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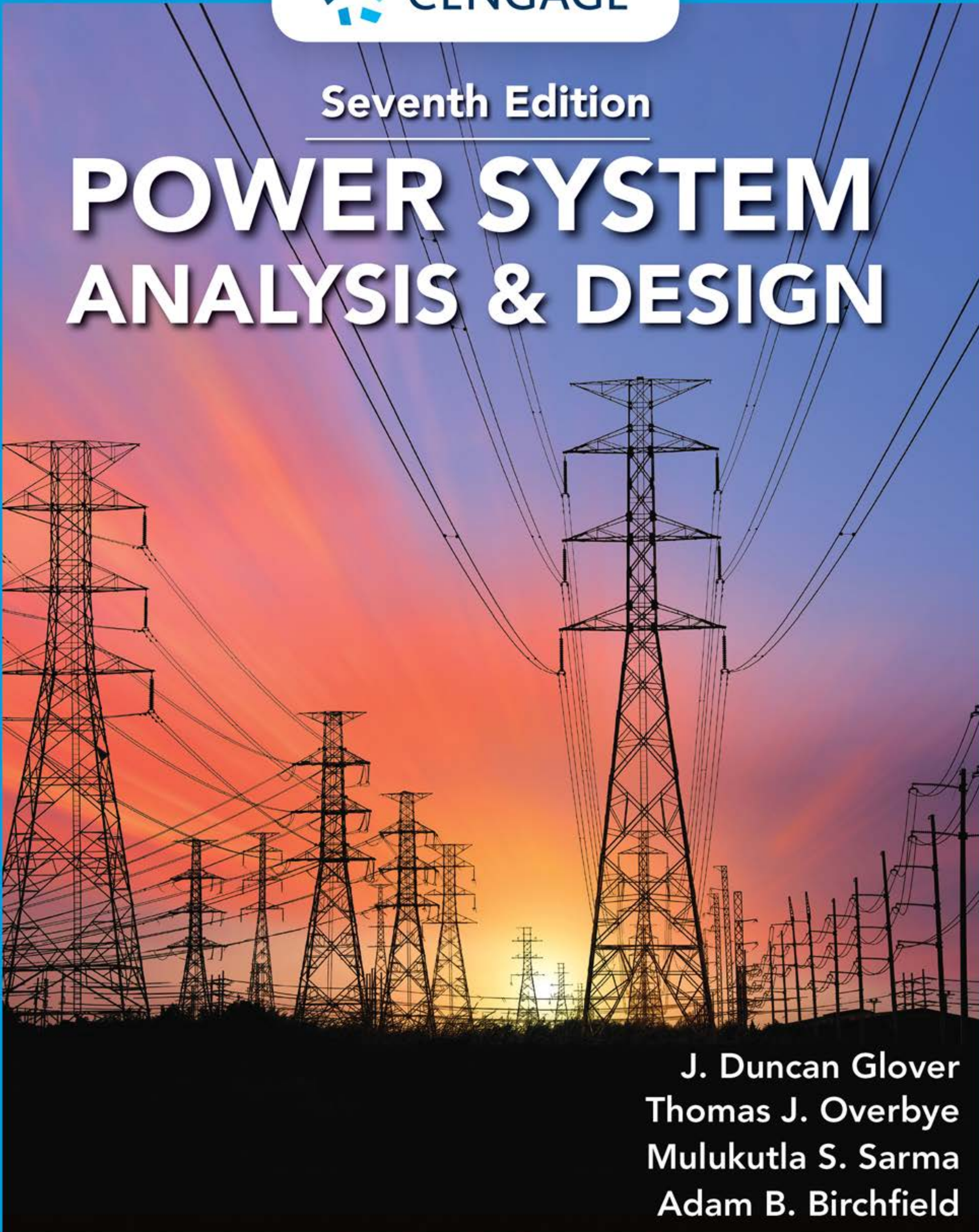
POWER SYSTEM ANALYSIS & DESIGN



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POWER SYSTEM ANALYSIS & DESIGN

SEVENTH EDITION

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***Power System Analysis & Design,* Seventh Edition**

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From J. Duncan Glover:

To my grandchildren: Natalie, John, Brigid, Emily, Anna, and Owen

From Thomas J. Overbye:

To Jo, Tim, Hannah, and Amanda

Contents

Preface

The objective of this book is to present methods of power system analysis and design, particularly with the aid of a personal computer, in sufficient depth to give the student the basic theory at the undergraduate level. The approach is designed to develop students' thinking processes, enabling them to reach a sound understanding of a broad range of topics related to power system engineering, while motivating their interest in the electrical power industry. Because we believe that fundamental physical concepts underlie creative engineering and form the most valuable and permanent part of an engineering education, we highlight physical concepts while giving due attention to mathematical techniques. Both theory and modeling are developed from simple beginnings so that they can be readily extended to new and complex situations.

NEW TO THIS EDITION

We welcome Adam B. Birchfield as a co-author for this edition. Dr. Birchfield insures that the text will continue to be updated with the latest technological advances in power systems.

New chapter-opening case studies bring principles to life for students by providing practical, real-world engineering applications for the material discussed in each chapter.

Comprehensively revised problem sets ensure students have the practice they need to master critical skills.

KEY FEATURES

The text presents present-day, practical applications and new technologies along with ample coverage of the ongoing restructuring of the electric utility industry. It is supported by an ample number of worked examples, including illustrations, covering most of the theoretical points raised. It also includes PowerWorld Simulator version 22 to extend fully worked examples into computer implementations of the solutions. Version 22 includes power flow, optimal power flow, contingency analysis, short circuit, and transient stability.

The text includes a chapter on Power Distribution with content on Smart Grids.

It also includes discussions on modeling of wind turbines in power flow and transient stability.

Four design projects are included, all of which meet ABET requirements.

POWERWORLD SIMULATOR

One of the most challenging aspects of engineering education is giving students an intuitive feel for the systems they are studying. Engineering systems are, for the most part, complex. While paper-and-pencil exercises can be quite useful for highlighting the fundamentals, they often fall short in imparting the desired intuitive insight. To help provide this insight, the book uses PowerWorld Simulator version 22 to integrate computer-based examples, problems, and design projects throughout the text.

PowerWorld Simulator was originally developed at the University of Illinois at Urbana-Champaign to teach the basics of power systems to nontechnical people involved in the electricity industry, with version 1.0 introduced in June 1994. The program's interactive and graphical design made it an immediate hit as an educational tool, but a funny thing happened—its interactive and graphical design also appealed to engineers doing analysis of real power systems. To meet the needs of a growing group of users, PowerWorld Simulator was commercialized in 1996 by the formation of PowerWorld Corporation. Thus while retaining its appeal for education, over the years PowerWorld Simulator has evolved into a top-notch analysis package, able to handle power systems of any size. PowerWorld Simulator is now used throughout the power industry, with a range of users encompassing universities, utilities of all sizes, government regulators, power marketers, and consulting firms.

In integrating PowerWorld Simulator with the text, our design philosophy has been to use the software to extend, rather than replace, the fully worked examples provided in previous editions. Therefore, except when the problem size makes it impractical, each PowerWorld Simulator example includes a fully worked hand solution of the problem along with a PowerWorld Simulator case. This format allows students to simultaneously see the details of how a problem is solved and a computer implementation of the solution. The added benefit from PowerWorld Simulator is its ability to easily extend the example. Through its interactive design, students can quickly vary example parameters and immediately see the impact such changes have on the solution. By reworking the examples with the new parameters, students get immediate feedback on whether they understand the solution process. The interactive and visual design of PowerWorld Simulator also makes it an excellent tool for instructors to use for in-class demonstrations. With numerous examples utilizing PowerWorld Simulator instructors can easily demonstrate many of the text topics. Additional PowerWorld Simulator functionality is introduced in the text problems and design projects.

The latest version of the valuable PowerWorld Simulator (version 22) is included and integrated throughout the text.

PREREQUISITES

As background for this course, it is assumed that students have had courses in electric network theory (including transient analysis) and ordinary differential equations and have been exposed to linear systems, matrix algebra, and computer programming. In addition, it would be helpful, but not necessary, to have had an electric machines course.

ORGANIZATION

The text is intended to be fully covered in a two-semester or three-quarter course offered to seniors and first-year graduate students. The organization of chapters and individual sections is flexible enough to give the instructor sufficient latitude in choosing topics to cover, especially in a one-semester course. The text is supported by an ample number of worked examples covering most of the theoretical points raised. The many problems to be worked with a calculator as well as problems to be worked using a personal computer have been revised in this edition.

After an introduction to the history of electric power systems along with present and future trends, *Chapter 2* orients the students to the terminology and serves as a brief review of fundamentals. The chapter reviews phasor concepts, power, network equations, single-phase as well as balanced three-phase circuits and a brief discussion of energy conversion.

Chapters 3 through 5 examine power transformers including the per-unit system, transmission-line parameters, and steady-state operation of transmission lines. *Chapter 6* examines power flows including the Newton-Raphson method, control of power flow, sparsity techniques, and power-flow modeling of wind and solar generation. Chapter 7 covers economic dispatch and optimal power flow, including coverage of unit commitment and markets. These chapters provide a basic understanding of power systems under balanced three-phase, steady-state, normal operating conditions.

Chapters 8 through 11, which cover symmetrical faults, symmetrical components, unsymmetrical faults, and system protection, come under the general heading of power system short-circuit protection. *Chapter 12* examines transient stability, which includes the swing equation, the equal-area criterion, and multi-machine stability with modeling of wind turbine and solar PV systems. *Chapter 13* covers power system controls, including generator-voltage control, turbine-governor control, load frequency control, and power system stabilizer control. *Chapter 14* examines transient operation of transmission lines including power system overvoltages, insulation coordinationand surge protection.

Chapter 15 introduces the basic features of primary and secondary distribution systems as well as basic distribution components including distribution substation transformers, distribution transformers, and shunt capacitors. We list some of the major distribution software vendors followed by an introduction to distribution reliability, distribution automation, and smart grids.

Digital Resources

New Digital Solution for Your Engineering Classroom

WebAssign is a powerful digital solution designed by educators to enrich the engineering teaching and learning experience. With a robust computational engine at its core, WebAssign provides extensive content, instant assessment, and superior support. WebAssign's powerful question editor allows engineering instructors to create their own questions or modify existing questions. Each question can use any combination of text, mathematical equations and formulas, sound, pictures, video, and interactive HTML elements. Numbers, words, phrases, graphics, and sound or video files can be randomized so that each student receives a different version of the same question. In addition to common question types such as multiple choice, fill-in-the-blank, essay, and numerical, you can also incorporate robust answer entry palettes (mathPad, chemPad, calcPad, physPad, Graphing Tool) to input and grade symbolic expressions, equations, matrices, and chemical structures using powerful computer algebra systems.

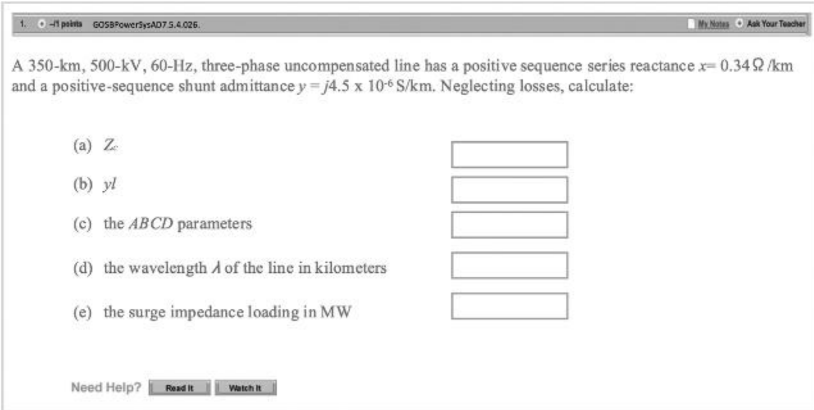
WebAssign Offers Engineering Instructors the Following

- The ability to create and edit algorithmic and numerical exercises.
- The opportunity to generate randomized iterations of algorithmic and numerical exercises. When instructors assign numerical WebAssign homework exercises (engineering math exercises), the WebAssign program offers them the ability to generate and assign their students differing versions of the same engineering math exercise. The computational engine extends beyond and provides the luxury of solving for correct solutions/answers.
- The ability to create and customize numerical questions, allowing students to enter units, use a specific number of significant digits, use a specific number of decimal places, respond with a computed answer, or answer within a different tolerance value than the default.

Visit www.webassign.com/instructors/features/ to learn more. To create an account, instructors can go directly to the signup page at www.webassign.net/signup.html.

WebAssign Features for Students

- **Review Concepts at Point of Use**
  Within WebAssign, a "Read It" button at the bottom of each question links students to corresponding sections of the textbook, enabling access to the MindTap Reader at the precise moment of learning. A "Watch It" button allows a short video to play. These videos help students understand and review the problem they need to complete, enabling support at the precise moment of learning.

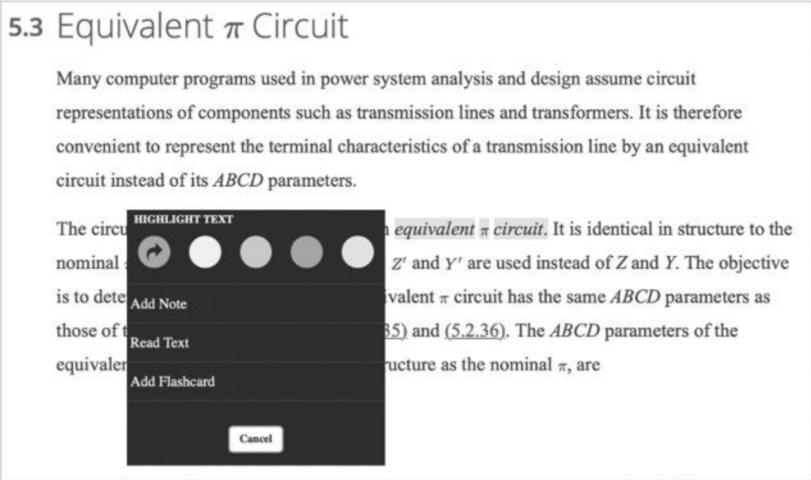


- **My Class Insights**
  WebAssign's built-in study feature shows performance across course topics so that students can quickly identify which concepts they have mastered and which areas they may need to spend more time on.
- **Ask Your Teacher**
  This powerful feature enables students to contact their instructor with questions about a specific assignment or problem they are working on.

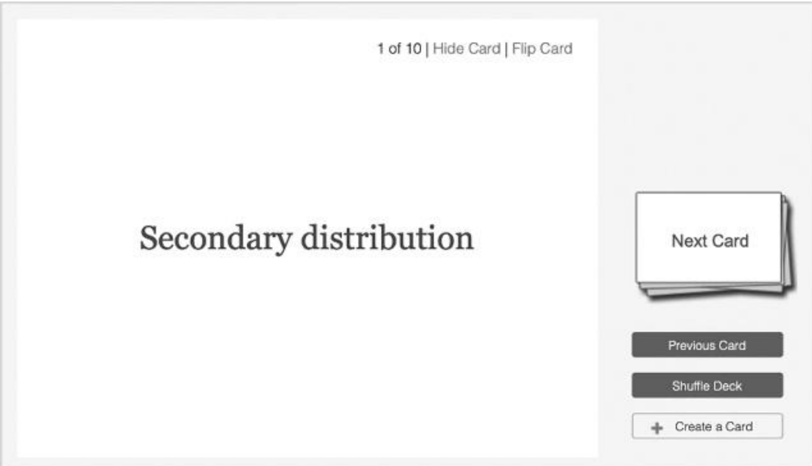
MindTap Reader

Available via WebAssign and our digital subscription service, Cengage Unlimited, MindTap Reader is Cengage's next-generation eBook for engineering students. The MindTap Reader provides more than just text learning for the student. It offers a variety of tools to help our future engineers learn chapter concepts in a way that resonates with their workflow and learning styles.

- **Personalize their experience**
  Within the MindTap Reader, students can highlight key concepts, add notes, and bookmark pages. These are collected in My Notes, ensuring they will have their own study guide when it comes time to study for exams.



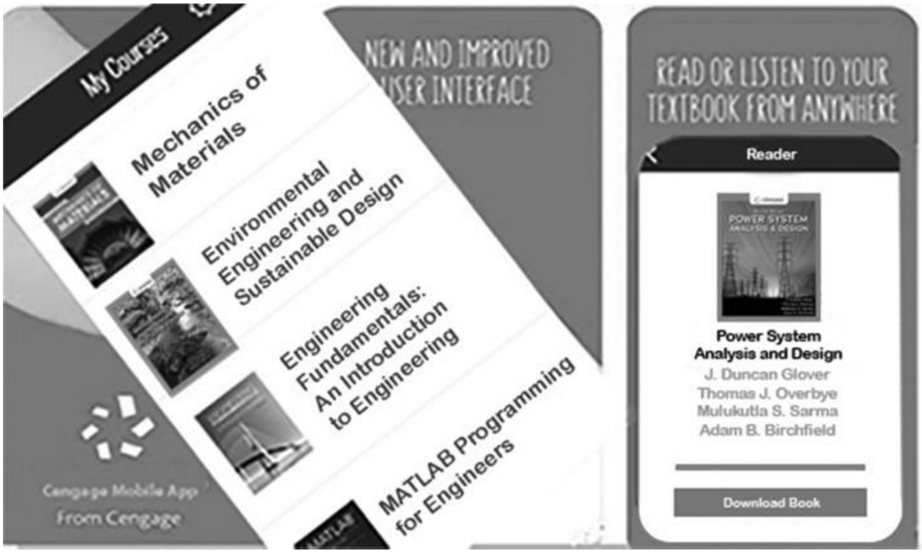
- **Flexibility at their fingertips**
  With access to the book's internal glossary, students can personalize their study experience by creating and collating their own custom flash-cards. The ReadSpeaker feature reads text aloud to students, so they can learn on the go—wherever they are.



THE CENGAGE MOBILE APP

Available on iOS and Android smartphones, the Cengage Mobile App provides convenience. Students can access their entire textbook anyplace and anytime. They can take notes, highlight important passages, and have their text read aloud whether they are online or off.

To learn more and download the mobile app, visit www.cengage.com/mobile-app/.



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SUPPLEMENTS FOR THE INSTRUCTOR

Supplements to the text include a Solution and Answer Guide that provides complete solutions to all problems, Lecture Note PowerPoint™ slides, and an image library of all figures in the book. These can be found on the password-protected Instructor's Resource website for the book at http://login.cengage.com.

SUPPLEMENTS FOR THE STUDENT

The **Student Companion Site** includes a link to download the free student version of PowerWorld, Case Studies, and Student PowerPoint Notes.

ACKNOWLEDGMENTS

The material in this text was gradually developed to meet the needs of classes taught at universities in the United States and abroad over the past 40 years. The original 13 chapters were written by the first author, J. Duncan Glover, *Failure Electrical LLC*, who is indebted to many people who helped during the planning and writing of this book. The profound influence of earlier texts written on power systems, particularly by W. D. Stevenson, Jr., and the developments made by various outstanding engineers are gratefully acknowledged. Details of sources can only be made through references at the end of each chapter, as they are otherwise too numerous to mention.

Chapter 7 (*Economic Dispatch and Optimal Power Flow*), included in Chapter 6 for prior editions, is now a separate chapter for the 7th edition.

Chapter 15 *(Power Distribution)* was a collaborative effort between Dr. Glover (Sections 15.1-15.7) and Co-author Thomas J. Overbye (Sections 15.8 & 15.9). Professor Overbye, *Texas A&M University also authored Sections 1.5, 2.8, 6.10, 6.11, 6.12, 7.4, 7.5, 12.6, 12.7, 12.8 and 13.4.* He further contributed to Section 13.1, provided PowerWorld Simulator examples and problems throughout the text and three design projects. Co-author Mulukutla Sarma, *Northeastern University (Emeritus), and Adam Birchfield, Texas A&M University,* contributed to end-of-chapter problems.

We commend the following Global Engineering team members at Cengage Learning: Timothy Anderson, Senior Product Manager; Sharon Chambliss, Senior Content Manager; and MariCarmen Constable, Learning Designer; as well as Rose Kernan of RPK Editorial Services, Inc. for their broad knowledge, skills, and ingenuity in publishing this edition. We also thank Matt Wood, Program Manager, Taylor Shenberger, Portfolio Marketing Manager, Simeon Lloyd-Wingard, Product Assistant.

Reviewers

Substantial contributions to prior editions of this text were made by a number of invaluable reviewers:

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Mahyar Zarghami, *California State University at Sacramento*

In conclusion, the objective in writing this text and the accompanying software package will have been fulfilled if the book is considered to be student-oriented, comprehensive, and up to date, with consistent notation and necessary detailed explanation at the level for which it is intended.

J. Duncan Glover

Thomas J. Overbye

Adam B. Birchfield

Mulukutla S. Sarma

List of Symbols, Units, and Notation

Symbol	Description
a	operator 1/120°
a_t	transformer turns ratio
A	area
A	transmission line parameter
$\boldsymbol{A}$	symmetrical components transformation matrix
B	Susceptance
B	Susceptance Matrix
B	loss coefficient
B	frequency bias constant
B	phasor magnetic flux density
B	transmission line parameter
C	capacitance
C	transmission line parameter
D	damping
D	distance
D	transmission line parameter
E	phasor source voltage
E	phasor electric field strengths
$\boldsymbol{f}$	frequency
G	conductance
G	conductance matrix
H	normalized inertia constant
H	phasor magnetic field intensity
$i(t)$	instantaneous current
I	current magnitude (rms unless otherwise indicated)
I	phasor current
I	vector of phasor currents
j	operator 1/90°
J	moment of inertia
l	length
l	length
L	inductance
L	inductance matrix
N	number (of buses, lines, turns, etc.)
Q	reactive power
p.f.	power factor
$p(t)$	instantaneous power
	magnetic flux linkage
P	real power
q	Charge
r	radius
R	resistance
R	turbine-governor regulation constant
R	resistance matrix
s	Laplace operator
S	apparent power
S	complex power
t	time
T	period
T	temperature
T	torque
$v(t)$	instantaneous voltage
V	voltage magnitude (rm unless otherwise indicated)
V	phasor voltage
$\boldsymbol{V}$	vector of phasor voltages
X	reactance
X	reactance matrix
Y	phasor admittance

Symbol	Description
$\boldsymbol{Y}$	admittance matrix
Z	phasor impedance
$\boldsymbol{Z}$	impedance matrix
α	angular acceleration
α	transformer phase shift angle
β	current angle
β	area frequency response characteristic
δ	voltage angle
δ	torque angle
ϵ	permittivity
Φ	magnetic flux

Symbol	Description
λ	Penalty factor
Γ	reflection or refraction λ coefficient
ϑ	impedance angle
ϑ	angular position
μ	permeability
θ	velocity of propagation
φ	radian frequency
ρ	resistivity
τ	time in cycles
τ	transmission line transit time

	SI Units
A	ampere
C	coulomb
F	farad
H	henry
Hz	hertz
J	joule
kg	kilogram
m	meter
N	newton
rad	radian
s	second
S	siemen
VA	volt-ampere
var	volt-ampere reactive
W	watt
Wb	weber
б	ohm

English Units	
BTU	British thermal unit
Cmil	circular mil
ft	foot
hp	horsepower
in	inch
mi	mile

Notation

Lowercase letters such as v(t) and i(t) indicate instantaneous values.
Uppercase letters such as V and I indicate rms values.
Uppercase letters in italic such as V and I indicate rms phasors.
Matrices and vectors with real components such as **R** and **I** are indicated by boldface type.
Matrices and vectors with complex components such as ***Z*** and ***I*** are indicated by boldface italic type.
Superscript T denotes vector or matrix transpose.
Asterisk (*) denotes complex conjugate.
$\boxed{\text{PW}}$ highlights problems that utilize PowerWorld Simulator.

1 Introduction

Blundell geothermal power plant near Milford, UT, USA. This 38-MW plant consists of two generating units powered by geothermal steam. Steam is created from water heated by magma at depths up to 6100 meters below Earth's surface. (Courtesy of PacifiCorp.)

LEARNING OBJECTIVES

At the conclusion of this chapter, you should be able to:

1. Briefly explain the history of the electric utility industry;
2. Discuss present and future trends in electric power systems;
3. Describe the restructuring of the electric utility industry;
4. Get up and running with PowerWorld Simulator, a power system analysis and simulation software package.

Electrical engineers are concerned with every step in the process of generation, transmission, distribution, and utilization of electrical energy. The electric utility industry is probably the largest and most complex industry in the world. The electrical engineer who works in that industry encounters challenging problems in designing future power systems to deliver increasing amounts of electrical energy in a safe, clean, and economical manner.

CASE STUDY

The following article describes the impacts that Distributed Energy Resources (DERs) are having on bulk power systems in four of the United States: Hawaii, California, New York, and North Carolina; as well as in South Australia. As DERs continue to grow around the world, the aggregate amount of them is having impacts on bulk power system planning and operation. The power system industry is learning from prior experience and taking actions in anticipation of future DER penetration levels. The article also describes the ongoing efforts of the North American Reliability Corporation, in coordination with its stakeholders, to study the effect of increasing DER penetration on bulk power systems [8].

Transformation of the Grid*

Ryan Quint, Lisa Dangelmaier, Irina Green,
David Edelson, Vijaya Ganugula, Robert Kaneshiro,
James Pigeon, Bill Quaintance, Jenny Riesz,
and Naomi Stringer

DISTRIBUTED ENERGY RESOURCES (DERs) are unlocking new opportunities, and the grid is undergoing a dramatic transformation with unprecedented change. Yet as DERs continue to grow in North America and around the world, it is apparent that the aggregate amount of them is having an impact on bulk power system (BPS) planning and operation. The effects of DERs can be attributed to the uncertainty, variability, and lack of visibility of these resources at the BPS level. From a BPS perspective, the key grid planning impacts generally include the following:

- transmission-distribution coordination and data exchange
- visibility, dispatchability, and controllability
- DER ride-through capability

* Transformation of the Grid, by Ryan Quint et al, © 2019 IEEE. Reprinted, with permission, from *Power & Energy Magazine* (November/December 2019), pp. 35–45.

- impacts to load-shedding programs
- aggregate DER modeling and changing reliability study approaches.

The industry is learning from prior experience and taking actions in anticipation of future DER penetration levels. Waiting for the effect of DERs to manifest before developing solutions may be extremely costly and even risk BPS reliability. However, the proactive development and coordination of requirements can ensure reliable operation of the BPS moving forward. The electric industry needs to address these challenges with innovative solutions earlier rather than later.

Distributed Energy Resource (DER) Impacts on Hawai'i's Grid Operation

The islands of Hawai'i, Oahu, and Maui have among the highest penetration levels of DERs in the United States, in terms of installed capacity relative to system size. Under favorable policies and the right economic circumstances, the rapid deployment of DERs can occur in an extremely short period of time. In only six years, the average distributed solar photovoltaic (D-PVs) contribution to meeting the gross peak daytime demand (net peak plus D-PVs) increased from 12 to 37% on Hawai'i island (see Figure 1). The instantaneous D-PVs penetration can exceed 71% of the daytime demand today, and it provides approximately 11% of the annual energy supply. With increasing DER penetration

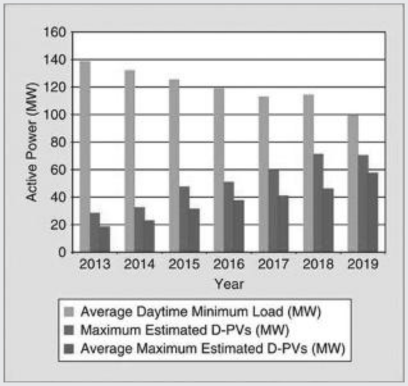


Figure 1 The rapid deployment of D-PVs for the island of Hawai'i.

levels come rapidly rising levels of variability and uncertainty. Hawai'i is now seeing more D-PVs systems with battery energy storage systems (BESSs), and it is anticipating the effect that these combined systems will have on the island grid. Needless to say, the long-term planning studies performed 10 years ago never anticipated such a major change.

The performance requirements needed for high DER penetration levels on the island grids were not initially supported by the requirements in IEEE Standards 1547-2003 and 1547a-2014. Hawai'i's DER interconnection standard (Rule 14 H) eventually deviated from IEEE Standard 1547 to support the continued integration of DERs. However, the new IEEE Standard 1547-2018 includes requirements that are beyond Rule 14 H and under consideration for inclusion in a revised Hawai'i standard. Based on Hawai'i's experience, robust interconnection requirements need to be in place well in advance of high penetration levels to support BPS reliability. It is extremely challenging and expensive to meet changing BPS needs by retroactively enhancing equipment that was installed with minimal performance requirements and capabilities.

For the Hawai'i grid, the following aspects of DER integration are top priorities:

- balancing solar PV variability with flexible energy resources that are capable of fast ramping and cycling and ensuring that regulation resources do not fall below minimum allowable dispatch levels
- managing frequency stability with sufficient frequency-responsive reserves and checking that newly installed DERs have active power-frequency controls enabled to assist the primary frequency response
- improving DER estimation techniques since nearly all DERs are behind-the-meter (BTM), with no visibility or control by the system operator; D-PVs output is estimated using field irradiance measurements provided to the operator via supervisory control and data acquisition
- ensuring effective system restoration with variable DER auto-reconnection and possibly adjusting reconnection criteria (although this will not address situations of high solar PV periods where DER control is necessary)
- studying the adverse impacts of DERs tripping during BPS faults and working with existing DER installations to modify trip settings and improve ride-through capabi-1ity, where possible.

There are also two issues related to frequency stability that are worth highlighting: the use of fast-responding battery energy storage to mitigate legacy DER tripping and the development of an adaptive UFLS program to ensure system security during severe resource-loss events.

Storage to Mitigate DER Loss

Some legacy DERs do not have a robust ride-through capability and, therefore, are subject to aggregate loss during over/under frequency and voltage excursions. The behavior of D-PVs is determined by the standard requirements at the time of interconnection, with different possible aggregate losses during these frequency and voltage excursions. The largest contingency concern for Hawai'i island is the loss of legacy DERs tripping at 60.5 Hz, as a large majority of the existing D-PVs is subject to trip at or near that frequency. The second-largest vulnerability is the loss of DERs during large-voltage excursions. On an island system like Hawai'i's, 60.5 Hz is possible after delayed fault clearing (due to transient swings following fault clearing) and major loss-of-load events, which can occur with transmission outages (both N-1 and N-1-1). The potential aggregate loss of D-PVs during high solar-production periods is roughly double the largest single-generator contingency, resulting in severe underfrequency conditions and the possible risk of system failure.

The loss of D-PVs also exacerbates other loss-of-generation events, with some additional D-PVs loss during the underfrequency situation. To address this concern, a battery energy storage study was conducted to analyze the effect of legacy DER tripping for low voltage during transmission faults, low frequency following generating-unit trips, and high frequency following a transmission line fault. The study found that retrofitting legacy DERs to full ride-through capability was the most effective solution, but that it was too costly and impractical. The study also found the following:

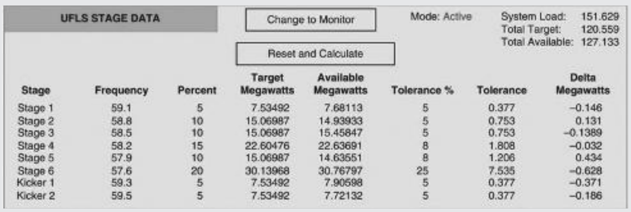
- Storage can replace DER energy lost during transient voltage and frequency conditions, preventing excessive underfrequency protection and reducing the risk of system failure for disturbances during high solar PV production.
- The size of the storage necessary to mitigate reliability issues depends on the number of legacy DERs installed.
- Increased numbers of spinning reserves could reduce the size of the necessary storage but not eliminate the need for it. Increasing reserves also exacerbates excess-energy concerns.

D-PVs protection systems are not consistently implemented, and performing sensitivity studies around the uncertainty of this DER behavior is critical.

Based on the studies, a BESS with 18 MW of capacity and a 30-minute duration was able to arrest frequency excursions and provide sufficient time to bring standby generation online. Increasing the duration to 1 hour enabled the BESS to respond to over-frequency conditions. Studies showed that two BESSs geographically and electrically separated from one another provided the best performance and grid resilience.

Underfrequency Load Shedding

The reliable operation of the Hawai'i island systems heavily relies on underfrequency load shedding (UFLS) that trips distribution circuits at preestablished frequency thresholds. However, as the penetration of DERs rapidly increases, variability in net loading on any given feeder poses significant challenges to the conventional UFLS design, which means that static UFLS arming is no longer effective. An adaptive UFLS program has been implemented to address this variability. Figure 2 is a dashboard of the adaptive program, including six instantaneous stages of UFLS arming between 59.1 and



UFLS STAGE DATA

Change to Monitor

Reset and Calculate

Mode: Active

System Load: 151.629
Total Target: 120.559
Total Available: 127.133

Stage	Frequency	Percent	Target Megawatts	Available Megawatts	Tolerance %	Tolerance	Delta Megawatts
Stage 1	59.1	5	7.53492	7.68113	5	0.377	−0.146
Stage 2	58.8	10	15.06987	14.93933	5	0.753	0.131
Stage 3	58.5	10	15.06987	15.45847	5	0.753	−0.1389
Stage 4	58.2	15	22.60476	22.63691	8	1.808	−0.032
Stage 5	57.9	10	15.06987	14.63551	8	1.206	0.434
Stage 6	57.6	20	30.13968	30.76797	25	7.535	−0.628
Kicker 1	59.3	5	7.53492	7.90598	5	0.377	−0.371
Kicker 2	59.5	5	7.53492	7.72132	5	0.377	−0.186

Figure 2 The adaptive UFLS-arming dashboard.

57.6 Hz and two kicker stages that operate with time delays at 59.3 and 59.5 Hz. The target megawatt value is calculated based on system net loading at the time, and available distribution circuits are automatically armed every 15 minutes to achieve the target net load level. An arming tolerance percentage and value are depicted as well as the difference between the available megawatt arming and the target megawatt value. Stages 1–2 sum to 15% and stages 1–4 sum to 40% of the system net load based on the maximum allowable load shedding for N-1 and N-1-l unit trips, respectively. Each stage operates with an eight-cycle relay time plus breaker operation time. A rate-of-change-of-frequency (ROCOF) load shedding element was also included in stages 1 and 2, with a 0.5-Hz/s set point and nine-cycle relay time plus breaker operation time.

More than 40 substations were modified, including relay and communications upgrades, and 78% of customer circuits (up to 70% of peak load) are participating. The adaptive UFLS program has performed well during N-1 and N-1-1 events at various times of day and is an effective reliability improvement. Figure 3 provides an example of a severe N-1-1 generator-loss disturbance where stages 1–4 operated successfully to arrest the frequency and mitigate a potential large-scale outage.

Rooftop Solar PV Deployment

California has a state mandate that 33% of its annual energy must come from renewable sources by 2020, with a target of 60% by 2030, established by a bill, SB100, that took effect in September 2018. However, on some days, instantaneous output from the renewable sources already exceeds 50% of the total generation output. A large portion of that penetration consists of BTM D-PVs, and the rapid deployment of D-PVs is forcing changes in transmission planning, forecasting, and grid operations at the California Independent System Operator (CAISO).

Figure 4 provides an example of the effect that D-PVs are having

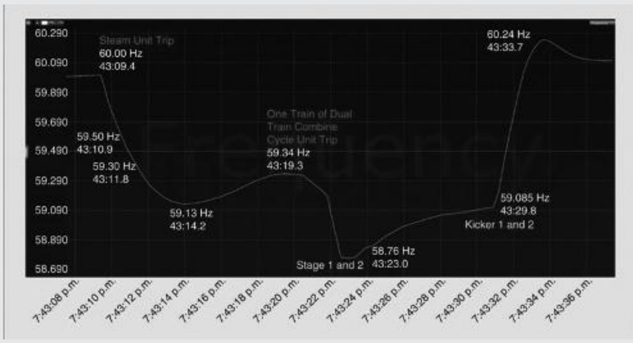


Figure 3 The operation of adaptive UFLS for a multiple-contingency event.

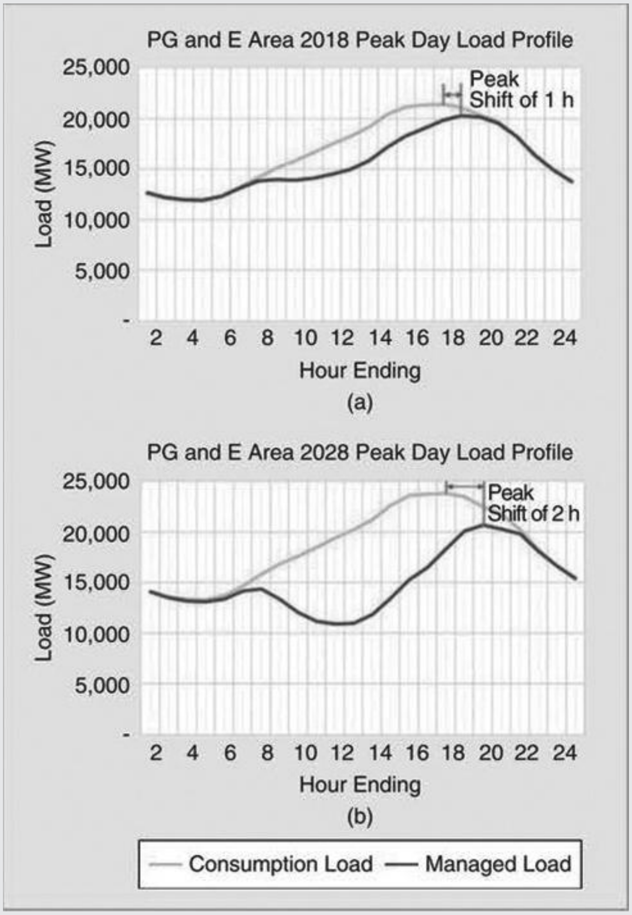


Figure 4 The PG&E net load impacts from DERs.

on the Pacific Gas & Electric (PG&E) net load profile, driving the need for different study times and net load levels from the CAISO's 2018–2019 transmission-planning process. The blue curves show the net load after subtracting the D-PVs' output, which is called the managed load. The figure clearly displays a shift in the peak net load time, which, in many parts of the state, is shifted outside the times when solar PV is available. D-PVs' penetration levels are also causing a drastic change in minimum net load levels, which need to be carefully studied. Sensitivity analysis is also needed to operate through and plan for ramping periods. All these issues are compounded by load modifiers, such as energy efficiency, demand response, time-of-use rates, and electric vehicle charging.

The uncertainty in net load forecasting, including D-PVs, is a concern for BPS reliability studies. The CAISO coordinates its load forecasts with and relies upon long-term forecasts produced by the California Energy Commission (CEC). The CEC's energy-demand forecast includes an hourly estimate of the consumption load and load modifiers to develop the managed outlook by which the transmission system is planned.

Since D-PVs are shifting net peak load periods, the selection of critical study conditions needs to change. Planning standards require an assessment of peak and off-peak conditions; however, with large numbers of DERs, critical system conditions may not occur during either of those periods. This requires even greater numbers of sensitivity studies of varying dispatch and load scenarios, including peak gross load, peak net load (at the transmission-distribution interface), and minimum net load conditions (for example, a spring weekend during off-peak load conditions). Tables 1 and 2 show how DERs were incorporated into the CAISO study scenarios during the 2018–2019 transmission planning process. In addition to these sensitivities, consideration for BPS-connected

	Day/Time			BTM-PV			AAEE			
Scenario	2020	2023	2028	2020	2023	2028	2020	2023	2028	Driver
Summer peak	10 Aug. HE 18	14 Aug. HE 19	14 Aug. HE 19	18%	3%	3%	90%	81%	76%	Hour of maximum managed load
Spring off peak	5 Apr. HE 12	6 Apr. HE 13	16 Apr. HE 13	79%	84%	85%	58%	56%	49%	Hour of minimum managed load
Winter off peak			13 Feb. HE 4			0%			28%	Hour of minimum consumption
Winter peak	15 Oct. HE 19	3 Oct. HE 18	3 Oct. HE 19	0%	1%	0%	77%	76%	72%	Hour of maximum managed load during winter

AAEE: additional achievable energy efficiency; HE: hour ending.

TABLE 1

The baseline scenarios and DER contributions.

Scenario	Starting Baseline Case	BTM-PV		AAEE	
		Baseline	Sensitivity	Baseline	Sensitivity
Summer peak with high CEC forecasted load	2023 summer peak	3%	3%	81%	0%
Off peak with heavy renewable output and minimum gas generation commitment	2023 off peak	84%	99%	56%	56%
Summer peak with heavy renewable output and minimum gas generation commitment	2020 summer peak	18%	99%	81%	81%

TABLE 2

The sensitivity scenarios and DER contributions.

generation dispatch and assumptions for neighboring planning areas is critical as they impact local or wide-area reliability issues. This leads to the need for wider coordination between planning administrators.

With the increasing penetration of DERs, CAISO has explicitly incorporated the forecast resources in power flow and stability studies for the past three planning cycles to account for their unique operational characteristics that are different from the end-use load behavior. This is especially important for stability studies, since the results between DERs netted with load versus modeled ones are significantly different. With a large penetration of DERs in California, study results would be inaccurate if DERs were only netted with load and would lead to erroneous conclusions. Retail-scale BTM DERs are modeled in the power flow and dynamic stability studies as part of a composite load model, and utility-scale DERs are modeled as aggregated generators on the transmission buses. Figure 5 illustrates these impacts on transient voltage response following a simulated BPS fault event. The results are different because modeling the DER characteristics explicitly (including DER tripping of legacy equipment) allows the simulation to differentiate between DERs' response and gross load response. This is critical as penetration levels of DERs increase, although DER prevalence has a study impact in all cases, even at low penetration levels.

CAISO currently uses parameter values for the DER models based on the Western Electricity Coordinating Council and North American Electric Reliability Corporation (NERC) guidelines and performs multiple sensitivity studies

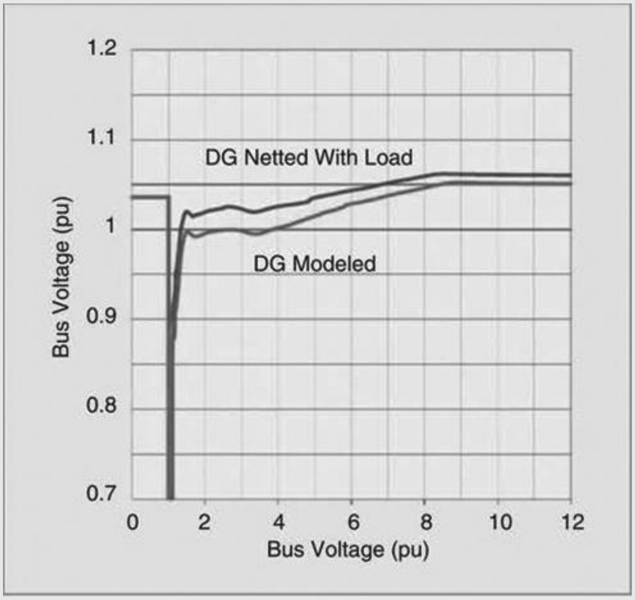


Figure 5 The 230-kV bus voltage close to a three-phase fault, with and without DER modeled. pu: per unit; DG: distributed generation.

to determine the impact that variations in the DER parameters have on BPS performance: The most sensitive parameters DER undervoltage trip settings, the fraction of DERs that recover when voltage returns, and whether DERs provide voltage regulation (and the characteristics of that regulation). Figure 6 illustrates the net load and DER response on a 230-kV bus and the BPS voltage for a three-phase fault close to the BPS bus. The plots show the DERs netted with load as well as two cases of DERs modeled explicitly with different voltage trip settings. One set uses the IEEE Standard 1547-2018 settings, and the other uses California Rule 21 settings. The DERs are on the different feeders and aggregated to the 230-kV bus. System performance differences are dominated by the different responses of the gross load and DERs. Although the difference is not that significant for one bus, the aggregate effect across a large portion of the system has a significant impact on the study results.

New York's DER Management

New York State is on the cusp of a transformation as it expects a significant penetration of DERs. New York's Reforming the Energy Vision and Clean Energy Standard initiatives, combined with efforts to expand transfer capability on the BPS, offer a comprehensive energy strategy to achieve its goal of 50% of its electricity delivered by renewable

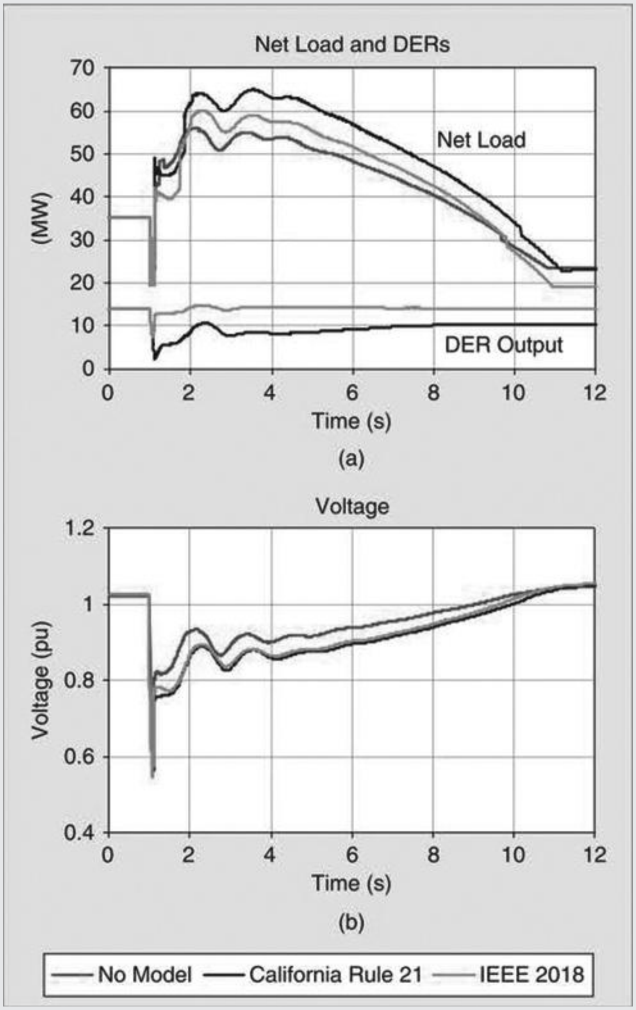


Figure 6 The sensitivities of net load, DER output, and BPS bus voltage to DER modeling settings.

energy sources by 2030. New York has also established a policy to achieve 1,500 MW of energy storage by 2025 and 3,000 MW by 2030.

The New York Independent System Operator (NYISO) expects DERs to play a significant role in achieving the state's goals. Due to the expected growth of DERs in the near future, NYISO is developing market-based mechanisms to integrate DERs into the wholesale electricity markets that it administers. NYISO's DER market design is expected to be implemented in 2021. The proposed design recognizes the unique characteristics of DERs. For example, the market design acknowledges that individual DERs may be small in size yet aggregate to a large capacity and that they can be fast-acting but with a limited capability to deliver energy for long durations. The proposed market design considers DERs that may have the capability to provide services to wholesale markets, retail markets, and end-use customers (see Figure 7).

NYISO's DER integration proposal focuses on enhancing operational coordination among BPS and distribution system operators and on developing market rules that allow DERs to aggregate to provide wholesale market services. Individual DERs that do not have sufficient capability to participate in the wholesale markets can aggregate with other DERs as a larger virtual resource. NYISO is lowering its minimum participation threshold from 1 MW to 100 kW for DERs. Aggregators can enroll many DERs of different technologies at different physical locations (as long as they are behind the same BPS transmission node) and choose to use DERs in the aggregation, or a subset of those DERs, to respond to NYISO market dispatch instructions. DER aggregators can submit offers to provide energy, regulation, operating reserves, and capacity. To determine the least-cost resource dispatch, NYISO will evaluate these offers with those from other BPS supply resources in its multi-interval, security-constrained economic dispatch to co-optimize energy, regulation, and operating reserves. Dispatch instructions from NYISO will be directed to the entire aggregation. DER aggregators will be responsible for

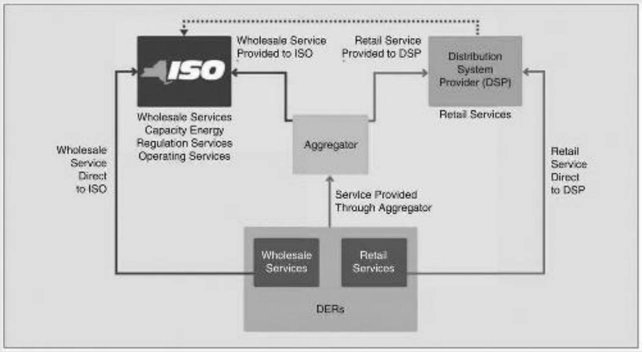


Figure 7 The concept of the NYISO wholesale and retail market designs incorporating DERs.

1. receiving the aggregation-level dispatch instructions from NYISO in real time
2. identifying the dispatch of individual DERs within the aggregation
3. transmitting dispatch instructions to individual DERs
4. collecting responses from individual DERs
5. consolidating the responses to an aggregation level
6. communicating the aggregation-level response back to NYISO with real-time telemetry.

Performance will be measured for the DER aggregation rather than individual DERs. As NYISO encounters transmission constraints, its market dispatch signals can effectively dispatch the aggregation of DERs to address reliability issues at the lowest cost. This approach allows aggregators the flexibility to meet NYISO dispatches using DERs within the aggregation, based on availability, costs, and other factors.

Enhanced operational coordination among the wholesale system operator, distribution system platform (DSP) operator, aggregator, and individual DERs is necessary to ensure the reliability of the transmission and distribution systems. DERs may provide services to the wholesale and retail markets and to end-use customers (see Figure 7). Individual DERs that make up an aggregation may be located on different distribution feeders and have different impacts on each of them. Enhanced coordination ensures that the DSPs have situational awareness of the impacts of NYISO dispatch signals across the transmission-distribution system interface. In the event of conflicts between the transmission and distribution systems' reliability needs, under NYISO's proposed rules, priority will be given to maintaining the transmission system's reliability. DER aggregators must work with the DSPs to meet local reliability criteria and coordinate with NYISO to deliver the expected services.

Enhanced operational coordination starts two days prior to the operating day, when the DSP communicates any potential or expected outages to the DER aggregator. One day prior to the operating day, aggregators use this information to assess the availability of the overall aggregation and submit DER aggregation offers to the NYISO day-ahead market. NYISO will evaluate these offers with those from other BPS suppliers and schedule day-ahead market resources. Aggregators report to the DSP their intended dispatch of individual DERs to meet the NYISO day-ahead market schedule. DSPs can use this information to identify any potential reliability impacts on their systems and communicate any restrictions on individual DER dispatches to the aggregators.

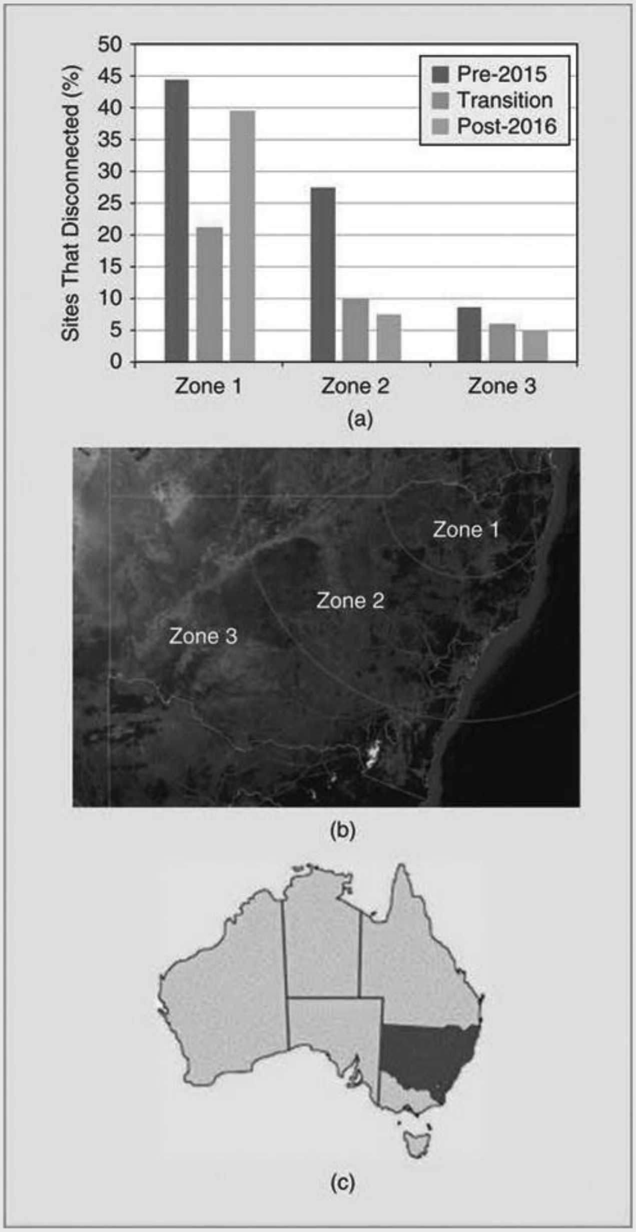


Figure 8 The geographic distribution of the monitored D-PVs sites disconnecting in New South Wales during the 25 August 2018 event.

Ongoing communication will be necessary among the DSPs, DERs, and aggregators after the NYISO day-ahead market is posted, and it will continue in real time to identify and address changes in the distribution system conditions and potential impacts on individual DERs. Aggregators will be required to communicate aggregation-level changes to NYISO so that they are reflected in the real-time dispatch. The DSPs can also request NYISO operations to dispatch DER aggregations to address reliability issues. This enhanced operational coordination framework recognizes the transmission-distribution system interface and allows DERs to effectively provide services to both the BPS and DSP.

Managing DERs in Australia

The installed capacity of DERs, particularly D-PVs, is rapidly growing in Australia's National Electricity Market (NEM), with more than 6,000 MW installed and a projected increase to 10–17 GW by 2030 (with peak demand of roughly 35 GW). The South Australia region of the NEM has been a focus for analyzing D-PVs integration. This region is geographically the approximate size of Texas, yet with a demand of 600–3,000 MW, it has already experienced periods where more than half of its requirement has been supplied by D-PVs. By 2026–2027, the Australian Energy Market Operator (AEMO) predicts that the D-PVs capacity may be high enough to periodically supply the region's entire demand. The region is connected to the rest of the NEM via a single double-circuit ac interconnector, with the expectation that South Australia will continue to operate as an island if it is separated from the rest of the network. This raises challenges and questions about how to successfully operate when the majority of the load is supplied by D-PVs. To explore these challenges, AEMO launched a program to identify and implement the actions required to maintain the security and operability of the system.

One of the key focus areas in the program is understanding and managing the behavior of DERs during grid disturbances. If a large DER capacity disconnects during a disturbance, the loss exacerbates the disturbance and could lead to instability. AEMO has been gathering data on DER responses during grid disturbances and identified the following:

- D-PVs are more prone to tripping during grid disturbances than end-use loads.
- Net demand post-fault is higher than predisturbance levels, indicative of D-PVs disconnection.
- Data from actual grid disturbances in Victoria, South Australia, and New South Wales estimated that as much

as 30–40% of the aggregate D-PYs may disconnect during a disturbance.

- Laboratory inverter testing showed multiple reasons for inverter tripping, including voltage phase jumps greater than 30°, ROCOF levels exceeding 0.4 Hz/s, and an inability to meet the ride-through requirements specified in standard AS/NZ4777.2-2015.
- Laboratory testing also showed sluggish responses for control modes (frequency–watt and volt–watt) that are compliant with the standard but provide little support to the grid.

Those findings highlight a number of potential security risks that the AEMO is trying to address. They also suggest a need to review Australian standards to more explicitly specify required responses.

Collecting suitable data related to D-PVs has been one of the main challenges that AEMO has faced in this program. Feeder-level monitoring captures aggregate DERs and load behavior but does not separate the two. Furthermore, disturbances during high D-PVs output periods are rare (for example, voltage disturbances are often associated with lighting strikes where cloud cover impacts D-PVs' output). AEMO has been working with Solar Analytics, Redfern, Australia, and the University of New South Wales, Sydney, Australia, to develop new techniques to analyze DER responses.

Solar Analytics provided AEMO with 1-minute-resolution data for 5,000 D-PVs systems during a disturbance on 25 August 2018. A fault occurred at the Queensland-New South Wales interconnector, causing a voltage dip across the northern part of New South Wales. Figure 8 shows the D-PVs' responses for systems installed prior to October 2015 (AS/NZ4777.3-2005 compliant), after October 2016 (AS/NZ4777.2-2015 compliant), and during the transition period (which could meet either standard). Nearly 45% of the pre-2015 D-PVs in zone 1 (a 540-km-diameter area) disconnected. Compliance to the newer standard appeared to have improved voltage disturbance ride-through capabilities, especially in zone 2 where the voltage dip was less severe. Future versions of DER standards can build on this improvement in capabilities, minimizing risks to power system security.

D-PVs can also provide valuable grid support. AS/NZ4777.2-2015 specifies that D-PVs should provide over-frequency droop response when frequency exceeds 50.25 Hz, with a linear ramp to zero generation by 52 Hz. This was observed during the August 2018 event, as illustrated in Figure 9. The fault led to the separation of Queensland and South Australia from the rest of the NEM, causing over-frequency in those regions.

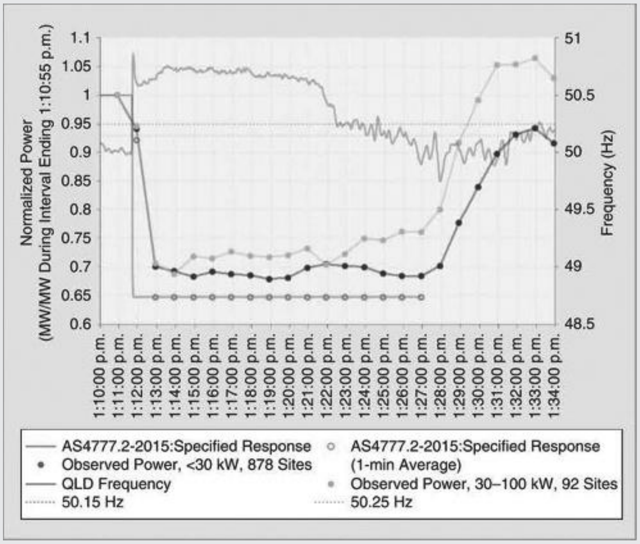


Figure 9 The behavior of post-2016 D-PVs' inverters in Queensland on 25 August 2018.

Many D-PVs systems behaved according to the standard and reduced output to assist with managing frequency. However, more than 15% of the D-PVs in Queensland and more than 30% in South Australia did not behave according to the standard, suggesting issues with compliance.

Those findings demonstrate a range of areas in which the DER standards in Australia need to be reviewed to ensure the reliability of the BPS. The review and implementation of advanced standards should be pursued years in advance of significant DER penetration due to the extensive stakeholder consultation that is required and the need for transition periods for manufacturers to implement new capabilities. Further, dynamic models that represent DER behavior during grid disturbances need to adapt quickly to those changes since these studies are of paramount importance for grid reliability.

The Duke Energy Progress Experience With DERs

Solar PV has grown significantly in North Carolina during the past five years due to government policies, the avoided cost of energy, available land, and falling prices for solar technology. Approximately 3,100 MW of solar PV capacity were connected in North Carolina, as of January 2019, across the Duke Energy North Carolina balancing areas. Roughly 2,300 MW are located in the Duke Energy

Progress (DEP) region, with a winter peak demand of approximately 15,000 MW. About two-thirds of the solar PV capacity is in utility-scale DERs, with the most common DER capacity being 5 MW, due to past incentives. The rest is transmission connected, with sizes ranging from 20 to 80 MW. Very little solar PV is colocated with customer loads in North Carolina. As such, D-PVs in the state are modeled as a stand-alone generating resource at the distribution level. Location is critically important, and some areas of the transmission grid are saturated with generation and need upgrades to accommodate additional generation of any type. DER back-feeding onto the transmission grid is common, but even without it, DERs are having an impact.

Traditionally, utilities have understood and been able to accurately predict the daily and seasonal fluctuations of customer demand. Unplanned generation or transmission outages have long been incorporated into planning and operating practices. The significant growth of solar PV generation has added a new and independent dimension to planning and operating the BPS. Solar output does not follow load and is generally not dispatchable. Figure 10 presents an example of a daily load curve for generation and customer load in a DEP on a mild winter day. The top orange line represents a typical winter customer load shape, with dual peaks in the morning and evening. Generation resources are separated into baseload nuclear, regulating resources such as gas and coal generation, and solar PV. Solar is further split into distribution- and transmission-connected categories. As the figure shows, the customer load is at a minimum when solar generation is at its maximum on a winter day. Regulating resources that need to be online for the peaks have a minimum output represented by the red line and are potentially forced off at midday due to solar PV generation. However, many regulating resources have start-up and shut-down times of hours or days. The only solutions on some days are to sell energy to neighboring balancing areas at a low price, buy peak energy from neighbors at a high cost, and curtail solar PV generation.

Determining the planning conditions for the BPS requires understanding how the grid operates, which, as discussed, has become more complicated. Transmission planners examine the worst realistic conditions; in North Carolina, that has been the summer and winter peak loads and the valley load. With the addition of DERs, new operating hours are becoming the most limiting or worst case. As shown in Figure 10, generation output can vary significantly throughout the day. While the annual minimum customer load may occur at night, light load conditions on a mild Sunday afternoon during spring can closely correlate with the maximum solar PV output, resulting in the minimum net customer load. BPS voltages can be high, and power-flow patterns may occur that have never been observed in operating practice. During summer, while

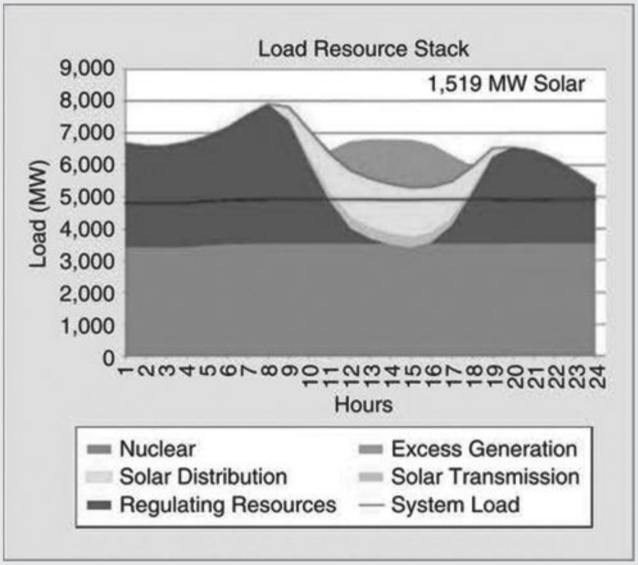


Figure 10 An example of a mild-winter load curve and resource stack in DEP.

the customer load may peak at 5 p.m., high solar PV output earlier in the day may increase flows on the transmission system.

Worst-case conditions can occur during nontraditional planning hours, and DEP is frequently reviewing the actual operating conditions to ensure that planners are focusing on the worst realistic conditions for the BPS. DEP is currently planning for various combinations of customer load and solar output, focusing on the following situations of stressed system conditions:

1. 100% summer peak load, 50% solar output (summer peak hour)
2. 90% summer peak load, 100% solar output (1 p.m. on a summer peak day)
3. 90% summer peak load, 0% solar output (sunset on a summer peak day)
4. 100% winter peak load, 0% solar output (winter peak hour)
5. 35% load, 0% solar output (a mild night during spring)
6. 40% load, 100% solar output (noontime on a mild spring Sunday).

NERC System Planning Impacts of DER Working Group

NERC, in coordination with its stakeholders, has been studying the effect of increasing DER penetration on the BPS. The focus of these efforts is ensuring that the BPS has sufficient essential reliability services: inertial response and stability, frequency control and balancing, and reactive power capability and voltage support. While modern inverter-based resources can be equipped with these capabilities and controls, changes in planning and operating paradigms must occur to utilize those capabilities. A BPS with increasing numbers of inverter-based resources, including DERs, presents new challenges that must be addressed to ensure a reliable grid.

NERC has strengthened its focus on DER impacts on the BPS and formed the System Planning Impacts of DER Working Group (SPIDERWG). This group is developing guidance to address the planning and modeling challenges that come with the increasing penetration of DERs across North America. NERC SPIDERWG membership includes distribution and transmission entities across North America, and the body is focusing on four primary topics: advancing aggregate DER modeling capabilities, verifying DER models and performance, developing study techniques with increasing penetration of DERs, and coordination between industry stakeholders.

Summary

While some may argue that the BPS is becoming obsolete in the face of DERs, others believe that it has never been more critical for the reliable delivery of power to end-use customers. However, we can all agree that the breadth of the DER impact on BPS reliability is immense. For now, we are focused on ride-through capability, evolving modeling and study techniques, changing control strategies and requirements, adjusting market designs, and the impending growth of energy storage. Interconnection standards are rapidly evolving to keep up with the transition from centralized control to truly distributed and decentralized architectures. Requirements for grid connection are more important now than ever before, and engagement from transmission providers and grid operators is essential for maintaining BPS reliability. Proactive improvements to interconnection requirements are imperative since retrofitting legacy DERs is cost prohibitive.

DERs pose one of the biggest evolutions in BPS planning and operation since the inception of polyphase ac power systems more than 130 years ago. Anyone who generates, transfers, controls, delivers, or utilizes electric energy should commit to these reliability efforts as we move toward an integrated energy system. Historically, these resources acted passively and were even required to trip offline during disturbances, but they are becoming a major component of the grid and must actively support it as a whole, including the mitigation of variability impacts and maintaining adequate levels of reliability at a reasonable cost. The successful path forward involves collaboration, communication, and coordination among these groups, breaking down barriers that have existed for many years.

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1.1 HISTORY OF ELECTRIC POWER SYSTEMS

In 1878, Thomas A. Edison began work on the electric light and formulated the concept of a centrally located power station with distributed lighting serving a surrounding area. He perfected his light by October 1879, and the opening of his historic Pearl Street Station in New York City on September 4, 1882 marked the beginning of the electric utility industry (see Figure 1.1). At Pearl Street, dc generators, then called dynamos, were driven by steam engines to supply an initial load of 30 kW for 110-V incandescent lighting to 59 customers in a one-square-mile area. From this beginning in 1882 through 1972, the electric utility industry grew at a remarkable pace—a growth based on continuous reductions in the price of electricity due primarily to technological accomplishment and creative engineering [1].

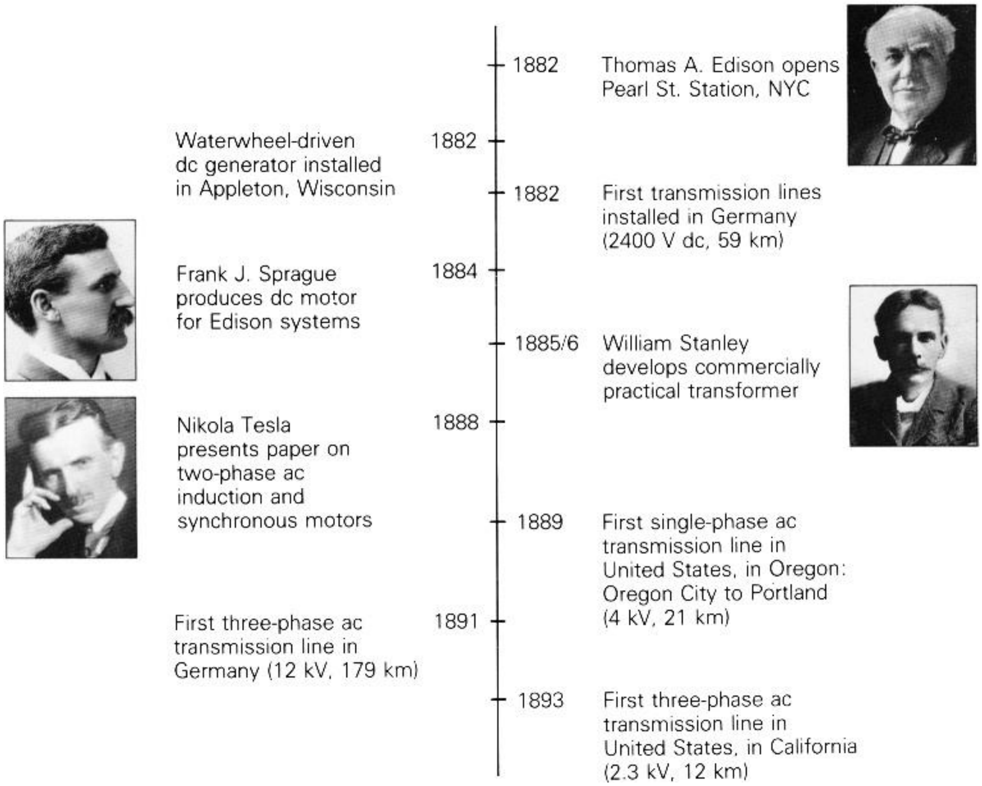

FIGURE 1.1

Milestones of the early electric utility industry [1]. (H.M. Rustebakke et al., *Electric Utility Systems Practice*, 4th Ed. (New York: Wiley, 1983). Reprinted with permission of John Wiley & Sons, Inc. Photos courtesy of Westinghouse Historical Collection.) (Photos courtesy of Westinghouse Historical Collection.)
(Based on H.M. Rustebakke et al., Electric Utility Systems Practice, 4th. Ed. (New York: Wiley, 1983).)

The introduction of the practical dc motor by Sprague Electric, as well as the growth of incandescent lighting, promoted the expansion of Edison's dc systems. The development of three-wire, 220-V dc systems allowed load to increase somewhat, but as transmission distances and loads continued to increase, voltage problems were encountered. These limitations of maximum distance and load were overcome in 1885 by William Stanley's development of a commercially practical transformer. Stanley installed an ac distribution system in Great Barrington, Massachusetts, to supply 150 lamps. With the transformer, the ability to transmit power at high voltage with corresponding lower current and lower line-voltage drops made ac more attractive than dc. The first single-phase ac line in the United States operated in 1889 in Oregon, between Oregon City and Portland—21 km at 4 kV.

The growth of ac systems, further encouraged in 1888 when Nikola Tesla presented a paper at a meeting of the American Institute of Electrical Engineers describing two-phase induction and synchronous motors, made evident the advantages of polyphase versus single-phase systems. The first three-phase line in Germany became operational in 1891, transmitting power 179 km at 12 kV. The first three-phase line in the United States (in California) became operational in 1893, transmitting power 12 km at 2.3 kV. The three-phase induction motor conceived by Tesla went on to become the workhorse of the industry.

In the same year that Edison's steam-driven generators were inaugurated, a waterwheel-driven generator was installed in Appleton, Wisconsin. Since then, most electric energy has been generated in steam-powered and in water-powered (called hydro) turbine plants. Today, steam turbines account for more than 80% of U.S. electric energy generation, whereas hydro turbines account for about 7%. Gas turbines are used in some cases to meet peak loads. Also, the addition of wind turbines and solar cells into the bulk power system is expected to grow considerably in the near future.

Steam plants are fueled primarily by gas, coal, oil, and uranium. From 2012 to 2019, gas and coal exchanged places as the two leading fuels used for electricity production in the United States. Gas increased from 30% in 2012 to 38% in 2019, due to the shale gas revolution in the USA, reduced carbon emissions, and the clean burning feature of gas. Coal, however, decreased from 37% in 2012 to 24% in 2019, due to the retirement of uneconomical coal-fired units and environmental concerns [2].

Starting in the 1990s, the choice of fuel for new power plants in the United States has been natural gas due to its availability and low cost as well as the higher efficiency, lower emissions, shorter construction lead times, safety, and lack of controversy associated with power plants that use natural gas. Natural gas is used to generate electricity by the following processes:

1. Gas combustion turbines use natural gas directly to fire the turbine.
2. Steam turbines burn natural gas to create steam in a boiler, which is then run through the steam turbine.
3. Combined cycle units use a gas combustion turbine by burning natural gas, and the hot exhaust gases from the combustion turbine are used to boil water that operates a steam turbine.

4. Fuel cells powered by natural gas generate electricity using electrochemical reactions by passing streams of natural gas and oxidants over electrodes that are separated by an electrolyte. In 2019, approximately 38% of electricity in the United States was generated from natural gas [2, 3, 7].

In 1957, nuclear units with 90-MW steam-turbine capacity, fueled by uranium, were installed. As of April 2020, there were 440 nuclear reactors in operation in thirty countries with up to 1600-MW steam-turbine capacity. In 2019, approximately 19% of electricity in the United States was generated from uranium via 96 operating nuclear reactors at 58 power plants. However, the growth of nuclear capacity in the United States has been delayed by rising construction costs, licensing delays, and public opinion. Although there are no emissions associated with nuclear power generation, there are safety issues and environmental issues, such as the disposal of used nuclear fuel and the impact of heated cooling-tower water on aquatic habitats. In 2016, Tennessee Valley Authority's (TVA) Unit-2 reactor at the Watts Bar Nuclear Generating Station became the first U.S. reactor to enter commercial operation since 1996. Also in 2013, construction began on the Vogtle Electric Generating Plant Units 3 and 4 in the state of Georgia, with a November 2021 target in-service date for Unit 3. Future technologies for nuclear power are concentrated on safety and environmental issues [2, 3, 7].

Renewable energy sources have the advantage of providing a more sustainable use of finite energy sources with little or no contribution to polluting emissions. Renewable sources include conventional hydroelectric (water power), geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. In 2019, in the United States, approximately 18% of electricity was generated by renewable sources [2, 3]. Germany, which has an official governmental goal to generate 65% of electricity from renewable sources by 2030, achieved 46% in 2019 [13].

Substantial research efforts have shown nuclear fusion energy to be a promising technology for producing safe, pollution-free, and economical electric energy later in the 21st century and beyond. The fuel consumed in a nuclear fusion reaction is deuterium, of which a virtually inexhaustible supply is present in seawater.

The early ac systems operated at various frequencies including 25, 50, 60, and 133 Hz. In 1891, it was proposed that 60 Hz be the standard frequency in the United States. In 1893, 25-Hz systems were introduced with the synchronous converter. However, these systems were used primarily for railroad electrification (and many are now retired) because they had the disadvantage of causing incandescent lights to flicker. In California, the Los Angeles Department of Power and Water operated at 50 Hz but converted to 60 Hz when power from the Hoover Dam became operational in 1937. In 1949, Southern California Edison also converted from 50 to 60 Hz. Today, the two standard frequencies for generation, transmission, and distribution of electric power in the world are 60 Hz (in the United States, Canada, Mexico, and Brazil) and 50 Hz (in Europe, the former Soviet republics, China, South America, except Brazil, and India). In Japan, the western part of the country, including Kyoto, uses 60 Hz, while the eastern part, including Tokyo, uses 50 Hz. The advantage of 60-Hz systems is that generators, motors, and transformers in these systems are generally smaller than 50-Hz equipment with the same ratings. The advantage of 50-Hz systems is that transmission lines and transformers have smaller reactances at 50 Hz than at 60 Hz.

As shown in Figure 1.2, the rate of growth of electric energy generation in the United States was approximately 7% per year from 1902 to 1972. This corresponds to a doubling of electric energy generation every 10 years over the 70-year period. In other words, every 10 years, the industry installed a new electric system equal in energy-producing capacity to the total of what it had built since the industry began. The annual growth rate slowed after the oil embargo of 1973 to 1974. Kilowatt-hour generation in the United States increased by 3.4% per year from 1972 to 1980, and by only 0.7% per year from 2000 to 2011. In 2019, total net U.S. electricity generation was approximately 4.16×10^{12} kilowatt-hours (kWh), about the same as in 2010.

Along with increases in load growth, there have been continuing increases in the size of generating units (Table 1.1). The principal incentive to build larger units has been economy of scale—that is, a reduction in installed cost per kilowatt of capacity for larger units. However, there have also been steady improvements in generation efficiency. For example, in 1934, the average heat rate for steam generation in the U.S. electric industry was 17,950 BTU/kWh, which corresponds to 19% efficiency. By 1991, the average heat rate was 10,367 BTU/kWh, which corresponds to 33% efficiency. These improvements in thermal efficiency due to increases in unit size and in steam temperature and pressure, as well as to the use of steam reheat, have resulted in savings in fuel costs and overall operating costs.

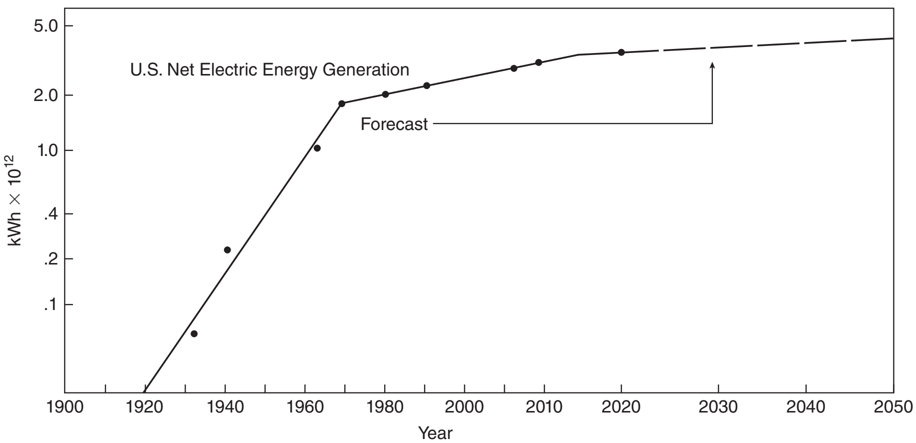

FIGURE 1.2

Growth of U.S. net electric energy generation [3]. (www.eia.gov, U.S. Energy Information Administration, Annual Energy Outlook 2019)

Hydroelectric Generators		Generators Driven by Single-Shaft, 3600 r/min Fossil-Fueled Steam Turbines	
Size (MVA)	Year of Installation	Size (MVA)	Year of Installation
4	1895	5	1914
108	1941	50	1937
158	1966	216	1953
232	1973	506	1963
615	1975	907	1969
718	1978	1120	1974

TABLE 1.1

Growth of generator sizes in the United States [1].

(*Source:* Based on H.M. Rustebakke et al., *Electric Utility Systems Practice*, 4th. Ed. (New York: Wiley, 1983.)

There have been continuing increases, too, in transmission voltages (Table 1.2). From Edison's 220-V three-wire dc grid to 4-kV single-phase and 2.3-kV three-phase transmission, ac transmission voltages in the United States have risen progressively to 150, 230, 345, 500, and now 765 kV. And in 2009, in China, the first 1000-kV ultra-high voltage (UHV) ac transmission line, a 650-km line from Shaanxi Province to Hubei Province, began commercial operation [14]. The incentives for increasing transmission voltages have been: (1) increases in transmission distance and transmission capacity; (2) smaller line-voltage drops; (3) reduced line losses; (4) reduced right-of-way requirements per MW transfer; and (5) lower capital and operating costs of transmission. Today, one 765-kV three-phase line can transmit thousands of megawatts over hundreds of kilometers.

Voltage (kV)	Year of Installation
2.3	1893
44	1897
150	1913
165	1922
230	1923
287	1935
345	1953
500	1965
765	1969

TABLE 1.2

History of increases in three-phase transmission voltages in the United States [1].

(*Source:* Based on H.M. Rustebakke et al., *Electric Utility Systems Practice*, 4th. Ed. (New York: Wiley, 1983.)

The technological developments that have occurred in conjunction with ac transmission, including developments in insulation, protection, and control, are in themselves important. The following examples are noteworthy:

1. The suspension insulator;
2. The high-speed relay system, currently capable of detecting short-circuit currents within one cycle (0.017 s);
3. High-speed, extra-high-voltage (EHV) circuit breakers, capable of interrupting up to 63-kA three-phase, short-circuit currents within two cycles (0.033 s);
4. High-speed reclosure of EHV lines, which enables automatic return to service within a fraction of a second after a fault has been cleared;
5. The EHV surge arrester, which provides protection against transient overvoltages due to lightning strikes and line-switching operations;
6. Power-line carrier, microwave, and fiber optics as communication mechanisms for protecting, controlling, and metering transmission lines;

7. The principle of insulation coordination applied to the design of an entire transmission system;
8. Energy control centers with supervisory control and data acquisition (SCADA) and with automatic generation control (AGC) for centralized computer monitoring and control of generation, transmission, and distribution;
9. Automated distribution features, including advanced metering infrastructure (AMI), reclosers, and remotely controlled sectionalizing switches with fault-indicating capability, along with automated mapping/facilities management (AM/FM) and geographic information systems (GIS) for quick isolation and identification of outages and for rapid restoration of customer services; and
10. Digital relays capable of circuit breaker control, data logging, fault locating, self-checking, fault analysis, remote query, and relay event monitoring/recording.

In 1954, the first modern high-voltage dc (HVDC) transmission line was put into commercial operation in Sweden between Vastervik and the island of Gotland in the Baltic Sea; it operated at 100 kV for a distance of 100 km. The first HVDC line in the United States was the ±400-kV (now ±500-kV), 1360-km Pacific Intertie line, installed between Oregon and California in 1970. As of 2019, 12 HVDC lines up to ±500 kV and 16 back-to-back ac-dc links had been installed in the United States, and a total of 146 HVDC lines up to ±800 kV had been installed worldwide [4]. And in 2019, in China, the first ±1100-kV UHVDC transmission line, a 3293-km line from Changji to Guquan, went into operation [15].

For an HVDC line embedded in an ac system, solid-state converters at both ends of the dc line operate as rectifiers and inverters. Since the cost of an HVDC transmission line is less than that of an ac line with the same capacity, the additional cost of converters for dc transmission is offset when the line is long enough. Studies have shown that overhead HVDC transmission is economical in the United States for transmission distances longer than about 600 km. However, HVDC also has the advantage that it may be the only feasible method to:

1. interconnect two asynchronous networks;
2. utilize long underground or underwater cable circuits;
3. bypass network congestion;
4. reduce fault currents;
5. share utility rights-of-way without degrading reliability; and
6. mitigate environmental concerns [5].

In the United States, electric utilities grew first as isolated systems, with new ones continuously starting up throughout the country. Gradually, however, neighboring electric utilities began to interconnect, to operate in parallel. This improved both reliability and economy. Figure 1.3 shows major 115-kV and higher-voltage, interconnected transmission in the United States. An interconnected system has many

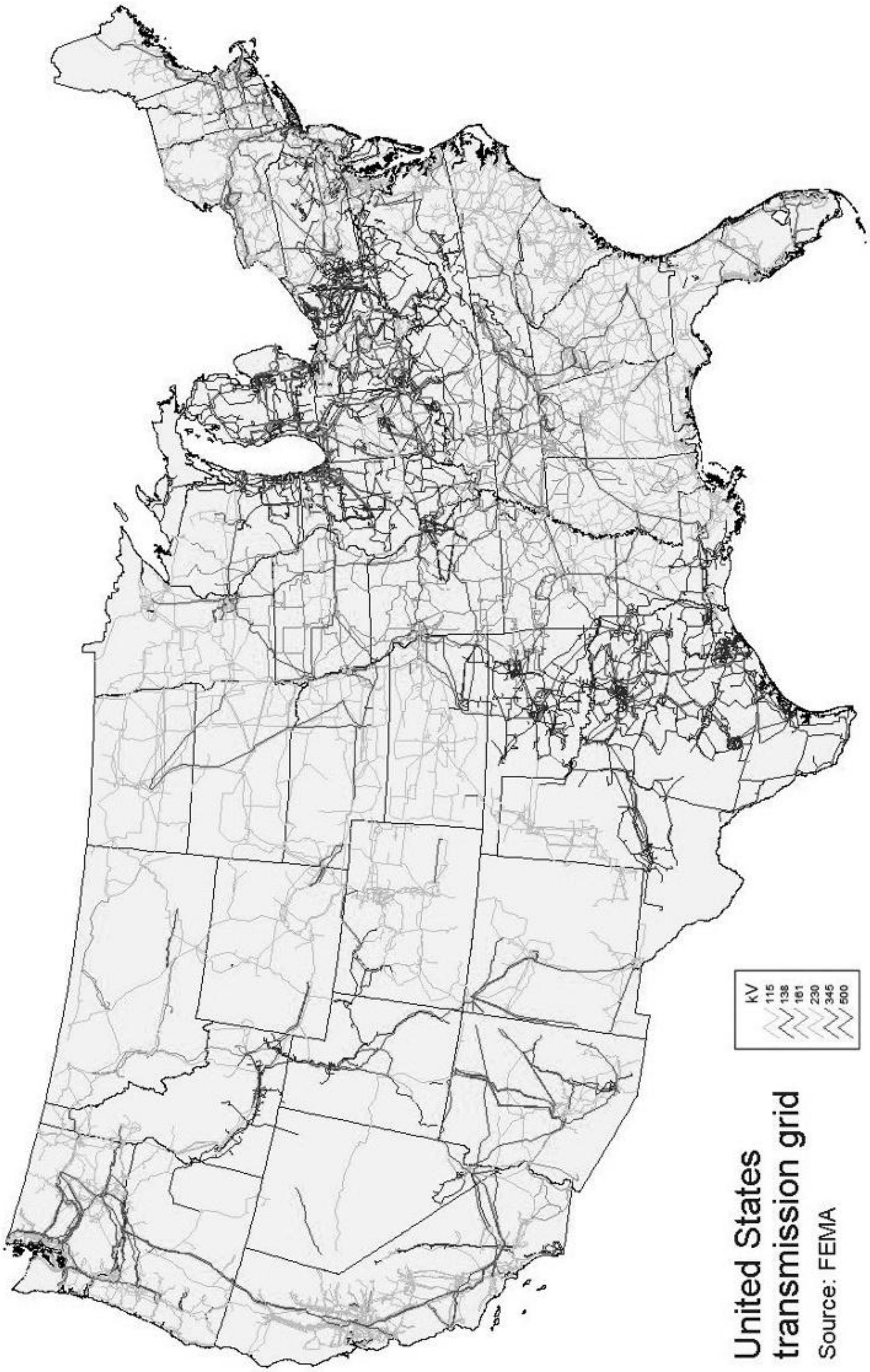

FIGURE 1.3
Major transmission in the United States (FEMA).

advantages. An interconnected utility can draw upon another's rotating generator reserves during a time of need (such as a sudden generator outage or load increase), thereby maintaining continuity of service, increasing reliability, and reducing the total number of generators that need to be kept running under no-load conditions. Also, interconnected utilities can schedule power transfers during normal periods to take advantage of energy-cost differences in respective areas, load diversity, time zone differences, and seasonal conditions. For example, utilities whose generation is primarily hydro can supply low-cost power during high-water periods in spring/summer and can receive power from the interconnection during low-water periods in fall/winter. Interconnections also allow shared ownership of larger, more efficient generating units.

While sharing the benefits of interconnected operation, each utility is obligated to help neighbors who are in trouble, to maintain scheduled intertie transfers during normal periods, and to participate in system frequency regulation.

In addition to the benefits and obligations of interconnected operation, there are disadvantages. Interconnections, for example, have increased fault currents that occur during short circuits, thus requiring the use of circuit breakers with higher interrupting capability. Furthermore, although overall system reliability and economy have improved dramatically through interconnection, there is a remote possibility that an initial disturbance may lead to a regional blackout, such as the one that occurred in August 2003 in the northeastern United States and Canada.

1.2 PRESENT AND FUTURE TRENDS

The electric power industry is making long-term investment and planning decisions and is transforming the energy grid to be responsive to new resources, new technology options, and changing customer expectations. The industry advances economic growth, promotes business development and expansion, provides solid employment opportunities, enhances the quality of life for its users, and powers the world. Today, the United States electric power industry is a robust, $880-billion-plus industry with nearly 500,000 employees. In the United States economy, the industry represents approximately 5% of real gross domestic product (GDP) [6].

As shown in Figure 1.2, the growth rate in the use of electricity in the United States is projected to increase by about 0.7% per year from 2019 to 2030 [3]. Although electricity forecasts for the next eleven years are based on economic and social factors that are subject to change, 0.7% annual growth rate is considered necessary to generate the GDP anticipated over that period. Variations in forecasts of 0.5 to 1.0% annual growth from 2019 to 2030 are based on low-to-high ranges in economic growth. Average end-use price of electricity (2019 cents/kWh) is forecasted to remain flat at 10.4 cents per kilowatt-hour from 2019 to 2030 [2, 3].

Figure 1.4 shows the percentages of various fuels used to meet U.S. electric energy requirements for 2019 and those forecasted for 2030 and 2050. Several trends are apparent in the chart. One trend is that renewables are the fastest-growing source of electricity generation in the United States through 2050 because of