Systems Analysis in Electric Power Sector Modeling

A Review of the Recent Literature and Capabilities of Selected Capacity Planning Tools

Systems Analysis in Electric Power Sector Modeling

A Review of the Recent Literature and Capabilities of Selected Capacity Planning Tools

EPRI Project Manager
J. Bistline

ELECTRIC POWER RESEARCH INSTITUTE

3420 Hillview Avenue
Palo Alto, CA 94304-1338
USA

PO Box 10412
Palo Alto, CA 94303-0813
USA

800.313.3774
650.855.2121

askepri@epri.com

www.epri.com

3002011102
Final Report, June 2017

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

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.

Acknowledgments

The Electric Power Research Institute (EPRI) prepared this report.

Principal Investigators
N. Santen
J. Bistline
G. Blanford
F. de la Chesnaye

This report describes research sponsored by EPRI.

The authors would like to gratefully acknowledge the support of Resources for the Future and the U.S. Department of Energy, Energy Policy and Systems Analysis (EPSA) Office. We also would like to acknowledge the guidance provided by Robert Horner at EPSA.

Several EPRI Subject Matter Experts contributed comments and insights to this final report from the Grid Operations & Planning Group and the Energy & Environmental Analysis Group.

This publication is a corporate document that should be cited in the literature in the following manner:

Systems Analysis in Electric Power Sector Modeling: A Review of the Recent Literature and Capabilities of Selected Capacity Planning Tools. EPRI, Palo Alto, CA: 2017. 3002011102.

Abstract

The electric power sector continues to evolve dynamically, displaying increases in renewable energy technologies, distributed energy resources, and energy storage; shifting consumer participation in end-use energy choices; and continued innovation and technological change. To remain useful, the modeling tools used to analyze this sector must keep pace with these rapid developments. The physical and socio-economic interactions between the component parts of the power system are numerous and complex, often requiring a "systems approach" to capture different subsectors and their important feedbacks.

This report summarizes contemporary research in electric power sector systems analysis, and the capabilities of a selected set of long-range capacity planning models for exploring systems analysis concepts. Four key areas of recent systems analysis research are reviewed in detail with respect to improving the capabilities of long-range planning models: improving temporal resolution, improving spatial resolution, representing end-use details, and representing uncertainty. Likewise, a series of popular long-range utility-scale, national-scale, and multi-sector planning models are reviewed for their systems analysis capabilities along these dimensions.

Through the review, the report finds the following as immediate research needs: (1) the integration of hourly or sub-hourly chronology and unit-level details within intertemporal optimization frameworks; (2) better representation of the transmission network, its power flows, and expansion opportunities in capacity planning models with wide geographic coverage; (3) integration of endogenous end-use models within capacity planning models; and (4) development of stochastic optimization models to explicitly account for uncertainty and craft flexible capacity plans.

Keywords

Long-term planning models
Capacity planning
Systems analysis

ELECTRIC POWER RESEARCH INSTITUTE

Deliverable Number: 3002011102

Product Type: Technical Report

Product Title: Systems Analysis in Electric Power Sector Modeling: A Review of the Recent Literature and Capabilities of Selected Capacity Planning Tools

PRIMARY AUDIENCE: Stakeholders who develop, apply, or rely on electric sector capacity planning tools

KEY RESEARCH QUESTION

The electric power sector continues to evolve dynamically with increasing deployment of novel technologies, changes in regional and national policies and markets, shifting consumer participation in end-use energy choices, and continuing innovation and technological change. To remain useful, the modeling tools used to analyze this sector must keep pace with these rapid developments. The physical and socio-economic interactions between the component parts of the power system are numerous and complex, often requiring a "systems approach" to capture different subsectors and important feedbacks. Although these tools are used in settings ranging from utility-scale resource planning to national regulatory impact analysis, questions remain about the most critical gaps between today's widely used models and systems analysis needs.

RESEARCH OVERVIEW

This report summarizes contemporary research in electric power sector systems analysis and the capabilities of a selected set of long-range capacity planning models for exploring systems analysis concepts. Four key areas of recent systems analysis research are reviewed in detail with respect to improving the capabilities of capacity planning models: the role of model temporal resolution, the role of model spatial resolution, the representation of end users and load, and the capability of models to perform uncertainty analysis. Likewise, a series of popular long-range utility-scale, national-scale, and multi-sector planning models are reviewed for their systems analysis capabilities along these dimensions. Other notable systems analysis modeling concepts are also briefly surveyed.

KEY FINDINGS

- With respect to temporal resolution, the review highlights a need for both hourly and sub-hourly chronology, as well as unit-level detail within long-term capacity planning models. Doing so can better represent system responses to increased variable renewable energy technologies, demand-side resources, storage, and distributed generation. It can also capture the effect of these system responses on optimal capacity planning decisions.
- With respect to spatial resolution, the review illustrates a need for improved representations of transmission and electricity flow between disaggregated subregions and other non-electricity market commodities. This is especially true for geographical areas like the U.S. that have wide disparities between regions in existing resource bases, renewables potentials, market regimes, and policies.
- With respect to end-use details, the review shows a need for an explicit endogenous representation of changing end-use demand via consumer adoption and use of distributed energy resources, price-responsive demand, and real-time pricing to integrate additional opportunities for cost-effective long-term capacity planning.
- With respect to uncertainty analysis, the review suggests that improved methods for explicitly considering uncertainty and developing adaptable long-range capacity plans are required to plan systems that are resilient to future unknowns.

WHY THIS MATTERS

Many of the existing challenges in systems analysis using capacity planning models are due to the tension between model fidelity (i.e., the accuracy with which a model represents reality) and computational tractability (i.e., the ease with which a model can be constructed and efficiently solved). The goal is thus to provide insights by keeping capacity planning models as simple as possible without sacrificing key features of modern power systems that could materially impact planning decisions. This report is valuable for helping modelers to better navigate these fundamental tradeoffs in developing new tools and improving existing ones. This research also assists consumers of model outputs by highlighting emerging areas of inquiry, shortcomings and strengths of different approaches for different research questions, and impacts of adding or omitting systems analysis capabilities.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- Users of this report may be interested in EPRI's Project Set 178B (*Integrated Portfolio Planning and Market Analysis*), which helps members and the public to understand emerging resource planning issues and improved methods for integrated generation, transmission, and distribution planning and fuels management. Contact Adam Diamant at adiamant@epri.com for additional information.
- Users of this report may be interested in EPRI's Program 103 (*Analysis of Environmental Policy Design, Implementation, and Company Strategy*), which applies EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model to understand impacts of state and federal policies, emerging technologies, and market uncertainties on company strategy. Contact David Young at dyoung@epri.com for additional information. Reports, articles, and presentations are available at http://eea.epri.com/research.html.
- This report is part of a larger collaborative project on systems analysis in electric power sector modeling between the Electric Power Research Institute and Resources for the Future, supported by the U.S. Department of Energy's Office of Energy Policy and Systems Analysis.

EPRI CONTACTS: Nidhi Santen, Senior Technical Leader, nsanten@epri.com

PROGRAM: Energy and Climate Policy Analysis, 102

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

Non-Technical Glossary of Terms

capacity planning: The process of determining the amount and type of generation, transmission, infrastructure, and/or other resource needs in a power system to meet a set of specified constraints. Capacity plans are typically performed for long time-horizons (e.g., a few years to multiple decades).

demand response: Short-term changes (i.e., one to four hours) in end-user loads in response to an market price signal and/or utility or grid operator request. Examples include dimming lights, adjusting heating and cooling controls, and shifting manufacturing operations to another time.

demand-side management (DSM): Measures end users can take to reduce or shift their electricity demands permanently to benefit the system. Examples include installing more efficient light bulbs, upgrading insulation, improving HVAC systems, and using an automated thermostat.

demand-side resources: A general term for any "behind-the-meter" electricity-consuming resource, including electric vehicles, storage, efficient appliances, smart thermostats, and participation in utility demand-response programs.

endogenous: A dependent variable whose value is affected by the functional relationships within a model. Opposite of "exogenous."

exogenous: An independent variable within a model; its value can affect a model's relationships and results, but cannot be affected by the model itself. Exogenous variables are often referred to as "fixed." Opposite of "endogenous."

intertemporal optimization: A class of optimization problems with an objective to find the optimal time-path of control (i.e., decision) variables subject to a set of constraints, where current decisions affect what decisions are available in the future and vice versa.

load duration curve (LDC): A function of electric power demand versus time, sorted in descending order of power quantity rather than chronological time. The LDC describes the number of hours in a year that load was greater than or equal to a given level. An "annual" LDC is often used in electric power systems planning to quickly assess how many hours of the year generation must meet a specific amount of load.

"non-energy" markets (i.e., "power" markets): Electricity is comprised of both "energy" and "power." Energy markets coordinate the purchase and sale of electricity that flows through a given point (in MWh). Power markets coordinate the purchase and sale of energy per unit of time (in MW). Power markets operate to ensure reliability of the system, and include ancillary markets, such as reserves markets (e.g., spinning, non-spinning, operating, responsive), regulation services, and capacity.

operations planning: The process of determining how the installed infrastructure in a power system (e.g., generators, transmission lines, distribution lines, and other equipment) will work together to generate, transmit, and deliver power to users. Operational planning includes determining processes such as generator unit-commitment, startups and shutdowns, hydro-thermal unit coordination, and more.

recursive dynamic: A class of optimization problems with an objective to find optimal near-term values for control variables subject to a set of constraints, repeating the process through time to determine an optimal time-path for the control variables. The method is often used to decompose intertemporal optimization problems for computational tractability.

screening curves: A depiction of time versus total cost (capital and operating expense per hour) of an online electric generating unit (EGU) for that time. Screening curves can be used to simplify the problem of determining "merit order" for dispatch of existing and proposed EGUs, a critical element in the capacity planning problem.

unit commitment: The process of determining which units to operate and when, to meet electricity demand over a given interval of time, subject to a set of unit-level and power-system level operating constraints. Unit-commitment decisions are often made one day in advance, as some large thermal units can take several hours to startup or shutdown.

utility "service:" The electric power industry is comprised of several business operations. Utility "service" refers to such business operations as power generation, power transmission, power distribution, and even aggregation (e.g., companies that aggregate end-user loads to provide demand-response services).

Table of Contents

Abstract v

Executive Summary vii

Non-Technical Glossary of Terms ix

Section 1: Introduction 1-1
- What Is "Systems Analysis?" 1-1
- Report Content 1-2
- Report Scope 1-2

Section 2: The Recent Literature 2-1
- Improving Temporal Resolution 2-1
- Improving Spatial Resolution 2-4
- Representing End-Use Details 2-8
- Representing Uncertainty 2-10
- Other Areas in Electricity Sector Systems Analysis 2-12
  - Integrating Unit-Level Detail 2-12
  - Extending System Boundaries: Representing Sub-Systems and Other Related Systems 2-13
  - Modeling Economy-Wide Interactions 2-14
  - Representing Endogenous Technological Improvement 2-14
  - Integrating Pollution and Health Effects Modeling ... 2-15

Section 3: Systems Analysis Capabilities of Selected Planning Models 3-1
- Overview of Electricity Sector Planning Tools 3-1
- Utility-Scale Capacity Planning Models 3-2
- National-Scale Capacity Planning Models 3-4
- Multi-Sector Models 3-6

Section 4: Concluding Summary 4-1

Section 5: References 5-1

Appendix A: Model Descriptions A-1

List of Tables

Table 2-1 Common Temporal Simplifications in Long-Range Capacity Planning Models 2-2

Table 2-2 Common Spatial Simplifications in Long-Range Capacity Planning Models 2-5

Table 2-3 Common Simplifications in Representing End-Use Detail in Long-Range Capacity Planning Models 2-9

Table 2-4 Common Simplifications for Uncertainty Analysis in Long-Range Capacity Planning Models 2-11

Table 3-1 Utility-Scale Capacity Planning Models' System Analysis Capabilities 3-3

Table 3-2 National-Scale Capacity Planning Models' System Analysis Capabilities 3-5

Table 3-3 Multi-Sector Models' System Analysis Capabilities.. 3-7

Section 1: Introduction

This report summarizes contemporary research in electric power sector systems analysis, and the capabilities of a selected set of long-range capacity planning models for exploring systems analysis concepts. It is part of a larger collaborative project on systems analysis in electric power sector modeling between the Electric Power Research Institute and Resources for the Future, supported by the U.S. Department of Energy's Office of Energy Policy and Systems Analysis.

What Is "Systems Analysis?"

In the broadest sense, a system is simply a set of interacting or inter-dependent components with a well-defined purpose. The foundational systems analysis literature repeatedly relays variants of this definition [e.g., 1-7]. However, systems are unique from arbitrary sets of interacting components in that they often display characteristic feedbacks—where the behavior of one component can affect the state other components, which in turn can affect the state of the original component and additional components. Rash intervention in systems can result in unintended consequences [e.g., 1, 5]. Feedbacks are inherent in power systems, and thus important to consider in electric sector planning. Decisions made today regarding the installation of technologies to generate and transport electric power will affect the economy, consumer behavior, the environment, and much more for decades. These effects will elicit responses by industry, policymakers, and other stakeholders throughout this time horizon. In turn, these responses change—by constraining or supporting—the environment within which new technology development decisions can be made.

When an electric power system is defined not only by its physical generators, transmission lines, and end-users, but by the broader economic, social, and political context within which it sits, it becomes a prime example of a "complex system."

Complexity is another defining characteristic of a system, clearly exhibited in the electric sector. Complex systems contain many interacting components and are "difficult to describe, understand, predict, manage, design, and/or change" [2]. Power system complexity multiplies when its definition is extended to include not only the physical components that make up the grid (e.g., power plants, transmission lines, substations, transformers), but also to the broader economic, social, and political context within which it functions (e.g., technology and fuel suppliers, end users and their behaviors, governments).

"Systems analysis" describes a way of thinking about how the interacting components of a complex system work together to accomplish an overall objective [e.g., 7-8]. It is an approach that can be used to explicitly define the relationships between interacting components, preventing delayed consideration of a component until a crisis evolves [8].

A critical aspect of this approach involves using a life-cycle perspective, whereby a designer plans a system not only for its intended initial use, but considers how individual components of a system change dynamically (before and after). This approach is relevant for electric power systems, where decisions about long-lived infrastructure such as power plants or transmission lines benefit from considering interactions with new resources, policies, and market paradigms.

A second critical aspect of systems analysis includes active consideration of system boundaries. A natural tension arises when defining a system boundary; defining it so broadly that it includes essentially everything is not fruitful. However, considering a broader system boundary is one of the main areas of research in contemporary electric power systems analysis, where historically investigations have considered electric power sub-systems in relative isolation. This broadening includes temporal boundaries (e.g., integrating faster dynamics into models that traditionally consider slower timescales), spatial boundaries (e.g., explicitly considering the fine resolution of renewable resource availability), and even more conceptual boundaries (e.g., considering the impact of uncertain future events on optimal investment planning).

Report Content

Section 2 provides a literature review of contemporary research in electric power systems analysis, focusing on four key areas of inquiry related to long-range capacity planning models: improving spatial resolution, improving temporal resolution, representing end-use details, and representing uncertainty. This section also briefly describes additional noteworthy areas of active research. Section 3 reviews systems analysis capabilities of selected popular long-range capacity planning models in three model categories: utility-scale models, national-scale models, and multi-sector models with electricity sector capacity planning. That section describes how each model aligns with the research areas introduced in the literature review, and provides an overview of features typically included in each model category. Finally, Section 4 provides brief concluding remarks on the most critical gaps between today's widely used modeling tools and systems analysis needs.

Report Scope

A few caveats about the scope of this report are worth stating before proceeding. First, systems analysis, even when focused a single sector, is a broad area of inquiry. This report is thus not intended to be an exhaustive review of all recent research in electric power systems analysis. Instead, its goal is to provide a review of the most salient topics being explored by the research community today, using a selected set of illustrative literature from the past five to ten years.

Second, given that systems analysis can focus on any part of the electric power system, many types of computational models are used to explore questions that fall within this space. This report focuses on long-range planning—particularly capacity planning for policy analysis—and as such, the literature and models reviewed concentrate on this subset of modeling tools. In Section 3, a brief description of other model categories is included. Additionally, the systems analysis community typically explores questions from either an "optimization" perspective, or a "simulation" perspective (occasionally both). This is analogous to approaching an analysis with a normative (optimization) versus descriptive (simulation) objective in mind, although subtle overlap between these areas exist.[1] This report focuses on the literature and models that approach electricity sector systems analysis using an optimization framework, as most long-range capacity planning models fall into this category.

Third, as the focus of the report is on modeling tools, this report does not review the wide range of existing research on estimating the inputs used by the modeling community to perform systems analysis. This includes estimating elasticities (e.g., demand, fuel), renewable resource availability, developing distributions for future uncertainties, and much more. The authors acknowledge that this research is also a critical aspect of systems analysis, but it is excluded here for brevity.

Finally, the list of individual topics that fall jointly under "electric power systems analysis" and "long-range planning" is plentiful. To keep the number of topics discussed manageable, this report focuses on the systems analysis topics chosen for detailed inquiry in the collaborative RFF and EPRI modeling project, and will be discussed in the forthcoming report. Where noteworthy other areas of systems analysis exist, they are listed and discussed briefly.

[1] In practice, optimization models are routinely used by the modeling community to predict the future, although requiring the assumption that the "optimal response" is followed through time.

Section 2: The Recent Literature

Systems analysis in the electricity sector can span many levels (or "subsystems") of the physical power system—generation, transmission, distribution, end-user (i.e., behind-the-meter) operations, as well as the larger socio-economic and political systems. There are thus countless questions associated with one or more of these component systems. This section reviews the contemporary academic literature in electric power systems analysis focusing on four key areas in long-range capacity planning modeling: the role of model temporal resolution, the role of model spatial resolution, the representation of end users and load, and the capability of models to perform uncertainty analysis. Other notable systems analysis modeling concepts are also briefly surveyed.

A multi-phased approach was used to select the literature for review, which allowed a sufficient cross-section of contemporary research to be included. First, published papers, working papers, and doctoral dissertations of several well-known electric power systems analysis modeling research groups around the world were reviewed. This included academic research centers at institutions such as MIT, Carnegie Mellon, Stanford, UC Berkeley, University of Illinois, and the Institute for Research in Technology at Comillas University in Madrid; DOE national labs such as NREL and Argonne; and popular energy research think tanks and consulting firms. The reference lists of each of these documents were then reviewed, and recurring literature cited within them were retrieved and reviewed. Finally, the subset of literature selected for inclusion was peer-reviewed by a set of energy systems modeling experts, and additional literature was incorporated based on their comments.

Improving Temporal Resolution

Long-range electricity generation capacity planning models traditionally represent between one and fifty to sixty years into the future, making investment decisions in yearly or multi-yearly intervals. Due to the computational intractability of modeling hourly (or sub-hourly) operations chronologically several decades into this future, they typically incorporate simplified representations of many inputs that have a faster intra-annual temporal dimension. These inputs include, for example, electricity demand (i.e., load) and energy output of non-dispatchable generating technologies such as wind and solar. Simplifications can consist of "load duration curves" (LDCs), which cluster similar hours of the year together into discrete blocks of time, but lose the chronology between those hours and days; "representative weeks" for the year, which retain chronology but make strong assumptions that the year will proceed just as the representative weeks did; and sequential modeling, which uses LDC-based capacity planning modeling to optimize capacity investments over time followed by a detailed operational model that uses the pre-optimized capacity investments as inputs to study detailed, chronological operations [9]. Sequential modeling has the drawback of being unable to endogenously consider the hourly chronology and other operational details, such as the number and cost of startup and shutdowns or unit commitment, in the actual capacity investment decision. The critical "feedback" from operations to long-range planning is thus missed. Table 2-1 summarizes the advantages and disadvantages associated with these common approaches to simplifying the temporal dimension in long-range electricity sector capacity planning models.

The capacity investment decision is directly linked to utilization. Yet, integrating unit-level operational details at an appropriate temporal resolution to account for operations remains a central challenge in long-term capacity planning modeling.

Table 2-1
Common Temporal Simplifications in Long-Range Capacity Planning Models

Simplification	Disadvantages	Advantages
Load Duration Curves (LDCs)	Loses chronological detail	Computationally efficient
Representative Weeks with Hourly Chronology	Requires assumption of historical replicability	Computationally efficient; captures temporal variability better than LDCs
Sequential Modeling	Misses co-optimizing operational decisions with long-term investment planning decisions	Computationally efficient; modeling is less complex

These simplifications were suitable for planning a system dominated by conventional, operationally-predictable technologies such as coal, oil, and natural gas plants. However, the expansion of variable renewable energy like wind and solar, increases in complementary emerging technologies like energy storage, and more active demand-side management options has created the need to consider more detailed temporal operations in long-term planning. Existing and new dispatchable resources (e.g., natural gas turbines, storage2) will now be used in a more dynamic way, responding in shorter time intervals to fluctuations that variable renewables impart on the system. With this comes a need to determine which existing and new resources to startup, shutdown, or adjust output over time to cost-effectively and reliably meet load. Long-range capacity planning now needs to consider this temporal detail, given how a plant's utilization and associated revenues are critical factors in capacity planning decisions.

Representing non-energy markets such as capacity and ancillary services (e.g., spinning reserves, voltage support via reactive power) is another motivation for

[2] Storage technologies present a unique challenge in long-term planning modeling. A storage device's state, and thus ability to charge or discharge power in any given period, is a direct function of its state in the previous period. Retaining chronological detail is therefore imperative in accurately modeling the value storage can add to a power system.

Developing new methods to integrate chronological, hourly (and sub-hourly) time steps for demand, wind, and solar, and unit-level operational details within long-range capacity planning models is one of the most active research areas in electricity sector systems analysis.

refining the temporal scope of long-range capacity planning models. Revenue streams for new resources are tied to their participation not only in energy markets to meet direct load, but also in many non-energy markets. Accurately capturing opportunities in these additional markets requires modeling hourly and even sub-hourly timescales. Unfortunately, these finely-resolved operations are missed when using many of the simplifications described above.

Several researchers are developing methods to capture hourly chronology, sub-hourly detail, as well as unit-level operational detail (the last of which is discussed further in a later sub-section) into long-range capacity planning models. This is one of the most active areas of contemporary research in capacity planning modeling.

In [10-12], the authors present and apply a novel "system states" method to recover hourly chronological information lost with conventional LDCs by introducing a tool known as a transition matrix to the LDC. The matrix retains information about when the system moves from one time block (or "system state") to another. In doing so, the authors can account for operational details and more precisely model the impacts of renewable technologies and energy storage on capacity planning decisions, without modeling full hourly chronology in a multi-year model.

In [13-14], the authors present an integer clustering method that efficiently approximates hourly chronological operations of the power system. The application allows for a reduction of dimensionality in capacity planning models such that critical operating constraints such as hourly startup and shutdowns, unit-commitment, and ancillary services (e.g., regulation reserves, load following) can be considered. In [15], the authors also present an efficient approach for coupling multiple timescales to cover both long-term (capacity planning) and shorter-term (generation operations) dynamics.

Other research uses "representative periods" to capture intra-annual variability in long-term capacity planning models [16-18]. The authors' methods reduce the dimensionality burden of modeling hourly operations over long time-horizons by almost two orders of magnitude (i.e., 8,760 hours to approximately 100 hours) by focusing on hours that capture key properties of the joint underlying distributions (e.g., load, wind output, solar output). In [16], the author shows that as little as ten representative time blocks can be a reasonable approximation of annual electricity demand, but that significantly more (e.g., 1,000) are needed when wind and solar power variability are also considered. While the representative periods approach does not explicitly address the challenge in modeling hourly chronological load and renewable resource details, it helps address an important underlying problem of not modeling hourly chronology—that key time periods (e.g., extremely low or high loads) impacted by the variable nature of renewables would be missed.

In [19-20], the authors present a new capacity planning model that hybridizes a national-scale and utility-scale model. The latter (discussed in more detail in Chapter 3) can typically represent temporal detail better due to its smaller spatial scale (and thus relatively reduced dimensionality). The authors co-optimize across both energy and ancillary services (i.e., regulation reserves, spinning contingency reserves, flexibility reserves), representing down to five-minute intervals for regulation. Also presented is a series of case studies on the effect of using different configurations of representative periods for annual operations. The authors find that, on an interconnect-wide basis, the magnitude of differences in capacity decisions from adding temporal detail can be small. The authors' method is similar to the representative weeks method found in [21], but based on [22].

Finally, researchers have been embedding increased temporal and operational detail into other types of capacity planning tools, as well. The authors in [23] present a method to incorporate a better representation of the cycling of thermal power plants by developing an "enhanced screening curves" capacity planning tool. [24] develops a capacity planning model for integration within an economy-wide general equilibrium model, using a recursive dynamic framework that optimizes in two-year time steps. This formulation, based on simplifications found in [25-26] allows for full hourly chronology of load and renewable resources, as well as co-optimization of dispatch, operational planning (e.g., startup and shutdowns), and capacity planning decisions. However, because the recursive dynamic framework employed optimizes decisions over shorter two-year segments instead of simultaneously over the full planning horizon, it forgoes the opportunity to consider the impact of potential future decisions on near-term decisions—an important consideration when planning for long-lived infrastructure. The formulation also uses capacity blocks to represent generation technologies instead of individual units, which can result in outputs that are difficult to interpret.

Improving Spatial Resolution

Due to computational tractability, a practical tradeoff exists in the ability of models to capture highly resolved spatial detail. The wider the geographic coverage, the more simplified the spatial detail. This extends to models of transmission, non-energy trading, and market design.

Most long-range capacity planning models used for electricity sector analyses focus on representing a single "service" subsector (e.g., generation, transmission, distribution) well, but typically do not cover more than one or two with rigor. There remains a high degree of variation in how different inter-dependent subsystems are represented; researchers have a long way to go in achieving true systems analysis capabilities in this area.

Currently, variation in spatial resolution depends on the geographic scope of the model itself. For example, capacity planning models that cover only a utility service area can often represent both the generation sector and transmission sector in detail (e.g., individual plants, nodal transmission). In contrast, a model covering the continental United States may model the generation sector in detail, but use an overly simplified representation of the transmission network and its power flows. Common assumptions across national-scale long-range capacity planning models include "copper plate" modeling that ignores the existence of transmission lines altogether (i.e., assumes free-flowing electricity across model regions), and simple "pipe flow" transport modeling that allows for power exchange between defined regions based on aggregate transmission line capacities. These assumptions leave the capability to represent electricity trade substantially different between models of different geographic coverage.

Analogous to the challenges of increasing temporal resolution, most of the tradeoffs are due to computational tractability. As a general rule, larger geographical areas limit the number of subregions under consideration, as well as their level of interaction. Models with smaller geographic coverage tend to represent intra-regional electricity flows well, but make strong assumptions about interregional electricity trade. Conversely, models with larger geographic coverage can represent interregional trade, but tend to ignore intra-regional trade. The limitation extends to other markets as well. As spatial aggregation increases, representing the flow of other commodities (e.g., emissions cap-and-trade programs credits, renewable energy credits (RECs) for state renewable portfolio standards) is challenged.

A second common spatial simplification involves renewable resource availability and potentials. Many models employ single resource values for large geographic regions and do not resolve details between different classes of resources with large variation in the potential to generate electricity. This is motivated by the lack of computational power, as much as a lack of available data.

Finally, a third simplification is to assume that all regions modeled operate under a single (usually competitive) market regime. Modeling different regions as operating within either a cost-of-service rate-regulated or a competitive (i.e., "deregulated") market adds a level of complexity in the modeling that most tend to ignore. For U.S. policy analysis, where there is a large degree of heterogeneity in markets across the country, this can limit effective systems analysis.

Table 2-2
Common Spatial Simplifications in Long-Range Capacity Planning Models

Simplification	Disadvantages	Advantages
"Copper Plate" Transmission Network	Ignores transmission constraints for electricity flow	Less complex modeling
Zonal "Pipe-Flow" Transmission Network	Ignores important physical properties of power flow	Captures some transmission constraints (e.g., line limits)
Zonal DC Power Flow Transmission	Still ignores many physical power flow properties (e.g., no reactive power, assumes small voltage angle differences, voltage is constant)	Simplest method of including Kirchhoff's laws of flow and voltage conservation; more realistic than alternatives

Table 2-2 (continued)
Common Spatial Simplifications in Long-Range Capacity Planning Models

Simplification	Disadvantages	Advantages
Single or Few Modeling Regions	Misses energy and non-energy trade between regions; requires assumption of heterogeneity in resource base, renewables potentials, etc. within regions	Less complex modeling; computationally efficient
Homogenous Capacity Factors for Renewables	Misses heterogeneity in renewable resource potentials	Less complex modeling; less data intensive
Single Market Regime	Misses representing retail pricing and investment cost-recovery methods	Less complex modeling

Increasing the geographic granularity with which renewable resources are represented and more realistically modeling the transmission network in models with wide geographic coverage are two areas of active research in improving the spatial resolution of models.

Today's transitioning power system is challenging the status quo in most capacity planning models' spatial modeling capabilities. First, the magnitude and pace of renewable deployment requires a more detailed representation of optimal capacity investment opportunities across all possible resource types. Renewable energy resources (e.g., onshore wind, offshore wind, solar PV, CSP) have a high degree of geographic variation in their potentials, both in their average annual output and the shape of their hourly and sub-hourly generation. Understanding optimal resource allocation across space and time along with co-optimized supporting resources (e.g., transmission, storage, flexible fossil generation) requires stronger resolutions in their representation. Second, electricity markets are becoming increasingly connected to respond to additional variable renewable resource deployment, support overall system stability, and help with cost-effective compliance solutions to various environmental and other regulations (e.g., buying and selling bundled and unbundled RECs). This increased inter-connectedness calls for representing electricity and other electricity-related commodity flows (e.g., RECs) with more rigor than in the past. Finally, representing spatial variation within market-types is becoming increasingly important given that emerging technologies' mechanisms for cost recovery are tied to the service markets they can participate in—energy and non-energy markets (e.g., capacity markets, reserves markets). The existence and functioning of these markets varies across regions, so understanding technologies' values and their capability to recover costs is thus tied to how well these market attributes can be represented.

There is active research in improving methods to increase spatial granularity within capacity planning models. In [29], researchers at the National Renewable Energy Laboratory (NREL) continue to develop the Regional Energy Deployment System (ReEDS)—a national-scale model with a very high spatial resolution. The U.S.-focused model uses 134 separate load balancing areas, and 356 resource regions for renewable wind and solar output. The model is able to achieve this level of spatial granularity by simplifying the temporal dimension, using load duration curves with time blocks instead of an hourly chronological framework. Meanwhile, NREL authors also develop and illustrate the capabilities of a new capacity planning model—the Resource Planning Model (RPM)—which uses a novel method of spatial aggregation to manage the dimensionality of the capacity planning problem while retaining an hourly chronological structure [28]. The geographic coverage of the model is a large interconnect (i.e., the entire Western Interconnection), but within this area, the authors model two utility service regions with much greater levels of detail—approaching that of commercial models used by utilities (i.e., 376 individual generators, 1,406 nodes, and 1,840 transmission lines). The analyses show that certain aspects of spatial detail, such as representing renewable spur lines and their costs, can have dramatic effects on resulting capacities. Research presented in [29] uses RPM for a series of experiments focused on the effect of spatial resolution on generation capacity investment decisions. The authors find that the degree of spatial aggregation in a model can have significant impacts on the choice of capacity investment. Specifically, solar PV deployment can be very sensitive to this model feature, with lower levels of PV deployment (and comparably higher levels of wind deployment) with coarser geographic resolution.

Other research explores the effects of grid-representation and power flow on capacity investments. In [30], the authors present a capacity planning model for the eastern U.S. and Canada, with a very detailed representation of the transmission network and its power flows. The model is used to systematically study the effect of reduced-form representations of the transmission network, running scenarios with the region represented with 5,000 nodes, 300 nodes, and a single node. Results show that simulating the region with 300 nodes instead of 5,000 can affect model outputs (i.e., generation capacity investment and retirement, carbon emissions, electricity price) by more than 20%. In [31], researchers at MIT present results from a new integrated distribution and wholesale-level capacity planning model (GenX), that co-optimizes generation capacity decisions across all three network voltage levels (i.e., high, medium, low). This research area is still emerging, but is critical given the increasing interest and deployment of distributed energy resources. Several researchers are interested in investigating how to co-optimize capacity investments across an "integrated generation, transmission, and distribution (GT&D) network." Earlier foundational work in this area can be seen in [32], where an integrated GT&D approach to capacity planning was developed for an energy storage application.

Finally, research improving spatial resolution in capacity planning models also focuses on more realistically describing the heterogeneity in "cost-of-service" versus competitive "deregulated" markets across regions. Most capacity planning models, particularly national-scale models, assume perfectly competitive markets, missing the distinction and influence different market designs and market power can have on model outputs. In [18], researchers at the Electric Power Research Institute present US-REGEN, a national-scale capacity planning model with a linked macro-economic model, to explore regional differences in how costs from Clean Energy Standard credits are "passed through" to retail markets in cost-of-service versus competitive pricing regimes. The model uses a novel framework to incorporate these different market structures, and the authors show that electricity price increases are not uniform across different regimes (which in turn has strong implications for generation investment incentives). In [10], the authors present a new capacity planning framework that explicitly considers the profit-maximizing behavior of electricity generation firms within a competitive market.

Representing End-Use Details

A third active area of research in electric power systems analysis involves improving the representation of end users and their loads within capacity planning models. From a systems analysis perspective, the need for this representation has been heightened due to the magnitude of end users active in their decisions about energy consumption and production. This is the result of utility energy efficiency and demand-response programs, the onset of advanced metering infrastructure and real-time pricing programs, smart thermostats and home "energy box" devices that deliver automated tuning of energy-using devices in the home, plug-in hybrid and electric vehicles (PHEVs) and storage, and behind-the-meter electricity production via technologies such as rooftop solar PV. Each of these technologies has changed the nature of electricity end use, and the process utilities need to consider as they forecast generation supply needs and perform long-term planning.

More active end user participation in energy decisions, and the variability of these decisions on load, calls for increased attention in the way end-use activities are represented in long-range capacity planning models.

Historically, capacity planning models have used simple assumptions about end-use operations and demand. One approach is to assume an exogenous growth rate for total annual demand, applied to an LDC in aggregate to scale the LDC profile "up" (or "down") over time. With the onset of greater demand response, energy efficiency, and customer-sited PHEVs, storage, and solar PV, researchers have sought to exogenously change both the profile and height of the LDC. Estimates for how changes in end-use operations affect demand are developed, and then applied to the LDCs. Nevertheless, an ability to endogenously represent end-use operations is important given the feedbacks present between end use, electricity supply, and prices faced by consumers. State-of-the-art capacity planning models include endogenous representations of the elasticity of demand, detailed demand-side energy use, demand response programs, real-time pricing, and explicit consumer adoption of emerging distributed energy resources.

Table 2-3
Common Simplifications in Representing End-Use Detail in Long-Range Capacity Planning Models

Simplification	Disadvantages	Advantages
Exogenous Growth Rate to LDC	Misses how changing technology and consumer behavior affect load shapes	Less complex modeling; less data intensive
Exogenous Changes to LDC Profile	Misses linking materially important model outputs (e.g., renewable capacity investments) to the shape of the LDC	Less complex modeling; computationally more efficient than endogenous changes

To date, few capacity planning models incorporate a detailed end-use model. EIA's National Energy Modeling System (NEMS) is an exception [33]. Separate residential, commercial, and industrial demand modules provide a detailed representation of end-use services, housing and building types, many end-use technologies, distributed generation, and co-generation. Moreover, this detail is derived for nine different Census regions. While a separate submodule translates the output of the detailed demand for use in the long-term capacity planning model (preventing the end-use module from being truly endogenous), the level of detail in NEMS' demand modules exceeds other models' current capabilities.

Incorporating price-responsive demand and representing time-dependent rate structures within long-range planning models are active areas of research. Efforts to integrate detailed (bottom-up) technology- and consumer-based end-use models are still emerging.

In other research, [34] presents a new capacity planning model that explicitly incorporates price-responsive demand, and uses it for a case study in Georgia. The authors explore a renewable portfolio standard for the state, illustrating the impact on emission reductions from both demand response and changing generation capacity investments. They also show results from the model with and without elastic demand, and illustrate that while different demand elasticities can have minor effects on electricity price and emissions, they can have substantial effects on the long-term generation mix. [35] uses the MARKAL-MACRO model, which also includes price-responsive demand, to study carbon emission reduction scenarios in Taiwan. In [18], the authors' use of US-REGEN for a Clean Energy Standard policy analysis includes an explicit, structured representation of energy end-use-specific capital via an integrated electric-sector and macro-economic model, as well as price-responsive demand. The separate structured representation of demand response offers a detailed portrait of how load shapes and electrification can evolve under different policy and technology futures. [36] presents and [37] applies the Engineering, Economic, and Environmental Electricity Simulation Tool (E4ST), which predicts investments in generation, simultaneously optimizes investments in transmission and demand-side management, and includes price-responsive demand and real-time pricing capabilities. [37] uses the model to study the effect of real time prices in different regions of the Eastern Interconnection, showing that pricing structure can lead to higher emission levels in some regions. Finally, the MIT Utility of the Future Study's GenX model, presented in [31], includes flexible demand as a potential distributed energy resource. The investigation employs the model to calculate the long-run equilibrium of central versus distributed generation capacity under a range of policy and operating conditions.

Representing Uncertainty

Improving the capability of capacity planning models to explicitly model decisions under uncertainty can help generate plans that are robust and/or flexible across different possible futures. Most current planning models lack this ability.

Understanding the effect of uncertainty on optimal long-range capacity planning is an important emerging topic in electric power sector systems analysis. While uncertainty does not have as explicit an association to the concept of a "system boundary" as the above three systems analysis concepts, accounting for uncertainty in long-term planning is essential given unknown future technology costs and availabilities, variable renewable energy, planning and bidding behaviors of other competitive firms, new market structures and policies, changing environmental and other regulations, and much more. Moreover, uncertainty is a critical dimension for analysis to support systems that are robust and flexible.[3] Studying systems, particularly complex systems with socio-economic and political subsystem extensions such as the electric power system, for their robustness and/or flexibility are cornerstones of systems analysis. Both provide important information about resiliency against future unknowns.

Explicit integration of uncertainty analysis in capacity planning models is still emerging. Common methods to date include using sensitivity analysis and scenario analysis, or Monte Carlo analysis for more formal applications. Sensitivity analysis provides decision-makers with an understanding of how a system would optimally respond if the future for an uncertain input (e.g., future policy and/or natural gas price) *was* known, but was different from a reference path. In the same way, scenario analysis methods often combine uncertainties into detailed "storylines" depicting alternate futures. Optimal plans are then developed for each storyline. In both cases, decision-makers review model results, choosing one or a combination of plans to implement. Most utility planning processes around the country rely on sensitivity and/or scenario analysis to conduct long-range capacity planning and consider risk. It is also an acceptable method of considering uncertainty in most integrated resource planning (IRP) states. Increasingly (although still rare), utilities will perform formal Monte Carlo analysis, which exploits the probabilistic nature of an uncertain input to develop a distribution of optimal long-term capacity plans based on each value in a distribution of the uncertain input or set of uncertain inputs. Planners will then use the output distribution to consider a best implementation plan, per their level of risk tolerance.

[3] Robust systems are those which an original system design continues to function optimally under a variety of future uncertainties. Flexible systems are those that adapt to changing, uncertain futures.

Table 2-4
Common Simplifications for Uncertainty Analysis in Long-Range Capacity Planning Models

Simplification	Disadvantages	Advantages
Sensitivity Analysis	Misses capturing a wide range of possible futures	Computationally efficient; simple to implement; less data intensive; provides insight about how inputs relate to outputs
Scenario Analysis	Misses capturing a wide range of possible futures; if not done systematically, can be difficult to understand results	Computationally efficient; provides insight about how inputs relate to outputs
Monte Carlo Analysis	Misses creating adaptable/flexible long-range capacity plans	Systematically explores a wide range of possible futures; creates a distribution of outputs to support decision-making; can identify robust plans

While these methods provide important information about optimal long-range plans under different scenarios, they miss the ability to craft plans that are adaptable to future uncertain conditions. There are three main reasons why methods to develop adaptable long-range plans are not more prevalent. First, the dimensionality of the planning problem grows too large, too quickly, for standard computers when multiple decisions, uncertainties, and time-periods need to be considered simultaneously. This renders many capacity planning problems under uncertainty computationally intractable. Second, adequate data to describe future unknowns remain scarce. Most often, historical data are used to develop distributions for future uncertainties, but it is not always clear that the past accurately portrays future uncertainties. This is particularly true in the electric power sector, where it is common to witness large structural changes. Finally, adopting a planning method based on expectations of the future requires decision-makers to adopt a new mentality that the optimal long-range plan under uncertainty is optimal over an "expectation" of the future, not over a single or specific set of futures. The goal of a long-term plan under uncertainty is to stay as close to the "true" optimum (which cannot be known a priori) as possible. This remains challenging for a planning community that historically has not relied on formal hedging methods to make decisions about long-lived infrastructure.

Formal stochastic programming frameworks have been incorporated in many shorter-term power system models, but are still emerging in the long-range capacity planning literature. Computational tractability remains a central challenge in modeling sequential decisions under uncertainty over long time horizons.

Research has focused on introducing new frameworks to incorporate uncertainty into electric power systems analysis and develop adaptable long-term plans that combat the challenges listed above. For example, [38] presents a stochastic capacity planning model that considers long-term uncertainty in the availability and variability of wind resources, applying a two-stage investment decision model to a case study of Illinois. The authors use a scenario reduction method to keep the model computationally tractable. [39] shows a long-range (20-year) planning model that considers future wind power production uncertainty, as well as demand uncertainty. Considering uncertainties surrounding off-shore wind power, [40] presents a two-stage stochastic optimization model to study the optimal configuration of wind farms under wind-speed uncertainty and uncertainty in reliability of off-shore system infrastructure components.

Recent research has also focused on presenting frameworks for optimal investment timing for energy storage investments under uncertainty in market structure and technology costs [41]; generation capacity planning under uncertainty in CO_2 regulatory policy stringency and fuel prices [42]; and optimal generation capacity planning from the perspective of a single firm, considering uncertainty in the investments of other competitive firms [43]. In each, the authors present different methods for handling the dimensionality problem that arises when studying decision-making under uncertainty for long time horizons, making use of various simplifications and heuristics for structuring the problem.

An additional line of research related to uncertainty and long-term capacity planning explores questions of electricity-sector R&D investment decision-making. One example is shown in [44], which presents an analytical framework for making optimal R&D investment allocation decisions in fossil-based generation, renewable energy, and carbon capture and sequestration technologies. The author applies the framework using the MERGE global economy model—an intertemporal general equilibrium model with a bottom-up representation of the energy sector—to illustrate its implementation. [45] discusses a range of useful metrics for evaluating decisions under technological and policy uncertainties. In this work, the authors construct a two-stage stochastic version of the MARKAL bottom-up energy systems model to study optimal investments under uncertainty in carbon policy stringency, carbon capture and sequestration technology availability, and nuclear availability and public acceptance. Finally, in [46, 47], the authors develop a stochastic capacity planning model that co-optimizes R&D investments across a range of different technologies (e.g., solar, wind, advanced nuclear, CCS) under uncertain returns to R&D. They illustrate use of a method called approximate dynamic programming to control the dimensionality of the problem and keep it computationally tractable.

Integrating unit-level detail can be related to improving model temporal resolution. In many instances, unit-level operational detail (e.g., unit-commitment-related costs and constraints) are not included because the chronological information needed to track a unit's state is not represented.

Other Areas in Electricity Sector Systems Analysis

In addition to the areas of electric power systems analysis discussed above, five other prominent areas of research are worth briefly mentioning.

Integrating Unit-Level Detail

To keep long-range capacity planning models computationally tractable, a common simplification involves grouping power plants into "capacity blocks," effectively treating technologies as aggregated units instead of individual power plants. This is applied mostly to "dispatchable" technologies such as coal, natural gas, oil, and nuclear, although it can also be used for any type of resource. While this simplification was suitable in power systems dominated by conventional, predictable fossil technologies, the increase in variable and intermittent renewable energy technologies requires consideration of the detailed, flexibility-lending operations of the rest of the system (described earlier in this section). Thus, in addition to representing hourly chronological operations described earlier, researchers are developing methods to integrate generating unit-level commitment (designating generator availability as "on" or "off"), startup and shutdown costs, and ramping constraints into long-range capacity planning frameworks. Both chronology and unit-level detail are closely related issues. For example, the decision to commit a unit in one hour depends on its position in the preceding hour. Unit ramping is also directly related to a generator's load level in the previous period.

Adding this level of detail is not trivial. It explodes the dimensionality of the problem, particularly in models with an intertemporal optimization framework covering many years. It also changes the underlying structure of the optimization problem, as representing individual units and their commitment states introduces integer variables—adding layers of complexity modelers previously sought to avoid in long-range planning.

Different approaches have been proposed to keep these problems as tractable as possible, while still benefiting from unit-level detail. This includes using a recursive dynamic framework instead an intertemporal optimization framework to minimize the number of time periods that need to be simultaneously solved; using representative weeks instead of a full year to integrate hourly chronology and unit commitment; using an enhanced "screening curve" method for capacity investment decisions instead of a more conventional capacity planning model that explicitly separates the engineering costs of candidate technologies and considers other important system constraints; and applying unit-level operations to a static (single-year) model. See [21, 23, 28, 38, 48] for examples of recent efforts at integrating unit-level operations for studying long-term planning.

Extending System Boundaries: Representing Sub-Systems and Other Related Systems

The complexity of representing the electric power system in computational models means that long-term planning usually considers the smallest *possible* system boundary for a specific planning question. For example, as described earlier, it is typical for capacity planning models used for national policy analysis to consider the transmission network as a "copper plate" and ignore its expansion. This simplifies the problem immensely; the assumption is that if generation capacity of a specific technology is determined necessary for a future point in time, separate analyses can determine its optimal location and ensure that the necessary transmission is planned and built to connect it to the grid. Similarly, it is common for generation planning to proceed separately from natural gas network planning, despite the intricate link between the two systems. Finally, distribution system planning sometimes proceeds without explicit acknowledgement of the bulk system (i.e., centralized generation capacity or the transmission network), despite the increasing interaction between the two systems. Across the power system, there are many examples of sub-systems being studied in isolation due to the complexity introduced by considering extended system boundaries, yet from a systems analysis perspective, this is precisely the need.

While isolated analyses may have been suitable in the past, the changing nature of the power system (e.g., increased renewable energy distributed energy resources, layering of environmental regulations and policy) is stressing this analytical framework. Increasingly, it has become important to consider the interactions between sub-systems within the electric power system and between the electric power system and other systems it commonly encounters to ensure that optimal capacity plans are in fact optimal from a range of perspectives. Doing so helps avoid unnecessary externalities from surfacing after plans are developed, creating more holistic and robust plans.

Recent research in this area has focused on integrating distribution, transmission, and generation planning [e.g., 31, 32, 49]; integrating natural gas and electricity sector planning [e.g., 50]; modeling the water-energy nexus [e.g., 51-53]; transmission expansion planning with and without uncertainty in generator siting [54-57]; and representing electricity flows and expansion opportunities between geographically connected international power systems [58].

Modeling Economy-Wide Interactions

Understanding the links between the electricity sector, the wider energy sector it sits within, and the macro-economy has been another important area of research in electric power systems analysis. The motivation for doing so is multi-faceted. There is a desire to co-optimize emissions mitigation solutions for potential economy-wide environmental regulations, as well as a desire to understand important feedbacks between electricity generation capacity investment, key economic inputs (e.g., labor, materials), and other sectors of the economy (e.g., manufacturing, fuels). Unfortunately, due to computational tractability most economy-wide models do not have a detailed representation of the electricity sector. Thus, while interactions between sectors of the macro-economy are well represented, these models often miss important operations within the electricity sector that researchers have shown can affect model results. Recently, there has been work to integrate detailed “bottom-up” representations of the electricity sector within “top-down” macro-economic models to close this gap. See [24, 59, 60, 61] for recent examples.

Representing Endogenous Technological Improvement

Understanding and representing technological change is one of the most important considerations for long-term planning in the power sector. Many technologies needed for reaching various economic and environmental policy goals are still either unavailable or not yet cost-competitive with conventional technologies; knowledge about the commercialization potential for emerging technologies, and their costs, is imperative to making informed choices.

Long-range capacity planning models typically use exogenous assumptions about the availability, performance, and costs of electricity generation technologies.

These assumptions can be informed by any number of sources, including historical change in technologies' costs and performance, expert elicitation of how technologies are expected to change over time, and comparison of future technologies to those most like it today (e.g., assuming carbon capture and sequestration technology will experience cost changes as nuclear technology did, because both are capital-intensive baseload technologies). The common form these exogenous assumptions take are costs and performance trends as a function of time.

Other options for representing technological improvement exist, but methods for integrating them within long-term planning models are still emerging. Like most other detailed systems analysis concepts described throughout this report, the challenge is in the complexity of the resulting model, as well as a lack of available data. A popular method involves using learning curves, whereby the cost (or performance) of a technology decreases (increases) as a function of cumulative installed capacity or another endogenous variable in the model. The learning curve simulates the process of "learning-by-doing." A second, less widely-employed learning curve is a "learning-by-research" curve, whereby the costs (or performance) of a technology decreases (increases) as a function of cumulative R&D and/or another research-based metric. A key challenge in including R&D-based technological improvement within capacity planning models is a lack of reliable data. How does one translate R&D funding to the technology change parameters used within capacity planning models? For recent research in these areas, see [44, 46, 47, 62, 63, 64, 72].

Integrating Pollution and Health Effects Modeling

Finally, modeling the fate and transport of pollutants released from the electric power generation sector through the environment, and their effects on public health and welfare has been a growing area of academic inquiry in recent years. Understanding changes in welfare due to electric power sector emissions has been important in developing policies for mitigating their negative effects, while continuing to ensure reliable and affordable electricity. From a systems perspective, this is a natural area of research: integrating capacity planning with the fleet's effect on the natural environment and health is a specific instance of extending the system boundary to internalize externalities that were not previously considered in the analysis.

Most existing capacity planning models do not consider this extended boundary, unless specifically required for regulatory analyses. In these cases, the feedback loop that describes pollutant emissions (e.g., water, air, hazardous waste) through the environment (e.g., atmospheric transport, dispersion through waterways) and the economy (e.g., hospital stays, fewer labor hours), and back to the electricity sector—a "life-cycle" systems analysis—is rarely considered. The analysis is usually one-way; estimated power plant emissions via capacity planning and dispatch modeling, followed by pollution transport and fate modeling, followed by toxicological modeling to calculate public health effects. Even this level of modeling, however, requires use of a high-resolution electricity sector dispatch model (to accurately represent the geography of emissions releases), and linking to detailed atmospheric chemistry models. An added challenge is modeling unit-level non-CO_2 pollutant releases, as this requires unit-level engineering detail and a thorough understanding of how emission rates change as a function of generator load. True life-cycle based systems modeling whereby public health effects affect the optimal capacity plan via feedback mechanisms are thus still emerging. For recent research in this area, see [65-68].

Section 3: Systems Analysis Capabilities of Selected Planning Models

This section examines a select set of today's most widely-used capacity planning models for their systems analysis capabilities. Reviewing the three main classes—utility-scale models, national-scale models, and multi-sector models—the section discusses their typical features, structural differences, and the types of systems analysis questions they are best used for. The models are reviewed along the systems analysis dimensions presented in Section 2: temporal resolution, spatial resolution, end-use details, uncertainty analysis capability, and other areas. For more information on each model, see Appendix A.

Overview of Electricity Sector Planning Tools

Electricity sector modeling takes place on many scales—from sub-seconds to decades, and over a range of functions; for each function, a tool exists to support analysis and decision-making. On one end of the spectrum lies a set of **network reliability tools** for transient stability management, power-frequency regulation, fault analysis, security analysis, voltage stability analysis, and power flow. These are tools that operate on the sub-second to minute timescale, and address issues such as generator and load dynamics, demand variations, power exchanges, and frequency control. They are mostly utilized by ISO/RTOs, reliability organizations, and large vertically integrated utilities responsible for ensuring a reliable and safe network. The next set of tools lies in the middle of the spectrum. These are **operational models** that perform unit-commitment, production costing, maintenance planning, hydro-thermal coordination, and fuel planning. These models operate on a day to year timeframe, and handle most medium-term generation and other operations planning of the power system. Finally, at the other end of the spectrum lie the models this report focuses on—**long-range capacity planning models**. These models operate on a multi-year to decadal timeframe, and address issues such as new generation and transmission capacity investment, and existing capacity retirement/retrofit [69, 70]. Between these model types, there is not currently substantial overlap in features and capabilities.

In recent years, there has been growing interest in merging features of tools that sit at different points on the spectrum, particularly integrating features of tools that operate on faster timescales and with greater spatial resolution into capacity planning models. As one example, adding capabilities such as unit-commitment and startup/shutdown costs and constraints (typical in medium-term production cost models) into a long-range, intertemporal optimization capacity planning model is a very active area of research. Moving away from simpler zonal transmission modeling to more realistic nodal transmission modeling within capacity planning models is another example. The motivation for these efforts is discussed in Section 2.

Within each class of models—utility-scale, national-scale, and multi-sector—the tension between model fidelity and model tractability arises.

Nevertheless, there continues to be tension between achieving model fidelity—the accuracy with which a model represents reality, and model tractability—the ease with which a model can be constructed and efficiently solved. Integrating production costing approaches into long-range capacity planning, or modeling a more detailed transmission network, can provide insight into how a system's operation impacts capacity investment opportunities. However, this comes at the expense of model dimensionality and thus computational time. Many systems analysis concepts discussed in this report fall prey to this modeler's dilemma. The goal is thus to keep capacity planning models as simple as possible, but with new features essential to model key issues of modern power systems. In this section, three classes of capacity planning models are reviewed for their systems analysis capabilities. Both within each class, as well as between classes, each of these models are making trade-offs between fidelity and tractability to incorporate specific analytic capabilities.

Utility-Scale Capacity Planning Models

Utility-scale capacity planning models optimize generation capacity investments to meet demand years to decades into the future. They typically co-optimize transmission investments needed to support the new generation, and represent the network via a discrete set of lines with DC power flow between designated "zones" (although occasionally via actual AC power flow between nodes). Investment and dispatch decisions are usually made at the EGU-level (i.e., individual plants are represented), and the optimal capacity plan is developed for a utility service area (or another similar discrete region). Temporally, utility-scale models often include simplifications of an hourly chronological model, using representative weeks of the year and modeling them hourly before scaling results to the full year. This simplification is made to keep the models computationally tractable. While the geographic scope of these models is not unduly large, representing individual EGUs, as well as multiple years, is computationally expensive. However, compared to other capacity planning models, utility-scale models retain the highest temporal and spatial resolutions due to their smallest geographic scope. Optimization of demand-side technologies is not common; they are most often included as exogenous resources with fixed load shapes. Utility-scale capacity planning models are mostly used by utilities and their consultants in preparing integrated resource plans and other long-range generation capacity plans for utilities to make their investment decisions. Other stakeholders also make use of them for state and regional-level policy analysis. Table 3-1 compares six well known utility-scale capacity planning models for their systems analysis capabilities.

Utility-scale models typically retain the highest temporal and spatial resolutions due to their relatively restricted geographic scope.

Table 3-1
Utility-Scale Capacity Planning Models' System Analysis Capabilities

Model	Temporal Resolution	Spatial Resolution	End-Use Details	Uncertainty Analysis	Other
System Optimizer (ABB)	Hourly chronological, via representative weeks	Customizable (service area or slightly larger); zonal transmission	Optional endogenous demand-side resources; energy efficiency	Sensitivity, scenario analysis	Individual EGUs; transmission expansion; water-energy modeling
Strategist (ABB)	LDCs; representative week per month for wind/solar output	Service area	Optional endogenous demand-side resources; energy efficiency; time-of-use rates	Sensitivity, scenario analysis	Individual EGUs (limited detail)
AURORAxmp Resource Expansion Module (EPIS)	Hourly chronological operations	Service area to balancing authority; zonal transmission	Optional endogenous demand-side resources	Sensitivity, scenario, Monte Carlo analysis	Individual EGUs; transmission expansion
PLEXOS LT Plan (Energy Exemplar)	Hourly chronological operations	Customizable (service area or larger); zonal DC power flow or nodal/AC transmission	Optional endogenous demand response / price-elastic demand	Sensitivity, scenario analysis	Individual EGUs; transmission expansion; gas-electric and water-electric coordination
Resource Planning Model (NREL)	Hourly chronological operations	Customizable (service area, state, balancing authority); DC-power flow zonal and nodal transmission	Endogenous demand response; interruptible load	Sensitivity, scenario analysis	Individual EGUs in focal areas; transmission expansion
EGEAS (EPRI)	LDCs, various options for time blocks	Customizable (service area, states, balancing authority); zonal	Endogenous DSM / price-elastic demand	Sensitivity, scenario analysis	Individual EGUs

National-Scale Capacity Planning Models

Despite their temporal, spatial, and technological simplifications, national-scale models typically have the strongest capability to consider the interactions between large geographic regions compared to other model classes.

National-scale capacity planning models also optimize generation capacity investments years to decades into the future to meet a given level of demand, but do so over relatively large geographic regions—an interconnection, country, or even continent. Due to their broad geographic scope, these models make several simplifications for tractability. First, national-scale models typically represent existing and new capacity as aggregate technologies or "capacity blocks," rather than individual generating units. Individually representing generating units over such a large area would be computationally expensive, and is thus uncommon.

Representation of the transmission network varies. The simplest representation involves an assumption that the grid is a "copper plate" and that electricity is free flowing between all regions included. Electricity trade between regions in this case is most commonly ignored (e.g., electricity is shared by all), estimated by some pre-defined function, or fixed. Other more rigorous applications within this class of models includes either a transport ("pipe flow") model, which allows power exchange between defined regions based on line capacities only, or a DC optimal power flow (OPF) framework that defines power exchange between network connected regions, while obeying Kirchhoff's laws of flow and voltage conservation. National-scale capacity planning models also typically use a zonal, rather than nodal, framework for the transmission network. This zonal framework is a simplification of the full network; it utilizes fictitious lines that connect each region (or "zone") in the model for power exchange.

Temporally, national-scale capacity planning models most often use either load duration curves, or another reduced-form of demand such as representative weeks. As described in Section 2, integrating hourly detail into a national-scale model to investigate the opportunity for renewables and demand-side resources is an active area of research. Due both to the temporal scale and aggregate capacity block representation of power plants, national-scale models do not often incorporate unit-level operations such as unit-commitment, startup/shutdown costs, and ramping constraints in detail.

This class of model is used mainly by academics, governments, and other stakeholders for policy analysis, as well as utilities for strategic planning activities. Because of its simplifications, it is not often used directly for making capacity investment decisions. However, despite their temporal, spatial, and generation technology simplifications, compared to other model classes, national-scale models have the strongest capability to consider interactions between large geographic regions. Table 3-2 reviews five popular national-scale capacity planning models for their systems analysis capabilities.

Table 3-2
National-Scale Capacity Planning Models' System Analysis Capabilities

Model	Temporal Resolution	Spatial Resolution	End-Use Details	Uncertainty Analysis	Other
IPM (EPA)	LDCs, 96 time blocks	75-region model (U.S. + some Canada); zonal transmission	Default fixed demand; optional price-elastic demand	Sensitivity, scenario analysis	Integrated gas modeling; transmission expansion; limited international coverage
ReEDS (NREL)	LDCs, 17 time blocks	48-state U.S. model; 134 balancing areas, 356 wind/solar regions; zonal transmission	Demand-side resources; interruptible load; optional price-elastic demand	Sensitivity, scenario analysis	Transmission expansion
US-REGEN Electric Sector Model (EPRI)	Representa-tive segments, based on joint distribution of demand, wind, and solar	15-region and 48-state U.S. models; zonal transmission	Default fixed demand; optional price-elastic demand	Sensitivity, scenario analysis	Economy-wide modeling (via integrated macro-economic model); transmission expansion
E4ST (RFF, Cornell, ASU, RPI)	Customiza-ble (default 37 time blocks)	8000-node US-Canada model; DC power flow zonal transmission; 3000-county air pollution model	Demand-side resources (storage); real-time pricing; price-elastic demand	Stochastic optimization capability; sensitivity, scenario analysis	Individual EGUs; integrated pollution and health effects modeling; transmission expansion
HAIKU (RFF)	LDCs, 12 time blocks	26-region model; zonal transmission	Demand-side energy efficiency; cost-of-service and competitive prices; price-elastic demand	Sensitivity, scenario analysis	

Multi-Sector Models

Multi-sector models are often the easiest to integrate systems analysis features like economy-wide interactions, integrated pollution and health effects modeling, or endogenous technological change.

Finally, multi-sector models fall into two distinct categories—those that cover the entire macro-economy using a general equilibrium framework, and those that cover a selected set of economic sectors (e.g., all energy) in a partial equilibrium framework. The goal of these models is not typically capacity planning explicitly, but maximizing social welfare or minimizing costs of simultaneously meeting several sectoral demands over time. Multi-sector models represent the flow of goods and services through the economy, capturing markets they participate in via supply and demand dynamics. They are a good example of extending system boundaries for systems analysis; they capture important feedbacks between subsectors in a way that the other model classes cannot.

While electricity generation capacity planning is not the primary objective of these models, those that retain a bottom-up representation of the power system have this capability. The optimization still takes place over the same long multi-year time horizon as the other classes, but multi-sector models tend to have relatively coarse temporal and spatial resolutions. Temporally, multi-sector models typically treat demand and renewable electricity production with either an annual demand level (i.e., one time block) or an LDC with a few time blocks. Spatially, it is common for these models to cover large regions or countries, but the transmission network is commonly ignored. Conversely, representing endogenous end-use details, such as demand response, energy efficiency, or adoption of distributed generation, can be a strength of these models. End users can comprise a separate subsector represented in the model, and their adoption and energy use patterns can be explicitly modeled and fed-back into the overall optimization problem. Technologies are most commonly represented as model plants or aggregated technology blocks, although more recently have become unit-based depending on the dimensionality of the original model. Finally, multi-sector models are often the easiest to integrate other systems analysis features within, such as economy-wide interactions, integrated pollution and health effects modeling, or endogenous technological change. This is partly due the natural existence of other sectors already in the model, but also due to the relatively lower dimensionality within each sector. The models are thus able to handle these extensions while still being tractable.

Multi-sector models are mostly used by academics, think-tanks, governments, and industry stakeholders for policy analysis and to inform the policy-making process. Their resolution does not allow for detailed information to help utilities establish long-range resource plans, although industry sometimes use these models for strategic and regulatory planning purposes. Table 3-3 reviews three popular multi-sector models that explicitly include capacity planning decisions in their frameworks.

Table 3-3
Multi-Sector Models' System Analysis Capabilities

Model	Temporal Resolution	Spatial Resolution	End-Use Details	Uncertainty Analysis	Other
NEMS (EIA)	LDCs, 9 time blocks	22-region U.S. model; cost-of-service and competitive markets	4 detailed, sectoral demand modules (exogenous); endogenous distributed generation	Sensitivity, scenario analysis	Economy-wide modeling; transmission expansion; distributed generation; international coverage; technology learning
NewERA (NERA)	LDCs	Custom (default is 11 U.S. regions for macro model, 77 for electric submodule); zonal (power pool) transmission	Endogenous demand response / price-elastic demand	Sensitivity, scenario analysis	Individual EGUs; economy-wide modeling; integrated gas modeling; some inter-national coverage
NE-MARKAL (NESCAUM)	LDCs; 6 time blocks	12-region Northeast U.S. model; zonal transmission	Detailed end-use modeling (integrated model)	Sensitivity, scenario analysis	Individual EGUs; multi-energy sector modeling

Section 4: Concluding Summary

This report reviewed foundational "systems" and "systems analysis" concepts, defining an electric power system as a complex system given its unique and numerous inter-dependent physical, socio-economic, and political components.

It has also summarized the recent literature in electric power systems analysis, focusing on four areas of long-range capacity planning modeling researchers have been particularly active in during the last decade: 1) improving models' temporal resolution; 2) improving models' spatial resolution; 3) improving model representations of end-use detail; and 4) increasing models' uncertainty analysis capability. With respect to temporal resolution, the review highlights a need for both hourly and sub-hourly chronology, as well as unit-level detail within long-term capacity planning models. Doing so can better represent system responses to increased renewable energy technologies, demand-side resources, storage, and distributed generation. It can also capture the effect (i.e., feedback) of these system responses on optimal capacity planning decisions. With respect to spatial resolution, the review illustrates a need for improved representations of transmission and electricity flow between disaggregated subregions and other non-electricity market commodities. This is especially true for large geographical areas like continental U.S. that have wide disparities between regions in existing resource bases, renewables potentials, market regimes, and policies. With respect to end-use details, the review shows a need for an explicit endogenous representation of changing end-use demand via consumer adoption and use of distributed energy resources, price-responsive demand, and real-time pricing to integrate additional opportunities for cost-effective long-term capacity planning. Finally, improved methods for explicitly considering uncertainty and developing adaptable long-range capacity plans are required to plan systems that are resilient to future unknowns. The need for many of these model improvements is also echoed in a recent technical update by EPRI that presents results from a survey of users and vendors of generation planning software tools [71].

Three classes of state-of-the-art capacity planning models (i.e., utility-scale models, national-scale models, and multi-sector models) were then reviewed for their systems analysis capabilities along these four dimensions. Within each model class, tradeoffs between model "fidelity" and model "tractability" are made to account for as much of these systems analysis needs as possible, while still retaining a tool that solves in a reasonable amount of time. The review shows that across these models classes, smaller geographies and scope (e.g., utility-scale models) can incorporate more detail within the subregions represented (e.g., hourly chronology, detailed electricity flow), but can miss important extra-region linkages. Conversely, wider geographies and scopes (e.g., multi-sector models) incorporate key systems concepts such as feedbacks more readily, but miss important details of electricity sector operations (e.g., using LDCs). The review also shows that within each class, while there is some variation in how individual tools specifically resolve temporal and spatial details, end-use, and uncertainty analysis capability, the following areas stand out as immediate research needs:

- Integration of hourly or sub-hourly chronology, and unit-level details (e.g., unit commitment, startup/shutdown costs and constraints, ramping constraints) within an intertemporal optimization framework
- Better representation of the transmission network, its power flows, and expansion opportunities in capacity planning models covering wide geographies (e.g., continental U.S.)
- Integration of endogenous end-use models within capacity planning models to resolve changing loads (magnitudes and shapes) due to electrification, demand-side resources, and distributed generation
- Development of methods to restructure capacity planning models as stochastic optimization models to explicitly account for uncertainty and craft flexible capacity plans

Ultimately, as described throughout this report, many of the existing challenges in systems analysis using capacity planning models are due to the "fidelity" versus "tractability" dilemma that all modeling communities face. However, if the objective is to extend the systems analysis capabilities of these models just enough to include the most salient features of modern power systems and provide insight into optimal planning, the following are next steps the modeling community can take to facilitate development of these tools and accomplish the goals above: 1) continue to develop methods for problem dimensionality reduction and efficient computation to relieve computational burdens, and 2) continue investigating when and how adding additional systems analysis capability matters—how precisely do these features affect optimal capacity planning results?

In a forthcoming report, the Electric Power Research Institute and Resources for the Future investigate the second of these research areas, focusing on the impacts of temporal and spatial resolution, end-use detail, and uncertainty representation on optimal long-term planning in the power sector.

Section 5: References

1. J. Moses, “Foundational Issues in Engineering Systems: A Framing Paper,” MIT Engineering Systems Monograph, Cambridge, MA (2004).
2. C. L. Magee and O. L. de Weck, “An Attempt at Complex System Classification,” MIT Engineering Systems Division Working Paper ESD-WP-2003-01.02, Cambridge, MA (2002).
3. *Complex, Engineered, Organizational, & Natural Systems, Issues Underlying the Complexity of Systems and Fundamental Research Needed to Address These Issues.* Engineering Directorate, National Science Foundation, Washington, D.C.: 2007.
4. D. A. Mindell, "Bodies, Ideas, and Dynamics: Historical Perspectives on Systems Thinking in Engineering,” MIT Engineering Systems Division Working Paper ESD-WP-2003-01.23, Cambridge, MA (2002).
5. Peter M. Senge. *The Fifth Discipline, The Art and Practice of the Learning Organization*. Doubleday/Currency, New York, NY 1990, pp. 57-67.
6. R. L. Ackoff, “Systems, Organizations, and Interdisciplinary Research,” *General Systems Yearbook.* Vol. 5, p. 1 (1960).
7. S. Tilles, “The Manager’s Job: A Systems Approach,” *Harvard Business Review*. Vol. 41, No. 2, p. 73 (1963).
8. C. West Churchman. *The Systems Approach.* Dell Publishing Co., Inc., New York, NY 1968, pp. 3-15.
9. S. Collins et al., “Integrating Short Term Variations of the Power System into Integrated Energy System Models: A Methodological Review,” *Renewable and Sustainable Energy Reviews*. Vol. 76, p. 839 (2017).
10. S. Wogrin et al., “A new approach to model load levels in electric power systems with high renewable penetration,” *IEEE Trans. Power Syst*. Vol. 29, No. 5, p. 2210 (2014).
11. A. Nogales, S. Wogrin, and E. Centeno, “Impact of technical operational details on generation expansion in oligopolistic power markets,” *IET Gener. Transm. Distrib*. Vol. 10, No. 9, p. 2118 (2016).
12. S. Wogrin, S. Galbally, and J. Reneses, “Optimizing storage operations in medium- and long-term power system models,” *IEEE Transactions on Power Systems.* Vol. 31, No. 4, p. 3129 (2016).

13. B. Palmintier, “Incorporating operational flexibility into electric generation planning: impacts and methods for system design and policy analysis,” MIT Engineering Systems Division PhD Dissertation, Cambridge, MA (2013).

14. B. Palmintier and M. Webster, “Impact of Operational Flexibility on Generation Planning,” *IEEE Transactions in Power Systems.* (in review).

15. P. Parpas and M. Webster, “A stochastic multiscale model for electricity generation capacity expansion,” *European Journal of Operational Research*. Vol. 232, p. 359 (2014).

16. J. Merrick, “On representation of temporal variability in electricity capacity planning models,” *Energy Economics.* Vol. 59, p. 261 (2016).

17. *Simulating Annual Variation in Load, Wind, and Solar by Representative Hour Selection*. EPRI, Palo Alto, CA: 2016. 3002008653.

18. G. J. Blanford, J. H. Merrick, and D. Young, “A Clean Energy Standard Analysis with the US-REGEN Model,” *The Energy Journal.* Vol. 35, p. 137 (2014).

19. *Implications of Model Structure and Detail for Utility Planning: Scenario Case Studies Using the Resource Planning Model.* NREL, Golden, CO: 2015. TP-6A20-63972.

20. C. Barrows, T. Mai, H. Hale, A. Lopez, and K. Eurek, “Considering Renewables in Capacity Expansion Models: Capturing Flexibility with Hourly Dispatch,” Paper presented at the IEEE Power and Energy Society General Meeting, Denver, CO (July 2015).

21. F. J. de Sisternes, “Investment Model for Renewable Electricity Systems (IMRES): An Electricity Generation Capacity Expansion Formulation with Unit Commitment Constraints,” MIT Center for Energy and Environmental Policy Research Working Paper CEEPR WP 2013-016, Cambridge, MA (2013).

22. P. Nahmmacher, E. Schmid, L. Hirth, and B. Knopf, “Carpe Diem: A Novel Approach to Select Representative Days for Long-Term Power System Models with High Shares of Renewable Energy Sources,” USAEE Working Paper No. 14-194, Cleveland, OH (2014).

23. C. Batlle and P. Rodilla, “An Enhanced Screening Curves Method for Considering Thermal Cycling Operation Costs in Generation Expansion Planning,” *IEEE Transactions on Power Systems.* Vol. 28, No. 4, p. 3683 (2013).

24. K. Tapia-Ahumada, C. Octaviano, S. Rausch, and I. Pérez-Arriaga, “Modeling intermittent renewable electricity technologies in general equilibrium models,” *Economic Modelling*. Vol. 51, p. 242 (2015).

25. C. Meseguer, I. J. Pérez-Arriaga, G. de Cuadra, A. Ramos, E. Garcia Vinas, and F. Pérez Thoden, “MARGEN: A Model for Strategic Study in Generation Expansion and Operation.” Proceedings of the 5th Spanish–Portuguese Conference on Electric Power Engineering, Oporto, Portugal (1995).

26. I. Pérez-Arriaga and C. Meseguer, "Wholesale marginal prices in competitive generation markets," *IEEE Trans. Power Syst*. Vol. 2, p. 710 (1997).

27. *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2016*. NREL, Golden, CO: 2016. TP-6A20-67067.

28. *Resource Planning Model: An Integrated Resource Planning and Dispatch Tool for Regional Electric Systems*. NREL, Golden, CO: 2013. TP-6A20-56723.

29. *Evaluating the Value of High Spatial Resolution in National Capacity Expansion Models using ReEDS*. NREL, Golden, CO: 2016. CP-6A20-66002.

30. D. Shawhan, J. Taber, D. Shi, R. Zimmerman, J. Yan, C. Marquet, Y. Qi, B. Mao, D. Tylavsky, R. Schuler, and W. Schulze, "Does a detailed model of the electricity grid matter? Estimating the impacts of the Regional Greenhouse Gas Initiative," *Resource and Energy Economic*s. Vol. 36, No. 1, p. 191 (2014).

31. *Utility of the Future: An MIT Energy Initiative response to an industry in transition*. MIT, Cambridge, MA: 2016. Available at: http://energy.mit.edu/research/utility-future-study/

32. D. Pudjianto, M. Aunedi, P. Djapic, and G. Strbac, "Whole-Systems Assessment of the Value of Energy Storage in Low-Carbon Electricity Systems," *IEEE Transactions on Smart Grid.* Vol. 5, p. 1098 (2014).

33. U.S. Energy Information Administration. *The National Energy Modeling System: An Overview 2009*. EIA Office of Integrated Analysis and Forecasting, Washington, D.C. 2009.

34. D. G. Choi and V.M. Thomasa, "An electricity generation planning model incorporating demand response," *Energy Policy.* Vol. 42, p. 429 (2012).

35. F-K. Ko, C-B. Huang, P-Y. Tseng, C-H. Lin, B-Y. Zheng, and H-M. Chiu, "Long term CO_2 emissions reduction target and scenarios of power sector in Taiwan," *Energy Policy.* Vol. 38, p. 288 (2010).

36. B. Mao, D. Shawhan, R. Zimmerman, J. Yan, Y. Zhu, W. Schulze, R. Schuler, and D. Tylavsky, "The engineering, economic and environmental electricity simulation tool (E4ST): description and an illustration of its capability and use as a planning/policy analysis tool," Proceedings of the 49th Annual Hawaii International Conference on System Sciences, Kauai, HI (January 2016).

37. J. Yan, "Essays in Behavioral and Energy Economics," Cornell University Charles H. Dyson School of Applied Economics and Management PhD Dissertation, Ithaca, NY (2015).

38. S. Jin, A. Botterud, and S.M. Ryan, "Temporal vs. Stochastic Granularity in Thermal Generation Capacity Planning with Wind Power," *IEEE Transactions on Power Systems*. Vol. 29, No. 5, p. 2033 (2014).

39. Botterud A., N. Abdel-Karim, and M. Ilić, “Generation Planning under Uncertainty with Variable Resources," *Engineering IT-Enabled Sustainable Electricity Services: The Tale of Two Low-Cost Green Azores Islands*, *Series: Power Electronics and Power Systems*, Ilić, Marija D.; Xie, Le; Liu, Qixing (eds.). Vol. 30, p. 535 (2013).

40. M. Banzo and A. Ramos, “Stochastic optimization model for electric power system planning of offshore wind farms,” *IEEE Transactions on Power Systems.* Vol. 26, No. 3, p. 1338 (2011).

41. I. Bakke, S-E. Fleten, L. I. Hagfors, V. Hagspiel, B. Norheim, and S. Wogrin, “Investment in electric energy storage under uncertainty: a real options approach,” *Computational Management Science*. Vol. 13, No. 3, P. 483 (2016).

42. A. Klein, J. Bouchard, and S. Goutier, “Generation Capacity Expansion under Long-Term Uncertainties in the U.S. Electric Market,” Paper presented at the 28th USAEE/IAEE North American Conference, New Orleans, LA (December 2008).

43. S. Wogrin, E. Centeno, and J. Barquín, “Generation capacity expansion in liberalized electricity markets: a stochastic MPEC approach,” *IEEE Transactions on Power Systems.* Vol. 26, No. 4, p. 2526 (2011).

44. G. J. Blanford, “R&D investment strategy for climate change,” *Energy Economics*. Vol. 31, No. S1, p. S27 (2009).

45. J. E. Bistline and J.P. Weyant, “Electric Sector Investments Under Technological and Policy-Related Uncertainties: A Stochastic Programming Approach,” *Climatic Change.* Vol. 121, No. 2, p. 143 (2013).

46. N. R. Santen, M. D. Webster, D. Popp, and I. J. Perez-Arriaga, “Inter-temporal R&D and Capital Investment Portfolios for the Electricity Industry’s Low Carbon Future,” *The Energy Journal*. Vol. 38, No. 5, p. 197 (2017).

47. N. R. Santen and L. Diaz Anadon, “Balancing solar PV deployment and RD&D: A comprehensive framework for managing innovation uncertainty in electricity technology investment planning,” *Renewable and Sustainable Energy Reviews.* Vol. 60, p. 560 (2016).

48. *US-REGEN Unit Commitment Model Documentation*. EPRI, Palo Alto, CA: 2015. 3002004748.

49. W. Cole, H. Lewis, B. Sigrin, and R. Margolis, “Interactions of rooftop PV deployment with the capacity expansion of the bulk power system,” *Applied Energy*. Vol. 168, p. 473 (2016).

50. W. J. Cole, K. B. Medlock III, and J. Aditya, "A view to the future of Natural Gas and Electricity: An integrated modeling approach," *Energy Economics*. Vol. 60, p. 486 (2016).

51. Z. Khan, P. Linares, and J. García-González, “Adaptation to climate - induced regional water constraints in the Spanish energy sector: An integrated assessment,” *Energy Policy*. Vol. 97, p. 123 (2016).

52. Z. Khan, P. Linares, and J. García-González, "Integrating water and energy models for policy driven applications: A review of contemporary work and recommendations for future developments," *Renewable and Sustainable Energy Reviews.* Vol. 67, p. 1123 (2017).
53. M. Webster, P. Donohoo, and B. Palmintier, "Water-CO_2 Tradeoffs in Electricity Generation Planning," *Nature Climate Change.* Vol. 3, p. 1029 (2013).
54. M. Moradi, H. Abdi, S. Lumbreras, A. Ramos, and S. Karimi, "Transmission expansion planning in the presence of wind farms with a mixed AC and DC power flow model using an imperialist competitive algorithm," *Electric Power Systems Research.* Vol. 140, p. 493 (2015).
55. G. Drayton, N. McCoy, M. Pereira, E. Cazalet, M. Johannis, and D. Phillips, "Transmission expansion planning in the Western interconnection-the planning process and the analytical tools that will be needed to do the job," Paper presented at the 2004 IEEE Power Systems Conference and Exposition Paper, New York, NY (October 2004).
56. S. Lumbreras, D. W., Bunn, A. Ramos, and M. Chronopoulos, "Real options valuation applied to transmission expansion planning," *Quantitative Finance.* Vol. 16 No. 2, p. 231 (2016).
57. P.E. Donohoo-Vallett, "Design of wide-area electric transmission networks under uncertainty: methods for dimensionality reduction," MIT Engineering Systems Division PhD Dissertation, Cambridge, MA (2015).
58. E. Ibanez and O. Zinaman, "Modeling the integrated expansion of the Canadian and U.S. power sectors," *The Electricity Journal.* Vol. 29, No. 1, p. 71 (2016).
59. *US-REGEN Model Documentation*. EPRI, Palo Alto, CA: 2017. 3002010956.
60. C. A. Octaviano Villasana, "The value of electricity storage under large-scale penetration of renewable energy: a hybrid modeling approach," MIT Engineering Systems Division PhD Dissertation, Cambridge, MA (2015).
61. S. Rausch and M. Mowers, "Distributional and efficiency impacts of clean and renewable energy standards for electricity," *Resour. Energy Econ*. Vol. 36, No. 2, p. 556 (2014).
62. E. Baker and S. Solak, "Climate Change and Optimal Energy Technology R&D Policy," *European Journal of Operations Research.* Vol. 213, p. 442 (2011).
63. C. Berglund and P. Soderholm, "Modeling technical change in energy system analysis: analyzing the introduction of learning-by-doing in bottom-up energy models," *Energy Policy.* Vol. 34, p. 1344 (2006).
64. L. Barreto and S. Kypreos, "Endogenizing R&D and market experience in the 'bottom-up' energy systems ERIS model," *Technovation*. Vol. 24, p. 615 (2004).

65. K. Siler-Evan, I. Lima Azevedo, G. M. Morgan, and J. Apt, "Regional variations in the health, environmental, and climate benefits of wind and solar generation," *Proc. Natl. Acad. Sci.* Vol. 110, No. 29, p. 11768 (2013).

66. J. J. Buonocore, K. F. Lambert, D. Burtraw, S. Sekar, and C.T. Driscoll, "An Analysis of Costs and Health Co-Benefits for a U.S. Power Plant Carbon Standard," *PLoS ONE.* Vol. 11, No. 6, p. e0156308 (2016).

67. *On the Path to SunShot: The Environmental and Public Health Benefits of Achieving High Penetrations of Solar Energy in the United States*. NREL, Golden, CO: 2016. TP-6A20-65628.

68. R. K. Saari, "Air quality impacts and benefits under U.S. policy for air pollution, climate change, and clean energy," MIT Engineering Systems Division PhD Dissertation, Cambridge, MA (2015).

69. A. M. Foley, B. P. Ó Gallachóir, J. Hur, R. Baldick, and E.J. McKeogh, "A strategic review of electricity systems models," *Energy.* Vol. 35, p. 4522 (2010).

70. Ignacio J. Perez-Arriaga (ed). *Regulation of the Power Sector.* Springer-Verlag, London, England 2013, 728pps.

71. *Key Insights from Surveys of Users and Vendors of Software Tools Used for Electric System Generation Planning Technology Assessment, Market Analysis and Integrated Portfolio Planning*. EPRI, Palo Alto, CA: 2014. 3002003947.

72. J. Bistline, "Energy technology R&D portfolio management: Modeling uncertain returns and market diffusion," *Applied Energy*. Vol. 183, p. 1181 (2016).

Appendix A: Model Descriptions

AURORAxmp (EPIS, LLC)

AURORAxmp is a proprietary, commercial-grade electricity forecasting and analysis tool, comprised of several different modules. The tool has a resource expansion module that determines the optimal long-term capacity expansion and retirement schedule in a transmission-constrained, zonal network. The model uses a "recursive optimization" framework that reduces dimensionality substantially and therefore allows integrating unit-level details (e.g., economic unit commitment) and hourly, chronological representation of electricity demand and generator dispatch. The model chooses new resources based on the net present value of hourly market values for each possible unit, comparing these possible units to existing units to determine optimal additions to the fleet. AURORAxmp can consider a range of fuel prices, generation technologies, environmental policies and other constraints, and future demand forecasts. It can consider uncertainty using sensitivity/scenario-based analyses, and due to its structure and speed is particularly suited to Monte Carlo analyses. More information about AURORAxmp's long-term resource expansion model is available at: http://epis.com/aurora_xmp/long_term_expansion.php

E4ST (Cornell University, Arizona State University, Rensselaer Polytechnic Institute, and Resources for the Future)

The Engineering, Economic, and Environmental Electricity Simulation Tool, E4ST (pronounced "East"), is new open-source software built to simulate in detail how the power sector will respond to changes in environmental and non-environmental policies and regulations, input costs, transmission investments, generation investments, etc. It predicts operation, entry and exit of generators, prices, all elements of social surplus, and other outcomes. E4ST is a large linear program that assumes perfect competition, and uses a detailed direct-current-like approximation of the operation of the grid to predict power flows. It models successive multi-year periods, with each multi-year period represented by time slices that capture the variation of demand, wind, and sun. E4ST's developers have also developed detailed models of the three major U.S. and Canadian grids, using E4ST. The models contain the 19,000 existing generators with their detailed individual characteristics, tens of thousands of buildable generators including location- and hour-specific wind and solar availability, and approximately 20,000 transmission line segments. The segments include all high-voltage (>200 kV) segments, selected lower-voltage segments in areas of chronic congestion, and equivalent lines to represent removed low-voltage lines. The models also include detailed generator emission rates and an air pollution fate and transport model, to enable E4ST to calculate emissions and health effects. The models can be customized to represent phenomena such as policies, storage operation, electric vehicles, other deferrable loads, dynamic pricing, and investment and retirement under uncertainty. E4ST is built on the foundation of the popular MATPOWER open-source optimal power flow software. Simulations can be run quickly in large batches to consider various futures via sensitivity and scenario analyses. More information about E4ST is available at: http://e4st.com/

EGEAS (Electric Power Research Institute)[4]

The Electric Generation Expansion Analysis System (EGEAS) is a modular state-of-the-art generation expansion software package. EGEAS is used by utility planners to produce integrated resource plans, evaluate independent power producers, develop avoided costs and environmental compliance plans, and analyze life extension alternatives. EGEAS is a set of computer modules that determine an optimum expansion plan or simulate detailed production costs for a prespecified 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 objective function specified by the user. Typical objective functions include: minimizing total costs, minimizing customer rates, minimizing societal costs, maximizing earnings. EGEAS can handle a wide variety of generation technologies including thermal (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 can also analyze DSM options such as conservation, strategic marketing, load management, storage, and rate design. More information about EGEAS is available at: http://eea.epri.com/models.html#tab=3

HAIKU (Resources for the Future)

The Haiku model is a simulation of regional electricity markets and interregional electricity trade in the continental United States that accounts for regulations to control emissions of nitrogen oxide (NO_x), sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury from the electricity sector. The model can project market equilibrium in each of 21 regions of the lower 48 states through the year 2030 during three seasons of the year and four time blocks within each season. Electricity demand is characterized by price-responsive functions for each region and time period for three sectors of the economy: residential, commercial, and

[4] *EGEAS Capabilities Manual: Version 11.0*. EPRI, Palo Alto, CA: 2015. 3002006439.

industrial. Electricity supply is characterized for each region and time period by a set of fully integrated modules that determine generation capacity investment and retirement, system operation including interregional power trading, prices and production in fuel markets, and compliance strategies for emissions regulations including investment in pollution abatement technologies. Generation capacity is classified in model plants that are distinguished by geographic region and a set of salient technology characteristics including fuel type, vintage, and generator technology. Haiku has versatility in simulating pollution abatement policies as well as emerging electricity market structures and calculates relative measures of economic welfare. The model runs on a desktop computer and serves as a laboratory for sophisticated first-order policy analysis for the electricity industry in the United States.[5] More information about Haiku is available at: http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-Rpt-Haiku.v2.0.pdf

IPM (United States Environmental Protection Agency)

The Integrated Planning Model (IPM) was developed by the U.S. Environmental Protection Agency and ICF International. It is a long-range planning model of the U.S. electric power sector, and includes representations of fuel, emissions, and electricity markets. The model has been used in a wide variety of federally-mandated regulatory, economic impact, and market analyses. IPM is formulated as a deterministic linear program, with an objective to meet energy and peak demand at least cost. Geographically, the model covers the NERC and ISO/RTO regions of the U.S. Transmission via bulk power flow is represented between the individual regions (zonal transmission modeling). Generation units are represented as a series of model plants (i.e., technology blocks), using a classification scheme based on several unit-specific characteristics: geographical region, technology type, unit configuration, emission rates, heat rates, fuel, size, and more. The main decisions IPM makes are capacity, dispatch, electricity trade between regions, emission allowances, and fuel use. IPM endogenously models fuel prices for coal, natural gas, and biomass. In addition to traditional fossil and nuclear technologies, IPM models wind, landfill gas, geothermal, solar thermal, solar photovoltaic and biomass.[6] More information about IPM is available at: https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

NE-MARKAL (NESCAUM)

NE-MARKAL is a long-range energy systems modeling tool that chooses technologies to install and use by comparing "life-cycle" costs of alternative technologies. It models the energy system through its subsectors, including

---

[5] Retrieved from description of HAIKU presented in: A. Paul, D. Burtraw, and K. Palmer, "HAIKU Documentation: RFF'S Electricity Market Model. Version 2.0," RFF Report, Washington, D.C. (2009).

[6] U.S. Environmental Protection Agency. *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model.* U.S Environmental Protection Agency Clean Air Markets Division, Washington, D.C. November 2013.

mining and fuel production through intermediate uses such as by the electric power sector, and finally through end uses such as heating and cooling, and passenger transport. Its geographic scope extends to twelve northeast states: Maine, Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, and the District of Columbia. The power sector in NE-MARKAL is particularly developed, and is therefore reviewed in this literature review. Electricity generation units greater than 25 MW are represented as individual units in NE-MARKAL; below this threshold, plants are aggregated by technology, fuel type, and vintage. Electricity trade is represented via a zonal transmission network, where each state represents a different zone. Constraints on electricity flow between the zones are represented as bi-lateral constraints that define the capacity transfer limit of power between two states, as well as a "joint constraint" that represents the amount of electricity that can flow into or out of a state at one time. Together, these constraints represent the conditions required for grid stability. Temporally, the model represents electricity demand via a load duration curve divided into six time slices that represent three seasons, and days and nights. More information about NE-MARKAL is available at: http://www.nescaum.org/topics/ne-markal-model

NEMS (U.S. Energy Information Administration)

The National Energy Modeling System (NEMS) is the main modeling tool used by the U.S. Energy Information Administration (EIA) for long-range (out to 2050) energy-economy planning of the U.S. energy system. It consists of twelve energy-related modules, including domestic energy supply, demand, liquid fuels markets, a macro-economic module, an international energy module, and a detailed electricity market module. The Electricity Market Module (EMM) itself has four submodules that model electricity load and demand, electricity capacity planning, electricity dispatch, and electricity sector finance and pricing. For capacity planning and dispatch, NEMS employs an intertemporal linear-programing optimization formulation, and chooses the least-cost set of technologies in technology blocks to build, retrofit, or retire—and operate—in the electricity system over a multi-year timeframe. The model represents the U.S. as 22 regions, reflecting the NERC reliability subregions and ISO/RTO and/or state boundaries. Electricity trade is represented via a zonal transmission network, with trade permitted between neighboring regions subject to constraints between regions, and losses. The model uses an LDC approach with nine time slices that represents seasons and time of day. Unique features of NEMS include its endogenous distributed generation and end-use decisions, representation of both regulated (cost-of-service) and competitive (marginal cost-based) pricing mechanisms, and its integrated feedback structure between fuel supplies and electricity demand. More information about NEMS is available at: https://www.eia.gov/outlooks/aeo/info_nems_archive.cfm

NewERA (NERA Economic Consulting)

NewERA is a proprietary energy-economy model developed by NERA Economic Consulting that considers U.S. economy-wide supply and demand interactions, and includes a detailed representation of the electric power sector. The power sector model uses a least-cost optimization framework, making decisions about retrofits, retirements, and new capacity additions subject to a variety of physical and policy constraints (e.g., demand, peak demand, transmission limits, emission limits). NewERA represents individual electricity generating units across the U.S. as separate plants, dispatching them within an LDC framework for load. The North American electricity market is represented as 77 regions, with electricity trade modeled using a zonal "power pool to power pool" formulation and bi-lateral as well as joint constraints. NewERA performs endogenous transmission capacity expansion planning via the option to construct direct tie-lines for new dedicated sources of power. Full transmission network expansion proceeds exogenously. More information about NewERA is available at: http://www.nera.com/practice-areas/energy/newera-model.html

PLEXOS LT Plan (Energy Exemplar)

The commercial PLEXOS platform by Energy Exemplar contains several energy systems models for electric power systems planning at various timescales, including a short-term scheduling model (ST schedule), medium-term scheduling/production costing model (MT schedule), and a long-term capacity expansion planning model (LT Plan). Capacity expansion planning via the LT Plan uses a mixed integer programming formulation, with an objective to minimize the net present value of total expansion and production costs over the time horizon modeled (typically 10 to 20 years). PLEXOS is best known as a "utility-scale" model, where the geographic coverage of the modeled system consists of a utility service area, or other coordinated regional power system. Individual electricity generation units (EGU) are represented, as are their thermal limits, and forced outage and maintenance schedules. The transmission network can be represented as a network of zones with security-constrained (N-1) DC optimal power flow, or as a network of nodes with full nodal/AC power flow modeling. Three different options for representing the temporal nature of load and generator dispatch exist within PLEXOS, including an LDC-method with several choices for creating time blocks, a "fitted chronological" method that retains the ordering of weeks or months of the year, or a sampled chronological method that uses "representative" weeks of the year, and then replicates those representative weeks accordingly. Technically, a user could use the fitted-chronological method using an hourly time-step and represent time via an hourly-chronological framework, but computational limitations still prevent this practically in the PLEXOS LT Plan environment. Unique features of the PLEXOS long-term modeling environment include integrated (co-optimized) gas infrastructure modeling, as well as water-system modeling. While a commercial "off the shelf" tool, PLEXOS can also be customized a great deal by advanced users. More information about PLEXOS LT Plan is available at: https://energyexemplar.com/wp-content/uploads/2014/09/Portfolio-Optimization-Using-PLEXOS.pdf

ReEDS (NREL)

The Regional Energy Deployment System (ReEDS) Model, developed and maintained by the National Renewable Energy Laboratory (NREL) is a national-scale long-range generation and transmission capacity planning and electricity dispatch model, with a focus on detailed representation of renewable energy technologies. The model has a very high degree of spatial resolution, covering the U.S. using 134 model "balancing areas" and over 300 wind and solar resource regions. Electricity trade between the balancing areas is modeled via a zonal transmission network, with capacity limits between them. The full model time horizon is 2010-2050, operating as a recursive dynamic linear program that optimizes in two-year time steps. Temporally, the model uses an LDC approach with seventeen distinct time slices, representing four seasons, four times of day, and a separate "superpeak" that represents the highest non-consecutive 40 hours of load during the year. Electricity generating units are aggregated into technology capacity blocks. ReEDS has been used for a wide variety of prominent national energy planning and policy analysis studies; more information is available at: http://www.nrel.gov/analysis/reeds/

RPM (NREL)

The Resource Planning Model (RPM) is a new mid- to long-range capacity planning model developed and maintained by NREL. It was designed with the intention to capture more detailed temporal and spatial granularity, given the upsurge in renewable energy resources and need to model their operations and interaction with the rest of the power system more precisely. While ReEDS is a national-scale model, RPM is intended to model regional power systems in more detail. RPM is capable of modeling "focus areas" in a great deal of detail (e.g., individual power plants). Temporally, the model retains an hourly chronological framework for demand, renewable resources, and generator dispatch. The model is solved as a sequential mixed-integer programming optimization model, in five-year time steps between 2010 and 2030. Because of the model's ability to retain unit-level detail with the regions of focus, RPM models dispatch, as well as ancillary service (e.g., spinning reserve) positions of the fleet, and consider these values within its cost-minimization framework. The main decision variables of RPM include capacity expansion and dispatch/power flow for generators, transmission, and storage. The transmission network is represented as a combined nodal/zonal model, with the focal areas modeled as their full nodal networks (i.e., nodes, generating units, and lines). More information about RPM is available at: http://www.nrel.gov/analysis/models_rpm.html

Strategist (ABB)

Strategist is a long-range commercial electric power systems resource planning model, widely used by the electric power industry as a generation capacity expansion planning screening tool. Strategist's capacity expansion module uses a dynamic programming formulation that simultaneously evaluates thousands of capacity expansion alternatives to determine an optimal (least-cost) plan. The model utilizes LDCs to represent time, dispatching the generation fleet accordingly. Variable wind and solar output are modeled using representative weeks per month. These temporal simplifications are used to keep the model computationally efficient in evaluating thousands of different competing resource plans. Individual electricity generating units are modeled within Strategist, although with limited operational detail defining individual units (i.e., unit-commitment, ramp rates are not modeled) and without transmission constraints. A unique feature of Strategist is the level of detail modeled in demand-side options. Demand response, energy efficiency, and time-of-use rates and real-time pricing options are included, as are the options to endogenously model other custom demand-side resources. More information about Strategist is available at: http://new.abb.com/enterprise-software/energy-portfolio-management/commercial-energy-operations/capacity-expansion

System Optimizer (ABB)

System Optimizer is a state-of-the-art long-range commercial electric power systems generation and transmission capacity expansion planning model. It is used by several large electric utilities to develop integrated resource plans and perform other portfolio planning activities. System optimizer uses either a mixed integer programming or linear programming formulation (depending on the constraints included), with an objective to find the optimal 20-30-year resource investment plan. The model can analyze the optimal selection of new generation capacity, new transmission, demand response, and energy-efficiency programs. Individual generating units are represented within the model, including their detailed operational constraints (e.g., startup/shutdown costs, ramp rates). System Optimizer is most commonly used to model a utility service area, or a set of adjacent utility service areas or states. Due to the level of temporal and spatial granularity typically represented, it is not often used to model entire interconnects or larger geographical areas. Transmission between regions modeled is represented (zonal transmission modeling), but intra-regional transmission is not modeled. Temporally, System Optimizer uses a chronological hourly time-step to model demand and supply, implementing this using a "representative weeks" method that replicates to fill in the full year. Unique features of System Optimizer include detailed demand response and energy efficiency modeling, and options for endogenously modeling other demand-side resources. The model also includes an optional detailed hydro-modeling module that allows for optimization of conventional and pumped-hydro units in power systems with large interconnected reservoirs. Reservoir water levels and water basin topologies are explicitly modeled and included in this optimization. More information about System Optimizer is available at: http://new.abb.com/docs/librariesprovider139/default-document-library/system-optimizer_br.pdf?sfvrsn=2

US-REGEN Electric Sector Model (Electric Power Research Institute)

The U.S. Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN) is an energy-economy model developed and maintained by the Electric Power Research Institute (EPRI). The electric sector component of US-REGEN is a detailed long-range generation planning model that uses an intertemporal optimization framework. In each three- to five-year time step, the model makes decisions about capacity (e.g., new investment, retrofit, or retire) and dispatch to meet electricity demand for both generation and inter-region transmission. It uses a bottom-up representation of power generation capacity in technology blocks, and dispatch across a range of intra-annual time segments. It models transmission capacity between regions (zonal), and requires that generation and load plus net exports and line losses balance in each time segment and for each region. The model can represent the U.S. as 15- regions, all lower 48 states, or using a customized approach. Unique features of US-REGEN's electric sector model include using a detailed "representative hours" method to simultaneously model the profiles of demand, solar, and wind, instead of a traditional load duration curve with seasonal and time of day time slices. Additionally, the model can represent the heterogeneity in electricity markets across different regions—whether competitive or cost-of-service—for its electricity price calculations. The option to include endogenous, price-responsive demand exists in the model, and efforts are currently underway to integrate a detailed end-use submodule into the electric sector model to inform loads.[7] More information about US-REGEN's electric sector model is available at: http://eea.epri.com/models.html

---

[7] *US-REGEN Model Documentation.* EPRI, Palo Alto, CA: 2017. 3002010956.

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:

Energy and Climate Policy Analysis

3002011102

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com