection and storage from BESSs deployed around the world. Historical data from all the sites are used in predictive-analytics algorithms. One algorithm, used to identify anomalies in battery modules, parses historical data from each rack for a site and associates indicators in the rack data (e.g., cell voltages, current, battery capacity, and operation hours) with system operations. These anomalies represent recoverable issues that could potentially lead to nonrecoverable faults. Examples include capacity degradation or a cell short circuit/thermal runaway that causes a system fire hazard (to date, NEC installations have not experienced any catastrophic events or fire hazards). Notifications about this anomalous behavior prompt further analysis to remove any false positives. If the engineers identify a real anomaly, they place the offending battery rack out of service until the module is replaced. In summary, predictive maintenance has allowed NEC to identify misbehaving battery modules before they trigger safety hazards, negatively impact system availability, or reduce system capacity. The approach has also led to a reduction in maintenance costs by allowing the service team to plan visits more efficiently in each geographic region.

Opportunities for Collaboration in Identifying Indicator-Fault Relationships

Because the goal of predictive maintenance is to reduce catastrophic outages of ESSs and improve safety, the tools for the process must be available to all BESS operators. The most critical asset is a comprehensive list of indicator-fault relationships. System integrators can identify some of these relationships during the system-design phase; however, substantial data sets for further analytics are not broadly available. In some cases, these data may be considered

table 4. An excerpt from a conventional, safety-focused FMEA for a BESS.

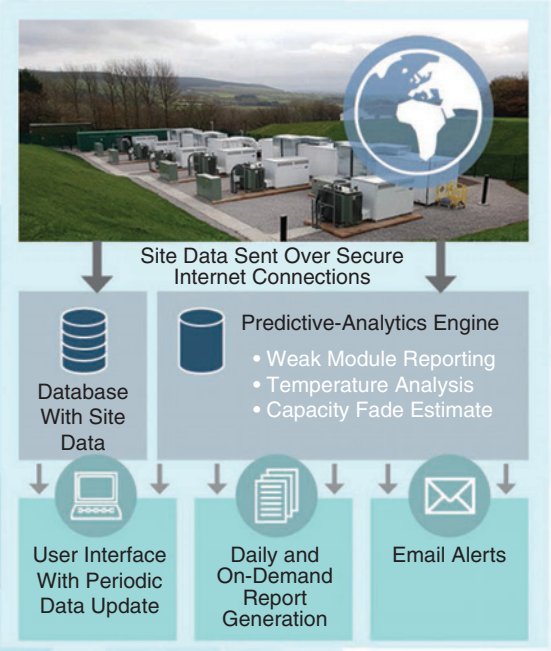
System or Component	Failure Mode	Hazard Effect	Consequence	Prevent	Detect	Probability; Severity	Value for Risk
BMS	System does not operate safely through normally expected temperature operating range	Fire	Safety incident	BMS testing	Independent temperature sensor	3; 10	30
Battery cell	Group of failures	Fire	Safety incident	Abuse testing	Fire alarm	3; 9	27
Battery pack	Group of failures	Fire	Safety incident	Abuse testing	Fire alarm	2; 10	20
BMS	Battery damage due to BMS malfunction	Fire or loss of functionality	Safety incident	Fusing, inverter protection	EMS fault on BMS behavior	2; 7	14
Inverter	Inverter fails to detect/react to overtemperature in insulated-gate bipolar transistors	Loss of functionality	Power output derating	Reliance on supplier	EMS fault on inverter temperature rise or inverter fault	3; 4	12

Case Study

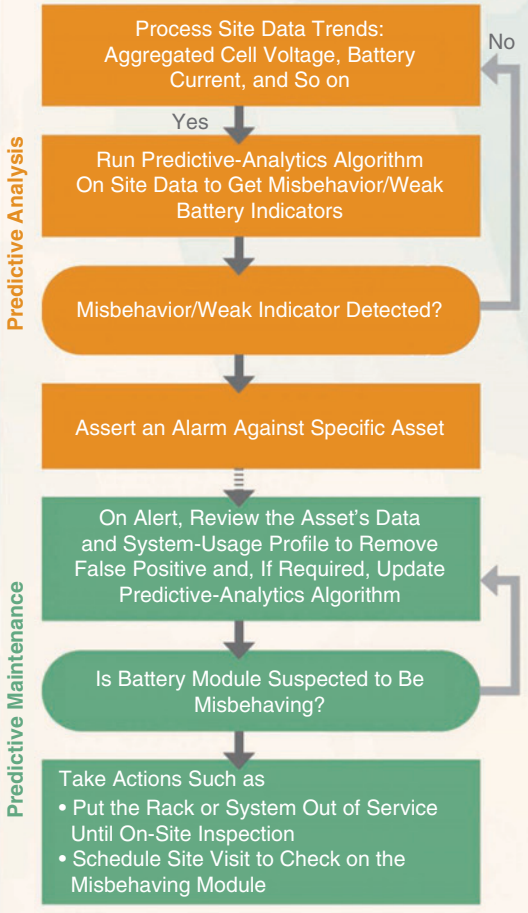
Predictive Maintenance Approaches for BESSs

This is an example application of predictive analytics on real-time and historical BMS data to identify indicators of unusual behavior. These indicators prompt alerts, which ultimately lead to predictive maintenance.

Information Flow



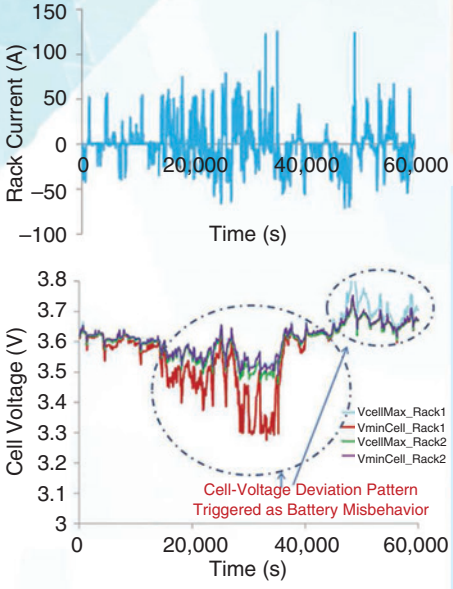
Action Sequence



Battery Misbehavior Indicator Warning

In this example, predictive analytics identified a pattern where the cell voltage of a module in rack number 1 was abnormally deviating from the other cell voltages.

The service team was alerted to this pattern, and they reviewed the data closely, subsequently replacing a battery module in this rack.



Results

Misbehaving battery modules were identified using predictive analytics algorithms before they could trigger safety hazards, negatively impact system availability, or reduce the system capacity. Furthermore, this approach helped the service team plan maintenance visits more efficiently in each geographic region, reducing the warranty costs.

figure 4. A predictive maintenance case study from NEC Energy Solutions.

proprietary and, in general, companies have understandable reluctance about releasing fault data. Today, the only public energy storage database (maintained by the DOE) focuses primarily on installations, technologies, and applications of energy storage. Creating a clearinghouse of fault information and issues is a more complicated request.

Thus, we recommend that independent third-party stakeholders create a public database of causal links and fault data that companies can use to enhance predictive-monitoring applications in their systems. This task may be daunting for individuals but may not be as difficult for those organizations dedicated to supporting ESS safety. The safety of first responders is enough of a reason to encourage system integrators and others involved in system maintenance to collaborate in the public process of identifying these causal relationships and leading indicators.

Summary and Recommendations

In this article, we recommended that the energy storage industry shift to a predictive-monitoring and maintenance process as the next step in improving BESS safety and operations. Predictive maintenance is already employed in other utility applications such as power plants, wind turbines, and PV systems. This process complements current BESS codes and standards and also contributes to broad efforts to design safer systems. Such an approach is necessary because of the following:

- ✔ BESS failures are still occurring despite tremendous efforts to mitigate the key faults believed to be the contributing factors in the failures.
- ✔ When faults do occur, the steps taken to contain the failure (and protect human safety) usually result in the total loss of the unit.
- ✔ Current standards for BESSs emphasize factory testing, commissioning, and emergency response rather than guidance for operation and maintenance.

The goal of a predictive process is to identify the indicator of a recoverable fault to initiate an inexpensive maintenance operation and prevent the initial fault from cascading into a catastrophic failure. However, creating the causal links between end-failure states and their key indicators is a daunting task, especially at this early stage of the BESS industry. This article described how system integrators may establish these links during the design phase and using data analytics on fielded systems. Despite challenges, the benefits of predictive maintenance approaches in reducing catastrophic failures and improving safety are too great to ignore. Even today, with companies such as NEC using only their own historical data, the approach is providing great value. Despite this success story, the industry would ultimately benefit from a public/professional consortium creating a database of all the issues that lead to larger problems/warning signs of failure. This greater transparency would enhance safety without eroding commercial competitive advantages.

Acknowledgments

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For Further Reading

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in memoriam

Patrick Ryan

THE IEEE POWER & ENERGY Society (PES) is saddened to announce the passing of Patrick Ryan, IEEE PES executive director, on Tuesday, 8 September 2020.

Pat Ryan was a courageous individual who fought very hard to beat his battle with cancer. He faced this challenge with his usual tenacity and positive attitude, but he was sadly unable to overcome it.

Pat became the third PES executive director in 2007 and was a driving force in transforming PES into the second-largest Society within the IEEE. He had a relentless focus on the IEEE and PES mission and vision and a strong belief that there needed to be significant volunteer engagement to pursue anything new. Pat was recently selected as the 2020 recipient of the IEEE Eric Herz Outstanding Staff Member Award "for leadership in creating a successful model for IEEE and Society memberships by fostering member value and partnerships with volunteers."

No matter how good an idea was, Pat would not pursue it unless there was significant volunteer engagement. He clearly held the volunteers at the core of the organization. Under his leadership as executive director, Pat drove several significant achievements for PES, including the following:

- ✔ the name change of the Society from the IEEE Power Engineering Society to the IEEE Power & Energy Society to better reflect the PES mission and vision
- ✔ the increase in PES membership from 22,000 in 2006 to more than 40,000 by the end of 2019
- ✔ the development of business processes that helped increase PES reserves, enabling the Society to create and establish humanitarian programs
- ✔ the foundation of the IEEE PES Scholarship Plus Initiative, which has distributed more than 1,500 scholarships to undergraduate students
- ✔ the founding of IEEE PES Resource Center, providing practical content and educational courses to industry professionals
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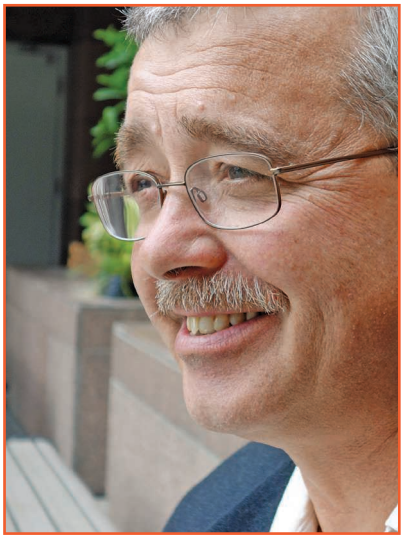

Patrick Ryan

Pat had a unique sense of humor. With his panache for making friends and cultivating relationships, a main focus of his life, along with his cherished wife, was to raise his three children with strong values. He was so proud to watch them each become positive, contributing citizens of the community at large. He also enjoyed hunting, fishing, and anything involving the great outdoors.

Pat is survived by his wife, Patricia J. Hunkele Ryan, and his children Roman, Nicholas, and Bridget. For further information, please see https://www.ieee-pes.org/about-pes/pes-staff/in-memoriam-pat-ryan.

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Robert D. Barnett

electrochemical loads

served by Niagara Falls hydroelectric power

In previous "History" columns, we have explored a number of aspects of electrical power associated in the Niagara Falls area. In this issue, we present a view from the perspective of the loads consumed by customers of the early hydroelectric generation plants in the Niagara Falls area. This article focuses on early electrochemical factories and the distribution methods used to serve these loads.

We welcome back Robert D. Barnett for a fifth time to the "History" pages of our *IEEE Power & Energy Magazine*. A Life Senior Member of IEEE, Barnett graduated from the University of Waterloo and Niagara College. In 1982, he formed the Niagara Society for Industrial History as a support group for a proposed museum in a former Niagara Falls power plant, and he has written on the history of the topic.

John Paserba,
Associate Editor, "History"

IN 1895, THE NIAGARA FALLS Power Company installed an early large-scale polyphase generating station at Niagara Falls, New York. Later named *Adams Plant No. 1*, power was first produced in 1895. Ten years later, a total of six ac-generating stations were in operation on both sides of the U.S.–Canadian border. The rapid development of power generation at Niagara Falls was in no small part a result of the burgeoning electrochemical industry.

The Adams Plant generated two-phase power. The industries that would use this power required a mix of ac and dc. For the ac plants, only a transformer was required to provide the process voltage. For dc requirements, however, rotary converters were needed. These machines, normally located in the manufacturing plant, were the usual means for supplying high-current dc in the days before the development of mercury-arc rectifiers or, later, solid-state power devices.

The Industries

Although Niagara Falls, New York, was not the birthplace of the American electrochemical industry, it certainly was its nursery. Martha Moore Trescott, in her book *The Rise of the American Electrochemicals Industry*, said, "Most of the early advances in electrothermic electrochemicals occurred in Niagara Falls after 1895." Trescott also noted that the U.S. Census Bureau said in 1910, "Niagara Falls, New York, is the chief seat of the electrochemical industry, and it has held this position from the beginning."

The first electrochemical plant to take power was the Pittsburgh Reduction Company. The plants of the Carborundum Company and Union Carbide Company (now known as Union Carbide Corporation) followed it closely. Several more plants were added in the next decade (see Table 1 for a listing of most of the large ones). Figure 1 shows a 1904 map of the area near the Adams Plants in the part of the river just above the falls. By the late 1890s, another generating station owned by Niagara Falls Hydraulic Power & Manufacturing Company and located below the falls began to supply power to electrochemical industries in their area. Niagara Falls Hydraulic Power & Manufacturing Company had been in operation since the 1880s, but because it was originally a plant with small-size generators, it was not suitable for supplying the large amount of power required by the electrochemical processes. This article focuses on the industries supplied by the Adams Plant, looks at three of the larger loads in some detail, and comments on their impact to the development of load-serving power equipment.

Local Distribution

Initially, Adams Power House No. 1 had only a single two-phase alternator, but this alternator was 5,000 hp at a time when a 500-hp machine was considered large. In addition, the best practices governing the characteristics of ac circuits were not well understood at the time.

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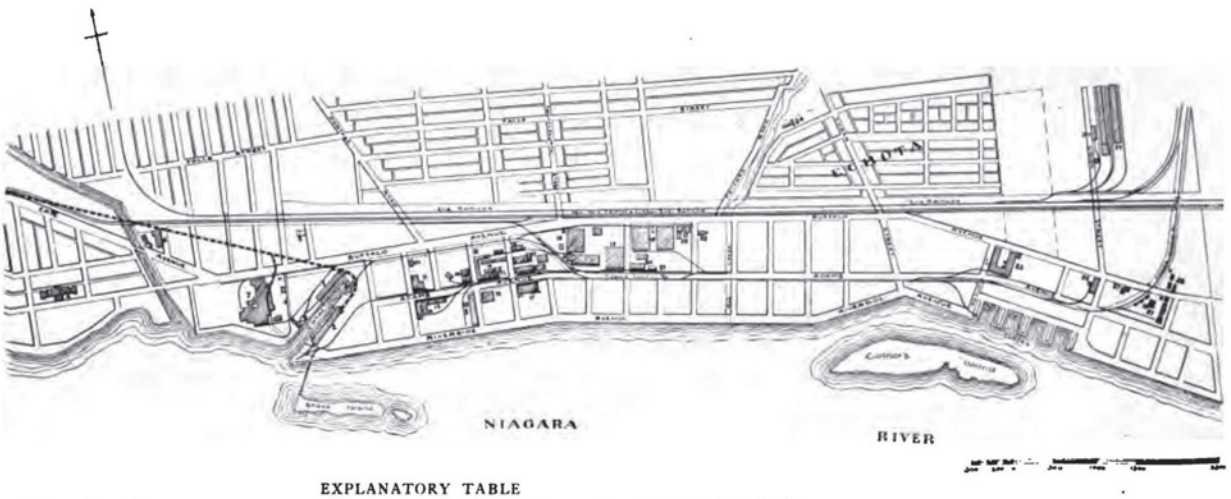
The Niagara Falls Power Company, in conjunction with Westinghouse Electric & Manufacturing Company and General Electric Company, would develop these practices over the next decade. In some cases, these practices were a result of serious electrical faults. Most problems were not anticipated because of the groundbreaking nature of the work. There was no grid. There were no "systems." There was an alternator and there were some customers. They took what the British call the "suck-it-and-see" method. Frequently, it was the former.

From the 2,200-V power house bus bars, the system was divided into three distinct classes of service: local distribution, intermediate distribution, and long-distance transmission (see Figure 2). The local distribution was fed directly from the 2,200-V, two-phase, 25-Hz station bus. Note that in Figure 2, there are no fuses or circuit breakers shown. In 1896, protective devices for transmission lines were conspicuous by their complete absence. There was

table 1. The early electrochemical companies in the Niagara Falls region presented in Figure 1. (Source: *The Niagara Falls Electrical Handbook*.)

	Map Reference	Maximum Horsepower	Miles
The Pittsburgh Reduction Company (later, Alcoa)	17	8,000	0.46
The Carborundum Company	15	5,000	0.25
Union Carbide Company	30	15,000	2
Niagara Electrochemical Company	19	2,000	0.75
Electrical Lead Reduction Company	11	500	0.19
Castner Electrolytic Alkali Company	18	7,000	0.85
International Acheson Graphite Company	14	1,000	0.28
Roberts Chemical Company	26	500	1.9
Francis Hook and Eye and Fastener Co.	5	15	0.47
Norton Emery Wheel Company	22	650	0.95
Ramapo Iron Works	25	500	1.7
The Composite Board Co.	13	200	0.34
Niagara Research Labs	10	500	0.28
Oldbury Electrochemical Company	27	1,500	2.18
Atmospheric Products Company	16	50	0.47



EXPLANATORY TABLE

1 Power House No. 1
2 Power House No. 2
3 Main Transformer Station
4 The Natural Food Co.
5 Francis Hook & Eye & Fastener Co.
6 Niagara Surface Coating Co.
7 International Paper Co.
8 Buffalo and Niagara Falls Electric Light and Power Co.
9 The Niagara Falls Water Works Co.
10 Niagara Research Laboratories
11 Electrical Lead Reduction Co.
12 By-Products Paper Co.
13 Composite Board Co.
14 International Acheson Graphite Co.
15 The Carborundum Co.
16 Atmospheric Products Co.
17 The Pittsburg Reduction Co.
18 Castner Electrolytic Alkali Co.
19 Niagara Electro Chemical Co.
20 The United Barium Co.
21 Ampere Electro Chemical Co.
22 Norton Emery Wheel Co.
23 Acetyvone Manufacturing Co.
24 Echota Disposal Works
25 Ramapo Iron Works
26 Roberts Chemical Co.
27 Oldbury Electro-Chemical Co.
28 Phosphorus Compounds Co.
29 Union Carbide Co.
30 Union-Street Substation

Map Showing Location of Local Tenants on Lands of the Niagara Falls Power Company

figure 1. A 1904 map of the area near the Adams Plants in the portion of the Niagara River just above the falls, which shows the local tenants on land owned by the Niagara Falls Power Company. (Source: *The Niagara Falls Electrical Handbook,* 1904.)

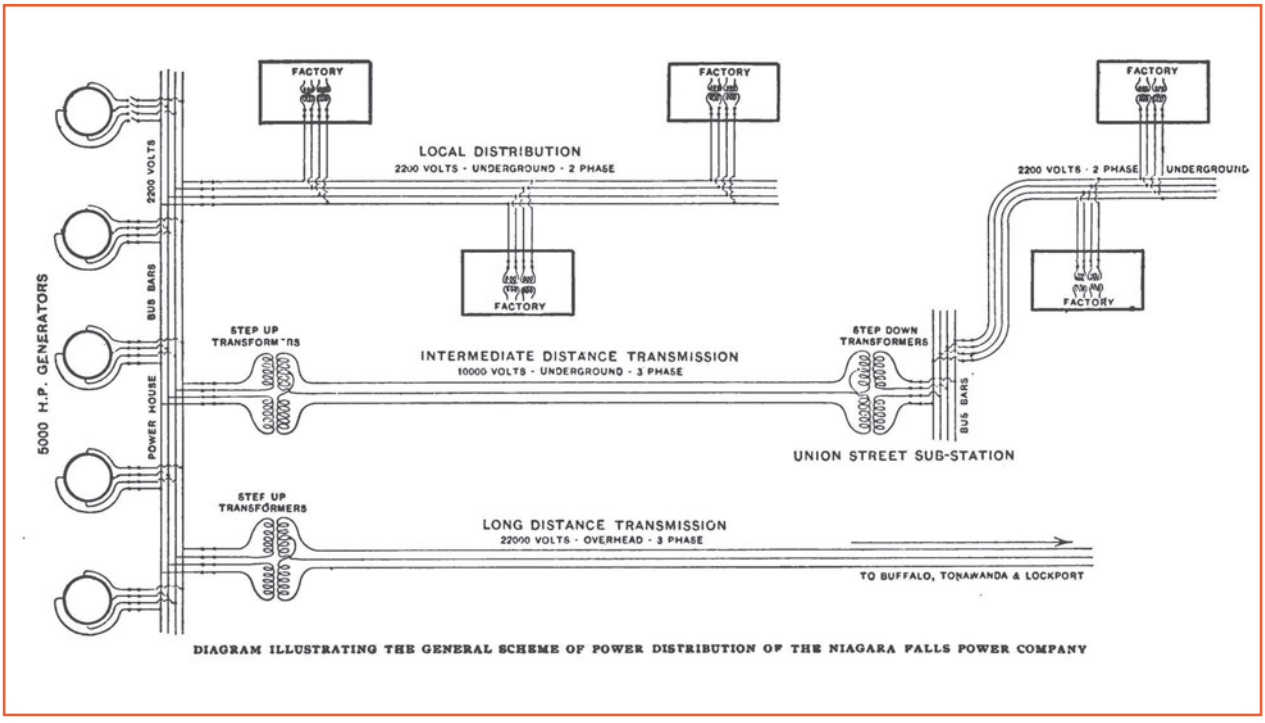


figure 2. A diagram illustrating the general scheme of power distribution of the Niagara Falls Power Company. (Source: *The Niagara Falls Electrical Handbook,* 1904.)

no known method by which a short circuit on a transmission line of the capacity of that at Niagara Falls could be opened without causing damage to the circuit breaker. Fuses were tried in the Adams Plant, but the interrupting duty was too severe. They were removed because they exploded when clearing a fault and caused more trouble than they prevented. The solution was to disconnect the alternator's field, shutting down the entire section of bus. This would not prove to be a long-term solution, however.

Having been accustomed to dealing with the relatively small level of short circuits in the dc Edison systems, no one had anticipated the magnitude of faults possible on ac systems. There were isolating switches used to connect the generators to the bus, but these were never intended to interrupt any level of fault current. As most of the short circuits were on the transmission line, the local distribution system was fed from a section separated from the transmission circuits. Eventually, this untenable situation would lead to the development of the oil circuit breaker. But that would take a number of years and was dependent on gaining a better understanding of short circuit phenomena.

The first electrochemical plant to take power was the Pittsburgh Reduction Company.

The conductors used for local distribution were routed through a concrete tunnel 2,000 ft in length. Iron brackets were mounted on the walls of the tunnel; each bracket carried four, lead-covered, single-conductor copper cables (see Figure 3). This tunnel ended in a manhole near the plants of the Pittsburgh Reduction and Carborundum companies. The cables for these two plants left the tunnel and ran on wooden poles to the customers' premises. But in the same

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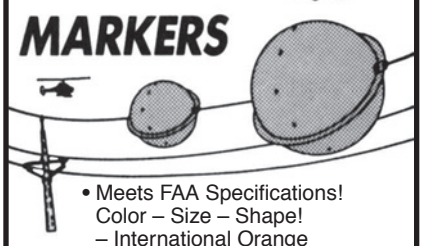

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figure 3. The cross section of a cable tunnel. (Source: *The Harnessing of Niagara,* 1895.)



figure 4. Putting down cable conduits at Niagara Falls. (Source: *The Harnessing of Niagara,* 1895.)

The electrochemical industry was also a catalyst in the development of the electrical equipment manufacturing industry.

year, before additional pole lines could be constructed, two more industries contracted for power from Power House No. 1: The Mathieson Alkali and Niagara Electrochemical companies. Louis B. Stillwell, a leading electrical engineer of the time, wrote (for additional information, see Stillwell in the "For Further Reading" section):

> There was no provision in the way of conduits for the cables which extended from the manhole to these companies. As an expedient, the cables had simply been laid upon the top of the ground and extended across the fields to the several establishments supplied with power.

By the end of its first year of operation, however, with a large influx of industrial customers continuously expanding its facilities and adding new ones, the Niagara Falls Power Company realized that its major load would be within 5 mi of the plant and not in Buffalo, New York, as had been originally envisioned. The company soon began an extensive network of underground conduits and overhead power lines that would be continuously extended well into World War I (see Figure 4).

The electrochemical industry was also a catalyst in the development of the electrical equipment manufacturing

industry. Transformer development is one example. Because the secondary voltage for the ac electrochemical loads was in the order of 10–50 V, this resulted in unusually high secondary current. This high current produced electrical losses at a level not seen before. Load fluctuations were high, and overloads were common. Operation for 24 h under heavy loading was a normal requirement. As a result, heat was usually removed using water to cool the insulating oil. In most cases, there was a need to vary the secondary voltage. These all were conditions not previously encountered where transformers were used for lighting or motor loads in factories that did not have a continuous process.

Given that the large electrochemical load was what supported the generating station in its first decade, it was fortunate that electricity was chosen as the power-generation medium. In the late 19th century, there were several large pneumatic generating stations being proposed or under construction in Europe. Pneumatic power was considered by many as a better choice, especially for the transmission of power to Buffalo. Power House No. 2 was planned as a pneumatic station and is shown as such in contemporary drawings (see Barnett in the "For Further Reading" section). Had air compressors been installed instead of electrical generators, a pneumatic engine would have had to drive a generator to supply power to what was to be the largest load on the Adams Plants—the electrochemical industries at Niagara Falls.

The Pittsburgh Reduction Company produced aluminum using an electrolytic process. The Carborundum Company used an electrothermal process to produce carborundum. A third plant, the Union Carbide Company, produced calcium carbide (CaC_2), which was used in the manufacture of fertilizers and to produce acetylene gas.

These three processes were typical of most of the chemical industries in Niagara Falls at that time. Although the chemical-process details differed significantly, the electrical-distribution technology was very similar for all, differing only in the detailed design.

Aluminum

Aluminum was discovered by Hans Christian Oersted, a Danish chemist, in 1825 and has always had useful properties. It was initially produced in small amounts because it was difficult to refine. An American chemist, Charles Martin Hall, and a French chemist, Paul L.T. Héroult, each invented nearly the same process for refining aluminum, independently, in 1886.

Power House No. 2 was planned as a pneumatic station and is shown as such in contemporary drawings.

Hall began his operations in Pittsburgh, Pennsylvania, where originally the aluminum production process was carried out in a furnace fired by various hydrocarbon fuels. Even though this process produced a relative large yield, it required an amount of power that was not economically available at that time. This all changed with the commissioning of the first units at the Niagara Falls Power Company. The Pittsburgh Reduction Company began operations at Niagara Falls in July 1895.

Figure 5 shows a simplified diagram of a Hall cell, sometimes known as a furnace because of the high amount of heat energy required to melt the component chemicals. Using this process, aluminum is refined from bauxite, an impure hydrated oxide of aluminum. Bauxite is a good insulator and difficult to melt. This difficulty was overcome by first melting cryolite, which has a lower melting point than bauxite. Purified bauxite (alumina) is readily soluble in molten cryolite and dissociates, producing aluminum ions. The valence of aluminum is +3 so when dissociated in solution, its positive charges look to gain three electrons to become aluminum. The gaining of electrons is known as reduction. These electrons come from the cathode, which, in turn, gets its electrons from the power plant. The negative oxygen ions unite with the carbon of the anode and carbon monoxide (CO) is produced.

To start the process, cryolite was added and the electrodes (anodes) lowered until they touched the cathode. Electrical power in the form of dc was then applied, and the resulting current melted the cryolite. After a sufficient amount of cryolite had melted, the alumina was added, and the reduction process began. The normal operating

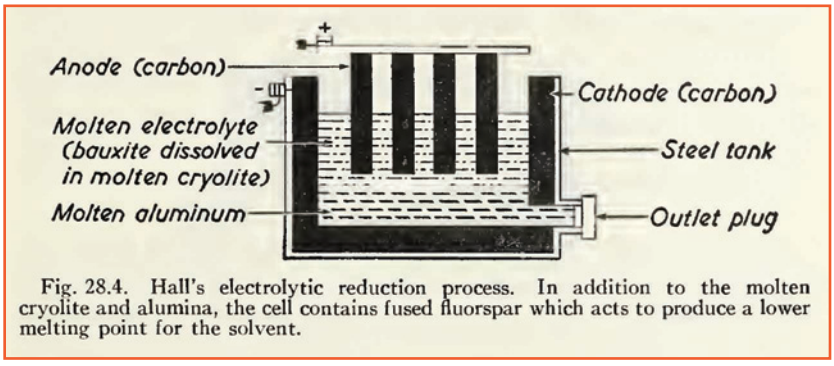


Fig. 28.4. Hall's electrolytic reduction process. In addition to the molten cryolite and alumina, the cell contains fused fluorspar which acts to produce a lower melting point for the solvent.

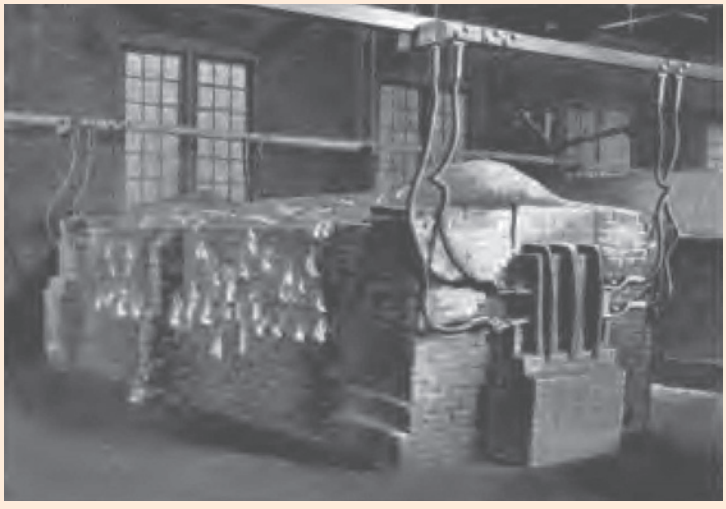
figure 5. A simplified diagram of a Hall cell (sometimes known as a *furnace* because of the high amount of heat energy required to melt the component chemicals). (Source: A.G. Croal, *Chemistry for Secondary Schools,* Toronto, Copp Clark Publishing Co., 1955, p. 295; used with permission.)



figure 6. The interior of Alcoa's Smallman Street facility in Pittsburgh, Pennsylvania (circa 1888).



(a)



(b)

figure 7. The Carborundum Company. (a) A furnace ready for burning and (b) a furnace during burning. (Source: *The Niagara Falls Electrical Handbook,* 1904.)

voltage of the cell was typically 8 V, and the current was 1,800 A. The voltage was monitored on voltmeters positioned so that they were visible to the attendant, as depicted in Figure 6. As the process progressed and the voltage dropped, more cryolite was added by hand. Refined aluminum was collected at the cathode. The process was tapped at suitable intervals, and the molten aluminum cast into pigs.

The plant was supplied with an ac of 500 A at 2,500 V, two-phase. This was transformed at the Pittsburgh Reduction Company's site to 115-V ac to drive three rotary converters. These converters produced 160-V dc to give a total output of 7,500 A for use by the furnaces. As the process was continuous, once it was started it had to run to completion. If the molten aluminum solidified, the furnace would be ruined. The Niagara Falls Power Company guaranteed a continuous supply 24/7 for the length of the contract. A spare converter was also connected and the dc side backed up by storage batteries.

By 1907, the Pittsburgh Reduction Company had changed its name to the Aluminum Company of America—Alcoa. It ceased production in Niagara Falls, New York, in 1949.

Carborundum

The Carborundum Company began operations in the fall of 1895. Edward G. Acheson, one of the inventors (1891) of the carborundum process, was also the president of the company. The material known as carborundum is the compound silicon carbide (SiC). SiC is a synthetic mineral, i.e., not found in nature. It is formed using a mixture of carbonaceous material (usually petroleum coke) and a silica or quartz sand, which react at high temperatures to form SiC and CO. The energy for the reaction was provided by passing an ac through the core. This core was composed of very pure carbon to offer lower resistance to the passage of the electric current than that of the surrounding material. It also had to be capable of being heated to an intense degree without destruction.

The material surrounding the core was a mixture of 20 parts, by weight, of coal, coke, or other form of carbon reduced to small particles; 29 parts of sand; five parts of common salt; and two parts of sawdust. After a few hours of operation, the heat from the core caused the surrounding mixture to ignite, as depicted in Figure 7. This both increased its temperature and produced savings in the amount of electric energy expended. The process lasted approximately 24 h, after which the power was turned off, and the pig was left to cool.

The furnace was a simple rectangular structure, as shown in Figure 8. The walls and ends were made of brick with no mortar between the bricks. The walls were 7 ft long and the ends 6 ft wide. The height was 6 ft. At each end of the furnace there was a large bronze plate to which the power cables were connected. These cables were connected to bus bars located beneath the operating floor. Projecting into the furnace from the bronze plates were 60 carbon rods, each with a length of 30 in and a diameter of 3 in. The charge, consisting of powdered coke mixed with sand, sawdust, and salt, was loaded into the furnace. The carbon rods allowed for intimate contact to facilitate the flow of current, which produced a temperature in the 1,700–2,500 °C range. The cycle took roughly 24 h. The SiC developed as a solid cylindrical ingot around the core, with radial layers ranging from graphite in the inside to various SiC grades toward the outside. After completion, the furnace walls were pulled down, which allowed for the carborundum that had formed around the core to be removed for further processing for various applications, most commonly, abrasive wheels and papers.

An induction regulator is like an induction motor that does not rotate.

The control of the furnace was manual, with the operator using an induction regulator to change the voltage applied. During operation, the chemical changes in the mix caused its resistance to gradually reduce. To keep the reaction drawing power at a more-or-less constant value (750 kW), the voltage was reduced as the process progressed. A typical set of values for this early furnace was 240 V, 3,000 A and 100 V, 7,500 A at its start and completion, respectively. An induction regulator is like an induction motor that does not rotate. The "rotor" is turned to change the ratio of the primary (stator) to the secondary (rotor), and this changes

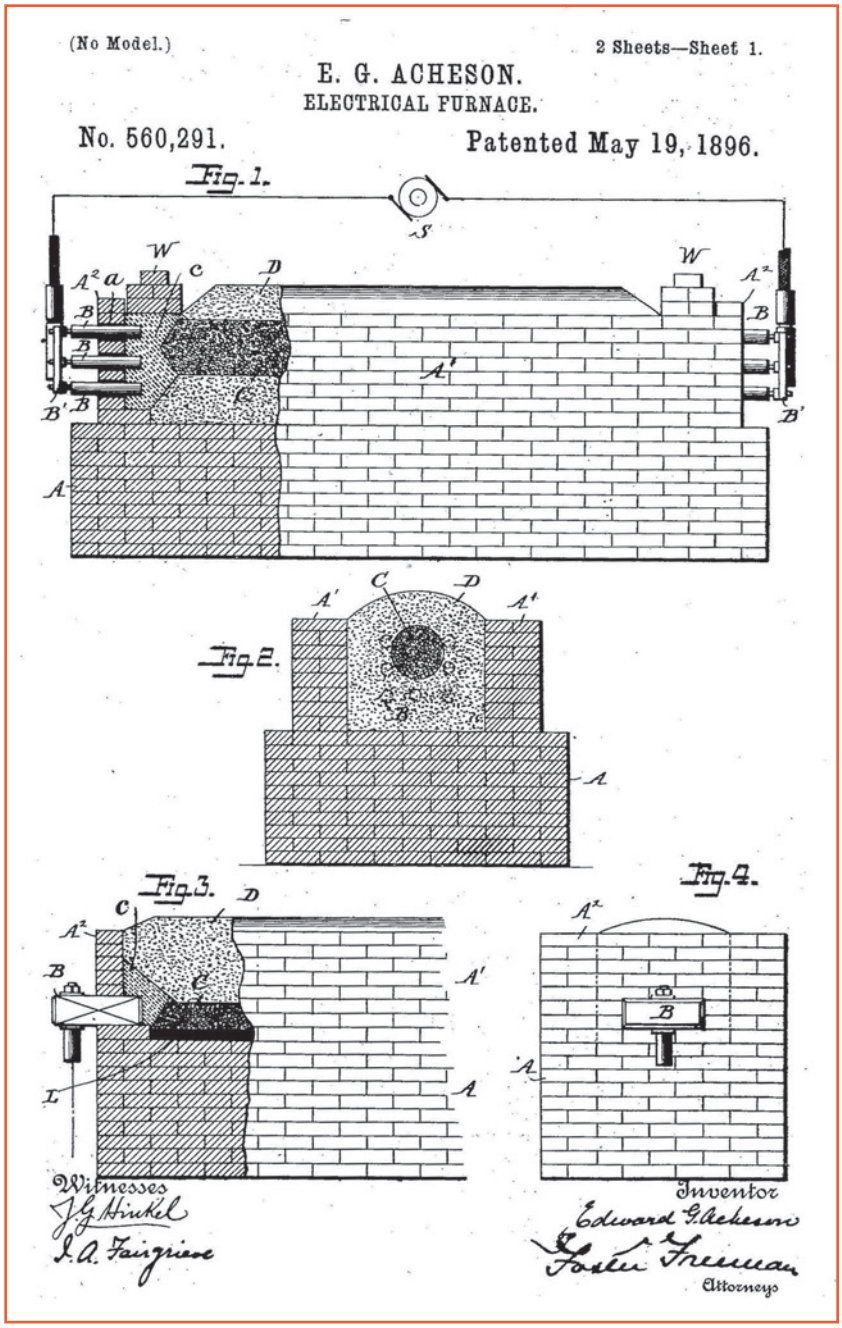


figure 8. The U.S. patent issued for the electrical furnace. (Source: The U.S. Patent Office, U.S. Patent 560,291, 19 May 1896.)

the turns ratio. The secondary is connected to the primary, as shown in Figure 9. It can cause the voltage to increase or decrease, depending upon its position relative to the primary.

Next to the furnace room was the transformer building. Initially, only one transformer powered five furnaces. By 1904, 72 furnaces had been installed. At 1,000 electrical hp (approximately 1,000 kVA), it was the largest transformer in the world at the time of installation. Both the transformer and regulator were oil cooled, as shown in Figure 10, which shows the regulator on the left. The wheel turns the secondary of the regulator to control the voltage. On the right is the furnace power transformer.

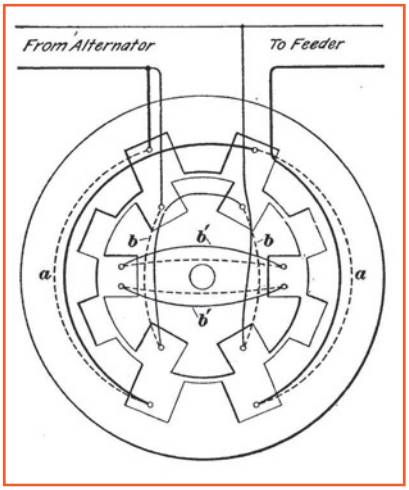


figure 9. A single-phase induction regulator. (Source: *The International Library of Technology,* International Textbook Company, 1922.)



figure 10. The Carborundum Company's 1,000-hp transformer with induction regulator. Note that the wheel turns the secondary of the regulator to control the voltage. On the right is the furnace power transformer. (Source: *The Niagara Falls Electrical Handbook*.)

Nikola Tesla's original patents were for two-phase circuits, so when Westinghouse bought these patents, it acquired a two-phase system.

Calcium Carbide

Union Carbide Company began operation in Niagara Falls in 1898. It manufactured calcium carbide (CaC_2) using burnt lime, also known as quick lime or simply lime. Lime is produced by heating limestone to 1,000 °C (1,830 °F) in a lime kiln. The lime is then combined with carbon by mixing it with ground coke in a carbide furnace at a temperature of 1,090 °C (2,000 °F) to produce CaC_2.

Initially, the furnaces produced ingots of CaC_2 in a batch-process furnace, but by the time of the American Institute of Electrical Engineers conference in Niagara Falls in 1904, the operation had become continuous by using the Horry rotary carbide furnace. There were 50 ac arc furnaces in operation, each of which was circular, 10 ft in diameter, 3 ft wide, and made of steel. Two carbon electrodes were located at the top in the hopper, into which the charge of coke and lime were fed, as depicted by point (E) in Figure 11. The lime and carbon were fused by the arc between the electrodes and the resulting carbide formed at point (C). The fluid carbide gradually solidified as the wheel rotated at the rate of one revolution every 48 h. Cover plates were attached to the wheel at point (P) and, after the rotation had brought them to (Q), were removed to allow the solidified carbide to be broken away. Each furnace drew 4,000 A at 75–80 V.

One pound of CaC_2, when exposed to water, furnished 5 ft^3 of acetylene gas. Gaslighting was one of the major uses of acetylene at the turn of the 20th century. Acetylene was, and to some extent still is, used in the cutting and welding of steel. The production of fertilizer by nitrogen fixation is its most important use.

AC power was supplied to Union Carbide at 2,250 V, and the consumption was typically 5,000 hp. The plant contained 10 2,000-hp transformers and two 500-hp transformers as well as 40 two-phase motors ranging from 1 to 200 hp.

Summary

In the engineering world of the 19th century, much cerebral energy was expended

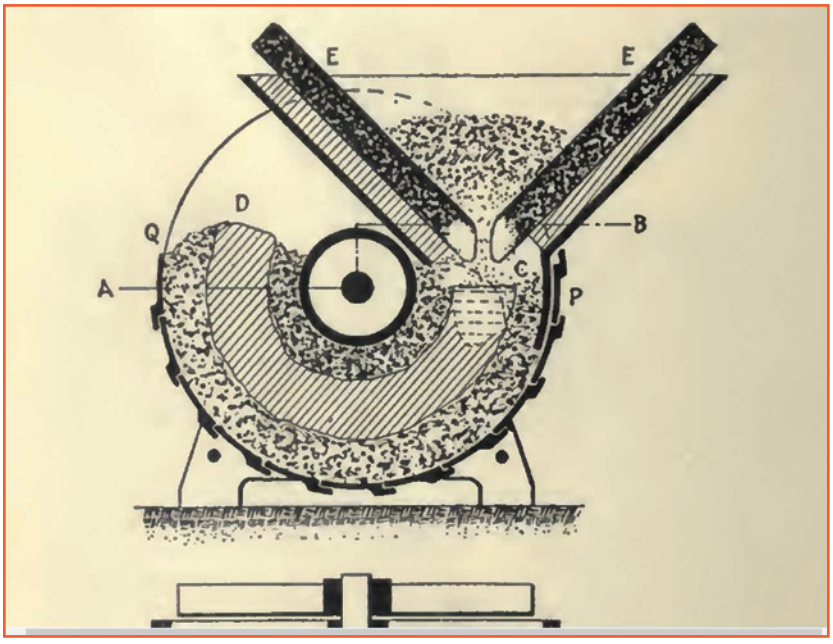


figure 11. The Horry carbide furnace. (Source: *The Electric Furnace*, 1914.)

debating whether two or three phase power would be best for transmission and utilization. Some thought that two phase would be better for lighting and three phase for industrial power. This followed from the fact that lighting, the major load at the time, was single phase. There was also the concern that single-phase loads drawn from a three-phase circuit would cause serious voltage-balance problems. It was anticipated that most industrial loads would be motors, and three-phase motors were considered better for that application. As it turned out, at Niagara Falls, most of the early industrial processes were electrochemical and thus would be either single-phase ac or dc, with the dc being provided by two-phase synchronous converters.

One may well wonder why two phase was considered in the first place. Nikola Tesla's original patents were for two-phase circuits, so when Westinghouse bought these patents, it acquired a two-phase system. Westinghouse designed and built the first Niagara alternators, so they were two phase by default. Two-phase systems would not to be repeated for large-power alternators outside of the two original Adams Plants. The other four generating stations at Niagara Falls, with several units online by 1910, would use three-phase alternators closely resembling those in modern-day use.

In a way, the first Adams Plant could be considered a pilot project for modern power technology. Several concepts were worked out during the operation of this plant, while some were never repeated. Others would be a template for what would follow, such as using oil circuit breakers on high-voltage transmission circuits to protect against short circuits of a magnitude not previously envisioned but, from the level of faults experienced at Niagara, their need became painfully obvious. The removal of power circuit breakers for the operator's location was first done in the Adams Plants. Previously, all the breakers and fuses were located on a common board in the operator's control room. The realization that all the phases of a circuit should be in the same cable to reduce eddy currents and that circuits should be separated from each other to stop fault propagation resulted from painful incidents at Niagara Falls.

The first Adams Plant could be considered a pilot project for modern power technology.

Today, only a few of the original industries are active in Niagara Falls, and they are known by different names. But those early industries left an important legacy. If it were not for the electrochemical industry providing the financial incentive to find a better way, the electrical technology we know today may have taken decades longer to develop.

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THIS ISSUE'S "BOOK REVIEW" column discusses *Power System Modeling, Computation, and Control*, by Joe H. Chow and Juan J. Sanchez-Gasca. The reviewer says that it is "a welcome addition to the body of literature on power system modeling, computation, and control."

Power System Modeling, Computation, and Control

By Joe H. Chow and Juan J. Sanchez-Gasca

Power System Modeling, Computation, and Control (Wiley-IEEE Press, 2020) is designed to make the advanced topics of modeling, computation, and control more accessible to graduate students, power engineers, and control design professionals. The initial use of this text was for teaching a two-course sequence on the topics at Rensselaer Polytechnic Institute as an evolution to the use of the well-known text *Power System Stability and Control*, by Dr. Prabha Kundur. The new text offering chapters that address flexible ac transmission systems and wind-turbine-generator technology.

The authors of *Power System Modeling, Computation, and Control* have more than 40 years of experience working in power systems, were colleagues at General Electric Company, and have been long-time collaborators within the IEEE Power & Energy Society's

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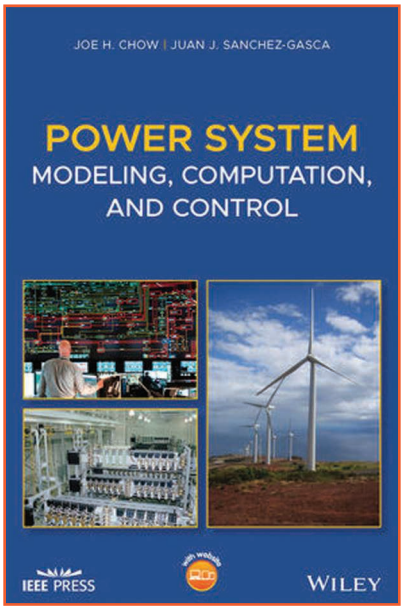

Power System Dynamic Performance Committee and its various subcommittees, working groups, and task forces.

The organization and material in this text reflect the preferences of the authors for 1) the topics covered, 2) the depth of the material included for each topic, and 3) how the material is explained. In the Preface, the authors describe their contribution as "In addition to being a modeling and control book, it is also a systems and computation book." A distinctive feature of this text is that most of the topics are illustrated with detailed numerical examples. The depth of their respective industry experience is clearly shown throughout the nearly 600-page treatment of the topics.

The text is organized into three parts after a brief Introductory chapter:

- ✔ Part I: System Concepts
  - Steady-State Power Flow
  - Steady-State Voltage Stability Analysis
  - Power System Dynamics and Simulations
  - Direct Transient Stability Analysis
  - Linear Analysis and Small-Signal Stability.
- ✔ Part II: Synchronous Machine Models and Their Control
  - Steady-State Models and Operation of Synchronous Machines
  - Dynamic Models of Synchronous Machines
  - Excitations Systems
  - Power System Stabilizers
  - Load and Induction Motor Models
  - Turbine-Governor Models and Frequency Control.
- ✔ Part III: Advanced Power System Topics
  - High-Voltage Direct Current Transmission Systems
  - Flexible AC Transmission Systems
  - Wind Power Generations and Modeling
  - Power System Coherency and Model Reduction.

The book offers a comprehensive list of 243 references and a thorough index as well as color versions of key figures. Each chapter ends with a set of problems, totaling 155 for the entire book.

(continued on p. 111)

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 website for the most current information.

November 2020

IEEE Electronic Power Grid (eGRID 2020), 2–4 November, Aachen, Germany, virtual event, contact info@egrid2020.org, https://egrid2020.org/

IEEE International Future Energy Conference (IFEC 2020), 9–12 November, Aalborg, Denmark, contact Huai Wang, hwa@et.aau.dk, http://energychallenge.weebly.com/ifec-2020.html

IEEE Sustainable Power and Energy Conference (iSPEC 2020), 23–25 November, Chengdu, China, contact Min Liu, min-liu@csee.org.cn, http://2020.ieee-spec.com/

December 2020

IEEE PES Transactive Energy Systems Conference 2020 (TESC 2020), 8–10 December, virtual event, contact Ron Melton, ron.melton@pnnl.gov, https://ieee-tesc.org/

IEEE International Conference on Power Electronics, Drives and Energy System (PEDES 2020), 16–19 December, Jaipur, India, virtual event, contact Suryanarayana Doolla, doolla@gmail.com, http://pedes2020.com

January 2021

IEEE PES 2021 Joint Technical Committee Meeting (JTCM 2021), 7–15 January, New Orleans, Louisiana, United States, contact Solveig Ward, sward@quanta-technology.com, www.pestechnical.org

February 2021

IEEE PES Innovative Smart Grid Technologies (ISGT 2020), 15–18 February, Washington D.C., United States, virtual event, contact Kathy Heilman, kathy.heilman@ieee.org, https://ieee-isgt.org/

May 2021

IEEE International Conference on Electrical Machines and Drives (IEMDC 2021), 16–19 May, Hartford, Connecticut, United States, contact Ali Bazzi, alibassi@ieee.org, http://iemdc-conference.org/

June 2021

IEEE PowerTech Milan (PowerTech 2021), 28 June–2 July, Madrid, Spain, contact Tomas Gomez San-Roman, tomas.gomez@comillas.edu

July 2021

IEEE PES General Meeting (GM 2021), 18–22 July, Washington, D.C., United States, contact Roseanne Jones, roseanne.jones@ieee.org

September 2021

IEEE PES GT&D International Conference and Exposition, Istanbul (GTD), 14–17 September, Istanbul, Turkey, contact Omer Usta, usta@ieee.org, https://ieee-gtd.org/

December 2021

IEEE PES Innovative Smart Grid Technologies Asia (ISGT Asia 2021), 5–8 December, Brisbane, Australia, contact Tapan Saha, saha@itee.uq.edu.au

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distribution management system (ADMS) Voices of Experience effort, DOE researchers found that a surprisingly low number—only a handful—of utilities in the United States either had or were considering deploying an ADMS. An ADMS provides a critical view of the system and manages conventional utility resources, such as capacitors, regulators, transformers, switches, and so on, which is key to advancing a more resilient and reliable energy future. All resources need to be managed concurrently to operate the grid both safely and reliably.

Without an ADMS to provide visibility into grid conditions, how do you leverage DERs? To forecast and determine a service need and effectuate that request to either the distribution system or wholesale market, a DERMS is a necessary software and control tool to integrate into distribution operations.

ADMS deployment not only comes before the DERMS, but its functionality (power flow model, volt/var management, and so on) must be vetted prior to DERMS implementation. The DERMS must be integrated into the ADMS, allowing a single unified view of the distribution system; the DERMS guides the dispatch of all resources, subject to the total grid operating state based on grid constraints, switch state, load, and DER capabilities.

Based on two rounds of requests for proposals at SDG&E several years apart, I learned that the distributed, federated, hierarchical control structure necessary to control large, scalable quantities of DERs—tens of thousands to millions—is not currently available commercially. Only pilot projects or customized, one-off software solutions are being used to control small quantities of DERs. The DOE is funding DERMS R&D through its Grid Modernization Lab Consortium as well as its Office of Electricity.

Lack of Measurement and Verification Techniques

Finally, certain measurement and verification techniques must be in place to provide compensation for grid services. At the wholesale market level, the requirements are clear, but DER aggregators believe that they are too burdensome, and there are distribution system operating constraints that impact the aggregation availability. At the distribution level, without a generator output meter, it is unclear what the actual response to a request for service would be. (In 1999, California investor-owned utilities asked policy makers to require a generator output meter, but the request was rejected due to concerns that the additional requirement would drive up the cost of solar installations.) While it is possible to estimate a PV system's power output based on solar irradiance data and the panel orientation, in California, solar panels are oriented in all directions, including north, based on facility/property siting constraints.

A Little Bit of History

In the late 1990s, DERs, or distributed generation (DG) as it was known at the time, was deployed by larger entities with a significant heat load in combined heat and power applications. However, during that time period, PV systems and microturbines developed with an inverter (dc-to-ac converter) interface to the grid were also beginning to be deployed. At the end of 2000, SDG&E had 32 PV installations totaling 105 kW.

In 1999, the California Public Utilities Commission (CPUC) opened a rulemaking on DG interconnection with the goal of reducing barriers, lowering costs, and accelerating adoption. This inclusive stakeholder effort, codified under Rule 21, resulted in standard requirements for inverters. Utilities were required to evaluate DG as an alternative to traditional "wires" solutions, with vendors offering to supply, rent, or lease a generator to the utility. This Rule 21 revision led the parties involved and a broader group of stakeholders to develop IEEE 1547 and update UL 1741. A key tenet of the standards was that the DG unit do no harm under normal operating conditions and disconnect as quickly as possible under abnormal conditions. Given the cost of a PV system at the time, the growth of installations was expected to be small for the foreseeable future.

Just a decade later, at the end of 2010, SDG&E had 11,644 PV installations totaling 84,765 kW. We were beginning to get a good sense of how DERs impact the grid when there is widespread deployment.

In 2011, on a rural circuit in San Diego County, an excellent example of the impact of DERs on the grid was discovered. Power quality meters had been set on the secondary of a primary metering station at the end of a long circuit, which utilized a small copper conductor for the last line segment. At the end of the circuit, a 1-MW PV system was connected. The primary circuit voltage was observed to fluctuate wildly due to intermittent power production from this PV system with a legacy inverter as the morning fog burned off. SDG&E had identified the factors that determined the impact of a PV system on the grid and recognized, given the German experience (which California was emulating), that it was necessary to update the Rule 21 interconnection requirements to incorporate smart inverter functionality to avoid the German 50.2-Hz retrofit experience.

After a 2013 CPUC-sponsored workshop, an effort to update Rule 21 was authorized, and the Smart Inverter Working Group began work on the technical requirements. This effort resulted in requirements and timelines for implementation and the development of the UL 1741-SA standard to allow for testing to the new California Rule 21. An update to IEEE 1547 was initiated and approved, leveraging the California work. IEEE 1547.1, the test standard for smart inverters, has also been approved and will be published soon. I expect this to set off another round of work to harmonize all of the standards. The key point of the 1547 standard was that the DER unit

needs to be grid supportive and fix issues created by the DER addition, such as intermittency, variability, and high voltage.

At the end of 2019, SDG&E had approximately 179,000 PV installations with a nameplate capacity totaling 1,233 MW. In aggregate, this is the largest generator in SDG&E's service territory, which, due to NEM policies, is not directly metered or controlled by grid operators. As a result, grid operators face formidable challenges. They must maintain balance between supply and demand on the grid in real time in the face of fluctuating energy generation from PV systems that can challenge grid stability.

Advancing DER Integration at SDG&E

DER adoption has grown exponentially over the past two decades, and it is poised to continue to expand. At SDG&E, we take pride in having a very streamlined interconnection process. Using an online customer portal, commercial and residential fast-track customers (86% of all applications) can obtain permission to operate in parallel with the grid within 1.3 and 2.5 days, respectively.

Our distribution resource plan incorporated pilots of PV aggregations with smart inverters to attempt primary voltage regulation and microgrid services. Significant investments were made in hosting capacity analysis software that, in a year and a half, changed the distribution planning process. Our load flow analysis went from 1 peak hour of the year to quasi-dynamic 576 h for 10 different DER profiles, looking at two days (typical high and low) for 24 h for each of the 12 months of the year. Engineers at SDG&E also developed a distribution investment deferral framework for distribution services as defined in California: peak thermal overloads, reliability back-tie, resiliency/microgrids, and voltage regulation.

SDG&E also quantifies the nature of the need (e.g., magnitude) for DERs to potentially defer more typical solutions, and there is a distribution planning advisory group and an independent professional engineer reviewing utility projects annually. Wholesale market participation by DERs and aggregations for both energy and ancillary services are available.

We Have Our Work Cut Out for Us

While our industry has made significant strides, there is still a long way to go before we can collectively realize the vision of leveraging DERs for grid services. To help our industry get there, an important next step is to take an open and transparent inventory of the gaps that need to be addressed to ensure the world's energy system remains safe, reliable, resilient, and secure. Progress also needs to be made in the areas of interoperability requirements, validated model-based development, standards development, and end-to-end testing. Additionally, the DOE, its national labs, and other R&D organizations around the globe should leverage their funding to conduct research and pilot studies to resolve these issues and identify, at a macro level, the cost to achieve the end-state vision. The five articles in this issue about the integration of DERs are a start in this direction.

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book review *(continued from p. 108)*

The authors note that the examples and problems are a key part of the treatment of the material and serve two purposes: 1) to illustrate analytical expressions with numerical values and 2) to provide examples of practical power systems. In both cases, the examples and problems show that seemingly complex situations can be solved using some straightforward calculations. Students in a graduate course using this text will be expected to perform dynamic simulations as part of their learning experience.

There is a comprehensive companion website for this book hosted by Wiley at www.wiley.com/go/chow/power-system-modeling. The site is divided into a section for instructors and for students. The instructor site contains examples, lecture slides, problems, and solutions. The student site comprises the examples, including downloads of the computer files needed for dynamic simulations, which can be used directly by the Power System Toolbox (PST), a MATLAB-based software. Computer code for additional models is also available at the companion website. PST is open sourced and free for education use. A user would need a MATLAB license to use PST.

The authors note that Part I of the book is suitable for an advanced undergraduate course for students who have completed an introductory course on power system analysis, while Part III features advanced topics suitable for a second graduate course on power system dynamics.

This book is a welcome addition to the body of literature on power system modeling, computation, and control and will prove valuable both in an academic setting and for practitioners.

—John Paserba



Tom Bialek

distributed generation

leveraging for grid services

IN THE PAST TWO DECADES, SIGnificant progress has been made to deploy distributed energy resources (DERs) in California. The Golden State (as California is nicknamed) now has a much more open planning process where DERs can be utilized for grid services. With the tools and processes already instituted and given the quantity and size of the aggregated deployment, many people believe DERs should be providing these services and enabling utilities to defer large quantities of traditional infrastructure investment.

The reality is that this is not happening yet because leveraging DERs for grid services is not as simple as flipping a switch. There are many technical challenges that we as an industry must first overcome.

During my quest for answers as to why DERs have not yet reached their full potential, I identified some but not all of the technical gaps that must be filled: device interoperability, device and system cybersecurity, unique identifiers for DERs, communication networks, participation decisions, the development of DER management systems (DERMSs), and measurement and verification techniques. Certainly, there are many other potential nontechnical challenges, such as developing provider business models and restructuring legacy compensation and incentives to focus deployment on locational grid needs.

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Grid Challenges Associated With DERs

Interoperability Issues

San Diego Gas and Electric (SDG&E) engineers observed device interoperability issues while attempting to utilize photovoltaic (PV) systems with smart inverters to provide voltage regulation service. In our testing lab, two different inverters of the same model and manufacturer performed differently when tested. In another instance, different energy storage devices responded to charge and discharge requests in very different ways. When running predefined operating schedules, we also observed that some devices returned to a home state first before adjusting to the newly scheduled set points. Finally, customized interfaces are required to communicate to each device and control it.

Cybersecurity

Based on a review of installed DER systems in SDG&E's service territory where I live and work, 58% of all systems utilize an inverter from only two manufacturers. Both leverage the cloud and a customer's Internet connection to monitor and provide firmware updates, and the commands within the inverter utilize Modbus protocols. As the aggregate numbers increase, so do the number of attack vectors. In California, there are approximately 8,000 MW of rooftop PVs installed. Device and system cybersecurity are critical as the grid is operated in a high-penetration DER environment.

Lack of a Unique Identifier

For a DER to provide a service, a request must be made that uniquely identifies the location of the device expected to perform that service. IEEE Standard 2030.5 for common smart inverter profile implementation provides a structure and method for locating devices to service transformers; however, the provisioning of this identification method has not yet been included as part of new system interconnections.

Legacy Inverters

Until 8 September 2017, all DER installations had a legacy inverter designed without critical communications and testing requirements in mind and were installed under some version of a net energy metering (NEM) tariff. In California, the phase 2 communication requirement that allows for manufacturer attestation, not an end-to-end test, was in place 22 June 2020. This creates two issues for utilizing existing DERs for grid services. First, with a NEM tariff that compensates energy exported to the grid at the full retail rate, there is little incentive for customers to do anything else. Second, even if customers would, how would/could they accept a voltage regulation service request, for example, if they do not have a tested smart inverter?

Slow Adoption of Critical Management Platforms

While participating in the U.S. Department of Energy's (DOE's) advanced

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