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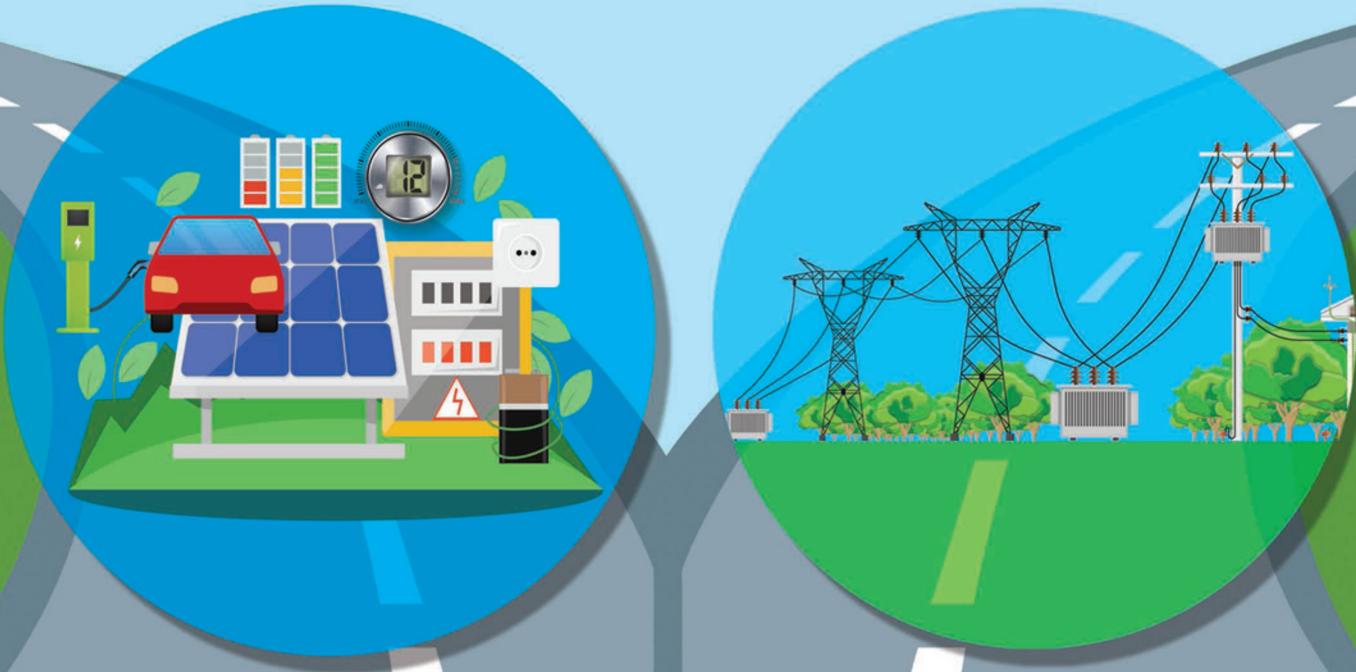
IEEE power&energy magazine

for electric power professionals

An Expanding Route of Choices

Making the Case for Non-Wires Alternatives



100th Anniversary

Milestone in Distribution System Evolution

Class of 2022

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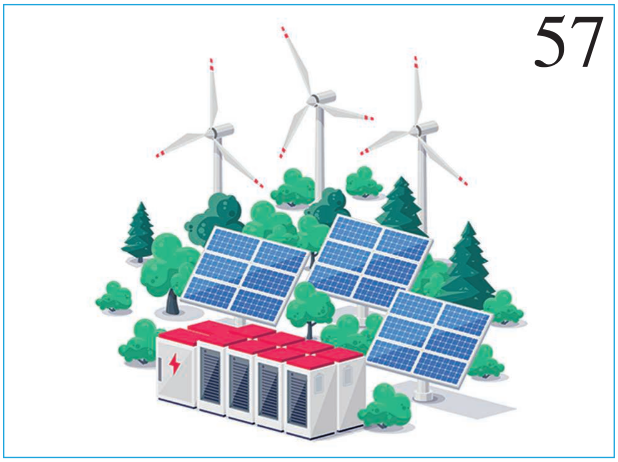

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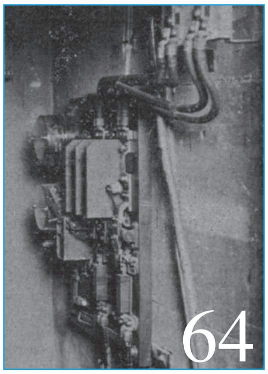
contents

features



columns & departments

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editors' voice

Barry Mather and Steve Widergren

competing choices

planning infrastructure investments

RECENT ISSUES OF *POWER & Energy Magazine* reviewed the transformational implications of high variable renewable energy penetration. This, coupled with the emerging ability to coordinate the operation of smart devices and systems at the distribution and customer levels of the grid bring a new perspective to the future of power system planning and operations.

Microgrids, smart buildings, electric vehicle (EV) charging, batteries, and load management contribute to the notion of harnessing flexibility from distributed energy resources (DERs) to address a host of system operations challenges. Not the least of these is planning investments in the electricity delivery infrastructure. The capital devoted to transmission and distribution equipment and the complexity of siting substations and lines figure into the challenge.

The sizing of the electricity delivery system to satisfy peak periods has historically resulted in poor asset utilization characteristics. As the delivery system expands and changes through this transformation, power system operating organizations have opportunities to coordinate the management of local supply and demand that can influence the calculus. This issue explores initiatives that are underway that value the operational flexibility from DERs to make future investments in the delivery infrastructure more cost-effective.

The sizing of the electricity delivery system to satisfy peak periods has historically resulted in poor asset utilization characteristics.

In This Issue

Nondairy creamer, nonfiction books, and nonalcoholic beer—sometimes, things are best explained by what they are not. So it is with nonwire alternatives (NWAs), meaning approaches that provide a solution without the need for traditional grid upgrades (e.g., not requiring more or higher-capacity "wires.") This issue provides an in-depth look at the NWA landscape where the NWA solution involves DERs, including distributed battery energy storage systems and controlled EV charging.

This topic is of particular interest right now as DER deployment continues to grow at a considerable pace and opportunities for them to provide grid services develop. The potential to implement DER-based NWA solutions to lower costs and increase overall system flexibility is a reality in some service territories and being piloted and considered in many more. The first five articles in this issue discuss the following topics:

- ✔ an overview of U.S. DER-based NWA activities by state, including legislation and other initiatives as well as a discussion of how NWAs are being integrated into distribution planning and operations
- ✔ a detailed look at NWA opportunities in California and the valuation methodology for NWAs for both distribution and transmission systems, along with a view of the changes needed in regulatory policy to fully capture DER-based NWA value
- ✔ a case study from northern California of the costs and overall value of using DERs capable of flexible demand, such as controlled EV charging, to avoid traditional distribution grid upgrades, including an introduction to the new distribution planning approaches needed to assess NWA benefits
- ✔ the challenges of determining the value of NWAs that are highly location-dependent as well as the presentation of a methodology and results of determining the locational marginal value of DERs to mitigate distribution system constraints
- ✔ the findings from a project that sought to evaluate the effectiveness of using auctions to procure NWAs to overcome capacity, energy, and reserve requirements.

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The sixth article in this issue describes the potential for using small modular reactors (SMRs) as a critical part of remote renewable microgrids. It reviews the various SMR types under development and presents an analysis on how an SMR could be integrated into a remote microgrid with wind, solar, and battery energy storage to significantly lessen the battery energy storage requirements when wind and solar resources are not available. At the back of the issue, the "In My View" column returns to the DER-based NWA theme, discussing how DER opportunities relate to increases in power system flexibility and resilience as well as the alignment of environmental, regulatory, and business goals.

Society Meetings and Awards

Feeling a bit stir crazy at the inability to mingle with your peers after two years of COVID-19 restrictions? Vice President of Meetings Wayne Bishop is ecstatic to announce that two major IEEE Power & Energy Society (PES) conferences are preparing for in-person attendance. Bishop invites you to the Transmission and Distribution Conference on 25–28 April 2022 in New Orleans, Louisiana, and the PES General Meeting on 17–21 July 2022 in Denver, Colorado. Read about what is being planned in the "Leader's Corner" column and get ready to look presentable at the opportunities to see your colleagues again.

The "Awards" column presents the PES members elevated to the class of IEEE Fellows for 2022. We recognize each recently named Fellow along with a statement of his or her contribution. The grade of IEEE Fellow is attained by a select few individuals. Congratulations to those awarded this prestigious designation.

> Ralph Masiello and Amin Khodaei have assembled a fine set of authors to cover a broad range of NWA perspectives.

History

On 12 April 1922, a new ac distribution method was proven on Manhattan's Upper West Side (New York, United States). It determined the future of urban distribution and remains its backbone today. On that day, the United Electric Light and Power Company initiated the operation of the first fully successful automatic distribution network. It covered a 30-block area of primarily residential customers with some commercial businesses, mostly stores. In this month's "History" column, we explore the 100th anniversary of this significant milestone in distribution systems.

Timely Update on Power Systems Economics

Editorial Board member Edvina Uzunovic offers her views on the second edition of *Fundamentals of Power System Economics* by Daniel Kirschen and Goran Strbac. An update of power system economics and the related market systems is timely for a couple of reasons. First, the shift toward renewable energy is changing the electric power system landscape with impacts to the generation mix and the need for operational flexibility to address the variability associated with the new generation. Second, smart systems are penetrating all aspects of the electric grid and empowering the coordination of distributed generation, storage, and loads to deliver this flexibility.

In Conclusion

Significant effort has gone into developing this issue on NWAs. Ralph Masiello and Amin Khodaei have assembled a fine set of authors to cover a broad range of NWA perspectives. While mainly North American in origin, the diversity of the topics and complexity of the issues can be shared worldwide. We thank them for their contributions.

The magazine is also thankful to those individuals who regularly submit material to us for publishing consideration. The feature article on SMRs is an example of such a submission. It educates us about developments in the nuclear energy area that have not been covered in recent issues. We look forward to developing material in a future issue on the theme of advancements in generation and energy conversion in general.

We tip our cap to Assistant Editor Susan O'Bryan for her editorial prowess and exceptional hard work on this issue. Recognition also goes to Associate Editor John Paserba for his yeoman efforts to cultivate contributions to the "History" column, Associate Editor Brian Johnson for overseeing the book reviews, and Journals Production Manager, Kristin LaFleur, and the fine folks at IEEE Publishing who polish the raw content into the product before you. p&e

S&C TECHNOLOGY FOR THE ENERGY TRANSITION

The energy transition is intensifying the need for a more reliable and resilient grid. This evolution requires advanced technology to manage changes today and build a foundation for the future. From PulseClosing® Technology, which enables flexibility and unlimited feeder segmentation, to the VacuFuse® II Self-Resetting Interrupter that brings fault-testing to the edge of the grid, S&C's innovations are providing a modern fault-management strategy that reduces operating expenses and improves customer satisfaction. These are the cutting-edge technologies that transform the grid and create a stronger, smarter system.

Experience our solutions at IEEE T&D Booth 8229.

Wayne Bishop, Jr.

welcome back!

in-person meetings return

THE PAST TWO YEARS HAVE CHALLENGED all of us to rethink and reimagine everything we do. With many of us "pent up" since 2020, we can hardly wait to attend the upcoming 2022 IEEE Power & Energy Society (PES) T&D Conference and Exposition on 25–28 April 2022.

This year's T&D will be held in New Orleans, Louisiana. The Crescent City has always been known for its great hospitality, outstanding cuisine, and entertainment, and it is probably the best place to reunite with old friends from the industry. Entergy is the host utility, and it has put together an outstanding technical program, bringing together some of the brightest minds in our industry.

I find it hard to believe that the last T&D was held four years ago. This is an excellent opportunity to reconnect and see what's new in our industry. There will be more than 500 companies displaying their equipment and services. See the product, talk to the manufacturers, say hello to old friends, and make new ones, too, as you network in the exhibit hall. This will be one of the best T&Ds yet and one you won't want to miss!

What's New at This Year's IEEE T&D Conference and Exposition?

T&D Utility Saver Package

To provide utilities with more opportunities to experience the 2022 IEEE PES T&D Conference and Exposition as a team, an exclusive T&D Utility Saver package will be offered. It will allow you to send 10 utility employees with full conference registration for a total of only US$1,000, an enormous discount compared to the cost of traditional registration.

The packages for 10 employees allow various departments and teams within a utility to participate in the meeting. There is no limit on the number of packages a utility can purchase. Bring your team and save on registration!

IEEE Smart Cities Pavilion

New in 2022, the IEEE PES T&D Conference and Exposition is excited to announce the addition of the Smart Cities Pavilion. This dedicated location on the exhibit floor will feature a variety of case study exhibits highlighting effective collaboration to make smarter cities a reality. Technologies will include smart street lighting, advanced electric vehicle-charging infrastructure, sensors, intelligent monitoring, and more.

Innovation Stages

With so many transformational changes happening in the power and energy industry, it is important to keep abreast of all of the new technologies. The IEEE PES T&D Conference and Exposition is the place to go for a wide breadth of new solutions that will deliver the promise of a reliable, safe, and affordable energy grid. Conveniently located on the show floor, Innovation Stages will provide a unique forum to debut state-of-the-art technologies and discuss practical product applications. While onstage, presenters will discuss case studies that offer insights into emerging trends and share valuable best practices. On the exhibit floor, you will be able to hear short presentations from some of the industry's leading suppliers and knowledge providers.

The IEEE PES T&D Conference and Exposition delivers practical, solution-oriented training on key trends impacting the industry, including case studies and lessons learned through a dynamic and robust series of supersessions, forum sessions, panel discussions, poster presentations, and tutorials. The 2022 program features conversations regarding the electrification of infrastructure, the integration and operation of renewables, and lessons learned from the pandemic and recent climate disruptions.

The conference also offers certificates for professional development hours, which can be earned by attending forum and panel sessions, and continuing education units, which are available for tutorials as well as the Plain Talk and Leading Technical Teams workshops. These certificates are useful for professional engineers in states where continuing education is required and attendees wanting to attain and meet their own personal and company developmental objectives. The technical program includes panel sessions, paper forum sessions, supersessions, tutorials, and workshops.

This is an exciting time to be part of the electric power industry with so many changes happening. Many have said that there have been more changes

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in our industry during the last five years than in the last 100. There's no better place to experience and learn about these than the IEEE PES T&D Conference and Exposition. You can hear about these new approaches from some of the world's best speakers at the conference and see some of these new and emerging technologies on the exposition floor. We look forward to seeing you in New Orleans on 25–28 April 2022! For the latest information, please visit our website: https://www.IEEET-D.ORG.

IEEE PES 2022 General Meeting

Every year I look forward to attending the annual PES General Meeting (GM), as I am able to hear firsthand the latest developments in the power and energy industry, including trending current events and ongoing industry changes. I can directly connect with leading peers from pre-eminent organizations and further develop my professional network and technical acumen. While I enjoyed the technical content from the 2020 and 2021 PES GMs, I missed the opportunity to engage with my peers in person.

I am happy to report that the PES GM will return to an in-person event when we meet in Denver, Colorado, United States, on 17–21 July 2022. The last time we met in Denver was in 2015, and we had more than 3,400 attendees from 60 countries participate. The 2022 PES GM's theme is "Powering a Sustainable Future in a Changing World," and it is the premier annual power engineering conference.

If you haven't previously attended a PES GM, this year is the perfect opportunity to get out and see what you have been missing. Gain exclusive access to the current industry news, latest technical content, and global networking opportunities with engineers from around the world. While the technical program is being developed, I can report we will have more than 100 panel sessions. The leading supersession topics include the following:

- ✔ "Extreme Events and Their Impact on Power Systems"
- ✔ "Energy Sustainability"
- ✔ "Artificial Intelligence in Power Systems"
- ✔ "Impact of Power Electronics on Electrical Infrastructure."

The 2022 PES GM organizing committee and Student Meeting Activities Subcommittee of the IEEE PES Power and Energy Education Committee are happy to announce that there will be a student poster session and contest at the PES GM. We are also excited to share that we are bringing back the Student Industry and Faculty Luncheon and Job Fair at the 2022 PES GM. Even though it feels like we have been attending virtual conferences and meetings forever, as organizers, we are anxious to see you in person in April at the IEEE PES T&D Conference and Exposition in New Orleans and in Denver this July for the PES GM!

Ralph Masiello and Amin Khodaei

nonwire alternatives

much ado about nothing?

THE GROWING PROLIFERATION of distributed energy resources (DERs) is perceived as both a challenge and an opportunity for electric utilities. DER integration requires a modernized power grid capable of addressing the two-way flow of power as well as managing increased energy usage, availability uncertainty, and potentially higher feeder hosting capacity to ensure these new additions do not cause network congestion.

At the same time, DERs can be used as viable solutions to provide a multitude of benefits for customers, electric utilities, wholesale energy markets, and the environment. In particular, DERs can serve as nonwire alternatives (NWAs) that defer, reduce, or avoid the need for conventional investments in the grid. Multiple states have legislation, regulatory proceedings, or initiatives underway to mandate the incorporation of DERs as NWAs in technology and development planning. This introduces new complexities in the planning and evaluation of nonconventional alternatives for increasing grid capacity, photovoltaic hosting capacity, and reliability. This issue goes beyond the technical challenges and investigates how to evaluate the benefits NWAs and DERs provide to the grid and compensate for their provided services.

This issue of *IEEE Power & Energy Magazine* focuses on this timely and increasingly important topic by gathering multiple outlooks from leading authorities in the field. The issue comprises six articles. Five provide an all-inclusive view into existing practices, challenges, and the multiple potential value streams of DERs when integrated into the grid. A sixth article offers background on small modular reactors. While different from the NWA theme, a new look at nuclear generation for meeting decarbonization goals is attracting interest.

DERs can serve as nonwire alternatives that defer, reduce, or avoid the need for conventional investments in the grid.

In "Unwiring the Country—The United States' Alternatives Today," Khashayar Mahani and Farnaz Farzan summarize NWA activities, highlighting the ongoing efforts in 13 states and the District of Columbia. They further provide an inclusive perspective into NWA integration into utility practices, including distribution planning and operations, incorporation into the planning cycle, and the role of third-party and NWA stakeholders. The authors rightly conclude that the NWA concept is gaining momentum, and definitions and frameworks are rapidly evolving. However, regulators, stakeholders, and utilities are still in a learning mode concerning constructing and implementing a streamlined NWA-related framework and process.

Beth Reid, Joe Bourg, and Devon Schmidt investigate the impact of climate change on the value proposition for DERs in terms of the overall increased value, specifically as NWAs, in "Let's Make a Deal: Non-Wires Alternatives for Traditional Transmission and Distribution?" Focusing on California as a state seeing a growing proliferation of DERs while being heavily impacted by climate change, the authors provide an overview of valuation frameworks for distribution upgrade deferral, resilience, and reliability from NWAs. The article discusses the regulatory policy and valuation methodology enhancements needed to capture the full value and increase deployments of DER-based NWA strategies. The authors conclude that DER valuation frameworks that do not take additional NWA values into account have led to solutions that undervalue new project solutions and may keep projects from moving forward to development.

Olof Bystrom explains how to capture the value of DERs in "Next-Generation Distribution Planning," sharing the experience of the Sacramento Municipal Utility District with DER integration. The author fittingly mentions that utilities and regulators recognize the potential value of DERs, but few have looked at the implications for distribution planning and the

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required evolution to capture the value of DERs. The article provides a study of DER valuation, looking at different scenarios of business as usual (upgrading the grid to meet the increasing demand) and DER support (for load reduction and investment deferral). The article concludes that capturing DER value requires rethinking legacy planning practices, further providing multiple opportunities.

In "Realizing the Value of DERs," Aleksi Paaso, Nicholas Burica, and Ryan Burg share the experience of Commonwealth Edison Company in valuing DERs and its developed DER valuation software tool that can be integrated into existing planning systems. The authors discuss the unique role of electric utilities in establishing a coherent methodology to fairly value DERs considering associated grid contributions. They mention the significance of this methodology to incentivize the deployment of DERs, promote fair treatment, and support the achievement of broader public goals established by policymakers. They further elaborate on the lessons learned and conclude that continuous development is needed to establish operational models, support customer interactions with utility signals, and encourage participation.

> A new look at nuclear generation for meeting decarbonization goals is attracting interest.

In "Auctions for Nonwires Alternatives," Ali Golriz, Inna Vilgan, Hamza Mortage, Fahimeh Kazempour, and Mohamed Ahmed explore how auction mechanisms can facilitate transactions to enable NWA projects, including identifying the parties to transact with, discovering economically efficient prices, and guiding the allocation of resources. Auctions generally have open, fair, and transparent (while preserving privacy) processes that can lower transaction costs and other barriers to entry for participants. The approach benefits smaller parties using new technologies with less financial wherewithal versus larger or more established ones

The authors demonstrate the performance of an NWA auction in the southern part of the York Region, part of the Greater Toronto Area of Ontario, Canada, and test the processes that a distribution system operator could use to manage DERs as NWAs, with a particular focus on reliability considerations and coordination with wholesale markets. They show that a distribution system operator can use auction mechanisms at the distribution level to manage NWA projects and create an open, fair, competitive, and transparent marketplace, lowering the costs to participate and other barriers to entry.

Dennis Michaelson and Jin Jiang present a summary of the state of small modular reactor plants and their potential role in isolated renewable microgrids in "Integration of Small Modular Reactors Into Renewable Energy-Based Standalone Microgrids." While on a completely different subject than DER-based NWAs, the role small modular reactors may soon play in isolated microgrid systems could be a game changer for managing renewable energy generation variability. As presented by the authors, these nuclear power plants benefit from standardized design and offsite construction and are conveniently sized for inclusion in isolated microgrid systems, which often have high levels of renewable generation. They may find their first use in remote microgrids with traditionally high energy costs.

To wrap up the issue's NWA-focused discussion, Paul Centolella's "In My View" guest editorial provides a comprehensive discourse on some of the policy developments underway, including initiatives beyond North America. He also offers perspectives on where things should go, looking forward.

We hope you find this issue on NWAs informative both about the current state of affairs and real-world problems of implementation that the industry has to work through. As frameworks and processes for NWAs are developed, we can hope that "all's well that ends well." p&e

Unwiring the Country

By Khashayar Mahani and Farnaz Farzan

NONWIRES ALTERNATIVES (NWAs) AND DISTRIBUTED energy resources (DERs) are the main elements of a shift in transmission and distribution planning toward a more multi-stakeholder-engaged paradigm. The concepts around NWA planning, evaluation, and implementation are fast evolving in the United States. Different states, stakeholders, and utilities are experimenting with implementation variations in search of improved outcomes. Goals include reducing utility capitalized rate bases or at least cutting the growth rate of capital, incentivizing additional renewable penetration, and seeking overall lower costs and better energy supply performance. They can be achieved with planning procedures that holistically incorporate grid enhancements and DERs. State initiatives vary in two significant ways. One is the different attributes of DERs that can be brought to bear on NWA options and how cost–benefit analyses are performed. The second involves the roles and responsibilities of utilities, regulators, third-party entities engaged in evaluating utility plans and NWA proposals, and DER developers and stakeholders.

The first part of this article provides a summary of NWA activities and approaches in certain states. Several states are also compared and contrasted concerning roles and responsibilities they assume for different parties in NWA implementation. The second part focuses on a few aspects of NWA integration into distribution utility planning and operations. In particular, the role of third-party independent entities is discussed in more detail, as NWAs have opened discussions

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The United States' Alternatives Today

around expanding the role of outside parties beyond what has been traditionally considered within utility planning frameworks.

Summary of States' NWA Activities

Several states have ongoing activities to mandate and incentivize DERs as NWAs to defer and avoid grid investments as part of utility capital planning processes. These activities align with the regulatory objectives of fair rates, reliable service, societal and environmental benefits, and public safety. While some U.S. utilities are choosing to explore NWA opportunities on their own, a significant number of projects result from state-level regulatory processes and activities. In many states, NWA initiatives are targeted at deploying energy storage for grid services among other applications that incorporate power storage as part of routine utility planning. The activities summarized here are shown in Figure 1 and classified as investigation, initiative, and legislation. *Investigation* refers to states with proceedings to gather information and seek stakeholders' inputs. *Initiative* represents states with orders requiring utilities to make proposals and gather stakeholders' comments. *Legislation* denotes states with specific mandates from legislatures and utility commissions. The benefit streams that are "counted" in different state NWA frameworks vary to some extent. Table 1 summarizes this situation.

California

California is one of the pioneers in establishing formal NWA programs. In 2013, it was the first state to set an aggressive energy storage procurement or deployment target of 1,325 MW (with a maximum of 50% utility ownership) by 2024. In 2016, a bill (AB 2868) was signed into law, allowing 500 MW of energy storage to be rate based by the three investor-owned utilities (IOUs) in the state. The law also permits utility ownership of behind-the-meter storage as long as that does not unreasonably limit or impair the ability of nonutility enterprises to market and deploy energy storage systems.

Also in 2013, the California Public Utilities Commission (CPUC) instituted section 769 of the California Public Utilities Code, requiring electrical corporations to file distribution resources plan proposals. The objective was to identify optimal locations for the deployment of DERs. The code further instructs the CPUC to review plan proposals submitted for approval and modification to maximize ratepayer benefits from utilities' investments in distributed resources. Another important activity was conducted by a locational net benefits analysis working group examining the locational value of DERs, considering various value streams, such as transmission and distribution capacity deferral, wholesale energy market participation, and environmental benefits.

To further promote the deployment of distributed resources, the CPUC approved a pilot regulatory incentive mechanism that awards a 3–4% pretax incentive to utilities deploying cost-effective DERs that defer and displace traditional distribution investments. In addition, the body directed IOUs to procure at least 150 MW of preferred resources (e.g., energy efficiency, solar photovoltaic, and power storage resources). In 2018, it instructed IOUs to submit distribution deferral opportunity reports identifying prospects for DERs to cost effectively postpone and avoid traditional IOU investments to mitigate forecast distribution system deficiencies. These opportunities should be identified by using a set of screening criteria to ensure

that DER solutions are technically feasible and that sufficient time exists to issue requests for proposals.

To promote transparency, IOUs are also required to provide assessment reports and publish their locational net benefits analysis data, similar to integration capacity analysis maps. IOUs have hosted and participated in workshop processes to develop tools related to capacity and locational benefit analyses. There also has been standardization in the state for developing DER growth scenarios and load forecasts.

Colorado

The Energy Storage Procurement Act of 2018 required the Colorado Public Utilities Commission to establish mechanisms for the procurement of energy storage systems as part of utility planning processes. The bill also increased the renewable energy standard to 30% by 2020 for IOUs (i.e., Xcel Energy and Black Hills Corporation). Legislation requiring 3% of all electricity sales to come from renewable distributed generation by 2020, the Energy Storage Procurement Act, was signed in 2018, directing the Public Utilities Commission to establish mechanisms for the procurement of energy storage systems as part of utilities' planning. Xcel Energy and Black Hills also created a working group to analyze the benefits and challenges of energy storage and other NWA technologies.

Connecticut

In June 2019, the Connecticut General Assembly energized the rapidly growing energy storage market by enacting legislation authorizing electric distribution utilities to own and rate base wholesale storage generation assets for the first time since industry restructuring was authorized, in 1998. The law allows utilities to build, own, and operate unlimited quantities of energy storage systems and automatically recover prudently incurred costs from ratepayers. A senate bill (SB 952) signed into law in June 2021 also establishes a target of 1,000 MW of energy storage by the end of 2030.

In October 2019, the state's Public Utilities Regulatory Authority (PURA) issued an interim decision (docket number 17-12-03) outlining PURA's framework for investigating methods to achieve an equitable modern electric grid. Several topics were identified for investigation in three phases from 2019 through 2021. In June 2020, NWAs were investigated as part of phase 3, whose objective was to establish a transparent and competitive process for comparing potential NWAs against traditional distribution system upgrades and other utility expenses. In March 2021, Eversource, an IOU, submitted its NWA screening process consisting of three phases: 1) technology screening and approval, 2) one NWA screening process per identified need (the company has an in-house tool for this screening phase), and 3) vendor qualification and NWA-based solution deployment.

District of Columbia

In December 2019, the Public Service Commission of the District of Columbia passed an order to consider NWAs to defer distribution substation projects. According to the directive, the following factors are considered:

- ✔ the ability of NWAs to manage peaks caused by extreme weather conditions and provide capacity during rest of the year for transformers' N-1 contingency scenarios
- ✔ the controllability and robustness of communications for customer-owned storage resources
- ✔ safety considerations and standards (e.g., the fire code) for deploying stationary energy storage systems, particularly in densely populated urban locations.

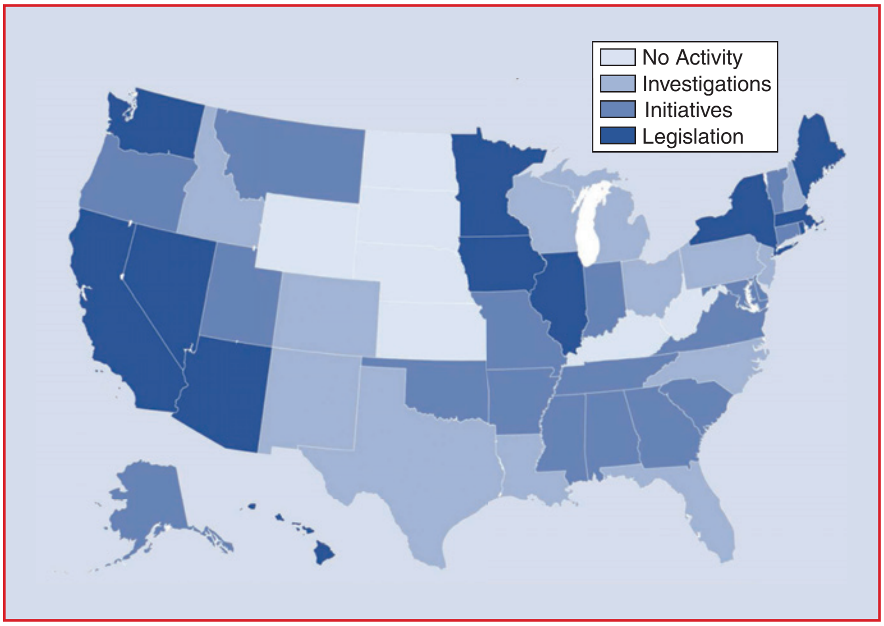

figure 1. The NWA activities in different states.

Hawaii

Hawaiian Electric is pursuing integrated grid planning that would expand opportunities for resources, grid services, and NWAs for the transmission and distribution system. The Hawaii Public Utility Commission approved the plan in March 2019, and a soft launch was set to demonstrate the sourcing and evaluation of NWAs the same year. Hawaiian Electric was seeking solutions, including aggregated DERs, that could defer the expansion of East Kapolei's (located in Oahu) distribution capacity, which was forecast to be impacted by considerable load growth. The sourcing was technology agnostic and included behind- and front-of-the-meter solutions.

Other highlights of this planning process include the following:

- establishing customer-centric planning
- creating greater market opportunities for DERs and demand response providers and grid-scale developers
- enabling the development of an optimal portfolio of solutions to address resource, transmission, and distribution needs
- maintaining transparency through multilevel stakeholder engagement and an independent technical advisory panel
- implementing a streamlined 18-month planning process culminating in a five-year integrated plan with discrete proposals submitted to the Public Utility Commission for review
- facilitating most of the key aspects of the integrated grid planning development process, such as forecast assumptions and market barriers, through subject matter expert-based working groups.

Illinois

In 2017, the Illinois Commerce Commission launched NextGrid, an initiative to create a shared base of information about electric utility industry issues and opportunities for grid modernization. It is based on collaboration between key stakeholders and includes several working groups of subject

table 1. The benefit value streams in selected states.

Value Category	Value Stream	State											
		CA	MA	NY	NV	HI	IL	NH	CO	MD	MN	ME	NJ
Generation	Avoided energy	■	■	■	■	■	■	■	■	■	■	■	■
	Avoided fuel hedge			■					■	■	■		■
	Avoided capacity and reserves	■	■	■	■	■	■	■	■	■	■	■	■
	Avoided ancillary services	■		■	■	■	■		■			■	
	Avoided renewable procurement	■	■		■			■		■			■
	Market price reduction		■	■			■	■		■		■	■
Transmission	Avoided deferred transmission investment	■	■	■	■	■	■	■	■	■	■	■	■
	Avoided transmission losses	■	■	■	■	■	■	■	■	■	■	■	■
	Avoided transmission operation and maintenance			■									
Distribution	Avoided deferred distribution investment	■	■	■	■	■	■	■	■	■	■	■	■
	Avoided distribution losses	■	■	■	■	■	■	■	■	■	■	■	■
	Avoided distribution operation and maintenance			■									
	Avoided reliability costs	■		■			■						
	Avoided resiliency costs	■		■			■						
Environmental/society	Monetized environmental/ health benefits	■	■	■	■		■	■	■	■			
	Social environmental benefits			■		■				■	■	■	■
	Security enhancement/risk		■	■			■						■
	Societal (economy/jobs)		■	■			■			■			■

CA: California; MA: Massachusetts; NY: New York; NV: Nevada; HI: Hawaii; IL: Illinois; NH: New Hampshire; CO: Colorado; MD: Maryland; MN: Minnesota; ME: Maine; NJ: New Jersey.
Source: "Locational Value of Distributed Energy Resources."

matter experts from utilities, businesses, and environmental organizations. The groups identified solutions to address challenges facing the state as it moved into the next stage of electric grid modernization, including new technologies and policies to improve the network. The NextGrid process identified the value of DERs to the grid as a key topic. This built on the Future Energy Jobs Act, calling for the implementation of locational and temporal DER evaluation after a 5% threshold of photovoltaic penetration was passed. The 2021 Clean Energy Job Acts (SB 2408) revised this, extending the photovoltaic incentives, creating a new photovoltaic-plus-storage incentive, and requiring utilities to prepare filings addressing additional avoided-grid-cost benefits and evaluations.

Maine

In 2019, the Maine legislature passed an act to manage electricity costs by using NWAs. Based on this law, every IOU must produce an annual subtransmission and distribution plan and identify forecast needs and corresponding traditional grid upgrades. This plan must analyze system requirements for the next five years and provide a schedule and associated costs. Moreover, system capacity and forecast loads by substations and circuits must be described.

Further, utilities need to perform NWA opportunity screening for the identified needs. NWAs will be considered if the estimated cost of a traditional grid project is more than US$500,000. For distribution projects above that threshold, an NWA solution will be analyzed if there is a reasonable likelihood that it would be more cost effective than a proposed wire project. Projects with one of the following criteria are excluded from NWA screening:

- ✔ They are needed for redundant supply to a radial load.
- ✔ They are necessary to address maintenance, asset condition, and safety needs.
- ✔ They are required to solve stability and short circuit problems.
- ✔ They must be in service within one year.

Massachusetts

In February 2019, the state's Department of Public Utilities issued two orders for storage rules that opened revenue streams to utilities, third-party developers, and customers. The orders clarified net metering rules for solar-plus-storage facilities and capacity rights ownership to dispatch storage resources. In early 2021, a bill (S.2144) was introduced in the Massachusetts Senate, requiring every electric utility to prepare a grid modernization plan every three years. The plan is required to do the following:

- ✔ evaluate the locational benefits and costs of current local energy resources and identify optimal areas for local energy resources during the next 10 years, based on reductions and increases in regional generation capacity and demand, avoided and increased investments in transmission and distribution infrastructure, safety benefits, and reliability benefits, including other savings local energy resources provide to the grid and avoiding costs to ratepayers
- ✔ provide information about the interconnection of distributed generation via hosting capacity maps that are accessible to the public and updated regularly
- ✔ update interconnection procedures for distributed generation
- ✔ propose and identify locational-based incentives and other mechanisms for the deployment of cost-effective local energy resources that satisfy planning objectives
- ✔ propose cost-effective methods of coordinating programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of local energy resources
- ✔ identify additional utility spending to integrate cost-effective local energy resources into distribution planning
- ✔ recognize additional barriers to the deployment of local energy resources.

Minnesota

In August 2018, the Minnesota Public Utility Commission approved integrated distribution planning requirements for Xcel Energy. This framework orders Xcel to develop processes that analyze the value of DERs to the distribution grid. The Public Utility Commission requires Xcel Energy to file an integrated distribution planning report annually and smaller utilities to file every two years, specifying distribution investments five years into the future. Utilities are to itemize nontraditional distribution projects, including NWA analysis.

Xcel Energy filed its second integrated distribution planning report in November 2019, indicating that in future analyses, the utility would consider locational net benefits. In this plan, Xcel Energy also reviewed the viability of using a portfolio of demand response, storage, and solar as NWAs for nine distribution system projects. In June 2019, the Minneapolis-based Center for Energy and Environment launched an NWA pilot in partnership with Xcel Energy to test whether targeted energy efficiency and demand response promotion could defer distribution grid investments.

Nevada

Nevada lawmakers have approved several clean energy and energy storage bills. In 2017, a bill (Senate Bill 204) directed state regulators to consider requiring utilities to purchase energy storage in the following years. A separate piece of legislation (Senate Bill 145) would establish an incentive program for energy storage within the state's solar program. Nevada Senate Bill 146, passed in June 2017, required Nevada Energy to submit a distributed resources plan to the Public Utility Commission of Nevada by 1 April 2019 as an addendum to its integrated resource plan. The plan's requirements included the following:

- ✔ evaluation of the locational benefits and costs of DERs
- ✔ proposed standard tariffs for the deployment of cost-effective DERs
- ✔ a proposal for cost-effective methods of coordinating existing programs to maximize the locational benefits of DERs
- ✔ identification of additional spending to integrate distributed resources into distribution planning
- ✔ classification of barriers to DER deployments.

The commission opened an investigation and rulemaking docket in July 2017 and approved temporary regulations in 2018 that established the filing, content, approval, and updating process for distributed resources plans. In 2018, it approved an order requiring Nevada Energy to incorporate DERs, such as solar and energy storage, into its three-year system plan. The requirements for the distribution resource planning outlined the following key components:

- ✔ a forecast of the net distribution system load and DER penetration (both energy and nameplate capacity) at the system, substation, and feeder levels
- ✔ a hosting capacity analysis to determine the number of DERs that can be accommodated on each feeder section without adverse impacts
- ✔ a locational net gains analysis supporting a location-specific cost–benefit analysis of DER projects to serve as the basis for comparison between NWAs and traditional solutions
- ✔ a grid needs assessment that combines the three preceding components for an analysis of NWAs to identify constraints on the electric grid as well as infrastructure upgrades and DER projects that may provide solutions to those restrictions.

New Hampshire

In 2016, the state legislature passed a bill requiring the New Hampshire Public Utilities Commission to initiate a proceeding to develop new alternative net metering tariffs. Recognizing that more information would be needed to inform the process, the commission ordered a value-of-DERs study and NWA pilot. In 2018, a systemwide value-of-DERs study scope was proposed, but the commission decided to modify its NWA pilot into a study of the locational value of distributed generation. The goal was to determine the avoided costs of deferred capacity investments at the distribution level. This became the focus of New Hampshire's work under the Multistate Initiative to Develop Solar in Locations That Provide Benefits to the Grid project.

In 2018, Public Utilities Commission staff began gathering stakeholders to develop a locational-value-of-distributed-generation study scope and held a public, in-person technical workshop focused on it. In 2019, the staff filed a proposed study scope, which was followed by a public hearing and written comment period before final commission approval with some modifications. The selected approach will closely follow current utility planning methods and practices to best represent investment decision making in the New Hampshire context. Consultants will work closely with the state's three regulated utilities through three high-level steps: 1) identifying locations for detailed analysis, 2) determining avoided and deferred investment costs, and 3) assigning values, using load profiles to map against generation profiles. This study scope has formed the basis of a request for proposals to solicit a vendor to conduct the analysis.

New York

One of the objectives of New York's "Reforming the Energy Vision" is to incentivize utilities to leverage the deployment of DERs to address problems traditionally handled by new investments in centralized generation, transmission, and distribution infrastructure. In early 2016, the New York Public Service Commission issued formalized guidance to utilities, requiring that they file NWA candidate opportunities in their distributed system implementation plans. It further directed every utility to file a benefit–cost analysis handbook including methods and formulas for calculating utility-specific DER values and avoided costs (project- and location-specific when applicable) in the context of NWA projects.

The utilities were also required to propose NWA suitability criteria as part of their planning procedures and identify all projects in their five-year capital plan to meet the conditions and indicate when NWA solicitations would be issued. The proposed suitability criteria developed by the joint utilities consider eligible project types, such as load relief, reliability, power quality, conservation voltage reduction, and resiliency. Any project that requires the relocation of an existing facility or investment in communication and software capabilities is excluded. A timeline and minimum grid project cost threshold (e.g., US$1 million for large projects) are other stipulations. From 2020 data, New York utilities had 45 current and upcoming NWA procurements listed on their "Joint Utility" website and summarized in their distribution system implementation plans. Among the projects, the success rate in terms of implemented NWAs was 18%.

The Public Service Commission further required regulated utilities to propose tariff-based compensation to DERs based on the stack of values that can be delivered, including wholesale energy, capacity, environmental value, demand reduction, and locational system relief based on marginal-cost-of-service studies. New York also has an energy storage road map. It identifies short-term recommendations for how power storage can deliver value to consumers and cost effectively address the grid's needs and demands. This supports the governor's energy storage target of 1,500 MW by 2025.

Rhode Island

According to the Comprehensive Energy Conservation, Efficiency, and Affordability Act passed in 2006, the state's utilities are required to consider NWAs to defer transmission and distribution investments in their annual system reliability procurement plan. In addition, according to updated Rhode Island Public Utility Commission "Least Cost Procurement Standards," the utilities must evaluate NWAs based on the following criteria:

- ✔ The need is based on asset conditions.
- ✔ The cost for the grid solution is more than US$1 million.
- ✔ If load reduction is necessary, it must be less than 20% of the relevant peak in an area.
- ✔ The start date for a traditional grid project is at least 30 months in the future.

The procurement standards also encourage the utilities to consider hybrid solutions if NWAs can defer only part of traditional grid investments. Thus, cost-effective combined NWAs and grid bundles would be studied.

figure 2. The role of different actors in NWA implementation.

Virginia

The Grid Transformation and Security Act (2018) allowed Dominion Energy Virginia to invest in up to 30 MW of battery storage pilot projects. In August 2019, the utility signed off on four projects with a combined capacity of 16 MW to expand opportunities for additional energy storage to support its boost in renewables and improve grid reliability. These pilots were to help Dominion analyze the use of energy storage for grid stability support instead of traditional system upgrades. There is also an administrative code in Virginia (56-585.5 D 4) that requires utilities to address NWA programs and file for approval of NWA initiatives related to energy storage every year.

NWA Implementation in Utility Distribution Planning and Operations

Integrated distribution planning offers an opportunity for increased transparency and an improved ability to inform and obtain input from stakeholders. The main method of achieving greater transparency is stakeholder engagement, which has been a component of integrated distribution planning processes in Hawaii, California, and other states. Increased transparency can lead to greater investment support, innovative solutions to grid constraints, and additional benefits. Key to the success of NWA implementation is the clear definition of responsibilities for various actors (commissions, utilities, market operators, independent third-parties/evaluators, DER developers, and stakeholders) and effective coordination among them.

Figure 2 illustrates the main steps of an NWA implementation life cycle along with actors involved in each stage. The process starts with load, DER, and electrification forecasts. As shown, a utility is engaged in almost every stage and often plays the lead role except for operating NWAs for market applications where an independent operator would assume the main responsibility. Even for market applications, the utility needs to be involved to make sure DER market participation does not compromise the reliability of the distribution grid. Similarly, for NWAs owned by a third party, the utility is not engaged in the construction phase.

The role of the commission is normally related to the review and approval of a utility's plans and decisions except load and electrification forecasts, which in California are the responsibility of the CPUC. Third-party independent entities are typically engaged to review and audit steps such as issuing requests for proposals, proposal evaluation, and benefit–cost analysis of NWAs versus grid investment. Feedback and inputs from DER developers and stakeholders concerning certain steps, such as NWA requirements, technology and configuration feasibility, and benefit–cost analysis, would be very helpful in the process. For NWAs owned by third parties and for nonreliability DER operations (e.g., behind-the-meter backup generation), developers should assume the lead role.

NWA Integration Into Utility Planning Cycles

Many distribution system upgrades are done on an annual cycle. In the fall, capacity and reliability issues exposed in the summer will drive planning, and construction is planned for the spring to be operational well before the next summer peaks. Projects are planned based on the uncovered problems, and engineering designs are executed to budget these projects. Once reviewed and approved, the projects proceed to procurement and construction. The timing of this cycle poses some challenges to incorporating NWA evaluation, developing NWA requests for proposals, reviews by independent third-party entities, procurement, negotiation, and contracting, constructing, testing, and certifying NWAs. Further, this cycle does not facilitate grid investment as a fallback should the procurement fail. Therefore, it is necessary to develop a set of suitability criteria to guide utility planners as to which projects should be evaluated for NWA potential.

For example, the routine end-of-life replacement of assets (poles, transformers, and circuit breakers) is always going to be more economical and faster than any NWA approach and should be excluded. The alternative is to extend the planning cycle to accommodate the NWA procurement process. California is one of the states that has excluded these routine, short-term grid upgrades from consideration for NWAs for this reason. Without a properly defined set of criteria, the utility planning and budgeting process must be compressed without compromising the quality and accuracy of the results. The quality and accuracy of budgeting, in particular, are critical, as they are the basis of evaluating NWA solutions.

NWA Operations

Utilities should develop detailed and comprehensive NWA operational requirements, especially for nonutility-owned and operated NWA, as these will provide critical reliability services to the distribution grid. Unlike in wholesale energy markets, the performance of a resource in the distribution grid is not fungible. That is, in wholesale markets, if a resource fails to meet its scheduling or dispatch, the market will have ensured sufficient reserves to replace it at the moment, and the nonperforming resource bears the cost of that plus any applicable penalties. When an NWA resource fails to perform, however, some grid constraint is presumably violated, with implications for asset life, potential customer service interruptions, and quality reduction. In the worst case, there could be more than just an underserved load if grid and customer equipment is damaged.

Different mechanisms can be established to mitigate NWA nonperformance issues. For example, a utility can acquire the equivalent of NWA capacity reserves that are available should primary NWAs fail to ensure the reliability of the system. Some nonperformance provisions need to be specified in the contracts with the NWA operator, reflecting the possible costs to consumers and the utility. The utility should also include reasonable NWA monitoring and operational control requirements via integration into its systems to ensure compliance.

Role of Third Parties and NWA Stakeholders

Many stakeholders recommend that an independent third party play a significant role in different stages of NWA planning and deployment. Consequently, some public commissions intend to write into law specific roles for independent entities, from reviewing utility plans (e.g., Connecticut's strawman proposal) to assessing NWA offers. These stakeholders argue that involving third parties would improve the transparency of utility planning and decision-making processes, enable a leveler field for NWAs to compete with traditional solutions, and result in more NWA deployment.

Currently, the level of stakeholder engagement varies by state according to integrated distribution planning and NWA procedures. In California, independent evaluators should review utilities' grid assessments, traditional upgrade candidate solutions eligible for NWA evaluation, and NWA decisions within a preestablished program framework. However, evaluators neither conduct grid assessments nor design NWA solutions. The state uses a distribution investment deferral framework to assess the potential of NWAs and procure DERs as infrastructure investment alternatives. Utilities are responsible for grid planning and soliciting and evaluating bids, and evaluators are responsible for monitoring the process and verifying evaluations. Third parties can also advise utilities on the operation and control phase by providing technical, operational inputs for different technologies.

In New York, developers (aggregators) operate/control DERs based on need assessments conducted by utilities in accordance to design parameters. The role of stakeholders in NWA planning and decision steps is limited to providing input and feedback about the methodology and framework adopted by utilities. One of the highlights in Hawaiian Electric's proposed integrated grid planning in 2018 was a multilevel stakeholder engagement that included designing different utility-led working groups. The groups advised the utility by providing input and feedback on the methodology of different steps, from load and DER forecasting to NWA decisions and benefit–cost analysis. While stakeholders' engagement is necessary to promote a transparent and increased integration of NWA into the electric grid, given the highly technical and critical nature of utility planning and operations, there are some considerations to be made to effectively involve third parties without compromising the reliability of the distribution system.

Conclusions

Until recently, this summary would have been limited to California and New York. Today, a significant portion of the United States has legislation, commission orders, and investigations underway. The NWA concept is gaining momentum. Details regarding definitions, frameworks, scopes, roles, and responsibilities are rapidly evolving. Regulators, stakeholders, and utilities are still very much in a learning mode concerning constructing and implementing a streamlined NWA-related framework and process.

Utilities are responsible for grid investment plans to ensure the reliable, safe, and equitable delivery of power to consumers in a cost-effective manner. DERs can and should be an integral part of grid planning in a systematic way, as they can realize avoided-cost benefits, among others. Besides the theoretical questions about how to calculate and capture the benefits, there are numerous planning, policy, and implementation considerations to be accounted for to seamlessly integrate NWAs into utility planning and operations.

Frameworks for lowering grid costs through DERs continue to be evaluated. However, to have an accurate and fair evaluation, there should be a two-by-two matrix of costs and benefits on both axes. While a final decision will incorporate the direct costs of a DER solution (via a request-for-proposals process, for example), benefits beyond solving immediate planning problems are not considered. For instance, the benefit of a grid investment in terms of increasing hosting capacity is not taken into account in most frameworks. The value of the grid has been taken for granted for decades, but now it needs to be assessed against the value of DERs. This and other issues will have to be resolved through time as the NWA concept's implementation evolves and matures.

Articles in the popular media focused on decarbonization and electrification have recently begun mentioning that major grid investments will be needed to accommodate the electrification of transportation, buildings, industry, and even agriculture. Decarbonization leads to increased distributed renewable resources, e.g., DERs, so planning the grid investments needed in the short-to-medium term to enable full-bore electrification in the medium-to-longer term will necessarily include integrated planning and NWAs. Today's NWA planning efforts can be seen as the first steps in developing a process for grid investments supporting electrification.

For Further Reading

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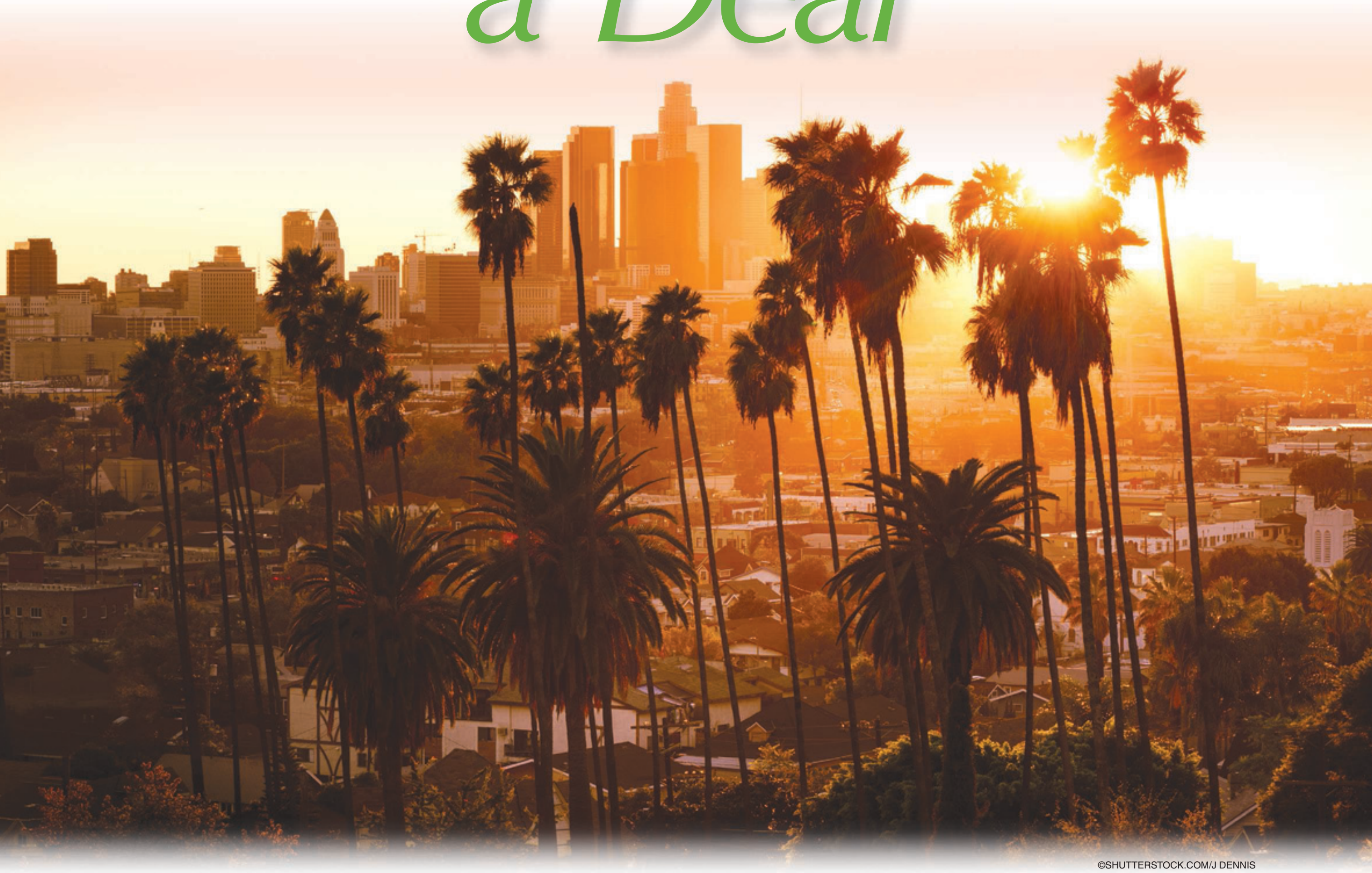
Let's Make a Deal



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By Beth Reid, Joe Bourg, and Devon Schmidt

Non-Wires Alternatives for Traditional Transmission and Distribution?

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CLIMATE CHANGE MITIGATION AND ADAPTATION strategies are having a profound impact on California's regulatory policies, electrical system loads, and resource planning strategies. This changing landscape is ushering in a new era of opportunity for the use of distributed energy resources (DERs) in nonwires alternatives (NWA) applications.

For this article, the authors have defined DERs as resource portfolios comprised of distributed generation, energy storage technologies, and flexible loads. Increased loading on transmission and distribution lines and rising demand for energy supplies are creating

> As these mitigation strategies multiply, there is a need to balance decarbonization strategies with maintaining the reliability and resiliency of the grid.

opportunities for DER-based NWA solutions as a result of 1) climate-related events, such as heat storms and wildfires; and 2) climate change mitigation strategies, such as regulatory requirements for deployment of clean energy generation and electrification initiatives to replace natural gas end-use equipment. This article explores how climate change impacts are changing the value proposition for DERs in terms of overall increased value, and specifically the increased value that DERs can provide in NWA applications.

The deployment of climate change impact mitigation strategies is causing serious challenges to maintain the reliability and resilience of California's electrical power system. Mitigation strategies such as the increased deployment of clean energy generation to meet California Renewable Portfolio Standards (RPS) of 60% carbon-free resources by 2030 and 100% by 2045, with largely intermittent resources like solar and wind, have significantly altered the state's system supply profile. In the summer months, these impacts are characterized by 1) an abundance of renewable energy in the morning and early afternoon hours, 2) a dramatic "ramping" period from 3 to 6 p.m. caused by decreasing renewable energy supply coupled with increasing demand driven by cooling loads, and 3) a capacity-constrained peak period between 6 and 9 p.m. This problem is amplified by frequent and prolonged climate-induced high-temperature events, resulting in escalating cooling loads that cause additional stress on the grid.

Mitigation strategies, such as electrification of cooling equipment, water heaters, and vehicles, are adding demand to the grid resulting in increased system strain unless these devices are operated flexibly. As these mitigation strategies multiply, there is a need to balance decarbonization strategies with maintaining the reliability and resiliency of the grid. A key theme of this article is to demonstrate how regulatory policies, valuation methodology enhancements, and DER deployment strategies can support decarbonization initiatives while providing NWA benefits of resiliency, reliability, and transmission and distribution (T&D) capacity upgrade deferral services.

This article reviews 1) the current NWA landscape in California, 2) the impacts of climate change on electrical system requirements and planning, 3) an overview of valuation frameworks for distribution upgrade deferral, resilience, and reliability from NWAs, and 4) and discusses the regulatory policy and valuation methodology enhancements needed to capture the full value and increase deployments of DER-based NWA strategies.

California NWA Landscape

The following sections provide an overview of the NWA landscape in California, including regulatory and planning processes for deferring distribution upgrade investments and resiliency measures, completed project summaries, and current procurement methods for grid services provided by NWA projects.

Regulatory Frameworks for Distribution Deferral

Growth in DER installations has increased dramatically among residential, commercial, and industrial consumers throughout California in recent years. They have purchased rooftop solar, electric vehicles, energy storage systems, smart thermostats, and other grid-enabled devices without significant central or localized planning. This has resulted in variable localized grid impacts, and California's utilities have sought out various mechanisms to help balance the distribution system with customer-sited DERs.

To begin addressing the need for more central and localized planning of DERs in NWA applications, the California Public Utilities Commission (CPUC) launched the Distribution Resource Plan proceeding in 2014 to identify strategies to incorporate DERs into IOUs grid investment planning processes. The result included the Distribution Investment Deferral Framework (DIDF), wherein utilities perform an annual review of their five-year grid investment priorities and identify those projects that could be replaced or deferred through DERs. The identified projects are then ranked into "tiers" of potential deferral opportunity based on cost-effectiveness, forecast certainty, and market assessment. Projects in Tier 1 are considered the best candidates for NWAs because they have the best chance of deferring investment for 10 years. Once projects are selected and ranked, the investor-owned utility (IOU) conducts a request for offers (RFO) to select projects to be awarded and developed.

Across all three of California's electric IOUs—Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—31 projects were proposed involving over 100 MW of capacity. Two have been completed to date, and 11 were canceled or were not awarded a contract. Projects were canceled either because the substation was in a wildfire burn area or load forecast resulted in the specification of traditional distribution upgrades. The IOUs did not award contracts for other proposed projects because no subset of offers met the project requirements or the proposed project was deemed not to be cost-effective.

Of the projects, SCE has procured DER solutions for seven proposed deferral projects totaling 35 MW of capacity, and PG&E has offered contracts for 13 DER-based deferral projects with 30 MW of capacity. SDG&E did not award any deferral contracts or identify an eligible distribution investment project in either 2019 or 2020 DIDF cycles. Further details on the results of the DIDF solicitation are shown in Table 1.

As demonstrated by the limited number of procured projects and the lack of implemented solutions, the existing DIDF process has been slow to result in NWAs effectively replacing traditional grid investments. Some stakeholders maintain that the limited efficacy is attributable to several factors. For one, the framework directs utilities to take action counter to the incentives established for regulated utilities. In the regulated context, utilities are incentivized to make traditional investments designed to improve system reliability because these investments allow them a guaranteed rate of return.

A 2020 Greentech Media article states, "NWAs, by contrast, ask utilities to rely on third-party DER providers or aggregators to deliver the same level of reliability, and they offer no clear path to recovering costs involved, even if they're lower than a traditional upgrade." However, NWAs can benefit a utility by providing opportunities to distribute the risks of a project across both the utility and the DER provider. The utility internalizes the risk associated with overloading lines if the DER does not perform, while the DER provider is at risk of not getting paid if the DER is unable to perform.

As a result of the slow progress of the DIDF RFO process, the CPUC developed two more procurement mechanisms to encourage NWA deployment: 1) the IOU Partnership Pilot and 2) the Standard Offer Contract (SOC) Pilot. The IOU pilot creates a new tariff for IOUs to support DER procurement. It requires that the utilities prescreen energy solutions providers (ESPs) to help customers in targeted locations enroll their DERs into the program. The budget cap for each project will be 85% of the estimated conventional wires-based upgrade cost, ensuring at least 15% savings to ratepayers when projects are implemented. Of this budget, ESPs will receive 20% of the budget allocation for new DER installations, 30% as a capacity reservation payment, and the remaining 50% for event-based performance when dispatched by the utility.

The second proposed pilot mechanism, the SOC pilot, is a three-year program focused on securing larger-scale front-of-the-meter solutions that address a distribution need identified in the DIDF. The SOC pilot differs from the existing RFO mechanism as it requires the utility to select one Tier 1 candidate project each year to enter into the standard offer process. The utility will document the set of DER services necessary to defer investment and produce a price sheet indicating the utility's willingness to pay for DER products. When 90% of the project need is met by DER provider offers, the utility has enough confidence in achieving 100% or better that they will enter into a contract with the providers that submitted conforming bids and move forward with the deferral.

SCE has implemented two DER projects for NWA applications that have successfully deferred distribution investment. In 2015, SCE procured a 2.4 MW/3.9 MWh in-front-of-the-meter battery to avoid a distribution update of a new circuit management system. The battery is maintained by a third party but is owned and operated by the utility. In addition, SCE procured 85 MW of behind-the-meter energy storage that offers flexible capacity throughout the Western Los Angeles Basin. This capacity allows SCE to balance the grid in local reliability subareas during critical peak times.

Regulatory Frameworks for Incentivizing Resiliency and Microgrid Installations

In support of the need for increased resilience in the California electric grid, NWA solutions and microgrids are being proposed as a strategy by regulatory authorities. In 2019, the CPUC launched the "Order Instituting Rulemaking" to formally initiate the Resiliency and Microgrid Proceeding. The proceeding aims to facilitate microgrid deployment and

table 1. DIDF solicitation results.

Investor-Owned Utility	Advice Letter Year	Proposed Capacity (MW)	Number of Proposed Deferral Projects	Number of Projects Awarded
PG&E	2017	4	1	0
	2018	12.6	4	4
	2019	>14.5	4	2
	2020	>19.2	7	7
SCE	2017	0	0	0
	2018	>12.7	4	0
	2019	35.4	6	6
	2020	9.6	2	0
SDG&E	2017	not disclosed	1	0
	2018	0	0	0
	2019	0	0	0
	2020	0	0	0

> The utility will document the set of DER services necessary to defer investment and produce a price sheet indicating the utility's willingness to pay for DER products.

improve electric resiliency in the face of California's changing climate landscape.

In January 2021, the CPUC initiated the Microgrid Incentive Program as part of Track 2, which authorizes a US$200 million budget to fund the construction of microgrids supplied by clean energy resources and deployed in vulnerable communities. The budget set aside for the Microgrid Incentive Program is expected to fund 15 projects across the three IOU service territories. Although the incentive program represents a small piece of what will be necessary to build and operate a resilient and carbon-neutral electricity system, it will facilitate demonstration projects to help address the many challenges presented by multiproperty microgrids (i.e., microgrids, which include multiple independently owned assets).

The need for DER-based NWAs to augment electricity resilience in California is clear. The rising risk of wildfires has frequently limited the use of crucial T&D lines. This is exemplified by the Public Safety Power Shutoff (PSPS) program, which impacted millions of customers by initiating power outage events in many communities over the last few years. This repeated lack of access to electricity for many in California, often within the same geographic areas, has led to considerable private and public investment in backup diesel generation to support critical loads during PSPS events. In 2019, the CPUC authorized PG&E to procure 450 MW of backup diesel generation for the 2020 wildfire season. To balance the need for both clean energy and resilience requirements in California, utilities and ratepayers will have to dedicate thought and resources to developing and implementing clean energy microgrids.

Climate Change Impacts on System Requirements and Planning

Climate change impacts on California's electrical system are systemic, including reduced resiliency and reliability due to overstretched generation resources, insufficient levels of resource adequacy (RA), drought-induced reductions in hydroelectric generation capacity, transmission lines shut down due to wildfires, and PSPS events to prevent wildfires during extreme weather events. The consequences of reduced reliability and resiliency directly impact public health and safety and disrupt people's lives and normal business operations.

In August 2020, the California Independent System Operator (CAISO) was forced to institute a two-day rolling electricity outage in response to emergency conditions from a prolonged heat storm. These were the first rolling outages, and the first time there was more than one emergency declaration since the RA implementation in 2006. There were many questions about what went wrong.

The CAISO, CPUC, and California Energy Commission (CEC) jointly prepared a root cause analysis to determine contributing factors that triggered the rolling outages. Increased air conditioning usage, lower efficiency of conventional generation, and lower hydroelectric output due to drought conditions all played a part, but the ultimate question is, "Why was there not adequate resource capacity?" The analysis identified several challenges that contributed to the emergency, the most relevant being that the unexpected increase in system demand exceeded RA and planning targets, and that while transitioning to a clean energy portfolio, planning for ramping energy needs in the early evening hours has not kept pace with grid needs.

The generation shortfalls in August 2020 had many potential main causes, including inaccurate load-serving entity demand schedules in the day-ahead market and the unexpected loss of a generator delivering 475 MW. Many actions were taken by the CAISO to mitigate the loss of operating reserves, but ultimately the CAISO initiated forced outages of 932 MW and 466 MW across two days to stay within acceptable reserves to maintain overall system reliability. Subsequent days of the heat storm required no outages due to a combination of operator actions, regional coordination, demand response (DR) programs, and successful public campaigns for consumers to reduce their energy usage.

This emergency spawned a new CPUC emergency reliability rule (R.20-11-003) ordering a new DR program, the Emergency Load Reduction Program (ELRP), followed by an executive order creating another new DR program, the California State Emergency Program. Each program has a fixed payment of US$1/kWh and US$2/kWh, respectively, to customers reducing their loads after emergency notifications. However, emergency programs do little to influence the development of DERs generally or NWAs specifically. While incentives for load reduction are high, there is no certainty in emergency programs since the number or duration of events in a year is unpredictable. Yet, in Phase 2 of the emergency reliability rulemaking, the CPUC has identified a shortfall of as much as 5,000 MW for 2022, indicating there will likely be a need for continued load reduction from emergency programs in the coming years.

While incentives for load reduction are high, there is no certainty in emergency programs since the number or duration of events in a year is unpredictable.

As recently as April, May, and July 2021, a state of emergency was declared in 50 California counties due to severe drought conditions, In June and July 2021, a state of emergency was also declared due to extreme heat events across the western United States. As a result of the drought and heat events, over 1,000 megawatts of capacity were lost when the low water levels in reservoirs hindered the use of hydroelectric power plants. Another 4,000 megawatts could not be imported into California from the Pacific Northwest when the Bootleg fire in Oregon shut down a major transmission corridor. As seen in recent years, prolonged elevated temperatures result in increased system demand, requiring the dispatch of marginal generating units (many of which are inefficient, older, and unable to handle the stress of high operating temperatures), and resulting in extremely high peak energy prices. It also increases stress on the T&D grid due to congestion, increases line losses, and reduces the lines' carrying capacity.

Addressing the impacts of climate change events and mitigation strategies comes with a high cost to the electrical T&D system. In a 2018 report on the impact of climate change on the California electric grid, the CEC indicated that outages due to wildfire may cause up to US$9 million in transmission costs and US$61 million in distribution costs annually by midcentury. California utilities need to be prepared for increased financial uncertainty due to wildfires in the future.

Regulators have taken significant actions to mitigate the worst impacts of climate change on grid operations. In response to record wildfires in 2017 and 2018, regulators instituted the PSPS program for the summer of 2019, which proactively deenergized circuits for extended periods. While PSPS events have become less frequent, of shorter duration, and enacted within smaller geographic areas, these events continue to this day and are expected to continue for years to come. These events not only disrupt people's lives but also impact businesses' ability to operate unless they invest in backup generators, microgrids, or energy storage equipment capable of operating in island mode.

Based on current statewide planning models, forecasted short-term supply shortfalls of 5 GW and medium-term shortfalls of nearly 12 GW support the need for rapid deployment of DERs in NWA applications to bridge this supply gap. For NWAs to contribute significantly to the supply portfolio, changes are required to current planning processes to account for the full value that can be contributed by NWAs, which can be deployed more quickly, efficiently, and incrementally than conventional generation.

Consequences of Adaptation to Climate Change Impacts

One of the consequences of the PSPS program is that a large number of new fossil-fueled generators have been installed in recent years by facility owners to maintain operations during grid outages. According to a 2021 report by MCubed, there was an estimated 34% increase in backup diesel generation capacity from 2018 to 2021 in the South Coast Air Basin, and a 22% increase from 2020 to 2021 in the nine county Bay Area, totaling approximately 12 GW of capacity, which is equivalent to nearly 15% of California's generation fleet. Nearly all newly installed backup generation is diesel-fueled, and this is expected to increase over the coming years. Not only does the increased diesel generation capacity work against California's RPS targets and greenhouse gas (GHG) reduction goals, but this proliferation of diesel generator installations also highlights a major opportunity for clean energy technology NWAs to provide resiliency value.

The increase in backup generator installations and use also highlights the delicate balance between the need for increased grid resiliency and climate change mitigation efforts, such as the RPS mandating clean energy generation targets. The RPS/GHG goals versus. the need for increased grid resiliency issue came to light during the rulemaking process for the ELRP and the California State Emergency Program launched in mid-2021. While backup generators had previously been allowed to operate for only emergency backup and required test events, they were considered "prohibited resources" and not allowed to participate in DR programs or dispatches. The final decision order for the ELRP allowed prohibited resources to participate in emergency events, followed by a similar approval in the executive order establishing the California State Emergency Program.

Climate change mitigation strategies will also have a significant impact on the electrical grid as homes and buildings rapidly deploy electrification measures, such as chillers, water heaters, and electric vehicles, in support of all-electric buildings initiatives and in response to bans on natural gas service in new buildings in some jurisdictions. Increased building electrification and electric vehicle charging loads will significantly increase the state's peak load, which will require tripling the current electrical grid system capacity as well as overall energy consumption in the state according to a 2021 CEC Joint Agency Report. Figure 1 shows the projected impact of high building and transportation electrification on annual energy consumption in California through 2050, representing an increase of nearly 100 TWh per year. Climate mitigation strategies will put increased stress on the T&D systems and will require widespread and costly upgrades to keep up with the growing electricity demand, simultaneously increasing the value proposition for NWA solutions.

Valuation Frameworks for DER-Based NWA Solutions

This section summarizes DER valuation frameworks that incorporate the cost and benefits of NWA solutions, such as T&D capacity deferral, resilience, and/or reliability services to overcome the limitations of more traditional DER frameworks.

Valuation of T&D Investment Deferral Benefits

Accurately valuing transmission and distribution deferral benefits in DER valuation methodologies is crucial for identifying localized project opportunities for DER-based NWA solutions in place of traditional T&D upgrades. Accordingly, the CPUC's Integrated Distributed Energy Resources proceeding, which focuses on increasing the use of demand-side resources to better serve the electricity system, has led to an additional proceeding devoted to the development of a standardized DER valuation methodology for use in California.

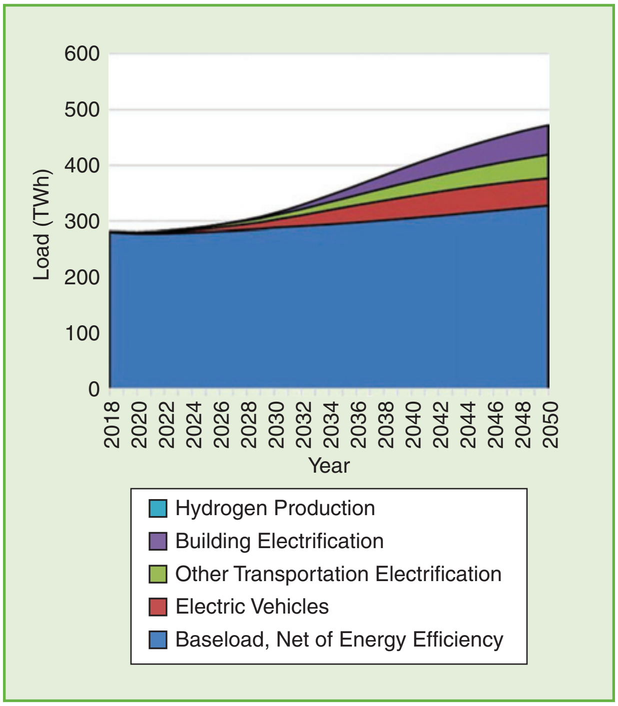

figure 1. The projected demand growth in California through 2050 in high electrification scenario. (Source: Energy and Environmental Economics, 2021.)

This led to the development of the Avoided Cost Calculator (ACC), which is an annual modeling process to quantify benefits associated with demand-side resources over a specified planning period.

The ACC model incorporates value derived from the avoided costs of all of the activities associated with generating and distributing electrical energy. These costs are then simulated for each hour of each year in the study period. Figure 2 illustrates 1) the types of costs included in the model (avoided GHG in blue, energy in green, generation capacity in yellow, transmission capacity in brown, line losses (not visible), distribution capacity in red, and costs due to methane leakage in light green); and 2) the changes that have occurred to the model over the last three iterations (2019–2021).

The 2021 version of the ACC assumes that the marginal unit of generating capacity in the evening is utility-scale storage, which will have a significantly lower cost and GHG emissions profile than the previously modeled marginal unit, a gas combustion turbine. Therefore, DERs are replacing a less expensive, lower-emitting storage unit in the evening hours with highly effective load-carrying capacity, reducing its replacement value. In addition, the 2021 version uses a production cost model to simulate future prices rather than using historical price trends, which assumes lower energy costs in future years, further reducing the avoided cost.

The ACC standard framework is not required for utilities to use as part of DIDF NWA solicitations. For these procurement cycles, utilities may conduct their own cost-effectiveness analysis, which has traditionally not been made public. Implementing a standard framework that is transparent and compulsory for solicitation may help push more projects through the contracting process. The SOC mechanism may be a step in this direction. Under this mechanism, the utility communicates upfront what it is willing to pay for a particular DER service or product and thus defines a target for DER providers to aim for. The 2022 cycle will be the first to include an SOC solicitation so it is yet to be determined whether this concept will help deliver more DER projects for distribution investment deferral.

For the IOU Partnership Pilot, the burden of DER valuation falls on the ESPs selected by the utilities. Under this framework, utilities define a circuit-specific budget using 85% of the cost of the estimated conventional upgrade cost to procure DER capacity for distribution upgrade deferral. Since the utility has already defined its willingness to pay for DER/DR-based NWAs, so it is up to the ESP to determine if the value set by the utility will be sufficient to justify a project and/or if there are additional value streams available to earn revenue from these same assets (i.e., wholesale market participation).

There are also still significant limitations in cost/benefit modeling in the face of extended climate-related power outages. The ACC does not assign any value to

DER projects based on the ability to withstand difficult-to-predict, yet inevitable outages. This limits the potential to allocate distribution and transmission investment funds toward DER projects to support or construct community microgrids that can offer both resiliency and local capacity for distribution deferral value. Nevertheless, in light of the potential for widespread outages due to PSPS and wildfires, the CPUC set aside significant incentives in its Self-Generation Incentive Program (SGIP) to target higher uptake of customer-sited storage and renewable DERs in vulnerable areas.

In a 2019 CPUC decision, the CPUC allocated budgets for two set-aside energy storage programs: US$70 million to the SGIP Equity Program and US$100 million to the Equity Resiliency Program. The SGIP program offered US$850/kWh for installed capacity for residential and nonresidential customers located in disadvantaged or low-income communities, and the equity program offered US$1,000/kWh to low-income or medical baseline customers in high wildfire risk areas. These incentives were designed to expedite the construction of over 180 MWh of storage statewide. These two incentive tranches in the SGIP budgets were quickly oversubscribed, and there is currently a waiting list of approved projects with no budget available. As more resiliency-focused projects are installed, they will offer the opportunity to collect data to support the development of

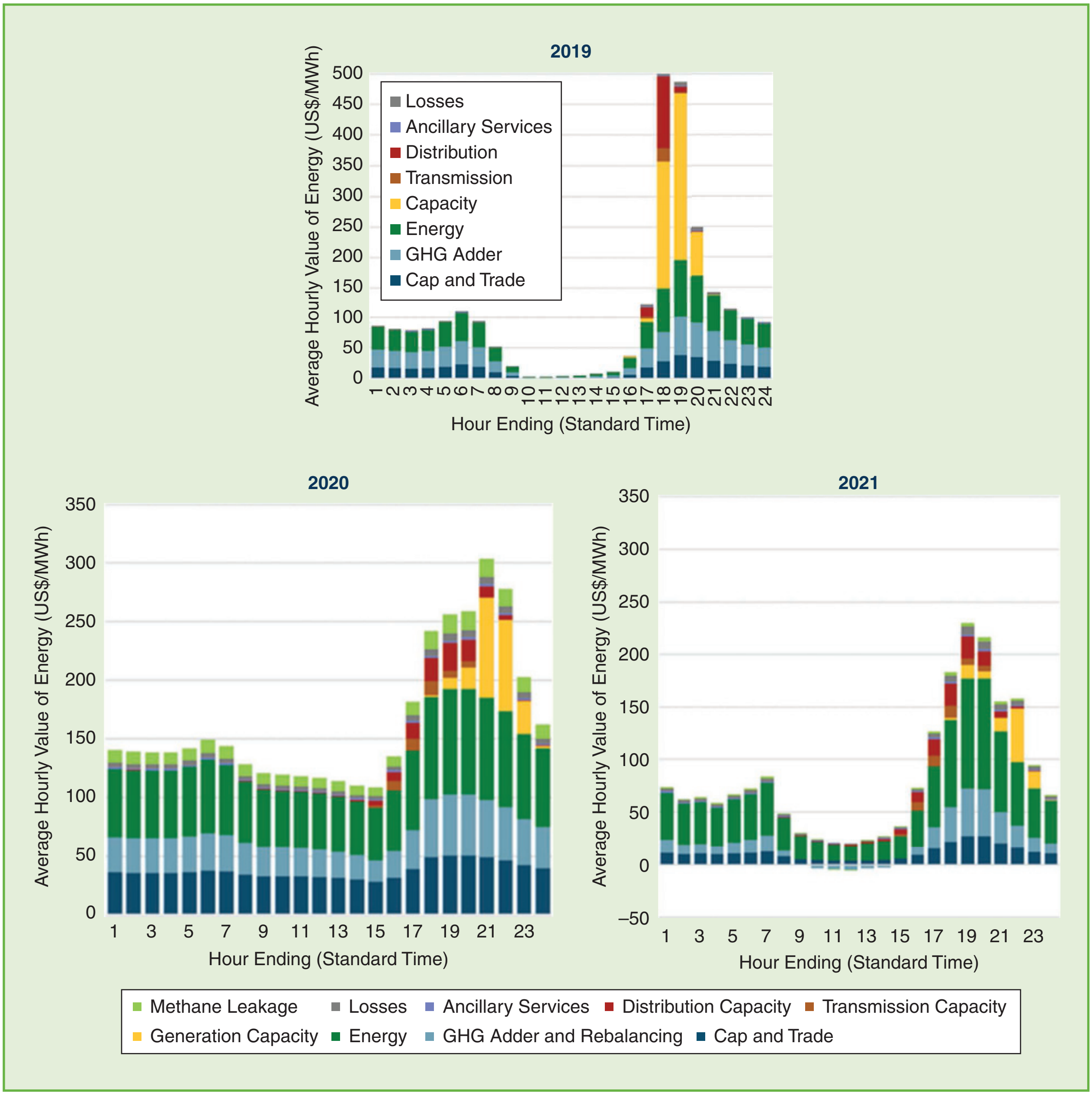

figure 2. The estimated hourly avoided costs of DER programs. (Source: Energy and Environmental Economics, 2021.)

valuation methodologies that include resiliency as well as other value streams from NWA services.

Valuation for Resilience and Reliability

Reliability has long been at the core of grid planning, but regulators are increasingly focusing on resiliency. Conventional resource planning has focused on meeting peak system or local grid needs through a combination of generation, transmission, and distribution infrastructure. DER-based NWAs can play a much-needed role in avoiding the need for grid investment in the context of long-term system planning, deferral, and capacity. In contrast to traditional reliability metrics that are generally focused on predictable growth in demand and associated infrastructure needed to support it, resiliency is defined as the ability to respond to unplanned disturbances. The CPUC staff concept paper on resiliency highlights the "resilience" benefits a DER can provide as illustrated in Figure 3.

Ascribing a specific resilience adder to conventional valuation methodologies can be challenging because there is a blurred line between systemwide benefits and individual customer benefits. DER-based NWAs are in the early stages of demonstrating their role in deferral of generation, transmission, and distribution costs as well as in providing capacity value that contributes to resilience and reliability of the grid, despite agreement within traditional planning processes on the value of resilience and reliability. While efforts by state regulators have pushed the inclusion of NWAs into these resource planning processes, attempts to value resilience and reliability from NWAs have been inconsistent. Resilience is often not valued quantitatively in many valuation models because it is difficult to scope out and conventional reliability metrics are not easily adaptable to the new paradigm.

Attempts by regulators to assign a specific value to resiliency have relied heavily on quantification of the cost of interrupted power. These valuations follow one of two main approaches: bottom-up or economy-wide. Consumer preferences are measured via "stated preferences" on customer willingness to pay for measures to avoid power outages and/or "revealed preferences" of actual customer purchases (e.g., backup generators and/or energy storage equipment) to avoid power outages). More holistic resilience valuation methodologies are the "economy-wide" approaches that seek to quantify the impact of sustained power outages on regional economies, including a loss of productivity, revenues, wages, and employment.

While several proceedings and research projects are addressing the need to value resilience and reliability in NWA methodologies, there has been limited progress in developing widely accepted valuation methods. A 2019 National Association of Regulatory Utility Commissions report stated, "At present, there are no standardized approaches for policymakers or energy project developers to identify and value energy resilience investments at the state, local, or individual facility levels." The report highlights several case studies where bottom-up and economy-wide approaches were used by states, cities, and institutions in their valuation of proposed NWA solutions. The report pointed out that while these case studies enhance NWA value, each approach is limited either in scalability, outage duration, or scope of outputs to warrant adoption in a regulatory context. While there have been more efforts to deploy DERs for resilience purposes since the report's publication, there remains no agreed-upon standard to value DER's ability to avoid outages or for DERs to reduce reliance on fossil-powered backup generation.

In 2019, testimony as part of the Integrated Distributed Energy Resources proceedings, VoteSolar and the Solar Energy Industries Association proposed an explicit "resiliency" adder of solar plus storage in avoided cost modeling used by the CPUC. In their testimony, they estimated the additional benefit of resilience attributed to solar and storage systems based on a revealed preference model, assuming that solar and storage would be installed in place of a portable fossil-fuel generator. The "resiliency adder" included calculations of equipment, installation, and air quality costs of backup generators, arriving at an estimated value

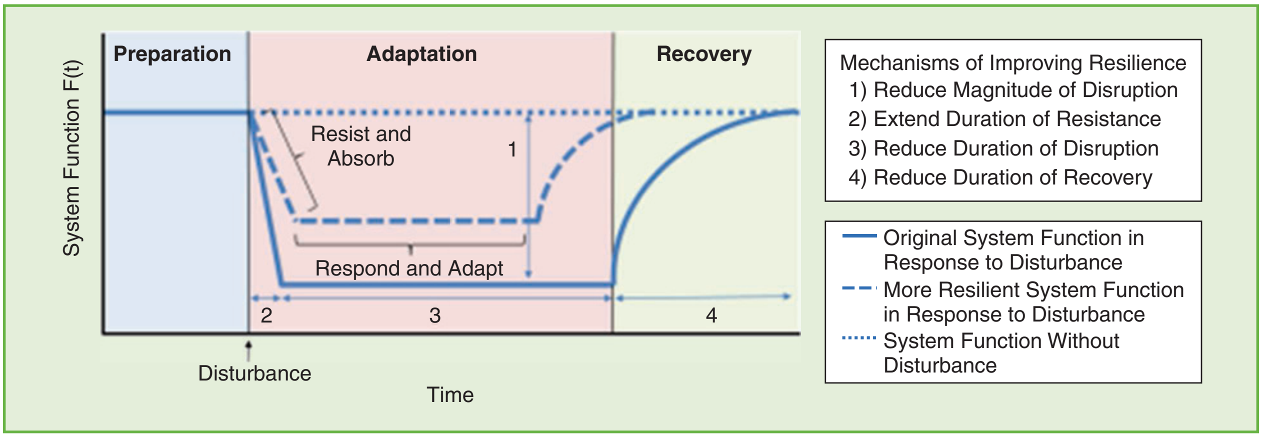

figure 3. Resiliency and system functions. (Source: CPUC 2020.)

of US$104/kW-year. The proposal for a resiliency adder was criticized by utilities and consumer advocates both as a concept and in total value. Utilities argued that despite the clear resilience benefits of DERs, there was no proper way to quantify system benefits (rather than just individual customer benefits). The Utility Reform Network contended that solar and storage "resiliency" does not avoid ratepayer costs. Ultimately, the CPUC agreed that while there is a case to be made for valuing resiliency, there was insufficient evidence to explicitly include it in the ACC.

In summer 2020, the CPUC staff launched Track 2 of its Resiliency and Microgrid Proceeding, an extensive proposal describing barriers related to microgrid adoption with resiliency valuation highlighted as a key objective. CPUC staff suggested that resiliency is a special case of reliability, noting that replacing aging distribution equipment would be a "reliability" enhancement while actions taken specifically to protect the system from flooding, wildfires, or other extreme weather events would be a resiliency enhancement. In this context, all NWAs provide system reliability benefits, but only certain NWA applications provide additional resiliency value. Microgrids are a specific application of DERs often targeting resiliency as the main benefit, but without a clear valuation framework, community microgrids are often found to be not cost-effective. In summer 2021, the CPUC held a series of workshops to discuss an evaluation framework for resilience, showing continued progress but still not arriving at a standardized methodology.

Summary

If climate change impacts in California, such as ongoing drought, catastrophic wildfires, and heat storms, are becoming the new normal, as many climate scientists suggest, accounting for their impacts in valuation modeling will result in a higher value of DERs supporting NWA solutions. These values will accrue from continued high peak energy prices, higher prices for RA as supply shortfalls continue, high incentives for participation in ELRPs, increasing the value of reliability and resiliency, and cost-effective deployment of DERs to defer distribution capacity upgrades. In addition, these resources provide reductions in CO_2 emissions and support the continued deployment of clean energy resources to combat climate change.

California is projected to experience supply shortfalls of 5 GW in 2022 and nearly 12 GW over the next five years. Due to the short time needed to deploy DERs compared to other supply options, DER-based NWA strategies can play a key role in bridging the gap in the supply shortfalls while providing reliability and resilience benefits to the grid. While NWA solutions are not a new concept, implementation of these solutions has been slow due to limitations in current DER and NWA valuation methodologies as well as the continued specification of wires-based solutions through established legacy technology solutions and planning processes. As valuation methodologies are enhanced and standardized to capture NWA values of distribution capacity deferral value, resilience, and reliability, the resulting scale of these solutions will serve to alleviate the perceived risk to utility planners.

A recurring theme in this article is that a key challenge facing DER-based NWAs, and the electrical system as a whole, is the need to balance climate change mitigation measures with the increasing need for grid resilience historically provided by fossil-fuel generation and other legacy technologies—all while maintaining stable retail rates to ratepayers. Enhancements in valuation methodologies, alleviation of utility risk concerns with third-party-provided NWA solutions, and continued demonstration of these commercially proven resources are critical steps to clearing the pathway for the deployment of these solutions at scale.

For Further Reading

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MANY STUDIES SUGGEST THAT DISTRIBUTED energy resources (DERs) have significant value for the distribution system by providing an alternative to conventional system upgrades. Solar photovoltaic (PV) resources can help reduce the flow on lines and substations, and battery storage can help support the capacity to serve load behind a constrained substation transformer. Distributed batteries and smart-inverter-equipped solar can help stabilize the voltage. Taken together, this means investments in conventional solutions for the distribution system, such as upgrades to and the replacement of substations, secondary transformers, and capacitor banks, may be deferred and, in some cases, eliminated.

For this article, DERs include solar PVs, distributed batteries, demand response (or flexible demand), energy efficiency, and electric vehicles (EVs) (managed charging and discharging). Many utilities and regulators recognize the potential value of DERs, and several have quantified them and started to develop best practices in regulation and investment planning. However, few studies have looked at the implications for distribution planning and how utility practices will need to evolve to capture and integrate the value of DERs when these resources grow in prevalence and importance.

Planning for DERs—Utilities and Regulators Learn as They Go

Over the past decade, the value of DERs in deferring or eliminating utility investments in generation, transmission, and distribution has increasingly been recognized. Many utilities and regulators are in the process of quantifying DER values. For example, in 2021, Seattle City Light released a grid modernization

Next-Generation Distribution Planning

By Olof Bystrom

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plan and road map that recognizes the critical importance of gaining experience and an understanding of DER values and their impact on the distribution system. Austin Energy and the Los Angeles Department of Water and Power (LADWP) have both worked for years on capturing and integrating the value of DERs.

Austin was among the first utilities to adopt a value-of-solar tariff that recognizes the value of DERs compared to grid assets, and the LADWP has developed pilot tariffs to incentivize DERs to defer up to 10 MW of capacity upgrades in its distribution system. LADWP is also among the growing number of utilities that have formed special planning departments for DERs, different from other transmission and distribution or resource planning functions. Utilities in the eastern United States, such as Eversource and ConEd, have deployed DERs as nonwire alternatives to system upgrades, and Puerto Rico, in its efforts to rebuild its electric system, is looking closely at DERs, microgrids, and nonwire alternatives to support resilience and reliability.

How Do We Capture the Value of Distributed Energy Resources?

In this article, we use the results from a recent study by the Sacramento Municipal Utility District (SMUD) to show that, although the theoretical value of DERs can be significant, capturing it will require new thinking and methodologies for distribution planning. These insights should be broadly applicable for distribution utilities facing significant growth of DERs over the next decade. For SMUD, a careful assessment of DERs is of particular importance since it adopted an ambitious zero-carbon plan in 2021 to fully eliminate the use of fossil fuels in its power supply through the use of distributed and grid-scale renewable energy, storage technologies, and distributed resources. DERs and electrification are important building blocks in that journey to decarbonize SMUD's power supply and also contribute to an economy-wide reduction of greenhouse gas emissions.

A Case Study of DER Values

SMUD is a municipal electric utility serving about 514,000 customers in the Sacramento metropolitan area in California. The utility district has about 900 mi of distribution lines and more than 600 substations. SMUD rolled out smart meters to all customers in the 2009–2012 period and is currently implementing an advanced distribution management system (ADMS) and distributed resource management system (DERMS) that will be fully operational in the next 12 months. The service territory is relatively circular, urban, and well-integrated, which allows for multiple electric paths to serve load in most areas of the service territory, thus providing flexibility while minimizing down-time in case of equipment failure. In the spring of 2021, the utility adopted a goal to eliminate all greenhouse gas emissions from its power supply by investing in renewable energy, DERs, storage, and emerging technologies by the year 2030.

A 2020 study performed by SMUD called the *Integrated Distributed Resource Plan* (IDRP), laid out a 10-year perspective on the distribution system and identified the investments needed to support the growth of DERs and EVs. The study also estimated the potential value of DERs in deferring conventional distribution system investments for substations, transformers, and reconductoring. The findings show that, by utilizing the capabilities of DERs to support voltage and provide capacity, the total investment needs over 10 years could be reduced up to 10%.

The analysis looked at several DER scenarios to see how DERs could impact system performance and analyzed mitigation needs based on two alternative views:

- ✔ *Business-as-usual*: Increasing electric demand from DERs, EVs, and general growth would be met by upgrades to substations, distribution lines, and secondary transformers.
- ✔ *DER support*: The capabilities of DERs are taken into account to help manage load and reduce or defer investments by utilizing battery storage capacity, demand response, energy efficiency, and the managed charging of EVs.

Key Results

The IDRP study revealed several important factors that will impact distribution planning. A failure to account for these findings could lead to an overinvestment in the distribution system and unnecessary rate-payer costs. Our study shows that a significant increase in DERs can be accommodated without major cost increases as long as the growth in DERs is balanced and well managed. For example, SMUD's long-term 2030 Zero-Carbon Plan adopted in 2021 anticipates EVs in the Sacramento region to grow from about 20,000 to nearly 300,000 by 2030 and all-electric homes to increase from about 50,000 today to about 150,000 in 2030. These dramatic changes must be managed carefully to maintain low rates and continued high reliability. In particular, four results stand out, each of which has implications for planning and operations and is discussed in the following sections.

Unless Carefully Managed, EVs Could Constitute 10% of Peak Demand by 2030

The number of EVs is expected to grow dramatically in California over the next decade and, this will be the most significant driver of load growth. Not surprisingly, unless we manage that load carefully, EVs could wreak havoc on the distribution system and constitute as much as 10% of our peak load by 2030. However, if managed properly, the strong growth of EVs (and even higher volumes) could be accommodated within the existing infrastructure. The key is to avoid charging during peak hours and manage the charging.

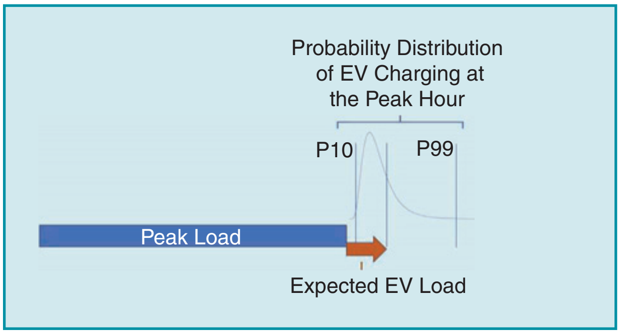

figure 1. The expected vehicle load impact versus probability outcomes.

To successfully manage EV charging, we must not only have the right equipment—communication between the grid and vehicles, ideally combined with a DERMS and an ADMS—but we must also understand where the load will show up. This means learning which customers are the most likely to buy an EV, their charging habits, and which parts of the distribution grid they will impact. This entails developing detailed locational forecasts of EV charging demand.

For planning purposes, we must know not just the expected impacts on each feeder but the probability distribution of the EV charging load. This is necessary to anticipate the likelihood that system components will be overloaded. Merely using the expected values based on a load profile is too simplistic. We risk overloading the equipment if the load goes higher, thus putting reliability at risk. Conversely, if we use an equally simplistic worst-case scenario for planning [for example, the tail end of a probability distribution where there is a 99% (P99) chance that the load would be lower than the indicated level], we risk overinvesting, which results in high costs. Each utility must also define its risk tolerance and approach to maintaining overall reliability. Figure 1 illustrates the expected peak load on a circuit and a probability distribution for EV charging that highlights the wide range of possible outcomes.

Due to the potentially significant impact of the load growth from EVs, EV charging needs to be coordinated to avoid surprises. This can be done through managed charging, either directly using a DERMS or working with an aggregator or indirectly through tariffs and incentives, which create uncertainty, as illustrated in Figure 1. The vertical bars labeled, respectively, *P10* and *P99* indicate the probability levels of the distribution. At P99, there is a 99% chance that the load will be at or below this line. At the P10 level, there is only a 10% chance that the load will be at or below the line (and, conversely, a 90% chance that the load will exceed the P10 level).

Due to the uncertainty of when and where the EV charging load appears on the grid, having flexibility on the distribution system also has value. For example, having an integrated distribution grid rather than radial lines allows the flexibility of switching the load between circuits to more efficiently manage the demand.

Solar PVs and Batteries Are Not Significant Drivers of Hosting Capacity Constraints

The second key finding is that solar PVs and batteries are not putting capacity constraints on the distribution system. Because the peak load typically occurs between 5 and 7 p.m., solar PVs have little impact on a circuit's net peak load. Similarly, the distributed batteries used by commercial customers to mitigate demand charges help reduce the peak load. This contributes to improved hosting capacity for new distributed growth, such as the electrification of buildings and EV charging.

At SMUD, retail electric rates were recently restructured for solar and storage to provide stronger incentives for energy storage. As the economics of energy storage continue to improve, and customers increasingly use storage to maximize onsite solar PV utilization and improve resilience in the case of outages, the distribution system hosting capacity for DERs and demand growth should also improve. Again, however, this depends on where batteries are installed on the system and the extent to which their use can be influenced.

Nearly all of today's PV and storage systems are also equipped with "smart inverters" that can ride through voltage swings and autonomously adjust to stabilize the voltage and frequency on a circuit, thus contributing to stability and capacity rather than placing limitations on the hosting capacity. Therefore, rather than being concerned about the hosting capacity for DERs, these resources can become assets that reduce operation costs and help accommodate the significant load growth expectations from the electrification of transportation and buildings.

Capturing the Value of Flexible Load Will Significantly Reduce Costs for Integrating DERs

In our scenarios, DERs add load, mainly through the growth of EVs and electrification of buildings. As the load increases, so does the need for distribution system upgrades to support the growth. The question for DERs, then, becomes, "How can we use them to reduce the overall costs for distribution system upgrades and operation?"

The study shows that the difference in costs between a system where DERs are carefully managed and one in which DERs are not controlled and capabilities are not used to support distribution system operations is about 10%. In other words, distribution system capital costs can be reduced by 10% by harnessing DERs' capabilities to reduce the peak load, support voltage stability, minimize backfeed, and control the timing of the load. These savings are made possible by a relatively limited subset of DERs, namely, demand response, managed charging, and demand response from EVs, as well as the managed use of distributed battery storage. Together, these resources help to defer investments, primarily in distribution substation upgrades and, to a lesser extent, the costs of service transformer upgrades and reconductoring.

Figure 2 illustrates the relative magnitude of cost savings for substations, feeder upgrades, and service transformers as a result of utilizing the capabilities and demand impacts of DERs. Not surprisingly, the exact locations of new load growth and controllable DERs are very uncertain, and modeling future system scenarios is driven, in part, by assumptions. Therefore, the estimated cost savings shown in Figure 2 are also uncertain. Despite that, it is important to count and consider these potential savings and adjust distribution planning practices to make the savings visible.

Figure 2 suggests that, overall, the peak contribution of DERs is fairly limited. (SMUD's annual system peak is about 3,000 MW.) However, small contributions in strategic locations of the grid can provide significant value. Figure 2 also indicates that the contributions from energy storage and EVs are limited. This is mainly a result of the relatively low adoption expected among residential customers. While valuable, these resources take time to grow, and there is little operational experience to see how they perform when their reliability and predictability are critical, e.g., at summer peak load conditions, when they may need to deliver energy and capacity for multiple days during a heatwave.

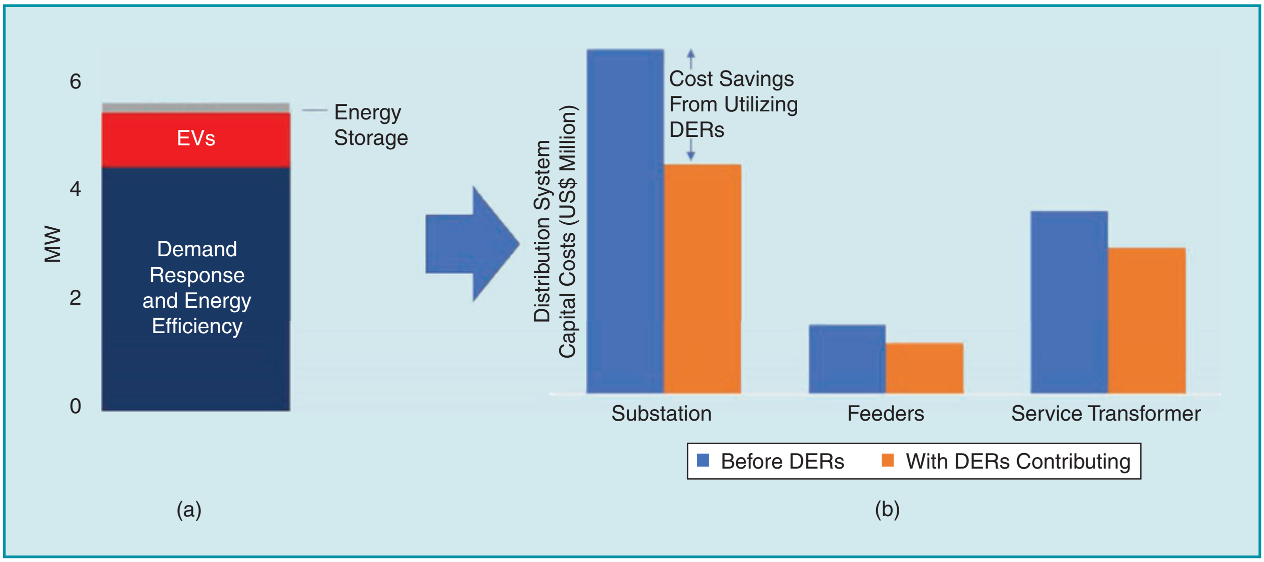

figure 2. The DER costs and value of DER controls in SMUD's IDRP study: the (a) DER capacity at the system peak in 2030 and (b) cumulative cost of supporting DER growth.

For flexible demand to realize its value in five to 10 years, viable programs need to start today, along with sustainable business models, that demonstrate their performance in the field.

Utilizing DERs Requires Visibility and Control

While the IDRP study shows the theoretical value of DERs, the reality of capturing that value is complex. Since DERs are typically behind or at the customer meter, most utilities have little control or visibility of what these devices are doing. Indeed, many utilities also have limited visibility to the concurrent status and loading of individual distribution circuits and feeders. To utilize the flexibility and control options for DERs, both the visibility of the distribution system and the ability to control individual DERs or groups of DERs are necessary. In other words, having both an ADMS and a DERMS is important to fully utilize and control DERs. SMUD is currently implementing ADMS and DERMS capabilities that will enable the capture of DER value and control the risks that they introduce.

Capturing DER Values Requires a New Approach to Planning

Most California utilities expect to see continued strong growth of DERs. The electrification of transportation and buildings is a policy priority and will be the main driver of load growth for the next several decades. At the same time, this new load cannot be treated or forecasted in the same manner as done in the past. With electrified buildings and transportation, there are more opportunities to manage the load so that the system costs of supporting it can be minimized. If successfully managed, DERs can increase the load factor on our distribution systems, defer upgrades, increase reliability, and save money for customers. However, to capture these values, improved planning as well as new tools and methodologies are needed.

Historically, many utilities, including SMUD, have used a simple distribution planning approach based on the utility's actual annual system peak, which is then normalized to account for weather conditions and converted to a lower-probability but higher-impact event, such as a once-in-every-10-years peak load. Planning is based on the "unmanaged" load where only the historical trend of DERs is considered and, often, not future growth. The forecasted peak load is then distributed across subareas of the distribution system using historical data and expert judgment, and deterministic load flow scenarios are modeled for the peak demand hour of the year under consideration.

There are two main reasons why this approach must change. First, it may not lead to a cost-effective outcome because it does not consider the impact of future DER growth and value DERs can have in controlling and modifying the peak load. Second, despite the investments that are identified using this method, the reliability may deteriorate because some DERs can increase the load and could have a disproportionate impact on subsets of the distribution system that could be missed if the DER growth is not explicitly forecasted. To better capture the value of DERs and modernize distribution planning to meet the needs of the changing grid, three areas of opportunity are discussed in the following section.

Load Forecast

The simple distribution planning approach described previously risks missing both the variability of the load and locational effects of nonhomogenous DER growth.

DERs and Other Load Drivers

DERs will grow in response to signals unrelated to the distribution system and be primarily driven by factors such as demographics; income level; the cost of DER technologies; subsidy levels; and, perhaps, local political, financial, and regulatory support for DERs. For example, one city might provide tax rebates for those who install batteries and help accelerate or simplify permitting, whereas another may have a less accommodating approach. All of these factors will contribute to an uneven load growth, which translates into a varying impact on substations and feeders.

DER growth may also change the load shape so that the timing and duration of peak load events are different compared to history. When doing long-term distribution system planning, it is essential to consider these factors. This means a top-down, systemwide load forecast may need to be replaced—or at least complemented—by a bottom-up locational forecast that captures different growth expectations in the service territory. As these patterns emerge, they may also open opportunities to strategically incentivize DERs in areas where they could help alleviate constraints or defer upgrades.

Managed Versus Unmanaged Load

Distribution planning forecasts usually use unmanaged load as the basis for planning. This means that future customer behavior load impacts beyond those already reflected in the historical load data series are not included in the load forecast. Managed load, on the other hand, includes customer-influenced behavior, such as energy efficiency forecasts, the demand response, solar PVs, and customer-sited batteries. The practice of using the unmanaged forecast becomes problematic when many of our expected drivers of load growth and shape are not in the historical record, including the acceleration of energy efficiency and demand response, uptake of EVs, and electrification of behind-the-meter energy uses. A sophisticated managed forecast is, therefore, essential to capture these load impacts.

Net Load and the Variability of Net Load

The sum of the base underlying electric demand and emerging impacts of the demand response, energy efficiency, EVs, solar, and battery storage together form the net load on a feeder and the system. On the bulk system, the concept of the duck curve is well known, where solar and wind can result in significant decreases of the net load during the day and trigger a dramatic ramping of the load as solar generation declines simultaneously with increases in electric demand. The same concept also holds for distribution feeders and circuits, but, since each circuit or feeder is smaller than the entire system, the individual impacts of DERs could potentially be significant relative to the capacity of the feeder or circuit because DER adoption from circuit to circuit can vary greatly. The variability of the load on feeders could also increase. Planning for this variability and uncertainty requires careful investigation of the net load and its variability circuit by circuit rather than averaging the system variability down to individual feeders uniformly.

Modeling Approach—Single-Hour Deterministic Versus Multihour Probabilistic or Stochastic Models

The growth of DERs on circuits and feeders will change the net load shape, and, just like for the bigger bulk system, ramping and managing the peak load become more important. Also, with the growth of electrification, such as EVs, the timing of future system and local peaks may shift to a different time of day or even year. For example, with significant electrification and, at the same time, significant growth of solar and storage, many California utilities may go from summer to winter peaking.

To appropriately plan for this and capture both the costs and values of DERs, we must model more hours than just the annual peak hour. Depending on the system, this may mean modeling all 8,760 h of the year or a subset thereof. In addition, the introduction of more DERs and customer-sited load management systems brings new sources of uncertainty that need to be accounted for. In the underlying load itself, uncertainty exists regarding whether new DERs, such as batteries, the demand response, and their control systems, will perform as needed. There is uncertainty at the level of the distributed generation available to offload the feeder transformer for a given load level. Therefore, in addition to expanded time-sequential modeling, uncertainty must be factored appropriately, ideally by applying stochastic and probabilistic modeling techniques.

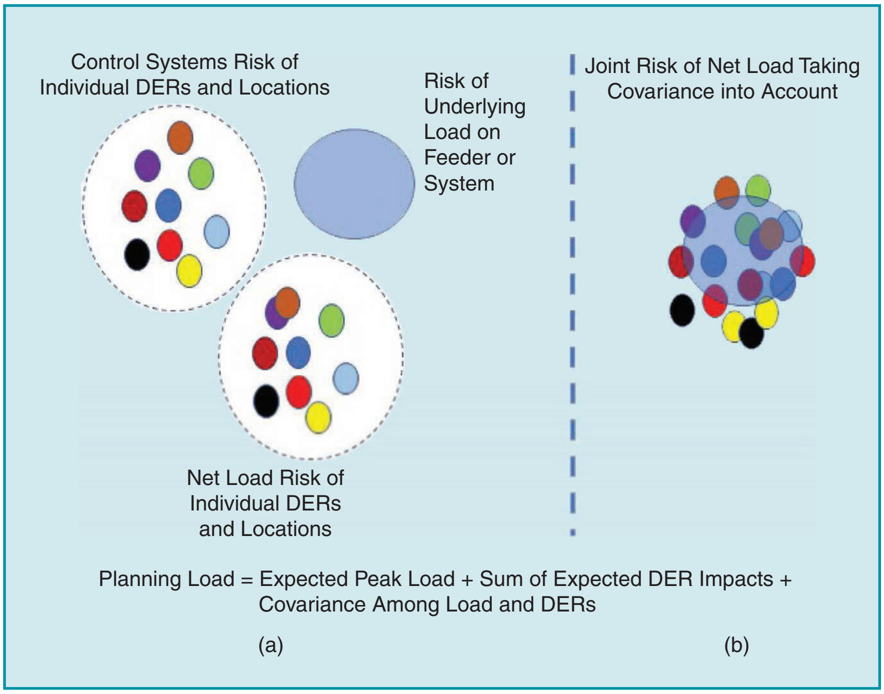

figure 3. The (a) load and DER risks and (b) impact of covariance for the variability of the net load.

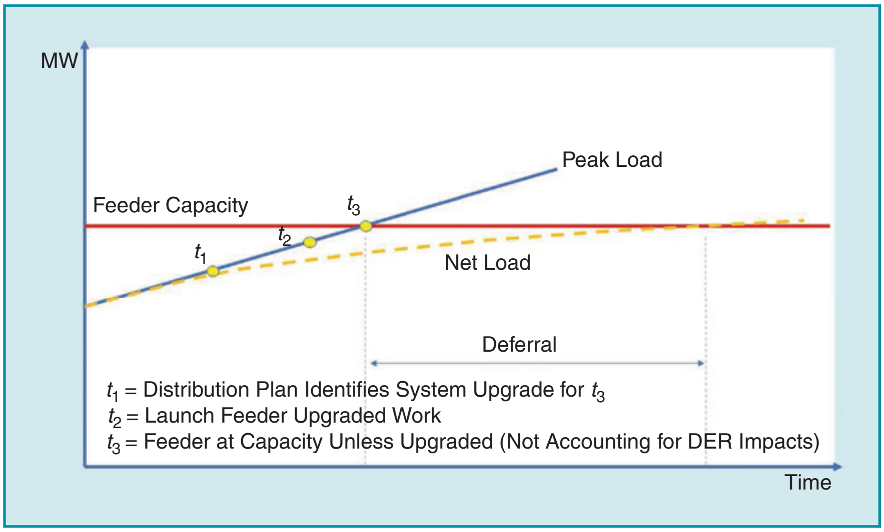

figure 4. The distribution planner's dilemma.

Continuing to rely on simplified rules and margins is convenient but could easily lead to overestimating the uncertainty of the net load, which, in turn, could lead to overinvesting in the distribution system. A stochastic modeling technique can factor in the variability of each net load element, its probability distribution function, and its covariance with other net load elements. Because of the various characteristics of different DERs and their geographical spread, there is a covariance among elements that will result in the variability of the net load being significantly lower than the sum of the uncertainties associated with each DER. This is an important reason why probabilistic modeling techniques that take into account the variability of the net load need to be used to capture the value of DERs (Figure 3).

Planning With Uncertainty

The growth of DERs will not remove the need for conventional distribution system upgrades. On the contrary, since many DERs add net load, we will need to continue increasing the capacity of our distribution systems as DERs grow. However, the use of the load and voltage management features of DERs can help defer investments in upgrades. This is what the IDRP study showed (see Figure 2). However, the distribution planning process often requires long lead times to complete upgrades, such as replacing substations or reconductoring lines in time to meet the expected increase in demand. This creates a planner's dilemma: if we invest too soon in conventional upgrades, the value of DERs cannot be realized because the deferral value was eliminated by the upgrade.

On the other hand, DER growth takes time, and, if we miss the forecast, there is a risk of overloading the feeder and jeopardizing reliability. This dilemma is illustrated in Figure 4, where at time t_1, conventional distribution planning techniques would identify the need to complete a capacity upgrade by time t_3 to avoid overloading. At time t_1, DERs have not grown enough to offset the upgrade need. At time t_2, the utility needs to start its work to upgrade the circuit to finish by time t_3. However, at this time, DERs are growing, but there is still uncertainty as to whether sufficient capacity will be available to offset the conventional upgrade. The dilemma is whether to wait for DERs to grow or take the safer but most costly route of upgrading the capacity-constrained element even if it may not be needed for several years.

To solve the distribution planner's dilemma and capture the value of DERs, utilities must become more nimble and able to reduce the elapsed time between identifying needs, procuring equipment, and completing the upgrade. This may mean that utilities adjust their procurement policy to keep the equipment for substation and line upgrades readily available for deployment yet remain flexible on the exact location of the investment until customers' DER investment patterns become clear.

Conclusion

Three key results from SMUD's recent IDRP study have been highlighted:

- ✔ Unless carefully managed, EVs could constitute up to 10% of the peak load in the next 10 years. Considering that the timing of EV charging loads is highly uncertain, this has a profound impact on planning.
- ✔ Adding solar PV and battery storage does not introduce hosting capacity constraints. On the contrary, they can help offset capacity constraints on the feeder.
- ✔ Utilizing the flexible load characteristics and control options for DERs can reduce the costs of distribution system upgrades up to 10% over 10 years.

The implications for distribution planning with DERs are profound. In this article, we have identified four practices that may be needed to capture the value of DERs and plan for cost-effective distribution system upgrades:

- ✔ move from system to locational load forecasting
- ✔ explicitly account for DER impacts by modeling the managed net load rather than the unmanaged load
- ✔ adopt expanded chronological modeling and stochastic modeling techniques
- ✔ improve flexibility and shorten the construction time for system upgrades.

For Further Reading

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Biography

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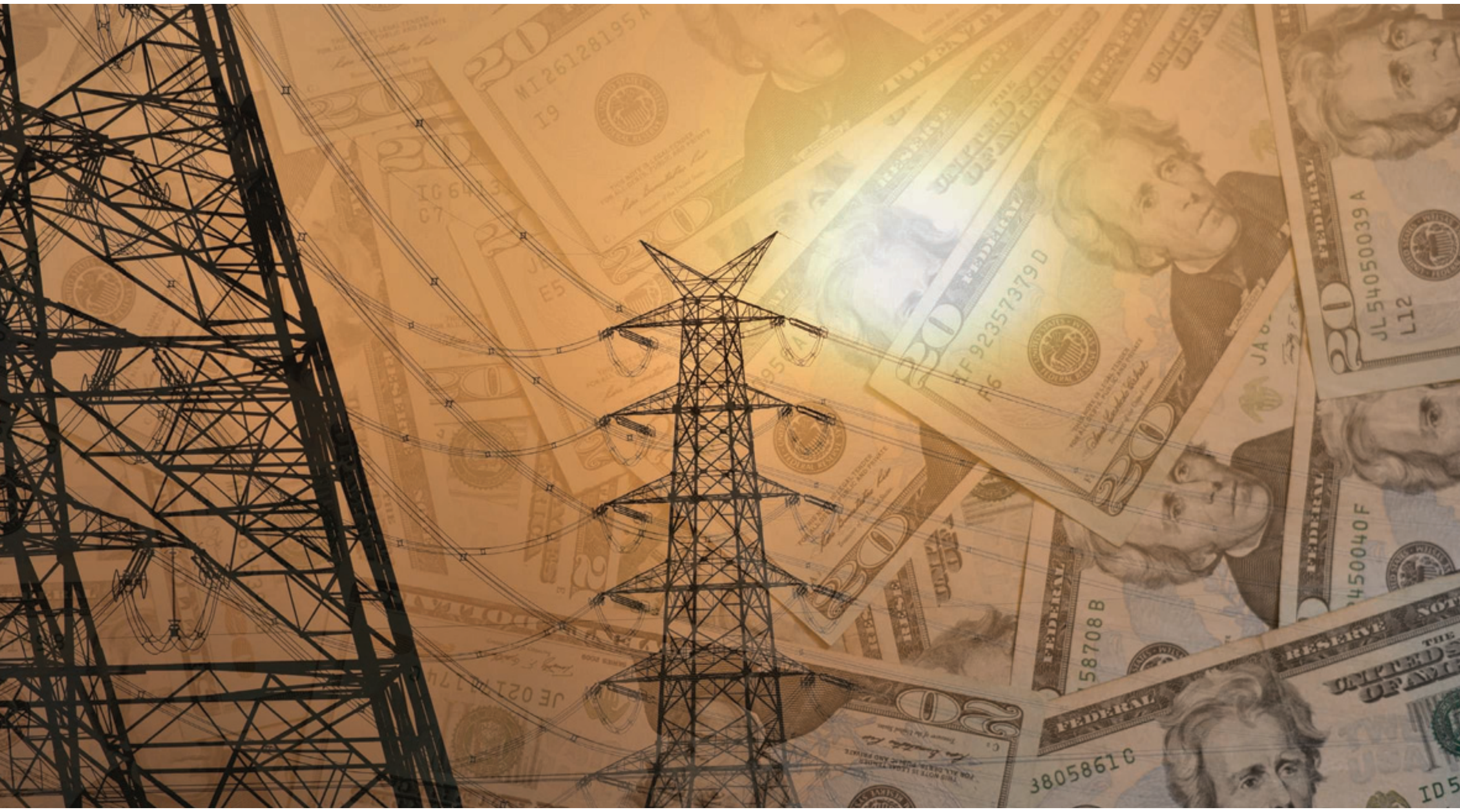
Realizing the Value of DERs

A Utility Perspective

By Aleksi Paaso, Nicholas Burica, and Ryan Burg



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ACROSS THE WORLD, POLICY MAKERS ARE ENCOURaging the deployment of large quantities of distributed energy resources (DERs), including photovoltaics (PVs) and battery energy storage, to mitigate the effects of climate change and implement resiliency-enhancing grid technologies. As part of this effort, many have emphasized the potential value that DERs can provide directly to the distribution grid, thereby increasing their total social, environmental, and infrastructure value stack. However, these same DERs pose integration challenges to electric utilities, particularly as utilities seek to ensure that grid benefits can be affordably and equitably leveraged by all communities the utilities serve. Fairly and accurately quantifying the value that each DER provides to the grid is critical to

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> Fairly and accurately quantifying the value that each DER provides to the grid is critical to developing a sustainable economic model for the integration of future DERs.

developing a sustainable economic model for the integration of future DERs.

Utilities have a unique responsibility in establishing a coherent and public-minded methodology that fairly values DER grid contributions. Such a methodology accomplishes important and mutually beneficial objectives for electric utilities and their customers. Specifically, a DER valuation methodology can incentivize the deployment of DERs, promote fair treatment of the integration of this technology for both DER owners and other customers, and support the achievement of broader public goals as established by policy makers. ComEd, a utility serving 4 million customers in northern Illinois (including Chicago), has developed a software tool to establish DER valuation for solar, wind, and storage that can be integrated into existing planning systems. The motivations, methods, and lessons learned in the tool's development are described in the following sections to capture key considerations for DER valuation from a utility perspective.

Incentivizing the Deployment of DERs for Utility Service Territories

Quantifying the value that DERs provide to the grid can accelerate the adoption process. Compensating DER owners for their contributions to the grid provides an additional value stream that can make deployment more economical. This support for the deployment of DERs extends public policy goals and increases opportunities for DERs to provide additional value to the grid in the future.

For example, increased DER penetration sited closer to the load can reduce energy losses on the system and enable a modular grid design, provided that the generation output coincides with demand. As clusters of DER aggregate close to load centers, new grid designs become increasingly feasible, including the formation of microgrids that could provide higher levels of resiliency. Also, the investments necessary to integrate this higher penetration of DERs can provide incremental benefits to utility service, including potentially enhanced reliability.

In a larger sense, the increased penetration of DERs with appropriate capabilities at certain locations can alter how the grid is planned and operated. Instead of power going from centrally located generation through the transmission system, to the distribution system, and then to customers, more power is moving directly from local generation to the distribution system and end customers.

Managing the Increased Adoption of DERs

This changing paradigm poses both challenges and opportunities. Electric utilities must integrate DERs into a grid that is becoming more complex, but this integration also unlocks new opportunities. For example, the same energy storage system interconnected to the distribution system to meet sustainability or resiliency goals may, under certain circumstances, be used to defer traditional capacity upgrades or regulate voltage.

Using DERs for grid purposes encourages value spillovers that benefit customers through more affordable energy, provided that a methodology of DER valuation accurately establishes DER benefits to the distribution system. If the value is overestimated, it might increase customers' cost burden. If it is underestimated, it might disincentivize DER developers from deploying DERs. Electric utilities play a crucial role in navigating between these shoals. It is also important to consider how the valuation is done so that the customer, developer, and electric utility all benefit from utilizing DERs instead of more traditional solutions for capacity upgrades.

Supporting Broader Societal Goals

When DER deployments are effectively incentivized to serve grid purposes, electric utilities can further support broader societal goals. Enhanced DER incentives support an environmentally sustainable electric grid and enable technologies to enhance grid resiliency. Greater economic investment also brings growth opportunities for the regions that utilities serve. Incentives for DER adoption can encourage beneficial electrification by strengthening environmental and public health benefits. As the grid energy supply grows cleaner and more resilient, the carbon reduction benefits of electrification also increase. Furthermore, implementing advanced grid-edge technologies also sustains regional competitiveness through improved service and workforce development.

In many parts of the United States, societal goals have been driven by specific policies that promote DER development. In Illinois, for example, the General Assembly included DER incentives in both the 2016 Future Energy Jobs Act and 2021 Illinois Clean Energy Law (PA 102–0662). The 2021 law establishes base rebate values for distributed generation and storage. It also requires the Illinois Commerce Commission to initiate an investigation into DER value by June 2023.

This is just one example of how regulators are seeking methodologies to value DERs, thereby directing the evolution of the electric grid. The policy push requires a broad and deep industry discussion of methods that meet the goals and priorities of electric utilities and stakeholders alike. By investigating the Illinois example in detail and describing a consistent theory-driven approach, this analysis elaborates on key considerations for DER valuation across the industry.

Using Theory to Guide DER Valuation From Policy to Practice

The rebate valuations outlined in the 2021 Illinois Clean Energy Law provide a recent example of how DER incentives benefit from a careful consideration of the theory behind efficient utility investment. Under the same legislation, Illinois utilities are required to compensate distributed generation and energy storage assets through a statutorily defined rebate amount.

ComEd has developed a framework that identifies the marginal value of the real power in kilowatts or reactive power in kilovolt–ampere reactive (kilovar) capacity provided by distributed resources. The framework deals with the avoided cost for delivery capacity and voltage control. Further, it develops a locational marginal value (LMV) on a nodal and hourly basis to value a particular DER technology or configuration. Using this framework, we can express the locational value of DER real or reactive power injection at each hour in terms of the injection's marginal impact on all of the capacity costs for all violations needing corrections in that hour. As legislative initiatives around DER valuation evolve, frameworks like this one will play an essential role in defining the incentives available for DERs that provide value to the grid.

For instance, if a circuit is projected to be overloaded in the evening, the value of PVs to reduce that overload is significantly decreased when compared to a predicted overload that occurs midafternoon. Suppose the PV is located upstream of an overload on a radial circuit. Its output cannot mitigate the flow at the location of the overload and, accordingly, provides less value than PVs downstream of the overload. Figure 1 illustrates four principles of DER valuation. When DERs are installed on a circuit with projected investment needs, the generation or storage will have value to the extent that the DERs can operate during the hours of the year when the condition needs to be mitigated, and the DER capabilities provide the required real or reactive power.

There are six primary goals for a practical methodology to evaluate the contributions of DERs:

- ✔ Identify and quantify the benefits of DERs used to defer or avoid traditional distribution investments. The avoided cost includes the addition of delivery capacity to serve the increased load and needed grid investments to mitigate voltage violations.
- ✔ Provide an LMV for the marginal real and reactive power injected to or absorbed from the grid at each

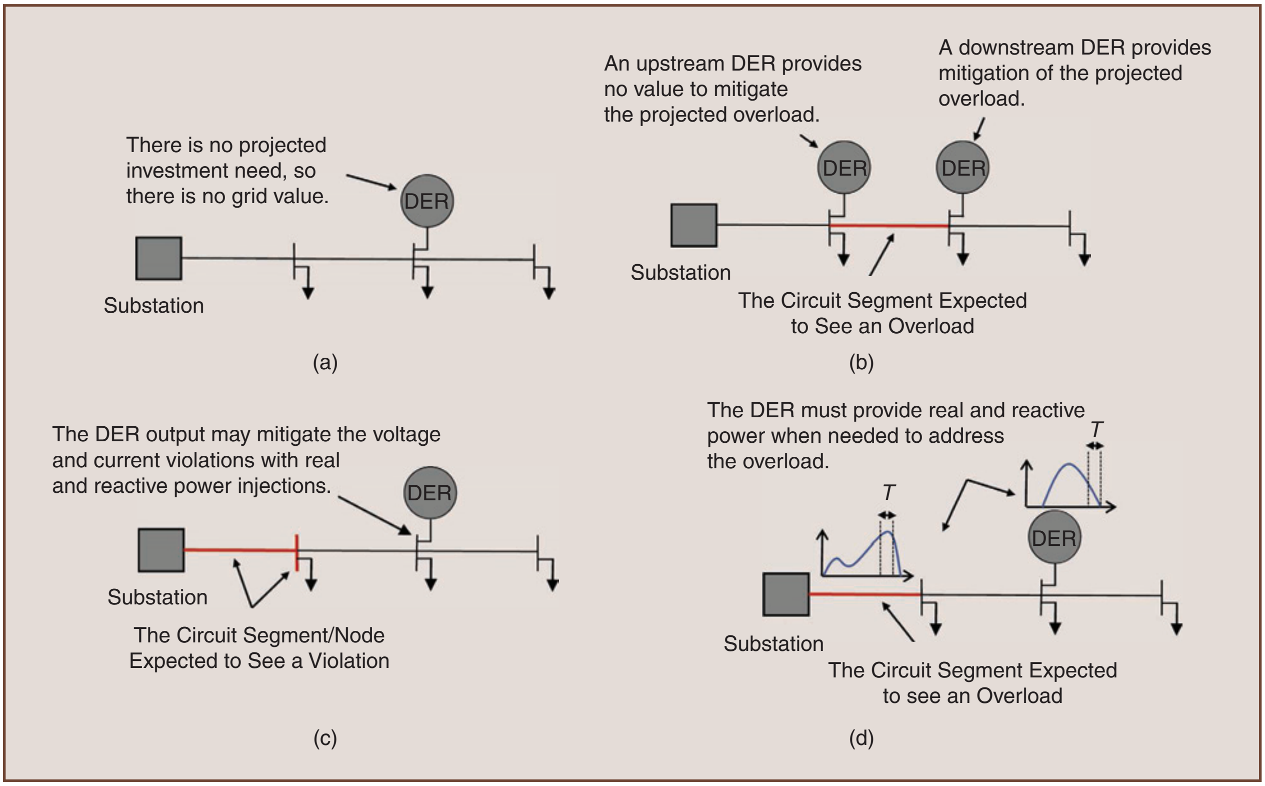

figure 1. The key principles of DER valuation. (a) Principle 1: the DER value is nonzero only in the presence of system needs for an upgrade. (b) Principle 2: the DER value is locational. (c) Principle 3: the DER value should be expressed based on both real and reactive power. (d) Principle 4: the DER value is temporal.

By investigating the Illinois example in detail and describing a consistent theory-driven approach, this analysis elaborates on key considerations for DER valuation across the industry.

"node" in the system (i.e., at each location where the load or DER can be connected).

- ✔ Capture the value of DERs in avoiding the potential cost of future grid investments to meet forecasted capacity needs.
- ✔ Express the LMV as a set of geospatial and temporal values.
- ✔ Account for distribution losses, including transformer and line losses.
- ✔ Provide valuations of generic DERs, which could be either a single technology or multiple technologies combined, for example, solar and storage.

We need to know more than the grid location to understand how a given injection of real or reactive power from a DER will affect a circuit constraint. Often, more than one branch of a circuit will be overloaded to varying degrees and at different times. When nodal voltages are high or low, multiple nearby nodes are likely to exhibit related voltage deviations to differing degrees. Depending upon its location, a DER may impact all overloaded branches equally or only one, or it might affect multiple branches differently. Similarly, it may have a greater or lesser impact on different nodes with voltage issues.

The comparison with a conventional grid investment adds more complexity to the framework. Typically, a conventional investment is a single project intended to address all forecasted problems on a circuit, station, or network component. Such an investment may involve upgrades, multiple pieces of distribution equipment, and the cost of installing them. There is a substantial challenge in attributing the aggregate characteristics of such an upgrade to the specific nodes where DERs can provide services to avoid upgrade costs.

The complexities associated with this level of analysis only increase as realistic networks and circuits are considered. Voltage problems and the effect of reactive power add still more complexity.

Key Concepts in the Value of DERs Framework

The value of DERs (VDER) framework has two key concepts:

1) Allocate the costs of traditional investments to locations on the system according to whether they exhibit forecast limit (current and voltage) violations triggering the investment.
2) Assign a value to DER real and reactive power according to the sensitivity of the forecasted violations to nodal DER kilowatt and kilovar injections and proportional to the allocated costs of those violations.

The first concept is implemented by allocating the project cost to each overloaded piece of equipment according to the extent of that equipment's loading and voltage violation, calculated on an hourly basis. No costs are allocated to equipment with no forecasted violations, even if some project costs are spent on them. Costs are allocated only in those hours when violations are forecast for a specific piece of equipment. This process results in an "allocated cost of capacity" that varies by system component and time (e.g., the hour of the year).

The second concept is implemented by calculating the "treatment effectiveness" for each violation, given a DER injecting real or reactive power at a specific location and time. The treatment effectiveness is applied as a discount against the allocated cost of capacity to determine the local grid benefit that the DER provides.

In this way, we define the *LMV* as the incremental value of the DER on a kilowatt and kilovar basis at a given location (node) given that specific DER's ability to reduce overloads, over- or undervoltages, and so on. This is very similar to the "locational marginal price" concept in markets and can be derived in a similar way as the shadow cost of a constraint. The key difference is that, instead of being an energy-clearing price, it is the marginal effect of the cost of capacity.

An ideal methodology would be technology agnostic. In other words, it would treat all forms of DERs equally depending strictly on their contributions to the grid. We can extend the VDER methodology to determine the values of different DER technologies by running LMV calculations specific to them.

The LMV calculated for a generic DER is the maximum value that a DER can realize, assuming there are no temporal or operational restrictions for the DER to inject or draw real and reactive power. However, this is not the case for some DER technologies for which the real power output is limited by their energy source, such as wind and solar resources, or battery storage, where there are constraints due to the size of the energy storage system. Therefore, to accurately capture the value of these resources, we need to understand how grid needs are aligned with the injection/draw capability of a specific resource both temporally and spatially. For example, a solar resource on a feeder that requires thermal overload relief in the evening has minimal to no value for the grid, and this should be reflected in its LMV. However, if the same solar resource is large enough and paired with a properly sized battery, it may provide the complete value of a generic DER.

There is precedent for the treatment of "energy-limited resources" in wholesale capacity markets, where independent system operators define a *capacity factor* for each resource type accounting for its "availability" to provide energy. In the context of value to the distribution grid, other utilities, for example, in New York, define a *coincidence factor* that captures the alignment of resource availability and grid need. The choice of coincidence factor depends on the grid service required for the bulk, transmission, and distribution systems as well as DER location and type. To simplify the calculation, these utilities use a single-value approximation for the coincidence factor. For example, they model the normalized (per nameplate capacity) energy behavior of the DER on a time series basis and compare that normalized behavior to peaks in the system load and constraints.

Since the generic LMV is already determined on an hourly basis and reflects the temporal and spatial aspects of grid needs, the DER-specific LMV is a relatively straightforward calculation that involves multiplying the normalized hourly profile of specific DERs by the generic hourly LMV profile. The calculation of the DER-specific LMV is formulated as an optimization problem. In this formulation, 1 kW of a specific DER technology or bundle of technologies is optimally dispatched against the hourly LMV adhering to operational limits on the DER technology.

This approach does not require any additional data other than DER limitations since the generic hourly LMV is already calculated. Further, it is applicable to more complex situations, such as energy storage charge and discharge as well as the bundle of technologies where rules of thumb might fall short and/or become more complicated to establish. Numerical examples for several DER configurations are shown in Figure 2. For this analysis, renewable resources coupled with battery energy storage are limited to charging the battery with a renewable output.

Figure 2 illustrates several conclusions for the specific case studied:

1) For this situation, the PV system can produce 78% of the value of the generic DER (a DER that is dispatchable and capable of providing sufficient active and reactive power).
2) The PV system captures much more of the value than its capacity factor would indicate. This is because, in this example, thermal overloading correlates reasonably with peak PV production.
3) Combinations of PVs and storage are more effective than PVs only, depending on the ratio of storage to PVs in terms of power and energy. Due to the grid location and feeder constraints, a multihour storage capacity may be required to realize a generic DER value.
4) For this case, the wind resource can produce around 55% of the value of a generic DER. In this example, the feeder capacity need is better aligned with the temporal profile of PVs than that of wind.
5) Similar to PVs combined with battery energy storage configurations, adding storage to wind installation would increase its contribution and, thus, value.

Mapping LMVs and making these maps accessible would provide customers and developers insight into the potential incentive for each DER technology deployed at each location. This incentive is based on calculating the marginal value of each DER technology to the grid as a portion of the avoided distribution upgrade costs.

Practical Capabilities That Are Needed to Implement the VDER Framework

There are practical aspects to implementing the VDER computation methodology. First, the engineering and planning processes need be adjusted to support quantifying DER

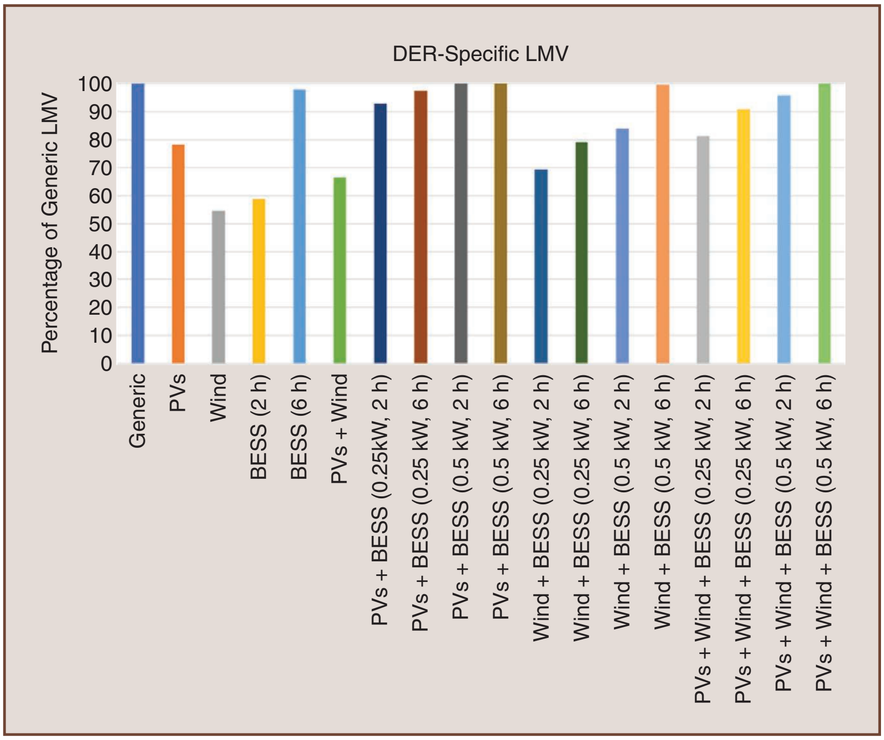

figure 2. The results of evaluating PVs with different storage configurations against a particular LMV profile. BESS: battery energy storage system.

> An annual hourly profile must be investigated to understand the hourly duration of the potential kilowatt overload on the peak day.

values. Second, the LMV calculation must be operationalized to provide the DER rebate value. Third, the measurement and verification of the DER response in real time need to be recorded.

Planning and Engineering

There are multiple practical aspects to implementing a VDER computation in the planning and engineering process. These include 1) the need to perform an 8,760-h time series analysis, 2) a node-branch circuit mode, and 3) adjusted planning cycles for short-term projects.

To implement this methodology, ComEd developed a software tool based on this framework. The tool integrates with existing distribution planning processes and is based on sound engineering and financial analyses.

The 8,760-h Time Series Analysis

Planning studies normally identify and investigate a peak hour for traditional capacity planning needs and high solar production hour in a spring or fall shoulder month for DER interconnection studies. However, an annual hourly profile must be investigated to understand the hourly duration of the potential kilowatt overload on the peak day or days. LMVs are calculated on an hourly basis for each node in the system to provide this result.

While some commercial software tools used in planning are capable of this analysis, there are issues with input data to consider:

- ✔ Feeder-level kilowatt, kilovar, or ampere loading and weather data obtained for use in planning contain anomalous, missing, or erroneous values that can be caused by feeder rollover, outages, and other factors. ComEd uses data filtering and repair methods to identify anomalous readings that require engineering review as well as make corrections and impute missing data based on traditional peak-load and distribution system planning needs.
- ✔ Planning generates a weather-adjusted load forecast per feeder that leverages recent peak-hour data and feeder weather-sensitivity factor to account for worst-case weather scenarios (e.g., a one-in-10-years weather event). Adjusting the 8,760-h data for a hot year can affect the temporal aspects of the LMV results. ComEd scales only a one-week window around the peak based on the worst-case weather and keeps the rest of the 8,760-h data intact.
- ✔ If feeder-level data are used, the loads along the feeder are scaled to the forecast peak according to their customer type profile. The entire feeder load profile must be adjusted to conform to the 8,760-h time series. If advanced metering infrastructure data are used as the basis for capacity planning instead, data preparation would require the usual cleanup of missing data and other data anomalies but also the reconciliation of data from different sources.
- ✔ The feeder level and advanced metering infrastructure data are "net" figures of the actual load less the PV production. For forecasting and the VDER calculations, the data must be separated either by estimating PV production from the installed capacity or, ideally, via submetering information.

Node–Branch Circuit Model

The LMV analysis requires a circuit model that is node branch in form. All load and DER injection are at nodes, and all branches have nonzero impedances, so there is a feasible power flow solution. In existing conventional distribution planning software tools, the load is often associated with sections (branches) instead of nodes. In these tools, the distribution equipment (e.g., a reconfiguration switch) is represented with zero impedance. A zero-impedance circuit is unrealistic in the real world and, as modeled, incapable of localizing the DER benefit. Our model relies upon impedances because they influence the DER's ability to alleviate a constraint.

Planning Cycle Adjustments for Short-Term Projects

Currently, electric utilities like ComEd use an annual planning cycle for short-term needs. At summer's end, ComEd reviews operations for pressing issues, and the system load forecast is updated for the next few years as the basis for studies of grid conditions. ComEd then identifies and plans projects based on the problems uncovered, and engineering designs are completed to budget these projects. Once reviewed and approved, projects proceed to construction that must be completed before the next summer peak. This schedule also should account for the DER adoption based on the VDERs at specific locations, construction, and the date the DER enters service. However, there must be enough time to proceed with grid construction solutions if the DER requirements are not satisfied at locations of urgent need.

Operationalizing the LMV Calculation for a DER Rebate

This VDER framework expresses the locational value of a kilowatt of real power injection and kilovar of reactive power injection at each hour. These effects are expressed in terms of their marginal impact on all of the capacity costs for all violations needing corrections in that hour. For practical purposes, the approach averages the nodal values into single area-wide values to determine the DER rebate value.

A five-step process allows us to work from the DER value framework to generate a standard, area-wide value downstream of the substation or mitigated overload. In practice, we can use these values to induce customer participation in incentive programs that bring DERs onto a local distribution network (substation or feeder) where the DERs will mitigate adverse conditions. These averaged values avoid the need to establish specific incentives that are localized to each customer site.

The LMV calculation follows a five-step process, as illustrated in Figure 3:

1) Quantify the locational impacts through a power flow sensitivities analysis.
2) Calculate the deferral value of the avoided cost of the capacity to violated locations.
3) Allocate the deferral value of the avoided cost of the capacity to violated locations.
4) Multiply the two quantities to get the LMV.
5) Average the nodal values to a single area-wide value.

These area-wide values will still be based on granular node-level calculations to determine the locational VDER necessary to incentivize DER adoption in place of traditional system upgrades. This will avoid customer confusion that may result from publishing nodal values for DER rebates.

A framework is necessary for auditing the DER response performance. The DER response must be recorded in real time, and an analysis should be planned to contrast utility and third-party DER management performance. This measurement and verification plan must be conducted at regular intervals, characterizing individual events and summarizing across aggregated events.

In practice, measurement and verification capabilities depend upon additional software and hardware that augment the buildout required to bring a VDER framework into the field. The VDER measurement and verification require a real-time communication infrastructure, information technology infrastructure, bandwidth, field equipment, and software systems. Software typically resides in a master station where it can communicate with sensors, substation equipment, and DER metering devices. These devices must be robust to cybersecurity threats and environmental conditions.

Implementation Considerations and the DER Management System

The presented framework for valuation is a way to evaluate the capability of a specific DER to respond to grid constraints based on location, performance, and generation profile. While this capability is significant in assigning a value, the realization of the value is far more important from the grid reliability and resilience standpoint. Once a constraint arises, the DER must replace the traditional grid asset and mitigate the constraint for those specific hours. For a simple PV system, the real power output is simply driven by the sun. However, the reactive power output may be adjusted by local drivers, such as the voltage based on the smart inverters' droop (reactive power) controls or set points provided by a supervisory system. For storage systems, solar and storage combination, and other dispatchable resources, the coordination of the real and reactive power outputs can be determined from the prevailing system conditions and again communicated to individual devices.

To implement coordination beyond a few devices, a reliable low-latency, high-bandwidth communication system is required to allow each device to follow a particular control signal. At the same time, establishing the appropriate control requires a resource management technology that identifies grid constraints, implements set point changes, and

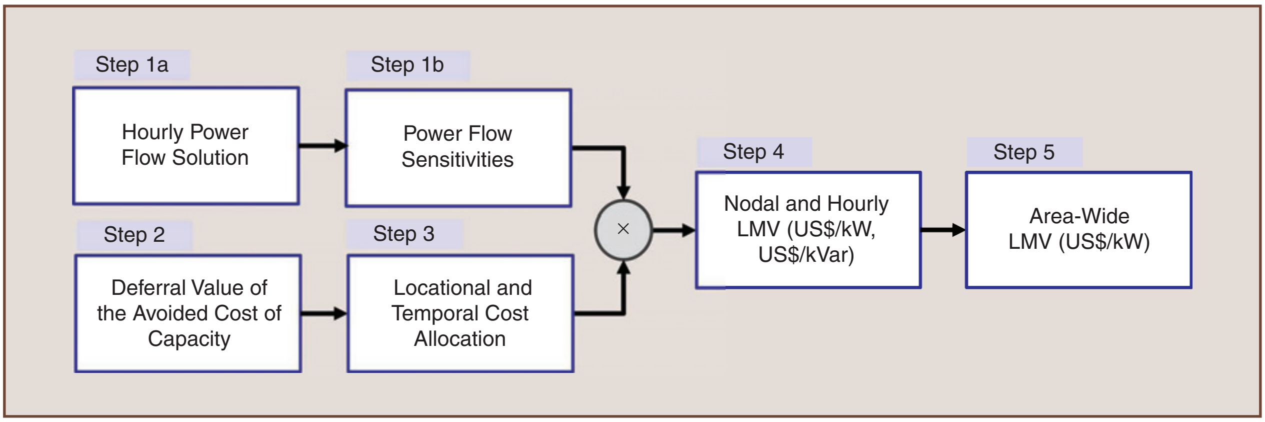

figure 3. A single area-wide value calculation.

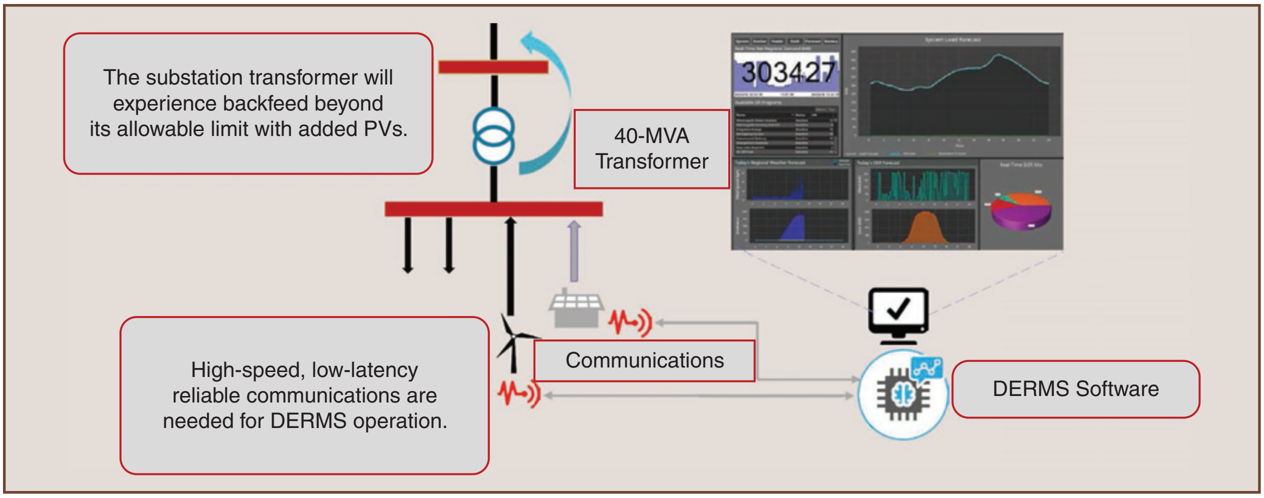

figure 4. A DERMS implementation to mitigate a transformer overload.

coordinates DER operations. Such control can be achieved through a DER management system (DERMS).

DERMSs are deployed for various purposes, many of which manage DERs on the distribution system. With these capabilities, DERMSs enable deferred or avoided capital costs. DERMSs can be leveraged to create the level of visibility for DERs needed for real-time grid operations, provide visibility of the grid constraints, forecast and monitor when the constraints may be reached, and manage DERs accordingly.

To demonstrate the future value, ComEd deployed its first DERMS in 2021. The system was designed to mitigate the overloading of a substation transformer due to a higher level of PV and wind integration in a particular area. Figure 4 illustrates the communications topology of ComEd's first DERMS demonstration. This DERMS monitors the transformer loading, DER output, and system conditions. It sends signals to manage DERs if any system violations occur. The same control principles apply to realize the local grid DER value: a system constraint is identified, its loading is constantly monitored, and when the overload occurs or is projected, the DER is dispatched to mitigate the overload. In ComEd's demonstration, the overload was caused by the simultaneous generation of both PV and wind during low system loading, but the same principles apply when overloading may be due to increased loading on a feeder or at a substation. Communication and management capabilities are vital in terms of the value to be realized from the DER installations to avoid or defer traditional grid investments.

Conclusion

Designing a VDER methodology is only the beginning. Additional development is required to move beyond measurement and verification and establish an ongoing operational model. For example, a practical framework for customers to interact with utility signals and sustain their ongoing program participation must also be designed and implemented. In turn, this framework will rely upon additional system capabilities, including fast, low-latency communications and other smart grid technologies.

As DER deployment is incentivized, electric utilities need to integrate these resources to maximize their value. Doing so requires leveraging not just the existing best practices but deploying state-of-the-art grid capabilities like sensors, DERMSs, and advanced communications infrastructure. Deploying these technologies can help communities to manage the costs and maximize the performance of DER assets in a way that reduces climate change emissions and increases energy system resilience. All of this requires a sustainable DER infrastructure that provides value to customers, an objective that a consistent and grid-informed VDER methodology can help to realize.

For Further Reading

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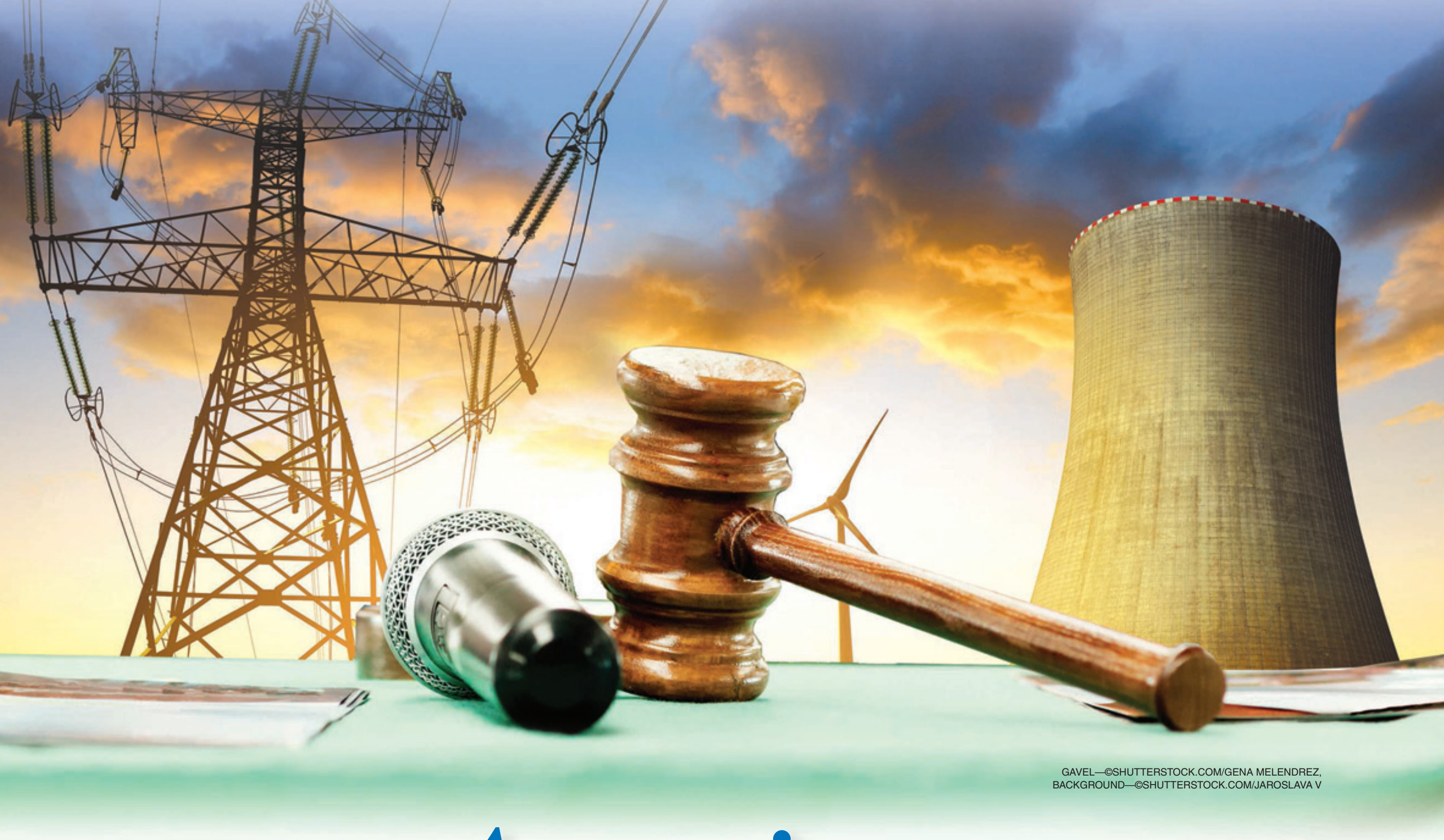

Auctions for Nonwires Alternatives

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Securing and Operating Dispatchable Distributed Energy Resources

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AS DISTRIBUTED ENERGY RESOURCES (DERs) decline in cost, improve in capability, and receive more interest from end consumers, there are increasing opportunities for them to play a role in managing the distribution system. One of the major ways DERs can provide services to the electricity system is by acting as nonwires alternatives (NWAs) to manage local peak demand and help defer or avoid capital and operational costs associated with traditional network infrastructure. NWA projects can help utilities and regulators reduce system costs and costumer

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NWA projects can help utilities and regulators reduce system costs and costumer bills if DERs are the less costly solution for meeting incremental load growth.

bills if DERs are the less costly solution for meeting incremental load growth.

DERs offer value in other ways, for instance, by participating in wholesale markets to provide system-level services. They can also provide valuable resilience benefits to end consumers and communities. Similarly, using DERs as NWAs represents one of the major ways DERs can provide services to the electricity system. While NWAs are nascent in the power and utility industry, there are many pilots underway, and some jurisdictions, such as New York, have begun larger-scale implementation. Approaches to NWA projects involve utility programs, such as incentives for energy efficiency, and request-for-proposal processes for procuring solutions. However, auctions can also be used to acquire services from DERs, including securing and operating DERs for NWA purposes.

Auction mechanisms are well suited to facilitating transactions to enable NWA projects, including identifying the parties to involve, discovering economically efficient prices, and guiding the allocation of resources. Auctions generally have open, fair, and transparent (while privacy-preserving) processes that can lower transaction costs and other barriers to entry. The approach is beneficial to smaller participants that may be using new technologies and have fewer financial resources than larger and more established organizations. Repeated auctions enable participants to observe outcomes under various conditions, helping them learn and identify suitable bidding strategies, leading to more predictable behavior and results. Importantly, auctions can involve complex clearing processes that account for constraints in what transactions can be accommodated while requiring only simple inputs from bidders. In other words, complex transactions can be simply facilitated from a participant's perspective.

It was with the benefits of auctions in mind that Ontario's Independent Electricity System Operator (IESO), in Canada, initiated the York Region NWA Demonstration in 2018. The project is funded by the IESO and Natural Resources Canada, with Alectra Utilities, the electricity distribution company in the demonstration area, acting as the distribution system operator (DSO) and delivering the project. The demonstration explores how a DSO could use local auctions to procure distribution-level electricity services from DERs while simultaneously coordinating with the transmission-level wholesale market. It tests auctions as means to secure and operate DERs to enable their use as NWAs. The project contributes to foundational work toward developing distribution-level markets. Auctions similar to those in the demonstration will likely be a feature of transactive energy systems in the future, where electricity resources participate in an automated manner to provide grid services. This article provides an overview of the design of the demonstration's three auction processes for capacity, energy, and reserves, including results to date and insights into learnings.

NWAs

DERs, such as generation, storage, and demand response resources connected to the distribution system, are capable of providing a range of services to the grid. One of the most promising use cases involves harnessing DERs as alternatives to constructing new transmission and distribution (T&D) network infrastructure, including traditional substations and lines. Through the inclusion of DERs, investments in T&D solutions can be deferred or avoided, reducing system costs if DERs are the more cost-effective solution. Services procured in an NWA project can be sourced from consumer-owned DERs and DERs owned by independent providers, opening opportunities for private investment and for consumers to reduce their utility bills.

The interest in NWAs is driven by the material installation of DERs across many jurisdictions in recent years and the expectation that the trend will continue. NWA projects represent a new and incremental opportunity to use DERs to provide grid services and generate value. In the demonstration, three separate services for capacity, energy, and reserves have been designed to facilitate the use of DERs as NWAs. Generally, local resources sited close to the end consumer load can be an alternative to new network infrastructure and more remote, larger centralized resources. For example, a project involving alternatives to distribution infrastructure would seek services from DERs located in the distribution area downstream of the assets being deferred. In other words, smaller resources located close to end consumers can be used to meet local demand without having to build remote centralized generating stations (GSs) and the network infrastructure to deliver the electricity.

A highly simplified example of an NWA project at the distribution level is depicted in Figure 1. In Figure 1(a), the existing system is shown, with a centralized GS, the transmission–distribution interface, a transformer station (TS), and a distribution-connected load. The transmission-connected generating station and TS are at their maximum capacity to generate and deliver electricity. Any growth in demand will necessitate new infrastructure investment. In

While NWAs are nascent in the power and utility industry, there are many pilots underway, and some jurisdictions, such as New York, have begun larger-scale implementation.

Figure 1(b), new load growth drives the need for supplementary infrastructure, which has been addressed through the traditional solution of adding centralized generating capacity and network equipment. In Figure 1(c), however, a DER is used as an alternative. DERs can serve as substitutes for centralized resources and T&D infrastructure, and when employed in this integrated manner, they may constitute a more cost-effective solution.

There are several drivers behind the economics of using DERs as NWAs. First, DERs can be employed in numerous ways, meaning that only a portion of their cost needs to be compensated for when they provide services for NWA purposes. For example, another major source of revenue for DER participants comes from providing services to the wholesale market at the transmission level. Second, DERs have a smaller, targeted, and continuous installation in comparison to the large and "lumpy" nature of T&D infrastructure investment, which is an economic driver for using them as NWAs. Typically, new T&D infrastructure is lightly loaded in the years directly following its construction, which means that the cost for a mostly unused asset is recovered from the end consumer. On the other hand, DERs, being modular, can be paid for through time as needed and in step with when load growth materializes and more installations need to be built. Third, while hard to quantify, when DERs are used as NWAs, they provide "option value" associated with the uncertainty in planning assumptions and the flexibility of making decisions in the future. The ability of a DSO to make smaller, staggered, and shorter-term payments to DERs (relative to traditional network infrastructure) provides value by keeping options open, permitting planners to observe whether expected load growth materializes before making a significant long-term investment. This approach also enables the DSO to monitor how technology cost trends unfold, such as the price of battery storage during the next several years. Finally, DERs contribute to the reduction of system losses, which can be material at the lower voltage levels of the distribution network and especially during peak demand. As a result, energy costs decline, as does the resource capacity that is needed through time. In short, traditional centralized solutions to meet electricity needs enjoy economies of scale that are not available to DERs. However, DERs have added locational value and an advantage in their smaller and modular installation, which may outweigh their lack of economies of scale, especially as their cost and capability continue to improve.

The Demonstration Project

Using DERs as NWAs remains an emerging concept and practice in the power and utility industry. There is limited real-life experience with relying on DERs to balance demand and supply in a very localized area as part of an NWA project. The demonstration was developed to test auctions as a means for a DSO to manage DERs as NWAs, with a particular focus on reliability considerations and coordination with wholesale markets. When initiating the demonstration, in 2019, white papers were developed as groundwork. Subsequently, the rules and contracts for participating were drafted. These documents spell out the requirements and processes for participants, including how auctions are cleared, prices are established, and payments are calculated and settled. The design concepts and rules and contract documents were presented in draft form to potential participants and broader Ontario industry stakeholders to solicit feedback.

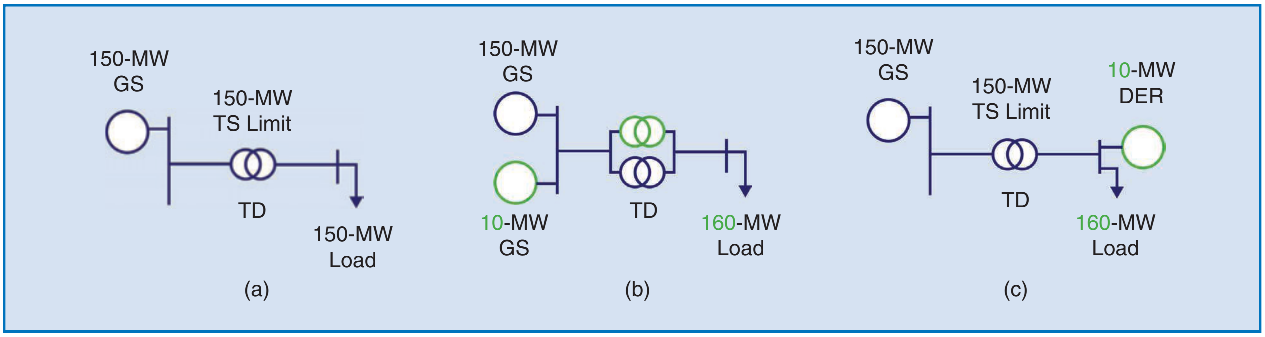

figure 1. DERs can be used as alternatives to traditional infrastructure. (a) An existing load, with the GS and transformer station (TS) at their limits. (b) Growth met with new TS and GS capacity. (c) Growth met with new DER capacity. TD: transmission–distribution.

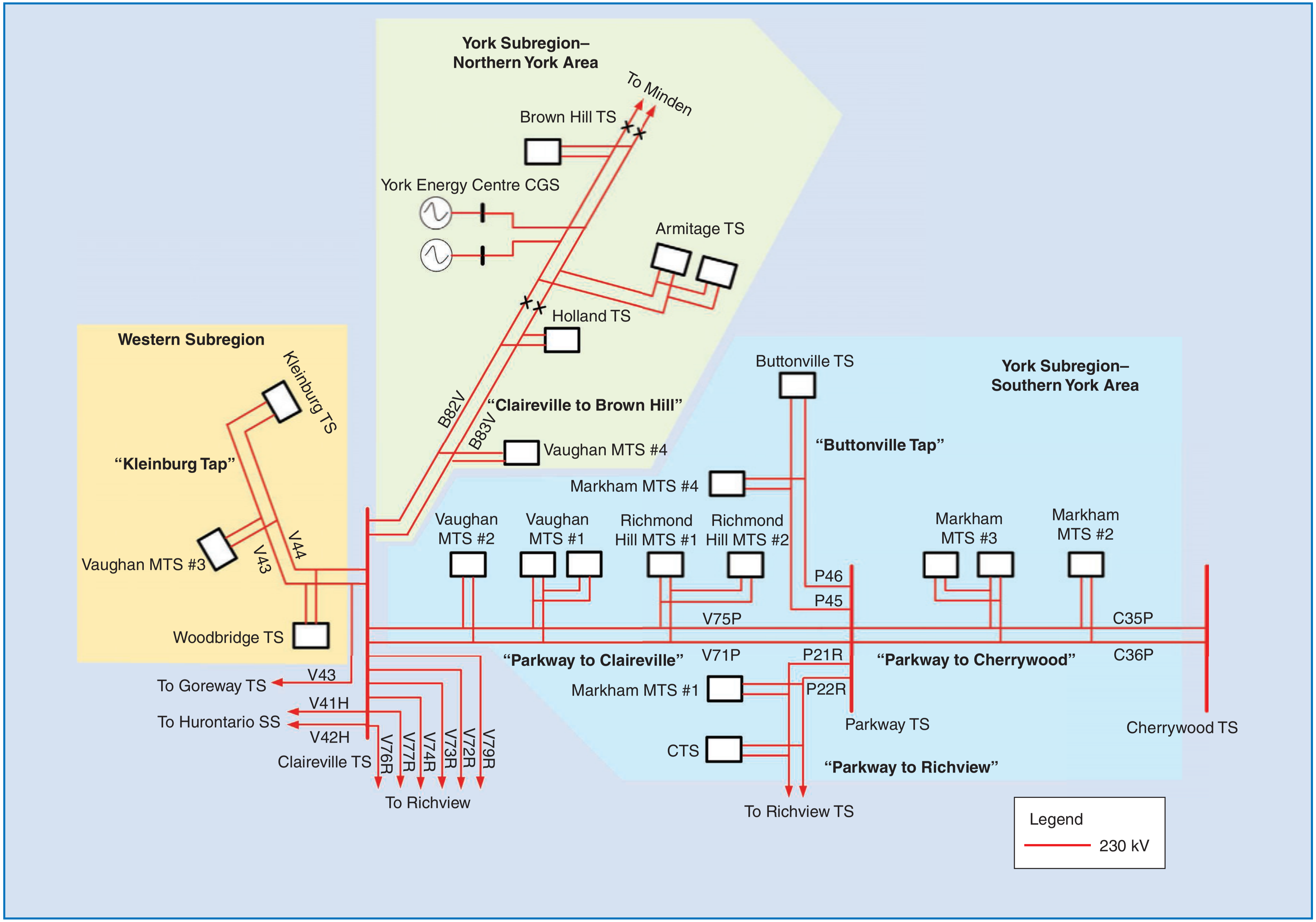

figure 2. The York Region transmission system. MTS: municipal transformer station; CGS: customer generating station; CTS: customer transformer station.

The operational phase launched in fall 2020, initiating the first year of the participant-facing part of the project. The second and final operational year commenced in fall 2021 and will run into 2022. The project will conclude by publishing lessons learned and other documentation. The following sections describe the demonstration's design and implementation and highlight some preliminary results.

Demonstration Area and Eligibility

The southern part of York Region was identified by system planners as a location well suited to the demonstration. York Region is part of the Greater Toronto Area of Ontario. It is also part of the inner ring of the Golden Horseshoe, which is a densely populated and industrialized area. Specifically, the demonstration focuses on southern York Region and captures the towns and municipalities of Richmond Hill, Markham, and Vaughan. To define eligibility in the project, the area is described electrically as being downstream of several of the substations in Figure 2. Demand in the area exceeds 1,300 MW during summer peak hours and consists of a mix of residential, commercial, and industrial loads. There are also DERs in the area, which, if operated in new and beneficial ways, could provide incremental value as NWAs.

Planning documents for York Region identify the area as fast growing, with extensive urbanization expected to continue. Due to this growth, new stations will be required during the next decade. However, the DERs participating in the demonstration are not being used to address an actual reliability need, which would be the case in a real implementation of an NWA project. Rather, the demonstration simulates the capacity, energy, and reserve needs expected to arise in the early 2030s if more stations are not be built. In this manner, the auction mechanisms and capabilities of participating DERs can be tested in a low-risk environment while still describing the actual potential of using DERs as NWAs in future years.

To test auction processes in managing an NWA project, eligibility in the demonstration is focused on dispatchable DERs. Specifically, demand response, storage, and thermal resources, such as combined heat and power and biomass facilities, that are owned and operated by third parties are eligible to participate. While other resources and measures, including solar photovoltaics and energy efficiency, can contribute to NWA projects, the demonstration excludes nondispatchable DERs to focus on the DSO's active management of dispatchable DERs in near real time. Aggregations are also eligible, enabling participants to group smaller-contributor DERs to meet the minimum size threshold of 100 kW. Even the aggregation of residential consumers, which may involve thousands of contributor DERs, is permitted. Standalone DERs qualify as long as they meet the 100-kW minimum threshold One hundred kW is also the level required by order 2222 issued by the U.S. Federal Energy Regulatory Commission (FERC) in September 2020. The FERC order allows standalone DERs and DER aggregations that are 100 kW and larger to participate in organized wholesale markets in the United States. Ontario, where the demonstration is situated, is not under FERC jurisdiction, but the order is recognized as an important benchmark for North America. The demonstration differs in its approach, however, in that the 100-kW threshold is for participation in the DSO's local auctions for DERs, while the minimum size threshold in the Ontario wholesale market is 1 MW.

Three Auction Processes

Implementing an NWA project at the distribution system level involves several processes that, in combination, could enable DERs to facilitate investment deferrals in traditional infrastructure. In the demonstration, three major processes are used, each defined as a distinct service with an associated auction for clearing DERs and establishing prices. The three services and auctions are modeled from similar mechanisms and processes in wholesale markets but are applied to enable DSOs to use DERs as NWAs to help manage the distribution system.

First, as part of a capacity service, a local capacity auction is conducted to enroll DERs several months in advance of the demonstration's commitment period, which is when the DERs will be used. This helps ensure that adequate capacity is secured and will be available to the DSO. It also provides participants with some lead time if they are installing or aggregating new DERs. Second, as part of an energy service, a series of local energy auctions is conducted during the six-month commitment period to activate DERs when the they are needed as NWAs (as described in the following). Activating DERs as part of the energy service takes place when demand exceeds a loading threshold established for the demonstration area, which is intended to simulate the conditions of an NWA project. Third, as part of a reserve service, local reserve auctions are conducted on activation days in tandem with local energy auctions to schedule DERs as reserve resources. The DERs on reserve can then be deployed on short notice if there is a contingency and they are needed.

To administer the three auction processes, a web-based platform has been developed for the demonstration. It enables the DSO, as the administrator, to set parameters for managing the project. The DSO can, for instance, schedule a local capacity auction and establish the capacity target the auction will seek to secure. It can also set the values for conditions that trigger an activation. Participants log in and manage their part on the platform, as well. The platform enables them to provide registration information and input bids for the three auction processes. In case DERs are unavailable, participants provide notice of the outage and information about it to the DSO. For participants with aggregations, the platform facilitates the periodic addition and removal of contributor DERs.

Based on the demonstration's rules, the platform automatically conducts the auction clearing process and presents the results to the DSO and participants. Participants also have insight into conditions that drive the activation of their DERs. The platform shows the DSO's demand forecast and loading threshold levels that trigger the need for DERs, as demonstrated in Figure 3. This feature introduces some transparency into the activation process and provides participants with data to incorporate into their assessments of when activations may take place. In this manner, the platform facilitates the demonstration and operationalizes the local capacity, energy, and reserve auctions.

Local Capacity Auction

The local capacity auction seeks to secure DER capacity to address distribution-level needs. This enables the DSO to meet peak demand during the commitment period, which is defined as 1 May–31 October 2021 for the first operational year and 1 May–31 October 2022 for the second operational year. As part of the project design, the demonstration area was identified as summer peaking, and the local capacity auction is therefore focused on the "summer half" of the year. The auction could easily be expanded to address the "winter half" if the need for DERs was identified during that period, too.

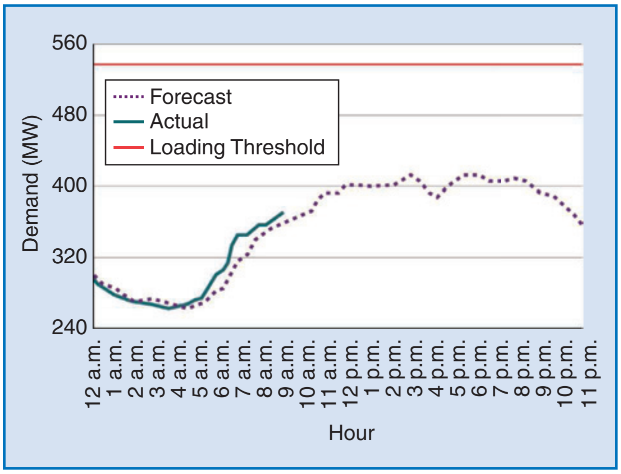

figure 3. The demand forecast for part of the demonstration area on 6 October 2021.

table 1. The 2020 local capacity auction results.		
Successful Participants	**Local Capacity Obligation (kW)**	**Resource Category**
EnergyHub Canada	1,200	Demand response
NRG Curtailment Solutions	400	Demand response
Longo Brothers Fruit Markets	1,000	Demand response
Edgecom Energy	3,000	Demand response
GC Project	1,000	Demand response
Markham District Energy	2,900	Thermal resource
Tycho Poly	500	Demand response
Total	**10,000**	

The target of the local capacity auction was 10 MW in the first year. While the goal was modest, it represented approximately 1% of the load in the demonstration area, which is not an insignificant quantity. For the second year, the target was increased to 15 MW. A key reason for the adjustment was to model how an NWA project could be structured with periodic expansions of the capacity target (e.g., year over year) as the load grows. While the approach was to secure a meaningful capacity target for demonstration purposes, in an actual implementation of an NWA scheme, planners would conduct a detailed study of the expected load growth, distribution network congestion, network upgrade requirements, and NWA deferral value to assess the economics of using DERs in comparison to network infrastructure upgrades.

As part of the local capacity auction, what represents capacity must be exactly defined. In the demonstration, DER capacity can be provided by thermal and storage resources that deliver energy and directly connect to the distribution system. DER capacity can also be provided by demand response resources that reduce energy consumption. Additionally, DERs must be capable of sustaining their capacity power output for at least four consecutive hours. This parameter may be adjusted as required to enable the DSO to reliably meet its expected needs. Similar to resource adequacy assessments conducted in bulk system planning, a rigorous analysis must be performed to ensure that the capacity service being sought from DERs will reliably address the needs of the distribution NWA project. The target and parameters that define DER capacity in the local capacity auction have to be set to ensure distribution-level resource adequacy.

The maximum clearing price in the local capacity auction is another key design parameter. It was set at CAD\$1.60/kW-day for the demonstration. The maximum price was based on data points that relate to the cost of centralized generation plus data points associated with the value of deferring investment in new network infrastructure. In setting the maximum clearing price, assumptions at the high end of the range were used to ensure sufficient incentive to drive participation in the project. The local capacity auction for the first operational year of the demonstration was held in November 2020 (see Table 1). It cleared 10 MW from seven participants at a price of CAD\$0.64/kW/business day in the commitment period, which is a substantial discount from the CAD\$1.60/kW-day maximum. Using other and perhaps more familiar units, CAD\$0.64/kW-day represents CAD\$80,000/MW for the May–October commitment period. Also, an interesting variety of DER types was observed among the successful participants in the auction. For instance, EnergyHub Canada is an aggregator of smart residential thermostats. Markham District Energy has combined heat and power facilities to provide district heating to surrounding commercial, institutional, and residential consumers. Longo Brothers Fruit Markets is a demand response aggregation of grocery stores in the demonstration area.

Most of the DERs participating in the demonstration are demand response resources with capabilities developed before the project was launched. However, DERs expected to be installed following the local capacity auction were eligible to participate. These resources, referred to as *future DERs*, did not need to exist at the time of the auction but were required to be in place before the commitment period commenced on 1 May. The demonstration did not, however, receive significant participation from future DERs. This may be attributed to the demonstration being time limited since it concludes in 2022. Revenue opportunities sustained during additional years are likely needed to stimulate greater investment in new DER installations. The local capacity auction design can be modified to address these considerations. Auctions can be held further in advance of when the DERs will be used, potentially giving participants years to invest in and develop installations. The auction design could also have longer commitment periods, potentially involving multiyear commitments to provide participants greater long-term revenue certainty.

Local Energy Auctions

The DERs that clear in the local capacity auction are required to make their capacity available in the demonstration's local energy auctions. Participants indicate the availability of their DERs to be activated for energy service by issuing bids in the local energy auctions. To provide participants flexibility to express the cost of operating their DERs at different output levels and times, bids can be broken down into five price-and-quantity pairs for any hour, enabling parties to specify prices for various output levels from their installations. Participants must also indicate whether each pair could be fully or partially activated, with the latter enabling the DSO to activate only a portion of the quantity of the price-and-quantity pair. While bids can be input at any time, the platform enables participants to provide standing bids that are used until they are updated.

Local energy auctions are held periodically during the project's commitment period, on days when the local demand is expected to peak and DERs need to be used for distribution NWA purposes. As illustrated in Figure 4, this need is referred to as the *local requirement* in the demonstration and represents the amount of energy that DERs must provide. DERs are required to deliver energy when local demand cannot be met by the upstream system because of network infrastructure limitations (i.e., the local area is import constrained). As noted, the reliability constraint in the demonstration is simulated. A loading threshold was chosen to mimic station limits. This facilitated an exploration of energy needs that could emerge in the future if an NWA project were to be implemented in the demonstration area.

As depicted in Figure 5, the process for the local energy auctions begins at 7 a.m. on business days throughout the commitment period. Shortly before that time, the platform checks the demand forecast for the demonstration area to see if it exceeds the loading threshold and whether a local requirement is expected. If there is a requirement, a

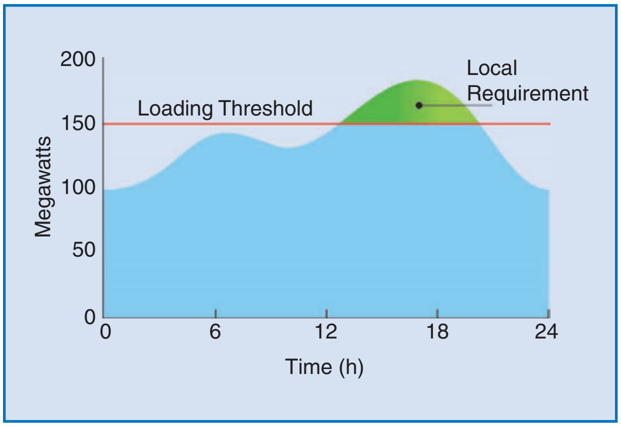

figure 4. The loading threshold and local requirement for energy.

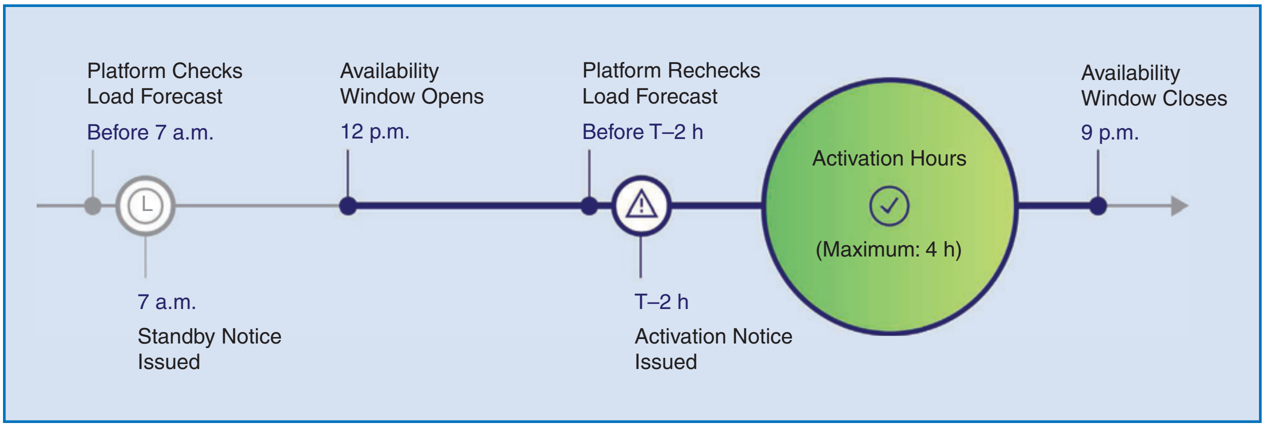

figure 5. A process for local energy service in the demonstration.

standby notice is sent to participants, indicating that there may be forthcoming energy activations. Subsequently, approximately two hours before each hour in the availability window, defined as noon to 9 p.m., the platform checks the latest demand forecast to confirm whether a local requirement is materializing. If a requirement is confirmed, a local energy auction is conducted by the platform to select the DERs that will be activated for energy, and an auction clearing price is determined.

The demonstration's local energy auction uses a simple clearing process, where bids are ordered according to price and DERs are selected until the local requirement is met. The bid of the DER selected last sets the clearing price in the demonstration's local energy auction. The clearing price is used as a simply derived distribution locational marginal price for settling participants for the energy service they provide. Several simplifications are embedded into the approach for deriving the distribution locational marginal price, including ignoring electrical losses and applicability only to radial systems. Nonetheless, the use of the distribution locational marginal price in the demonstration is an important step toward more granular pricing for DERs.

Furthermore, the performance of DERs that participate in the demonstration as demand response resources is measured against the installations' baseline consumption. Demand response is when end consumers reduce their electricity consumption because of activations in the demonstration and, more generally, other system needs and price signals. The baseline consumption for the performance assessment of demand response DERs represents what the use would have been had there not been an activation of the DERs. The demonstration's rules outline how the baseline is calculated based on historical meter data so that participants have transparency into the process.

Activations in the demonstration are limited to a maximum of 10 events, each lasting up to 4 h. The number of events was capped to give participants some certainty regarding the level of effort and cost involved. However, while this approach reduces the risk for participants, it increases the operational difficulty for the DSO, which needs to ensure that it will have DERs available for all expected periods with a local requirement throughout the duration of the commitment period.

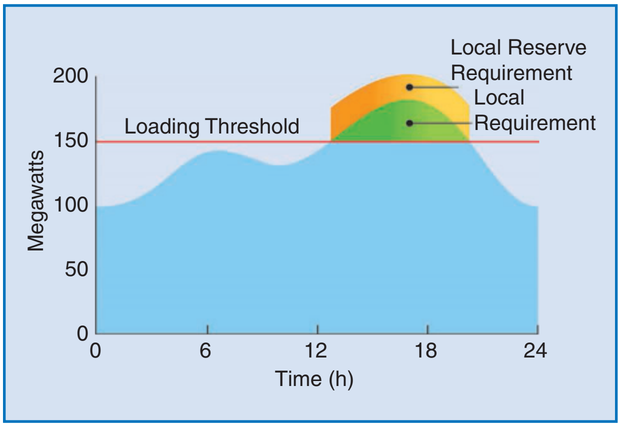

figure 6. The local energy and reserve requirements.

Year Two Enhancement: Local Reserve Auctions

In managing distribution NWA projects, DSOs need to ensure reliability, which could involve having reserves on standby to handle potential contingencies. DSOs are faced with faults, outages, and system restoration as part of their day-to-day distribution network operations and management. However, using DERs as NWAs involves DSOs relying on DERs to balance the local distribution system at times, which is an activity that differs from typical DSO functions. Using DERs to balance supply and demand at the distribution level introduces new contingency modes into the system. An example is if DERs activated for energy service unexpectedly become unavailable. In such a scenario, local DER reserves could be used to fill the shortfall on short notice. Importantly, operating reserves at the transmission level cannot be used to support distribution NWA projects, as they are not deliverable when DERs are needed for distribution NWA purposes (i.e., when the distribution system is import-constrained). Therefore, the DSO must source the reserve service from DERs sited downstream of the network infrastructure limitations that are giving rise to the need to use DERs as NWAs.

A reserve service has been introduced into the demonstration for the DSO to use, specifically in the hours when there is a local requirement and energy activations take place. There are different classes of reserve service that can be defined with varying degrees of readiness to respond to contingencies. For the demonstration, a 30-min reserve service has been developed, and if there is a contingency, DERs can be deployed to provide energy within half an hour. That amount of time was chosen because it was expected to enable a broader set of participants to provide reserve service in addition to energy service. It is possible to include only a 30-min reserve service, considering that the reliability needs in the demonstration are simulated. In an actual implementation of an NWA project with real reliability needs, reserves with faster readiness (e.g., 10 min) will likely be required.

As indicated in Figure 6, it is in the hours when a local requirement is identified that the DSO establishes a reserve requirement and conducts local auctions to meet it. Local reserve and energy auctions are linked because the same DERs participate in both and are available to provide either service. Similarly, in wholesale-level markets, energy and operating reserve auctions consider the same resources, and the processes are often co-optimized to ensure that assets are used in an overall optimal way. In the demonstration, the auctions are sequentially run, with the energy auction first and the reserve auction following, which is not as

> The amount of reserves needed in the context of distribution-level NWAs is unaddressed, and additional research and industry efforts to develop guidelines and standards for this issue would be beneficial.

rigorous as co-optimized clearing but is easier to communicate and demonstrate.

The results of the local reserve auctions determine the DERs to be scheduled and set the clearing price for the reserve service. The service involves being "on standby" on an hourly basis in case of a contingency event. As depicted in Figure 7, if an event takes place, the DERs receive a deployment notice, giving them 30 min to start providing energy. Then, the DSO can specify the required duration of the DERs response with a 5-min granularity, giving it more flexibility in addressing contingencies. Participants with DERs providing reserve service in the demonstration receive payments when scheduled as reserve (in Canadian dollars per kilowatt) in return for being "on standby," and they receive deployment payments (in Canadian dollars per kilowatt-hour) when there is a contingency and DERs are deployed. With the reserve service, the demonstration seeks to explore how operating reliability could potentially be met when relying on DERs as NWAs. However, the amount of reserves needed in the context of distribution-level NWAs is unaddressed, and additional research and industry efforts to develop guidelines and standards for this issue would be beneficial.

Limits of Auctions

Auctions are competitive processes. For them to function well and have economically efficient outcomes, conditions for competition must exist. Market power concerns are heightened when securing distribution-level services, given that their smaller, local nature may limit competition. The ability of many smaller DERs to participate in distribution-level markets could act as a balancing dynamic, enabling more competition. However, currently, as seen in the results of the demonstration, many DERs participate in opportunities to provide services as part of aggregations as opposed to contributing directly on an individual basis.

While there may be a great number of DERs participating indirectly as part of an aggregation, if the number of aggregator entities taking part in auction processes is small, competition may still be limited. Thus, market power is an important consideration in designing auction processes for distribution-level services. Processes to monitor and mitigate market power will be needed. In cases where distribution services must be sourced on a highly localized basis and competition may be highly restricted, auctions would not be appropriate. For such circumstances, other service procurement designs could be considered, such as programs with predetermined prices.

Future Work

At the time of writing, the demonstration was ongoing. The November 2020 local capacity auction had taken place, and the May–October 2021 commitment period, throughout which local energy auctions and associated energy activations had occured, had come to an end. As discussed, the 2021 local capacity auction was forthcoming, and a local reserve auction mechanism had been added for the May–October 2022 commitment period, which is expected to yield new and interesting insights. In parallel to the operational aspects of the demonstration, a study and technical paper were being developed.

One of the demonstration's primary objectives is to explore the coordination required between a transmission-level

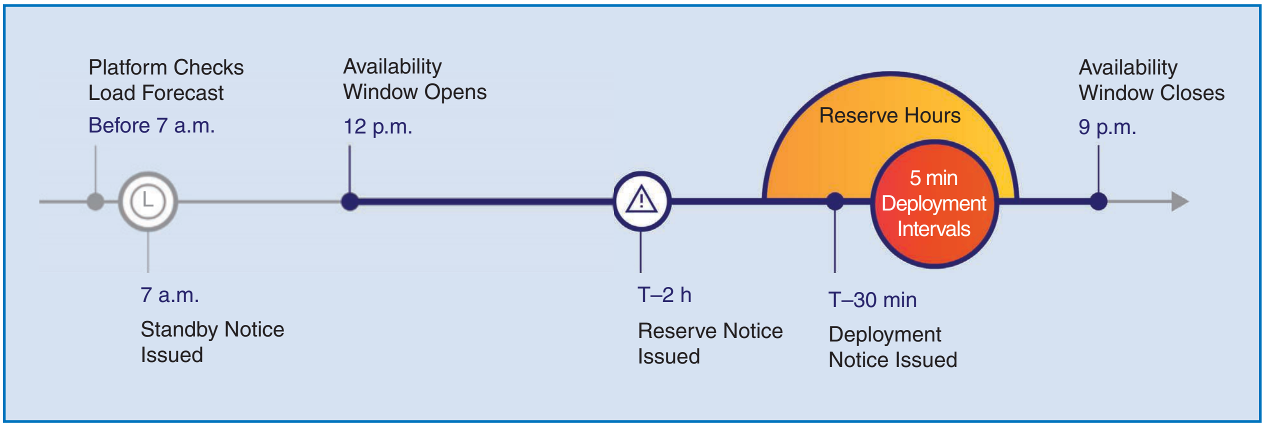

figure 7. A process example for local reserve service in the demonstration.

independent system operator (ISO) and a distribution-level DSO. The demonstration's design assumes that prices and needs in the wholesale market are communicated to DERs such that the installations may contribute to services at both the distribution and transmission levels. ISO–DSO coordination, especially in the context of DSOs procuring services from DERs for distribution-level needs, is an important area for future work.

As an extension of the demonstration, a study is being initiated to conduct a steady-state power flow analysis of several scenarios. They relate to DERs being used for distribution NWA purposes while simultaneously being available to the wholesale market as appropriate. In particular, the study will investigate whether DER output can be delivered to the distribution–transmission interface under various conditions, some of which will involve distribution system constraints that may restrict a DER's ability to provide services to the transmission level. The analysis of the deliverability of DER output will be used to inform potential ISO–DSO coordination processes. It will also contribute to developing rules for participating DERs to simultaneously bid in auction processes at the distribution and wholesale market levels.

A technical paper is being prepared in the context of the demonstration as well as to propose methods for conducting distribution expansion planning to inform the design of local capacity auctions. The proposed methods will use the net present value of employing DERs to defer distribution network upgrades to help DSOs decide whether to acquire DERs and to set parameters for procurement. These studies include conducting distribution expansion planning to assess the tradeoff between investments in wires and DERs as NWAs to determine when those outlays are needed and assess the cost savings for a DSO from pursuing NWA projects. The cost savings, in turn, will be used to influence the DSO's willingness to pay for DERs. The results of the distribution expansion planning model will be employed to enhance the design of local capacity auctions, including minimum and maximum limits for procuring DER capacity in different locations in the distribution system to meet existing and expected needs. The enhanced design will also produce capacity price separation in the system, sending participants in local capacity auctions improved price signals for making DER investments. Publications about the project are expected in late 2022.

Conclusions

As DERs continue to improve in performance and decrease in cost, and as transportation and heating become electrified, the distribution system will evolve to become more dynamic in the coming years. Increased DER installation will provide new opportunities to generate value and reduce system costs, including those related to the distribution system. A key use case for DERs relates to employing them as NWAs at the distribution level. The IESO's York Region NWA demonstration involves securing DERs for capacity service, activating DERs for energy service, and scheduling and deploying DERs as part of reserve service. The project shows that a DSO can use auction mechanisms at the distribution level to manage NWA projects and create an open, fair, competitive, and transparent marketplace, lowering costs to participate and other barriers to entry. Auctions have a very natural fit in a future environment with mass participation of DERs that provide granular grid services in automated ways through intelligent software and Internet communication.

For Further Reading

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Integration of Small Modular Reactors Into Renewable Energy-Based Standalone Microgrids

By Dennis Michaelson and Jin Jiang

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An Energy Management Perspective

THE ENVIRONMENTAL IMPACT OF human activities has become a significant consideration when making energy infrastructure decisions. To reduce energy poverty worldwide, there is growing interest in providing electricity in an environmentally sustainable way that minimizes greenhouse gas emissions. The same applies to the energy supply for off-grid industrial activities, such as mining projects and remote communities. These applications have traditionally been served by diesel generators, and more recently by wind-diesel hybrid power systems. Diesel and fuel oils are notorious for the high cost of transportation to remote sites, and for emissions of particulate pollution and greenhouse gasses. Such emissions can profoundly impact the environment in comparison to other types of power generation.

Renewable energy in the form of wind and solar resources presents a clean and low-carbon solution that is becoming increasingly economical. These diverse energy sources can be integrated into the form of a microgrid, which combines multiple sources, loads, and energy storage into a self-contained energy hub that can operate both with and without

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the support of a larger grid. Due to its distributed nature, a microgrid can reduce power transmission losses and provide increased resiliency (avoidance or minimization of power disruptions during contingency conditions) by maintaining the electricity supply to critical loads in the event of grid disruptions due to natural causes (e.g., earthquakes) or man-made events (e.g., cyberattacks).

Unfortunately, the intermittent nature and seasonal variations of these renewable resources create challenges, especially in standalone microgrids. As a result, a microgrid with renewable sources alone cannot fully meet the needs of most off-grid applications without including a sizeable amount of storage, typically in the form of batteries. At present, such storage systems are relatively expensive for large microgrids, and their manufacture has its own environmental issues. Therefore, there remains a need for some additional controllable sources that can fill the gap between the renewable energy supply and the load demand.

An emerging solution is the small modular reactor (SMR), which can provide a low-carbon sustainable energy supply through one or more small nuclear units. This approach is being pursued in part to address the historically challenging economics of large-scale nuclear power plant construction. Standardization, factory production, and simplified on-site installation are expected to reduce the total time and cost for SMR projects. A set of SMRs can complement renewable sources in a microgrid environment to provide a reliable supply of power with a near-zero greenhouse gas footprint. A conceptual system is illustrated in Figure 1.

In this article, the concept, advantages, complementary features, and potential challenges of control and energy management for integrating SMRs and renewable energy-based microgrids are discussed. The properties of different SMR types will be presented, along with some key considerations related to their integration, control, and coordination. Both electricity production and district/process heat are considered. Some key open issues are highlighted to stimulate research and development.

SMRs

Unlike existing large-scale nuclear power plants, the output capacity of SMRs is more comparable to those of renewable energy plants. The flexibility offered by modular design allows system designers to specify the number of units to be employed. As demand changes over time, more units could be added or removed accordingly. Most SMRs are equipped with passive safety features that lower the risk of catastrophic accidents, and also include load-following capabilities to meet changes in demand. They are well suited to applications with varying load demand in the presence of uncertainties and variability associated with renewables. They not only provide electricity but also thermal energy for applications in remote communities and industrial sites.

The definition of “small” for SMRs refers to single-reactor units of less than 300 MWe power generation capacity. For example, consider the 160 MWe/525 MWt Holtec SMR-160 reactor design, which involves a containment structure that is 62 m tall (though partially buried underground) on a 4.6-acre site. Several SMR designs are sized to be well suited for placement on brownfield sites previously used for comparably rated fossil-fuel plants, thus allowing for reuse of existing infrastructure such as local transmission substations and site services.

The modular aspect refers to two salient features: modularity in reactor design, and the potential to link multiple modules to form a larger system. A standardized reactor module can be produced in volume in a factory. Therefore, the manufacture of the reactor systems and site construction can be carried out in parallel. In addition, the use of standardized modules can potentially reduce the site-specific engineering requirements by providing turnkey facility reference

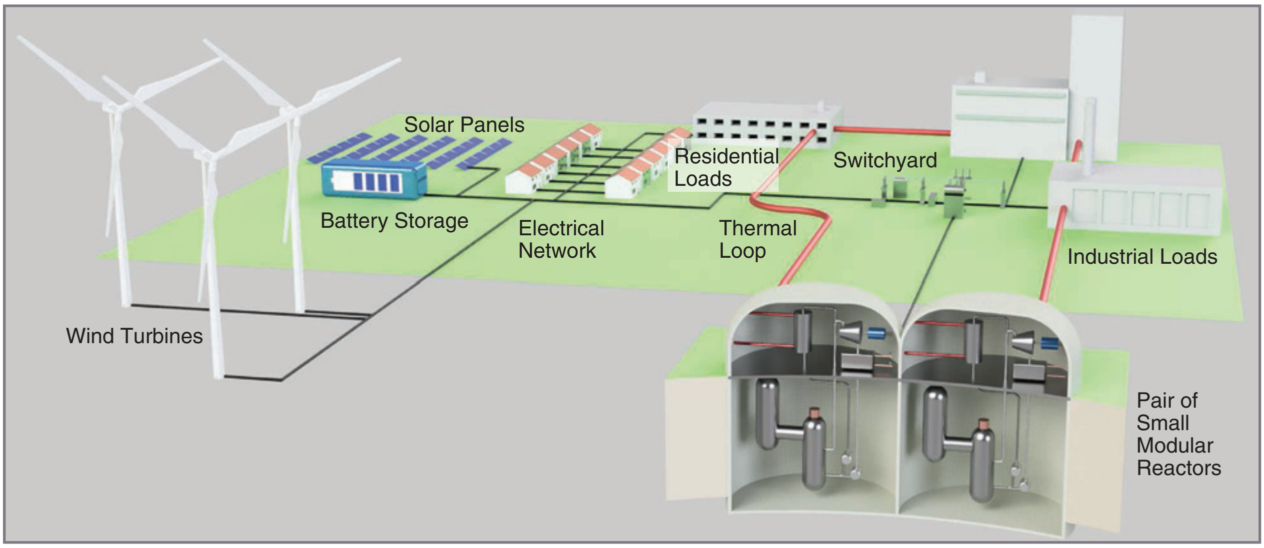

figure 1. A microgrid with SMRs and renewable energy resources.

designs that use known and tested balance-of-plant components, such as steam turbines, condensers, generators, switchgear, protection devices, and control platforms. This modular design approach can also simplify licensing and regulatory compliance to help shorten the time to project completion.

The multimodule concept allows for the scaling of an SMR system to match the demand of a specific application. A multimodule SMR facility can either operate together to meet demands greater than the rating of each unit and/or operate in a staggered or redundant fashion to provide continuity of supply. As demand grows, additional modules could be added at the same premises. For example, the NuScale system design includes a reactor building that can hold up to 12 reactor modules. By incrementally adding capacity as needed, the up-front cost and construction time can be optimized, so a return on the investment can be realized more quickly than for a larger site-built nuclear power plant with a similar output capacity.

The modular design also makes it possible to load the nuclear fuel at a factory to produce a sealed transportable unit, which is sometimes referred to as a "nuclear battery." In this case, all handling of radioactive materials would occur in the controlled, secure environment of the factory. This type of unit would be deployed for a fixed operating life span. At the end of that period, the entire reactor system could be removed and returned to the factory for refurbishment and refueling. Some designs target a 30-year refueling interval. This feature reduces the operational complexity, particularly for deployments at remote sites, and the contamination risk of handling radioactive materials on site. Also, it reduces the proliferation risk of nuclear materials being diverted into unauthorized hands.

Another key feature that SMR designs have in common with the latest fourth-generation large-scale reactor designs is the use of passive safety systems. In particular, several proposed designs include a convective primary cooling loop that eliminates the need for pumps, resulting in a simpler design and eliminating potential points of failure. SMR cores are also physically smaller than those of larger reactors, with lower thermal power ratings and core power densities. In some designs, the compact cores also place the fuel closer to the exterior of the reactor vessel. This simplifies the task of decay heat removal once the reactor is shut down. This can reduce the risk of a core meltdown. The goal of these passive safety design features is to create a reactor facility that is walk-away safe even in the event of a total loss of auxiliary electrical power at the site.

Four major types of SMRs and their key characteristics and design parameters are shown in Table 1. The integrated pressurized vessel designs are based on well-established water-cooled technologies. They have reactor output temperature levels suitable for both seawater desalination or district heating applications in addition to electricity generation. The gas-cooled SMRs, which are typically cooled with helium, offer even higher temperatures for the process heat. (See "One Module of an SMR Plant.") This opens up more possibilities for industrial applications, including steam methane reforming, biomass gasification, and high-temperature steam electrolysis. The molten-salt- and liquid-metal-cooled reactors include several fast reactor designs with the potential to use spent fuels from other commercial reactors. This contributes to the more efficient use of nuclear fuel.

The most common balance-of-plant systems for SMRs use a traditional steam Rankine cycle turbine and synchronous generator pair, leveraging well-understood and widely available technologies. However, some designs are based on direct-cycle helium gas and supercritical CO_2 Brayton cycle turbines. These designs can reduce the size of balance-of-plant components dramatically, although with tradeoffs in cost, working pressure, and potentially shaft speed, necessitating the use of a gearbox in some cases.

In remote communities and industrial sites, the cost of diesel fuel-generated electricity can reach over US$.50/kWh due to their isolation and dependence on seasonal roads or water access for delivery. Given such high cost, and the CO_2, NO_x, and particulate emissions from combustion, these applications could represent a viable market for SMRs. They have been identified as a key target of deployment by the Canadian government in a recently released SMR roadmap. However, the electrical power demands for remote communities are modest, typically between 2 and 10 MWe, so only designs on the low power end of the SMR scale would be applicable. These small SMRs are sometimes referred to as micromodular reactors, micro-SMRs, or very small modular reactors.

For remote industrial applications, the power requirements can be significantly higher than for remote communities, ranging from 4 to 125 MWe (though typically 25–30 MWe) for mining, and 300+ MWe for oil and gas extraction and processing. In addition to electrical power, these applications also need high-temperature process heat. For mining sites, the nuclear battery concept is particularly attractive since the deployment is meant to be limited to the life span of the project, after which the infrastructure can be "picked up" and the site remediated. Another important consideration for both industrial and remote sites is the lack of available water for cooling in some locations. This factor favors SMRs that can potentially use air cooling instead of relying on lake, river, or ocean water.

There are over 50 different SMR designs at various stages of development worldwide, according to the International Atomic Energy Agency. The earliest planned commercial deployment is targeted for 2026. Given the number and variety of these designs, there remains a significant amount of work in modeling, instrumentation, and control to effectively optimize the designs to complement modern power systems. This includes microgrid applications with renewable energy resources.

Applications of SMRs in Microgrids

In all power systems, the electricity supply must match the load demand at all times to achieve stable operation. However, this is a particular challenge in standalone renewable microgrids due to the intermittent nature of wind and solar resources, the lack of rotating inertia in inverter-interfaced sources, and the large load variations (i.e., large with

table 1. SMR types.

SMR Type	Example Design	Rating (MWt)	Rating (MWe)	Temperature (° C)	Refueling (years)
Water-Cooled	NuScale	250	77	302	2
	KAERI SMART	330	100	323	3
	Holtec SMR-160	525	160	315	1.5–2
Gas-Cooled	General Atomics EM2	500	265	850	30
	USNC Micro-Modular Reactor	15	5	630	20
	URENCO U-Battery	10	4	750	5
Molten-Salt-Cooled	Terrestrial Energy IMSR-400	400	192	700	7
	Moltex Energy Stable Salt Reactor	750	300	650	continuous
Liquid-Metal-Cooled	LeadCold SEALER	8	3	432	30
	ARC-100	286	100	510	20

One Module of an SMR Plant

A conceptualized small modular high-temperature gas reactor is shown here (Figure S1). The two-vessel design links the reactor core with the steam generator through a nested pair of tubes that carry the helium coolant. The uranium fuel is in the form of carbon/silicon carbide encapsulated particles packaged into either spherical "pebbles" or prismatic assemblies that the coolant flows over. Neutron-absorbing control rods are used to regulate the reactivity in the core to adjust the thermal output power. Primary coolant circulates inside the reactor vessel using a helium circulator, moving down through the core and extracting the heat, then flowing across to the steam generator where it transfers that heat to a secondary loop. The steam then drives a turbine, which is connected to a synchronous generator to produce electricity. The steam from the turbine outlet is condensed back into water using an external cooling loop and pumped back to the inlet of the steam generator. An additional loop and heat exchanger are used to extract heat for industrial processes or for district heating applications.

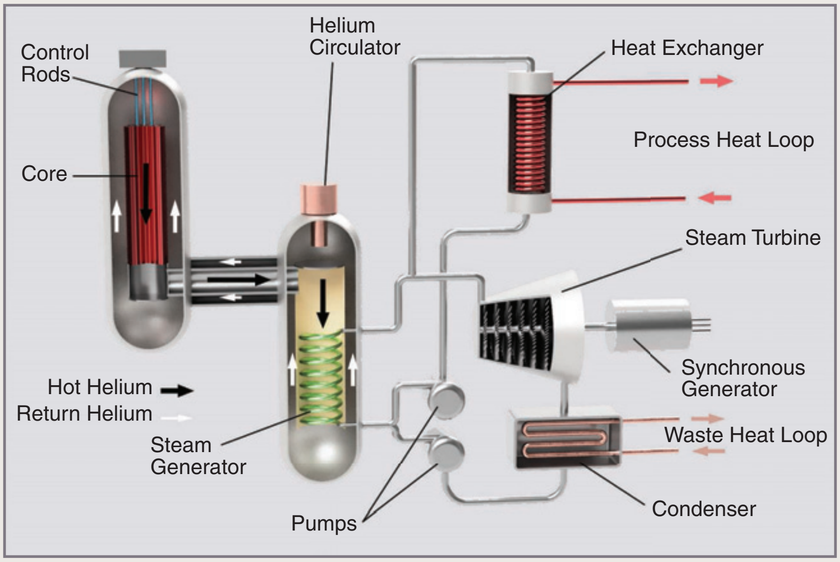

figure S1. A conceptualized small modular high-temperature gas reactor.

respect to the ratings of the power sources). It is challenging to attain such a balance unless some form of dispatchable energy resources, storage, and/or demand-side management schemes are used. As the proportion of renewable sources increases in such systems, this problem becomes even more challenging. Unlike in traditional power systems, the relatively small geographic area of a microgrid means the effects of local weather conditions, such as clouds and wind gusts, are not spread out, leading to potentially large fluctuations in power production. There are also predictable daily and seasonal variations in renewable power production that need to be considered. In this case, an SMR can serve as a reliable source of continuous controllable power, ramping up and down according to changes in demand or variations in renewable power sources.

As an example, consider a simple standalone microgrid shown in Figure 2(a) with the corresponding 48-h load and generation profiles illustrated in Figure 2(b). The load profile in Figure 2(b), panel (i) exhibits small peaks in the morning and larger ones in the evening. The solar photovoltaic (PV) and wind power outputs in Figure 2(b), panels (ii) and (iii) vary due to changes in the weather conditions. Notably, the production does not match the load profile by using PV and wind sources alone.

When an SMR is incorporated into the supply mix, one operating strategy, as illustrated in Figure 2(b), panel (iv), adjusts its output power to meet the anticipated peak demands and to smooth out the variations associated with the renewable resources. However, the rate of power changes in an SMR may be constrained by physical and safety limits and may not be able to match the load demand precisely on its own. Different power regulation techniques need to be developed. For example, upon a sudden drop in demand, one option is to use a steam-bypass mechanism to quickly trim the turbine-generator output power without ramping down reactor power itself. However, in circumstances when the reactor is operating at a low power level, different solutions are needed to accommodate a sudden large increase in demand.

To deal with this problem, a relatively small capacity battery energy storage system can be introduced into the microgrid to balance any remaining mismatches between the demand and the supply as shown in Figure 2(b), panel (v). In this case, the battery charges whenever there is surplus power available and discharges if the combined PV, wind, and SMR outputs are unable to support the load demand. Sudden unexpected power imbalances can be compensated by the battery. The battery can react relatively quickly as long as it operates at an intermediate state-of-charge level where it can both supply and absorb energy as needed. This is illustrated in Figure 2(b), panel (vi).

Control and Energy Management in SMR/Renewable Microgrids

Since microgrids integrate multiple types of energy sources of wildly different characteristics, storage, and loads, it is challenging to control them effectively to achieve the desired level of service quality. Control and energy management strategies for microgrids are commonly organized in a hierarchical form. The lowest level contains the real time control loops, which regulate

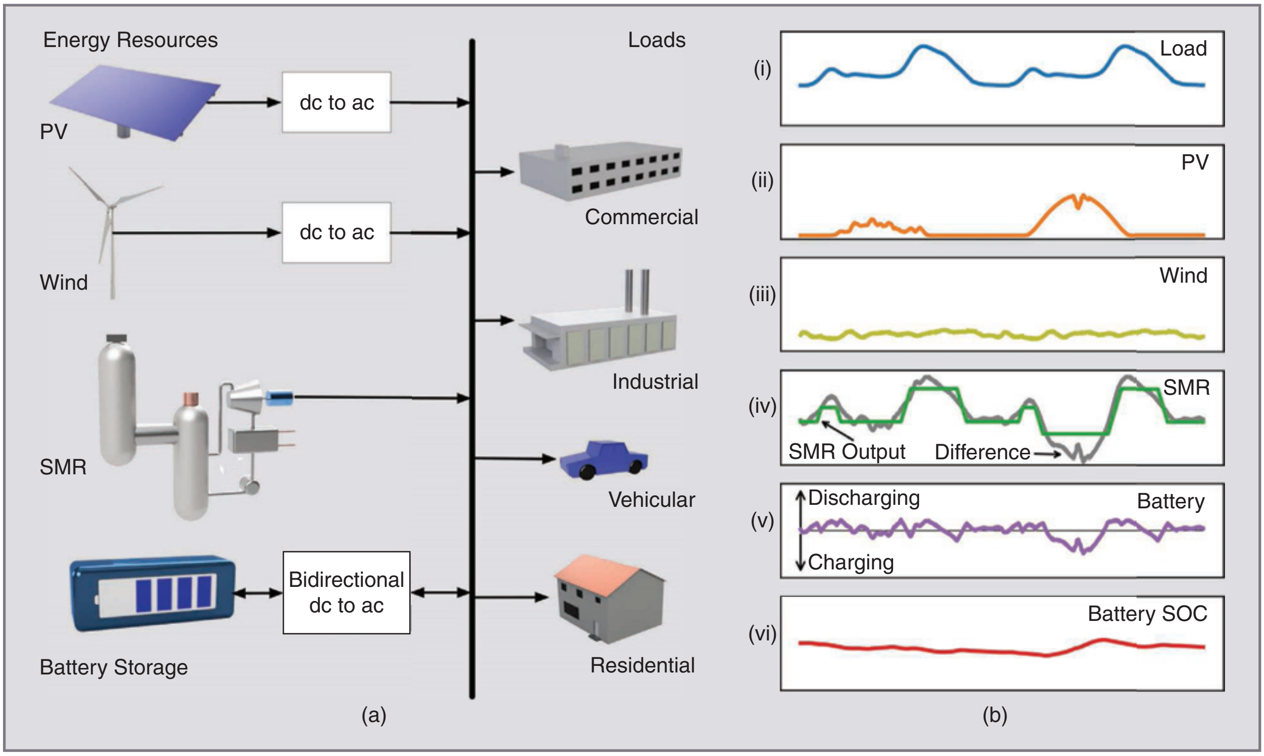

figure 2. (a) Microgrid configuration; (b) Example operation scenario showing 48-h power profiles: (i) load profile; (ii) PV profile; (iii) wind profile; (iv) SMR ramping; (v) battery charging/discharging; and (vi) battery SOC: state-of-charge.

the power-electronic switching signals for inverter-based renewable sources and voltage and frequency control of synchronous generators for the SMR. The primary layer deals with power-sharing among different energy sources. The secondary layer regulates the overall microgrid frequency and the voltage levels for dynamic stability and reactive power support. The tertiary layer deals with the overall operation of the microgrid for long-term viability, such as set-point adjustments for seasonal variations, maintenance scheduling, and economic optimization.

At the lower layers, both centralized and distributed mechanisms have been investigated. Distributed power/frequency droop-based approaches are being adopted to minimize the dependency on any high-bandwidth communications among physically dispersed energy resources. In these approaches, the system frequency "droops" lower as the power demand increases. Suitable power-sharing among different power sources can be achieved through different droop ratios. This approach has been extended to a multisegment adaptive droop approach to accommodate battery charge limits and PV curtailment. A further extension to incorporate multi-unit SMRs can be considered, where the operational decisions for each unit may depend on factors such as safety, economy, and regulatory guidelines.

At the secondary layer, system setpoints can be adjusted infrequently over low-bandwidth communication links to maintain the desired voltage profiles and recommended sharing of real and reactive power. The tertiary level deals with energy management issues, such as optimal dispatch of generators in SMRs, management of the charging status of storage devices, and the coordination of demand–response. This includes making use of weather forecasts to predict future renewable power production levels and planning for maintenance outages of SMRs to improve the power availability.

Within this framework, selecting when and how much to change the SMR output power level is the responsibility of the microgrid energy management system (EMS). The EMS may consider multiple objectives and constraints to determine the optimal operation strategy for the whole system. These considerations can include fuel costs, efficiency, reserve capacity, reliability, and equipment stress. For example, the predicted overnight load demand can be used to select the output power level for the SMR over this period. The battery can balance out any short-term variations in the load demand. Microgrid EMSs typically include simplified models of the power system components used in an optimization formulation. The optimization determines the operating schedule and may also incorporate demand–response mechanisms to manage loads in addition to generation and storage resources.

The Electric Power Research Institute Utility Requirements Document referenced by Ingersoll and colleagues for light-water type reactors has been updated to set out minimum performance expectations for these types of SMRs. It specifies a 24-h load cycle of 100% down to 20% and back to 100%, a ramp rate of 40% per h, and a step change of 20% in 10 min. Given these ramp rate requirements, and other design-specific constraints, accurate forecasts for renewable energy production are needed so the power outputs of the SMR can be adjusted appropriately. The mechanism for adjusting the power output involves control actions that adjust the reactivity of the reactor core, thus changing the heat output. This may involve motorized movement of neutron-absorbing control rods in and out of the core to control the neutron density.

The control strategies for traditional nuclear power plants can be classified either as a turbine-led or a reactor-led mode of operation. To achieve load-following capabilities, the turbine-led mode is used. If small, but rapid power adjustments are needed for fast actions, such as frequency regulation, the previously mentioned steam-bypass mechanism could be employed. It provides an adjustment band of 5 to 10% of the full power rating of the module. The ramp rates for larger core power adjustments are limited by the buildup of neutron-absorbing nuclear reaction by-products that need time to decay. In some cases, mechanical stresses on the fuel cladding and piping can result from thermal shock if recommended ramp rates are exceeded. The control actions and modes of operation must follow safety specifications strictly regulated by local nuclear safety regulators, such as the Nuclear Regulatory Commission in the United States and the Canadian Nuclear Safety Commission.

An alternative approach to adjusting the SMR power level is to run the reactor at near-full power and redirect a portion of its output to another process. Several variations have been considered, including a combination of electrical and thermal outputs for hydrogen production, which can then support a more efficient high-temperature electrolysis process. Since the electrolysis process can be started and stopped on demand, it can be a desirable way for absorbing excess reactor output, converting this energy into hydrogen. Stored hydrogen can later be reverted into electricity by a fuel-cell-powered system, used in fuel-cell-powered vehicles in remote communities and industrial sites, or burned directly for process heat. Related approaches have also been proposed to use the excess heat energy to generate synthetic gas and operate desalination plants.

Some design concepts include a molten-salt secondary cooling loop that includes thermal storage tanks. This effectively decouples the SMR from the turbine-generator, though at the expense of some thermal efficiency. This approach leverages the existing technologies developed for solar thermal power plants. In situations where these alternative heat applications are desirable, both electricity generation and thermal applications have to be considered to achieve the most efficient and effective energy management strategies for the microgrid.

Multi-unit SMRs can potentially offer higher degrees of flexibility in operation. However, the corresponding control strategies can be more complex depending on the system configurations. If different modules have independent steam turbines and generators, each module can be treated as a relatively separate unit. The control, in this case, is relatively straightforward. However, for systems in which different modules share a common steam header, interactions among the reactors can be more complex. These systems may require additional control actions to achieve the desired balance in power outputs among different modules. Variations include operating all of the units in a shared load-following configuration or assigning some units to fixed-output operation and others as load-following ones. Such differential operation may offer some inherent advantages. Newly fueled units generally exhibit more responsive characteristics in a load-following mode, than those near the end of their fueling lifecycle due to their higher reactivity. Thus, these units can be used for finer output adjustments.

Open Issues

Several open problems need to be investigated concerning the integration of SMRs into renewable energy microgrids. Aspects of these problems require interdisciplinary research that incorporates nuclear, thermal-hydraulic, electrical power system operation, and advanced instrumentation and control topics.

The Sizing Problem

Selecting the optimal size of one or more SMRs (and the corresponding renewable sources and storage capacity within SMR/renewable microgrids) relative to a given load scenario requires significant research. An analysis must study short-term system stability, long-term energy production, and the proportions of the sources. Even though this type of analysis is well established in the microgrid field for various nonnuclear resources, these approaches need to be extended to include the operational behavior and regulatory constraints of SMRs. Research should also consider the lifetime performance of SMRs and potential operating strategies for multi-unit SMRs. Examples include combinations of fixed-output units and load-following units. Also, strategies need to be developed for tiered deployment strategies where different renewable energy resources and SMR units are added or removed as the load demand changes.

The Interaction Problem

In applications of SMR/renewable microgrids in remote communities, the relative sizes of the energy sources and the loads to be supported are closer in proportion than those in traditional power grids. The dynamic interactions among the primary energy sources may need to be considered to deal with rapid changes in load. Investigations must be carried out to understand the impact of such coupling and to explore mitigation strategies. Advanced control strategies for the power-electronic interfaced sources, traditional synchronous generators, and energy storage systems are needed to ensure that the entire microgrid operates stably, reliably, and within power quality constraints. Systems that include thermal loads form an integral part of the energy management strategy. Control strategies for such loads, in concert with the electrical generation system, also need to be developed.

The Autonomous Monitoring/Control/Management Problem

Several of the proposed SMR designs are meant to be installed and operated as essentially zero-maintenance, walk-away safe units. In some cases, these can be buried underground and monitored/operated remotely. Achieving this level of autonomy will require the development of high-reliability sensing and remote monitoring technologies to initiate necessary remedial actions if anomalies are detected. While the proposed SMR designs include safety features that can shut the reactor down in the event of a fault, the remainder of the microgrid should continue to operate, though presumably at a reduced capability. Advanced instrumentation and control approaches to support this autonomous operation need to be developed and validated for multiple operating scenarios within a microgrid environment.

Conclusions

SMRs with load-following capability can complement the intermittent nature of renewable energy sources in a standalone microgrid environment. Effective controls will allow these sources to be integrated with moderate-sized energy storage to provide a high-quality, reliable, low-carbon supply of power. SMRs can be key enablers for the widespread adoption of renewable energy-based microgrids in off-grid applications. However, research is still required to understand the intricate relationships among the different energy resources and develop effective control strategies for achieving safe and reliable operation with a high quality of service under various load and environmental conditions.

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Joseph J. Cunningham

AC network centennial

years of distribution networks

In this issue's "History" column, we highlight the 100th anniversary of a significant milestone in distribution system evolution. On 12 April 1922, a new ac distribution method was proven on Manhattan's (New York, United States) Upper West Side that determined the future of urban distribution and remains its backbone today. On that day, the United Electric Light and Power Company initiated operation of the first fully successful automatic distribution network in an area that was primarily residential with some commercial customers—mostly stores.

Joseph J. Cunningham returns for his 10th time to the pages of this "History" column. Joseph has contributed to these pages on topics such as industrial electrification, electric utility power systems, and electric rail transportation. His book *New York Power*, was published in 2013 by IEEE History Center Press. We welcome back Joseph as our "History" author for this issue of *IEEE Power & Energy Magazine*.

John Paserba,
Associate Editor, "History"

AUTOMATIC AC SECONDARY DIStribution networks are the norm in urban areas of dense load concentration; no electrical distribution engineer could imagine any other technique. A century ago, dc distribution predominated in such urban areas. Alternating current distribution was minimal, with radial feeders from transformer substations to the local transformers that supplied customers. It was not as efficient or reliable as dc and lacked battery backup. Direct current distribution systems were expensive, and ac promised a potential 500% reduction in distribution costs by elimination of the substations and heavy cables required by dc systems if reliability and efficiency could be improved.

On 12 April 1922, a new ac distribution method was proven on Manhattan's Upper West Side, which determined the future of urban distribution and remains its backbone today. On that day, the United Electric Light and Power Company initiated operation of the first fully successful automatic distribution network in an area that was primarily residential with some commercial customers—mostly stores.

A century ago, dc distribution predominated in such urban areas.

The United Company had pursued ac distribution prior to acquisition by the Westinghouse Electric and Manufacturing Company in 1889. The ultimate goal was a refined ac distribution system superior to that of dc. To that end, United, in 1892, was the first utility to attempt interconnection of supply transformers, as noted in a 1936 paper by two Consolidated Edison Company engineers, Henry J. Sexton and Howard S. Orcutt. Their work appears to be the first historical account of the process by which urban ac distribution developed.

Thirty Years of Effort

That initial 1892 experiment on West Street in Lower Manhattan was conducted by Station Master W. J. Kelly, Superintendent Schuller, and Assistant Superintendent John T. Simon. It connected two transformer secondaries, both supplied from the same primary feeder from United's Station K on Washington Street. The system was overhead, with pole-mounted transformers for lighting circuits. It is considered the first use of banked transformers (grouped in parallel with secondaries tied together), and the concept became the first single-feeder ac system installed when the lines were placed underground.

Little is known about the United systems prior to 1896. Most evolved from arc-light systems powered by small, localized generating plants. The West Street experiment displayed the boldness of the company at a time when most ac system components were still experimental. The established Edison

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dc system continued to grow and replaced local dc generation with dc-conversion substations powered by central ac-generating stations. It was expensive but met demand. AC distribution to customers was largely confined to areas of sparse development insufficient to amortize the investment required for dc.

Automatic protective relays were vital for an ac network to achieve superiority over dc distribution.

United specialized in such areas and built a customer base where electric lights were a luxury that was affordable by very few. United perceived those areas as a huge potential market and moved to establish a presence there and in the undeveloped northern area of Manhattan Island. Utilities then classified customers as either "lighting," which meant single-phase residential and light commercial load, while "power" customers were usually industrial, with heavy motor loads. The feeders were two phase at 60 Hz, with single-phase distribution for lighting customers, and two-phase lines to power customers.

The high cost associated with dc distribution encouraged research to develop a less-expensive ac distribution system with equal or greater reliability. In 1915, Thomas E. Murray, a leading executive in New York City utilities, reported that fully 50% of the fixed plant investment in a dc system was in the substations and cables. The initial efforts to distribute ac based on a dc concept were neither economical nor efficient. The dc system simply connected cables with protection (usually in junction boxes) against overloads. When tried with ac, problems resulted from unbalanced transformer loads, excessive reactive power, and instability. The available ac motors also lacked the efficiency of their dc counterparts.

First Steps Elsewhere

Nonetheless, many utilities planned for the gradual supplementation of dc systems with ac, some with banked distribution transformers in dense areas. Most of the schemes used radial distribution with a specific feeder or set of feeders and a transformer bank operated as a unit to power the secondary lines to customer connections. Some employed loop distribution, with feeder protection at each end of the loop. The next step was the use of interleaved parallel feeders with alternate transformer banks connected to different primary feeders to provide power in the event of an outage on one.

The first system considered to be an independent standalone network was installed in 1915 with overhead lines in 16 city blocks in downtown Peoria, Illinois. It connected directly to power station low-tension feeders but had high-tension feeders to transformers at the outer ends to address voltage drop. It operated for 10 years, although it was subject to outage from any failure and was as costly as the dc system.

Most of the urban utilities began to install ac at the fringes of the dense downtown load areas as an initial step. By 1922, such companies expanded ac distribution and limited their dc territory to the most dense areas and planned the complete substitution of ac whenever practical. Soon most of them were exploring networked transformer secondaries, and network design was the prevailing topic of the day in most trade journals and meetings. The trend was encouraged by failures of dc distribution to the extent that a national conference was held to address that issue. The New York Edison system was promoted as the premier example of the superiority of dc distribution in dense load areas. That reputation came into question after a failure in early 1919 blacked out the Midtown Garment District, an area heavily dependent on electric power.

As for ac, the primary issue was that a single feeder to a secondary distribution network was superior to a radial system for lighting loads, but power customers required multiple feeders for adequate capacity and reliability. Furthermore, multiple feeders were needed by customers such as large office and commercial buildings, department stores, industrial plants, apartment houses, theaters, hospitals, and other concentrated loads. If multiple feeders to transformers operated at the transmission voltage there would be no need for intermediate transformer substations. The concept could be deployed initially in areas of light load and expanded as the need arose.

United Takes the Lead

United distribution relied on manhole and street vault manual switches; reactive power compensation was controlled by manually operated mechanical synchronous condensers (capacitors) in the transformer substations. The United distribution system in Manhattan was radial, divided into 70 sections with long feeders from five transformer substations to the local distribution transformers. Two-hundred and fifty manual-switch installations enabled the transfer of loads to adjacent feeders in the event of problems, but the time to reach and operate those switches in an emergency was excessive. Practicality necessitated an automatic network (see Figure 1).

The requirements for such an ac network were complex. Beyond economics and reliability superior to dc distribution, it had to be simple to install and maintain. It had to be compatible with existing radial distribution to permit future substitution without expensive replacement of components. It had to provide voltage regulation superior to dc, and combine light and power loads. It had to allow expansion to accommodate new demand and be capable of connecting to multiple sources. It also had to be able to connect directly to the power station's high voltage lines to eliminate the transformer substations.

Automatic protective relays were vital for an ac network to achieve superiority over dc distribution. United began an effort with suppliers to develop those relays. In 1920, the Palmer Electric and Manufacturing Company perfected an automatic switch that would detect a reverse current from the network to protect the primary feeders and transformer. It would open on the magnetizing current of the transformer and close when the current stabilized but not close on a crossed connection. The Palmer network switch was operated by relays in the secondary circuit to trip on reverse flow of power. In the event of an outage on the primary side, it would prevent reverse flow from the network into a faulted transformer. It closed only upon the flow of true (actual) power from the transformer into the network.

The Sexton and Orcutt report credits the Palmer relay as the key to the success of the United effort. Earlier network protectors such as those marketed in 1913 by the Metropolitan Engineering Company (a Murray company) protected the network by isolation of a defective transformer but apparently not from reverse current from the network into a faulted transformer.

The United Automatic Network

The Upper West Side of Manhattan had developed rapidly after the opening of the first subway line in 1904. Large apartment buildings with elevators presented a heavy load and United captured much of that business. That success was bolstered by innovation in transformers, system design, and reactive power compensation. The radial distribution feeders from a United transformer substation on 146th Street supplied local transformers with two-phase power by three-wire 2,100-/3,000-V feeders. Lighting transformers were connected to the pair of 3,000-V wires to supply single-phase customers at 110/220 V. Two-phase power was supplied from all three wires of the feeder by two-phase transformers that delivered 220-V two-phase power by three-wire circuits to customer motors.

As customer load increased with additional building construction, a new transformer substation was constructed on West 97th Street in 1922. The most modern of similar United installations, it was supplied by 13,200-V three-phase feeders, a new transmission scheme that supplanted, and in time, replaced the 3,000 V two-phase lines.

Ten years of research and experiments proved successful on that April day in 1922 when the automatic network assumed the load that extended from 93rd Street to 101st Street and from Broadway to Riverside Drive. Four sets of three-phase, three-wire 2,750 V primary feeders from the West 97th Street transformer substation fed 29 transformer banks. The transformer secondaries were connected to form a network throughout the area. The total capacity was 1,275 kVA on two separate three-wire low-tension networks. One network carried single-phase lighting loads on three-wire 110-/220-V circuits, the other supplied power loads on three-wire, 220-V two-phase circuits as two-phase distribution for power customers was still the norm. Each transformer bank held a 25-kVA transformer for the lighting network and a pair of 50- or a pair of 100-kVA transformers for the two-phase power network. The lighting cables were 200 mcm, and the power used 80 mcm (see Figures 2 and 3).

The Palmer network switch proved highly successful as detailed event records of the first year of network operation showed it to be nearly trouble free.

The secondaries were spliced at intersections, customer connections were made in manholes, and no additional junction boxes were required. In dense areas, lines were placed on both sides of the street; this improved efficiency by the reduction of load on the lines, which reduced the reactance in the lines. Moreover, it decreased the length of customer laterals. The transformers were located at each street intersection. An external reactance of 8.7% was

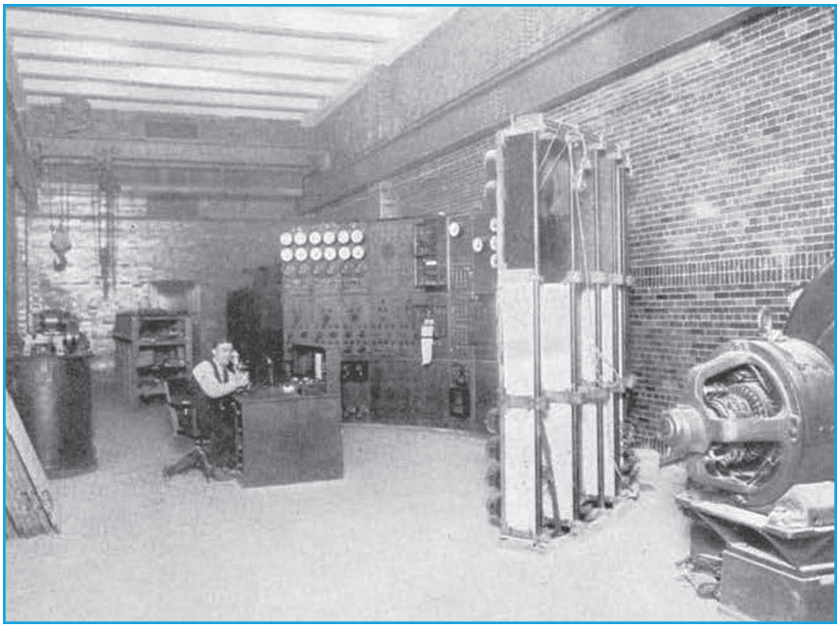


figure 1. The interior of the United West 45th Street ac distribution substation, similar in capacity to the West 97th Street location, showing the operator's board and synchronous condenser in the lower-right corner. (Courtesy of Electrical World.)

employed to balance the transformer loads and also to provide reactance sufficient for multiple source supply when that might become available. The network capacity was sufficient to carry the rated load with the failure of a transformer.

The primary feeders were controlled from the transformer substation, which gave operators the ability to reduce transformer reactive power loss during times of minimal load by disconnecting some transformers. The savings over a 24-h period was said to equal the cost of the protective relays. The transformer reactance was approximately 300% of normal to ensure an equal division of loads. The transformer substation operators regulated feeder voltage and monitored overcurrent protection to isolate defective transformers or feeder faults.

The Palmer network switch proved highly successful as detailed event records of the first year of network operation showed it to be nearly trouble free (see Figure 4). The stated goal of the engineers was to develop units with a reliability equal to that of railroad signal relays, which had undergone three decades of development. The fuses between the relay and the network provided protection to the network should a fault not burn clear.

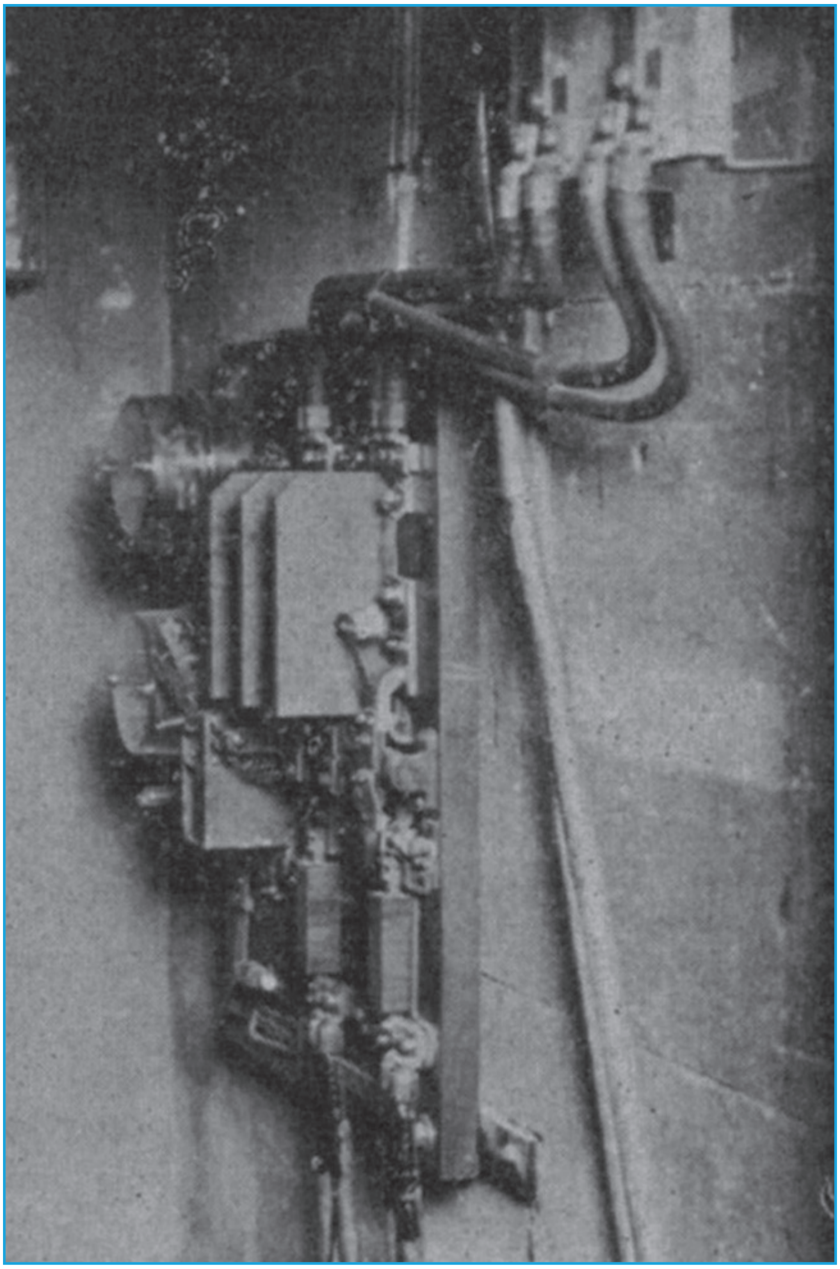


figure 2. The Network Street vault relays and switches. (Courtesy of *AIEE Transactions*.)

The cables had to have a total capacity of 25 kVA to provide a voltage gradient of 6 V per 100 ft to ensure that faults would burn clear. The faults burned clear as long as transformer capacity provided adequate burning current. United carried out extensive research on the issue of fault currents and the current needed to ensure that they would burn clear. Experience with dc had shown that larger cables tended to sustain faults as the greater surface area spread the arc, and the more molten the material, the stronger the arc. It was also determined that the impedance of the larger cable impacted the striking and sustaining of the arc. The cables of 250 mcm or less would burn clear satisfactorily. A fault on the secondary side would burn clear at lower voltages, thus no protection was needed as long as the cable size was limited. An extensive review of these tests was included in "Underground Alternating Current Network Distribution for Central Station Systems" and "Low Voltage A-C Networks Part I Application" (see the "For Further Reading" section).

The network did not combine both power and lighting loads but was superior to radial distribution and produced innovation. Over the next three years, a rapid increase in load required the use of separate (apparently meaning multiple) single-phase networks to permit rapid change of distribution from radial to network. Each network tied into one phase of a three-phase feeder to allow the best overall distribution of load across the feeders. Thus, lighting load was quickly networked while power load remained on radial distribution. It was engineered to make use of radial system transformers and primary feeders while the network was substituted.

The Combined Network

The combination of light and power load on a single automatic network was the goal and an opportunity appeared in the Times Square Theater District. United had established a substantial load in the form of animated advertising signs in which the complex relays used ac to reduce arcing. New York Edison's dc distribution system ducts were "saturated" with cables for the heavy load from lighting hotels and restaurants while both companies supplied the heavy load of the refrigeration plants of theater air conditioning systems.

Once again, the Upper West Side was the test area. An experimental three-phase, four-wire combined light and power network was initiated in July 1923, located between Columbus Avenue and Central Park West, a residential area of large apartment buildings and small stores. The goal was a network free of light flicker from motor operation. Three banks of transformers, each with a trio of 25-kVA units and a pair of 12.5-kVA units, supplied the lighting and power loads, the latter included 15 two-phase elevator motors. Each elevator motor received 220 V, as two phase from auto transformers supplied at 190 V three phase from the network. Those transformers had only 3% reactance; the load distribution was found to be very good on motor starting. The elevator motors were found to impact voltage by less than 3% with no noticeable impact on lighting.

The first complete three-phase, four-wire automatic network for combined light and power went into operation in the Times Square area on 28 October 1925. Forty-four transformers provided 4,950 kVA to the network from five radial three-phase, 3,000-V feeders powered from the West 45th Street transformer substation. The protection was provided by Westinghouse CM relays that had begun to supplant the Palmer type two years prior. By the end of 1925, the techniques of multiple-feed automatic networks had been established. Furthermore, the replacement of two-phase distribution by three phase had been initiated in 1923 as new calculation methods (Fortescu equations and Clark calculation tools) made practical the equal balance of single-phase lighting loads on three-phase circuits. The stage was set for the final breakthrough.

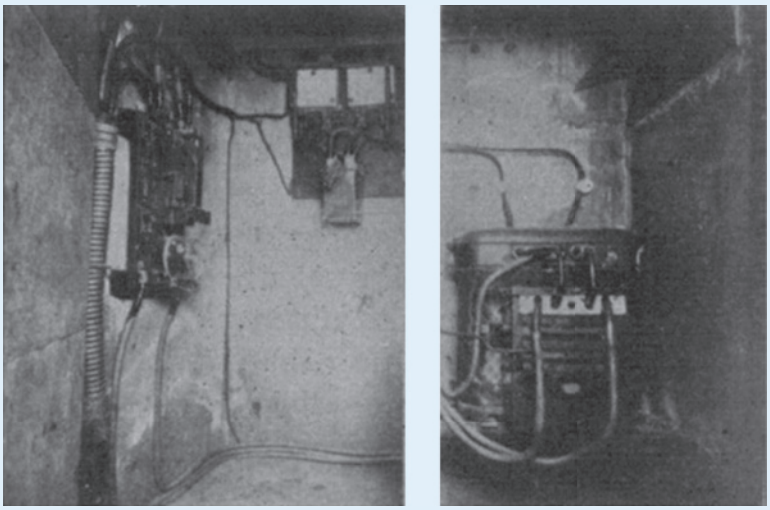
The Final Goal Achieved

On 1 April 1926, three-phase 13,200-V feeders from the generating stations at Sherman Creek and Hell Gate were connected directly to the network transformers; initially supplemented by 3,000-V feeders from the transformer substations that were in place. In time, both the transformer substation and heavy, 3,000-V feeder cables from those substations were eliminated. The distribution networks fed directly from the power station reduced the cost of ac distribution to 20–25% of that of an equivalent dc system.

United continued experiments to determine voltage drop in cables and also to improve reliability. The protective relays that worked well on lower voltages were not always usable for the higher voltages, and new designs were needed. The early relays were relatively simple, triggered by the transformer magnetizing current produced by the flow of cable charging current. Those relative values changed at the higher voltages, and separate lockout relays were required to prevent "pumping" (repetitive opening and closing) of the protective relay. In one instance, the regenerated current of elevator motors was sufficient to trigger pumping when loads were light. New relay connection schemes were necessary.

The protective relays that worked well on lower voltages were not always usable for the higher voltages, and new designs were needed.

In late 1928, the validity of the United network was key in New York Edison President Matthew Sloan's decision that the entire dc distribution system in Manhattan would no longer be expanded and would be changed to ac over time. He stated specifically that "given the economy, reliability, and efficiency" of the United network, there was "no justification for continued extension of the Edison dc system." Subsequent announcements



(a) (b)

figure 3. The Network Street vault. (a) The relays and switches and (b) network feeder transformer. (Courtesy of *AIEE Transactions*.)

detailed plans to retire the dc system. New York Edison had been the lone exception to the trend toward replacement of dc distribution until the United automatic network ended that status.

Vertical and Spot Networks

The nature of the automatic network lent itself to installation in large buildings as the 13-kV feeders were extended up to strategic points in tall structures. The first building in New York City to be so equipped was the Chrysler Building in 1929. The Empire State Building followed in 1931; within a decade, a total of 22 larger Manhattan buildings were equipped with vertical networks. The elimination of high-current/low-voltage riser cables reduced shaft requirements to the extent that significant floor space was made available for other purposes and/or increased rental area. For installations above the ground floor, company policy required the customer to perform the installation under United field supervision, although it supplied the equipment and performed subsequent maintenance. For ground floor or basement installations, the company provided the equipment and also performed the installation and maintenance.

Similarly, large complexes with a concentrated load became the sites of localized internal networks in which 13-kV feeders entered the premises to supply network transformers at strategic locations. One of the first was installed in 1928 at the new Columbia-Presbyterian Medical Center at 168th Street. Similar installations supplied the gigantic Merchandise Mart exposition center in Chicago and the National Archives building in Washington D.C.

The 1928 Blake report documented a variety of system and component concepts, but the United system became the leader. That was manifested in a 1933 survey that found 157 similar networks in 60 cities across the United States. Some cities with different systems converted to the United system and all but three made it their standard. New York City had a total of 27 networks. United had four networks in operation, Brooklyn Edison

TABLE I.
NETWORK SWITCH OPERATIONS
Number and Type of Failures

Cause of Failure	1922 Apr. 12 to Dec. 31	1923 Jan. 1 to Dec. 31	1924 Jan. 1 to Mar. 22	Total
Sticking of no-voltage relay core...	73	53	2	128
Poor contacts on no-voltage relay switch......................	5	5	2	12
Latch failure....................	8	3	2	13
Failure of pallet switch...........	14	7	0	21
Burnt switch leaves...............	3	0	0	3
Master relay out of adjustment....	3	11	2	16
Friction in master relay...........	27	15	4	46
Dirt on master relay contacts......	2	2	0	4
Dirt on relay disc................	1	0	0	1
Burnt out closing coil (cause unknown)	4	3	1	8
Burnt out closing coil (caused by faulty no-voltage relay switch)	3	0	0	3
Burnt out closing coil (caused by switch chattering due to faulty latch)	1	0	0	1
Switch chattering................	5	0	0	5
Lead to closing coil burnt out......	1	0	0	1
Tripping mechanism out of adjustment.......................	0	24	2	26
Causes—undetermined*..........	130	17	0	147
Causes—Miscellaneous...........	1	4	0	5
Total failures............	281	144	15	440
Total operations.........	26,451	19,602	2,179	48,232
Per cent failures...............	1.062	0.734	0.688	0.912

*Includes switch failures from undetermined causes and back feeds on undetermined switches.

figure 4. The network switch operations. The number and type of failures. (Courtesy of *AIEE Transactions*.)

had installed three. New York Edison installed eight in Manhattan as it switched former dc customers to ac, and also three in the Bronx. As industrial areas in Queens expanded and new residential zones began to develop, the New York and Queens Electric Light and Power Company installed nine. (By 2000, there were a total of 55 networks in the Consolidated Edison system, 33 in Manhattan, eight in Brooklyn and in Queens, and six in the Bronx.)

An Edison Electric Institute report of 1932–1933 listed the customer connection as 122 V single phase and 211 V three phase in the systems of the United, New York Edison, Brooklyn Edison, and the New York and Queens Electric Light and Power companies. It should be noted that the early reports on United reference a 115-/199-V standard, while even earlier reports mention 110/191 V, and 125/216 was also explored. The present standard of 120 V single phase and 208 V three phase was listed in cities across the nation and apparently adopted by the New York companies at some later date.

United's Legacy

Thereafter, the focus was on network protectors. The rapid change from dc to ac distribution across the nation produced a demand for a variety of protective and control relays. Surveys of 79 cities showed that half used the high-voltage standard established by United in the 11–13 kV range, two used 22 kV, two used 27 kV, and the balance retained lower voltages in the 2,300 and 4,100 V ranges. By 1933, a total of 7,000 automatic protective relays of various types were in operation in 56 cities.

The 1930s were marked by a rapid development of protective devices of increased sophistication and the use of automatic load tap changers on power transformers. In time, protective relays became a major portion of the ac network components as system complexity caused unintended operation of the relays when portions of a network were de-energized for repair work. That concern was addressed initially in 1930 when United and Westinghouse took the lead in development of components with phase-sequence relays. Ten were installed the following year and proved successful. The relays combined a directional relay and two overcurrent relays to prevent trips unless the feeder breaker opened. In 1931, engineers developed relays that were sensitive to the difference between circulating current and true reverse current to reduce

(continued on p. 76)

IEEE fellows

congratulations to the class of 2022

THE IEEE FELLOW AWARD IS A special recognition for IEEE Members with extraordinary accomplishments in IEEE technical fields. The number of recipients every year cannot exceed 0.1% of the total higher-grade membership. This ensures the exceptional status of becoming a Fellow.

The Class of 2022 Fellows

A rousing cheer goes to the following outstanding IEEE Power & Energy Society (PES) members and to those who were evaluated by PES for their achievements.

Abdolhosein Nasiri
For contributions to high-power converters for energy storage systems and microgrids.

Anurag Srivastava
For contributions to electric grid resiliency.

Babak Nahid-Mobarakeh
For contributions to the service continuity of electric motor drive systems.

Bulent Sarlioglu
For applications of electrical drives in the aerospace industry.

Chul-hwan Kim
For contributions to protective relaying methods to reduce power system outages.

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Donald Dunn
For contributions to process control systems.

Gianmario Pellegrino
For contributions to synchronous reluctance machines identification and control.

Joao Paulo Catalao
For contributions to power system operations and demand response.

Kiyohisa Terai
For contributions to optical fiber sensors and electrical discharge applications.

Le Xie
For contributions to economic and secure operations of power systems and big data analytics.

Lei Wu
For contributions to the stochastic modeling and optimization of power systems and large interdependent infrastructures.

Liangzhong Yao
For leadership in the high-voltage dc grid-supporting integration of large wind farms.

Lingling Fan
For contributions to the stability analysis and control of inverter-based resources.

Mario Paolone
For contributions to the situational awareness and control of power distribution systems.

Marjan Popov
For contributions to high-frequency transformer and circuit breaker modeling.

Maryam Saeedifard
For contributions to the modulation, control, and protection of multilevel converters for high-voltage dc transmission.

Mikhail Vaiman
For contributions to methods and software for real-time analysis and control of electric power systems.

Mladen Sasic
For contributions to the development of diagnostics testing of motor and generator windings.

Mukesh Nagpal
For contributions to the economic and safe integration of distributed renewables in electric utility networks.

Qi Huang
For leadership in informatics for smart electric energy systems.

Rajapandian Ayyanar
For contributions to the power conversion and grid integration of renewable resources.

Richard Tabors
For the development of technologies for the real-time locational pricing of electricity for efficient electric power markets.

Satish Ranade
For contributions to the integration of renewable and distributed energy resources into power systems.

Subhashish Bhattacharya
For contributions to power conversion systems and active power filters.

Tianshu Bi
For contributions to synchrophasor technology and protective relay applications.

Trevor Maguire
For leadership in the development of large-scale, real-time power systems simulators.

Tseng King Jet
For contributions to permanent magnet machines and distributed energy resources.

p&e

new practices

an update for power system markets

THIS ISSUE'S "BOOK REVIEW" column discusses *Fundamentals of Power System Economics*, second edition, by Daniel S. Kirschen and Goran Strbac. The reviewer writes, "The book makes for easy reading, with straightforward and descriptive examples."

Fundamentals of Power System Economics, Second Edition

By Daniel S. Kirschen and Goran Strbac

The second edition of *Fundamentals of Power System Economics* is an update written by two well-known power system professors, Daniel Kirschen, University of Washington, and Goran Strbac, Imperial College London. As the title suggests, the book introduces the fundamentals of power systems economics. The second edition reflects developments in power systems market practices. In particular, it covers the impacts of uncertainty from the rapid increase of variable renewable generation adoption and the need for flexible sources, such as energy storage and demand-side responses.

Electrical power systems can be traced to the late 19th century, propelled by the innovation of incandescent lamps. The electric utility industry as we know it commenced with Edison Electric Light supplying dc power to several thousand lamps in New York

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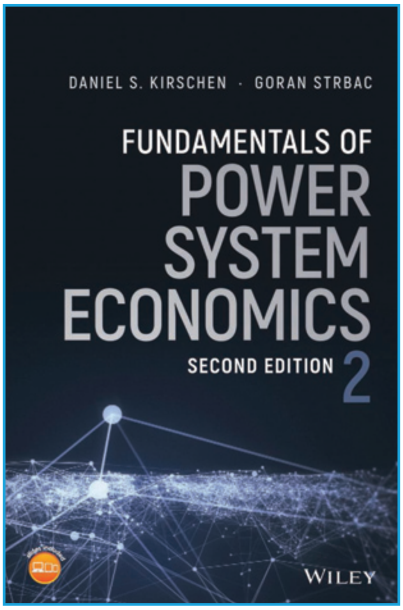

City. That was the first so-called vertically integrated utility that owned the generation, distribution, and retail of electricity. This model was adopted by ac power systems that succeeded due to their ability to reduce energy losses. For the next hundred years, the power system industry was in the hands of vertically integrated utilities. Some of those were state owned, and some were investor owned, but in both cases, they were monopoly utilities.

The book introduces the fundamentals of power systems economics.

By the late 1990s, competition was introduced by unbundling vertically integrated utilities into separately owned and operated generating, transmission, and distribution companies. For example, some utilities and states in the United States still operate under the traditional vertically integrated model, but the majority now participate in wholesale electricity markets. The book continues with basic concepts from microeconomics, explaining characteristics of spot markets, forward and future contracts, and markets by using simple yet effective examples from real life. Throughout the book, the authors include practical examples to explain facets of microeconomics to readers not well versed in the subject.

The concepts of microeconomics are further treated in the book, explaining the meaning of bilateral trading and spot markets and the interaction of participants within electrical energy markets. One chapter discusses in detail the operations of generators, consumers, storage facilities, and pumped-hydro plants. Another chapter focuses on power system security and explains the reasons for the ancillary services market. The restructuring of power systems began with regulatory policies granting electric power producers uninterrupted access to transmission networks. The book studies

(continued on p. 76)

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

IEEE International Future Energy Challenge (IFEC 2022), 28–20 April, Knoxville, Tennessee, United States, contact Hua Bai, hbai2@utk.edu, http://energychallenge.weebly.com/ifec-2022

May 2022

IEEE PES Transactive Energy Systems Conference 2022 (TESC 2022), 3–5 May, virtual event, contact Karen Studarus, karen.studarus@pnnl.gov

June 2022

IEEE Transportation Electrification Conference & Expo (ITEC 2022), 15–17 June, Anaheim, California, United States, contact Rebecca Krishnamurthy, rebecca.k@rna-associates.com, https://itec-conf.com

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

August 2022

IEEE PES/IAS PowerAfrica Conference (PowerAfrica 2022), 22–26 August, Kigali, Rwanda, contact Samantha Niyoyita, niyoyitasamantha@gmail.com, https://ieee-powerafrica.org/

September 2022

IEEE International Conference on Power Systems Technology (PowerCon 2022), 14–16 September, Kuala, Lumpur, Malaysia, contact Zuhaina Zakaria, zuhaina@gmail.com, https://attend.ieee.org/powercon-2022/

October 2022

IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe 2022), 10–12 October, Novi Sad, Serbia, contact Bane Popadic, bane@uns.ac.rs

IEEE PES Generation Transmission and Distribution Conference and Expo Latin America (GTD LA 2022), 22–24 October, virtual event, contact Israel Troncoso, itroncoso@ftibolivia.com,

November 2022

IEEE PES Innovative Smart Grid Technologies Conference Asia (ISGT Asia), 2–6 November, Singapore, hybrid event, contact Naayagi Ramasamy, Naayagi.Ramasamy@newcastle.ac.uk

IEEE Electrical Energy Storage Application and Technologies Conference (EESAT 2022), 8–9 November, Austin, Texas, United States, contact Christopher Searles, chris.searles@ieee.org

IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC 2022), 20–23 November, Melbourne, Australia, contact Shama Islam, shama.i@deakin.edu.au

January 2023

IEEE PES Joint Technical Committee Meeting (JTCM 2023), 8–12 January, Jacksonville, Florida, United States, contact Dan Sabin, d.sabin@ieee.org

IEEE PES Innovative Smart Grid Technologies (ISGT 2023), 15–19 January, Washington, DC, United States, contact Kathy Heilman, kathy.heilman@ieee.org

April 2023

IEEE PES Grid Edge Technologies Conference and Expo (Gride Edge), 24–27 April, San Diego, California, United States, contact Kathy Heilman, kathy.heilman@ieee.org

May 2023

IEEE PES International Conference and Exposition (GT&D Turkey), 22–25 May, Istanbul, Turkey, contact Omer Usta, usta@ieee.org, https://ieee-gtd.org/

July 2023

IEEE PES General Meeting (GM 2023), 16–20 July, Orlando, Florida, United States, contact Roseanne Jones, roseanne.jones@ieee.org

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history *(continued from p. 71)*

excessive tripping. Thereafter, the techniques became even more sophisticated: some General Electric relays employed electronic control features.

In 1938, a "limiter" was developed by Consolidated Edison engineers. A fusible link prevented heavy short circuits from destroying cables in the network when "solid" shorts did not burn clear. Over the next three decades, 1,500,000 such limiters were installed. The company's engineers also developed the "Crab Joint" connector to enable a more reliable and rapid connection of cables. Adopted by a variety of utility companies, some crab joint connectors contained limiters.

Over the next two decades, 414 networks were in operation in 82 cities. By half a century after the first United success, 315 U.S. cities had one or more networks. Today, cities are more dependent on reliable power than ever before. Network control and regulation is a major focus of the effort to secure that reliability, a quest that first succeeded on Manhattan's Upper West Side on an April day a century ago.

For Further Reading

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book review *(continued from p. 74)*

the effects that a transmission network has on the trading of electrical energy. This includes price fluctuations due to transmission network congestion.

Generation capacity from consumer and investor perspectives is further explained. Since careful planning of generation capacity has been supported by competitive investment in generation units, investments in the upgrade and construction of new transmission lines have a positive effect on power system reliability and electricity prices. The book explains how new transmission can increase the market participation of both affordable generation and consumers.

Each of the book's eight chapters treats a different topic related to wholesale electricity markets. The authors provide relevant references in each chapter for further reading. The book makes for easy reading, with straightforward and descriptive examples. Power and energy industry practitioners with a solid understanding of technical aspects, but a not-so-thorough comprehension of electricity markets, can gain a deeper understanding of this important yet novel subject. Novices with no background in the industry will gain insights into the technical aspects of power systems and energy trading.

—Edvina Uzunovic

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Power System Flexibility

> [T]here is broad industry consensus that regional transmission organizations (RTOs)/ independent system operators (ISOs) will need more operational flexibility … to reliably serve loads as the resource mix evolves to include more weather-dependent variable energy resources (VERs) ….
>
> —Federal Energy Regulatory Commission Staff Paper Docket Number AD 21-10-000 (September 2021)

In every U.S. ISO/RTO except PJM, variable wind and solar are expected to supply more—in some markets much more—than 30% of total energy by 2030. The rapid growth of variable renewable resources is being driven by the 90% drop in the unsubsidized cost of utility-scale PV and a 70% decline in the unsubsidized cost of onshore wind since 2009. On an energy basis, building new wind or solar generation is often less expensive than operating existing coal-fired generation and is becoming competitive with natural gas. At the end of 2020, solar, wind, and energy storage projects made up more than 90% of the capacity in U.S. interconnection queues.

VERs present significant challenges. In several markets, wind and solar energy will provide nearly all the energy required in some hours, while meeting only a small portion of energy requirements in others. Rapid, often difficult-to-forecast changes in the output of wind resources have required the Midcontinent Independent System Operator and the Southwest Power Pool to each compensate for declines in wind generation of 8 GW within 4-hr periods. With VERs providing 28% of energy, the California ISO has had to offset 3-hr ramps exceeding 15 GW. Without the immediate response of balancing resources, such variability can produce rapid changes in power flows and impact system stability.

Flexible demand can offset this variability. A 2019 Brattle Group study estimated that the United States will add more than 120 GW of new, cost-effective flexible demand by 2030, in addition to 16 GW of new, conventional demand response. The additional flexible demand could provide benefits in excess of US$15 billion per year. Much of the increase in flexible demand could come from smart thermostats, water heaters, and building management systems. Smart technology can shift the timing of power consumption without impacting consumers by taking advantage of the thermal inertia inherent in the 38% of U.S. electricity consumption devoted to cooling, heating, ventilation, and refrigeration. Additional flexibility will be available with increases in the adoption of electric vehicles, electrification of home heating, and deployment of intelligent industrial and agricultural control systems. Smart systems can shape, shift, and modulate flexible demand, often at a cost that is below the cost of battery energy storage. Intelligent systems can also optimize the operation of batteries and other behind-the-meter DERs.

Smart technology will require changes in how customers participate in power markets. Existing demand response programs pay customers for reducing demand compared to a recent baseline period. Smart technology will anticipate demand response events and increase baseline usage to maximize incentive payments. Moreover, smart devices will respond to simple time-of-use rates with rapid, discrete, potentially destabilizing spikes in demand when prices drop.

In large regional markets, system operators dispatch several hundred to a few thousand generators. In a distribution system with millions of intelligent end-use devices, hundreds of thousands of electric vehicles, and hundreds of megawatts of distributed generation and storage, dispatching DERs will become computationally intractable. Centralized dispatch may be limited to large and operationally critical DERs. Operators will have to rely on price signals to integrate most of the DERs.

Fundamental economic principles provide a road map for developing retail rates that incorporate the necessary dynamic prices. An efficient and equitable rate design should have the following three components:

1) A dynamic spot market or marginal, cost based price. The European Union's 2019 electricity directive requires larger electric suppliers to offer rates that include spot-market prices.
2) Recovery of the utility's remaining transmission and distribution revenue requirements in differentiated, fixed access charges. Many European electric utilities require consumers to subscribe to one of several demand-based access charges. This approach offers an income-progressive alternative to recovering fixed utility costs in kilowatt-hour rates.
3) An insurance component for customers who want high-bill protection.

In a client study, we analyzed two years of advanced metering data from more than 450,000 customers and illustrated how such three-component, real-time pricing rates could benefit most of the consumers, protect low-income customers, and align with accepted equity principles. An efficient and equitable rate design could accelerate the development of new demand and DER management services, optimize flexible demand, and provide efficient incentives for DER development and operation.

Realizing the potential of demand and DER flexibility requires efficient pricing and smart technology. Field experiments are needed to test the performance and customer acceptance of different combinations of dynamic pricing and smart technology as well as alternatives that might combine simpler rate designs with demand and DER management services. The results of such experiments

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are needed before the growing reliance on variable resources impacts system reliability.

Resilience: Preparation for Extreme Weather

High-impact weather events are no longer infrequent. The average number of extreme weather events in the United States causing more than US$1 billion in damages has increased from 2.9 per year in the 1980s to 16 per year in 2016–2020. The average annual cost of these events has increased from US$17.8 billion to US$126 billion per year. The number and severity of extreme weather events have increased with

- ✔ the increasing intensity and slower postlandfall weakening of hurricanes. For example, Hurricane Ida took out the transmission lines serving New Orleans and brought down power lines and flooded streets and basement apartments, killing 56 people in four northeastern states.
- ✔ the increasing frequency and intensity of other extreme precipitation events, i.e., tornados, hailstorms, and floods.
- ✔ increases in the frequency, duration, and geographic scope of heat waves. For example, the June 2021 Pacific Northwest heat dome increased temperatures in Seattle to 109° F, Portland to 116°, and towns in eastern Washington and British Columbia to above 120°.
- ✔ severe drought conditions across nearly 90% of western states, shrinking reservoirs at Colorado River dams and reducing hydroelectric power in California by 38%.
- ✔ elevated wildfire risks that require de-energizing transmission lines in fire-prone areas
- ✔ large areas of unusually cold winter temperatures. For example, Winter Storm Uri in February 2021 caused 61.8 GW of unplanned generator outages and 23.4 GW of firm load shedding.

Climate models suggest that the frequency and severity of extreme weather events are likely to increase. Some extreme events, such as the Northwest heat wave, now considered to be a one-in-1,000-year event, will be beyond what can be predicted from available data. Climate conditions are already well outside the range of human experience. The average atmospheric concentration of carbon dioxide in 2020 was 37% higher than the highest levels in the 800,000 years before 1900. Extreme weather causes common mode failures: widespread demand increases during heat waves and cold-weather events, unplanned outages at multiple generating units, interrupted fuel supplies, damage to multiple transmission lines, and distribution outages.

Conventional resource planning systematically understates the probability, depth, and costs of such events. Generator outages are often assumed to be independent, uncorrelated events. Standard resource adequacy metrics are based on expected values, limiting the weight and attention given to high-impact events that are infrequent in the historical data. Moreover, societal and customer outage costs are not included in North American Electric Reliability Corporation's standard reliability risk metrics.

A January 2021 Electric Power Research Institute report, for which I was one of the principal investigators, described the limitations of current practices and a set of steps for developing stochastic resource adequacy models that include high-impact events and value-of-load-at-risk metrics—comparable to financial value-at-risk metrics. Such models and metrics will enable planners and regulators to evaluate risk—the likelihood and cost of disruptive events—and to compare different options that could avoid or mitigate the impacts of these events. The report also includes recommendations to improve natural gas data reporting, create a gas reliability organization comparable to North American Electric Reliability Corporation, and enhance coordination of gas and electric markets to reduce the uncertainty of natural gas supplies when gas systems are stressed.

Probabilistic weather forecasts can identify more than a week in advance the risk of weather conditions that could disrupt the power system. We are working with an ISO and a weather forecasting organization to use granular, probabilistic weather forecasts to develop locational reliability pricing. This work on stochastic nodal adequacy pricing is being supported by the U.S. Advanced Research Projects Agency-Energy. It could improve existing scarcity pricing mechanisms and provide risk-based price signals, enabling consumers and resources, including DERs, to prepare for extreme weather. A broader, risk-based reliability component in short-term prices would be reflected in forward contracts and help support investment in the resources best able to mitigate weather-related risks.

Adding resources and hardening assets is insufficient for minimizing the impact of extreme events. More frequent, extreme weather requires creating more resilient systems. Resilience differs from resource adequacy and reliability. It focuses on high-impact, region-specific risks, including long-duration and wide-area power outages, and events that degrade other critical systems. Resilience requires working with public and private partners to maintain critical services during extreme events and the restoration of normal operations. It assumes extreme events will degrade power system capabilities and focuses on how utilities and their partners can manage during, recover after, and incorporate lessons learned from such events.

DERs can contribute to the development of a more resilient power system. In this issue of *IEEE Power & Energy Magazine*, Reid et al. cite the example of developing microgrids to support community centers and libraries in San Francisco. Such facilities are needed to provide support services when major outages happen. An urban area power outage that coincides with a heat wave could leave hundreds of thousands

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exposed to dangerous temperatures. Although many cities designate cooling centers for those without air conditioning, such centers often have the capacity to serve less than 2% of a city's population and may not be required to have backup power supplies. Community resilience should start by deploying DERs and microgrids to maintain power at critical facilities.

In some regions, climate change will require more fundamental changes in the structure and operation of power systems. With the knowledge that extreme weather will periodically degrade the system, the grid will need to evolve into a layered system with defined relationships between bulk power, distribution, and circuit-level segments; fractal zones that can balance supply and demand in an islanded mode and participate in the larger grid; and autonomous operations that combine distributed control and locational pricing to balance demand and resource availability. Developing the capabilities needed for this smarter, more resilient system will require the participation of multiple engineering disciplines, innovation, and field experiments.

Aligning Utility Regulatory and Business Models With Environmental Goals

More than 270 electric companies serving more than 70% of U.S. consumers have objectives to rely on 100% clean energy or to become carbon neutral by 2050. Reconciling these objectives with affordable and reliable service will require a combination of efficient investment and optimized use of existing capabilities. Greater flexibility, including flexible demand that will reduce peak requirements, is needed to balance VERs, match demand and supply in constrained areas, and improve asset utilization. The efficient use of smart grid technologies, including volt-var optimization, power flow controls, dynamic line ratings, and topology management, can reduce investment requirements and help utilities manage costs. Additionally, the efficient development and operation of nonutility DERs can provide important community-resilience benefits.

Unfortunately, utility regulation seldom provides incentives for optimizing existing assets or reducing the need for future utility investment. Utility profits are based on earning a return on capital investment. Regulation should also encourage actions that advance clean energy transition and require little or no utility capital investment.

A few jurisdictions have sought to align regulation with the transition to a clean energy future. In 2014, the U.K.'s Office of Gas and Electric Markets implemented an innovative form of incentive regulation that included a multiyear revenue cap on total expenditures. At the start of the rate plan, the regulator fixed the percentages of revenue recovered in each rate year (fast revenue) and capitalized to be recovered over time (slow revenue). Thereafter, recovery did not depend on the nature of the utility's expenditures. Earnings were no longer tied to capital investments. The plan also included funding for innovation projects and significant outcome-based incentives. The Office of Gas and Electric Markets is currently developing the second round of distribution rates for 2023–2028.

New York followed some elements of the U.K. model, including performance incentives that "both encourage achievement of new policy objectives and counter the implicit negative incentives that the current ratemaking model provides." The New York Commission concluded that outcome-based incentives "will tend to be the most effective approach" and should not be confined "to items under direct control or strong influence of the utility." It has approved incentives for reductions in greenhouse gas emissions from customer adoption of electric vehicles and heat pumps; distributed PVs, wind, and storage; reducing peak demand below forecast levels; and improving load factors in constrained areas. Both the U.K. and New York regulators gathered extensive input, including from the engineering community and other independent experts.

Concluding Thoughts

The transition to a clean energy future provides opportunities for DERs to create significant value by

- ✔ increasing system flexibility, primarily by shaping and adjusting net load in response to anticipated prices
- ✔ enhancing resilience, initially for critical facilities, and over time in an increasingly fractal, autonomous system that maintains basic services in islanded circuits.

Realizing these benefits will require changes in the regulation, structure, and operation of the power system. Creating the systems needed to achieve an affordable, reliable, resilient, and environmentally sustainable future will be one of this century's major engineering challenges.

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Paul Centolella

distributed energy resources

transitioning to a clean energy future

IN MY 40-YEAR CAREER AS A utility consumer advocate, regulator, and consultant, I have participated in key power industry transitions, including

- ✔ in the 1980s, advocating integrated resource planning and collaborating with utilities to design energy efficiency programs.
- ✔ as a proponent of the acid rain cap and trade program in the 1990 Clean Air Act amendments and helping the U.S. Environmental Protection Agency develop the SO_2 allowance trading program.
- ✔ leading modeling on the benefits of locational marginal pricing in the 1990s and later supporting the development of the Midcontinent Independent System Operator's energy and ancillary service markets.
- ✔ encouraging smart grid investments as a commissioner on the Public Utilities Commission of Ohio from 2007 to 2012 and helping guide standards development on the Board of the Smart Grid Interoperability Panel and Federal Advisory Committees for the Department of Energy and National Institute of Standards and Technology.
- ✔ as a consultant, advising clients on aligning utility business and regulatory models with the transition to a clean energy economy.

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Each transition began by asking simple questions. What is needed to achieve a more affordable, reliable, and environmentally sustainable energy future? What are the gaps between current practice, and what is needed? In what areas will new learning and innovation be required? Asking these questions inevitably led to valuable collaborations, systems thinking, detailed analysis, innovation, and often market-based solutions.

A 2016 white paper for New York's Renewing the Energy Vision initiative, which I coauthored with several colleagues, addresses how to efficiently integrate distributed energy resources (DERs). It describes the design of distribution-level markets and proposes distributed locational marginal pricing for real and reactive power, a digital platform market to facilitate financial transactions and animate development of retail products combining energy and smart technology, and auctions to procure DER option contracts for the purpose of deferring distribution investments. Two of the articles in this issue of *IEEE Power & Energy Magazine* (Golriz et al. and Paaso et al.) examine applications of these concepts.

It is often asked: why aren't DERs more widely used as nonwires alternatives? The answer may be that identifying DER value requires a wider lens. Not all DERs provide energy when needed to avoid distribution investments, e.g., solar photovoltaics (PVs) on an evening peaking circuit. A nonwires alternative's value is also location specific. As stated in the Illinois Future Energy Jobs Act, the relevant value of DERs is "to the distribution system at the location at which it is interconnected …." Environmental benefits also are time and location specific and vary based on the marginal generators displaced. Moreover, economies of scale can outweigh the benefits of being distributed, e.g., unsubsidized utility-scale PV costs are one-fourth residential PV costs. Generic DER incentives, using area averages to value distribution benefits (e.g., California's Avoided Cost Calculator), capitalizing estimated value streams more accurately represented by market prices, and kilowatt-hour rates that exceed marginal costs can induce DER investments that fail to provide net value.

Understanding the true value of DERs requires starting with the question: what is needed to achieve an affordable, reliable, resilient, and environmentally sustainable future? Only as the road map to this future emerges, will it become evident where DERs can contribute.

The pursuit of the following three necessary conditions for achieving an affordable, reliable, resilient, clean energy future will help shape and expand opportunities for DERs:

1) power system flexibility, including flexible demand
2) resilience: preparation for extreme weather
3) alignment of utility regulatory and business models with environmental goals.

(continued on p. 78)