DEVELOPING A FRAMEWORK FOR INTEGRATED ENERGY NETWORK PLANNING (IEN-P)

10 KEY CHALLENGES FOR FUTURE ELECTRIC SYSTEM RESOURCE PLANNING
THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY’S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER’S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

REFERENCE HEREIN TO ANY SPECIFIC COMMERCIAL PRODUCT, PROCESS, OR SERVICE BY ITS TRADE NAME, TRADEMARK, MANUFACTURER, OR OTHERWISE, DOES NOT NECESSARILY CONSTITUTE OR IMPLY ITS ENDORSEMENT, RECOMMENDATION, OR FAVORING BY EPRI.

THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Electric Power Research Institute, EPRI, and TOGETHER... SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

Copyright © 2018 Electric Power Research Institute, Inc. All rights reserved.
ACKNOWLEDGMENTS

This paper describes research sponsored and conducted by EPRI. Staff in EPRI’s Energy and Environment\(^1\) and Power Delivery and Utilization\(^2\) sectors prepared this paper. EPRI’s Technology Innovation (TI) program provided financial support for this effort. The content of this paper and the views expressed in it are solely EPRI’s responsibility, and do not necessarily reflect the views of EPRI members or any other contributor.

**Principal Investigators**
- A. Diamant
- T. Wilson
- D. Brooks

**Contributors**
- A. Tuohy
- E. Ela
- O. Siddiqui
- E. Lannoye
- J. Taylor
- R. Entriken
- J. Boemer
- A. Gaikwad

EPRI would like to express its gratitude to the members of the project Technical Advisory Committee (TAC) who provided advice and guidance as we developed and produced this paper. The TAC is comprised of staff from 22 EPRI member companies that represent investor-owned utilities, generation and transmission cooperatives, publicly-owned utilities, and regional transmission organizations and independent system operators. The TAC members are recognized experts in electric sector generation, transmission, and distribution planning and wholesale power market design.

In addition, we appreciate the valuable insights gained from discussing this material with EPRI’s Advisory Council (comprised of senior external advisors from academia, state public utility commissions, environmental organizations, and financial institutions), EPRI’s Research Advisory Committee (comprised of senior executives and staff from EPRI member companies), and members of EPRI research Program 178: Integrated Energy Planning, Market Analysis and Technology Assessment.

---

1 Include staff from research program on Integrated Energy Planning, Market Analysis and Technology Assessment (178).

2 Include staff from research programs on Transmission Operations (39); Transmission Planning (40); Bulk Power System Integration of Variable Generation (173); Integration of Distributed Energy Resources (174); Understanding Electric Utility Customers (182); and, Distribution System Operations and Planning (200).
This white paper identifies and describes complex and large-scale challenges confronted today by electric power system planners, regulators, and other stakeholders in some regions of the United States and internationally. These challenges are expected to become more widespread in the future. The critical overarching challenge is to develop power system resource plans that will continue to guide investments that provide safe, affordable, reliable, and environmentally responsible electricity supply. These plans also need to be resilient and flexible as well as support the unprecedented pace of change occurring in the production, delivery, and use of electricity—and in the policies that govern energy use.

In particular, the paper describes how traditional electric sector resource planning tools, methods, and processes need to evolve to address key transformations occurring in the electric sector, such as integration of variable renewable (VER) and distributed energy resources (DER); multi-directional power flow; increased reliance on natural-gas-fired generation; increasing customer choice and control; evolution of the electric company regulatory and operating environments; efficient electrification of transport, heat, and other end uses; consideration of broader societal objectives such as environment, security, and sustainability; and growing stakeholder engagement. This white paper identifies key research gaps that need to be closed to address these changes more effectively.

Every region faces different circumstances, opportunities, and challenges as can be observed by the wide variation in planning approaches in use today across the United States and around the world. The importance of particular planning challenges, and the approaches best suited to address these challenges, will vary by region. The ideas communicated here are intended to provide context, understanding, and insights regardless of specific geographic location.

The exploration of these challenges is an outgrowth of the development of EPRI’s Integrated Energy Network (IEN), http://ien.epri.com. Electric companies, regulators, and other stakeholders can take key steps to implement the IEN by addressing the planning challenges described in this paper.

**Keywords**

- Capacity expansion
- Distributed energy resources
- Distribution planning
- Integrated resource planning
- Production cost
- Renewable integration
- Transmission planning
EXECUTIVE SUMMARY

The fundamental goal of electric company resource planning traditionally has been to develop a least-cost portfolio of electric power resources, including both supply-side (that is, generation) and demand-side resources, that can be used to meet expected peak customer electricity demand plus a planning reserve margin within a defined geographic region over a specified planning time period (for example, 5–20+ years). This approach has been used to plan expansion of electric power systems for more than three decades. Although roles and responsibilities for conducting assessments have evolved in some locales as regional electricity markets have emerged (for example, ISOs and RTOs in the United States), the fundamental goal of planning has remained largely unchanged. More than 30 states require electric companies to develop Integrated Resource Plans (IRPs) or similar documents, and many of the remaining states require electric utilities to do some form of resource planning to demonstrate that company investment plans to meet electricity demand are in the public interest.

In recent years, the electric power industry has undergone a dramatic transformation that is expected to continue and accelerate. This transformation is driven by a variety of factors, including rapid deployment of large-scale variable renewable energy resources (VER) and distributed energy resources (DER); dramatic advances in digital energy and communications technologies that spur increasing customer choice and control; persistent low natural gas prices and increased reliance on just-in-time delivery of natural gas to support gas-fired generation (in some regions); increased awareness of potential high-impact, low-frequency (HILF) events that may disrupt electricity service over wide areas; and growing awareness of the electric sector’s potential role in achieving environmental and other broad, societal goals (EPRI describes this future at http://ien.epri.com).

Where some or all of these changes are occurring, traditional resource planning methods may no longer be sufficient to efficiently develop a safe, reliable, affordable, and environmentally responsible power system. A threshold issue is maintaining system reliability. For more than a century, the vast majority of electricity was produced from large rotating machinery, which inherently provided a range of services that kept the overall power system running. As VER and DER displace more traditional synchronous generation—and as customers become more active consumers and producers of energy—planning increasingly will need to explicitly consider the characteristics of supply-side and demand-side options to choose systems that maintain reliability. The focus on reliability will transition from a focus on meeting peak demand to developing a more flexible system that can balance an expanding set of supply and demand resources with continuously changing electricity loads. Another significant change is geographic scope. Renewable resource quality varies widely by region. Given the variation in regional resources and the variability of output, there can be significant economic advantage to analyzing broader geographic areas. In addition, long-term fuel price and energy policy uncertainty, coupled with the needs to reduce environmental impacts and withstand or recover quickly from HILF events, will require new attributes—such as resiliency, flexibility, and sustainability—to be explicitly included in the resource planning processes.

Goals

This EPRI white paper identifies the key resource planning challenges and associated operational issues that increasing-ly could be faced by electric companies in a rapidly evolving future that includes large-scale VER and DER deployment and expanded customer choice. We aim to communicate both the magnitude of these planning challenges and the challenge of developing and implementing new, more holistic approaches to electric resource planning, while recognizing that each locale will have specific options and needs. This paper also identifies resource planning capabilities and processes we believe need to evolve to address these critical planning challenges. Finally, we have identified key research gaps to be addressed to develop a new Integrated Energy Network Planning (IEN-P) Framework.
**Audience**

This paper can inform electric system planners, state public utility commission (PUC) and related regulatory staff, and others interested in the future evolution of the electric sector and related infrastructure. Although the United States is the primary geographic focus of this paper, the challenges described should be relevant and valuable to international audiences.

**10 Key Resource Planning Challenges**

This white paper highlights 10 complex, large-scale challenges electric power system planners and regulators are beginning to confront today and that are expected to become more pressing and widespread. It describes the ways in which traditional electric sector resource planning will need to evolve so that electric companies, regulators, and other stakeholders can effectively address these emerging challenges and benefit from new opportunities arising from the ongoing transformation of the electric sector. It describes needs for new methodologies and functionality, new planning processes, and organizational changes that may be needed to continue to develop robust plans that provide safe, reliable, environmentally responsible, and affordable electric service that also is resilient and flexible.

The 10 critical resource planning challenges are interrelated and can be introduced and grouped in various ways. They are organized for clarity of communication into three groups: 1) modeling the changing power system, 2) integrating forecasts, and 3) expanding planning boundaries. The specific order of the challenges shown next and described in this report does not imply relative importance. System planning is inherently a local activity. The key challenges planners face today—and may face in the future—certainly will vary by geographic region and jurisdiction. Not all of these challenges will need to be addressed immediately or simultaneously. The specific challenges, and the approaches and timing with which to address them, will depend on the specific issues faced by each electric company and jurisdiction.

- **Modeling the changing power system:**
  1. **Incorporating operational detail.** As emerging power system resources (primarily solar and wind) replace synchronous generators (for example, coal, natural gas, and nuclear) that traditionally have provided needed operational reliability services, resource planners will need to explicitly consider operational reliability capabilities of candidate resources and methods to mitigate potential impacts.
  2. **Increasing modeling granularity.** Computer models for conducting long-range resource planning need to include finer geographic resolution and temporal granularity to address new resource planning challenges.
  3. **Integrating generation, transmission, and distribution planning.** Future resource planning will benefit from closer interaction of planners across the entire electricity supply chain to understand how decisions at one planning level may impact other levels as well as the ability to make trade-offs between potential investments in each of these subsystems to optimize the future overall electric power system. Closer integration—driven by value—reverses the recent trend to separate generation, transmission, and distribution planning to promote a competitive environment.
  4. **Expanding analysis boundaries and interfaces.** Electric companies are beginning to be asked by regulators and external stakeholders to address issues outside of their electric service territories and in other parts of the economy as part of their resource planning activities. Efficient electrification of end-use sectors—such as transportation, in which electricity historically has played little role—will further expand these boundaries.
  5. **Addressing uncertainty and managing risk.** There is a growing need for resource planners to account more explicitly for key uncertainties when developing resource plans and to adopt new approaches for managing evolving corporate risks.
Integrating forecasts:

6. **Improving forecasting.** Improved and more granular forecasting is critical for robust long-term resource planning. More accurate forecasts of electric load, VER production, DER adoption, future natural gas prices, and weather are high priorities.

7. **Improving modeling of customer behavior and interaction.** Robust system planning in the future will need to incorporate deeper understanding of electric customer behavior, incentives to change customer behavior, and how customer behavior may impact the performance of emerging customer resources for energy supply, storage, and demand.

Expanding planning boundaries:

8. **Incorporating new planning objectives and constraints.** Future resource plans will need to be optimized to achieve objectives beyond traditional least-cost resource adequacy—including resiliency, flexibility, and new environmental and societal objectives—while adhering to system operational reliability constraints.

9. **Integrating wholesale power markets.** Increasingly, planners will need to consider the evolution of wholesale power markets that provide opportunities for companies to buy and sell energy, capacity, and ancillary services along with the impact of these markets on the economic viability of resources that provide reliability services and other desired system attributes.

10. **Supporting expanded stakeholder engagement.** In recent years, public involvement in company resource planning has increased dramatically. Electric utilities are engaged now more than ever in designing extensive stakeholder engagement processes related to resource planning and responding to stakeholder comments.

**Value of This Paper**

This paper and the future IEN-P Framework can provide value to electric companies, state regulators, and other entities engaged in planning the future evolution of the electric sector. It communicates the drivers and strong needs for increased communication and coordination along the electricity supply chain and among the multiple industries that are becoming more interdependent with the electric sector every day.

For electric companies, this paper provides a common vision for the multiple internal company planning groups that often operate independently and may not routinely communicate and coordinate their activities. It identifies key resource planning challenges to focus future corporate action and resource planning efforts, and it can be used to identify and prioritize future internal and external research and development (R&D) efforts. Although Integrated Resource Planning (IRP) has been done by regulated electric utilities for many years, we envision the future planning paradigm discussed here to be of value to regulated and unregulated electric companies alike as they address their future planning needs. Company leadership and staff can use it to frame key resource planning issues when communicating with internal company stakeholders, state regulators, and other external stakeholders.

For regulators, this paper can provide a more comprehensive understanding of the key planning challenges facing electric company resource planners and company leaders. It can be used to identify and prioritize future R&D efforts and to communicate the challenges facing electric system planners with external stakeholders.

**Learning and EPRI Engagement Opportunities**

Many companies and researchers are beginning to grapple with these challenges. Some efforts are documented publicly in IRPs, some are in the peer-reviewed scientific literature, and many are in development.
Many parts of EPRI are making progress in addressing the 10 key challenges. Research to address the planning challenges described in this paper is being conducted in individual EPRI programmatic research areas (typically, research focused on particular types of assets or functions within utilities), including the following:

- Electric Transportation (Program 18)
- Transmission Operations (Program 39)
- Transmission Planning (Program 40)
- Flexible (Nuclear) Operations (Program 41.11.01)
- Water Availability and Ecological Risk (Program 55)
- Fossil Fleet for Tomorrow (Program 66)
- Energy Storage and Distributed Generation (Program 94)
- End-Use Energy Efficiency and Demand Response (Program 170)
- Bulk System Integration of Variable Renewable Resources (Program 173)
- Integration of Distributed Energy Resources (Program 174)
- Integrated Energy Planning, Market Analysis, and Technology Assessment (Program 178)
- Understanding Electric Utility Customers (Program 182)
- Renewable Generation (Program 193)
- Strategic Sustainability Science (Program 198)
- Electrification for Customer Productivity (Program 199)
- Distribution System Operations and Planning (Program 200)
- Energy, Environmental, and Climate Analysis (Program 201)

In addition, EPRI’s Technology Innovation (TI) program has several cross-cutting research efforts underway that aim to integrate across company and EPRI program areas, ranging from modeling- and process-focused efforts to link generation, transmission, and distribution planning; efforts to incorporate operational detail in longer term planning; and research to broaden the scope of planning.

Readers who may be interested in engaging with EPRI to address these issues should connect with an appropriate research program listed previously and in Appendix A or contact one of the authors of this report. Also, you can learn more online about EPRI’s [Annual Research Program](#). The challenges facing planners today are unparalleled—but equally so are the potential value and opportunities associated with conducting resource planning in a more integrated manner as described in this paper.
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AI</td>
<td>artificial intelligence</td>
</tr>
<tr>
<td>A/S</td>
<td>ancillary services</td>
</tr>
<tr>
<td>BES</td>
<td>bulk energy system</td>
</tr>
<tr>
<td>BTM</td>
<td>behind-the-meter</td>
</tr>
<tr>
<td>CAISO</td>
<td>California Independent System Operator</td>
</tr>
<tr>
<td>CCA</td>
<td>community choice aggregation</td>
</tr>
<tr>
<td>CCS</td>
<td>carbon capture and storage</td>
</tr>
<tr>
<td>CEC</td>
<td>California Energy Commission</td>
</tr>
<tr>
<td>CPCN</td>
<td>certificate of public convenience and necessity</td>
</tr>
<tr>
<td>CPP</td>
<td>Clean Power Plan</td>
</tr>
<tr>
<td>CPUC</td>
<td>California Public Utilities Commission</td>
</tr>
<tr>
<td>CSP</td>
<td>concentrating solar power</td>
</tr>
<tr>
<td>DCE</td>
<td>discrete choice experimentation</td>
</tr>
<tr>
<td>DER</td>
<td>distributed energy resources</td>
</tr>
<tr>
<td>DG</td>
<td>distributed generation</td>
</tr>
<tr>
<td>DG PV</td>
<td>distributed generation solar photovoltaic</td>
</tr>
<tr>
<td>DOE</td>
<td>United States Department of Energy</td>
</tr>
<tr>
<td>DR</td>
<td>demand response</td>
</tr>
<tr>
<td>DSM</td>
<td>demand-side management</td>
</tr>
<tr>
<td>DSPP</td>
<td>Distribution System Platform Provider</td>
</tr>
<tr>
<td>DSO</td>
<td>distribution system operator</td>
</tr>
<tr>
<td>EE</td>
<td>energy efficiency</td>
</tr>
<tr>
<td>EGU</td>
<td>electric generating unit</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Electric Reliability Council of Texas</td>
</tr>
<tr>
<td>ERS</td>
<td>essential reliability services</td>
</tr>
<tr>
<td>EU</td>
<td>European Union</td>
</tr>
<tr>
<td>FACTS</td>
<td>flexible alternating current transmission system</td>
</tr>
<tr>
<td>GHG</td>
<td>greenhouse gas</td>
</tr>
<tr>
<td>GT&amp;D</td>
<td>generation, transmission, and distribution</td>
</tr>
<tr>
<td>HEC</td>
<td>Hawaiian Electric Companies</td>
</tr>
<tr>
<td>HILF</td>
<td>high-impact, low-frequency events</td>
</tr>
<tr>
<td>HPUC</td>
<td>Hawaii Public Utilities Commission</td>
</tr>
<tr>
<td>HVDC</td>
<td>high-voltage direct current</td>
</tr>
<tr>
<td>IEN-P</td>
<td>Integrated Energy Network Planning</td>
</tr>
<tr>
<td>IOU</td>
<td>investor-owned utility</td>
</tr>
<tr>
<td>IRP</td>
<td>Integrated Resource Planning</td>
</tr>
</tbody>
</table>
ISO  independent system operator
LDC  local (natural gas) distribution company
LOLE  loss of load expectation
LOLH  loss of load hours
LOLP  loss of load probability
LSE  load serving entity
MISO  Midcontinent Independent System Operator
MW  Megawatt
MWh  megawatt-hour
NEM  net energy metering
NGCC  natural-gas combined-cycle
NGCT  natural-gas combustion-turbine
NGO  nongovernmental organization
NSPS  new source performance standard
OTC  once-through cooling
PEV  plug-in electric vehicle
PG&E  Pacific Gas and Electric Company
POU  publicly owned utility
PPA  power purchase agreement
PRM  planning reserve margin
PSIP  Power Supply Improvement Plan
PURPA  Public Utility Regulatory Policies Act
PV  Photovoltaic
PVRR  present value revenue requirement
REV  New York’s Reforming the Energy Vision initiative
RPS  renewable portfolio standards
RP  resource planning
RTO  regional transmission organization
TOU  time-of-use
TVA  Tennessee Valley Authority
UNFCCC  United Nations Framework Convention on Climate Change
WEUIP  water and electricity utility integrated planning
VER  variable (renewable) energy resources
VOLL  value of lost load
# TABLE OF CONTENTS

Abstract ........................................................................................................................................................................... 5
Executive Summary ......................................................................................................................................................... 7
Acronyms ...................................................................................................................................................................... 11
Section 1: Introduction .................................................................................................................................................. 17
Section 2: Electric System Resource Planning ........................................................................................................... 19
   Traditional Resource Planning goals .......................................................................................................................... 19
   History and Evolution .................................................................................................................................................. 20
   Contexts and Approaches ......................................................................................................................................... 22
   Resource Planning in the International Context ....................................................................................................... 22
   Resource Planning Process ....................................................................................................................................... 22
   Analytic Methods and Tools .................................................................................................................................... 23
Section 3: Drivers of Change ....................................................................................................................................... 25
   Rapid Ongoing Transformation of the Electric Sector ............................................................................................... 25
      Declining Cost of Utility-Scale Renewables and Battery Storage Combined with Policy Incentives .......... 25
      Low-Cost Natural Gas Generation ......................................................................................................................... 26
      New Environmental Regulations ........................................................................................................................... 26
      Integrated Grid and Growing Deployment of DER ............................................................................................. 27
      Changing Net Load Shapes .................................................................................................................................... 28
      Changing Customer Behavior ............................................................................................................................... 28
   Regional U.S. Policy Drivers and Societal Preferences ............................................................................................ 29
      California ............................................................................................................................................................... 29
      Hawaii .................................................................................................................................................................... 30
      New York ............................................................................................................................................................ 30
   International Experience .......................................................................................................................................... 31
      European Union .................................................................................................................................................... 31
      Germany ............................................................................................................................................................... 32
      Australia ............................................................................................................................................................... 32
Section 4: Key Resource Planning Challenges ............................................................................................................ 35
   Modeling the Changing Power System ..................................................................................................................... 35
      Challenge #1 — Incorporating Operational Detail ................................................................................................. 36
      Challenge #2 — Increasing Modeling Granularity ................................................................................................. 37
      Challenge #3 — Integrating Generation, Transmission, and Distribution Planning ........................................... 39
      Challenge #4 — Expanding Analysis Boundaries and Interfaces ......................................................................... 42
      Challenge #5 — Addressing Uncertainty and Managing Risk ............................................................................... 45
   Integrating Forecasts into Resource Planning Analyses .......................................................................................... 48
Challenge #6 — Improving Forecasting ................................................................. 48
Challenge #7 — Improving Modeling of Customer Behavior and Interaction .......... 49
Expanding Planning Boundaries ........................................................................... 51
Challenge #8 — Incorporating New Planning Objectives and Constraints ............. 51
Challenge #9 — Integrating Wholesale Power Markets ........................................ 55
Challenge #10 — Supporting Expanded Stakeholder Engagement ....................... 56
Section 5: Conclusions and Actions to Implement the IEN-P .................................. 59
Selected EPRI Research Activities to Address IEN-P Challenges ......................... 59
Next Steps for the IEN-P .................................................................................... 61
Appendix A: Selected EPRI Research Programs Addressing IEN-P Challenges .......... 63
Program 18: Electric Transportation ...................................................................... 63
Program 39: Transmission Operations ................................................................... 63
Program 40: Transmission Planning ...................................................................... 63
Program 41.11.01: Flexible (Nuclear) Operations .................................................. 63
Program 55: Water Availability and Ecological Risk .............................................. 63
Program 66: Fossil Fleet for Tomorrow .................................................................. 64
Program 94: Energy Storage and Distributed Generation ..................................... 64
Program 170: End-Use Energy Efficiency and Demand Response ....................... 64
Program 173: Bulk Power System Integration of Variable Generation .................. 64
Program 174: Integration of Distributed Energy Resources .................................. 64
Program 178: Integrated Energy Planning, Market Analysis, and Technology Assessment ............................................................................................................. 65
Program 182: Understanding Electric Utility Customers ....................................... 65
Program 193: Renewable Generation .................................................................... 65
Program 198: Strategic Sustainability Science ...................................................... 65
Program 199: Electrification for Customer Productivity ........................................ 65
Program 200: Distribution Operations and Planning ............................................. 66
Program 201: Energy, Environmental, and Climate Policy Analysis ..................... 66
Appendix B: EPRI Analytic Tools Related to the IEN-P Challenges ......................... 67
Distributed Resource Integration and Value Estimation Tool (DRIVE) ............... 67
Electric Generation Expansion Analysis System (EGEAS) .................................. 67
InFLEXion Software ........................................................................................... 68
Scenario Builder Tool ......................................................................................... 68
TAGWeb™ Software – Technology Cost and Performance Data .......................... 68
Transmission Hosting Capacity Tool (THCT) ....................................................... 68
United States Regional Greenhouse Gas and Energy Model (US-REGEN) ............ 68
Appendix C: References .................................................................................... 71
LIST OF FIGURES
Figure 1. States That Required Integrated Resources Planning as of 2015 ................................................................. 21
Figure 2. Activities Involved in Integrated Resource Planning .......................................................................................... 24
Figure 3. U.S. Net Electricity Generation from Select Fuels (billion kilowatt hours) ............................................................ 36
Figure 4. Wind and Solar Generation Can Increase Power System Flexibility Needs .......................................................... 38
Figure 5. PJM Jan 7, 2014 Forced Outages. ................................................................................................................... 43
Figure 6. Winter to Summer Peak Ratio for the TVA Power System. .................................................................................. 46

LIST OF TABLES
Table 1. Key Steps in Integrated Resource Planning ...................................................................................................... 23
Table 2. 10 Key IEN Planning Challenges ................................................................................................................... 35
Table 3. Addressing Uncertain Variables in System Planning .......................................................................................... 47
Table 4. Selected EPRI Annual Research and Development Programs Related to the IEN-P Challenges .......................... 60
Table 5. Selected 2018 EPRI Technology Innovation and Demonstration Projects Focused on the IEN-P Challenges ...... 62
EPRI launched this Technology Innovation (TI) project to identify and describe the complex, large-scale challenges electric power system planners and regulators are beginning to confront today, and which are expected to become even more pressing in the future. The exploration of the critical planning challenges described in this paper is an outgrowth of EPRI’s development of the Integrated Energy Network (IEN).³

This white paper describes EPRI’s view of how traditional electric resource planning tools, methods, processes, metrics, and approaches need to evolve so electric companies⁴, ISO and RTOs, regulators, and other stakeholders can address these key challenges, and continue to develop robust plans that provide safe, reliable, environmentally responsible, and affordable electric service which is resilient and flexible. These entities can begin to implement the IEN by addressing the challenges described here.

The resource planning challenges described here also reflect findings from a 2017 EPRI project that reviewed long-term resource plans published by 15 electric companies. The purpose of that project was to learn how electric system planners have tried to address a set of specific issues in resource planning. The 15 resource plans selected for that study represented a cross-section of companies operating in the electric sector today, and included diverse geographic locations, ownership types, and market operating environments [1].

We envision future development of a new Framework for Integrated Energy Network Planning (IEN-P) that augments traditional approaches and methods that have been used for decades to conduct Integrated Resource Planning (IRP) and other related resource planning analyses.

This paper is organized as follows:

- Section 2 provides an overview of the historic evolution of electric sector resource planning.
- Section 3 describes the drivers of change causing the transformation of the electricity business we are beginning to experience today.
- Section 4 summarizes 10 critical large-scale resource planning challenges that need to be addressed to develop a new, more holistic Framework for Integrated Energy Network Planning.
- Section 5 highlights key insights and EPRI’s ongoing and planned research and development activities to begin to address the challenges described in this paper.
- Appendix A identifies and describes selected EPRI research programs working to address the IEN-P challenges described in this paper.
- Appendix B briefly describes EPRI software tools that can be used to address some of the planning challenges described in this paper.

³ Learn more about EPRI’s Integrated Energy Network (IEN) online at http://ien.epri.com.
⁴ We use the term “electric companies” in this paper to refer to the broad range of entities engaged in generation, transmission and distribution of electric power, including investor-owned utilities, electric cooperatives, municipal utilities, public power agencies, independent power providers, and “wires only” electric transmission and distribution companies. This term does not refer to regional transmission organizations (RTOs) or independent system operators (ISOs).
This section describes the historic context, evolution and current status of electric sector system planning.

Traditional Resource Planning Goals

The fundamental goal of electric company resource planning has been to develop a least-cost portfolio\(^5\) of electric power resources, including both supply-side (i.e., generation) and demand-side resources, that can be used to reliably meet expected peak customer electricity demand plus a planning reserve margin within a defined geographic region over a specified planning time period (e.g., 5-20+ years). This approach has been used to plan expansion of electric power systems for more than three decades.

Integrated Resource Planning (IRP)

The term Integrated Resource Planning for an electric utility was defined in the Energy Policy Act of 1992 to mean “…a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost.”

“…The process shall take into account necessary features for system operation, such as diversity, reliability, dispatch ability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.”

Resource planning is focused on achieving a level of resource adequacy to meet specific physical reliability standards for the high voltage, bulk energy system (BES)\(^6\). The dominant standard in North America—a loss-of-load expectation (LOLE) of “1-in-10-years”—has been used since the 1940s, and became the centerpiece of resource planning [1]. Electric utilities and regulators typically have translated these reliability standards into an equivalent planning reserve margin (e.g., a 15% reserve margin), or the percentage by which the total generating capacity needs to exceed the annual peak load to maintain a given LOLE target [2].

The North American Electric Reliability Corporation (NERC) has developed the NERC Functional Model\(^8\) that defines functions and functional entities that together ensure the safe and reliable operation of BES throughout most of North America. Together with the NERC Glossary\(^9\) and a host of planning standards\(^10\) tied to the BES planning functions, this model defines the goals that electric company planners seek to achieve. NERC does not enforce resource adequacy standards, but rather provides guidance that is used by companies and state public utilities commissions.

---

\(^5\) “Least cost” in the resource planning context typically refers to the resource portfolio that has the lowest overall capital cost plus production cost measured on a present value basis. Production costs typically include operations and maintenance (O&M), fuel costs, emissions costs and any other costs associated with achieving a given level of resource adequacy. Least cost does not necessarily mean the least cost of power to the end-use consumer or the lowest electric rate.

\(^6\) These reliability standards are defined by NERC, a non-profit international regulatory authority whose mission is to assure the reliability and security of the BES in North America. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people. See www.NERC.com.

\(^7\) The interpretation of “1-in-10 years” varies widely across North America. In some cases it is interpreted as 1 event in 10 years (0.1 events per year), and in other cases it is interpreted as equal to 1 day in 10 years (or 2.4 hours per year).


\(^10\) NERC Standards online at http://www.nerc.com/pa/Stand/Pages/Default.aspx.
The emphasis on least-cost planning requires company planners and regulators to develop a portfolio of existing and new generation assets and demand-side programs that can minimize short- and long-run costs in the face of uncertainty about the cost and performance of different potential generation, delivery, and control technologies, fuel prices, future regulations, and other key variables. Integrated Resource Planning (IRP) predominately is focused on assuring that sufficient supply and demand-side resources are available, and typically is done by company staff with specialized expertise in resource planning.

Transmission system planning usually is done by a different group within a vertically integrated electric company. Transmission planners use data and information provided by resource planners to develop potential transmission plans to address different scenarios for the potential buildout of the generation system. Often, more complex reliability analyses are completed to identify the most robust transmission plan to implement. In regions where the transmission grid is managed by regional transmission organizations (RTOs) or independent system operators (ISOs), transmission planning typically is done by the RTO or ISO as part of a stakeholder process that includes the member electric companies.

Distribution system planning typically is done by a third distinct group within electric companies, and the interaction among these three groups traditionally has been limited. Transmission planners typically inform distribution system planners about the range of power factors and voltage the distribution planners can expect on the higher voltage side of the distribution substation transformer. Transmission planners also analyze local load growth scenarios to verify them. This relationship is described in a standard transmission connection agreement, which is evolving as the role of the distribution-level resources changes and becomes more significant.

**History and Evolution**

As of 2015, more than 30 states required electric utilities to do some form of resource planning to demonstrate company investment plans to meet electricity demand in the public interest. Figure 1 highlights these states. In addition, in many states companies must seek power plant investment preapprovals by obtaining a Certificate of Public Convenience and Necessity (CPCN).

Current resource planning practices are rooted in the 1970s. In that era, rapid load growth coupled with concerns over rising costs, reliability, and environmental protection led to development of least-cost planning processes, with a goal of minimizing the total costs of an electric utility’s power generation resource portfolio, subject to reliability and emissions constraints. Growing regulatory, cost and demand uncertainties contributed to development of IRP in the 1980s.

Electric system resource planning has undergone three important changes since the 1980s. First, the passage in 1978 of the Public Utility Regulatory Policies Act (PURPA) and the Energy Policy Act (EPAct) in 1992 formalized and standardized IRP. In response to PURPA, individual states developed formal electricity resource planning processes, and began to require electric utilities to conduct resource planning under state oversight. The EPAct codified and standardized the evolving planning processes under federal law. By the early 1990s, all but nine states had some variant of an IRP process in place.

Second, the introduction of regional wholesale power markets in California, the Northeast, the Midwest, and Texas shifted responsibility for key aspects of resource planning. Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) that operate regional transmission grids, and manage regional wholesale power markets now have some planning responsibilities that previously were solely the responsibility of electric companies, particularly related to resource adequacy and transmission planning. FERC Orders 890 and 1000 mandated regional transmission planning requirements which typically are implemented by the RTOs/ISOs in regions where they operate.

---

11 These planning requirements typically fall into one of four categories: (i) IRPs; (ii) Plans submitted to obtain discrete approval for specific power generation or demand response resources; (iii) Plans associated with providing default electric service in competitive states; and (iv) Long-term asset procurement planning.

12 “Least-cost planning” refers here broadly to any planning process designed to minimize costs subject to a set of constraints, rather than more narrowly to formal integrated resource planning.

13 “Utility” here refers to any entity that acquires electricity resources to serve end-use customers.

14 The Public Utility Regulatory Policies Act (PURPA, Public Law 95–617, 92 Stat. 3117, enacted November 9, 1978) was passed by Congress as part of the National Energy Act. This federal law was envisioned to promote energy conservation and greater use of domestic energy and renewable energy sources.

Figure 1. States That Required Integrated Resources Planning as of 2015\textsuperscript{6}


\textsuperscript{6}We have highlighted TN in Figure 1 because the 1992 Energy Policy Act requires the Tennessee Valley Authority (TVA) to prepare IRPs, and TVA is responsible for delivering electric service to most consumers and regions in the state. California and Florida have been added to the original version of Figure 1. With passage of SB-350 in 2015, electric companies in CA are required to submit IRPs. Electric companies in FL are required to submit IRPs in the form of 10-Year Site Plans.
Third, the structure of electric companies has changed significantly. The rise of regional wholesale power markets was accompanied by the divestiture of utility-owned generation assets in some regions, and altered the role of utilities. Rather than building, owning, and operating generation resources, some utilities began to purchase energy and capacity through a combination of bilateral and centralized market transactions. In recent years, an increasing number of companies with historic resource planning responsibilities have restructured, and are no longer vertically-integrated. This restructuring also was pushed forward by the advent of retail consumer choice in some regions of the country.

**Contexts and Approaches**

The planning process differs significantly across states, and it differs depending on the business structure of the electric company engaged in it. Companies with resource planning responsibilities today include a range of organizational structures, including investor-owned utilities (IOUs), generation and transmission cooperatives (G&T), publicly-owned utilities (POUs), load-serving entities (LSEs), “wires only” distribution companies, independent power providers (IPPs), and community choice aggregators (CCAs).

Each of these types of organizations has different responsibilities for generation (G), transmission (T) and distribution (D) systems and operations planning. Regardless of the many differences in planning processes, most resource planning processes are completed administratively and consider costs, benefits and risks over the long term.

A number of vertically-integrated electric companies continue to operate and conduct IRPs as part of the process to obtain approval to construct specific new facilities, retire existing facilities, and as a part of routine communications with state PUCs. For LSEs operating in restructured electricity markets, resource planning may be used to inform how they procure electricity to meet demand from customers who do not choose to buy electricity from a competitive electricity supplier. In regions where the grid is managed by an RTO or ISO, regional transmission planning often is done by the RTO or ISO. Also, resource planning studies now are being conducted by public policy organizations, particularly in states with retail open access policies and with third-party administrators of energy efficiency and renewable energy programs.

State public utilities commissions (PUCs) typically are the state regulatory agencies that oversee development and implementation of IRPs. PUCs in different states take different roles in the IRP process. Typically, PUCs do not require or enforce specific IRP findings or outcomes, but rather engage in formal proceedings to approve the content of an IRP, and to acknowledge the IRP process was completed appropriately. In some states, such as California, Indiana, Georgia and Oregon, the review and evaluation of IRPs are conducted in formal regulatory dockets in which commission staff and stakeholders may issue formal or informal discovery and submit comments on an IRP’s assumptions and development. Electric cooperatives and municipal utilities often are not subject to state PUC oversight. Typically, boards of directors appointed by member-customers are responsible for oversight of electric cooperatives, and municipal governments that supply electric services regulate their own utilities.\[17,18\]

**Resource Planning in the International Context**

Electric company resource planning is done by many different companies and organizations around the world, and the need for energy, capacity and ancillary services (A/S) transcends national borders. While specific regulatory requirements and public policy goals may differ from country to country, the electric power systems of countries with advanced industrial economies, as well as many developing countries, are planned and developed based on long-range resource planning that involves GT&D system planning. This paper discusses some of the current resource planning challenges confronting electric companies operating in Australia, Germany, the United States and elsewhere to provide a more “universal” perspective on the challenges associated with long-term electric system resource planning.

**Resource Planning Process**

The basic principles and practice of resource planning have remained largely unchanged for more than three decades, although improvements in computing power have made it possible to do more sophisticated analyses. Table 1 and Figure 2 identify the main steps associated with conducting “traditional” generation resource planning as it is still largely practiced today. However, this practice may not be sustainable with growing deploy-

---

\[17\] EPA 2015, p 727.

\[18\] In rare cases, such as in Kentucky and to a very limited extent in Minnesota, the state PUC reviews and regulates cooperatively owned utilities.
ment of variable energy resources\textsuperscript{19} (VER) and distributed energy resources\textsuperscript{20} (DER), and the other rapid changes occurring in the electric industry today which are discussed in Section 3 of this paper.

To date, resource planning has focused primarily on meeting resource adequacy requirements. Typically, resource planning includes very limited representations of distributed resources, transmission and distribution, and customers as active participants in the real-time balancing of the electric system – all potentially key elements of the future electric system as we describe in the next section.

**Analytic Methods and Tools**

Significant improvements in computing power in the 1980s and 1990s enabled development of complementary planning tools to conduct least-cost generation resource planning, including (i) production cost models that simulate the operation of the power system and calculate its operating costs over a discrete time period; and (ii) capacity expansion models that identify least-cost expansion plans over time, based on simplified representations of system operations \[4,7,8\].

Today, electric company resource planners use a variety of production cost and capacity expansion models, including EPRI’s Electric Generation Expansion Analysis System (EGEAS)\textsuperscript{21}, and other proprietary software tools, including AURORA, MIDAS, Planning and Risk (PaR), PLEXOS, PROSYM, Strategist, System Optimizer and others.

### Table 1. Key Steps in Integrated Resource Planning

<table>
<thead>
<tr>
<th>Activity</th>
<th>Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Regulatory Review</td>
<td>Review existing and expected future regulatory requirements.</td>
</tr>
<tr>
<td>2. Forecast Demand</td>
<td>Forecast expected future electric system load for different time intervals (e.g., hourly, daily, weekly).</td>
</tr>
<tr>
<td>3. Forecast Other Key Inputs</td>
<td>Forecast other key inputs, including expected future prices for (i) fuels (e.g., coal, natural gas), (ii) emission allowances (e.g., SOx, NOx); and (iii) wholesale power (e.g., capacity, energy, ancillary services).</td>
</tr>
<tr>
<td>4. Define System Requirements</td>
<td>Define electric system requirements, objectives, and constraints, including reliability, economic, environmental, and financial.</td>
</tr>
<tr>
<td>5. Identify Resource Options</td>
<td>Enumerate and characterize the performance and cost to operate existing supply and demand-side resources, and to build and operate potential new resources to meet projected energy or capacity deficits.</td>
</tr>
<tr>
<td>6. Develop and Evaluate Resource Portfolios</td>
<td>Use computer simulation models or other methods to develop and evaluate portfolios of specific supply and demand-side resources that can meet system requirements over the planning horizon.</td>
</tr>
<tr>
<td>7. Decision Analysis</td>
<td>Use computer simulation models to analyze different potential resource portfolios, and select the optimal one that meets the planning objective at least economic cost, typically defined as the portfolio with the lowest present value revenue requirement (PVRR).</td>
</tr>
</tbody>
</table>

\textsuperscript{19}We use the term variable energy resources (VER) to refer to renewable electric generation resources that are non-dispatchable due their variable and uncertain energy generation, such as wind and solar power resources. These types of resources also are sometime referred to as variable renewable energy (VRE) resources.

\textsuperscript{20}We use the term distributed energy resources (DER) to refer broadly to supply and demand resources that are connected to the distribution system.

\textsuperscript{21}The Electric Generation Expansion Analysis System (EGEAS) software developed by EPRI in the early 1980s is an example of a planning tool that combines production cost and capacity expansion modeling capabilities [49]. Learn more about EGEAS online at http://eea.epri.com/models.html\#tab=3\&tab=3 and https://www.epri.com/#/pages/product/000000003002008244/.
Figure 2. Activities Involved in Integrated Resource Planning

Source: EPRI based on Hirst 1992, p. 5 (9)
The market and regulatory environments in which electric companies operate and conduct long-term system planning have changed significantly in recent years. The specific drivers of this transformation vary across the United States and internationally. Some of these key drivers are described below.

**Rapid Ongoing Transformation of the Electric Sector**

**Declining Cost of Utility-Scale Renewables and Battery Storage Combined with Policy Incentives**

Over the past decade, the capital cost to install wind and solar PV resources has declined significantly due to a mix of government incentives, ongoing research and development, and economies of scale. In many cases, declining capital costs have been accompanied by improved technical performance resulting in higher capacity factors and lower outage rates. These performance improvements are expected to continue in the coming years. While onshore wind generation and larger utility-scale PV offer the lowest capital costs among renewables, the capital costs for offshore wind, residential PV and concentrating solar power (CSP) facilities also have declined. Capital costs continue to fall while performance improves for energy storage technologies, other renewable resources (e.g., tidal and wave, although both still are at early deployment stages), and small-scale distributed generation (DG) resources [10].

---

### Costs Continue to Decline for Wind and Solar PV

The median installed price for utility-scale solar power plants larger than 500 kW in the United States has fallen from just under $8/Wdc in 2006 to a little over $2/Wdc in 2015 [51]. And in 2017, contracts were signed for PV plants under $2/Wdc. While the rate of decline has slowed in recent years, year-over-year cost reductions still are likely for the foreseeable future. The decline in wind power costs has not been as rapid, but they continue to fall as turbine blades get bigger and other powertrain components improve. Wind costs below $2,000/kW for onshore wind facilities have been reported [52].

Note: Typically, the capital cost of solar power is expressed in $/W, while the capital cost for other power generation technologies is expressed in $/kW. $2/W is equal to $2,000/kW.

In recent years, the cost of the lithium-ion batteries that power plug-in electric vehicles (PEVs) has declined significantly, going from approximately $750/KWh in 2010 to $200/KWh in 201722. At this point, further declines in lithium-ion battery costs are likely to be production driven, and will depend on future deployment of PEVs and concomitant increased battery production. Also, increasing demand for lithium-ion batteries already has started to lead to price increases in battery raw materials such as lithium, which may affect costs and deployment going forward.

Utility-scale solar and wind projects have deployed rapidly in many locales driven by falling capital costs, improvements in technical performance, renewable portfolio standards, tax incentives, feed-in tariffs and other policy tools. The Federal Production Tax Credit23 (PTC) for wind generation, and the Federal Business Energy Investment Tax Credit24 (ITC) for solar generation provided powerful financial incentives that increased deployment of these resources in the

---

22Bloomberg New Energy Finance reported in December 2017 that the average price of a lithium-ion battery pack had dropped to $209/kWh and projected a price of $100/kWh by 2025. https://www.bloomberg.com/news/articles/2017-12-05/latest-bull-case-for-electric-cars-the-cheapest-batteries-ever.

23The PTC is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified renewable energy resources. The duration of the credit is 10 years after the date the facility is placed in service. Renewable energy facilities placed in service after 2008 and commencing construction prior to 2015 (or 2020 for wind facilities) may elect to claim the Investment Tax Credit (ITC) in lieu of the PTC. See http://energy.gov/savings/renewable-electricity-production-tax-credit-pts for more information on the PTC.

24Renewable energy facilities placed in service after 2008 and commencing construction prior to 2015 (or 2020 for wind facilities) may elect to claim the ITC in lieu of the PTC. The ITC amount for wind facilities is reduced by the same phase-down specified for the PTC for facilities commencing construction in 2017, 2018, or 2019. See http://energy.gov/savings/business-energy-investment-tax-credit-itc for more information on the ITC.
United States. A variety of renewable incentives has driven similar changes in Europe, Australia, and other regions, with varying degrees of incentive size and scale of ambition.

In the United States, state renewable portfolio standard (RPS) mandates also have been a key driver of increased deployment of utility-scale renewable resources. An RPS typically requires a certain percentage of electricity delivered to end-use customers in a state to be generated by specified “renewable” resources by a certain date (sometimes this can include hydro resources, as well as wind and solar).

For example, California’s current RPS requires 50% of electricity delivered in 2030 to be renewable. As of February 2017, 29 states had an RPS, and another 8 have adopted renewable goals. Existing state RPS goals range from 10% in 2015 (Wisconsin) to 50% by 2030 (California) to 100% by 2045 (Hawaii). A number of states also have adopted voluntary renewable energy goals. Renewable mandates are also appearing at the local level, with many cities around the world seeking to control emissions. In addition, many large corporations have established renewable targets designed to ensure a prescribed portion of their energy needs is met by renewables generation. For example, both Apple and Google announced their worldwide operations are now powered with 100% renewable generation resources.

**Low-Cost Natural Gas Generation**

In recent years, the technical performance of natural gas-fired generation units also has improved. Abundant natural gas supplies and persistent low prices coupled with improvements in gas generation technologies have contributed to dramatic changes in the U.S. electricity resource mix, including retirement of coal and nuclear power plants and greater reliance on natural gas-fired generation. Over the longer run, persistent low natural gas prices may challenge the cost effectiveness of some renewable resources and end-use EE measures. In many regions of the United States, natural gas has become the largest fuel source for electric power generation. Electricity generation from natural gas exceeded generation from coal on a monthly basis in April 2015 and in 2016, and gas-fired generation exceeded coal-fired generation for the year.

Natural gas capacity additions represented 30% of new capacity additions in 2015, and essentially all non-renewable generation capacity additions. This situation has highlighted the growing interdependence between natural gas and electric systems, and the need to consider natural gas just-in-time delivery issues and competition for natural gas in electric system planning. Low natural gas prices also can depress electricity prices, reducing the financial incentive to build new generation, and reducing opportunities to arbitrage energy and heat storage on the electric system. Going forward, it will be critically important to manage how uncertain natural gas availability is handled in electric resource planning to ensure there is sufficient generation flexibility to respond to system needs.

**New Environmental Regulations**

In recent years, a variety of new environmental policies and regulations implemented at the international, federal, state and regional levels has contributed to changes in the generation mix, and new power system investments in the United States and internationally. Many of these new policies and regulations have focused on reducing the environmental and climate-related impacts of existing fossil-fired power plants, including reducing GHG emissions and “criteria” pollutants (e.g., SO₂ and NOₓ).

For example, the implementation in 2015 of the Cross-State Air Pollution Rule (CSAPR) effectively required coal-fired generation units in the United States that had not previously been retrofit with SO₂ “scrubbers” and selective catalytic reduction (SCR) units to reduce NOₓ emissions to do so to continue to operate. CSAPR also was one factor that changed the relative economics of different power generation technologies, such as coal and natural gas-fired power plants and fuels, and contributed to a recent decline in the dispatch of coal-fired units relative to gas-fired plants. Other key emissions-related regulations include the Mercury and Air Toxics Standards

---


28 Federal Register, 76 FR 48208. On July 6, 2011 the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR) that limits the interstate transport of emissions of nitrogen oxides (NOₓ) and sulfur dioxide (SO₂) that contribute to harmful levels of fine particulate matter (PM2.5) and ozone in downwind states. The CSAPR requires 28 states in the eastern U.S. to reduce SO₂, annual NOₓ and ozone season NOₓ emissions from fossil fuel-fired power plants.
(MATS) and specific state standards that seek to control different air and water-related emissions. Also, in the future, generation facilities that have installed the required new emissions controls may face more compliance challenges (e.g., coal combustion residuals, effluent limits), and additional costs going forward as the pollution constituents are being addressed in power plant waste water collection and disposal systems.

While federal regulation of electric sector carbon dioxide (CO₂) emissions remains uncertain, many states already have mandated CO₂ emissions reductions. For example, in 2009 nine states in the U.S. Northeast implemented a mandatory CO₂ cap-and-trade program for regional electric power plants. In 2012, California implemented a multi-sector CO₂ cap-and-trade program and other measures to reduce statewide GHG emission, with a current goal to reduce GHG emissions by 2030 to 40% below 1990 levels.

The U.S. Generation Mix Has Changed Dramatically

According to the U.S. Energy Information Administration (EIA), in 2005, coal-fired generation accounted for the largest portion of the U.S. electric generation mix, accounting for 50% of net generation, followed by natural gas and nuclear generation, which each accounted for 19%. By 2015, coal-fired generation had fallen dramatically to 33% of net generation, while natural gas generation had grown rapidly from 19% in 2005 to 33% by 2015, a proportion equal to coal generation. And in 2016, natural gas generation reached 34% of generation while coal declined to 30%. Over this same time period, utility-scale renewable generation, excluding large hydropower, grew from just 2% of net generation to 7%.

These and other new federal and state regulations have been among the factors that have shifted the U.S. electric power generation mix away from being dominated by coal-fired generation to a more diverse mix, including coal, nuclear, natural gas, renewables and other generation sources.

Integrated Grid and Growing Deployment of DER

Rapidly expanding DER deployment, including behind-the-meter generation (e.g., rooftop solar PV), energy efficiency (EE), demand response (DR), energy storage and other DER, has led to increased interactions among customers, the distribution system and the transmission system. Electric power now flows in directions that differ from those planned for in the past, and there is growing likelihood that significant amounts of load may be supplied locally. This development has been accompanied by the emergence of efforts, such as EPRI’s Integrated Grid framework, that are designed to integrate DER effectively with central power stations and utility operations through communication across the T&D interface.

Distributed Energy Resources (DER)

DER is defined differently in different contexts. This paper uses a broad definition of DER, focusing on resources connected to the distribution system, including:

- Distributed generation (DG) – Generation connected directly to the distribution system, including solar PV, wind, fuel cells, combined heat-and-power (CHP), and natural gas-fired micro-turbines.
- Energy efficiency (EE) – Permanent load reductions due to end-use efficiency improvements, such as through implementation of LED lighting programs.
- Demand response (DR) – Temporary load reductions under capacity-constrained conditions, such as through interruptible load programs.
- Flexible loads / Advanced DR – Temporary load increases or decreases under flexibility-constrained conditions, such as EV charging during times of high solar PV generation.
- Energy storage – Distribution-level or customer-side energy storage, including batteries and thermal energy storage.

Some DER technologies may extend across these categories. For instance, PEVs can be viewed either as a flexible load or as a form of energy storage, depending on their operating characteristics.

30 The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO₂ emissions from the power sector. Since 2005, electric sector CO₂ emissions have declined more than 45% in the RGGI region. The nine RGGI states implemented a new 2014 RGGI CO₂ cap of 91 million short tons. The RGGI cap declines 2.5 percent each year from 2015 to 2020. See http://www.rggi.org/.
31 See http://www.climatechange.ca.gov/state/ab32.html.
32 For more information on factors that have shifted the U.S. electric power mix in recent years, see US DOE 2017. https://www.energy.gov/downloads/download-staff-report-secretary-electricity-markets-and-reliability.
33 See http://integratedgrid.epri.com for more details.
**Changing Net Load Shapes**

Increased VER and DER deployment is changing the shape of daily net electric loads in many regions. The so-called “duck curve”\(^{34}\), which depicts load net of VER and DER generation that must be fulfilled by dispatchable supply and demand resources, is evident now in regions of the United States and internationally. This well-known curve illustrates how net electric load can decrease sharply during the middle of the day in response to increasing VER and DER generation. In California, this requires a steep “ramp-down” of dispatchable generation in the morning as the sun rises and a steep “ramp-up” in resources as evening approaches.

Reliance on the traditional mix of baseload, load-following and peak load generation resources\(^{35}\) to meet growing and increasingly rapid fluctuations in daily load may not be sufficient to maintain system reliability in the future as the difference between minimum and maximum load increases on a daily and monthly basis. Responding to these changing load characteristics may require changes in how power plants are designed and built, may alter operating strategies for existing baseload and load following generation sources, may drive changes in electricity market design, may change how we measure reliability, and so are likely to impact future resource planning strategies.

Load shapes are also likely to be impacted by new categories of electric load. For example, efficient electrification of the economy, such as a shift to more electric heat and transportation driven by technology advances, economics, environmental/energy security considerations, and increased customer choice, could significantly alter future daily and seasonal net load curves, with some of the loads at least partially controllable.

For example, depending on the evolution of the policy and technical frameworks associated with charging PEVs, growing PEV deployment could either exacerbate or smooth growing swings in daily electric load depending on adoption of “smart charging” approaches. Electrification of certain types of heating is less flexible since heating is needed when it is cold, but in some cases, electrification of space heating may align well with the output of wind power plants. This may provide a way to utilize “surplus” wind generation that exceeds electricity demand rather than curtailing the excess generation\(^{36}\).

---

**Managing Future Distribution Systems**

As customer participation in behind-the-meter generation and DER integration continue to grow, along with the increased ability to observe and control DER, the future role of the distribution system utility is expected to evolve. Future distribution company activities may extend beyond simply managing the distribution system network to becoming an active distribution system manager. This new role is referred to as a Distribution System Operator (DSO).

As used here, a DSO is an entity responsible for ensuring the safe, reliable, and efficient operation of the local distribution system in real-time along with the coordinated operation of interconnected DER, demand-side integration, energy suppliers, and interchange at the T&D interface. This definition does not require, nor does it preclude, DSO involvement in economic transactions between DER and wholesale markets.

The nature of specific DSO functions and implementations will depend on the specific benefits a DSO may be able to provide in each jurisdiction, and is likely to evolve over time and reflect regional regulatory differences and the number of energy transactions occurring at the distribution level. A variety of potential DSO-related activities and frameworks currently are being examined across the industry both in the United States and internationally.

---

**Changing Customer Behavior**

Commercial and residential customer behavior is changing rapidly as customers gain new options to self-generate electricity, sell excess energy back to the grid, and participate in EE and DR programs. And, thanks to digital technology, consumers can participate actively in the energy system without dedicating much time to it. By switching to efficient lighting, acquiring a PEV, or putting solar PV on their rooftop, customers can change their relationship with the electric system overnight. Customers also can manage their electricity consumption through third parties,

---


\(^{35}\) “Baseload” generation refers to power plants, such as nuclear and large coal-fired power plants, that are designed to operate 24 hours per day and generate a consistent, fixed level of energy output which does not change as electric load changes. “Load-following” resources, such as natural gas combined cycles, are designed to change energy output in response to shifts in electric load. “Peak load” resources, such as natural gas combustion turbines, are designed only to generate power for very few hours annually to help meet peak electric loads.

\(^{36}\) For example, in the MISO and ERCOT regions, strong winds at night sometimes lead to regional electric generation (i.e., wind generation plus “must-run” generation such as nuclear, slow-starting thermal resources, self-supply resources, and resources kept online to provide ancillary services) exceeding regional electricity demand.
and with technology according to their preferences and financial needs. This means electric company planners and regulators increasingly will need to consider customer preferences, and how customers will react to different price signals, such as energy prices, capacity charges and other signals, and the resulting impacts on energy, capacity and ancillary services.

**Regional U.S. Policy Drivers and Societal Preferences**

In recent years, electric sector resource planning has begun to evolve rapidly in some regions of the United States. This evolution has been particularly pronounced in California, Hawaii and New York, and reflects changes in state regulatory policies, power supply economics, and proactive consumer choices highlighted below.

**California**

In recent years, CA has adopted a variety of policies and programs that have significantly altered how resource planning is conducted. First, in 2003, energy regulators adopted a “loading order” to guide future energy decisions. This order provides a hierarchy of preferred resources to be used to close projected capacity needs. It prioritizes demand-side options by increasing EE and DR, and then meeting new resource needs first with VER and DER, and second with “clean” fossil-fueled generation.

Second, CA adopted a distribution resource planning requirement that requires IOUs to develop Distribution Resources Plans (DRPs) which are intended to be blueprints for integrating DER into distribution operations, planning, and investment.

Third — and perhaps most significantly — CA enacted Senate Bill 350 in 2015 which mandates the CA Public Utilities Commission (CPUC) to adopt a new IRP process that requires LSEs to meet GHG emissions targets that reflect the electricity sector’s contribution to achieving economy-wide GHG emissions reductions of 40% below 1990 levels by 2030. SB-350 also requires electric companies to (i) procure at least 50% eligible renewable energy resources by 2030 (i.e., 50% RPS); (ii) double end-use EE savings in electricity and natural gas by 2030; and (iii) achieve a series of other legislative objectives that impact long-term resource planning.

Other recent CA legislative and regulatory decisions also are likely to impact electric resource planning in the state, including (i) incentive programs to increase DG deployment; (ii) initiatives aimed at better integrating DR into the wholesale energy markets and the CPUC’s resource adequacy planning process; (iii) annual EE savings targets set by the CPUC; (iv) an energy storage mandate requiring IOUs to procure 1,325 MW of storage by 2020; and (v) aggressive zero emission vehicle goals requiring 1.5 million PEVs and fuel cell EVs to be on the road by 2025.

These initiatives are expected to drive DER penetrations much higher over the next decade. For instance, state policymakers set a goal of 12 GW of DG by 2020. Separately, the CPUC and IOUs are targeting 16 terawatt-hours (TWh) of cumulative energy savings by implementing EE programs between 2012 and 2020, equal to about 5% of forecasted 2020 demand. Pacific Gas & Electric (PG&E) expects growth in DER will reduce its peak demand by approximately 5-7 GW by 2020, and 7-12 GW by 2025. For reference, in 2014 the CA Energy Commission (CEC) forecasted PG&E’s peak demand to be about 27 GW in 2024.

---


38 For more on these plans and the DRP proceeding, see CPUC, “Distribution Resources Plan (R.14-08-013),” http://www.cpuc.ca.gov/General.aspx?id=5071.


45 CEC 2014. Based on the CEC 2013 final mid energy demand forecast of 305 TWh for 2020.


47 CEC 2014, Table 1, CED 2013 Final Mid Energy Load Forecast.
Hawaii

Hawaii’s electricity system is comprised of non-interconnected grids on six main islands, with load served by three IOUs and one cooperative. The three IOUs are required to procure new and replacement generation competitively through IPPs. These IRP and procurement processes are overseen by the Hawaii Public Utilities Commission (HPUC).

A combination of high retail electric rates, policy support, and declining costs has led to a dramatic increase in DG ownership, dominated by DG PV, across the three IOU service territories, beginning around 2010. As PV prices fell, commercial and residential customers responded quickly to net energy metering (NEM) and state tax incentives by installing DG PV. By the end of 2016, Hawaii generated 33.5% of all of its renewable energy from distributed PV (i.e., rooftop PV) accounting for 8.9% of total energy sales. The state’s IOUs reportedly expect a tripling of DG PV capacity by 2030.

In addition to DG, the utilities and HPUC have adopted other DER initiatives. These include Energy Efficiency Performance Standards (EEPS), which require the IOUs to meet cumulative energy savings targets equivalent to 30% of sales by 2030, and pilots for fast DR and distribution-level storage. In 2015, HI adopted House Bill 623 that set new RPS goals of 30% by 2020, 70% by 2040, and 100% by 2045.

In 2014, the Hawaiian Electric Companies (HEC) filed a Power Supply Improvement Plan [16] (PSIP) in response to a docket issued by the HPUC. The PSIPs of each of the three utilities that make up HEC included a preferred plan for the resource mix to ensure that Hawaii’s 100% RPS goal by 2045 can be achieved in a reliable and cost-effective manner. The preferred mix included 16% DG PV, 10% utility-scale solar PV, 33% wind, 27% biofuels, 6.5% geothermal, 6.5% waste and biomass, and 0.5% hydropower. The plan also includes strategies designed to help HI achieve this challenging target, including utilizing energy storage and DR to provide grid services, increasing the operational flexibility of generation resources, utilizing more liquefied natural gas in the near term to substitute for fuel oil, and improving the grid to deliver electricity more reliably.

The HEC’s 2016 PSIP Update [17] outlined a detailed plan charting the specific actions for the years 2017 through 2021 to accelerate the achievement of Hawaii’s 100% RPS by 2045. HEC projects that by implementing the proposed action plan, it will exceed the 2020 RPS mandate of 30%, achieving an estimated 48%, double the 2016 RPS. Under multiple longer-term scenarios, HEC projects its RPS can be at least 72% by 2030 and reach at least 100% by 2040, ahead of the 2045 deadline. In the aggregate, HEC’s latest PSIP estimates achieving a 52% RPS by 2021 by adding 326 MW of rooftop PV, 31 MW of Feed-In Tariff (FIT) solar generation, 115 MW of demand response (DR), 360 MW of grid-scale solar, and 157 MW of grid-scale wind resources across five islands.

New York

In April 2014, New York announced the Reforming the Energy Vision (REV) initiative with the objectives of increasing DER deployment and improving energy system efficiency, reliability, and resiliency. As part of REV, state policymakers are trying to reshape the traditional roles of utilities and regulators, creating space for third-party DER providers and a market platform for distribution-level electricity service transactions.

The REV envisions that utilities will transition away from their traditional role as centralized power generators to become distributed system platform providers (DSPP). In this new role, utilities would still be responsible for maintaining reliable and affordable service, but they would assume new responsibilities as operators of a distribution-level market platform, facilitating entry and participation by third-party DER providers. New revenue opportunities, such as providing data analytics, customer acquisition, aggregation, and energy management services, are envisioned to counteract declining bulk electricity sales.

Markets are seen as central to achieving the REV goals of innovation and cost-effective solutions.

New incentives adopted as part of the REV are expected to increase dramatically DER adoption in the state, but so far adoption has been small relative to CA and HI as the REV program has not yet been fully implemented. Many of the details related to rate and compensation reforms, as well as DER provider and utility business models, still are being worked out. As of June 2016, all utilities had submitted initial Distributed System Implementation Plans (DSIPs), which provide five-year plans for how they plan to develop their roles as DSPPs.
DER Expand Non-Wires Alternatives: ConEd’s BQDM Program Successfully Delays $1 Billion Distribution System Upgrade

One innovative project implemented as part of the REV – Consolidated Edison’s (ConEd) Brooklyn-Queens Demand Management (BQDM) program – has demonstrated the ability of new DER and so-called “non-wires alternatives” (NWA) to substitute cost-effectively for construction of new, expensive distribution system assets.

Facing growing customer electricity demand in three Brooklyn-Queens neighborhoods in New York City, ConEd engineers predicted several of their sub-transmission feeders would be overloaded in the next few years. Traditionally, accommodating this growth would require more than $1 billion investment in a new distribution substation.

Instead, ConEd proposed the innovative BQDM program, an NWA based on implementing DER in targeted locations to meet the growing demand and prevent expected overloading. It leverages a broad array of DER, including DSM, fuel cells, community solar, battery energy storage, and other distributed technologies, and non-traditional utility-side solutions. The overall program is expected to cost about $200 million, less than one-fifth the cost of a new substation.

The BQDM program demonstrates that NWA in some cases can be more cost-effective than conventional grid infrastructure. It established a model that allows cost savings realized through NWAs to benefit both the utility and ratepayers. The ConEd program is a very specifically focused project, but it has broad implications for the industry. Other New York utilities, which are also required to invest in more NWA to meet changing demand, are interested in the program — as are utilities across the nation that increasingly are interested in leveraging grid-edge resources to benefit the utility’s entire system.

International Experience

Many of the factors described above that are transforming electric systems in the United States also have impacted operations and planning of electric systems in other parts of the world. Below, we describe recent experiences in the European Union (EU), Germany and Australia as examples. Similar developments also have taken place in Canada, Ireland, Spain and elsewhere.

European Union

The resource mix in many European power systems has changed dramatically in recent years due in part to implementation of binding, “top-down” community-wide and national policies that strongly incentivize VER and DER deployment. Adoption of binding targets set by the EU has been a major factor driving changes in the resource mix and the resource planning process. These EU 2030 targets include (i) reducing GHG gas emissions by 40% compared to 1990; (ii) reaching 27% final energy consumption from renewable sources; and (iii) continued improvement in EE to reduce energy consumption in domestic and industrial appliances, vehicles and buildings.

These EU targets translate into binding national targets that constrain the resource options considered during the planning process. National targets also influence the forecasting of key input factors, such as electric demand and GHG emission allowance prices.

Much of the effort to decarbonize Europe has focused to date on the electric power sector. Increasing inverter-based generation on both the bulk and distribution systems has driven a need to re-evaluate the reliability services required to maintain stable electric system operations. System operators and regulators have started to focus on mechanisms to ensure future power systems will have sufficient capabilities, such as capacity, flexibility, inertia, fault current and dynamic voltage support, to replace the contributions made by retiring conventional generation resources.

Given stringent national commitments to reduce GHG emissions, decarbonization policies also are being applied to other sectors of the economy in addition to the electric sector. These include adopting targets and incentives to dramatically increase PEV deployment and charging infrastructure in the coming years.

France recently announced new policies to end the sales of gasoline and diesel vehicles by 2040 to help meet its targets under the Paris climate accord. Norway has set a target of only allowing sales of 100% electric or plug-in hybrid cars by 2025.

In addition, cities also are beginning to consider banning non-electric vehicles. Germany’s highest administrative court recently ruled cities can ban cars from some streets to improve urban air quality. Stuttgart and Düsseldorf — German cities with high pollution levels — reportedly are considering implementing bans. In 2017, Stuttgart announced that starting in 2018 it will prohibit diesel


https://electrek.co/2016/06/14/all-new-cars-mandated-electric-germany-2030/.

vehicles that don’t meet emissions standards from entering the city on high-pollution days. Oslo plans to permanently ban all cars from its city center by 2019 — six years before Norway’s country-wide ban would go into effect. Some countries have developed multi-faceted solutions, such as district heating and cooling where cogeneration resources meet both thermal and power requirements.

In parallel, the EU has been developing a series of unified Network Codes that address several aspects of the power system, including interconnection requirements, capacity allocation, electricity balancing and system operation. These codes will trigger updates to the resource planning processes. For example, the Network Code on Requirements for Generators establishes requirements for smart inverter functions applicable to all newly-connected energy resources in 40+ European countries starting in May 2019.

Land use concerns in Europe are a key driver of resource and grid expansion choices as the electric system transforms. Examples include: deployment of offshore high-voltage direct current (HVDC) transmission system reinforcements in United Kingdom (UK) and onshore in Germany; development of substantial offshore wind generation and substations; and adoption of flexible alternating current technologies for grid management. These new options are drastically increasing the scope of planning efforts, leading to the need for new tools, processes and information sharing initiatives.

**Germany**

Germany’s robust existing distribution and highly interconnected BES made it possible to integrate large amounts of VER and DER (up to ~20% of annual energy consumption) in recent years without the need to implement major grid upgrades. However, as Germany began to move beyond these levels of VER and DER penetration, long-term transmission and distribution planning has become more important. In 2016, VER and DER supplied more than 30% of annual energy consumption and reverse power flows from the distribution system to the transmission system now occur on a daily basis in many German regions.

Concerns about electric supply security along with the need to increase system flexibility to integrate large amounts of VER have created opportunities to convert electricity into other energy types that can be used both for storage and consumption. For example, development of power-to-gas resources that convert renewable electricity into hydrogen gas potentially can alleviate transmission grid congestion at times of high VER output and help to decarbonize the natural gas supply.

In addition, recently proposed European energy regulations lay the foundation for consumers to be empowered to make a wider range of choices about their own energy consumption, including having greater access to energy and A/S markets for DER, and an emphasis on unlocking the flexibility potential of consumer demand. Increasingly proactive consumers are altering the existing electric utility business model, requiring better understanding of consumer behavior and risk management strategies in the resource planning process.

**Australia**

The electric sector has changed significantly in Australia over the past decade. For example, more than 7 GW of new wind and solar resources have been installed in the last decade in Australia’s eastern interconnection, now representing almost a quarter of a total of 30 GW capacity in this region. South Australia in particular has experienced high wind and solar penetration, and today these resources comprise more than two-thirds of the generation capacity in this region, and wind alone provides more than 40% of electric energy requirements. This situation has made it increasingly difficult to balance regional electric supply and demand, exacerbated by limited interconnections to other parts of the nation’s power system.

As a result, essential reliability services (ERS) in the regional system have declined. A 2016 blackout was caused by the loss of interconnection to other regions after wind plants tripped offline during a storm, and the system did not have sufficient reliability resources to avoid shedding load. This event demonstrates both the increasing value of inter-regional transmission interconnections,

---

54 Western link reference – http://www.westernhvdclink.co.uk/.
57 http://www.smartwires.com/2015/03/23/eirgrid-begins-type-registra-
tion-test-of-smart-wires-powerline-guardian-technology/.
and the need to study reliability issues and set inter-
connection requirements before large amounts of new
resources are connected to the system. In the future,
resource planners may need to focus more explicitly on
ensuring availability of sufficient reliability services as
an essential part of planning. This will require increased
coordination between transmission and distribution system
operations and planning, greater coordination between
electric system planning and planning of the natural gas
supply infrastructure, and may require deployment of
more demand-side measures.
This section describes 10 key resource planning challenges electric companies in some regions of the world are experiencing today, and which are likely to become more widespread and consequential in the future. It describes new methodologies and functionality, new planning processes, and potential organizational changes needed to develop robust system resource plans to continue to provide safe, reliable, affordable and environmentally responsible electric service. It also discusses the need to communicate plans with regulators and address rising stakeholder interest.

These challenges are inter-related and can be logically grouped together in various ways. They are categorized below and presented in the order shown in Table 2 to aid communication; the order shown does not necessarily imply relative importance.

Table 2. 10 Key IEN Planning Challenges

<table>
<thead>
<tr>
<th>Category</th>
<th>Key IEN Planning Challenge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Modeling the Changing Power System</td>
<td>1. Incorporating operational detail</td>
</tr>
<tr>
<td></td>
<td>2. Increasing modeling granularity</td>
</tr>
<tr>
<td></td>
<td>3. Integrating generation, transmission, and distribution planning</td>
</tr>
<tr>
<td></td>
<td>4. Expanding analysis boundaries and interfaces</td>
</tr>
<tr>
<td></td>
<td>5. Addressing uncertainty and managing risk</td>
</tr>
<tr>
<td>Integrating Forecasts</td>
<td>6. Improving forecasting</td>
</tr>
<tr>
<td></td>
<td>7. Improving modeling of customer behavior and interaction</td>
</tr>
<tr>
<td>Expanding Planning Boundaries</td>
<td>8. Incorporating new planning objectives and constraints</td>
</tr>
<tr>
<td></td>
<td>9. Integrating wholesale power markets</td>
</tr>
<tr>
<td></td>
<td>10. Supporting expanded stakeholder engagement</td>
</tr>
</tbody>
</table>

For each planning challenge, we describe the challenge, the context in which it has arisen, and how companies may consider responding to it. Where possible, we have tried to identify where existing analytical approaches may be affected, and the new functionality needed to address each challenge.

**Modeling the Changing Power System**

The five challenges listed below are related to analyzing and modeling the characteristics and capabilities of the rapidly changing system generation, storage and end-use resource mix:

1. Incorporating operational detail
2. Increasing modeling granularity
3. Integrating generation (G), transmission (T), and distribution (D) planning
4. Expanding analysis boundaries and interfaces and
5. Addressing uncertainty and managing risk

Emerging VER, DER and active customers independently and together drive a need for more operational detail and granularity, a reconsideration of uncertainty and risk, and more integrated consideration of generation, transmission and distribution planning. These factors, combined with the emergence of natural gas, and new electric demands, such as vehicle charging, make a broader look at electricity’s role in the energy system important.
Recent trends in relative fuel and capital costs and increased focus on reducing emissions, combined with market designs and incentives, have resulted in natural gas and variable renewable generation replacing coal and pressuring the economics of nuclear generation as shown in Figure 3. These changes in the centralized, transmission-connected generation mix have occurred at the same time as increasing DER penetration, customer interactions with the power system, and general stress on the transmission system due to long-distance delivery of remote energy resources.

The deployment of variable renewables fundamentally changes the generation resource adequacy challenge from one of simply having enough generation on-hand to meet an annual peak load to one of having sufficiently flexible generation on-hand to balance supply and demand for electricity throughout the year. Also, increased dependence on natural gas-fired electricity means that electric system reliability increasingly is dependent on the just-in-time delivery of natural gas (or backup strategies such as dual-fuel capability) and hence upon the natural gas delivery system and market structures.

**Challenge #1 — Incorporating Operational Detail**

Traditionally, resource planning has focused on ensuring sufficient power generation capacity would be available to meet average or normalized peak demand plus a specified reserve margin at the least total cost, including capital and operating costs. This reserve margin was designed primarily to cover unplanned outages due to equipment failure. Almost all generation was assumed to be available whenever it was needed except when equipment failed or was undergoing planned maintenance. Therefore, meeting a peak load required only building enough redundancy to overcome equipment failures and planned outages. In the future, reserve margins will likely need to address a number of other uncertainties, including weather variability, renewable resource availability and DER production. Some jurisdictions already are including some of these factors in developing their regional planning reserve margins. Also, explicit consideration of operational reliability needs (e.g., voltage regulation) was not required as the resource mix typically was dominated by synchronous generation, such as coal, nuclear, hydro, and natural gas generators, which inherently provided needed operational reliability services.

![Figure 3. U.S. Net Electricity Generation from Select Fuels (billion kilowatt hours)](image)


---

In some regions, such as ERCOT, the reserve margin also is designed to address other uncertainties, such as weather variability and wind resource variability, and ensure the RTO can achieve an LOLE equal to “1 day in 10 years.”
Increased dependence on large-scale renewable energy also may result in increased dependence on long-distance transmission to transfer these resources to where electric loads are located. Based on resource adequacy analysis, RTOs may need to evaluate whether they have the optimal transmission needed to efficiently and reliably deliver energy throughout their system. Energy delivery is an important new component for assessment given the changing location of energy production.

In addition to new resource availability challenges, not all resources have the same capabilities to provide needed real-time reliability services essential for system operation. For example, generation output from wind and solar resources is uncertain and variable on daily, hourly and minute-by-minute basis, and cannot provide services when they do not operate. The energy output of wind and solar power plants can change very rapidly, going up and down in seconds or minutes, requiring other resources on the grid to be able to ramp up and down quickly in response to maintain system reliability. Moreover, generation technologies vary widely in their ability to contribute to voltage control, frequency support, short circuit recovery and black start [13].

Tennessee Valley Authority (TVA) Explores Using Flexibility Metric in Resource Planning

In 2015, TVA included a flexibility metric for the first time in its Integrated Resource Plan [48]. This metric was designed to measure “…how responsive the generation portfolio of each resource plan is by evaluating the type / quantity of resources and the extent to which this mix can easily follow load swings.”

This was the first time TVA has used annual system regulating capability as a metric to assess the performance of a resource portfolio, and TVA plans future work to further develop this approach “…and determine what the minimum or optimum flexibility score should be for the TVA system.”

As a result, resource planners must consider the operational reliability realities of future resource buildouts to ensure they are comparing the full costs of realistic alternatives for producing and delivering energy, and that candidate power systems will be able to operate and deliver power in a flexible and reliable manner across all time frames. Three challenges stand out as keys to incorporating these new operational characteristics and to take full advantage of opportunities that these new technologies offer:

1. Increasing model granularity across time and space to support modeling of issues that become essential with deployment of variable renewables and increasingly active customers.
2. Integrating GT&D planning to achieve the full benefits of large and small resources throughout the system.
3. Expanding analysis boundaries and interfaces (e.g., adding natural gas supply and PEV charging infrastructure) to include all that are important to the future electric system.

Challenge #2 — Increasing Modeling Granularity

To consider the potential operational reliability impacts of different portfolios of system resources, resource planning models must increasingly represent operational details such as minimum levels that generation resources can operate, the ability of resources to ramp up and down in response to load changes, and the ability of resources to provide ERS, including frequency response and voltage control [18]. To understand both the potential operational impacts and needs for ERS, future planning studies will need to incorporate more granular temporal and spatial assessments of power system operation.

Temporal Granularity and Constraints

To respond to increased variability and uncertainty related to DER and VER being connected to the bulk transmission grid, resource planning tools and studies will need to ensure there is sufficient operational flexibility to meet system ramping requirements as shown in Figure 4 [19]. This will require greater fidelity related to representing ramp rates, start times, minimum generation levels and other characteristics of conventional generation resources. Also, this will require being able to represent energy storage and DR characteristics and HVDC transmission capability. Geographic diversity and temporal granularity and value are linked with HVDC, as HVDC can move energy resources in short periods of time over large distances. By including these details, planners will better understand the ability of the system to address variability and uncertainty in load, wind and solar production, and address issues such as the value of energy storage or DR used for energy arbitrage, the amount of curtailment that may be expected, and the benefits of retrofitting new investment in existing plants to make them more flexible.
Traditional production cost models used to support resource planning were designed to solve on an hourly basis using simulated wholesale electric market prices, often co-optimizing energy and ancillary services. Production cost tools have been enhanced significantly in recent years, and the most advanced tools now include the ability to model high temporal and spatial resolution, multiple decision points (e.g., day ahead, hour ahead, real time) to capture the impact of short-term uncertainty, several categories of A/S, and detailed representations of resources such as batteries and DR. Hourly or sub-hourly time steps (e.g., 5 minutes) are likely to be needed to understand system operational needs and to improve company forecasts of future power system revenues and production costs. Evaluating the potential benefits and costs of deploying energy storage systems and VER requires better representation of inter-temporal constraints and opportunities. Using these tools to study future system scenarios will become increasingly relevant to system planners.

In some situations, particularly with high VER penetration, there may be a need to move beyond traditional resource adequacy metrics such as LOLE to consider the likelihood of having insufficient operational flexibility to manage ramping [20] [18]. For example, in California, the need for new planning standards has been investigated; it showed traditional LOLE approaches may still be relevant, but that increased operational detail may be required in production cost models used to assess system adequacy. EPRI has been engaged in a research project with the California Independent System Operator (CAISO) to examine the need to include flexibility in resource adequacy studies. Other regions may determine it makes more sense to use multiple resource adequacy metrics in the future, rather than trying to capture all of the important information in a single metric [21].

**Reliability Services Granularity and Constraints**

It also will be important for resource planning models to represent explicitly some of the operational reliability issues traditionally associated with transmission planning, such as voltage, frequency, transient stability, system protection and voltage stability. Traditionally, operational reliability has not been considered in detail as part of resource planning, as a resource mix comprised

---

Figure 4. Wind and Solar Generation Can Increase Power System Flexibility Needs

primarily of coal, natural gas, hydroelectric and nuclear that was sufficient to meet energy resource needs typically has been sufficient to meet reliability needs, as long as adequate transmission capacity was available. However, because many of the new resources now being deployed do not provide ERS at the same level and in the same ways as more traditional, dispatchable generation resources, explicit evaluation of these services may need to be included in planning.

For example, many wind and solar integration studies have identified concerns related to ensuring sufficient frequency response exists on systems, and more recent studies also have focused on ensuring sufficient short circuit power, or system strength. While general rules of thumb can be developed in many cases (e.g., to ensure a sufficient portion of demand is met by local synchronous machines, or by non-synchronous resources providing certain services), there may be a need for resource planning efforts to include more detailed AC power flow and dynamic stability assessments.

Some new resources may be able to provide many of the same services as traditional generation resources, and other technologies, such as synchronous condensers, flexible alternating current transmission system (FACTS), and HVDC transmission, also may be able to assist the system. Thus, planners will need to consider the capability of many of these resources to support system stability, and specify technical interconnection requirements accordingly. Resource planning models will need to capture the technical differences between the services provided by DER and bulk system resources as well as costs. At a planning stage, one important goal is to ensure that a proposed future system can be operated in a reliable fashion. To do so, planners will need to develop methods to test if potential resource mixes are able to ensure system reliability across all necessary timeframes. This may require new detailed interactions with other tools or may include capturing additional reliability constraints in existing tools.

Spatial Granularity and Constraints

As noted above, the bulk transmission system is needed to deliver energy locally from remote resources. In addition, the location of resources can impact operational reliability and the costs associated with a given resource plan. Similarly, distributed resources such as PEVs and rooftop solar PV typically are adopted by neighborhood, so they can disproportionately impact local distribution circuits, and at high penetrations can aggregately impact local transmission. Targeting by electric companies of specific geographic locations to deploy DER and the actual locations where DER are deployed directly impact bulk generation and transmission investment decisions. Resource planners may need to model and simulate more granular spatial representations of resources and loads in the future to better understand these interdependent T&D planning needs.

Challenge #3 — Integrating Generation, Transmission, and Distribution Planning

Tighter integration of GT&D planning is needed to ensure future system reliability, and to optimize the system as a whole to minimize costs. As customer choice and behavior increasingly impact planning decisions, the integration also must extend beyond GT&D to modeling customer interactions, which is discussed below in Challenge #7.

Traditionally, electric companies, particularly vertically-integrated IOUs, have done GT&D planning as three separate processes that are aligned with respective business units and focused on operations (i.e., day-ahead to five years-ahead timeframe).

Generation Planning

The company group that conducts resource (i.e., generation) planning often is located in a separate group from T&D planners. Resource planners traditionally have interacted with other company planning functions, such as T&D planners and groups responsible for customer interaction and marketing, but these interactions typically have been limited to collecting some basic information that can be used to develop relatively high-level models or “rules-of-thumb” to guide resource planning analyses. As described in Section 2, resource planners typically use “capacity expansion” models that are driven by assumptions about future fuel, capital, and O&M costs and which include simplified representations of the transmission system (e.g., a “pipe and bubble” model) with associated costs. Resource planners typically use production cost models and related tools to analyze system resource adequacy.

Transmission Planning

Within an IOU, transmission planning groups typically are located in a separate corporate group that reports to a senior executive that may be different from the
executive responsible for resource planning. Typically, the organization responsible for long-term transmission planning receives scenarios of different potential future generation resources from the resource planning group, and then develops conceptual transmissions plans across these different scenarios to identify a “least regrets” transmission development plan. The transmission planners also conduct sophisticated, granular reliability analyses on one or more specific transmission plans being considered. Additionally, public utility transmission providers such as RTOs, ISOs and some electric companies are responsible for conducting regional transmission planning over large, multi-state areas as required by FERC Order 1000 and related orders. Order No. 1000 reformed the FERC’s electric transmission planning and cost allocation requirements for public utility transmission providers. It builds on Order No. 890 and refines the transmission planning processes and cost allocation methods to include:

- Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.

- Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.

- Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

**Distribution Planning**

Distribution planning is almost always housed in a separate corporate group, and the organization of this group depends on how an electric company is structured. For example, some electric companies only engage in G&T activities, and so do not have a dedicated distribution system planning group. Other large utilities may include distribution planning functions in their distribution operating companies, while resource and transmission planning may be located in a more central corporate organization that serves the entire company. Traditionally, the interaction between T&D planning groups has been limited to transmission planners informing distribution planners what power factors they can expect on the high voltage side of the distribution system sub-transformer and what voltage they can expect at the bus. Distribution planners, in turn, help update transmission planners’ “top down” load forecasts by supplying “bottom up” local load projections.

**Integrated Planning**

Increasingly, future resource planning choices will require coordination between GT&D planners, particularly as the distribution systems integrate more DER and increase their capability to provide A/S to supplement or compete with bulk A/S resources. Without closer integration, overbuilding of generation or transmission assets may occur as a consequence of not recognizing fully the system attributes and economic value DER may provide. Integrated analytics also can be used to study GT&D infrastructure to assess the potential for overlapping services, redundancy, and obsolescence which may lead to asset retirement strategies that differ from what originally was planned.

Appropriate data sharing and coordination of forecasts between distribution, transmission, and other associated functions in electric companies will be important to accurately capture both macro- and micro-level drivers. Conducting future resource planning in this more integrated manner also will require internally consistent forecasts and assumptions. Finally, conducting integrated planning may require developing methods that can meet the transmission planning requirements of FERC Order 1000 and the needs of generators and distribution entities.

Conducting more tightly integrated planning studies may challenge existing compartmentalized planning processes and may require development of new organization processes or structures that are less compartmentalized and more collaborative. Structured communication between resource planners and distribution and transmission grid planners (either intra-company or, as may be appropriate, inter-company) will be required. Currently, there is a trend among some companies to form specific cross-functional groups to address VER and DER integration. Some companies have now created a new Vice President position associated with the Integrated Grid that includes company experts from GT&D planning groups along with other functions to provide more integrated strategic planning around DER and VER integration.
Pacific, Gas and Electric (PG&E) are two companies that reportedly have done this in recent years.

Examples of critical planning decisions that highlight the need for increased coordination between T&D operators and planners include reactive power management at the T&D interface where DER control distribution level voltage, effective utilization of DER that may contribute to ERS such as frequency response, and the coordination of different smart inverter actions with potentially conflicting T&D objectives/impacts [22] [23].

**Optimize Investment**

Integrating GT&D planning can help to optimize company investments and capital allocation to reduce potential spending on non-productive assets, yielding lower prices to consumers. For example, integrated analysis can make it possible to evaluate non-transmission alternatives (NTA[^64]) to more costly transmission and generation development. Integrated analysis also may help to identify GT&D infrastructure that may be retired to reduce economics costs while maintaining system reliability.

DERs have the capability both to disrupt significantly the existing BES and to provide valuable services and support to the grid. As we gain more experience integrating DER into power systems, electric companies will need to include these resources in planning activities to maximize their value as these resources may provide significant amounts of potential energy, capacity and ERS.

Growing DER penetration also increases the challenge of maintaining the distribution circuit voltage within admissible limits. Autonomous voltage control based on reactive power exchanges with DER (Volt/VAR) and active power curtailment (Volt/Watt) can be used as cost-effective alternatives to uprating existing distribution lines. Curtailment of peak power output from VER and DER could be used effectively to reduce regional transmission congestion without significantly reducing energy generation. Integrated GT&D planning would make it possible to consider a variety of options to meet energy, capacity and A/S needs more efficiently even when facing large uncertainties.

**Incorporate Locational Value**

The value of DER is driven by location, and may depend on attributes such as the existing distribution and transmission infrastructure, load behavior and regional operating policies and standards. New tools like EPRI’s Distribution Resource Integration and Value Estimation (DRIVE) Tool[^65] may need to be used more frequently to evaluate the existing distribution system hosting capacity or to determine cost-effective DER-based mitigation measures. New market design options like distribution locational marginal prices (DLMPs) may be needed to consider marginal costs of congestion and marginal costs of losses at the distribution level to complement the bulk system LMP. Where applicable, programs that incentivize DER deployment in areas of high DER value may need to be considered. Without close integration, individual generation or transmission assets may be overbuilt or underbuilt as a result of not recognizing fully the potential value DER may provide. Lack of integrated analysis also may lead to deployment of DER in locations that are not optimal from a system perspective, leading to higher economic costs than may be necessary. Establishing specific locational operating characteristics and values could aid planners in determining the benefits of changing the resource mix or adding new resources, and better understanding when the needs for particular services have been satisfied or saturated.

**Improve Information Exchange**

Integrated GT&D planning requires improving information exchanges and “handshakes” between different planning functions. Sharing, and in some cases linkages, of demand and DER adoption forecasts between the distribution and bulk systems may improve forecasts by better capturing macro- and micro-level influences. Also, clearly defined practices for model and appropriate data exchange will permit more comprehensive planning functions by providing a more accurate representation of neighboring systems to reflect predicted and planned network configurations and interconnected resources. Data exchange including nameplate DER information and operational information, such as state of charge for energy storage could greatly improve DER visibility and control.

[^64]: Also sometimes referred to as “non-wires alternatives.”

[^65]: More information on EPRI’s DRIVE software can be found in Appendix B.
Telecommunications infrastructure and system architecture will need to improve to integrate GT&D effectively, for example, to enable real-time active and reactive power control of VER and DER. Communications, control, and data acquisition related to variable generation and DER will need to be improved to better coordinate the operation of the electricity supply chain.

**Challenge #4 — Expanding Analysis Boundaries and Interfaces**

Traditionally, electric sector planning has focused on narrow geographic regions and almost exclusively on electricity. Going forward, the geographic scope likely will expand as efficiencies drive the move to larger regional markets and balancing areas, and growing interfaces with other sectors such as natural gas and transportation will likely have increasing impacts on the need for different system resources. To assess these potential impacts, system planners are likely to need capabilities to model the power system over larger geographic regions, to simulate coordinated operation of the electric system with other related energy systems like natural gas, and to conduct more granular and broader-perspective scenario analyses.

**Modeling a Larger Geographic Footprint and Multiple Jurisdictions**

Historically, IRPs typically encompassed an electric company’s operating territory which geographically often was contained within one state. More recently, as electric companies have evolved into larger, multi-state corporations, companies have needed to develop IRPs that cross over into multiple jurisdictions, complicating their long-term resource planning activities.

In some cases, companies have addressed this challenge by separating their long-range planning efforts by jurisdiction, since different states may have different IRP requirements that are applicable to the same company. At the same time, some companies are conducting resource planning across multiple jurisdictions in a more integrated manner.

Historically, it was sufficient for each company to model its own service territory in isolation from larger regions for system planning purposes. However, increasing coordination across balancing areas and the integration of regional markets are making it more important for planners also to simulate larger footprints for planning studies, perhaps up to an entire interconnection.

For example, in regions with high VER potential, it may be important to model an entire interconnection to fully represent the diversity of the regional resources, and to understand potential imports and exports and the potential for VER to contribute to resource adequacy. This has been done in a variety of planning studies in California to support the state’s bi-annual Long-Term Procurement Process. These studies model the entire Western Interconnection to ensure that interties to and from the CAISO are represented accurately.

**Interactions with Other Sectors of the Economy**

Natural gas, water and transportation infrastructure are all becoming more tightly integrated with, and co-dependent on, the electric sector. These sectoral linkages are becoming increasingly important as society continues to seek to reduce GHG and other emissions, drive economic growth and productivity, and meet growing needs for energy. In recent years, electric companies, regulators and corporate leaders have become concerned about the growing linkages between the electric sector and these other key sectors of the economy and related critical infrastructure, such as natural gas, water and transportation.

**Electricity-Natural Gas Interface**

In recent years, the interdependence of the natural gas and electric systems has been highlighted by several high profile events that have made it clear to industry and political leaders that maintaining future electric system reliability depends more than ever before on closer integration of planning and operation of these important systems. NERC recently recommended that electric companies, “…should consider the loss of key natural gas infrastructure in their planning studies.” In addition, NERC wrote, “Natural Gas and electric industries must continue to advance coordination as the electric industry continues to become a larger percentage of total natural gas throughput [24].”

The 2014 Polar Vortex demonstrated the impact that unexpectedly cold weather could have on both the availability of natural gas to be used as a fuel to generate electric power (due to competition with heating demands),

---


68 NERC 2017, p. IX.

69 Ibid.
and on the ability of the natural gas pipelines and power plants to physically operate in those conditions. During the Polar Vortex in the PJM region, 36% of the approximately 53 GW of gas-fired capacity was forced out with 9.7 GW unavailable due to forced plant outages and another 9.3 GW unavailable due to unavailability of natural gas supply, as shown in Figure 5. Extreme weather has highlighted the natural gas-electric system connections in other regions as well.

In addition to highlighting the cold weather operating challenges for the natural gas and electric systems, the Polar Vortex highlighted the challenges of integrating the different market structures in the natural gas and electric sectors, and the important roles of daily “nominations” of natural gas deliveries and the use of firm and non-firm gas transmission contracts to access natural gas during high demand periods.

In response to the Polar Vortex, PJM, MISO and entities have made important operational and process changes to improve coordinated operation of the natural gas and electric sectors, particularly during extreme weather events. The efficacy of these operational and process changes was demonstrated during the January 2017 “cold snap” when both PJM and MISO demonstrated improved operational reliability compared to during the Polar Vortex.

Accidents in the gas supply chain also can impact electric reliability. The 2015-2016 Aliso Canyon natural gas storage leak in southern California led to the ongoing closure of the nation’s fourth largest natural gas storage facility and the need for electric companies and state regulators to take extraordinary and costly measures to maintain electric system reliability in the Los Angeles basin without access to natural gas fuel supplies.

Going forward, resource planners will need a more complete understanding of the potential dependence of power generation assets on local and regional natural gas supply systems and potential limitations and value added of these systems. They will need to evaluate more clearly how the natural gas system may impact their ability to provide reliable electricity services, and what contingencies can be used in the event of a natural gas system disruption, such as use of a secondary fuel. They will also need to understand better the ability and limitations of the natural gas system to provide needed fuel to generate electricity over a wider set of potential operational conditions.
scenarios than may have been routinely considered in the past. Finally, planners will need to develop approaches to better utilize natural gas supply and transportation systems being built and used to support power generation. These systems are expensive to build and maintain, and there are significant periods when they are underutilized.

Managing the gas-electric interface may be particularly challenging for combined electric and gas utilities that purchase and burn natural gas as a fuel for power generation, and also act as local gas distribution companies (LDCs) selling natural gas directly to end-use customers. Finally, it may become important to more closely align the business models of the electric and natural gas industries and build upon recent efforts to more closely align operations of the wholesale electricity and natural gas markets.

Energy-Water Nexus

The term “energy-water nexus” typically refers to the relationship between water used for energy production and energy used for water treatment and transport. Efforts to address withdrawal and consumption of water in power generation, and potential impacts of power generation on water resources and navigation in electric system planning are becoming more prominent. Increasingly, resource planners and others are exploring the nexus between electricity infrastructure (and energy infrastructure more broadly) and water resources. These two critical segments of modern infrastructure intersect and support one another in multiple ways that impact resource planning. For example, hydropower assets are important power generation sources in many regions of the United States, and water is used to cool nuclear, coal and natural gas thermal power plants.

Water presents strategic challenges and opportunities for the electric sector: using less water for power production conserves a scarce resource for other necessary uses; minimizing the environmental impacts of water used for power production preserves environmental resources and protects human health; and, using efficient electric technologies for water treatment, transport, desalination, industrial processes, and end-uses can reduce water demand and conserve electricity. The electric and water systems are both changing rapidly. Just as energy systems focus on more flexible, resilient, and efficient operations, water systems are changing as sensors are being deployed throughout the systems to monitor production, transport, use, water quality, and other factors. Against this backdrop of ongoing change, new challenges for our energy and water systems are emerging, and locally, the competition for scarce water resources is growing.

This growing interdependence of energy and water became apparent in 2010 when California regulators effectively banned new power plants that use “once-through cooling” (OTC) water technology. As a result, all new thermal power plants in the state now are required to use “dry cooling” technologies or non-potable water for cooling operations. This policy included new performance standards for existing facilities that are expected to result in the closure of 19 existing thermal power plants (including two nuclear plants that are closing for other reasons) that rely on OTC technology.

A 2017 study of water and electric utility integrated planning (WEUIP) reported that water and electric utilities see benefits in conducting WEUIP, and some are taking measures to actively develop integrated planning options. To date, however, there are limited examples of integrated planning across water and electricity systems. Water and electric utilities have similarities that provide opportunities to foster WEUIP. For example, water and electric companies both seek to use resources (water and energy) efficiently and to minimize costs. Both types of utilities also may be impacted by climate uncertainties and depend on water availability. There also are a variety of barriers that may limit future WEUIP, including differences in utility sizes, ownership structures and regulatory environments. Additional barriers include organizational silos; lack of communication; funding mechanisms; lack of integrated approaches to data collection, storage, and analysis; and terminology.

---

21On May 4, 2010 the California State Water Resource Control Board (SWRCB) adopted a Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. This policy became effective on October 1, 2010. The Policy applies to the 19 existing power plants (including two nuclear plants) that are able to withdraw more than 15 billion gallons per day of water using once-through cooling (OTC). See: http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/#questions. According to the SWRCB, as of 2016, eight plants had ceased their OTC operations, and the remaining 11 plants planned to comply by retiring their existing OTC plants’ equipment. In some cases, these plants are expected to repower their locations with modern non-water cooled systems.


23Ibid., p. 3.
Electrification and Transportation

Recent modeling done by EPRI to support the United States National Electrification Assessment (USNEA) study [28] suggests that technological change and policy incentives could drive significant changes to the U.S. energy system related to electrification as well as other factors. The transportation sector, especially light-duty cars and trucks, represents the single largest opportunity for efficient electrification. Over 40% of final energy in the United States is used for transportation, and nearly two-thirds of that (a quarter of U.S. total final energy) is consumed as liquid fuels for light-duty passenger vehicles.

In EPRI’s USNEA Reference modeling scenario, light-duty PEV and PHEVs are projected to comprise 75% of new vehicle sales and 70% of vehicle miles traveled by 2050, compared to virtually zero today. This shift, combined with large efficiency improvements in internal combustion engines, leads to a 60% drop by 2050 in final energy use for light-duty vehicles despite an assumed increase in vehicle miles traveled of almost 30%. In nearly every cost-effective application, electrification also lowers system-wide carbon emissions. Even without a carbon policy, CO₂ emissions fall 20% by 2050 in the Reference case, driven by efficiency gains and efficient electrification. Although not modeled in this analysis, improvements in air quality through reduction in criteria pollutants can be even more significant in some locales for driving a transformation. With greater reliance on PEVs and PHEVs likely in the future, it may be important to the transportation sector and its linkage to the electric sector to better understand the constraints and contributions transportation electrification can provide.

Challenge #5 — Addressing Uncertainty and Managing Risk

An EPRI review of recently published IRPs found that uncertainty and risk are prominently considered as part of company IRP planning processes. However, the variety of approaches used by the companies and their characterization of their approaches suggest that incorporating uncertainty in modeling and conducting risk assessments is challenging [1]. Moving forward, it will become increasingly important for resource planners to recognize uncertainty in planning, and develop improved risk management tools and methods to hedge against uncertainties.

There is growing recognition that deterministic modeling and scenario analysis may not be adequate in the future to conduct robust system resource planning. Planners likely need to do more stochastic modeling to capture the inherent variability and uncertainty in key aspects of the electric system, such as variability in future loads, VER production, and DER adoption and use.

Additionally, there is a growing need to develop methods and approaches to evaluate “non-market” risks as part of system planning. Some non-market risks that are becoming increasingly important to be considered as part of system planning include potential lack of “fuel diversity,” potential changes to system “reliability” due to changes in the resource mix, the ability of the power system to be “resilient,” and the ability to respond to changes in the external operating, policy and regulatory environments.

Uncertainty

It is becoming increasingly important for system planners to be able to incorporate the inherent uncertainty and variability in future loads, VER production, and DER adoption and use. In the future, uncertainty is expected to increase across all time horizons, including from minutes ahead (e.g., due to uncertainty in solar irradiance or wind speed) to years and decades ahead related to future load growth, VER production, DER adoption, and uncertainty in technology costs, performance and public policy.

While policy and technology cost assumptions may be the largest uncertainties, they may be addressed by using carefully developed scenarios, and ensuring there is sufficient flexibility in system resource plans to adapt to unforeseen outcomes. Other uncertainties may require development of probabilistic-based planning approaches and stochastic analysis methods that explicitly model uncertainty within the decision-making process. To conduct probabilistic planning and stochastic modeling, key uncertainties need to be described with probability distributions, or in other suitable ways like using uncertainty intervals.

Energy production from VER is not as certain as generation from other resources. Wind and solar PV generation fluctuate minute-to-minute, hourly, daily, weekly, seasonally and yearly. This variability impacts the power system in particular ways that planners increasingly need to take into account. While models can be developed to predict variability in VER production using meteorological information, inherent uncertainty remains. It is important for planners to gain a better understanding of the potential capacity contribution of VER, including using improved methods that account for annual variations in VER output, and methods that better capture the potential for VER to
contribute to meeting peak net demand. This will require aggregating large amounts of data over many years and development of new methods to use this data efficiently to develop deeper understanding of the long-term contribution VER can make to resource adequacy [29].

In addition, there is a growing need for planners to consider short-term VER production uncertainty. Production cost modeling will need to capture day(s) ahead and intra-day uncertainty. To capture these short-term uncertainties, there is a need to develop time-series data on VER production at existing and potential future VER locations that capture spatial and temporal relationships of the variability and uncertainty of VER output across the system, including its relationship with load, which is also partly weather driven. These data also should capture short-term uncertainty associated with current or expected future performance of short-term VER forecasting systems. For example, EPRI studies have shown that for power systems with high VER penetration, accounting for short-term uncertainty of VER output in resource adequacy calculations may result in the LOLE of the system being higher (i.e., a reduction in reliability) than would be calculated assuming perfect short-term forecasting [30]. This can be used with more advanced production cost models described earlier that can model such uncertainty.

Forecasting load is becoming increasingly uncertain and difficult as the components of load change. Forecasting peak load is becoming increasingly challenging, as some customers may be incentivized to lower their demand at times which may or may not coincide with the system peak demand. Forecasting net load throughout the day also is becoming more difficult with increased DER deployment and changing customer behavior. Changing load shapes and the impact of DER and VER (particularly solar PV) on load are creating some complexities related to using existing methods to determine resource adequacy.

Already some previously summer peaking electric companies are facing planning challenges associated with meeting unforeseen peak electricity demands in the winter. For example, Duke Energy recently determined that the method it used to define its planning reserve margin (PRM) in its service territories in North Carolina and South Carolina, which was based on summer peak conditions, was no longer sufficient due to increased solar PV generation. The company identified issues during the winter peak periods (typically early mornings) when solar resources were not available and overall system reserves were low. In response, Duke determined that a winter PRM is needed to ensure adequate reserve capacity is available to meet winter peak demand. As a result, Duke now plans its system to meet winter peak load plus PRM [31].

Figure 6. Winter to Summer Peak Ratio for the TVA Power System

Source: Tennessee Valley Authority (TVA).
Similarly, in recent years the seasonal peak load has shifted from summer to winter for TVA. Before 2008, as shown in Figure 6, winter peak demand averaged 94% of the summer peak. In 2008 and thereafter, the winter peak had increased and averaged 104% of the summer peak. This indicates how TVA’s system has transitioned to be winter peaking.

Going forward, system planners may need to move beyond forecasting peak load and total energy consumption to developing more granular forecasts to capture changing load shapes and load flexibility due to the presence of demand-side resources as well as long-term flexibility needs on the supply side.

While resource planners often use hourly load forecasts for production cost modeling, transmission and distribution planners typically use “snapshots” of critical time periods for planning. In the future, more detailed information about future grid operations that includes more than a few critical time periods and transitions across time periods may be required to make optimal planning and investment decisions.

These growing uncertainties can be managed in numerous ways, and increased computational capability offered by High Performance Computing and new solution algorithms can increase the capability of planners to understand and incorporate these uncertainties into resource planning. Key challenges include developing data sets that capture these uncertainties accurately, and models that can leverage the computational and solution algorithm capabilities to provide insightful results planners can use to make decisions that reflect these uncertainties, and not just overload them with more data and information they cannot use effectively.

Existing GT&D planning methods often attempt to consider the potential impact of uncertainties using deterministic methods. This often is done by considering worst-case planning scenarios, and typically does not consider tradeoffs between reliability and economics. The transformation of the electric sector that has occurred in the last 10 years described in Section 3 has exposed limitations to using deterministic approaches to make optimal decisions as system uncertainties have increased. Table 3 shows some examples of factors impacting GT&D planning for

<table>
<thead>
<tr>
<th>Variable Influencing System Planning</th>
<th>Methods Used Today</th>
<th>Where Is It Considered in Planning Process?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Changes in federal, state, and local regulatory policies</td>
<td>Scenario analysis</td>
<td>Resource adequacy; transmission and distribution planning</td>
</tr>
<tr>
<td>Changing supply- and demand-side resources (e.g., VER penetration, plant retirement, nuclear policies and penetration of demand-side resources)</td>
<td>Scenario analysis</td>
<td>Resource adequacy; transmission and distribution planning</td>
</tr>
<tr>
<td>Long-term economic activities and growth</td>
<td>Scenario analysis</td>
<td>Resource adequacy</td>
</tr>
<tr>
<td>Population movements and growth</td>
<td>Scenario analysis</td>
<td>Resource adequacy; transmission planning</td>
</tr>
<tr>
<td>Long-term fuel price variation</td>
<td>Scenario analysis</td>
<td>Resource adequacy</td>
</tr>
<tr>
<td>Technology improvements (e.g., demand-side technologies – electric vehicles, demand response; energy storage; carbon capture and potentially other technologies)</td>
<td>Scenario analysis</td>
<td>Resource adequacy; transmission and distribution planning</td>
</tr>
<tr>
<td>Weather-related variability (e.g., temporal variation of renewable generation, system loads; and hydro output)</td>
<td>Stochastic analysis</td>
<td>Resource adequacy; transmission planning</td>
</tr>
<tr>
<td>Performance of generation and transmission components</td>
<td>Stochastic analysis</td>
<td>Resource adequacy; transmission planning</td>
</tr>
</tbody>
</table>

Table 3. Addressing Uncertain Variables in System Planning

---

24 High Performance Computing generally refers to the practice of aggregating computing power in a way that delivers much higher performance than one can achieve using a typical desktop computer or workstation to solve large problems in science, engineering, and business. Examples of High Performance Computing include using “cloud” computing, parallel processing, and super computers.
which it could be beneficial to improve upon the deterministic analysis approaches often used today.

**Risk**

A recent EPRI review of recent IRPs suggests electric companies have different perspectives about risk, and are using different approaches to conduct risk analysis. Some companies use scenario analysis, while others prefer sensitivity analysis, stochastic analysis, or some combination of multiple analytic approaches. In addition, electric companies today use a diversity of metrics to compare different resource portfolios, and describe both quantitative and qualitative planning risks [1].

**Risk Metrics**

Electric companies have used a variety of risk-based metrics in recent electric company resource plans. These metrics include:

- The expected value of a probability distribution (P50) for different variables.
- Extreme value at risk – This risk metric considers the upper end of the probability outcome range, such as the value exceeded in only 5% of the cases (P95), or other metrics that reflect results at the extreme “tail” of the statistical distribution of the specific variable being considered. Metrics of this type provide information on the relative performance of portfolios under extreme adverse outcomes.
- Standard deviation of the entire outcome distribution, or the standard deviation of the outcomes in excess of the expected value.
- Risk benefit ratio that compares the range of values in excess of the expected value to the range of values below the expected value. This is a measure of the skewness of the cost outcome distribution.
- Risk-adjusted expected value – A weighted metric that uses the P50 and P95 values.

Companies that use stochastic modeling techniques often develop and use specific, probabilistic-based metrics to compare the potential performance of alternative resource portfolios. Some companies today compare the costs of alternative future capacity expansion plans to the total expected economic cost of a proposed plan. Typically, this cost is represented by the net present value (NPV) of the revenue requirements.

As uncertainty increases for many core elements of the planning process (e.g., load, VER and DER generation), and new perspectives emerge about how to achieve new system reliability and resiliency goals, existing risk metrics will need to be reviewed and new risk metrics may need to evolve.

**Integrating Forecasts into Resource Planning Analyses**

The two resource planning challenges described below relate to improving the data and information that need to be closely integrated into the resource planning process of the future:

6. Improving and integrating forecasting
7. Improving modeling of customer behavior and interaction

These challenges are related directly to ensuring the future resource mix incorporates adequate levels of all desired system attributes, some of which traditionally have not been considered explicitly in resource planning. This can be accomplished by improving forecasting of key operating variables, improving risk management and customer modeling, and more tightly integrating forecasts into resource planning.

**Challenge #6 — Improving Forecasting**

Improving the forecasting – both long-term and operational forecasts – of key elements that are critical to making power system planning decisions, such as current and future load, customer resource adoption, capital costs and fuel prices is critical for robust resource and network planning. While most of these activities historically have been performed separately and used as inputs to the planning process, many of them need to be much more closely integrated into resource planning in the future to achieve the potential benefits of integrated energy network planning.

According to a recent EPRI report [32], “… system [operational] forecast errors likely become more important to track for asset owners and system operators over time. Forecast errors impact reserve needs and prices and also are essential for determining least-cost commitment schedules for plant operators, especially if startups are costly. Better understanding diurnal and seasonal uncertainty in load, renewables, and other time-series forecasts will likely become more important over time as wind and solar deployment increase and end-use electrification changes load shapes75.”

---

75EPRI 2018, p. 4-9.
Some key factors that require enhanced forecasting methods and approaches include:

- **Electric load and DER adoption** – End-use customers both drive the demand for electricity and are increasingly choosing to supply or store it and to alter their demand. Because of this growing dual role, forecasting DER adoption and customer participation in DR programs is becoming increasingly important so companies can develop more robust forecasts of future electric loads. Given the uncertainty, non-uniform nature, and location of DER in the system, new analysis techniques and data streams will be needed to forecast load and generation at more granular levels in the system, and to project customer behaviors and other factors that will dictate new spatial and temporal behaviors of both DER and load. It will be increasingly important to integrate these forecasting tools into planning processes so that DER can operate dynamically with central resources across a wide range of scenarios rather than simply feeding a DER forecast into a capacity expansion model.

- **Market prices for electricity and emissions** – The evolution and expansion of wholesale power markets make it more important than ever to have access to sound forecasts of future prices for energy, capacity and A/S. Also, existing and emerging markets for environmental commodities will require the ability to forecast prices for these key commodities. And to the extent that planning scenarios can impact these values, it can be valuable to integrate them into the evaluation process.

- **Weather and renewable generation** – Historically, weather primarily impacted load. With the deployment of wind and solar, weather impacts load and generation simultaneously. Access to more robust weather forecasting and good data can reduce the short-term uncertainty associated with VER output and help companies to make better operations and planning decisions. To use these data effectively, they need to have consistent treatment of weather impacts on supply as well as load. Improved weather forecasting cannot reduce the inherent variability of the energy output from renewable resources, but can reduce some of the impacts.

- **Future policies and regulation** – It is important to develop an understanding of potential ways the electric system might evolve under different future policies, market designs and regulation. Some changes to markets seem almost inevitable as the generation mix and nature of demand change, but their pace and breadth are hard to predict. While it is difficult or impossible to predict future policy directions, it is valuable to understand the robustness of plans across a range of plausible futures.

- **Fuel prices and new technology cost and performance** – Natural gas prices and the cost and performance of key emerging technologies across the electric supply chain will impact system evolution. Natural gas price forecasts are ever more important given the increase in natural gas-fired generation and have some new fundamental sources of uncertainty, e.g., export levels. On the demand side, end-use prices such as the cost and performance of PEVs could become a key determinant of load growth.

It will not be possible for system planners to develop effective long-range plans if they do not have access to more robust methods and approaches to incorporate and capture the increasing levels of uncertainty inherent in these key forecasting factors and gain insights using computationally tractable methods. Addressing this uncertainty is considered separately in Challenge #5.

**Challenge #7 — Improving Modeling of Customer Behavior and Interaction**

Customers today have unprecedented access to emerging technologies and service options. As new choices continue to proliferate, their impact on electric system operation will increase and may change in fundamental ways. In the future, electric companies are expected to be responsible for many aspects of system planning and operations that will need to be more tightly integrated. However, many decisions that will impact electric system planning likely will be made outside of an individual company’s direct control by customers who choose to deploy and use DER, or by intermediaries that aggregate customer actions. As a result, it is becoming more important for resource planners to incorporate end-use customer behavior and choices that impact both load and resource dynamics into the resource planning process.

---

76For a discussion of the importance of maintaining consistency in these data, see Simulating Annual Variation in Load, Wind, and Solar by Representative Hour Selection. EPRI, Palo Alto, CA: 2016. 3002008653.
Some ways customer behavior and resource planning may interact include:

- Customer decisions may directly impact the design of GT&D systems and related investments.
- New forecasting techniques and system models will need to be developed to explore the possibilities of emerging customer behaviors and interactions within planning. These models and forecasts will need to represent financial and other stimuli that influence customer participation in programs, and any introduced dynamics, such as the rate customers may opt in and out of a program.
- Customer dynamics may require new planning analysis and design criteria to ensure system reliability.
- Advanced communications, metering, and novel rate mechanisms are changing the ways customers engage and participate in the power system.

Electric companies will need to plan for the potential impact these changes may have on the power system by using tools and insights to help predict how customers may adopt and use emerging technologies and service options, and be able to model the impact of these behaviors on the grid. Not adapting to this changing customer role may lead to sub-optimal infrastructure investments and service dislocations that may impact electric service reliability and affordability.

**Key Technologies and Service Options are Changing Load Shapes**

Historically, energy efficiency programs have focused on improving energy savings incrementally in ways that did not significantly alter end-use load shapes. However, innovations such as variable capacity heat pumps and heat pump water heaters operate in ways that change the traditional load profiles of air conditioning and water heating, respectively. Moreover, controls with embedded sensors, such as learning thermostats with smart phone interfaces, provide consumers with greater visibility into, and control over, their energy usage and expenditures, which is altering energy consumption patterns. Occupancy sensors and other lighting controls, especially coupled with LED technology, are affecting lighting load patterns, leading to significant load shape changes in addition to overall energy savings.

Consumer demand for online services is driving the digitization of society, leading to a proliferation of Internet-enabled electronic devices that require charging. While the energy intensity (i.e., energy use per unit of capacity) of most residential end-use categories has declined over the past decade, chiefly due to efficiency improvements, the amount of energy used for “plug loads” — including consumer electronics and home entertainment — has increased. Digitization is changing consumer habits, which in turn are altering the growth trajectory and time-use patterns of electricity use.

Since their commercial introduction to the U.S. market in Q4 2010, PEV sales have increased at a faster rate than hybrid vehicle sales when they were introduced a decade earlier. Projections suggest PEVs could exceed 5% of new vehicle sales by 2020, and large utilities could see hundreds of megawatts of new demand from charging hundreds of thousands of vehicles on their systems. The charging habits of PEV owners, as influenced by technologies and motivated by rate plans, can have large potential impacts on electric loads — especially at a local, distribution level. These new loads may enable the system to be run more efficiently if charging can be timed to match system generation profiles, or if not controlled, they may exacerbate local or system peaks.

The rapid growth of rooftop solar PV is impacting grid electric demand, particularly in California, Arizona, and Hawaii, as well as New Jersey and Massachusetts. Some observers project U.S. rooftop PV capacity could increase five-fold over the next three years. In areas with high expected PV growth rates, the impacts on system load profiles are projected to be significant in a manner similar to how utility-scale and residential PV has caused the well-known “duck curve” in California.

Battery storage systems are an emerging class of customer technology that also may impact customer load profiles, particularly when paired with solar PV. Their market penetration is largely driven by prevailing local rate structures. As battery costs decline and time-of-use (TOU) pricing structures become more prevalent, these systems may impact net end-use load shapes significantly.

**Predicting Adoption and Location of Technologies and Service Options**

Electric companies increasingly are challenged by the need to anticipate the pace and location of future adoption of load-altering customer technologies and services.

---

Footnote: For example, the energy intensity of refrigerators is measured in kWh/cu-ft. For lighting, energy intensity is measured as kWh/lumen.
to make optimal operational and planning decisions. While it is essential to segment customers into meaningful groups to do this, electric companies need to be able to map expected customer adoption of new end-use technologies and services to the utility service territory and specific transmission and distribution circuits that may be impacted. In addition, planners will need to get a better understanding of the price sensitivity of consumer demand (i.e., price elasticity) over a broader range of scenarios and alternatives. Companies will use planning tools to examine where cost of service incents both customer adoption and defection.

Planners will be challenged by predicting fast changing technologies and developing new ones, such as distributed ledger technologies (i.e., cryptocurrencies) that have the potential to very quickly change both the supply and demand of electric systems with respect to forecasting load (i.e., “mining” load), generation supply (i.e., micro-grid and generation management) and uncertainty analysis.

Customers represent a diverse set of characteristics, needs, and preferences. Aside from fundamental sectoral distinctions (e.g., residential, commercial, industrial, agricultural), customers can be classified by multiple attributes, from demographic to psychographic. Energy providers increasingly need to be able to distinguish which attributes are most relevant and actionable for predicting the adoption of key technologies and uptake of utility service options and programs. To accomplish this, electric companies will need to use sophisticated data analytics to estimate the combinatorial impact of technologies on net load shape over time by location. In the future, these more sophisticated and complex load forecasts will need to be tightly integrated with not only distribution system planning, but also with generation and transmission planning.

Forecasting Impacts of Company Interventions

DER adoption and new customer behaviors are happening today in response to changes in technology cost and performance, existing rate structures and powerful economic forces. DER adoption, customer behaviors and future loads also can be affected by future company interventions (e.g., incentive programs, information campaigns, or other activities) on segment-specific technology adoption over time, and these potential interventions need to be incorporated in projections. For example, companies can conduct customer surveys to evaluate how changes in TOU rate structures might impact PEV charging patterns during off-peak hours, or how incentives for smart thermostats might accelerate their adoption. The resulting forecasts of net demand impact can then inform distribution operations and planning decisions.

In the future, electric companies will be able to target deployment of location-specific customer interventions as cost-effective alternatives to traditional investments in distribution or transmission infrastructure or centralized or distributed generation assets.

The ability to analyze “big data” related to DER, customer behavior, operations, and other aspects of the electric system likely will require new analytic capabilities, data and model handling practices, and computational power. Elements of future integrated system planning may be too computationally intensive to use desktop computers, and may require new High Performance Computing capabilities and artificial intelligence (AI).

**Expanding Planning Boundaries**

The last three challenges are associated with expanding the objectives of resource planning in this new customer-centric, diverse electric sector that is becoming more widely interconnected every day:

8. Incorporating new planning objectives and constraints
9. Integrating wholesale power markets
10. Supporting expanded stakeholder engagement

**Challenge #8 — Incorporating New Planning Objectives and Constraints**

As noted earlier, traditional resource planning focused on identifying the least-cost generation portfolio to meet future demand forecasts with a specified reserve margin. Today, electric companies increasingly are being asked to meet new planning objectives, multiple objectives simultaneously, and to plan within new types of constraints. New objectives and constraints beyond least-cost resource adequacy that planners may need to consider in the future include (i) ensuring system resiliency and flexibility beyond traditional resource adequacy; (ii) reducing GHG emissions and achieving evolving RPS targets; (iii) addressing the impact of electric system operations on regional water resources; and (iv) meeting corporate sustainability objectives.

**Resiliency and Flexibility**

Many definitions for power system resilience have been provided by various industry experts. A recent EPRI white paper defines resilience as “the ability to harden the
system against—and quickly recover from—high impact, low frequency (HILF) events” where enhanced power system resilience is based on three elements: (i) damage prevention to harden the system to limit damage; (ii) system recovery to restore power as soon as practicable; and (iii) survivability to aid society in continuing some level of normal function during the period without full access to normal power sources78 [33].

While resource planning always has focused on ensuring reliability (i.e., adequacy of supply) and considered “typical” contingencies, such as the loss of one or more generation or transmission facilities, a resilient system must perform adequately with the simultaneous loss of many facilities resulting from very low probability events, such as extreme conventional terrestrial or space weather, natural disasters, or intentional physical or cyberattacks. A “reliable” system as measured by standard resource adequacy metrics is not necessarily a “resilient” one as noted in PJM’s 2017 study on evolving resource mix and system reliability [34]. In addition, this PJM study recommended PJM and its stakeholders “…should continue to examine resilience-related low-probability and high-impact events which can cause significant reliability impacts.”

**PJM Studies Evolving Resource Mix and System Reliability**

In recent years, the generation mix in the PJM Interconnection has changed dramatically. In 2005, coal and nuclear resources generated 91% of the electricity on the PJM system. Over time, policy initiatives, technology improvements, and economics spurred a shift from coal to natural gas and renewable generation. From 2010 to 2016 in PJM, coal-fired units made up 79% of the megawatts retired, and natural gas and renewables made up 87% of new megawatts placed in service. PJM’s installed capacity in 2016 consisted of 33% coal, 33% natural gas, 18% nuclear, and 6% renewables (including hydro).

In response to this shift in generation mix and stakeholder concerns that the PJM system may be becoming too dependent on natural gas generation, PJM has undertaken several recent analyses to assess the potential reliability impacts of this shift in the region’s generation mix.

Recently, PJM published a report that focuses on the reliability aspects of fuel mix diversity, including fuel security. The paper provides insights from a grid operator’s perspective about the potential impacts of the changing fuel mix on the ability of the PJM system to continue to provide reliable electric services [34].

The occurrence of several high visibility HILF events over the past decade has led to electric companies increasingly being asked to address power system resiliency on a more comprehensive basis as part of their resource planning activities79.

In addition, planners are being asked to ensure power system resiliency to the impacts of potential large solar storms and electromagnetic pulses [35]. Further, the recent increase in large-scale cyber-related attacks on national governments, corporations, and critical infrastructure suggests electric companies in the future are likely to need to address their ability to protect their GT&D systems from cyber threats, and to demonstrate how they plan to restore these systems if they are compromised.

A December 2015 cyberattack on the Ukraine power grid provided the first real-world example of the potential for cyberattacks to disrupt a national power system. In this attack, hackers compromised information systems of three energy distribution companies and temporarily disrupted electricity service to customers. In total, 30 substations were switched off, and approximately 230,000 people were left without electricity for 1-6 hours80 [36].

A question planners now are being asked is how do existing processes need to change to incentivize or prioritize resource attributes that result in a system that not only is reliable in the face of typical electrical system contingencies, but also resilient to HILF events, and flexible enough to remain reliable under large deviations from the planning futures considered. In addition, increased electric system reliance on natural gas as a generation fuel has led to consequent concerns about the resilience of natural gas infrastructure.

---

78 EPRI 2016, pp. 3 and 14.

80 Available online at https://www.wired.com/2016/03/inside-cunning-unprecedented-hack-ukraines-powergrid/.
Recent “Resiliency” Events

The recent events below highlight the evolving need to include system resiliency in resource planning:

- 2011 Japanese earthquake and tsunami resulted in meltdown of reactors at the Fukushima nuclear plant, led to the closure of all other nuclear reactors in Japan, and caused policy changes governing nuclear generation going forward.
- 2011 tornadoes in the southeastern United States damaged approximately 200 high voltage transmission lines across the TVA and Southern Company systems.
- 2012 Hurricane Sandy devastated parts of New York and other portions of the northeastern United States.
- 2013 rifle attack on PG&E’s Metcalf substation damaged 17 power transformers.
- 2014 Polar Vortex resulted in very low temperatures across a large cross section of the eastern United States driving very high demand for power and natural gas, and resulted in extremely high forced outage rates for many generators.
- 2015-2016 leak at the Aliso Canyon natural gas storage facility dramatically limited natural gas supplies to Southern California.
- 2017 series of hurricanes in the United States and Caribbean led to massive damage to power systems and months of recovery as highlighted by the ongoing recovery from Hurricane Maria in Puerto Rico.

Greenhouse Gas Emissions

Perhaps the most far-reaching new objective resource planners are facing today relates to evolving and uncertain requirements to reduce GHG emissions from electric power generation. While it is too early to determine exactly how evolving federal and state policies in the United States to reduce GHG emissions will play out over the coming years, system planners need to do resource planning today, and corporate leaders need to make decisions about future capital investments while federal and state regulatory policies to reduce GHG emissions remain highly uncertain. Because new power generation assets can be expected to operate for 30-50 years or longer, it is very difficult for electric system resource planners to address this kind of near-term policy uncertainty, and mitigate the potential for large capital investments to become stranded in the future.

In 2015, the EPA promulgated final regulations under Section 111(b) of the Clean Air Act (CAA) that limit CO₂ emissions from new and modified fossil-fired electric generating units (EGUs) [37], and under Section 111(d) to limit CO₂ emissions from existing fossil-fired EGU[s][38]. Although the EPA has adopted both of these final regulations, there is a great deal of uncertainty regarding whether and how these regulations will be implemented. On February 9, 2016, the U.S. Supreme Court issued a stay freezing implementation of the carbon pollution standards for existing power plants while the rule is under review by the U.S. Court of Appeals. In addition, on April 4, 2017, the EPA published proposed rulemakings to announce it is reviewing both the final GHG performance standards for new, modified and reconstructed sources[83] and the GHG performance standards for existing sources[84], and may initiate proceedings to suspend, revise or rescind both rules.

The outcomes of the development of both the New Source Performance Standards (NSPS) for “new” and “existing” fossil-fired generation sources could have significant implications on the future planning and operations of the U.S. electric sector. The NSPS for new sources effectively forestalls future development of new coal-fired power plants without CCS technologies. The existing source rule fundamentally could alter the generation mix in some areas of the country by incentivizing reduced dispatch of fossil-fired generation units, and promoting development of new renewable resources and increased reliance on end-use EE programs.

In addition to complying with uncertain federal regulations to reduce GHG emissions, power company planners must plan to comply with existing and evolving state and regional GHG reduction programs, such as the RGGI program in the northeastern United States. And, on a more local level, more than 200 U.S. cities have pledged to achieve aggressive future GHG emissions reduction goals that could impact future electric company planning, particularly for POUs operating in these jurisdictions[85]. And, a number of U.S. electric companies have adopted aggressive voluntary GHG emissions reduction goals

---

81 The regulations promulgated under Section 111(d) also are referred to as the Clean Power Plan (CPP).
82 The New Source Performance Standards (NSPS) for new EGUs require new natural gas-fired power plants to emit less than 1,000 pounds (lbs) CO₂ per MWh of generation, which can be achieved by the latest combined cycle technology. New coal power plants can emit no more than 1,400 lbs CO₂/MWh, which effectively bans their future development unless they incorporate carbon capture and storage (CCS) technology.
83 Federal Register, Vol. 82, pp. 16330-16331, April 17, 2016.
84 Federal Register, Vol. 82, pp. 16329-16330, April 17, 2016.
that already are being incorporated into their long-run resource planning activities and operations86.

Regulators now are beginning to account explicitly for GHG emissions, and plan for achieving future GHG reductions as part of evolving state IRP processes, and in response to state regulatory efforts to reduce GHG emissions. For example, as described earlier, in 2015 California enacted a new law (SB-350) that mandates the CPUC to adopt a new IRP process to ensure LSEs meet GHG emissions targets that reflect the electricity sector’s contribution to achieving economy-wide GHG emissions reductions of 40% below 1990 levels by 2030. The CPUC and others state regulators recently have developed guidelines and processes for the state’s electric companies to develop and submit new IRPs between 2018 and 2020 that address these and other new requirements included in the new law.87 SB-350 also expanded the types of electric companies required to submit IRPs. California IOUs like PG&E and SCE have submitted IRPs for many years. The new SB-350 IRP requirements also apply to POU’s whose new IRPs will be subject to CEC oversight, and to new community-choice aggregators (CCAs) that have grown rapidly in recent years throughout the state.

Internationally, the countries that are Parties to the United Nations Framework Convention on Climate Change (UNFCCC), including the United States, reached agreement in December 2015 to combat climate change and accelerate and intensify actions and investments to achieve a sustainable low carbon future. The central goal of the Paris Agreement is to keep a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels, and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. The Agreement requires all Parties to put forward their best efforts through “nationally determined contributions” (NDCs) and to strengthen these efforts in the years ahead. The Agreement entered into force in 2016 and 176 countries have now ratified it88. On June 1, 2017, President Trump announced his intention to withdraw the United States from the Paris Agreement89.

Renewable Portfolio Standards

As described in Section 3, electric companies in many parts of the United States now are required to meet state-based RPS goals that typically mandate a specific percentage of the electricity sold to end users be derived from approved “renewable resources.” The proliferation and evolution of RPS now require electric companies to ensure their expected future resource mix will meet local RPS goals, adding new constraints into the resource planning process. While most states with RPS goals have set targets of 5 to 10 to 20% of electricity to be generated by renewable sources, other states have set goals that will fundamentally change their systems. For example, California set a goal of 50% renewable electricity by 2030, and Hawaii aims to get 100% of electricity from renewables by 2045.

Water Resources

Electric companies also being asked to address a variety of issues associated with water resources as part of their resource plans, including addressing way to potentially limit water withdrawal and/or consumption. For example, California regulators recently imposed regulations that will effectively eliminate the operation of all power plants that use OTC technologies by 2029. In addition, California has limited the use of treated effluent for cooling new power plants (preserving that resource for groundwater recharge and other offsets to potable water use), and requires that new thermal power plants use dry cooling or other degraded water sources.

Also, electric companies are being required to comply with evolving federal and state regional water quality emissions restrictions, including Effluent Guidelines revisions, Total Maximum Daily Load (TMDL) requirements, and fish protection regulations promulgated under Section 316(a)&(b) of the Clean Water Act.

In addition, some power companies like the Tennessee Valley Authority (TVA) have recently been asked by stakeholders to analyze how the ongoing operation of

---

86For example, in 2017 Ameren Missouri announced plans to reduce its carbon dioxide (CO2) emissions 35% by 2030, 50% by 2040 and 80% by 2050 (based on 2005 levels) [54]. Early in 2018 American Electric Power (AEP) announced a strategy to reduce its CO2 emissions by 60% from 2000 levels by 2030, and 80% from 2000 levels by 2050 [55]. And, more recently, Southern Company announced its long-term goal of transitioning to “low- to no- carbon operations” by 2050 [53]. Other U.S. electric companies, such as Duke, Entergy and PPL also have adopted similarly aggressive CO2 reduction goals.


their existing power plants and any new proposed power plant development might impact ongoing river operations, navigation, and flood control.

Corporate Sustainability

There are many definitions of sustainability and approaches for how companies can simultaneously meet social, environmental and economic goals. Sustainable electricity companies discuss some of the most hotly debated challenges facing companies and society today such as renewable energy, water use, species impacts, employee engagement, stakeholder communications, resiliency and climate change, distributed energy, EE, GHG emissions, consumer preferences and business vitality [39]. It is becoming increasingly clear that electric companies will need to develop tools and adopt approaches that will help embed sustainability objectives and planning into their resource planning and strategic decision making.

Expectations for power companies to be transparent in their commitments and performance related to sustainability are rising as customers, investors, employees, and other stakeholders become more engaged in the sustainability dialogue. Also, stakeholders increasingly are clamoring for electric companies to disclose their sustainability performance publicly, making it increasingly important to develop a consistent approach to measure sustainability achievements that applies across this diverse industry.

Recently, EPRI completed research that identified which sustainability issues are most relevant to power companies operating in North America, and gathered perspectives on these issues from members of the industry and its stakeholders [40]. EPRI also recently identified 15 priority issues across the three “pillars” of sustainability—environmental, social, and economic—and 448 metrics that electric companies have been requested to report by different organizations for various purposes. Recent EPRI work has focused on refining this list to 77 metrics across 11 of the principal sustainability issues and reportable environmental events [41].

Challenge #9 — Integrating Wholesale Power Markets

Interactions between electric companies and the ISO/RTOs which manage wholesale power markets and the evolution of these electricity markets are starting to create new challenges for resource planners in electric companies and within ISO/RTOs. Historically, wholesale electricity prices have been quite volatile. Tighter integration with wholesale power markets has made it increasingly important for electric companies to forecast future wholesale power prices, and incorporate price uncertainty into their modeling tools. Going forward, resource planners will need to consider potential impacts of the evolving markets for wholesale energy, A/S, and capacity when they make new investments and to consider the future economic viability of their existing system resources. They will also need to consider where it may be more prudent to purchase energy, capacity and A/S in regional power markets rather than committing company capital to build new resources or committing to long-term power purchase agreements (PPAs).

Wholesale power markets are changing rapidly, driven primarily by the emergence of VER. The variability, uncertainty, and the near-zero variable cost of VER can change fundamentally how all generating resources earn money. Today, the vast majority of wholesale market revenue comes from energy markets. VER deployment can result in generally lower and more volatile energy prices, higher A/S prices, and higher forward-capacity prices depending on market design [42]. Electric companies will need to better understand how the increasingly important A/S and capacity markets may evolve over time, and understand differences in these markets from region to region. These markets, and alternative capital cost recovery mechanisms where markets do not currently exist, are important elements that may help to address the “missing money” problem [42].

Planning methods will need to consider how ISO/RTO markets will value different resource capabilities and attributes. For example, there is a growing need to define attributes and services, such as operational flexibility, resiliency, and ERS. The ISOs/RTOs and their stakeholder are working continuously to determine how to define and measure these attributes, and how much of each of them will be needed to maintain system reliability. This is particularly important as renewables penetration deepens since the energy output from renewables is uncertain and variable. Currently, some ERS are priced in electricity markets, while others are provided with cost recovery or no compensation at all. Good estimates of future reliability incentives are important to guide long-term investments in new generation and storage resources and transmission and distribution assets. However, this is not a simple
task, and it is complicated by technical and jurisdictional mismatches between the wholesale markets and the transmission system, and retail power markets and the distribution system, which can create complications associated with meeting the needs for both systems [43].

Regional markets also can be affected by state-level, political choices. For example, some states are considering or implementing policies designed to procure generation or infrastructure from the market, or prevent generation assets from retiring even when existing economic signals point to the need to do so (e.g., nuclear retirements in NY and IN, and coal retirement in OH). The opposite situation also may occur. Public policies may be implemented to shut down specific generation resources, even though market signals suggest they have ongoing economic value (e.g., the Indian Point nuclear plant in NY). Electricity markets are designed to achieve economic efficiency and promote system reliability. Public policy objectives often include additional goals, such as enhancing environmental benefits and preserving local jobs. This dichotomy poses a challenge for system planners who need to make decisions while simultaneously taking into account future public policy goals and electricity market signals.

**Challenge #10 — Supporting Expanded Stakeholder Engagement**

The primary “audience” for company IRPs traditionally has been state PUCs and related state regulators, while other stakeholders, such as environmental, consumer advocates, business groups, and other local non-governmental organizations (NGOs), have been more peripherally engaged.

In recent years, however, there has been a marked change in public expectations regarding involvement in electric company resource planning, and this is expected to continue. Stakeholders are becoming more actively engaged in the entire resource planning process. New types of stakeholders are participating, and some explicitly want to address a broader array of issues than have been covered traditionally in electric company resource planning, such as electricity rate design and rate setting.

Effective stakeholder engagement is growing in importance for many utilities and ISO/RTOs. Increasingly, electric companies and ISO/RTOs are becoming more actively involved in designing and managing extensive stakeholder engagement processes as a core part of their resource planning activities. This is occurring both domestically in the United States and in other countries. In addition to the opening up of planning activities, companies are involving customers and stakeholders more than ever before in the design and review of more aspects of their operations.

**Stakeholder Engagement Helps to Facilitate German Transmission Grid Siting**

Development of new overhead transmission lines in Germany traditionally has faced heavy public opposition.

Germany recently adopted a process to plan new transmission infrastructure needed to transport offshore wind energy from the North to load centers in the South of the country. This process incorporates extensive public consultation. This “network development plan” process is structured into four phases (in eight total steps): starting with (i) scenario development; followed by (ii) transmission expansion planning; (iii) consultation; and ultimately leading to (iv) federal demand planning.

The public is consulted in three of the eight steps, including the proposed planning scenarios and each of the two drafts of the network development plan. At the end of the process, the German Bundestag (i.e., the German parliament) specifies legally binding corridors for new transmission lines.

Given the challenging nature of transmission planning in this densely populated country, this extensive public consultation approach reportedly has accelerated the planning process, reduced the risk of lawsuits that could delay projects, and increased public support for new transmission siting.

Source: https://www.netzentwicklungsplan.de.

The case of TVA’s growing stakeholder engagement process over the past few years can be instructive to other electric companies that may be considering how to expand their stakeholder engagement process in resource planning. While TVA’s process may be somewhat unique due to its status as a federal government agency, it nevertheless provides an example for further consideration. In addition to highlighting TVA’s experience, we also highlight in the accompanying text box (above) how the German government has used a new and expanded stakeholder planning process to facilitate transmission system siting decisions.

TVA has had stakeholder engagement processes in place for many years that covered some aspects of its operations. In recent years, TVA has expanded the depth and levels of its stakeholder engagement to include input and advice in additional areas including energy planning,
energy resources and distributed generation. These efforts began in part with development of TVA’s 2011 IRP, and included detailed external review and input throughout the IRP process. This helped TVA to benefit from different perspectives on issues and resources as it developed its plans.

TVA built upon this foundation to further expand its stakeholder engagement for its 2015 IRP. For this effort, TVA also formed or used existing information exchange groups on specific energy resources (i.e., renewables and energy efficiency) to gather and vet data inputs for use in the development of the IRP. These groups provided valuable data inputs early in the planning process; their observations and recommendations were presented to a separate IRP working group for endorsement and inclusion in the study. This IRP working group met throughout the IRP development process to dig into the details and provide constructive input to TVA on nearly all aspects of the study, from input assumptions to modeling constraints and presentation of results.

The IRP Working Group meetings were designed to encourage discussion on all facets of the process and to facilitate information sharing, collaboration and expectation setting for the IRP. Group members reviewed and commented on planning assumptions, recommended scenarios and strategies for study, reviewed analytical techniques and proposed energy resource options. This group was heavily involved in the review of TVA’s new methodology for modeling energy efficiency as a resource in its IRP, and in robust reviews of TVA’s power delivery structure and load and commodity forecasts.

One of the keys to TVA’s stakeholder engagement program is the consideration of diverse viewpoints. This has enriched the dialogue both between TVA and the groups, and for the groups with one another. The makeup of the stakeholder group is intended to represent the key constituents in the TVA region: local power companies, advocacy groups, academia, economic development agencies and large industrial customers. This diverse mix of stakeholders provides for the robust dialogue that is key to a successful planning process. Stakeholder engagement is a central part of TVA’s resource planning efforts, and the company has established new relationships with key groups in its service territory through transparency and collaboration on both inputs and outputs of study work. This engagement has been beneficial to TVA not only for the two IRP studies, but has also influenced other projects TVA is undertaking.
This paper describes how traditional electric sector resource planning tools, methods, and processes will need to evolve to address the dramatic ongoing transformation of the electric sector in the United States and internationally. It identifies key research gaps that need to be closed to address these changes more effectively. Improving resource planning tools, methods and processes is essential to guide efficient energy sector investments that move toward a more integrated energy system, the Integrated Energy Network (http://ien.epri.com).

Previous sections of this paper describe traditional resource planning methods (Section 2), highlight technological, economic, policy and social drivers that are rapidly transforming the electricity and energy sectors (Section 3), and introduced 10 key resource planning challenges associated with modeling the changing power system, integrating forecasts, and expanding resource planning objectives (Section 4).

Given the breadth of these challenges, their multi-disciplinary nature and their inherent complexity, many actions will be needed to make substantive progress. Solutions to these challenges that will enable resource planners to identify the optimal mix of future resources considering emerging technologies, other energy sectors, and expanding objectives span many subject matter areas and corresponding research needs. The challenges will not be solved by revising or enhancing an existing tool presently focused on one of the challenges or through a singly focused research effort. Broad progress to address the individual challenges likely will result from integrating data, models, and tools developed across many disciplines. At the same time, forward progress along any dimension will be useful. For example, more effective processes for conducting stakeholder engagement may provide better planning outcomes even if the planning methodologies are little changed. The most important first steps will likely be determined by local circumstances.

Effectively addressing these planning challenges will require substantial and sustained research, development and demonstration activities by EPRI and its member companies, federal and state agencies, universities, national laboratories, consultants and others. Although the challenges outlined here are daunting, there is a lot of opportunity to take valuable steps forward. EPRI already is working to develop solutions to many of these individual aspects that comprise this larger goal.

**Selected EPRI Research Activities to Address IEN-P Challenges**

Research to address these challenges is being conducted across EPRI’s core Research and Development Portfolio, and in a number of specific Technology Innovation and Demonstration projects. Table 4 maps specific EPRI annual research programs to the 10 IEN-P challenges. Each of these research programs is described briefly in Appendix A.

In addition to these core research activities, EPRI’s Technology Innovation program is supporting a comprehensive suite of research projects designed to begin to address some of the elements that comprise the 10 IEN planning challenges. Some of these projects are designed to improve understanding and characterization of a specific challenge, including providing needed input data, assessing present knowledge and state-of-the-art tools and methods, summarizing case studies, and identifying and evaluating potential solutions. Other TI Projects are focused specifically on developing new modeling tools, approaches and algorithms to characterize and address key issues. These new algorithms may be incorporated in new models and software tools in the future.

Additional TI research efforts are focused on improving understanding of existing GT&D planning processes and developing new, more integrated planning processes that identify and explain the activities and flows of data and information. Some of these research activities may lead to development of new software tool(s) or enhancements to existing software. Table 5 provides a summary of some of the current EPRI TI projects focused on the IEN planning challenges.
<table>
<thead>
<tr>
<th>Selected EPRI Annual R&amp;D Programs</th>
<th>#1 Operational Details</th>
<th>#2 Model Granularity</th>
<th>#3 Integrated G/T/D</th>
<th>#4 Expand Boundaries</th>
<th>#5 Uncertainty &amp; Risk</th>
<th>#6 Improve Forecasting</th>
<th>#7 Customer Behavior</th>
<th>#8 New Objectives</th>
<th>#9 Integrate Markets</th>
<th>#10 Stakeholder Engagement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Program 18: Electric Transportation</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 39: Transmission Operations</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 40: Transmission Planning</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 41.11.01: Flexible (Nuclear) Operations</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 55: Water Availability and Ecological Risk</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 66: Fossil Fleet for Tomorrow</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 94: Energy Storage and Distributed Generation</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 170: End-Use Energy Efficiency and Demand Response</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 173: Bulk Power System Integration of Variable Generation</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 174: Integration of Distributed Energy Resources</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 178: Integrated Energy Planning, Market Analysis, and Technology Assessment</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 182: Understanding Electric Utility Customers</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 193: Renewable Generation</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 198: Strategic Sustainability Science</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 199: Electrification for Customer Productivity</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 200: Distribution Operations and Planning</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Program 201: Energy, Environmental, and Climate Policy Analysis</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
In addition to EPRI’s core research program and TI activities, EPRI has an existing set of software tools that are continuing to be enhanced to address the IEN-P challenges. These tools are highlighted below and described in more detail in Appendix B:

- **DRIVE**
- Electric Generation Expansion Analysis System (EGEAS)
- InFLEXion
- Scenario Builder Tool
- TAGWeb™
- Transmission Hosting Capacity Tool (TCHT)
- US Regional Economy, Greenhouse Gas and Energy (US-REGEN) Model

**Next Steps for the IEN-P**

In 2018, as shown in Table 5, EPRI’s TI program launched a second phase effort to develop a comprehensive Framework for Integrated Energy Network Planning. This effort is designed to begin to identify how the 10 IEN-P planning challenges may be addressed by EPRI, its member electric companies, regulators and the public through research, as well as by providing resources or strategies that can be used in practice. It aims to provide a “bridge” that can help electric companies and others begin to work on solving these challenges and related issues while even more focused EPRI R&D projects to address these challenges are developed, launched and completed.

The next phase of EPRI’s research encompasses a variety of inter-related activities to continue development of the EPRI IEN-P Framework, and lay the foundation for new EPRI research programs and supplemental projects that can address the 10 key IEN-P planning challenge. These activities include:

- **Annotated Bibliography** – Developing a comprehensive annotated bibliography of EPRI and other related research related to the 10 IEN planning challenges to provide guidance to electric company planners and others.
- **IEN-P Case Studies** – Developing case studies to highlight how different electric companies in the United States and internationally, and related entities (e.g., RTOs and ISOs), have started to address one or more of the key IEN-P challenges.
- **Workshops** – EPRI plans to organize and conduct 1-2 technical workshops for EPRI members, regulators and key stakeholders to facilitate further exploration and wider understanding of the current state of knowledge about one or more of the IEN-P challenge(s), and lay the foundation for future EPRI R&D in these areas.
- **Communications** – EPRI plans to continue to socialize the IEN-P planning challenges among electric companies, regulators, and other stakeholders by continuing our engagement with the IEN-P Technical Advisors Committee (TAC); conducting webcasts; publishing articles in *EPRI Journal* and trade publications; and making presentations at appropriate industry events and conferences.
### Table 5. Selected 2018 EPRI Technology Innovation and Demonstration Projects Focused on the IEN-P Challenges

<table>
<thead>
<tr>
<th>EPRI TI and Demonstration Projects</th>
<th>IEN Planning Challenge</th>
<th>#1 Operational Details</th>
<th>#2 Model Granularity</th>
<th>#3 Integrated G/T/D</th>
<th>#4 Expand Boundaries</th>
<th>#5 Uncertainty &amp; Risk</th>
<th>#6 Improve Forecasting</th>
<th>#7 Customer Behavior</th>
<th>#8 New Objectives</th>
<th>#9 Integrate Markets</th>
<th>#10 Stakeholder Engagement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Framework for Integrated Energy Network Planning – Phase 2</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Co-Optimization of Generation and Transmission Expansion Investment Decisions</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Linking Distribution and Transmission Models to Assess Impact of DER on Bulk System</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Integrating Grid Reliability and Energy Analytics Tools</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Benchmarking EPRI Production Cost and Capacity Expansion Modeling Tools</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Screening of Hourly Power Flow Scenarios for Stability and Reliability Assessments</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market Design and Resource Expansion Framework to Ensure System Resiliency</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Framework for Integrated Generation, Transmission and Distribution Planning</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen Technology Modeling Initiative</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>

**Continue EPRI’s efforts to develop a more comprehensive Framework for Integrated Energy Network Planning**

Investigate state-of-the-art approaches while proposing improvements and/or developing new techniques for practical implementation

Develop a link between EPRI’s DER hosting capacity tools for Distribution and Transmission

Develop and demonstrate methods to link resource expansion tools such as EPRI’s REGEN and grid reliability tools including detailed production cost models

Benchmark EPRI’s EGEAS software against other models; assess applicability of EGEAS for solving some of the key IEN-P challenges

Develop a high-level, steady-state screening framework and set of metrics to identify critical scenarios requiring detailed steady-state and time-domain dynamic analysis

Develop a customer model on technology adoption and usage and the impact on electricity demand; integrate with EPRI planning models

Evaluate market design and resource expansion changes needed to ensure systems remain reliable during extreme events or recover quickly

The project is focused on developing an integrated power system planning framework and process that can then be tested with EPRI-member companies in the future

Utilize EPRI modeling tools to evaluate scenarios where H₂ technologies could be a least-cost option to meet grid operations requirements and inform investment decisions
APPENDIX A: SELECTED EPRI RESEARCH PROGRAMS ADDRESSING IEN-P CHALLENGES

Research to address the 10 IEN-P challenges is being conducted across EPRI’s core Research and Development Portfolio. The EPRI research programs that are directly working to address these challenges are described briefly below.

Program 18: Electric Transportation
Contact: Dan Bowermaster, 650-855-8524, dbowermaster@epri.com
To help advance the use of electricity as a transportation fuel, the EPRI Electric Transportation program conducts research and development on electric vehicle and infrastructure technologies, analyzes the economic and environmental impacts of electric transportation, and provides impartial support to industry and utility programs to build public awareness of as well as foundational work for supporting electric transportation in the public interest.

Program 39: Transmission Operations
Contact: Daniel Brooks, 865-218-8040, dbrooks@epri.com
EPRI’s Transmission Operations research program focuses on numerous issues, including operational planning tools and methods, real-time situational awareness, tools that use synchrophasor and other measurements to assess the present system operating point relative to operating limits, evaluating methods for more intelligently managing alarms, developing control architectures and tools to manage the grid through extreme events and restore the system in the event of an outage, and providing research on the technical aspects of electricity market operations.

Program 40: Transmission Planning
Contact: Anish Gaikwad, 865-218-8066, agaikwad@epri.com
EPRI’s Grid Planning research program addresses aspects of each of the challenges related to transmission system modeling of the changing power system including development and validation of transmission planning study models, planning processes and frameworks including risk-based methods, integrating planning across generation, transmission, and distribution, and refining reliability assessment analytics that will be required to build a reliable and economic transmission grid that integrates an evolving generation mix to supply an increasingly complex load that can also act as a system resource.

Program 41.11.01: Flexible (Nuclear) Operations
Contact: Sherry Bernhoft, 704-595-2740, sbernhoft@epri.com
The Flexible Operations program conducts research to inform decisions regarding flexible nuclear plant operations and characterize associated impacts on plant health and grid reliability. The program collects operating experience on flexible operations, supports coordinated research among industry stakeholders, and executes EPRI R&D projects designed to identify and manage potential impacts from flexible operations on the plant and its components.

Program 55: Water Availability and Ecological Risk
Contact: Nalini Rao, 650-855-2044, nrao@epri.com
The Water Availability and Ecological Risk program helps power companies and other stakeholders to (i) understand the perspectives of all water resource stakeholders; (ii) participate in evolving energy/water/food nexus development; (iii) build resilience strategies for a natural resource-constrained future; and (iv) address questions raised by lending institutions and investors concerning potential resource-based limitations on business operations and growth.
Program 66: Fossil Fleet for Tomorrow

Contact: George Booras, 650-855-2471, gbooras@epri.com

EPRI’s Fossil Fleet for Tomorrow program seeks to identify, evaluate, and advance a portfolio of advanced fossil fuel power generation technologies suitable for future markets. Specifically, it aims to (i) develop methods for generating power from fossil fuels that are dramatically more efficient, reducing CO₂ emissions and most other emissions while also lowering marginal operating costs; (ii) create power plants that are designed from the beginning to capture CO₂ and minimize the cost of capturing CO₂ emissions; (iii) foster fossil fuel-based power generation technologies that can operate in a highly flexible manner to meet fluctuating power demands; and (iv) investigate energy storage technologies that can be integrated with fossil power plants to increase their capacity factors while minimizing stop/start cycles.

Program 94: Energy Storage and Distributed Generation

Contact: Benjamin Kaun, 650-855-2208, bkaun@epri.com

This program covers research related to energy storage and fueled distributed generation (DG) technologies. The scope covers energy storage connected to utility transmission system, distribution system, and customer premises. These technologies may provide a range of services and benefits to different stakeholders, including stacked services. It also covers fueled DG of less than 10 MW capacity, such as fuel cells or combined heat and power (CHP) connected to the utility distribution system or customer premise.

Program 170: End-Use Energy Efficiency and Demand Response

Contact: Ronald Domitrovic, 865-218-8061, rdomitrovic@epri.com

This program is focused on the assessment, testing, demonstration, deployment, and technology transfer of energy-efficient and demand-responsive end-use technologies to accelerate their adoption into utility programs, influence the progress of codes and standards, and ultimately lead to market transformation. The program also develops analytical frameworks essential to utility application of energy efficiency and DR in order to enable the Integrated Power System, with particular focus on end-use load research and data analytics.

Program 173: Bulk Power System Integration of Variable Generation

Contact: Aidan Tuohy, 773-893-5091, atuohy@epri.com

EPRI’s Bulk Power System Variable Generation Integration research program addresses the impact of VER and DER on the bulk system through research that leads to methods and tools used by system planners and operators to manage the variable and uncertain and inverter-based nature of the new resources. Specific research efforts include the development of models of bulk system and distributed resource models, new planning and resource screening methods that consider the operational impacts and capabilities of renewable resources for operational flexibility and resource adequacy, new forecasting methods, and operational implications including the impact on existing and new reliability services.

Program 174: Integration of Distributed Energy Resources

Contact: Brian Seal, 865-218-8181, bseal@epri.com

Increased amounts of distributed energy resources (DER) in the electric grid bring a number of challenges for the electric industry. This program addresses these challenges with project sets that assess feeder impacts, inverter interface electronics, interconnection and communication standards, and integration analytics. The program provides insights into utility interconnection practices and strategies related to future integration approaches. It also evaluates economic impacts and values of DER integration to the distribution system. Many of these activities support EPRI’s “The Integrated Grid” initiative. Finally, the program includes laboratory and field evaluations and demonstrations of improved DER power management and communications. A primary objective of the work in the field is to expand utility hands-on knowledge for managing distributed energy resources—without reducing safety, reliability, or asset utilization effectiveness.
**Program 178: Integrated Energy Planning, Market Analysis, and Technology Assessment**

Contact: Adam Diamant, 510-260-9105; adiamant@epri.com

This research program helps electric companies address a myriad of interconnected resource planning issues by providing objective technical data and information, and powerful analytic methodologies and software tools. Project sets address (i) technology cost and performance focusing on conventional and advanced technology for new generation capacity screening and project development; (ii) evolving natural gas market dynamics and the interaction of fuel and power markets; and (iii) development of new analytic methods, tools and approaches to help company planners address critical evolving resource planning challenges. This program acts as a research “hub” at EPRI for a wide range of research activities that are related to integrated energy network planning.

**Program 182: Understanding Electric Utility Customers**

Contact: Jennifer Robinson, 865-218-8068, jrobinson@epri.com

This program provides insights, tools, and methods to help utilities understand, serve and engage with their customers to empower them to make optimal choices with respect to their supply and use of electricity. These choices will enhance customer satisfaction while also aligning with the utility and societal objectives of keeping electricity service reliable, affordable, and environmentally responsible.

Most importantly, this program supports research to enable integration of customer resources by providing critical information related to customer preferences for and adoption of customer resources. It is also a critical component of EPRI’s vision for an Integrated Energy Network that strives to provide affordable, efficient and clean energy solutions to meet customers’ needs.

**Program 193: Renewable Generation**

Contact: Ronald Schoff, 704-595-2554, rschoff@epri.com

The Renewable Generation program provides a portfolio of research and development activities that (i) assesses the status, performance, and cost of renewable generating technologies of wind, solar, and hydropower; (ii) conducts targeted research and development to address critical issues relative to the technical assessment, operation, maintenance, and overall reliability of renewable generation assets; (iii) evaluates the technical and economic impacts, and O&M trends of emerging renewable energy technologies; and (iv) provides opportunities for members to engage in general-interest renewable generation activities for workshops, tours, and other events.

**Program 198: Strategic Sustainability Science**

Contact: Morgan Scott, 202-293-7515, mmsscott@epri.com

EPRI’s Strategic Sustainability Science program identifies and develops the tools, models, and analysis needed by electric power companies to manage complex choices that have unconsidered impacts on other priority sustainability issues. Serving as a resource nexus, EPRI brings sustainability thought leaders together to propel the scientific research and analysis needed. New research is essential to better inform decisions that help embed sustainable practices into day-to-day operations and long-range planning while also informing how electric power companies impact and contribute to a sustainable economy.

**Program 199: Electrification for Customer Productivity**

Contact: Allen Dennis, 865-218-8192, adennis@epri.com

Business enterprises are constantly striving to increase productivity and enhance their competitiveness. In many cases, electrification (i.e., the application of novel, energy-efficient electric technologies as alternatives to fossil-fueled or non-energized processes) can boost utility productivity and enhance the quality of service to the enterprise and the customers it serves. Electricity offers inherent advantages of controllability, precision, versatility, efficiency, and environmental benefits compared to fossil-fueled alternatives in many applications. This research program develops and refines analytical tools and a knowledge base of technologies, applications, and markets and facilitating stakeholder networks to help utilities evaluate and pursue electrification opportunities.
Program 200: Distribution Operations and Planning

Contact: Jeff Smith, 865-218-8069, jsmith@epri.com

EPRI’s Distribution System Operations and Planning program addresses Challenges #1-3 and #5 through research that supports grid modernization and provides tools for planners, operators, and analysis experts of the modern distribution system to integrate distributed resources and evaluate the costs and benefits of various scenarios and penetrations of distributed resources.

Program 201: Energy, Environmental, and Climate Policy Analysis

Contact: David Young, 650-855-8927, dyoung@epri.com

The Energy, Environmental, and Climate Policy Analysis program provides public- and private-sector decision makers with analyses and information on the potential costs and benefits of domestic and international policy proposals and regulations and implications of technological change and shifting market drivers. Program research focuses on estimating the economic costs of potential energy, environmental, and economic policies; identifying cost-effective strategies and policy principles for reducing these costs; and examining the role of emerging technologies and the value of technological advances in limiting policy costs. Investing in technology and policy design research today is essential to having these emission reduction options available when needed in the future. The program’s research also helps inform company strategies in the face of pervasive uncertainty about future policies and technologies.
APPENDIX B: EPRI ANALYTIC TOOLS RELATED TO THE IEN-P CHALLENGES

Each of the EPRI-developed software tools below was developed to address planning challenges that have arisen in recent years and continue to be improved and developed to address the IEN-P challenges.

**Distributed Resource Integration and Value Estimation Tool (DRIVE)**

In recent years, EPRI’s PDU sector has developed new distribution system modeling tools, such as the *Distributed Resource Integration and Value Estimation Tool (DRIVE)* [44]. This tool enables distribution planners to evaluate the impacts of distributed resources across their entire distribution system. The goal of this tool is to advance the state-of-the-art in distribution analytics by enabling distribution planners with new methods to efficiently and effectively analyze the technical impacts of DER, and therefore fully realize the true costs and benefits of DER to distribution.

Applications for this new hosting capacity method include: enabling distribution planners to more accurately and efficiently screen DER interconnection requests, providing information to DER developers as to where DER can be located such that grid upgrades can be minimized, and performing technical and economic analyses to better understand the potential cost implications for accommodating DER at specific levels and locations throughout the entire distribution system.

Hosting capacity is only the first step to fully realizing the technical and economic impacts of DER on distribution systems. While hosting capacity is a necessary step to minimizing the costs of DER, it does not address the value DER bring to the distribution system. As such, the next steps associated with DRIVE relate to leveraging ongoing EPRI research to provide distribution planners with the necessary tools to consider the time and location value of DER, such that DER can be analyzed as a non-wires alternative to grid upgrades.

**Electric Generation Expansion Analysis System (EGEAS)**

EGEAS is a commercial state-of-the-art modular production costing and generation expansion software package developed by EPRI for use by utility planners to develop and evaluate IRPs, avoided costs, and develop plant life management plans [45]. EPRI developed EGEAS in the early 1980s and has maintained and enhanced this software tool since that time. EGEAS was the forerunner of the current generation of planning simulation and optimization models used today, and continues to be used by a number of electric companies in the United States and internationally91.

EGEAS is a set of computer modules that can help determine an optimum expansion plan or simulate detailed production costs for a pre-specified plan. Expansion plans are defined by the type, size, and installation date for each new generating facility or demand-side management resource. Optimum expansion plans are developed in terms of annual costs, operating expenses, and carrying charges on investment; average system costs, and financial ratios. The objective is to find an integrated resource plan that meets the specified objective function. Typical objective functions include minimizing total costs, minimizing customer rates, minimizing societal costs, and maximizing earnings.

EGEAS can handle a wide variety of generation technologies including thermal (e.g., nuclear, fossil, combined cycle, combustion turbine), limited energy (hydroelectric, interruptible rates), storage (pumped hydro, cool storage batteries, compressed air), and non-dispatchable technologies (solar, wind, cogeneration, conservation load management). Additional features include interconnections to neighboring utilities or power pools, purchase and sale contracts, environmental constraints and calculations, automatic sensitivity analysis, and describing functions. EGEAS also can analyze DSM options, such as conservation, strategic marketing, load management, storage, and rate design.

In recent years, EPRI has enhanced EGEAS in a variety of ways to help resource planners address evolving issues in resource planning. The current version 12 released in 2017 includes several important enhancements, including (i)

---

91 Learn more about EGEAS online at [http://eea.epri.com/models.html#tab=3&tab=3](http://eea.epri.com/models.html#tab=3&tab=3) and [https://www.epri.com/#/pages/product/0000000003002008244/](https://www.epri.com/#/pages/product/0000000003002008244/).
the ability to develop resource plans that are optimized to comply with state-mandated RPS; (ii) the ability for resource planners to penalize “dump energy” – energy projected generated by the power system beyond customer demand; and (iii) capability to conduct resource plan optimization based on inclusion of emissions rate-based constraints (e.g., lbs. CO₂/MWh).

**InFLEXion Software**

EPRI’s Program 173 has developed the InFLEXion software tool [46] that calculates operational flexibility metrics and evaluates the adequacy of system operational flexibility for projected future load, renewable, and dispatchable resource scenarios. InFLEXion is a multi-level planning support tool for long-term generation and transmission planning which characterizes issues related to variability. By using demand, variable generation, resource characteristics and schedules, InFLEXion enables users to calculate system level flexibility metrics which can be used to determine planning risks. The multi-level approach allows users to gain insights appropriate to the data available at each timestep.

**Scenario Builder Tool**

Developed in Program 40 (Transmission Planning), this software tool is intended to support transmission planners in developing scenarios to be studied, considering increased uncertainty in the dispatch of renewable and conventional resources, increased uncertainty in load growth and the potential need to study more scenarios than traditional snapshot cases described earlier. It provides a set of probabilistic outputs that can be used with either existing transmission planning software in a deterministic fashion, or new probabilistic transmission planning tools.

**TAGWeb™ Software – Technology Cost and Performance Data**

Technology cost and performance assumptions are central to any planning exercise. EPRI’s web-based Technology Assessment Guide (TAGWeb™) software is an integrated, web-based software tool that provides current capital and O&M costs and technical performance data and future technology trends for a wide range of electric power generation technologies.

The TAGWeb™ serves as a source of technology information and data that can be customized to individual electric company needs for input into simulation models used to conduct IRP, such as EPRI’s EGEAS software (described below), leading to the selection of least-cost technology and fuel choices. EPRI uses TAGWeb™ data and information internally to inform public-domain technical analyses and assessments of energy technologies, energy-economic analyses, and potential ways to achieve reduced environmental emissions.

**Transmission Hosting Capacity Tool (THCT)**

EPRI’s PDU sector also has developed a Transmission Hosting Capacity Tool (THCT) to assess the ability of regional transmission systems to accommodate transmission- or distribution-connected renewables that can be interconnected without violating operational reliability limits. The THCT tool is not a substitute for conducting system impact or feasibility assessments, but rather is intended as a long-term planning screening tool to be used in conjunction with generation expansion modeling results to check the potential transmission investment required to accommodate generation build-out scenarios.

**United States Regional Greenhouse Gas and Energy Model (US-REGEN)**

The United States Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN) refers to a family of related proprietary energy-economy models developed by EPRI. These models are used internally by EPRI staff and are not available to be purchased or licensed from EPRI. The “fully integrated” version of US-REGEN combines a detailed dispatch and capacity expansion model of the U.S. electric sector with a high-level dynamic computable general equilibrium (CGE) model of the U.S. economy with sectoral detail in energy demand and transportation. The two models are solved iteratively to convergence, allowing analysis of policy impacts on the electric sector taking into account economy-level responses. This makes US-REGEN capable of modeling a wide range of environmental and energy policies in both the electric and generation technologies (i.e., coal and natural gas), nuclear power generation, VER (including wind, solar thermal, solar PV, geothermal, and biomass technologies) small-scale generation including fuel cells, internal combustion engines [diesel], small combustion turbines less than 25 MW, and micro-turbines, and storage technologies represented by compressed air energy (CAES), batteries, pumped hydro, flywheels, and superconducting magnetic energy technologies.

---

92 Learn more about TAGWeb online at https://www.epri.com/#/pages/product/0000000000002012114/.

93 The technologies that can be explored in TAGWeb include fossil-fired
non-electric sectors. EPRI completed development of the first version of US-REGEN in 2013, and has continued to develop the model since that time.

US-REGEN provides a test bed to evaluate the technical, economic, and environmental impacts of a range of national and regional policies that impact the electric power sector. US-REGEN has been used widely to investigate power sector and energy questions, including economic and engineering dimensions of the fossil fleet transition, comparing costs of meeting economy-wide GHG reduction targets, and the impacts of technological assumptions on clean energy standards. Additional detail is provided in the comprehensive US-REGEN model documentation (EPRI, 2017) [47].

US-REGEN is a regional model of the United States. It can consider multiple sub-regions of the continental United States to account for differences in resource endowments, energy demand, costs, policies, and policy impacts. By default, the model uses 15 sub-regions, each an aggregation of states, but it can be configured to evaluate any arbitrary aggregation of the continental 48 states. US-REGEN is an inter-temporal optimization model that solves for the time period 2016 to 2050. The model simultaneously solves a technologically detailed capacity planning problem, while co-optimizing transmission investments and dispatch.

US-REGEN’s detailed capacity planning and dispatch model of the electric sector can be run in conjunction with a newly developed “end-use” energy model with a high resolution of economy-wide energy use, as well as a representation of upstream non-electric energy activities. The end-use model is solved over the same time horizon as the electric model (typically in five-year time steps through 2050), with iteratively updated electricity prices and hourly load shapes based on the changing end-use mix. The US-REGEN end-use model divides economy-wide energy consumption into three broad categories: transportation, buildings, and industry.


The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI members represent 90% of the electric utility revenue in the United States with international participation in 35 countries. EPRI’s principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together...Shaping the Future of Electricity

Program:
Technology Innovation

© 2018 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute, EPRI, and TOGETHER...SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.