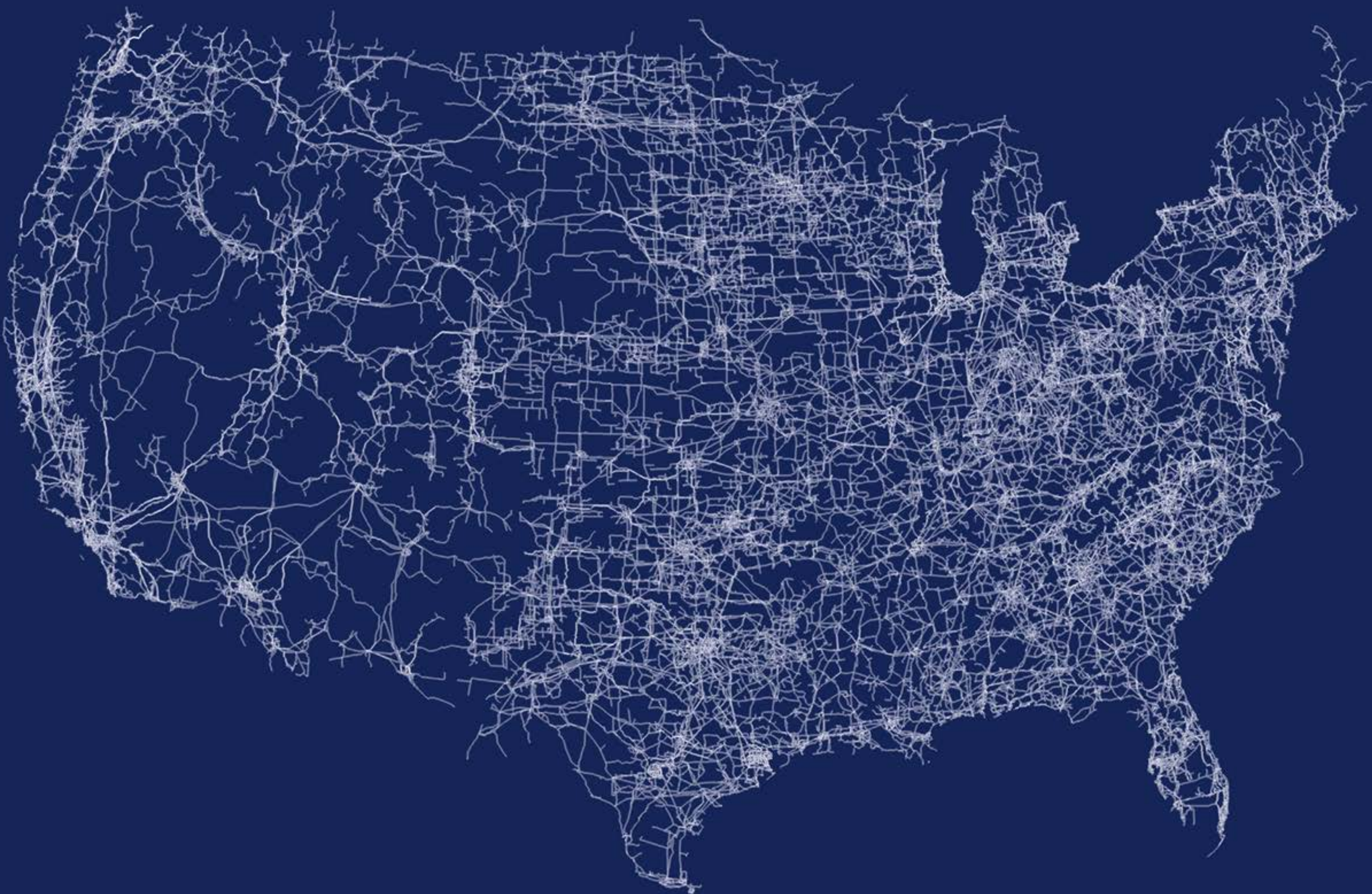

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Electricity Transmission System Research and Development: Economic Analysis and Planning Tools

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Electricity Transmission System Research and Development:

Economic Analysis and Planning Tools

Transmission Innovation Symposium: Modernizing the U.S. Electric Grid

2021 White Papers

Prepared for the
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Foreword

The foundation of the U.S. Department of Energy (DOE) Transmission Reliability research program was established 20 years ago through a series of commissioned white papers. The white papers reviewed the dramatic institutional and regulatory changes that the transmission grid was undergoing and articulated the technical challenges that those changes created. The challenges outlined in those white papers were used to formulate the initial research goals of the Transmission Reliability program. Today, 20 years later, many of the targets set out for the program have been accomplished. At the same time, the electricity grid is undergoing a dramatic shift with the addition of substantial renewable and distributed energy resources and heightened risks from phenomena such as severe weather. These shifts pose new challenges for the transmission grid, today and into the future. As a result, now is an appropriate time to step back and review the current technical challenges facing the industry and to identify the next set of targets for DOE's transmission-related research and development (R&D) programs within the Office of Electricity's Advanced Grid Research and Development Division.

To support this process, DOE, supported by Lawrence Berkeley National Laboratory (LBNL) and Pacific Northwest National Laboratory (PNNL), has commissioned small teams of experts drawn from the national laboratories and academia to prepare a new set of foundational white papers. Each white paper reviews and assesses the challenges now facing the U.S. transmission system from the perspective of the technologies that will be required to address these challenges. The focus of the white papers is on technical issues that must be addressed now to prepare the industry for the transmission system that will be required 10-20 years in the future. A key purpose of these papers is to identify technical areas in which DOE can take a leadership role to catalyze the transition to the future grid.

The five white papers are:

1. **U.S. Electricity Transmission System Research & Development: Grid Operations**
   Lead Authors: Anjan Bose, Washington State University, and Tom Overbye, Texas A&M University

2. **U.S. Electricity Transmission System Research & Development: Distribution Integrated with Transmission Operations**
   Lead Authors: Chen-Ching Liu, Virginia Polytechnic Institute and State University, and Emma Stewart, Lawrence Livermore National Laboratory

3. **U.S. Electricity Transmission System Research & Development: Automatic Control Systems**
   Lead Authors: Jeff Dagle, Pacific Northwest National Laboratory, and Dave Schoenwald, Sandia National Laboratories

4. **U.S. Electricity Transmission System Research & Development: Hardware and Components**
   Lead Authors: Christopher O'Reilley, Tom King, et al., Oak Ridge National Laboratory

5. **U.S. Electricity Transmission System Research & Development: Economic Analysis and Planning Tools**
   Lead Authors: Jessica Lau, National Renewable Energy Laboratory, and Ben Hobbs, Johns Hopkins University

The white papers will be vetted publicly at a DOE symposium in spring 2021. The *Transmission Innovations Symposium: Modernizing the U.S. Power Grid* will feature expert panels discussing each white paper. The symposium will also invite participation and comment from a broad spectrum of stakeholders to ensure that diverse perspectives on the white papers can be heard and discussed. Proceedings will be published as a record of the discussions at the symposium.

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Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

AC	alternating current
AI	artificial intelligence
B	billion
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
DC	direct current
DOE	Department of Energy
DER	distributed energy resources
DR	demand response
ERCOT	Electric Reliability Council of Texas
FACTS	flexible alternating current transmission system
FERC	Federal Energy Regulatory Commission
ISO	independent system operator
ISO-NE	New England Independent System Operator
LMP	locational marginal pricing
MISO	Midcontinent Independent System Operator
MWh	megawatt hour(s)
NYISO	New York Independent System Operator
RA	resource adequacy
R&D	research and development
RTO	regional transmission organization
TRP	transmission resource planning
WECC	Western Electricity Coordinating Council

Executive Summary

This paper describes ongoing and future needs for concepts, methods, data, processes, and technologies to support comprehensive planning for U.S. electricity transmission to meet reliability, economic, sustainability, and other policy goals. We focus specifically on research and development (R&D) recommendations for transmission economic analysis and planning. The intertwined relationships of all assets in the power system mandate full exploration of technologies and systems beyond the transmission system. This paper will recognize how various bulk and distribution system components, as well as supply, storage, and demand-side resources, interact in achieving the above goals, and how emerging technologies can contribute. This paper reflects on current common practices, the state of the art, and justifications for our conclusions about what research is needed. R&D priorities are defined based on their potential to support a reliable, resilient, affordable, and environmentally sustainable grid system. The opportunities and constraints identified are intended to inform decisions about what R&D in transmission grid planning should be supported by the U.S. Department of Energy (DOE) over the next two decades.

Improvements in planning methods are needed because of changes in the world and industry. Transmission technology has been evolving to include improved monitoring and control of flows. The resource mix is rapidly shifting away from reliance on large fossil-fueled generators toward variable renewables, batteries, and distributed resources. Consumers' ability to make personal energy choices and manage their loads is expanding. Markets and policies are playing increasingly complex and broad roles in investment and operating decisions.[1] Not only are the technical feasibility and physical impacts of transmission important, but so are economic and policy considerations, which will continue to play a large part in the ability to turn plans into reality. Stakeholders and their influences on market structures, rate of returns, and risk are also key in the appropriate and successful use of transmission technologies.

Since the 1882 construction of London's Holburn Viaduct and New York City's Pearl Street power stations and their associated neighborhood grids, the power industry has gone through several transformations of the functions it is called upon to perform and the technologies it has used. After each transformation, the nature of system planning changed. By the early twentieth century, the industry had grown rapidly and consolidated into vertically integrated utilities, organized as either regulated or publicly owned monopolies with exclusive service territories. Grid planning at that time was about connecting customers to the utility's resources. During the Great Depression, the trend in the United Kingdom and United States was to build regional grids with higher voltages to access larger and larger plants in order to exploit scale economies, often involving large renewable hydro developments. In some cases, regions with diverse resources and load patterns saw advantages in

[1] For example: "evolving challenges driven by disruptive changes in our customers, power supply resources and climate will require a new approach to designing and building the grid, using various combinations of grid designs and architectures to meet specific locational needs. Our grid planning approach will need to be more adaptive, agile and scenario/risk based" (Southern California Edison, 2020, p. 12).

interconnecting, so planning would consider the operating and reserve-margin savings that facilities such as the Pacific Coast Intertie could bring.

Transmission was recognized as a substitute for generation investment and helped drive further geographic consolidation of the industry. With the very large nuclear and coal plants that were being built starting during the late 1950s, this trend accelerated. The 1965 Northeast U.S. blackout brought a focus on strengthening interconnections to enhance reliability. The past 20 years have renewed interest in taking advantage of load differences across regions and accessing renewable resource diversity. In 1999, DOE commissioned a set of white papers that addressed challenges in transmission reliability and planning as understood at that time (U.S. DOE 1999).

Now another transformation of the functions of, and demands upon, the grid appears to be under way, justifying a review of R&D recommendations and a new set of white papers. In particular, with the rapid growth of demand management and distributed energy resources (DER), both behind and in front of the meter, we may be witnessing the emergence of coordinated planning and operations of the distribution and transmission systems. For example, distribution system operators will want and need to coordinate closely with bulk system independent system operators (ISOs) to ensure that incentives are provided to develop and use resources wherever those resources make the most economic, reliability, and environmental sense. Meanwhile, the overwhelming proportion of resource additions will be storage and variable renewables, with significant expansion of the grid being required to access the best resources and exploit diversity to maintain system reliability. Demand management will grow rapidly in importance, in part because environmental policy will drive increased electrification of buildings and transportation, and much of those loads will be flexible. As a result, the grid of 2050 may be supporting a power sector that looks very different from today's, simultaneously more decentralized but at the same time more strongly connected among regions. New tools and concepts are needed to support the planning of that grid.

As described in **Section 1** of this paper, which focuses on universal themes, tools and concepts will have to account for the multiple goals and functions of transmission. These will include facilitation of reliable, economic operations and resource investment, as well as support of social and environmental goals such as addressing greenhouse gases, air pollution, and landscape preservation. There is a need for more data and greatly enhanced computational abilities to simulate operations and evaluate resource and grid investments. This need is driven by the explosion of new devices and assets on the grid, by rapidly improving optimization methods, and by greater recognition of the profound uncertainties involved in long-run planning. Additionally, new research must be founded on social science-based understanding of market responses to network enhancements, transmission investment impacts on resource investments, and facilitation of inter-regional cooperation to make trade more efficient. Finally, to effectively harness this understanding and use those tools to design a grid that effectively addresses multiple goals, we need an appropriately trained planning and engineering workforce.

Section 1's universal themes related to what is needed in the future are explored in depth in **Section 2.** For instance, future tools will need to recognize that grid reinforcements can both substitute for and enhance the value of supply, storage, and demand-management investments. Thus, an anticipative transmission planning paradigm should be more widely used than is the case day. In this paradigm, grid planners consider the ways in which grid investments would affect not only how resource investments are operated, but also where and what technologies are built. For brevity, we use the term ***transmission resource planning (TRP)*** to refer to this holistic planning tool and process. TRP is not literal co-optimization in the sense that resource and transmission expansion decisions are not made by the same entity or closely coordinated; rather, the term means that transmission planners will make grid investment decisions taking into account how the market will respond, recognizing the availability and flexibility of resources in the system, and considering the interconnected nature of technical and economic decisions about resource investment and operations.

Thus, a comprehensive view of grid, supply, demand, and distribution-transmission relationships is necessary to correctly value and appropriately plan grid reinforcements. Correct valuation and appropriate planning will also require advances in technology modeling, economic theory, numerical optimization methods, and the design of institutions to align private incentives with overall market and social benefits and costs. Besides these complementary and substitutive relationships among bulk and distributed resources, storage, and grid reinforcements, future planning methodologies must account for several other analytical and practical challenges, which we address in detail in Section 2. These include, among others:

- compensation for the value that grid reinforcements provide not just to energy markets but also capacity and ancillary services;
- recognition that this value depends strongly on market designs and efficiency of trade and coordination among balancing authorities;
- decision making in the face of increasing short-term variability and long-run uncertainty;
- coordination of markets and infrastructure planning, and the increasing roles for assets, such as storage, that can receive both regulated and market revenues; and
- the need to provide incentives for participation in inter-balancing authority projects so that all participants benefit.

Through an exploration of visions of possible power system futures, universal themes, and evolving topics, **Section 3** outlines five research areas and 23 specific topic areas that we recommend that DOE consider as responses to the above challenges, to be pursued over the next 10 to 20 years. The five research areas are:

1. *Multi-value planning*: enabling assessment and planning of a variety of concurrent power system goals
2. *Workforce development*: training and empowering workers to support electricity consumers through education, learning, and experiences

3. *Behavioral underpinnings of economic valuation and market designs*: deepening of social science research to understand consumers, markets, operations, and non-techno-economic drivers
4. *Market simulation and planning models with flexibility and scalability*: expanding realism, flexibility, and scalability to appropriately model and plan for the grid of the future, including developing models with greater fidelity to actual physical and market systems as well as simplified models that are accessible to regulators and stakeholders who can use them for education and insight into the tradeoffs inherent in transmission planning
5. *Adaptive TRP under profound uncertainty*: advancing robust planning through risk assessments and scenario planning, considering the full range possible futures.

These research efforts should involve not only power engineers, but also computer scientists, empirical economists, and human factors specialists.

The paper is authored by Jessica Lau and Benjamin Hobbs and reflects their personal outlooks on the industry and R&D needs. It should in no way be interpreted as a representation of the opinions of DOE or other organizations. We acknowledge that not everyone will agree with the ideas and recommendations that have been shared in this paper. We welcome comments and discussion.

1. Universal Themes

Throughout our exploration of challenges and research needs associated with transmission grid economic analysis and planning, we found needs that are common to most or all of the technical topics. We organized those shared needs into four universal, cross-cutting themes that are generally applicable to the topics in Section 2. The four themes, listed below, are described in more detail in the subsections indicated:

1. Planning challenges posed by expansion of the objectives that transmission serves (Section 1.1)
2. Continuing needs for better data and computational capabilities (Section 1.2)
3. Potential contributions to improved planning from social-science-based understanding of the behavior of market participants and evolution of institutions (Section 1.3)
4. Need to develop a workforce whose members have the breadth and depth to plan effectively to best support society (Section 1.4)

For simplicity, we refer to future planning tools and processes using the term *transmission resource planning (TRP)*. TRP encompasses our vision that the future of transmission planning will take the form of comprehensive transmission, distribution, and resource planning. We do not envision TRP as integrated resource planning by a single entity but rather that transmission planners will anticipate how supply, storage, load, and distribution are intertwined and can provide grid reinforcements and respond to pricing.

Addressing the above four general topic areas plus the 23 areas of specific research identified in Section 2 is essential if the research agenda we propose is to achieve the objectives of preparing transmission planning, and planners, for designing a grid that meets society's future needs.

1.1 Reliability Is Not the Only Reason to Build Transmission

Planning for grid reliability. Reliability is the cornerstone of grid and transmission planning. There is no doubt about the importance of reliable power supply as electricity access has come to be viewed as a fundamental human right. This has led to our planning methods and processes being largely centered around reliable power supply and delivery to electricity consumers. However, this reliability-centric planning mentality means that processes and tools for addressing non-reliability-related motivations for transmission planning, such as market efficiency and public policy, are rapidly developing and in need of further fundamental and applied research.

Existing justifications for building transmission are often too limited. Legacy structure and processes, which include defined justification categories and rigorous technical study processes, have dictated most of the transmission built (Hesamzadeh et al. 2020). Transmission can bring multiple layers of benefits, but the existing stakeholder approved processes often consider only a narrow set of justifications that does not encompass the full range of potential benefits. The range of transmission benefits considered varies widely in regional transmission planning processes or vertical utilities, as does the means by which benefits are evaluated (Eto 2017). Technically, some transmission planning processes driven by market efficiency and public policy considerations exist, but, with notable exceptions (e.g., the Texas Competitive Renewable Energy Zones process, the Pacific interties), they tend to be less successful in justifying, and resulting in, actual grid expansions. This is not due to a lack of desire or the tenacity required by the transmission planning process but is instead because of the complexity and long list of metrics that a project must satisfy (Chang et al. 2013). The transmission justification and assessment frameworks are too narrow and, as a result, have become a barrier because they do not accept portfolio benefits approaches or other justifications of benefits.

The need to reflect multiple objectives in planning the grid is particularly acute because of the growing importance of public policy goals. Public policy is driving the resource mix toward low or even zero-carbon-emitting sources while also setting goals for electrifying transportation and buildings. At the same time, there is every reason to believe that public concerns about aesthetics and landscape preservation will be an important constraint on renewables and transmission siting, and tradeoffs among those impacts, costs, property rights, land use, and greenhouse gas emissions will be increasingly salient in planning and regulatory discussions. Finally, energy equity and economic analyses need to consider not only net benefits, but also retail customers: who benefits, whether they pay their fair share, and whether economically vulnerable members of society bear unfair cost burdens. Distributional, social, and environmental justice issues have to do with not only physical facilities, but also with how costs of facilities are recovered, and with the designs of the markets that use those facilities. Planning methods will need to explicitly recognize tradeoffs among objectives and seek to define a range of plans that offer tradeoffs for consideration in stakeholder and policy-maker negotiations.

Multi-value planning. Multi-value planning is critical to address in practice and in research at the same time. As the independent system operator (ISO)/regional transmission operator (RTO), utility, and co-op processes are continuing to evolve, so must the research in metrics and tools to support multi-value transmission and grid planning. First, the identification of individual, or combinations of, metrics to best quantify and qualify multi-value transmission projects would be most immediately useful.[2] Second, the development and application of such methods in appropriate models, including power flow, production cost, resource adequacy, and capacity expansion models, would ensure ability to calculate these metrics as well as the tradeoffs represented by alternative grid expansion plans. Third, rigorous testing, benchmarking, and long-range tracking of metric calculations and operational statistics will help verify and validate the multi-value quantification framework.

[2] For early examples of such tradeoff analyses, see the Midcontinent ISO (MISO) multi-value planning process https://www.misoenergy.org/planning/planning/multi-value-projects-mvps, or the California ISO (CAISO) (2004) TEAM approach, each of which uses multiple metrics so that tradeoffs can be assessed. Academic research includes Maghouli et al. (2010).

1.2 Advancements in Data and Models are Needed

Flexibility in models. Research advancement in data and models will continue to arm grid planners with the best possible tools. A universal truth is that the future is unknown. We will not know in advance the exact transmission network, load, resource mix, and other aspects of the future grid. However, these uncertainties should not hold back grid planners. R&D's role is to ensure advancement in data and models so that they are ready for any situation that a planner encounters in practice. Past grid planning took place largely within the context of vertically integrated, centralized transmission and distribution systems. Future grid planning will take place in the context of marketplaces with millions of assets competing to offer grid services. Future grid planning will also exist in a new paradigm that is only just under development. Research is needed to support advancement and to create flexibility in software models and tools that will be compatible with that paradigm. Subject to confidentiality protections when appropriate, open-source release of data and models will also support case-by-case development as needed. A myriad of tools will be required for future grid planning, some of which the industry already has, and some of which are yet to be created to support planning for a reliable, affordable grid.

Although we place heavy emphasis in this report on increasing the fidelity, and therefore complexity, of TRP models (especially their production-cost component), we emphasize that more complex models are not necessarily more accurate or more useful. Regarding accuracy, if the data for parameterizing complex models do not exist, then accuracy is unlikely to improve. Meanwhile, in regard to usefulness, simpler models that can be readily applied to many scenarios and that are transparent, easily understood, and replicable can produce very important insights and understanding for regulators and stakeholders. Indeed, education and communication are very important roles for models, in addition to providing accurate estimates of costs and optimal recommendations. Thus, development of simple, easy-to-use, yet reasonably realistic, models is needed to complement efforts to make larger, more complete, and more accurate models. Better understanding is needed of how the diverse user community benefits from models and how models can be made more insightful and truly useful. Early studies in energy modeling often addressed such questions (Greenberger et al. 1976), but these topics are unfortunately mostly neglected today.

More realistic production costing. A large portion of the estimated economic and operational benefit of transmission reinforcements results from production cost savings arising from more efficient delivery of energy and ancillary services and facilitation of trade among interconnected regions. The sources, amounts, and distribution of these economic benefits will change in the future as the generation mix evolves to include more renewables, storage, demand response (DR), and administrative-scarcity pricing mechanisms. Energy and ancillary service prices and, therefore, the benefits of transmission will be increasingly tied to the value of reliable power provision to customers, either through administrative pricing mechanisms based on guesses concerning that value or through, we hope, customer participation in markets and direct expression of their willingness to pay for reliable service. Better estimates of these benefits are recommended under most of the research topics in Section 2.

Estimates of the cost of operating a given network design and set of resources can be obtained from stand-alone production-cost models. Planners use such models to evaluate the impacts of alternative designs on operations. Production-cost models, usually simplified, are also embedded in optimization-based transmission planning models that include both grid reinforcements and resource operations as decision variables. Finally, full resource-transmission co-optimization models add resource investment as a set of decision variables.

Although planning models necessarily make more simplifications of the physics and economics of operations than stand-alone production-cost models, all models are approximations. The complexities of network physics, power plant dispatch, unit commitment constraints and costs, variations in resource availability, and the interactions of resources with load mean that accurate estimates of production-cost savings depend on the fidelity of the model's representation of system features. Critical features include physical constraints, economics, flexibility, and dependability of resources. Increasingly important are: 1) DR, distributed energy resources (DER), and storage resources (e.g., Maloney et al. 2020; Xu and Hobbs 2020a); 2) network models that capture features that limit or enhance deliverability, such as contingency-based flow limits, installation of flexible alternating current transmission system (FACTS) devices, and transmission switching (e.g., Villumsen et al. 2012); and 3) short-term forecasting errors that result in inefficient forward resource schedules and the need for flexibility (Weber et al. 2009). Better sampling of wind, solar, hydro, load, and other resource conditions over interconnected regions is also needed to improve confidence in estimates of operations and expected production cost savings from grid reinforcements. Furthermore, how different merchant developers and market participants behave can be complex and strategic. The details of market rules that govern the form of bids and offers, how the market is cleared, and how settlements are calculated also affect agent behavior in ways that production-cost models often greatly simplify by assuming cost-based bids rather than strategic behavior. A very large research literature has addressed the inclusion of strategic (market power) behavior in the representations of spot markets in production cost models (Blake 2003; Gabriel et al. 2012) but has failed to find acceptance in practice because of the complexity of the researchers' difficult- or impossible-to-verify behavioral assumptions, and because market power concerns have largely, although not completely, subsided since the California 2000-2001 crisis.

It is easy to identify particular ways in which research could improve the fidelity of production-cost models. However, what is not understood is how these improvements would affect estimates of net benefits of transmission reinforcement. Research is needed to understand which features of production costs and market operations would, if modeled simplistically, distort recommendations for transmission investment and potentially lead to significant loss of potential benefits resulting from inefficient investment. In turn, research is needed to understand how models' simplifications of production costing and transmission network operations can affect the estimated benefits and impacts of policy reforms (such as renewable portfolios standards [Munoz et al. 2013]), and, symmetrically, how such simplifications affect conclusions about how policy would affect the economics of transmission investment.

With effort, it is possible to quantify the value of model enhancements, and the results can be surprising. For instance, one study found quickly diminishing returns when more sample days were included in production-cost models, but much larger impacts on decisions and expected cost performance if long-run uncertainties in demand, policy, and technology are ignored by considering only one scenario (Xu and Hobbs 2019). In general, it should not be assumed that all improvements in fidelity improve decisions and are worthwhile. In fact, *decreased* fidelity can be desirable if it results in simpler, faster models that can be run without specialized software and hardware and can allow planners to explore more alternatives and future scenarios. Insight on how robust plans are to uncertainties is more important than a more refined benefit-cost ratio under a single planning scenario. If additional, more complex results can be visualized, communicated, and digested—which cannot be taken for granted—the outcome can be more informed and better decisions.

Decomposition and other methods for facilitating solutions of large-scale TRP models. TRP models are often formulated as large-scale optimization problems that include both transmission investments and resource operations (and sometimes resource investments) as decision variables. In the future, we expect planning to consider transmission and distribution lines as well as transmission and distribution resources. When a planning process is considering investment decisions in multiple years, several long-run scenarios, many operating conditions, and complex networks over a large region, the result can easily be a model with hundreds of millions of decision variables that cannot practically be solved by today's solvers. Being able to practically solve such models, across different simulations under alternative scenarios, would be useful in dealing with many of the topics discussed in Section 2.2 of this paper, including market benefits, interconnection benefits, and planning under uncertainty. However, the desire of modelers to include more detail and more realistic features will likely always exceed computational capabilities. So, as just pointed out in the context of production costing, planners, when deciding how to take advantage of enhanced capabilities, need to consider which features will most influence, and provide most value to, decision making.

Fortunately, the models in question often have a structure (e.g., separate operating days, multiple long-run scenarios, or loosely coupled regions) that facilitates decomposition (a divide-and-conquer approach). The decomposition can be by location, operating period, year, or future scenario. Generally, in decomposition, separate production-cost models interact and are coordinated with investment-decision models. Such approaches are based either on mathematical theories of decomposition that provide a basis for expecting convergence or practical heuristics that work well in computational tests (Barrows et al. 2019; McCalley et al. 2017; Munoz et al. 2016; Gomes and Saraiva 2019; Watson 2013).

Another approach that can help solve huge TRP models is pre-screening. This approach limits model size by heuristically identifying the network reinforcements that are most likely to be beneficial and then including just those alternatives. In addition, iterative schemes based on solving simplified models (e.g., more aggregate networks, or use of pipes-and-bubble formulations), and then using those results to inform and constrain more detailed models in an automated fashion, are another research direction (Maloney et al. 2020). Such a scheme could be compatible with how planners today use different models for various purposes in planning while keeping the process efficient. None of these three techniques (decomposition, pre-screening, and iteration between coupled simplified and complex models) is a standard part of TRP software. Research would be desirable to identify efficient formulations and implementations of these techniques that can be readily used by transmission planners.

1.3 Social and Economic Understanding are Key to Effective Transmission Planning

Engineering creates products and infrastructure that meet human needs and are supported by markets and institutions. Thus, successful transmission planning requires not only physical and mathematical understanding of the electrical engineering effects of system topology and technology, but also social science-rooted understanding of economic and social benefits and costs; public perception and concerns about those benefits and costs; and how to effectively recognize and reflect those concerns in plans. Each of the topics addressed in Section 2 involves research in the social sciences as well as in technology and computation. Improved transmission planning requires improved understanding of what motivates individual consumer behavior; how well-designed, and not-so-well designed, markets function to translate costs and use value into prices and incentives; and how institutions that support markets and technology evolve and can be improved. This research should draw heavily on experience with markets as well as modeling studies to analyze how alternative grid configurations and market designs affect incentives for efficient resource operations and investment. Below we describe four general social and economic problems areas that require attention: citizen engagement, consumer behavior, market designs and incentives, and institutional evolution.

Citizen engagement. Successful transmission project design and implementation require skillful handling of electrical and cost engineering, landscape architecture, environmental assessment, and, especially, citizen engagement. Many proposed transmission projects that would be economically and technically beneficial to the system suffer lengthy delays or cancellation because of local siting issues or diffuse concerns about who benefits and who bears the costs, including environmental and aesthetic costs. Equity concerns are especially acute when one region perceives that another benefits from the power delivered by a new facility with few perceived benefits to the locale where the line is placed. The electric power industry has used acronyms like Not In My Back Yard (NIMBY) to generalize public sentiment on new infrastructure. This perception is a result of a disconnect between system planners and the people who live with impacts every day.

Social scientists have studied controversies over large infrastructure projects, including transmission, and have proposed principles and methods for stakeholder engagement to promote acceptance of new facilities (Fischlein et al. 2013; McAdams 2021; Raab and Susskind 2009). A key to successful developments, such as the Sunrise Project in California, seems to be not so much public education as active outreach to stakeholders, sincere recognition of their concerns, and a willingness to modify designs and objectives to address those concerns. There is no silver bullet or guarantee of success, but further examination of successes and failures as well as experimentation with new approaches to integrate public engagement with planning could avoid wasted planning effort and project cancellations and delays.

Another key to successful citizen involvement processes is sincere, full, transparent consideration of alternatives to transmission for accomplishing a project's economic, reliability, and policy objectives while respecting social and fairness concerns. As discussed in several places in Section 2, a range of options could substitute for transmission and in some circumstances yield similar benefits for less cost, such as various types of demand-side, storage, and generation technologies; more flexible operations such as inclusion of transmission switching; and market reforms that promote more efficient use of all resources in a region as well as efficient trade with other regions. To identify and quantify the cost-effectiveness of a solution that relies on constructing a new transmission facility versus the full range of other options, further development of production costing and planning tools is needed, as recommended in Section 3 of this report.

Consumer behavior. The explosive growth in DERs, especially behind-the-meter resources, is due to both economics, such as net metering policies, and consumer preferences for non-monetary attributes, such as autonomy, advanced technology, and environmental responsibility. Consequently, it is difficult to predict future consumer investments in DERs, which, in turn, makes it difficult to forecast future growth in net loads and to estimate benefits and costs to consumers and subsequent shifts in DER investment that might arise from changes in retail and transmission pricing methodology and availability of transmission. High DER penetration has the potential to result in sustained negative growth rates in net load served by grid-based resources, diminishing the need for grid reinforcements. Alternatively, DERs and grid resources could evolve complementary roles that would result in large daily or seasonal shifts in the magnitude and even direction of load flows, which could justify improvements in management and planning of the grid. Economic, marketing, and sociological research are needed to understand how DER usage may evolve, and its implications for TRP.

Much future research should consist of empirical evaluations of DER and consumer behavior case studies of planning, operations, and economic outcomes in the marketplace. Research should be conducted to better understand consumers' values and priorities if the grid intends to rely on consumer behaviors and DERs. This could include randomized control trials in which alternative incentives and DER technologies are evaluated, as well as creative approaches that adaptively combine ethnographic research with data-gathering, surveying, and methods to better understand consumer expectations and energy-use practices.

Market designs and incentives. Markets determine which resources are built and operated, in what locations, and at what times, to meet what level of consumer demand. Today's market software coordinates the actions of hundreds or thousands of power sources with millions of consumers, accounting for individual operating constraints, costs, and economic value. In matching supply and demand, the software can also capture the network's highly complex physics, transfer capabilities, and risk-based limitations.

However, markets are not just about representing physics and matching supply and demand. The field of market design is also concerned with creating incentives that align private benefits and costs with societal net benefits so that market participants find it profitable to follow operator instructions and make investments and operating decisions that enhance market efficiency. This can be difficult to accomplish, especially when market designs make simplifications to accelerate solution times or in the interest of transparency, but which also distort prices and possibly operating and investment decisions. Examples include zonal market designs for energy or ancillary services that result in inability to deliver the products, and energy and capacity markets that fail to incentivize resource investment of the right type at the right place, or distortions due to, for instance, price caps, simplified capacity credits, or grid-use fees that do not reflect marginal short- or long-run costs. Distortions also arise when parties have significant market power; although market power is no longer the prominent issue it was after the 1999-2000 California crisis, it remains a risk and occasionally emerges in new and unexpected ways. Distortions resulting from strategic behavior and flawed market designs will affect the benefits of grid reinforcements by affecting the efficiency of the market that uses that grid.

As pointed out below in Sections 2.2 and 2.3, failure to consider 1) deliverability of ancillary services in market software and 2) price- and non-price barriers to trade between regions can greatly affect the apparent benefits of building transmission and thereby distort grid reinforcement decisions. Research is needed to understand the effects of inefficient market design and market party behavior on transmission benefit-cost analysis, as well as to understand how changes in grid capability will affect market outcomes. Reserve deliverability and barriers to trade have been particularly difficult to model; both technical and social science advances are needed to credibly model them and their dependence on market rules and grid design.

Market forces can be harnessed to decrease the cost of transmission construction, and the value of transmission services provided by new investment, by providing financial incentives to identify and efficiently implement high-value investments. In contrast, poorly designed markets and cost-plus-based regulation can thwart those objectives. Markets can also be used to allocate transmission capacity to highest-value services if the markets are set up to efficiently price congestion, losses, reactive power, hedges against congestion costs, and other attributes and services. Theoretical and empirical economic research can identify market designs to secure the potential benefits of market forces, and should be made a priority.

Institutional evolution. Market designs and the efficiency of trade, and their impacts on transmission expansion benefits, depend on the institutional structure of the power industry, the geographic size of markets, the roles of independent operators, the size and incentives of public and private resource owners, and how transmission is regulated and rewarded. Power-sector institutions have evolved quickly, sometimes astonishingly so, over the past four decades. In that time, power institutions have evolved from Samuel Insull's vertically integrated monopolies subject to average-cost-based regulated pricing to a largely, but not completely, unbundled industry in which prices drive operating and, to a lesser extent, investment decisions. Regulated competition has replaced cost-of-service ratemaking. Transmission networks remain regulated because they are natural monopolies, because the pricing of their services affects market efficiency and generation-market competitiveness, and because of their need for eminent domain power.[3]

In the United States, this transformation started with the Public Utilities Regulatory Policies Act of 1978, which created an unintended effect that forced vertically integrated regulated utilities to pay avoided cost for small and renewable resources. Then, in the 1990s, the desire of large customers to gain access to lower-priced electricity and the general anticipation of large efficiency benefits from restructuring led to Federal Energy Regulatory Commission (FERC) Order 888 and state initiatives, such as California's Assembly Bill 100, that led to creation of competitive electricity markets in much of the United States. This momentum was largely halted by the California 2000-2001 crisis. More recently, restructured markets have been expanding their geographic reach, bringing a larger fraction of U.S. energy transactions into RTO-type markets. We have also witnessed the recent rapid expansion of the Energy Imbalance Market across the west and plans for a complementary day-ahead market, which seemed a political impossibility a few short years ago. It was predicted early on that this restructuring could radically change the economic planning criteria and methods used in TRP (Baldick and Kahn 1993), a prediction that has largely been confirmed (Hesamzadeh et al. 2020).

To project the benefits of transmission investments over their approximate 50 years lifetimes, the fundamentals of resource technology costs and availability need to be understood as well as the institutions that make electricity trade possible or that discourage it. The factors that drive institutional evolution are complex, from economic fundamentals to social perceptions and concerns to politics. Three examples of fundamental drivers include: the fracking boom that recently cratered the price of natural gas; industry demands during the 1980s for access to low-marginal-cost power that was barred by retail regulation; and large price variations across regions resulting from differences in resource mix and availability such as the exceptionally low midday prices in the belly of California's duck curve. Meanwhile, examples of political factors include interstate tensions over governance of the California ISO (CAISO), public opposition to new transmission facilities, demand for growth of renewable power, and federal-state relationships that determine the extent to which the federal government can effectively promote the development of new transmission facilities and management institutions.

Research that examines the role of drivers, oversight, and institutional structure differences in the evolution of the power sector's institutions can shed light on what intentional responsibilities and structures can lead to beneficial and effective transmission expansion and corresponding incentives. For example, research can identify which economic and social conditions, public education efforts, and

[3] A reviewer pointed out that Adam Smith (1776) in *The Wealth of Nations* warned that "(t)he tolls for the maintenance of a highroad [highway] cannot, with any safety, be made the property of private persons. A high-road, though entirely neglected, does not become altogether impassable.... The proprietors of the tolls upon a high-road, therefore, might neglect altogether the repair of the road, and yet continue to levy very nearly the same tolls. It is proper, therefore, that the tolls for the maintenance of such a work should be put under the management of commissioners or trustees." To summarize, Smith saw a need for network regulation. Although transmission networks did not exist at the time, one can easily substitute "transmission" for the "high-road," and "congestion" for "impassible." More recently, Joskow and Schmalensee (1983) issued a similar warning for electric utility deregulation in their pathbreaking book *Markets for Power*.

stakeholder involvement efforts have been most supportive of the implementation of efficient market structures and designs.

1.4 Workforce Development and Informing the Public are Just as Important as Technology Development

Workforce development. Throughout this paper, we extensively discuss the need for technology, methods, and tool improvements. However, technological and societal changes also mean that the power industry's workforce needs to evolve and adapt its skillsets to future versions of the grid. The current transmission and grid planning workforce possesses wide-ranging technical skills, including electrical engineering, mechanical engineering, software engineering, and economics. To meet future needs, the workforce will also need to gain expertise in communications, cyber security, resilience, the internet of things, and other relevant areas. It is unlikely that the need for any current essential knowledge or skillset would disappear, but the type of knowledge needed will greatly expand as the power system becomes more complex and deploys new technologies. Any one technological innovation or advancement can have immense impact on the workforce. For example, Figure 1 describes the skillset shift stimulated by increasing automation and artificial intelligence (AI) across all workforces (Bughin et al. 2018). Transmission economic analysis and planning have taken, and are expected to continue taking advantage of advancements in automation and AI and therefore can be expected to have at least the same, if not more, impacts on the skills needed in the workforce as are shown in Figure 1.

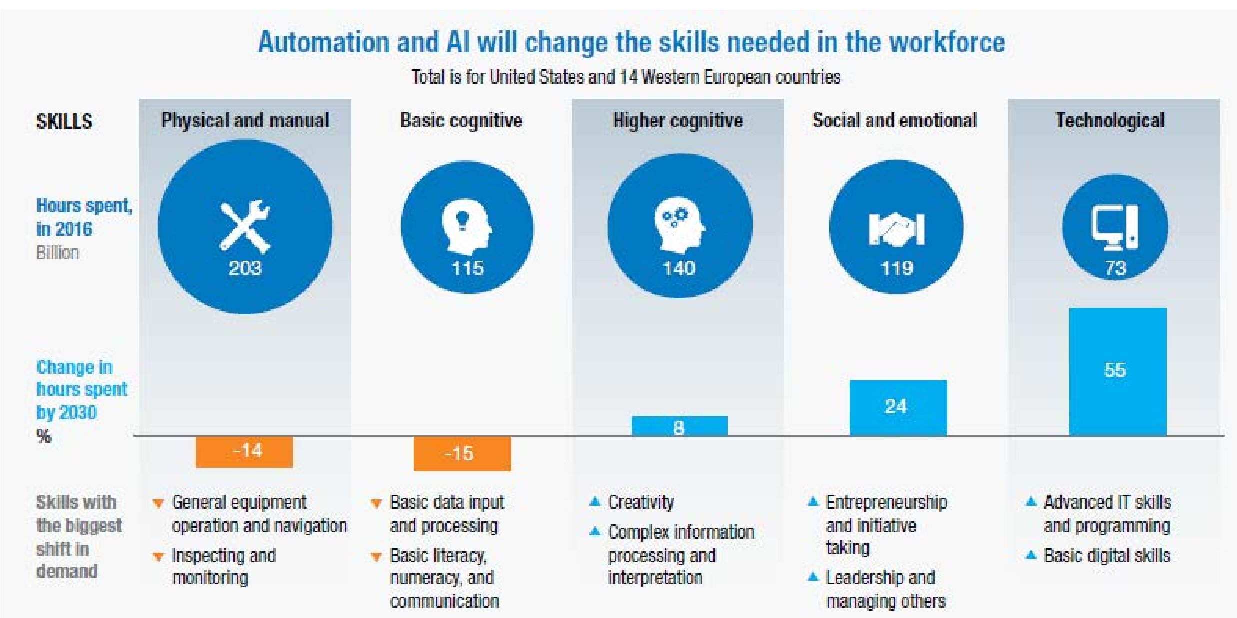

Figure 1. Estimated impact of automation and artificial intelligence on skills needed in the overall workforce (Bughin et al. 2018)

Research and development (R&D) programs can assess workforce gaps, which may span topics ranging from technology to function, outreach, economics, social science, and law. To address those gaps, R&D can help develop the future tools and skills that the workforce needs and identify the most effective means of educating and expanding the workforce, such as communicative visualizations, tools that incorporate human factors, and other user-friendly options. There are already efforts across the industry to do this (CEWD 2020); these can form a basis for continued, expanded research. We recommend taking a proactive approach because it takes decades to foster and develop professionals in the energy industry. Additionally, research can help support recruiting and education efforts to attract future members of the power systems workforce (NAS 2021). In Section 3.2.2, we recommend specific actions that the U.S. Department of Energy (DOE) can take to recruit and improve the workforce needed for future power system planning.

Supporting planning-process stakeholders. Developing human resources for TRP can also be viewed broadly as educating and upgrading the skills of stakeholders and regulators. Constructive involvement of these additional stakeholders is crucial to developing plans that are reliable, economical, effectively address sustainability goals, and gain sufficient public support to be implemented. Some may argue that existing practices have led to successful construction of transmission and other electricity system assets, but we must reckon with current circumstances and relationships among all energy stakeholders, which sometimes manifest in opposition to deployment of economically and environmentally beneficial technologies. There are existing misconceptions or misunderstandings between consumers and the energy industry, which is often highlighted during power outages or rate hikes. It is broadly accepted that stakeholders have a right to be informed, consulted, and empowered to influence energy infrastructure decisions that affect their pocketbooks and quality of life. To deploy improved power technologies efficiently and beneficially, planning practices must be improved to better communicate with and involve stakeholders.

Specifically, policy makers, legislators, ratepayers, environmental advocacy groups, and many other stakeholders all contribute to the development, approval, and public acceptance of proposed transmission plans. When opposition to new projects or plans arises, stakeholders can also be the reason that technically and economically efficient solutions do not move forward. In multi-stakeholder scenarios, which are typical in transmission planning, business models and values must be aligned to the extent that all parties will agree to move forward (NARUC 2021). Education and outreach activities are needed to help communicate complex technical justifications to stakeholders and policy makers, who then must balance those justifications with social, environmental, and other non-technical considerations (Matamala et al. 2019).

Research can help develop tools that can be used for stakeholder engagement, such as communication materials, visualizations, and educational activities for all ages, from primary school to retirees. Sometimes pilot programs can help demonstrate the significance--or insignificance--of personal, economic, and technical impacts on consumers. Research will be key in finding methods to improve communication of power system needs, technology impacts, and tradeoffs among objectives to the consumers that the power system serves. As we discussed in Section 1.2, simple, transparent models can also be an important tool for education of, and communication with, stakeholders and regulators.

2. Evolving Topics

In Section 1, we introduced four cross-cutting areas of research: multi-value planning, data/computation, social science-based understanding of behavior and institutions, and workforce development. In this section, we drill down into six more focused topics for TRP research, each of which involves several of those four broader areas. The six focused research topics (and the subsections in which they are discussed in more detail) are as follows:

1. Reasons for doing power system planning (Section 2.1);
2. Quantification of the value that transmission provides to energy, capacity, and ancillary service markets (Section 2.2);
3. Coordination of TRP across systems and institutional boundaries (Section 2.3);
4. Coordination of planning across transmission and distribution systems (Section 24);
5. Forecasting (Section 2.5); and
6. Consideration of uncertainty in planning (Section 2.6).

We explore each of the above six topics in some depth in subsequent subsections, using the following outline for each topic:

A. Definition and background
B. Overall challenges;
C. State of the art and industry practice
D. General recommendations for R&D

More specific recommendations for DOE-sponsored R&D over the next two decades are presented in the next section of this paper (Section 3).

As a reminder to the reader, we refer to future planning tools and processes as *transmission resource planning (TRP)* for simplicity. TRP refers to our vision of future transmission planning as encompassing comprehensive transmission, distribution, and resource planning. We do not envision TRP as integrated resource planning by a single entity, but rather that transmission planners will anticipate how supply, storage, load, and distribution are intertwined and can provide grid reinforcements and respond to pricing.

2.1 Reasons That We Do Power System Planning

A. **Definition and Background**

When the electric light bulb was invented, it was a novelty. In the 1880s, only people with the interest and means converted their home gas or candle lighting to electric, typically powered by their own generator. Fifty years later, most North American homes were electrified. Now, in the new millennium, electricity has become a fundamental right of a U.S. citizen, and candles are mainly a luxury purchase.

The objectives that we have held as a society to drive the planning of electricity infrastructure have also evolved. Early on, electricity infrastructure was built and prioritized first for limited lighting uses, then for industrial processes, then for population centers in cities; finally, electrical lines were expanded out across the states and the country to both urban and rural areas.

Over time, planning standards and design criteria were created to standardize the methods used to identify system needs and justify infrastructure investments. These standards and design criteria outline the technical analysis to be conducted and the findings required to trigger investment needs. A transformer unable to meet peak load or an inability to keep customers served after one asset outage (the so-called n-1 criteria) are examples of triggers for infrastructure investments.

B. The Challenge

To drive widespread electrification across the country to urban, suburban, and rural areas, large-scale investments were required. In the United States, the most frequent practice was that utility regulators set up an incentive, in the form of a guaranteed rate of return on capital investment, to compensate vertically integrated utilities for undertaking multi-million-dollar financial risks to build new infrastructure. In some places, public cooperatives and entities such as the Bonneville Power Administration (BPA) and Tennessee Valley Authority marshaled government resources to expand electricity access. At the time, the creation of private regulated monopolies was seen as beneficial and necessary to expand energy access in many regions; however, many question the relevance of this model today and whether utilities' financial structure still incentivizes appropriate investments. That questioning led, in many parts of the country, to vertical unbundling, as a result of which energy supply became subject to competitive pressures while transmission and distribution retained their regulated vertically integrated status (Brennan et al. 2002; Joskow and Schmalensee 1983).

As evidenced in the recent shift toward performance-based rates for transmission and distribution owners and operators (Felder 2020), it is clear that a few states and utilities have decided to bridge the current public policy goals with alternate rate structures, such as the 2011 Illinois Energy Infrastructure Modernization Act[4] and the 2016 New York Reforming Energy Vision.[5] These new models motivate utilities to achieve certain performance goals or improvements, such as decreasing overall energy demand and therefore infrastructure investments. This can be contrasted with the traditional approach of regulatory cost recovery, in which utilities filed rate cases to recover the costs of capital infrastructure investment, including a regulated rate of return. Sometimes, this created an unintended preference to construct new facilities instead of improving operating efficiencies or alternatives such as energy efficiency (Felder 2020). At this point, there is no ideal rate design and regulatory approach for the monopoly transmission and distribution functions, and any rate and incentive design to ensure reliable electricity supply is complex and highly specific to the geographic region, technical system, and institutional structures.

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[4] Illinois' 2011 Energy Infrastructure and Modernization Act and the 2016 Future Energy Jobs Act established performance-based ratemaking formulas as well as performance-based goals such as emissions reduction and energy efficiency.
[5] New York has promoted two initiatives, the 2015 Reforming Energy Vision and the Value of Distributed Energy Resources.

References are sometimes made to the “death spiral of the utility” in part because regulated monopoly utilities have difficulty responding to technology innovation and consumer desires. However, much of utilities’ inability to respond is a result of rate-of-return regulation and the associated business models that utilities have, as well as the fact that any changes require a regulator’s approval. Many utilities and ISO/RTOs seen their mission as “keeping the lights on,” expanding electrification from urban to rural customers, and supporting commercial and industrial revolutions and innovation. However, the business models of utilities and the energy industry must be able to adapt as public policy calls for focus on sustainability objectives such as environmental justice, air pollutant emissions reductions, decarbonization, and renewable energy portfolio standards. We have reached a new milestone in the evolution of the electric power industry where consideration should be given to societal goals of consumer choice, environmental impact reduction, equitable access, and energy burden[6] (the percentage of household income that goes toward energy costs). It is a difficult responsibility to balance these objectives with the need for system reliability, affordability, and other public policy goals. To assign policy makers the job of setting of goals for the grid while assigning utilities and ISO/RTOs the job of grid design and implementation represents a classic principal-agent problem in which objectives, design, and implementation are difficult to coordinate and are likely to be inconsistent (Joskow and Schmalensee 1983). This means we may design and build a grid that might be, in a narrow sense, a “technically correct” solution, but that does not effectively serve society’s best interests.

C. State of the Art and Industry Practice

Currently, reliability is the most important reason that we engage in power system planning. The most commonly used planning methods and metrics are resource adequacy assessments to determine whether a system will meet “1-day-in-10-years” loss of load expectation. Resource adequacy metrics were developed beginning in 1947; by 1960, the 1-day-in-10-year loss of load expectation “had been widely recognized by electric power industry, and most papers used or quoted this value as a standard” (Billinton 2015). However, there is no documentation of how the target of a 1-day-in-10-years measure was arrived at, other than vague references to “good industry practice” or “engineering judgment.” Some ISOs use a demand curve in their procurement of capacity (Hobbs et al. 2007), meaning the target can be less or more than 1-day-in-10-years if the price is withing a predefined reasonable range. However, the reality is that no one knows whether 1-in-10 is truly the appropriate target for resource adequacy. This is an example of a legacy planning standard that has unclear relevance or appropriateness to the future grid.

We foresee a future in which bulk system resource adequacy is important, but so is distribution grid resource adequacy. We also foresee a future in which we conduct transmission planning with greater understanding and reflection of uncertainty in the system, which will be discussed below in Section 2.6. The evolution from mostly one-way energy flow (from bulk system down to consumers) to two-way

[6] Nationally, low-income households spend a larger portion of their income on home energy costs (e.g., electricity, natural gas, and other home heating fuels) than other households spend. The portion of income spent for this purpose is often referred to as a household’s “energy burden.” One recent study found that low-income households face an energy burden three times greater than that of other households (U.S. DOE 2018).

dynamic energy flow with bi- or multi-directional transactive relationships will forever change the needs, standards, and analysis that we conduct for the grid as well.

When considering how resources and assets are added to the bulk electric grid, we can examine ongoing efforts to integrate offshore wind technology as an example of the interconnection process. As of September 2020, multiple U.S. states set procurement targets totaling 29,000 megawatts of offshore wind by 2035 (American Clean Power 2021). In the current planning process, the main method of integrating offshore wind is to build a generator-lead-line through the ISO/RTO or state interconnection queue.

This long-standing process worked well 20 years ago when there were significantly fewer interconnection requests – about 100 per year in the territories of ISO New England (ISO-NE), New York ISO (NYISO), and PJM, compared to about 1,000 interconnection requests per year in 2020 based on analysis of the ISO interconnection queues. Now, not only is the queue overwhelming in magnitude and slow in process, but also it does not lead to the most beneficial or efficient outcome for the grid. The interconnection process ensures equal treatment of all requests while verifying that new interconnections do no harm to the grid, but it does not plan for a better grid. From an efficiency standpoint, guiding generation interconnection to more beneficial interconnection points could lead to grid benefits, such congestion decreases and infrastructure investment deferrals. These grid benefits are not accounted for in the current interconnection process. Many of the current challenges are outcomes of incremental, well-intentioned FERC Orders and ISO/RTO process improvements. This includes FERC Order 2003, which standardized Large Generator Interconnection Procedures and Large Generator Interconnection Agreements. Additionally, it allowed for cost-allocation structures that deemed the generator the beneficiary that would therefore take on the interconnection costs. Ultimately, this interpretation and implementation of cost allocation and perception of fairness has dictated the way in which all resources and connected transmission are added to the grid. The current process assigns high upgrade costs to customers, fails to capture efficiencies that benefit all users, and adds risk and uncertainty to all parties in the process in mainly ISO/RTO regions (Caspary 2021).

The drivers for certain generation technologies, such as offshore wind, can be traced back to communities' environmental, carbon, or societal goals for the power system. Grid planners usually treat those goals as secondary to reliability. In reality, however, the power system balances generator air pollutant emissions limits, cooling water output, hydropower dam water release, and other objective-driven constraints in everyday operations. Multiple values also have been long recognized as a fundamental principle in, for instance, integrated resource planning (Hirst and Goldman 1991). Computational advancements have enabled multi-value planning, which would not have been technically possible before. The interdependent nature of electricity on other sectors, such as fuel supply, transportation, water, and communications, became (painfully) obvious during the Electric Reliability Council of Texas (ERCOT) outages of February 2021.

D. Needed Research

Much of the electric power industry continues to rely on legacy processes to create a stable operational and financial environment. With the grid modernization evolution during the past decade and the growth of new technologies, these legacy planning practices are reaching the point of being outdated or are being improved incrementally or in a piecemeal way to prepare for the future grid. This is obvious, for example, in the use of 1960s-style methods to assess resource adequacy for 21st-century systems with large amounts of variable renewables, battery storage, and DR. In California in August 2020, it became clear that methods that were, in the past, adequate for tallying up thermal generator contributions and comparing them to desired reserve margins were responsible for mischaracterizing that state's reliability with today's generation mix (CAISO et al. 2021).

Research should first focus on holistic power system planning that encompasses consumer choice in an environment that includes markets and public policy while aiming for a reliable, affordable grid. This may lead to optimization research respecting the many societal objectives and grid requirements. Also needed are validation and testing of the methods and models that are developed, in order to minimize deployment risk. In the end, the electric ratepayer pays for decisions that planners make for the grid. It is our duty to minimize societal risk as we conduct planning and execute grid plans.

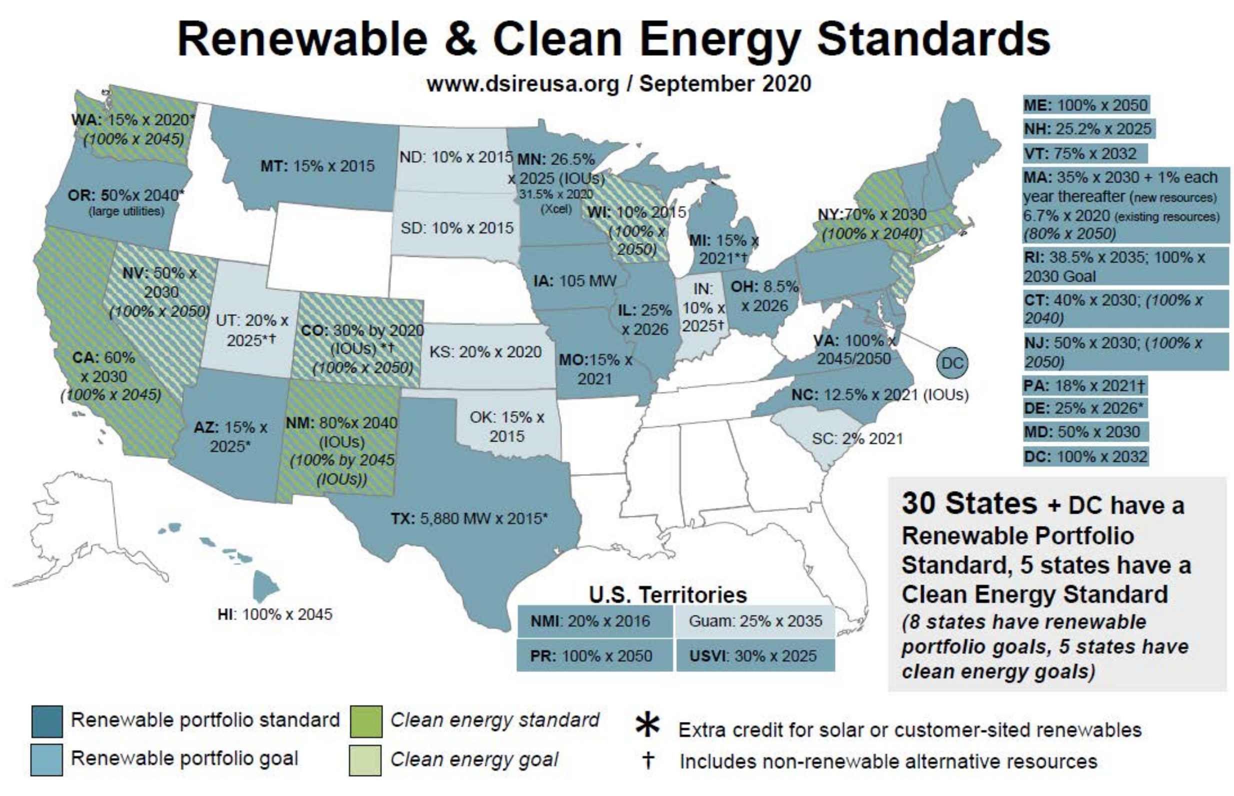

Figure 2. State Renewable Portfolio Standards and Clean Energy Standards as of September 2020 (DSIRE 2020)

It is in the nature of systems that decisions and changes have impacts on the system's interconnected components. This is true in electricity and energy systems. For example, across the United States, different states are setting renewable and clean energy goals (Figure 2). These decisions may seem isolated when considering state lines, but they are related and intertwined in the power systems of the states that form the Eastern and Western Interconnections. Ambitious environmental goals in one jurisdiction may be frustrated by pursuit of other priorities in other jurisdictions in the same interconnection; this is amply illustrated by the mixed record of state-level carbon regulation (Xu and Hobbs 2020c). We need analysis frameworks or models that can help understand the impact of one decision on the rest of the system, whether at a nationwide, regional, or local community level. And, vice versa, we need better understanding of the desire of consumers to drive appropriate policies and incentives. Often in energy research, the focus is on technical innovation. Although technical innovation is critical and indispensable, policy and regulations are often the drivers of changes in the grid. Supporting planners, policy makers, and regulators, and connecting their work to technology deployment is critical to creating future planning processes that reflect the societal desire for equitable, reliable energy for all.

To move the industry toward providing the grid reliability and other characteristics that consumers seek, such as minimizing pollution-related impacts, research should be conducted in the area of utility business models and their relationship and process approval in regulated environments under state utility commission-based regulation. These business models and incentive mechanisms should also enable coordination among multiple entities to support consumer, state, and federal goals, but also enable utilities to create timely and appropriate innovation. Not all of this research may be immediately applicable under current market and financial structures, but it may be able to explore alternative financial structures for the future.

Acquisition of resources, assets, and services for the grid must rely on metrics that capture the objectives of the planning processes for identifying, quantifying, and qualifying the needed grid resources, assets, and services. Traditional metrics need to be updated or discarded. An example is our discussion of the role of the 1-day-in-10-year loss of load expectation in standard resource adequacy planning; there are many such legacy reliability metrics and processes that should be reviewed and analyzed so that changes can be made to reflect the evolution of technology, laws, and public preferences. Research should look at the requirements and triggers for building, retiring, and investing in assets. Research should also be conducted on the creation of evolved or new metrics, how metrics can be used to support planning goals, and how they can be best implemented and used in holistic power system planning, such as TRP. This means that metrics that go beyond the idea of resource adequacy should be considered as well, such as design standards, contingency and planning standards, and balance of risk burden and incentives. Ultimate implementation will be dependent on geographical and electrical infrastructure characteristics, so it is unlikely that one uniform method for applying metrics would be effective.

2.2 Quantifying the Value Provided to Energy, Capacity, and Ancillary Service Markets

It is increasingly recognized that transmission provides economic benefits by improving the efficiency of markets for not only energy but also for resource capability (sometimes called "resource adequacy" or "installed capacity") and ancillary services. These benefits include lower costs of meeting needs for energy and the products that support energy delivery as well as improvements in prices and operations that result from deeper, more competitive markets. Better information on these benefits is needed to give planners a fuller picture of the relative merits of alternative grid designs, and to inform mechanisms for compensating, and thereby incentivizing, efficient grid investments. Here, we focus on quantifying the economic value of all services that grid investments provide to a given region. Market benefits arising from strengthening interconnections among different markets and balancing authorities are addressed in Section 2.3.

A. Definitions and Background

Measured in terms of costs or market revenues, energy (megawatt-hours [MWh]) is the most valuable commodity conveyed by the transmission grid. However, it is anticipated that as an increasing share of that energy is provided by resources that have low operating costs but high variability, the importance of ancillary services (primarily but not exclusively operating reserves) and installed capacity will increase and will thereby constitute a growing proportion of the benefits provided by grid reinforcements.

To deliver energy reliably, several types of ancillary services are required. The services that are traded within ISO markets include regulation to mitigate area control errors and frequency deviations; spinning and non-spinning reserves that are often intended to cover certain enumerated contingencies; and flexible ramp capability (sometimes called flexi-ramp or non-contingency reserves) to ensure that supply-demand balances can be maintained when net load ramps differ from forecasted values. In many markets, installed capacity or resource adequacy markets are relied upon to provide assurance that adequate capability to produce energy will be available and deliverable to meet net loads over longer periods, from one month to several years, for a given system reliability target. The system operator usually contracts directly for other ancillary services, such as voltage and reactive power support, automatic generation control, and black start. These services are not procured through bid-based markets because the cost of organizing such markets is usually viewed as unjustified; this may change in the future as the need for and value of such services grow and if effective competition can be ensured. It has been proposed in the academic literature that when transmission and generation can compete to provide the same ancillary service that both types of resources could be paid market-based rates. An example is reactive power and voltage support (O'Neill et al. 2008), which ISOs are considering modeling in its markets (Direct Energy 2016), which could be an initial step towards market pricing.

Two trends in ancillary services markets could increase the value of transmission. First, ancillary service needs have grown because of changes in the mix of generation resources. For instance, the amount of regulation needed to manage short-term variations in the CAISO markets has approximately doubled during the past several years (Weimar et al. 2018). Two ISOs have created ramp products (the Mid-continent Independent System Operator [MISO] and CAISO), and a third is proposing to do the same (the Southwest Power Pool). Although prices for these ancillary services have been unstable recently, it is widely anticipated that their total costs will continue to increase as well as the volume of services required. When demand increases in an ancillary services market, investors and resources will respond to incentives to participate, such as the large amounts of batteries offering regulation services in PJM, which immediately met PJM's goals (Lee 2017).

The second trend is a growing recognition that the effect of network constraints on deliverability of operating reserves is an important issue. The assumption that ancillary services procured anywhere in a balancing area or reserves zone can be delivered anywhere else within that area or zone irrespective of congestion is increasingly viewed as mistaken. For example, deliverability problems have meant that approximately half of the flexible ramp capacity procured in the Energy Imbalance Market was unable to be deployed when needed (CAISO 2019a). As a result of deliverability issues, at least one ISO (CAISO) is proposing to include explicit deliverability constraints that represent how reserves are dispatched after a contingency occurs (CAISO 2017) and how resources providing flexi-ramp would be operated if load ramps are unexpectedly high or low (CAISO 2020a). It logically follows that if transmission congestion limits the ability to exploit the least expensive sources of ancillary services, then there could be benefits to expanding transmission, in the form of lowered cost and increased effectiveness of procured operating reserves.

Some planning studies have recognized the economic value that transmission provides by allowing resources in one area to support long-run resource adequacy in others. The CAISO has, for instance, quantified the benefits of a proposed transmission reinforcement's ability to provide California access to less costly capacity from Arizona (CAISO 2004; Awad et al. 2010). More generally, academic studies have shown that if the effect of network capacity availability on resource siting is considered, then a significant portion of the benefits of new transmission derives from savings from more efficient patterns of resource investment (Spyrou et al. 2017). An example is provided below in Section 2.2.C.

B. The Challenge

Transmission investments can provide value by either substituting for or complementing supply resources, thereby lowering the expense of acquiring and deploying ancillary services and resource adequacy (RA) while maintaining or enhancing reliability. The challenges are to recognize and quantify this value, trade it off against the cost of grid reinforcements, and provide incentives that reward efficient and effective provision of this value. An appropriate perspective is to recognize that transmission investments can substitute for local sources of ancillary services and RA, and can complement development and imports of such services and RA from less expensive sources elsewhere. A holistic perspective is needed that recognizes that all components of the bulk power system, as well as the distribution system and DERs, can play important roles in providing these services and RA.

Conversely, it needs to be recognized that resources can substitute for transmission. For instance, storage and DR can delay or eliminate the need for substation or transmission upgrades, which has been recognized by recent FERC orders and policy statements (e.g., FERC 2017). A particular challenge is the design of incentives for efficient investment and operations of transmission assets and resources that provide some services that are subject to regulatory cost recovery as well as other services that can earn market revenues. Jurisdictional conflicts and cost-shifting are major concerns. Fundamentally, both fairness and economic efficiency issues come into play when assets that are subject to rate base-style regulation compete with assets that rely on market revenues (Sioshansi et al. 2012).

Thus, transmission planning is no longer about expanding the grid to deliver energy from an assumed build-out scenario of resources. To fully quantify the value to the market of a transmission reinforcement, a TRP methodology needs to:

- quantify the *short-term costs and value* of procuring and delivering energy, ancillary services, and RA associated with a given grid configuration of sites and mixes of resources; and
- quantify the *long-term costs and value* that arise from transmission-induced shifts in the amounts, kinds, and locations of investments in storage, demand-side, and supply resources that are built or retired.

To address the task of quantifying short-term costs and value, we need improved production simulation models that have fidelity regarding the system features that determine the value of the various market commodities, as explained in Section 2.2. To address the task of quantifying long-term costs and value requires so-called "proactive" or "anticipative" models (Krishnan et al. 2016; Sauma and Oren 2006) that represent both transmission and resource investments, their substitutive and complementary relationships, and, especially, how the transmission grid's expansion decisions affect where and what type of resources are developed. Although such models are similar to integrated resource planning models, they differ in their use and interpretation. The purpose of proactive models is just to support transmission decisions, not to evaluate potential resource investment decisions. Under simplifying assumptions, such as competitive generation markets, efficient transmission pricing, and a planning objective to maximize overall net market benefits, the formulation of anticipative transmission planning and integrated resource planning models can be the same (van der Wiejde and Hobbs 2012). But relaxation of those assumptions results in more complex "multi-level" models that separately model the optimization problems for resource owners, and, in effect, consider their solutions as constraints in the transmission planning problem (Gonzalez-Romero et al. 2020). In general, the assumption that generators do not respond to grid reinforcements has been identified as the major deficiency of transmission benefit-cost analyses of market interconnectors (de Nooij 2011). The need for both improved production simulation and anticipative planning models point to a need for enhanced computational capabilities.

Furthermore, market efficiency is not just a matter of cost when competition is imperfect or when regulators constrain prices or resource choices. The short- and long-term models should, ideally, recognize how regulation or significant exercise of market power can affect prices as well as the efficiency of resource operations and investment. Especially as demand becomes more price-responsive, a more appropriate metric is net market surplus, not cost. Market surplus is defined as the sum of the value received by consumers of electricity minus the resource and other costs of providing it. This sum is equivalent to the sum of the surpluses earned by all market parties (consumer surplus, profits earned by generators and other resources, congestion surplus, and even environmental revenues earned by regulators in California and potentially elsewhere who impose border carbon adjustments on power imports). Anticipative planning models should consider how institutional rules affect how congestion is priced, thereby impacting incentives provided for resource siting.

Estimates of the value of new transmission for energy, ancillary services, and capacity markets can inform and, therefore, we hope, improve planning of transmission infrastructure. However, to be fully effective, such estimates have to be considered in the design of markets and incentives that reward transmission and non-transmission asset owners for the value they provide in order to motivate efficient siting, sizing, and operations. Traditional regulatory structures based upon full cost recovery can be replaced or augmented by approaches that reward reductions in overall system cost and improvements in reliability performance (Felder 2020). In implementing ideas such as performance-based regulation, potential improvements in market efficiency need to be traded off against political and equity concerns about, for instance, the potential for windfall profits for owners of existing assets.

C. State of Practice and Art

Here, we briefly summarize the computational models that industry uses to address the issues described above. We discuss evaluation of market benefits of transmission, comprehensive planning models (including anticipative approaches), and markets and incentive designs.

Industry practice concerning the evaluation of market benefits of transmission reinforcements generally consists of two steps. First, alternative proposals for grid reinforcements are developed using engineering judgment informed by analyses of existing patterns of congestion and generation queues. Second, detailed production-cost and reliability models are applied to assess energy cost savings and network reliability impacts. However, the ancillary service benefits of transmission investments are not well addressed by existing production-cost models because the models do not usually assess deliverability of operating reserves post-contingency and how that deliverability could interact with decisions about where to procure such reserves. Furthermore, with few exceptions, those models do not usually evaluate how errors in forecasting of load and resource availability might affect balancing energy costs and dispatch of operating reserves. For these reasons, the value of transmission for facilitating ancillary services markets may be systematically understated. Recent experience with the design of flexi-ramp and pay-for-performance regulation (“mileage payments”), in which the prices for those market products have turned out to be much less than anticipated, also suggests that modeling flaws can result in overstatement of the value of those services.

Models are also used by industry to assess the need for local RA and what network reinforcements are needed to interconnect new resources and qualify them for RA credits. With few exceptions (CAISO 2004), however, present practice does not usually try to model how network reinforcements might affect incentives to site new resources or change their location, and the resulting capital cost changes;

the focus is instead on operational impacts and production-cost savings (Spyrou et al. 2017; Krishnan et al. 2016).

Researchers have been developing improved production costing and TRP methods. Notably, there has been extensive research on comprehensive reactive and anticipative planning models that are formulated as large-scale optimization problems. Reactive transmission planning models optimize transmission network additions by assuming a fixed build-out of generation (i.e., transmission "reacts" to generation expansion). The advantage of reactive planning models with detailed production costing that can address large systems is that they account for interactive effects of reinforcements of dispatch throughout the network and therefore most of the operational benefits of transmission investments. Meanwhile, as noted in Section 1.2, there is a great deal of research on enhancing the fidelity of production-cost models in the context of network planning models. Also, much research has addressed inclusion of renewable variability and long-run uncertainties, as discussed later in this report, and the associated computational challenges.

Computational research associated with reactive planning models has emphasized either dealing with or reducing the complexity and dimensionality of the TRP problem. Research topics have included decomposition, pre-screening, and iteration between simplified and more complex models, as indicated in Section 1.2.

But reactive models cannot quantify *long-run (capital cost) benefits of transmission* that result from changes in network capability that incentivize changes in the locations and mix of resource investment. In theory, anticipative planning models could be used to assess how transmission investments could affect resource capital costs in addition to operating costs. Such models explicitly represent how resource investments will respond to grid reinforcements. Practical models for co-optimizing transmission and generation under assumptions of efficient transmission pricing and perfect competition have been proposed and evaluated by potential users such as the Western Electricity Coordinating Council (WECC) and BPA but have not been put into practice yet. Studies have shown that the resulting estimates of capital cost savings can significantly alter the net benefits and configurations of optimal network plans. Such studies can inform the "chicken versus egg" debates, such as those stimulated by FERC Order 2003, about whether transmission should precede generation investment (and who should pay for it) versus whether transmission should just be in reaction to, and funded by, resource investment (Gardner and Lehr 2003).

An example of a co-optimization study is shown in Figure 3. The scenario is a national grid planning problem for the years 2010-30, which is analyzed using the Johns Hopkins Stochastic Multiperiod Integrated Network Expansion model. The figure shows that reactive transmission planning in response to an assumed generation build-out (Solution 1) would yield $50 billion (B) (present worth) in net savings (generation operations and transmission investment costs) relative to no transmission reinforcements, for a hypothetical national grid planning problem (Liu et al. 2013). In particular, $54B in transmission investment would yield $104B of generation fuel savings, a benefit-cost ratio exceeding 2.0. There are no resource capital cost savings because the reactive paradigm does not consider how grid reinforcements might affect resource investment. In contrast, full co-optimization (Solution 3, in which transmission plans fully anticipate how generation reacts, assuming efficient transmission pricing and competitive generation markets) projects saving an additional $150B in generation costs, most of which is capital costs, as a result of an additional expenditure of $63B on transmission. Meanwhile, Solution 2 shows that iterating between pure generation expansion models and reactive transmission planning models can realize some but not all of those benefits. These solutions show that co-optimization can increase the value of transmission. However, this is not necessarily because of reduced resource capital costs. In Spyrou et al. (2017), resource capital costs actually increased under co-optimization as a result of accessing more renewable resources, which resulted in savings in resource O&M costs that more than compensated for the increase in capital expenditures.

<u>Solution 0.</u> **Generation expansion only (with existing grid): $1846B present worth of transmission and generation investment and O&M costs**

<u>Solution 1.</u> **Reactive transmission planning (to meet generation built-out from Solution 0) $1766B PW**

- **$19B/$35B transmission investment in 2010-20/20-30:**

<u>Solution 2</u>: **Anticipative transmission planning; iterative co-optimization of transmission and generation (gen→trans→gen→ trans): $1716B**

- **$26B/$45B transmission investment in 2010-20/20-30:**

<u>Solution 3</u>: **Anticipative planning (simultaneous co-optimization) : $1679B**

- **$73B/$44B transmission investment in 2010-20/20-30. Red circles indicate changed transmission investments from Solutions 1,2**
- **Savings relative to Solution 1 (Reactive transmission): $88B in fuel, $62B in generation capacity; $63B more transmission investment**

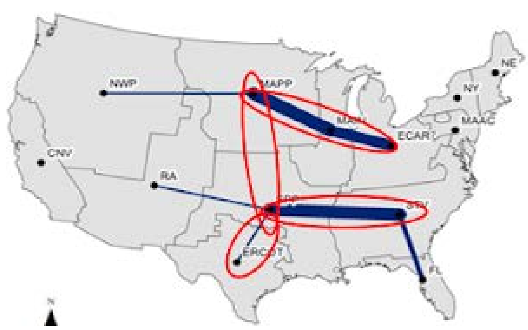

Figure 3. Benefits of anticipative transmission planning (co-optimized transmission and generation) for a hypothetical national grid study

Source: Liu et al. 2013, p. 130

B = billion; O&M = operations and maintenance

However, the restrictive assumptions that these simpler anticipative network planning models make about perfect competition, perfect information, and efficient locational marginal pricing (LMP) of transmission are criticized by practitioners and researchers. More elaborate models that account for inefficiencies in transmission pricing and market structure (e.g., market power or inconsistent carbon policies among jurisdictions in the market) have been proposed, usually resulting in elaborate multi-level optimization models (Pozo et al. 2012; Gonzalez-Romero et al. 2020). These models have not found industry acceptance for two reasons: 1) their computational complexity and the resulting need, in some cases, for specialized algorithms, which limits model size and user access; and 2) models of strategic behavior or other market imperfections make specific and often unverifiable assumptions about market participants' objectives and actions that are difficult to defend in regulatory proceedings. As a result, these models are currently most useful for broad insights about the possible implications of alternative assumptions about market imperfections rather than for developing specific plans. The model results supporting such insights are not directly useful for regulatory proceedings that demand precision, even if false precision, and tools that can withstand cross-examination. However, these models can be very helpful to policy makers and planners who want to understand whether market imperfections might imply that the most economic grid reinforcements might be very different from what naïve perfect-competition models suggest.

We now briefly consider current practice and research in designing markets and incentives that would reward transmission for the benefits it provides to energy, ancillary services, and capacity markets. Generally, with few exceptions, the financing and regulatory approval of transmission reinforcement investments in the United States has followed a regulatory rather than competitive model, with planners identifying need for new facilities and introducing competition by considering competing offers to build those facilities. Such central-planner-based processes have been criticized for not encouraging identification of creative solutions to congestion that might be discovered by competitive forces. These creative solutions could include non-transmission options, such as storage, distributed generation, and demand management, which FERC has strongly encouraged through actions such as FERC Order 841. Researchers have proposed mechanisms that could be used to support merchant transmission through awards of financial transmission rights whose value would be determined by the energy market (Hesamzadeh et al. 2020). However, both conceptual and practical problems have prevented these mechanisms' practical use except in narrow circumstances such as direct-current interconnections between buses with very different LMPs that can be arbitraged. Although LMPs provide a clear signal for the value of transmission additions in terms of short-term energy markets, thereby informing regulatory and planning processes, researchers have paid little attention to how the value that transmission can provide to ancillary services and RA markets can similarly be quantified and included. Major obstacles are the inefficient and often non-transparent ways that ancillary service and RA deliverability issues are managed in spot markets (e.g., zonal or system-wide procurement, as in the case of ancillary services markets and flexible ramp products).

D. Needed Research

We identify three areas of research to improve understanding of the full market benefits of transmission within individual markets, and to provide a basis for incentives based on those benefits.

First, market designs need to be improved to reflect how network limitations affect deliverability of ancillary services in both scheduling and pricing of ancillary services. Having the equivalent of congestion pricing for ancillary services would enhance system reliability and lower costs and would also provide a more transparent signal of the value of transmission reinforcements for improving deliverability. Research is needed on practical formulations of spot-market optimizations that could accomplish those goals, and how the quantified value of transmission can be translated into incentives to construct such transmission in what is likely to remain a highly regulated decision process.

Second, the production-cost methods used in transmission system optimization models need to be improved in how they represent the contingencies and system responses that drive ancillary services procurement and deployment. Research is needed into practical methods for decomposing and coordinating production-cost and investment models and putting large-scale yet quickly solvable models on planners' desks. A lack of specialized solvers or decomposition/coordination methods is a major hindrance to the use of large-scale models.

Third, research should be conducted to create models that mimic and reflect the nature of multiple competing parties and a competitive marketplace. These types of tools could complement, or provide an enhanced replacement of, current industry tools that assume a centralized planner. Practical large-scale anticipative planning models need to be developed. In addition, better understanding is needed of drivers of resource investment and how they interact with transmission network configuration. The assumptions of perfect competition, full information, risk-neutral decision making, and efficient transmission pricing that underlie practical anticipative planning models may or may not be good approximations. Empirical understanding of resource investment decision making could inform more realistic formulations of anticipative planning models that would avoid mischaracterizations of the reactions of resource investments, and the possible resulting distortions of the estimated value of transmission for improving the efficiency of such investments. Although such models may be difficult to use and defend in regulatory contexts that demand specific numerical results, such as benefit-cost ratios based on extensive production simulations, they could provide invaluable qualitative insights as to how the possible reactions of resource investment to grid reinforcements can change the relative attractiveness of broad alternative grid configurations. Finally, development and testing of auction mechanisms are needed that could lead to discovery of creative transmission and non-transmission solutions to congestion problems and to a level playing field for competition.

2.3 Coordination Across Systems and Institutional Boundaries

A. Definition and Background

It has long been recognized (Federal Power Commission 1971) that strengthening ties between different systems has economic value because it allows for exploiting diversity in load, renewable resource availability, and generation outages. Sales of power from low-price regions to high-price regions save fuel costs. In addition, strengthened ties can decrease requirements for installed reserve margins by recognizing that when generation capacity is subject to independent outages, the percent reserve margin required to assure a particular level of loss of load probability is inversely proportional to the square root of the total load served.[7] Recently, a number of studies have looked comprehensively at the potential benefits of a national grid linking all major demand and renewable-resource regions, motivated by the potential benefits of resource and load diversity (McCalley et al. 2017, Bloom et al. 2020) .

However, the economic contribution of adding transmission capability between systems with different operators depends on how trade in energy, ancillary services, and RA is managed. The reality of gaining approval for an inter-regional transmission project also depends on the alignment of ISO/RTO interconnection processes. The change in amount of trade and the economic value of that trade depend strongly on market designs within the individual systems; how trade is coordinated between the systems; and how use of transmission capacity is allocated, traded, and priced. The possible impact of accounting for actual market barriers to trade on the estimated net benefits and rankings of possible transmission additions is unknown and deserves consideration.

There are many types of economic and non-economic barriers to consummating energy trades across institutional boundaries and, thus, to realizing the full benefits of new reinforcements. One is requirements for imported power to pay a fixed $/MWh grid access charge; this means that MWh deals that would be worth less than the charge would go unconsummated. Deals that might have to traverse more than one balancing authority may face multiple such hurdles (called “pancaking”). Complicating matters further are transaction costs incurred because of the effort required of traders to identify profitable opportunities and to conclude deals in time to take advantage of them. Other barriers to trade include rules or limitations about, for instance, how imbalances are to be managed, the inability to trade operating reserves, limitations concerning the locations from which renewable credits can be imported, whether carbon emissions have to be accounted for, use of zonal energy prices and path-based methods to price trade, and inflexibilities posed by block requirements for standardized energy products and lead times for deals (e.g., van den Burgh et al. 2017); these issues can even harm reliability (CAISO 2021).

Another complication is that how one system manages its reliability affects the ability of other systems to trade. Inefficient coordination of contingency definitions and management leads to limits on system interconnections that are due to third parties whose incentive to correct the problems is thereby diminished. For instance, the most important contingencies limiting New England—Quebec transactions are due to PJM and NYISO. To paraphrase a *New York Times* critique of power transmission operations and planning (Wald 2013), to call the U.S. grid “Balkanized” insults southeast Europe.

These hurdles result in patterns of trade among balancing authorities that significantly deviate from the least-cost ideal; reduction or elimination of hurdles is a major source of benefits when balancing authorities are combined into a single market. One study, for instance, provides an indication that, in the Eastern Interconnection, power flows among authorities not only differ greatly in magnitude from

[7] This is based on the statistical observation that the variance of the sum of independent variables is the sum of their variances, so the standard deviation of that sum increases only in proportion to the square root of that sum.

those predicted by a least-cost planning model, but often differ even in direction for many important interfaces (Fisher 2014). Least-cost flows were estimated by the Charles Rivers Associates MRN-NEEM model used in the Eastern Interconnection Planning Collaborative (Hadley et al. 2014) while actual flows were obtained from an analysis of Open Access Technology International data (Open Access Technology International 2014). One of several possible interpretations of this result is that combined transactions among balancing authorities differ from estimated least-cost flows because many beneficial trade opportunities are overlooked under the present fragmented system.

Consistent with this interpretation are estimates of large increases in economically beneficial flows when markets expand their geographic scope and thereby lower or eliminate the incremental transaction costs of arranging trade among regions. Two prominent examples are PJM and the Energy Imbalance Market. Mansur and White (2009) estimated that, when PJM expanded westward, the volume of commercial transactions between the newly incorporated systems and the former PJM grew by 42%. The incremental benefit associated with extending nodal pricing westward was estimated at $180 million annually. Meanwhile, the benefit of linking 11 balancing authorities in the Energy Imbalance Market just for real-time balancing of energy transactions was estimated most recently as exceeding $100 million in the third quarter of 2020 (CAISO 2020b). Similar magnitudes of benefits are found in hypothetical studies that lowered or eliminated hurdle rates to trade among balancing authorities (e.g., Eto and Lesieutre 2005; Jordan and Piwko 2013; Bloom 2018; Potomac Associates 2019).

As a result, it has been argued that, when considering strengthening links between geographic markets (Bower 2005; Castanheira et al. 2005), market reforms might have more net benefits than line construction, and that such reforms should be implemented before further expensive network investments are made. (This has been the experience of the second author of this paper with benefit-cost analyses of grid expansions and market reforms in Central Asia.) It should be noted that studies of a national grid based on market assumptions such as fuel costs and resource diversity (e.g., Bloom et al. 2020) may generalize the benefits of such a grid unless grid expansion is accompanied by such market reforms or integration. Or, if the construction of large-scale interconnections among regions hastens such market integration, the benefits could actually be greater than what such studies estimate. Finally, it should be kept in mind that production-cost savings calculated using any present-day methods are a representation of the general magnitude but not the precise dollar-for-dollar savings that would be actually gained by society; it is not necessarily the case that refined estimates based on better characterizations of market barriers would appreciably change transmission decisions or their benefits.

Estimates of benefits, and their distribution among the participating markets and their market participants, are the logical basis for allocating costs of interconnections among beneficiaries, and for compensating parties who are economically harmed by the reinforcements. “Beneficiary pays” is a fundamental principle of FERC’s Order 1000. The history of the industry shows that it is indeed possible to allocate costs among beneficiaries in a way that will result in strong incentives for affected parties to agree to go forward with interconnections that have high net benefits. The alternating and direct-current (AC, DC) interties linking the Pacific Northwest and California are examples although the decades it took to complete these links are a cautionary sign. Since the 1960s when those interties were completed, there has been relatively little similar investment (with notable exceptions from Quebec to New England, and a 1990s addition to the Pacific AC intertie). In an attempt to jump-start additional investment in inter-regional facilities, the National Energy Policy Act of 2005 was passed, and subsequent FERC actions, notably Order 1000, have affirmed a national interest in inter-regional transmission capacity investments, and have included provisions to facilitate siting and financing of such facilities. Nonetheless, is widely understood that Order 1000 has not spurred the inter-regional transmission investment that was hoped (Joskow 2000).

B. The Challenge

Lack of coordination and inefficient congestion management will result in understating the total economic value of transfer capability among balancing authorities that do not participate in the same ISO market. Intuitively, one might also expect that the marginal economic value of augmenting interconnection capacity might be less than what frictionless trade might yield. However, if the coordination required to strengthen transmission ties is accompanied by market reforms, the total incremental benefits of the combination might be *greater* than what would be calculated if it were assumed that the markets were already efficiently coordinated.[8] In either event, the benefits of transmission additions might be appreciably different than what a cost-minimizing production-cost model would show. Furthermore, trading and dispatch arrangements may evolve greatly in the future, adding uncertainty to the future value of transmission.

Thus, the need is for TRP methodologies to value increased power exchanges and decreased congestion, recognizing how the value of these phenomena is strongly affected by present and future rules and institutions. Because the extent and causes of current inefficiencies are poorly understood, this valuation is difficult.

In order to value increased power exchanges and decreased congestion, we need to understand the dead-weight loss of current systems for managing interconnection congestion, including impacts on the volume and value of trade, especially during times of system stress. Furthermore, we need to understand how those losses would be affected by grid reinforcements; in particular, we must answer the question: *is the economic value of new transmission assets significantly affected by these inefficiencies?* This understanding should be based on empirical studies of actual congestion and marginal costs (system lambdas and nodal prices) in neighboring systems, building on studies like Fisher and Eto (2014).

If the answer to the above question is yes, then TRP methods that reflect this understanding are needed to project economic benefits of reinforcements as influenced by present and possible future market rules and institutions. Optimistic scenarios might be that, in the future, institutional and market

[8] For instance, assuming frictionless coordination across a regional grid might result in a relatively low amount of residual congestion and thus a low incremental value of transmission in terms of opportunities to trade. However, inefficient coordination might yield large price differences and potential value to additional trade – if grid expansion would result in that trade happening. True – Difficult Issue made more complex by considerable uncertainty.

rule barriers to efficient coordination and trade would become decreasingly important, or, alternatively, that such barriers increase the incremental value of transmission. Yet such assumptions would have to be justified.

In addition, computational methods for estimating the benefits of interconnections of different markets are limited for the reasons described in Section 2.2 above. In particular, simplifications and omissions made in production-cost models will affect estimates of energy and ancillary services benefits, and the lack of consideration of how resource investments and retirements will respond to grid reinforcements will result in distorted estimates of changes in resource capital costs.

A great deal of attention has been paid to the desirability of a more robust national-scale transmission infrastructure to take advantage of load and resource diversity, especially given the potential benefits of taking advantage of load and variable renewable diversity across regions. However, the National Environmental Policy Act siting authority has not been used, and, as noted above, the intended inter-regional investments have not materialized. Total transmission investments increased, by about a factor of 5, between 2002 and 2018 (U.S. EIA 2018), but almost all of the increase has been within individual market areas rather than from interconnections among areas. A notable exception, which remains just that, is the PacifiCorps' Energy Gateway effort to add 2,000 miles of transmission across the WECC region.

FERC Order 1000 was intended to encourage ISOs and other entities to seriously consider construction of additional interconnections. The order's basic principles are that benefits should be quantified, and a project's costs should be allocated to beneficiaries such that if a project's overall benefits exceed its costs, all regions involved are better off and should, in theory, be willing to participate. The reality is, of course, more complicated, and so agreements fail to be reached (or negotiations fail to even start) on apparently beneficial projects. Some of the complications include: distrust as to whether benefits shown by a model will actually be realized, especially benefits anticipated to occur decades in the future; the difficulty of acquiring new transmission right-of-ways, which gives existing right-of-ways an advantage; a diversity of interests within individual regions such that benefits to a particular region may accrue mainly to some stakeholders while others bear the costs; an inability to devise mechanisms to redistribute benefits and compensate harmed parties who are able to block a project; and objections to the aesthetic and ecological impacts of new or expanded corridors.

Therefore, cost allocation presents major economic challenges to the implementation of major new inter-regional interconnections (Rivier and Olmos 2020). These challenges result in at least two general research needs:

- The need to obtain credible estimates of benefits and their distribution among regions and parties within the regions over multi-decade horizons, and characterization of the uncertainty of those benefits, given possible economic, policy, and technology scenarios over the multi-decade lives of the projects. In practice, the principle of "the beneficiary pays" can be difficult to quantify. As one example, transmission upgrades that are paid for by interconnecting generators bring benefits not just to the generators themselves but more to the customers receiving the electricity whose costs are lowered. As another example, one state may pay for transmission upgrades while other interconnected states receive reliability benefits. These benefits may be diffused or, in the case of reliability, very difficult to assess. Adding to this uncertainty is that transmission additions themselves can encourage changes in economics and technology within the connected regions; scenarios of future economic conditions and load growth are not necessarily exogenous to decisions to interconnect.

- The need to reflect credible benefit estimates and their uncertainty in flexible cost allocations that can assure participating regions that, first, each will receive a fair share of the project benefits, and that, second, their share of the benefits will have a high likelihood of being well more than their costs under most scenarios over the life of the project.

C. State of Practice and Art

Studies of the effect of barriers to electricity trade tend to be based on either market simulations (see citations above) or coarse calibrations of hurdle rates in production-cost models to adjust flows to observed values. Very few studies quantify those effects using empirical data on changes in trade and prices resulting after removal of barriers. As a result, current practice in transmission planning includes, in production-cost models, hurdle rates that often have two components: one component represents known grid access charges, while the second component is sometimes termed a "behavioral" hurdle rate, which is usually assumed or calibrated. The hurdle rate may be applied only to energy transactions, or separate hurdle rates may be applied also to unit commitment decisions such as start-ups in order to separately model barriers to coordinating unit commitment and dispatch decisions (Potomac Associates 2019). Hurdle rates are, to our knowledge, not generally included in optimization-based TRP or joint transmission-generation co-optimization models; if included, they can distort assessments if changes in hurdle costs are interpreted as real economic effects.

Thus, a key issue in the use of hurdle rates when assessing the energy and other market benefits of new transmission is how to interpret the changes in the cost objective function of the production-cost model. There have been cases in which the major source of benefits for a new transmission addition is a reduction in the hurdle cost term itself. Inclusion of such reductions in benefit-cost calculations for new transmission is problematic for at least two reasons. First, if the major portion of the hurdle costs consists of grid access fees, these are properly viewed as contributions to fixed network costs that benefit the recipient, not as net costs to society. Second, if the major portion consists of assumed or calibrated behavioral hurdle rates, those are highly uncertain, and it is not known whether they are truly avoided social costs (e.g., savings in the personnel expenses associated with coordination/trading activities). Without an understanding of the sources of transaction costs that contribute to hurdle rates, estimates of those costs are likely to remain highly uncertain, and whether or not they represent avoided social costs will be unknown.

Another problem caused by the lack of understanding of the source and magnitude of hurdle costs is that there is a lack of basis for estimating how those costs might change as interconnection capacity and trade increase. The only exception is when two areas decide to join into a single ISO-type market, in which case the marginal hurdle cost for transactions can be assumed to fall to zero, as is usually assumed in benefit-cost studies of the creation or coordination of ISOs.

If barriers significantly distort benefits of transmission reinforcements, then transmission planning should account for them because of the risk that otherwise investments will be recommended that do not realize the anticipated benefits, or that the wrong line reinforcements will be made. Researchers have proposed multi-level anticipative planning models in which transmission choices are made in an upper level subject to the energy market's response in the lower level, accounting for market inefficiencies and perhaps including resource investments. As noted in Section 3.2, these models are currently difficult to solve because of their non-linear and non-convex nature, and they often require specialized software. Furthermore, there is considerable lack of understanding concerning the most appropriate formulation of the market imperfections. As a result, these are not practical tools to use at this time.

There is a considerable research on cost-allocation methods in inter-regional interconnection planning, based primarily on the notion of the "core" of a cooperative game (Gately 1974; Churkin et al. 2019). The notion of a core requires that a set of parties (regions, or individual interests, or sets of stakeholders within regions) have the ability to either consent to a project or, by withholding consent, to prevent its implementation. When a project has overall benefits in excess of its cost, the core is the set of possible cost allocations such that each party views its individual benefits as exceeding its costs. The definition of the core also constrains the allocation of costs to ensure that subsets ("sub-coalitions") of parties who can unilaterally cooperate just among themselves cannot obtain higher net benefits on their own by withdrawing from the project in question. This concept of the core can be useful in evaluating reforms to interconnection policies and cost allocations, for example. More sophisticated methods for identifying the core can account for incentives to parties to understate their benefits in order to reduce their cost allocations, as well as thresholds for net benefits for each party that reflect negotiating power. However, these methods have tended to be static and do not address the situation in which distributions of benefits change over the lifetime of a long-lived asset and, furthermore, are uncertain. More attention needs to be paid to design of adaptive cost-allocation schemes such that the participating regions or other affected parties who can block implementation can collectively maximize the likelihood that all will receive benefits in excess of their costs.

D. Needed Research

Empirical work based on experience in U.S. markets is needed to identify the most important barriers to trade under alternative market conditions and designs. This knowledge base can be used to quantify the effects of those barriers on quantities and pricing of power exchanges (and thus the benefits of removing the barriers), and to understand how those barriers and their impacts are affected by transmission capacity expansion. This understanding is needed in order to obtain more defensible estimates of the benefits of strengthening interconnections between different market areas.

Approximately 10 types of barriers were outlined in Section 2.3.A, above; different barriers can be the most costly in different situations.[9]

If understanding of market and regulatory barriers to trade and their impacts is sufficiently improved, then that understanding, together with improved computational capabilities, may make it possible to develop transmission planning models (Section 3.2) that account for those barriers (e.g., Grimm et al. 2016). The result could be development of transmission investment recommendations that consider trade inefficiencies in a realistic manner and therefore are more defensible.

There is a need to develop implementable approaches to allocating costs and financing large interconnections so that the allocations are adapted to changing financial conditions in a way that is viewed as fair and reasonable to all parties. These approaches could build upon the recent body of research on cost allocation based on cooperative game theory. The multi-decade lifetimes and huge cost of inter-regional interconnections will make this challenging, but overcoming this challenge is necessary if such projects are to attract support and be successfully implemented.

2.4 Coordination Across Transmission and Distribution Systems

A. Definition/Background

DER can produce energy on the distribution level and even behind the meter. These points of energy injection were not commonly used previously except for industrial and commercial cogeneration systems. DER are also decentralized by nature, which differs greatly from the bulk system's centralized planning pathways. Grid planning has been seeking a new equilibrium between enthusiasm for adoption and technological innovation on the one hand, and legacy planning processes that are relatively slow to evolve on the other.

DER often alter the traditional way in which consumers interact with the grid, turning them into "prosumers" (Parag and Sovacool 2016). From the consumer's perspective, their primary purpose of adopting DER is to meet personal goals, such as lowering total energy costs (particularly in jurisdictions with net metering rules), decreasing dependence on the local utility, and reducing carbon footprint. It is extremely unlikely that a consumer would procure DER with the primary goal of having those resources be a grid asset. For example, a consumer buying an electric vehicle is usually primarily motivated by the need for reliable transportation and decreased carbon footprint, not primarily by the idea that the vehicle would function as a grid battery.

B. The Challenge

For very practical reasons, legacy planning processes kept the design of transmission and distribution completely separated and largely isolated. This was an adequate, efficient way to conduct grid planning for many decades. However, the separate transmission and distribution planning processes and

[9] It should not be taken for granted that removal of market barriers and increased interconnection will result in positive economic benefits. Because of market failures and regulation, it is possible that increased trade will increase overall market costs rather than decrease them (De Villemeur and Pineau 2012; Sauma and Oren 2006).

methods are now increasingly inefficient and unsustainable as penetration of DER has increased along with consumer energy choices and support of technological advancement. Planning methodologies face the significant challenge of adding to transmission grid planning an understanding of distribution system impacts on the transmission system and vice versa.

One example of the inadequacy of the legacy separation of planning the two systems is that, from the transmission perspective, demand has traditionally been treated unchanging and non-dynamic load. In legacy planning processes, the only interesting information about demand has typically been peak load so that long term (10-20 year) planning studies would determine whether there was adequate capacity in feeders, transformers, substations, and transmission lines to serve that load. The addition of DER; DER aggregators; and residential, commercial, and industrial building energy management has led to load becoming a dynamic player on the grid that is less easily forecasted or predicted than in the past.

DER were first seen as the counterpart of bulk system generators but distributed across the distribution grid. This led to many grid planners adopting the false belief that consumers would be willing to forego their primary motivation for adopting DER if proper financial incentives were provided. Experience with various DR programs (Hobman et al. 2016) shows that financial incentives will not always upstage a consumer's needs and primary values. Integrated understanding of how each grid technology will impact the transmission and distribution system is now key to grid planning.

C. State of the Art and Practice

The current evolution in the relationship between distribution and transmission operators proves that changes are on their way for some grid systems. For example, New York has been implementing a set of transmission and distribution policies, operations, and planning from the Reforming Energy Vision and the NYISO DER Roadmap (NYISO 2017). The Reforming Energy Vision initiative aims to revise the grid's operations, planning, and investment in order to integrate DER into the wholesale market. This marks a milestone of policy, operations, and planning that the transmission and distribution systems will be considered jointly, in an integrated manner, in economics, operations, and planning.

But, just as deregulation was implemented in some regions of the nation while others stayed vertically integrated, the evolution of how the distribution and transmission grids interact will not be uniform. It is possible that, 20 years from now, when we discuss distribution and transmission grid planning, we will only be describing voltage differences, not isolated and separate transmission and distribution planning processes. The planning boundaries created by asset ownership and regulation bodies will likely continue for the next 20 years. Therefore, it is important to continue and expand the research and application of boundary methods for such cases, such as the European Network of Transmission System Operators for Electricity (2017) plan for flexibility across transmission and distribution. The line drawn between distribution planning and transmission planning has led to product and solution developments that are specific to those two parts of the grid. As technology and its value to the grid transcends these boundaries, planning processes, models, and tools will need to adjust accordingly.

An ongoing challenge is deployment of storage devices. Planners have struggled to compare the value propositions of an asset that could be deployed at various voltage levels and substitute either for rate based assets (such as transmission) and market assets (generation). An example is batteries, that can serve as a substation asset, a wholesale market asset, or a distribution asset (CAISO 2019b). The truth is that a battery can provide a range of benefits, simultaneously or sequentially, in a short or long period of time. These technological features have challenged legacy technical and cost-benefit planning structures as well as regulation and business models. Especially challenging to the isolated distribution and transmission planning processes are DERs that provide value to the transmission system. Although our legacy and mature process and tools have served us well, technological developments have grown beyond the typical legacy analysis frameworks. New ones will need to be created that allow for flexibility and can transcend the current boundaries.

D. Needed Research

Research is needed to find potential pathways for coordinated, cooperative future transmission and distribution planning. As noted above, transmission and distribution have been planned separately, but their increasingly two-way interaction has led to recognition of research needs in this area. We are in the midst of rapid industry evolution, and we do not know where the new equilibrium between transmission and distribution will end up, but the result is likely to be different in different regions. Therefore, it will be important to create flexible methods and tools. In order to provide research findings and developments in a timely manner for industry use, research should press the boundaries beyond likely or predicted scenarios to explore the realm of possibilities within a highly integrated transmission and distribution future.

Research is needed to understand how different technologies contribute grid services across the entire grid system (see also Section 2.4). This improved understanding and its embodiment in planning methods will better capture the integrated energy system and various technologies. New tools should be able to technically describe the impacts of a distribution-level grid asset (such as rooftop solar paired with batteries), its contribution, and its impacts on the distribution and transmission grid, and the same for a transmission asset. There should also be tools that describe the various economic structures and interactions among the many grid stakeholders, especially in response to FERC Order 2222.

Research is also needed to capture the grid services that the system requires and would in turn incentivize (see Sections 1.3 and 2.2). This way, we can plan the grid from the perspectives of both a centralized planner and a competitive multi-party participant in a way that ensures that the most cost-effective ways of providing and delivering energy and grid services are chosen, whether the assets are market-based, regulated cost-of-service, or a combination. Whether planning is undertaken by vertically integrated acquisitions or transmission and distribution system operators, there will continue to be diverse market and institutional structures that impact and oversee the grid planning and operations. Consequently, the planning processes and tools that support decisions by planners, regulators, and consumers will also need to be diverse.

Finally, testing environments and pilot programs can pair techno-economic designs with human behavior to assess practical performance. The industry possesses historical DER and consumer performance data, which can be used to help forecast DER and consumer responses. However, we are far from having sufficient social sciences-based understanding to describe and predict consumer choices and identify ways to improve consumer response to grid programs (Gumerman et al. 2003; Burger and Luke 2017). This type of research will be critical to adjust technological research and development with ultimate applications and end users (Lau 2020). Partnerships with industry organizations such as merchant generators, utilities, state utility commissions, and ISO/RTOs will lead to advancement and efficiency in future grid operations and planning in an integrated transmission and distribution future. In addition to researching and implementing pilot programs, there is no doubt that dissemintation and outreach will fuel improved consumer engagement and education on energy issues, which will be key to a more affordable and reliable grid.

2.5 Forecasting

A. Definition and Background

For many decades, the bulk electrical grid has seen and treated consumer load as a black box. In light of the historical way that customers were purely consumers, bulk system planners appropriately decided that the inner workings of the black box were not important in the context of load forecast. Over time, this practice has become insufficient. Forecasting methods in research and in practice are catching up to reflect the importance of consumers and their choices.

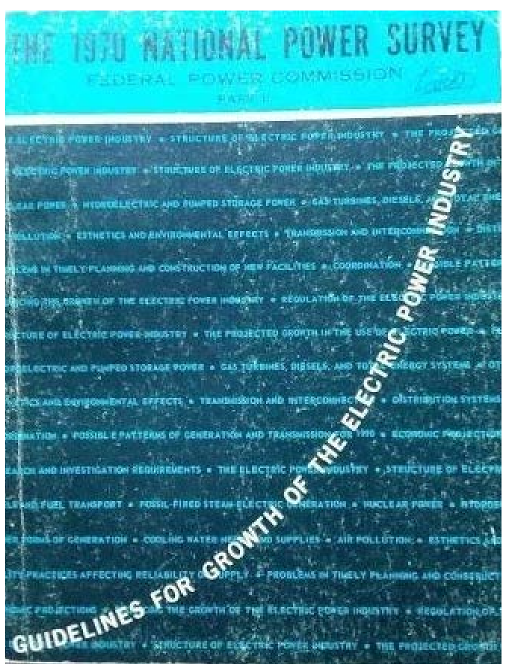

Figure 4. The cover of the 1970 National Power Survey reflects the power industry's assumption of exponential load growth in the mid-20th century (Federal Power Commission 1971).

One example is from the Federal Power Commission (1971) National Power Survey, which took historical consumer demand as a mark of what would continue for decades. As shown by the survey's cover (Figure 4), engineers at the time predicted that the 7% growth, doubling every 10 years, experienced in the 1950s and 60s would continue unabated. When the 1973 Oil Embargo ended that era of high growth, one of the authors of this white paper was working at Northeast Utilities where planners assured themselves that 7% growth would quickly resume.

Since then, planners have been humbled and learned that load growth is difficult to forecast, and that surprises should be expected. Figure 5 shows the results of a famous study of forecasts of U.S. energy usage made in the 1970s, nearly all of which overestimated growth by a wide margin (Craig et al.2002).

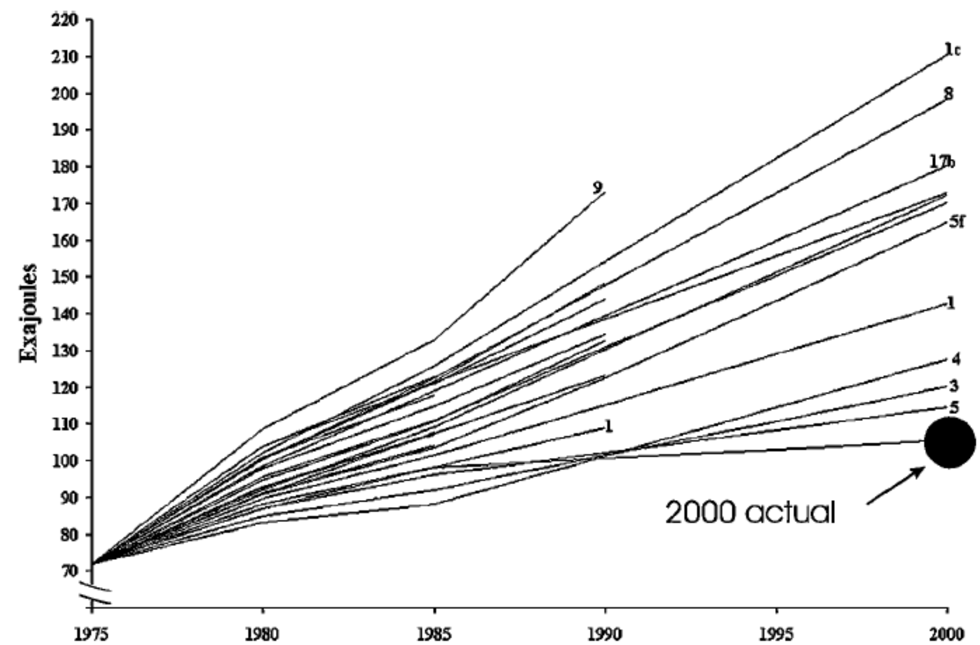

Figure 5. Projections of total U.S. primary energy use from the 1970s (redrawn from the original DOE source, and simplified from a summary of dozens of forecasts) (source: Craig et al. 2002)

Not only was load not increasing at a steady 7% anymore, but there were also energy efficiency developments that would soon lead to decreasing load trends. With the federal Energy Policy and Conservation Act of 1975 and ambitious goals in some states, energy efficiency found itself a specific line item and consideration in load forecasts. With increasing penetration of residential rooftop solar photovoltaics and smart thermostats in the early 2010s, the accumulation slowly grew to the point where it could no longer be ignored or considered noise in forecasting processes.

B. The Challenge

Fast-forward to today, and grid planners are aware of the evolving dynamics of consumers and technologies. The challenge is in pursuing a systems approach for grid planning where forecasts can help inform infrastructure investments and operational strategies. The grid is inherently a massively connected system. Isolated forecasting practices create challenges in planning for this system. For example, we observe that the electrification of the transportation sector will impact the electricity sector. Cross-sector impacts were rarely observed previously and were mostly limited to fuels for electricity generation. The future holds many more, different technologies that require their own techno-economic forecasts. A system view and forecast will be a critical challenge and a necessity in grid planning.

Beyond the design of holistic system forecasting methods and processes, we will need R&D to ensure smooth deployment with minimal ratepayer risk. The electricity forecast is likely the single most important calculation and assumption that drives infrastructure investment, which in turn impacts ratemaking and organizational revenue. The intertwined relationship, with the ratepayer being ultimately responsible for all costs, drives an urgent need to ensure that any new forecasting and planning process is well designed and tested prior to deployment. Capturing uncertainties and presenting enabling data and computations will be key to decreasing barriers to adoption by the industry.

C. State of the Art and Practice

There are many types of forecasts, based on time periods, geographic areas, customer segments, and applications. For example, there are day-ahead forecasts, conducted 24 hours prior to real time, that are used for planning the operation of grid assets. There are also long-term forecasts in which planners estimate system needs in 20 years in order to test design criteria and make infrastructure investment decisions. Long-term forecasts are driven by operational observations and future projections of residential population, commercial buildings, and industrial growth or decline. It takes about five years to build a distribution line and about 10 years to build a transmission line. Therefore, it is imperative to know grid needs well ahead of time to adequately plan for infrastructure design and construction.

Generally, load forecasting methods are divided into top-down or bottom-up forecasts. Top-down forecasts consider an area's macro-level characteristics, like gross domestic product, population growth, major customers, and historical growth, to form a system-level forecast that is then disaggregated in smaller areas. Bottom-up forecasts consider an area's micro-level characteristics, like specific new customers and construction, local population growth, and local DER adoption, to form a low-level forecast, such as at the transformer bank, or a per-phase forecast, which is then aggregated into a system forecast. Typically, either the top-down or bottom-up method is used although a practitioner can choose both knowing that the two types of models will not produce the same results. This discrepancy between model outcomes generally leads to an inability to line up a substation's forecast from customer usage to a system-area gross forecast of economic trends.

Entities can adopt new forecasting methods; however, there are two significant institutional challenges to adopting new forecasting methods and ensuring a quality data history. First, the new forecast will be referenced to previous values and trajectories and therefore cannot be fundamentally different. This is an obvious conflict because different methods would clearly lead to different results. Any significant difference can severely impact previous power system planning and cause volatility to a decade-long process of building energy infrastructure. Second, a planning entity would have to ensure that it has the data and extensive history of all the inputs needed in the new forecasting method. Many forecasting methods are driven by the past (demand, its relationship to weather or other factors); it can take decades to build data history for use in forecasting.

Increased penetration of residential rooftop photovoltaics during the past decade has significantly changed the net load of residential households in terms of amount of demand and time of day during which usage takes place. Additional distribution devices, like customer smart meters, distribution relays, and voltage regulators, can help provide measurements with a granularity that was not previously available. The additional data obtained through these devices can drive big data, digital intelligence, and artificial intelligence methods to help grid planners and operators. Identifying the right measurements to be taken and data to be saved will be key in ensuring future development and accuracy of forecasting and other grid planning.

A common question when discussing load forecasting methods is whether new methods would actually enhance forecast accuracy because of practical data limitations. In research, it is easy to create test systems and data to show potential advantages. However, as previously described, a user might need to make the necessary investment in years to build the appropriate data sets for new forecast methods.

D. Needed Research

Although forecasting is a mature area of research and industry application, the evolving nature of the grid and the current scarce ability to use state-of-the-art forecasting methods call for R&D. Forecasting research is critical because forecasting is likely the single most important calculation and input assumption for future grid planning. Forecasts drive what, when, and where grid investments happen. Long-term forecast errors can lead to stranded assets and costs. This research area should aim to advance grid planning while minimizing risks to ratepayers.

New or evolved forecasting methods should be researched to support multi-energy-sector and transmission and distribution integrated grids. Given the importance of fuel and renewable resource availability for system resource adequacy, and interactions of these resources with transmission constraints during peak-load periods, systems approaches to understand the relationship between other energy sectors and transmission/distribution are critical for planning a future grid. This could be accomplished in many ways, for example by a large and all-encompassing multi-sector model, as well as by simplified modular reflections of peripheral energy sectors to the power sector. Improved methods for long-term load forecasting are also needed, especially for projecting electrification technologies in the building and transportation sectors. A research collection of best practices would also be useful to planners. Although each geographic system has different electrical and system characteristics, there are fundamental principles that can be put together.

In practice, only a subset of the data required to use state-of-the-art forecasting methods has been available. Therefore, an assessment of currently available data and development of a research strategy for future data collection could enable successful industry adoption of new forecasting methods. An adoption of any forecasting method requires that data inputs be 1) available, 2) validated, and 3) quantified for uncertainty. For new data that need to be collected, research should be done on the accuracy of sensors and the feasibility of their mass deployment. Realistically, it will take time to collect new data, and data collection might not be possible in some cases, so research on methods to estimate or create representations of missing data will also be key.

Research on understanding load and its role in the future grid is vital. Research and pilots can take full advantage of sensors that are already deployed, such as consumer smart meters, to help identify data uses and processing that could benefit the planning process. In addition to the needs for data collection, processing, and enhancements that can be understood from existing load data and load management controls, research is also needed to establish possible future pathways for individual consumers' grid interactions and the impact on the grid of those interactions; this would include, for example, research on future load behaviors and profiles. It is possible that future electrical load will not be only tied to temperature but additional factors that we do not yet know. Research on consumer interactions with the grid can help maximize the possible contributions of load and DER and assist in the design of consumer participation, economic, technical and regulatory structures that will be needed. This research could also help maximize the benefit of investments that have already been made or will soon be. There are security and confidentiality concerns related to consumer data. The industry must sufficiently address these if we are to maximize the use of sensors and data in grid planning and operations.

Finally, we should quantify uncertainty and carry out validation related to forecasting accuracy and errors, including developing an understanding of when high accuracy matters in some data variables and when less accuracy does not matter. Similarly, research to determine when simplified and high-level models could be used to derive the same results as could be obtained from a highly detailed and granular model would help identify opportunities for enhancing efficiencies in the planning process and in data-collection efforts. This would ultimately help grid planners prioritize their investments and determine the most productive ways to apply forecasting methods. Besides state-of-the-art forecasting methods, which can define a vision, there needs to be more applied R&D with industry partners to consider data, workforce, and other issues that limit improvement in forecasting methods and practice.

2.6 Uncertainty in Planning

A. Definition and Background

The centrality of uncertainty to transmission planning was emphasized by the report by the National Academies of Science and Engineering (2021) on the future of the grid. Variability and uncertainties that are relevant to planning transmission operate at time scales from minutes to decades. *Short-term variations* in net load that result from renewable energy resource availability and load changes bestow an option value on transmission. This option value arises because connecting regions have load and resource diversity that allows those regions to exchange power when one region is in surplus and the other is in excess. At the other extreme, *long-term* economic, technology, and policy uncertainties mean that an individual balancing area may wish to hedge its bets concerning uncertainty in the cost and adequacy of its resources by linking to other regions that might be able to help out if the area is short of inexpensive power or, alternatively, that might provide access to potential purchases of the area's excess power.

The value of transmission to hedge risks and take advantage of diversity was recognized in the early 1900s when, for instance, proposals for a Pacific intertie were first floated. Hydro variability was a major motivator of that proposal, including not only predictable variability over the year (sell excess Northwest hydropower in the spring and early summer to California, and buy back power in the fall and early winter when hydropower is short), but also uncertainty in year-to-year output. The Federal Power Commission (1971) National Power Survey recognized another way that resource diversity contributes to the economic value of transmission by providing an analysis showing that transmission between systems lowers the cost of installed reserve margins necessary to cover generator contingencies, as explained in Section 2.3. This principle of taking advantage of diversity applies even more so today; variability in supply availability has been magnified by the tremendous growth in renewables, while a driver of interregional coordination is the spatial diversity in hourly and seasonal renewables production. This is a major motivation of proposals for implementation of a "national grid."

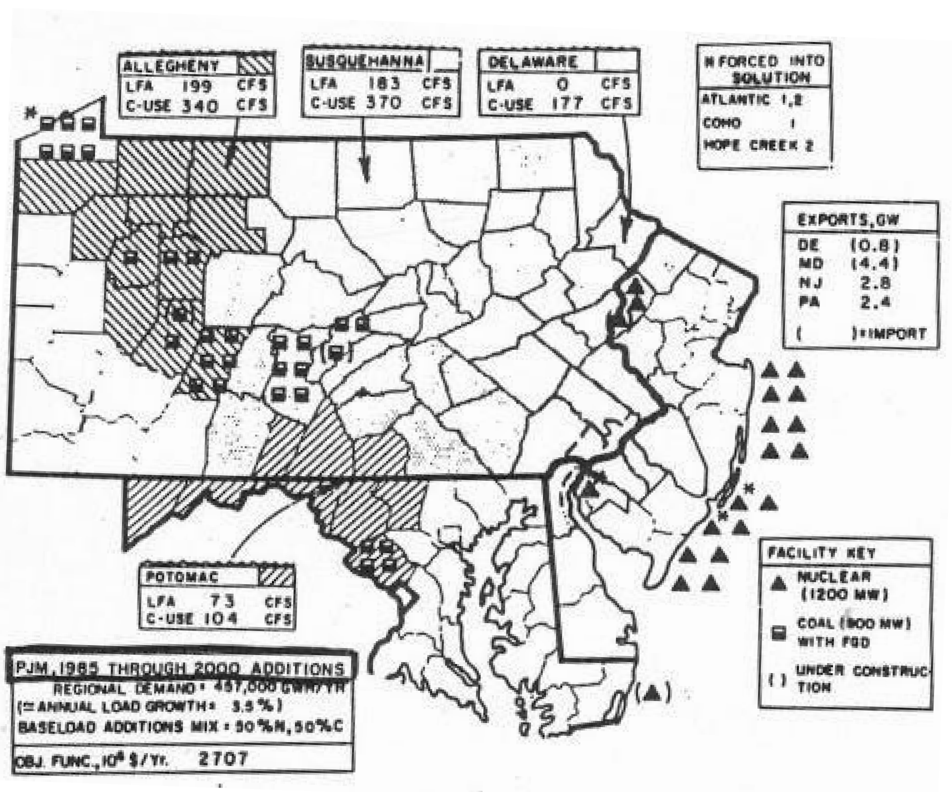

Figure 6. Siting Scenario developed as part of the 1978 National Coal Utilization Assessment for Year 2000, showing projections of new coal and floating nuclear power plants in the PJM region

Source: Hobbs and Meier 1979

Other uncertainties are difficult to forecast, especially in the long run. These include policy, for example future federal and state environmental rules and reforms directed at restructuring the industry. For instance, draft Congressional legislation under development in late 2020 would require all states to join an RTO. As described in Section 2.5, demand growth rates have changed dramatically since the 1960s, and, with efforts to decarbonize the building and transport sectors, may change again. Finally, the evolution of generation technology has resulted in several surprises, and future developments are difficult to forecast. For example, the National Academy of Sciences' Committee on Nuclear and Alternative Energy Systems concluded that the potential of wind energy was relatively low compared to other renewables, especially geothermal power (CONAES 1979). Meanwhile, the National Coal Utilization Assessment of the Carter Administration assumed a 3.5% growth rate in demand, floating nuclear power plants, and a prohibition of new gas-fired power plants, yielding forecasts such as in Figure 6.

Resilience is a particular type of uncertainty that has attracted attention recently. In the classic engineering definition, resilience is the ability to recover from a failure event and is measured by the expected duration of an outage or otherwise unsatisfactory condition. Like variability and uncertainty, resilience issues take place on several time scales. Short-term resilience focuses on response of the system to short-term increases in net load resulting mainly from meteorological events such as cold snaps that increase loads, tighten gas supplies, and disable generators; or multi-day cloudy periods with low wind. A resilient system would be able to withstand such events without lengthy customer outages, by relying on storage, back-up thermal capacity, and interconnections to make up for unavailable renewable power. Medium-term resilience might focus on natural events, such as earthquakes or hurricanes, that take down part of the network for weeks or months or result in long forced outages. Resilience is then a matter of both preparation, through redundancy and hardening, and response, through quick mobilization of crews and spare parts. Long-term resilience considers possibilities of structural or policy changes in energy markets that make relied-upon energy sources unavailable. The chronic natural gas shortages of the late 1970s, or the sudden unavailability of nuclear capacity in Japan after Fukushima, are examples. Resilient systems might rely on both the preventative strategy of redundancy and resource diversification, as well as corrective options such as quick acquisition of combustion turbines or diesel gensets.

B. The Challenge

After painful experiences with stranded costs and with the multiple surprises and twists and turns in the energy field during the past 50 years, it is widely recognized now that policy, economic, and technology uncertainties need to be considered in transmission planning. When transmission assets last a half century or more, the experience of the recent past reminds us that the uses and values of those assets may be quite different in 2050 than in 2020, and those uses and values are difficult to anticipate. In this section, we discuss crucial challenges in considering short-run variability, long-run uncertainties, and resilience in transmission planning.

Regarding short-run variability, the major challenge is to consider a wide range of possibilities, including extreme events that have a disproportionate effect on costs and reliability, and to appropriately weigh them in production-cost analyses, as noted in Section 1.2. As is well known from risk analysis, the more non-linear that cost functions become, the more that extreme cases will influence average coasts. It is therefore important it is to fully characterize distributions of net loads. Variability will increase in the future, and cost functions will be increasingly non-linear, with large amounts of zero-marginal cost capacity complemented by increasing use of demand management and scarcity pricing to manage peaks and steep ramps. Larger samples and cleverer sampling methods are needed because of the combination of increasingly convex variable cost functions; complex statistical interdependencies across resources and regions; and thick-tailed distributions in which extreme conditions such as multiple-day or even week-long “dunkelflaute” (windless) events contribute significantly to loss of load probabilities or costs.

Characterizing the probabilities of extreme events is subject to severe sample error because, by definition, these events are rarely observed, and data series are relatively short. The samples must be of full days or weeks, not just hours (as in load-duration curves) because smart management of the multi-hour storage in batteries is quickly growing in importance. Meteorology also involves non-stationarities, including both naturally occurring long cycles (such as the Hurst phenomenon in hydrology) and risks of greenhouse gas-induced shifts in distributions of winds, cloudiness, and extreme heat and cold.

The need to assess system resilience also means that better methods are needed to define plausible extreme meteorological and equipment failure conditions that contribute significantly to customer outage costs. Consideration is especially needed of long outages following common model failure events such as hurricanes or similar phenomena that contribute to lengthy, geographically extensive outages and large social costs. Because such events are often important drivers of costly redundancy in system designs, careful consideration needs to be given to risk-cost tradeoffs and the best mix of preventative measures (design) and corrective control (recovery actions).

Meanwhile, longer-term uncertainties are increasingly recognized as very important to transmission planning. Examples of uncertainties include the costs and role of storage, whether future resource developments will be local and distributed or remote and large scale, acceleration of state initiatives to decarbonize the power sector, the extent to which renewable energy costs will continue to decline, changes in future loads and fuel prices, and the possible sources and cost of clean baseload power technologies.

Uncertainty-aware transmission planning can prepare power systems to manage the above risks in several ways. Diversifying resources, by strengthening connections to regions with different resource bases, provides flexibility to respond to both short- and long-term fluctuations in resource costs and availability. Increased transmission investment can enhance this adaptability. Increased uncertainty can also increase the option value associated with deferring investments until future trends become clearer, in order to avoid stranded investments (Henao et al. 2018). The optimal mix of diversification and deferral can be assessed by stochastic or robust optimization methods for planning (Hobbs et al.

2016). Both trends have been observed when multiple scenarios are simultaneously considered in a hypothetical TRP in the BPA region (Maloney et al. 2019).

The importance of considering long-run uncertainties can be gauged by calculating the cost of ignoring long-run uncertainties: how do plans change, and how much do probability-weighted costs increase in the long run if investments are made considering only a deterministic "best-case" forecast? Disregarding long-run uncertainties can be much more costly than other TRP modeling simplifications. For instance, for a case study in the WECC region using an optimization-based TRP model for investments, consideration of a range of long-run scenarios of policies, economics, and technologies results in much greater improvements in near-term recommendations than does including more samples of days and unit commitment constraints, and using DC load-flow models rather than pipes-and-bubbles methods (Xu and Hobbs 2019).

The main challenge in considering long-run uncertainties is the curse of dimensionality that arises from considering costs over multiple years, multiple scenarios, and multiple market areas. It is easy for stochastic TRP models to expand from millions to hundreds of millions of variables when all the combinations are considered.

When considering resiliency in TRP, it is important to recognize that the extreme events that result in short, medium-, or long-term disruptions for which quick recovery is desired are by definition rare and often unprecedented; therefore, we lack reliable data on their frequency, severity, and duration. There are several conceptual challenges. One is to compare "apples and oranges"—to compare and weight expected (probability-weighted) cost and reliability consequences of short- and long-run uncertainties against the impacts of extreme events whose probabilities are unknown or controversial, and to trade off those risks (in the broad sense of the term) against the costs of preventative and corrective actions to mitigate them. A related challenge is the formulation and solution of TRP planning models that would account for probabilistic consequences, resiliency, and the costs of mitigating them. A third challenge is to have a process for identifying events and risks that haven't yet been experienced but are sufficiently plausible and consequential that it is reasonable to expend resources to reduce the system's vulnerability to them, or to enable the system to recover quickly if those risks occur and cause loss of load. Hurricane Maria in September 2017, the August 2020 California heat wave, and the February 2021 southern plains states cold snap are examples. What events and risks can be disregarded as too unlikely?

C. State of the Art and Practice

Transmission planning, when driven by reliability, considers only a few stress cases. There have been two responses in practice to the need to consider more short- and long-run conditions in TRP. One is to run more extensive and more realistic production-cost models for larger numbers of conditions in a simulation mode, in which the operating performance of pre-determined transmission plans and resource buildouts are assessed (CAISO 2004, Awad et al. 2010). Another is to consider additional operating conditions in TRP optimization models, greatly increasing the size of those models. Adding, for instance, more days in a TRP optimization model improves the quality of the resulting plans, in terms of their performance when tested against 8,760 hours (e.g., Figure 7), but at a diminishing rate and at the cost of much slower execution times.

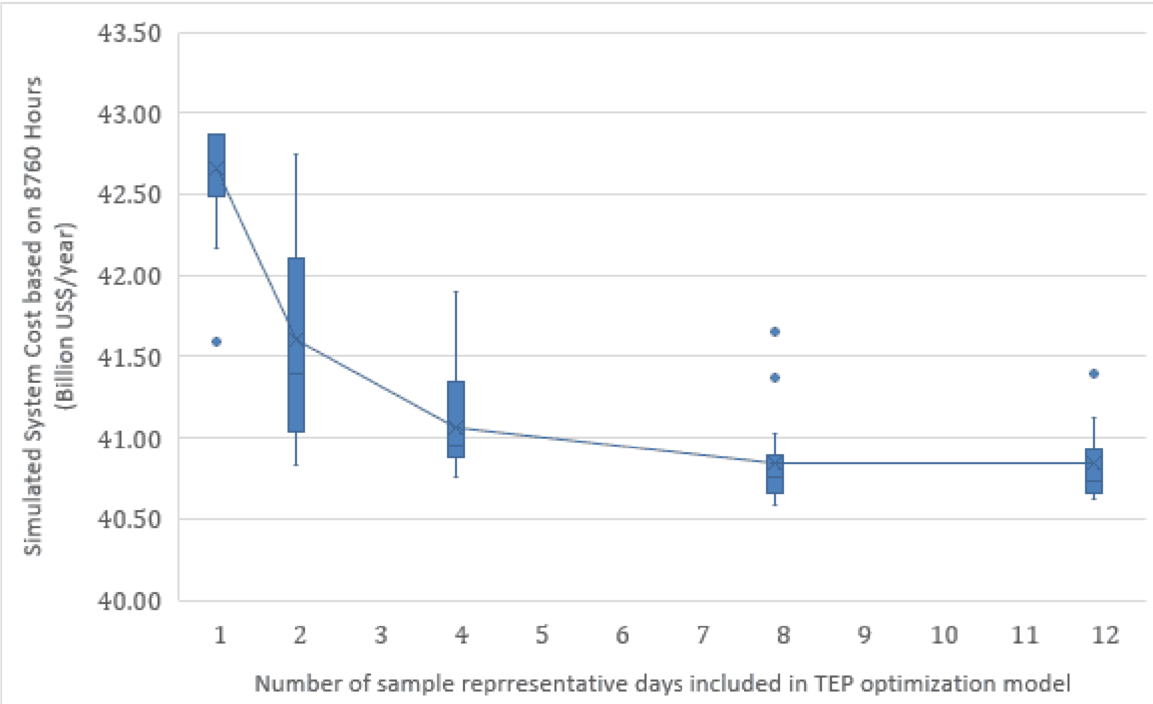

Figure 7. Post-solution verification of system costs using 8,760 hours of production costing for alternative plans from a TRP model incorporating differing number of representative operating days from a WECC case study for the year 2030; the curve shows the trend of the averages, and outliers are shown as circles (Xu and Hobbs 2020). The different values for a given number of representative days arise from alternative methods for sampling days within a year.

Missing from such TRP models are the extreme but rare cases in which transmission could be immensely valuable. For instance, it has been speculated that, during the 2000-2001 California crisis, large multi-gigawatt links between the eastern and western North American interconnections could have been worth hundreds of millions of dollars or more by increasing competition and facilitating imports (Awad et al. 2010). There is now intense debate over whether stronger interconnections between ERCOT and the Eastern Interconnection would have significantly ameliorated the load interruptions in the February 2021 cold snap. Also missing from production-cost methods typically used to evaluate transmission plans are the impacts of short-term forecast errors, which, as noted in Section 2.2, tend to make transmission more valuable because of the additional options that import and export capability would provide to operators to manage unexpected ramps and peaks. PLEXOS (Brinkerink et al. 2021), PSO (Yong et al. 2012), and FESTIV (Ela et al. 2019) are detailed production-cost models that consider day-ahead and other commitments and how forecast errors affect real-time balancing actions and costs, but, to our knowledge, no TRP investment optimization model includes approximations of such errors. As probabilistic and ensemble forecasting become more important in scheduling resources, planning models need to recognize how more sophisticated operations will affect the value from transmission and other investments that increase system flexibility and options available to the operator.

Turning to long-run uncertainties, current practice consists mainly of sensitivity analysis: defining a set of plans and then evaluating each under multiple scenarios. The purpose of sensitivity analysis is to identify which of the pre-determined plans performs acceptably under most scenarios and is therefore "robust." This is the approach used, for instance, in MISO's "Multi-Value Projects" planning approach and CAISO's identification of "least-regret investments." The World Bank has used such methods for at least 20 years to assess TRP robustness (de la Torre 1999). One disadvantage of the method is that the relative credibility or likelihood of different scenarios is disregarded; more general methods can assign probabilities or weights and minimize expected regret.

However, such sensitivity-based approaches will tend to overlook alternative plans that are robust because they are diverse and preserve expansion options but may not be the best under any individual scenario. In a few cases, transmission planners have considered probabilistic approaches (Judd et al. 2018). Methods are needed that optimize robustness by 1) simultaneously considering multiple long-run possibilities for supply, policy, and demand developments while 2) recognizing how these possibilities preserve adaptation options that can be deployed in later decision stages if necessary. Such methods are not used in practice but have attracted the attention of many researchers. In particular, researchers have been developing and testing stochastic and robust optimization methods for explicitly valuing diversity and adaptability under multiple scenarios (Hobbs et al. 2016; Maloney et al. 2016; Zhang and Conejo 2017). Potential users, such as BPA, WECC, and the Salt River Project, have investigated the use of stochastic programming (two-stage) planning models, evaluating whether the solutions they yield are different and potentially more robust than those from deterministic planning methods or sensitivity analysis. Research in this area has focused on two issues: (1) smart selection of scenarios to fully capture the range and impact of uncertainty while minimizing the number of scenarios and thus size of the model (Maloney 2020; Parpas et al. 2015; Park et al. 2019; Sun et al. 2018), and (2) decomposition methods that allow a set of smaller models (e.g., one per scenario as in decomposition) to be coordinated so that they converge in a reasonable time to the optimal solution of a single large multi-scenario model (Binato et al. 2001; Ryan et al. 2011; Munoz et al. 2016). Other tools for modeling long-run uncertainties in planning that have been proposed include Monte Carlo simulation (Roh et al.2009), chance-constrained programming (Yang and Wen 2005), conditional value at risk (CVaR) constraints (Munoz et al. 2017), adaptive programming (Maloney et al. 2016), and most recently, robust (data-driven) stochastic programming (Bagheri et al. 2016).

Turning to resilience against short-, medium-, and long-term events that could result in extended system outages, TRP in practice has tended to consider a small set of contingencies and test the system's ability to withstand those contingencies without failing (reliability) or, less commonly, to quickly recover (resilience).

Meanwhile, research on resilience and the related notion of robustness has been very active (Wang et al. 2015). Enumerated contingencies can be included in TRP optimization models, analogous to how dispatch models consider operating contingencies such as n-1 events (Majidi-Qadikolai and Baldick 2016). Robust programming has been widely promoted as a non-probabilistic optimization method for implicitly defining extreme events that the system must be able to withstand, either through preventive or corrective actions. These events are generated by considering all possibilities of uncertainty inputs (like demand and resource availability) within predefined "uncertainty sets." Such methods are being considered for use by ISOs in system operations (Zheng et al. 2012), and extensions to planning models have been proposed (Sauma et al. 2015). Other research has focused on defining resilience indices, such as loss of load or extreme prices integrated over multiple weeks after a disturbance, for example an extremely low hydro year or disruption of gas flows from the Gulf of Mexico (Gil and McCalley 2011). Although most such research has focused on supply disruptions, network recovery post-disaster has also been addressed. For instance, inventories of spare transformers and post-event deployment of those spares for enumerated disasters can be optimized in a combined preventative-corrective framework (Enders et al. 2010). TRP models can be combined with restoration and network reconfiguration to optimize combined preventative-corrective strategies (Dehghanian et al. 2018).

D. Needed Research

Computational improvements are crucial for this theme, as they are for other themes. The sheer number of short- and long-term contingencies and scenarios that need to be considered in stochastic and robust optimization models requires large numbers of production simulations to cover the range of possible system conditions, and the capability to solve very large planning optimization problems. Thus, the recommendations made elsewhere in this white paper for computational research are applicable here.

Particularly applicable to dealing with uncertainty are the following. First, cleverer formulations may allow for more compact models to accurately characterize the range of short-run conditions, including events in the tails that affect system resilience, as well as the range of possible long-run economic, technology, and policy conditions that drive the diversification and option values of investments. Second, decomposition-by-scenario approaches, such as progressive hedging, are likely to be particularly useful for dealing with uncertainty.[10] Third, approaches to scenario definition for short-run operating conditions and long-run policy, technology, and economic developments are needed for both probabilistic methods and non-probabilistic resiliency and robustness methods. These methods can benefit both from human factors/cognitive psychology research on fostering creative and expansive thinking that avoids well-known biases (Kahneman et al. 1982), and from research on combining experimental design/sampling theory with optimization to address how the most information about the

[10] Progressive hedging is a decomposition method that separates an optimization's problems into subsets of variables with relatively few coupling constraints between them. Examples include separate subsets for each scenario (e.g., capacity and operations under high versus low demand growth) where the coupling constraints are "non-anticipativity" constraints that require that early variables (e.g., year 2025) are the same for all scenarios, under the assumption that the planner doesn't know what scenario applies until after that year. Another example is to have separate subsets of variables for adjacent control areas, with coupling constraints being the transmission flows between them (exports from one equal the imports for the other). Progressive hedging relaxes those coupling constraints and penalizes the associated variables, and in an iterative fashion solves smaller optimimzations (one per subset) and adjusts the penalties until the coupling constraints are satisfied. See Watson (2013) and Gade et al. (2016).

range and impact of possible scenarios can be captured by a parsimonious sample (Park et al. 2019). It is important to consult a wide range of experienced economic, engineering, and policy experts who are keenly aware of present trends as well as the inaccuracy of past forecasts.

Particularly important is the applicability of these approaches under the explosive curse of dimensionality that arises when event trees are built that include multiple decision stages and multiple possibilities at each stage. Multiple stages and possibilities are key to considering adaptability and option values. This is especially true for optimal management of grid resilience, which must consider both preventative actions, such as network design and positioning inventories of spare equipment, and corrective actions, such as post-event repairs and restoration. However, the event trees that define the possible scenarios in each year grow rapidly in size as the number of stages increase. Consider what happens if there are, say, eight decision stages (for example, every five years over a 40-year time horizon) with just three possibilities in each year for, say, fuel price growth rates. After eight stages, there will be 3^8, or 6,561, possible combinations of these values, each one being a distinct scenario in the last stage. Each scenario will require its own set of investment and operating variables. The size of such a planning problem is obviously impractically huge. The ultimate objective is to develop TRP methods that consider resilience and multiple scenarios that are practical to solve using standard solvers on typical servers used by ISOs.

3. Summary of R&D Recommendations

In Sections 1 and 2, we identify a wide expanse of TRP R&D topics in the areas of economic analysis and transmission planning. We encourage the entire power industry to investigate these topics. In this section, we will describe a set of specifically targeted R&D efforts that we believe are most appropriate and important for DOE to pursue during the next decades. We used several criteria, described in Section 3.1, to justify the 23 recommendations in Section 3.2, which are organized by the general topic areas that we reviewed in Sections 2 and 3. A summary of our recommendations is presented in Section 3.3 where we categorize the topics by their urgency and whether they should be addressed by ongoing dedicated research programs or by focused shorter-term efforts.

As mentioned above, we refer to future planning tools and processes as *transmission resource planning (TRP)* for simplicity. TRP encompasses our vision of comprehensive transmission, distribution, and resource planning as the future of transmission planning. As explained earlier, this is not integrated resource planning by a single vertically integrated entity, but rather a paradigm in which transmission planners anticipate how grid augmentation and policy will affect the incentives for, and results of, investment in supply, storage, and demand management.

3.1 Criteria

DOE supports a **national strategy** for reliable, affordable, and resilient energy systems to promote the welfare of citizens and maintain the United States as a leading world economy. As a key component of this strategy, DOE should support research during the next two decades to ensure the development and deployment of innovative transmission technology and methods. The justifications for DOE's support of transmission planning research are akin to the familiar externalities' justifications for public support of infrastructure research in general. These include positive externalities in which technology improvements benefit trade and networks across the country where those benefits are often difficult to capture by private industry, and symmetrically, reduction of negative externalities imposed on other regions if one region has poor efficiency and reliability (Jaffe et al. 2003). These rationales particularly apply to electricity network planning because of the long life and capital intensity of power systems, and the just-in-time nature of power delivery.

One type of research that DOE should support is fundamental science, i.e., early-stage research.[11] Incentives for the private sector to support fundamental science and research are weak because the benefits may be widespread and difficult to capture by individual companies. DOE's R&D role would

[11] DOE has long funded fundamental research in the physical and mathematical sciences and has more recently partnered with the National Science Foundation (NSF) on fundamental research in, for instance, control, computational, and finance topics that are relevant to electric power. An example is the NSF Algorithms for Modern Power Systems program, which is currently co-funded by DOE. We encourage use of DOE-NSF cosponsored programs to further fundamental understanding and methodological developments, including broadening to include the social science research that we recommend in this section.

ensure that costs and economics do not pose an obstacle to developing understanding, technology, and system innovations that have net benefits to society. Additionally, DOE has a large, widespread R&D portfolio to enable research risk diversification whereas small and private companies may not be in a good position to take on that risk. Furthermore, research with significant societal spillovers or broad societal benefits may not be captured in revenues. Therefore, DOE plays a critical role in supporting research that private industry may not support but that is key to the welfare of the country and its residents.

DOE can also facilitate international cooperation and progress on technologies where scale economies are large and where success depends on large-scale efforts. For example, the Eastern and Western Interconnections both span the U.S. and Canada. Collaborations with other nations also facilitate transfer to the United States of knowledge and technologies developed outside the country, which will benefit our population. To ensure that state of the U.S.'s knowledge is leading or keeping pace with international research, significant effort should continue to be devoted to contributing to, and learning from, global energy research efforts and forums for exchange.

The criteria used to develop our recommendations include:

- relevance to transmission investment decisions
- the societal and engineering need for the R&D recommendation to be realized
- recent developments in fundamental science or enabling technologies (such as computer science), or recent experience with novel market and other institutions that could facilitate advances in transmission planning concepts and methods
- whether the knowledge and technologies developed could appreciably impact the amount, type, location, and timing of grid development to result in higher economic or other benefits
- whether DOE funding could be as or more effective in yielding new knowledge and technological innovation than relying on market incentives for private investment in research, or research by states or non-profit entities, and whether DOE leadership is likely to significantly enhance the probability that the needed research would take place.

These criteria are difficult to quantify, so our conclusions concerning priority research topics rely on our admittedly subjective judgment and experience.

3.2 Recommendations

Our specific recommendations for DOE-sponsored R&D on technologies for transmission economic analysis and planning are organized into five general categories: multi-value planning, workforce development, behavioral underpinnings of economic valuation and market designs, market simulation and planning models with flexibility and scalability, and adaptive TRP under profound uncertainty. General background and research needs for these five categories are described in detail in Sections 1 and 2.

3.2.1 Multi-Value Planning

Throughout transmission grid economic and analysis planning, the need to create a power system plan that involves stakeholders and effectively reflects their objectives and values is of the utmost importance. Stakeholder priorities have long been multi-valued, like finding the least-cost, reliable solution that avoids significant environmental damage and promotes environmental goals. However, R&D is needed to address additional emerging objectives, such as resilience, net-zero carbon goals, avoidance of non-renewable fuels, energy equity and access, and environmental justice.

- *Planning with multi-value objectives*. This area of research would enable power system planning to consider a variety of concurrent objectives in addition to, and beyond, the current state of art. During the past 10 years, different states and cities have set environmental goals (e.g., net-zero and decreasing air emissions) and technology goals (e.g., 80% renewable portfolio standard and 3 gigawatts offshore wind capacity). This research area may extend from multi-objective optimization to deterministic methods. The goal is to support the process and planning for furthering and balancing stakeholder objectives.
- *Advanced scenario and sensitivity creation.* Computational power and methods have enabled, and will continue to significantly enable, the exploration of various futures to test the technical, economic, feasibility, and robustness of different power system plans. Research in this area will help planners find their "least-regret" options and decrease possible stranded assets. Although research can explore near-endless scenarios, it can also help develop methods for scenario and sensitivity distillation that will conserve planners' time and resources.
- *Bridging and bonding transmission and distribution planning.* Research should be focused on the system, technical, and economic dynamics of the connected transmission and distribution system. Although separate planning practices used in the past have been adequate, the increasingly bilateral interactions between transmission and distribution call for research to model and analyze their interactions and relationships. Additionally, R&D support can be given to assessing and determining effective, efficient distribution and transmission system operator interaction and operations that can support the future grid.
- *Multi-sector interdependencies and planning*. This research topic would address the interaction and coordination of the electrical system with other dependent and interdependent sectors, such as natural gas, coal, water, communications, transportation, and land. The importance of this topic has never been so dramatically illustrated as by the February 2021 events in Texas whose severity was exacerbated by the tight interconnections of the Texas natural gas and electricity systems, with difficulties in one leading to problems in the other and vice versa, and then leading to widespread water system failures.

DOE-supported R&D in this area can be judged to be successful if new planning methods drive innovation in addressing and balancing stakeholder objectives, and facilitate public acceptance. For example, improved planning methods that consider the full range possible resource and transmission options might identify an unexpected power system configuration that costs less and yet better maintains reliability, endures extreme events, and achieves air pollution targets than other options.

Improved methods could quantify risks that might otherwise be overlooked, especially those arising from complex dependencies across institutional, technical, and sector boundaries. Additionally, DOE should support the measurement, gathering, and analysis of economic, environmental, reliability, and other data to support methods for quantifying objectives.

The necessity of this R&D is ongoing given the numerous, diverse, and (especially) rapidly evolving goals that different states and regions want their power systems to accomplish. The current need for this research area should be considered accelerated as different government and utility organizations have set ambitious policy goals for the power system in the 2030 to 2040 range at the same time that risks to system reliability and resilience are apparently increasing.

3.2.2 Workforce Development

It is crucial to maintain and grow the workforce that supports economic analysis and planning of transmission grids. There are a few academic programs across the United States that educate and train students in power system planning. However, the intricacies of each power system, including its geographic layout, regulatory framework, and stakeholder objectives, are mostly learned on the job. This makes industry experience paired with education imperative. DOE is in a position to increase the recruitment of students and retention of professionals into science, technology, engineering, mathematics, and power system planning fields.

- *Providing students and professionals with experience-building opportunities.* This effort can include the design, execution, and support of internships, co-ops, apprenticeships, rotational programs, and sabbaticals in which qualified individuals at various stages of their careers can participate. Many skillsets are evolving as a result of technological advancement, including in automation and AI. The extent and impact of new skillset requirements need to be estimated and appropriate responses developed over the next two decades. Given the multi-disciplinary teams that typically work together in transmission economic analysis and planning, opportunities that target cross-functional work experiences in the energy industry would be especially beneficial. To the extent appropriate, DOE can partner with industry professionals to ensure progress of R&D and mutual benefit.
- *Supporting educational and outreach tool development.* DOE should support R&D to create educational tools for students and professionals in power systems. This can include virtual reality to simulate field conditions and open-source software and data for conducting planning studies. Educational materials that address engineering, economics, policy, and law would be particularly useful. Many decision makers in the transmission infrastructure process are not necessarily well versed in engineering and technical details, so it is important to enable communication of complex technical materials in a generally relatable and understandable format for all audiences.
- *Increasing accessibility to all.* The power industry in general, and the planning field in particular, would benefit from diversifying the workforce (U.S. DOE 2017). Research should be conducted on how to help people of all backgrounds become aware of and able to pursue career

opportunities in power systems. Improving inclusion and equity in the workforce means that we will improve the quality and of the electricity product that consumers will receive while minimizing the cost burden.

DOE will be successful if an adequate number of qualified professionals is attracted to the field; if they are familiar with engineering, economics, regulatory law, and social concerns in addition to technical subjects; and if innovation in education, including life-long learning, continues. Currently, there is informal understanding in the industry that there is a shortage of transmission planning engineers and an aging workforce. DOE should create metrics to assess whether there is an adequate number of professionals in the field with the diversity of skills and training required, compared to likely future needs for such personnel. Additionally, DOE should quantitatively assess the existing professional workforce and pipeline of students to gauge the adequacy of domestic academic programs educating future power system professionals, including those specializing in planning and economics.

The need for workforce development research is ongoing and should be accelerated if the metrics show a deficiency of professionals in the areas of transmission grid economics and planning. Additionally, given the rapid growth of renewables and distributed resources and the need for closer integration of transmission and distribution planning, this research area should be accorded high priority.

3.2.3 Behavioral Underpinnings of Economic Valuation and Market Designs

As indicated in Sections 1.1 and 2.1, benefits and costs in TRP must be interpreted in a broad multi-value framework, in terms of contributions of grid reinforcements to economic, reliability, sustainability, and other goals. Given an agreed-upon set of metrics for these benefits and costs, tools and data are needed to provide quantitative estimates of those metrics for alternative plans and to characterize the uncertainty of those estimates. The estimates should reflect not an ideal world of frictionless perfect competition, but how transmission might change system operations and trade in a world that includes incomplete information; multiple balancing authorities that imperfectly coordinate with each other in the short and long term; and potentially inconsistent local, regional, and federal policies. Better computational tools are needed, as discussed in the next subsection, but so too is better understanding of institutions and how the incentives they provide affect the efficiency of use of the grid.

As we explained in Sections 1.3, 2.2, and 2.3, in order to project the benefits of transmission over the next few decades, not only must the fundamentals of resource technology costs and availability be understood, but also the institutions that facilitate–or discourage–electricity trade. In particular, social science research is needed to understand the effects of inefficient market design and behavior of market participants on the use of expanded transmission grids and the resulting economic outcomes, including prices, benefits, and costs. We recommend four focus areas for this research:

- *Social science research on evolution of power trading institutions that affect transmission economics*. Economic- and political science-based research that identifies drivers and examines the role of regional differences in the evolution of the power sector's institutions can shed light on where those institutions and their market rules may go in the future, and how that evolution may affect the market benefits of, and incentives for, transmission expansion. Empirical work based on experience in U.S. markets is needed to identify the most important barriers to trade under alternative market conditions and designs. This understanding is needed in order to obtain more defensible estimates of the benefits of strengthening interconnections between different market areas. If there is evidence that strengthening transmission interconnections itself stimulates changes in institutions and market rules, this is important to document as a further benefit of transmission.

- *Social science research on present and future market and non-market drivers of resource investment.* In order to understand how grid planning can improve the efficiency of where and what kind of resource investments are made, there is a clear need to base TRP on an anticipative or "co-optimization" philosophy. Anticipative TRP recognizes how distributed and grid-scale resource investments will be affected by where and when the grid is expanded, and how its services are priced. But we need better understanding of economic and technical drivers of resource investment and how they interact with network configuration and pricing. Empirical economic research on resource investment decisions by diverse competitors under different incentive regimes could inform more realistic anticipative planning models that will avoid mischaracterizing the reactions of resource investments, and thereby avoid the resulting distortions of the estimated value of transmission for improving the efficiency of those investments. Such empirical data-driven efforts can be complemented by discussion and forums with investors and developers to obtain a full picture of whether and how transmission planning and pricing decisions affect the location and mix of resources, so this can be accounted for in anticipative planning models.
- *Social science and economics research on consumer and distributed-resource decision making.* This can be viewed as a specific topic under the above theme of understanding resource investment. This research area would draw on both economic theory and empirical study of actual behavior to propose frameworks for incentivizing efficient customer and DER investment and operations, and to understand how grid configurations and pricing will affect those decisions and their economic benefits. In addition to social science, additional research is needed in distribution ratemaking and markets for front-of-the-meter and behind-the-meter resources, the coupling of distribution and transmission economics, and impacts on the transmission system.
- *Market designs and software to manage deliverability of ancillary services.* Empirical research on the evolution of power market institutions and how they affect resource operations and investment will also support the development of efficient market designs. Particularly needed are spot market designs that capture how network limitations affect deliverability of ancillary services in regard to both scheduling and pricing those services. Poor market designs are likely to render grid reinforcements less beneficial in terms of both economics and reliability.

In sum, if understanding of market barriers and their impacts is sufficiently improved, then that understanding, together with improved computational capabilities, may make it possible to develop practical anticipative TRP models that account for those barriers and identify grid enhancements that will yield greater net benefits.

Success of this research can be judged in several ways. One is whether the insights are included in software for anticipative TRP, and whether the result is grid plans whose quantified net benefits are increased because they have considered, in a realistic yet practical manner, the impacts of reinforcements on inter-area trade and resource investment. A second way is whether changes in power market designs are implemented that yield increases in, first, the volumes and benefits of power trading and, second, enhanced deliverability of ancillary services and concomitant decreases in amounts that need to be scheduled. A third measure of success concerns whether the lessons from social science research on behavior, market efficiency, and institutional evolution make their way into top journals in energy economics and related fields, and also influence decisions about ISO and other market designs as well as state and federal incentives for transmission construction.

This recommended research interacts with several other of our recommendations. For instance, if computational advances make anticipative TRP models sufficiently detailed and computationally efficient for practical use (Section 3.2.4), the value and applicability of the social science research described above will be enhanced. As another example, the possibility or even likelihood of power systems evolving toward a model in which distributed resources dominate new additions has large implications for what scenarios are considered when planning under uncertainty (Section 3.2.5). The need for this research will grow rapidly if the penetration of renewable and distributed resources in the U.S. power sector accelerates, increasing the benefits of reconfiguring the grid to accommodate them.

3.2.4 Market Simulation and Planning Models with Flexibility and Scalability

Successful implementation of many of the research recommendations in this report will depend on market simulation capabilities. There is a large and growing need to conduct detailed simulations of how the grid constrains market operations and how the pricing and availability of grid services affect operations as well as investment decisions by resource owners. These simulations will become increasingly complex because of:

- the expanding diversity of technologies and their operating complexities (storage, FACTS devices, and variable renewables, for example); and
- the widening geographic and temporal scope of planning exercises that embrace multiple regions or entire interconnections and look forward multiple decades in order to consider transitions to zero/low-carbon and/or largely distributed resource mixes.

At the same time, streamlined, transparent, and easy-to-use models that address fundamental drivers in transmission planning are also needed for stakeholder and regulator communications and engagement in planning processes. Transmission planners will therefore need to be able to extract more credible results and deeper insights from more technically and economically realistic models while at the same time using simpler models to help other participants in planning and regulatory processes learn about the tradeoffs in transmission planning.

Research recommendations in this area include:

- Conceptual frameworks and practical tools for developing reliability and security requirements based on detailed engineering models, and the integration of those requirements into economic planning models. Models for detailed AC power flows, transient stability, and system security are crucial in transmission planning, but it can be a challenge to integrate their results with economic benefit-cost analyses and wide-area optimization-based planning models that focus on economic impacts. Approaches and practical tools are needed to translate what is learned from engineering models into constraints that can be included in economic planning models, without constraining the results of those models more than necessary.
- More realistic and larger-scale production-cost models. Continued advances in large-scale computation and parallel processing promise that much bigger and more realistic market simulation models will be available in the future. Since the establishment of DOE (and its predecessor agencies), high-performance computing has been a major priority. We support the continuation of this effort, including an emphasis on applications in TRP. Not only would the ability to solve larger models more quickly facilitate more accurate modeling and, we hope, more accurate estimates of system performance, but, just as important, this would enable planners as well as regulators and stakeholders to explore a wider range of options and assumptions and thereby gain confidence in the quality of planning recommendations.
- Identification of fidelity improvements that would most improve plans. In general, it shouldn't be assumed that all enhancements in simulation model fidelity would improve decisions and yield benefits that make those model changes worth doing. Research is needed to understand which network and resource technological features and costs would, if modeled in more detail, appreciably reduce distortions in recommendations for transmission investment and potentially yield significant gains in potential benefits from more efficient investment. For instance, production-cost methods could be improved in terms of the accuracy of their representations of the contingencies and system responses that drive ancillary services procurement and deployment, which would potentially improve estimates of how grid reinforcements would reduce the cost and increase the effectiveness of those services.
- Enhanced flexibility in software models and tools**.** As optimization-based TRP models become more accepted and widely used, the range of types of applications is likely to increase. This suggests that research into enhancing the effectiveness of open-source release of data and models will support case-by-case development and adaptation to particular user situations (Pfenninger et al. 2017). Furthermore, the usefulness to stakeholders and regulators of reduced-form, easy-to-run, understandable models for gaining insights on tradeoffs and system behavior should be systematically evaluated in actual settings, especially as a way to communicate and interpret the results of complex analyses (Hunter et al. 2013).
- Representation of market inefficiencies and their effects on transmission benefits. Formulation and testing of models that account for intermarket trade barriers and other market inefficiencies is needed, based on the social sciences research recommended in Section 3.2.3.

These models may involve formulations that are more complex than simple cost minimization in order to represent the barriers and market participants' responses to them. If these are equilibrium models rather than cost-minimization optimizations, there is a need for efficient solvers for the resulting non-linear or complementarity-based mathematical problems. Such improved market representations could inform research on formulation and solution of large-scale, multi-level TRP models incorporating more realistic anticipative planning paradigms that proactively consider how grid changes influence resource investment and market operations. In contrast, current practical anticipative/co-optimization models assume an idealized situation of perfect competition, efficient LMPs, and perfect information.

- Decomposition for solving large-scale TRP models. Research is needed into practical methods for decomposition and coordination of production-cost and investment models that can put quickly solvable large-scale models on planners' desks. Improved methods for pre-screening potential investments and for iterating between simplified and complex models could also allow much more accurate characterization of the performance of transmission plans and consideration of a wider range of options.
- Modeling of extreme events and resilience in TRP. Research into development of data and methods to inject extreme events into power system planning will help planners to prepare for these unexpected events. For example, as experienced in 2020-2021, extreme cold and heat can alter transmission and generation operating parameters and even cause extreme interruptions. Characterizing the likelihood and plausibility of possible natural and intentional events and their resulting consequences should be one area of research. These characterizations need to recognize that historic data are inadequate and only partially relevant when, for instance, climate and human systems are not stationary or there is deep uncertainty about these systems' future evolution.

These research efforts will benefit from the results of fundamental social science work on the functioning of markets and will contribute to several other of the research areas recommended in Section 3. An example is TRP under uncertainty (Section 3.2.5), which requires much larger TRP models than are in use now if multiple operating conditions and long-run scenarios are to be considered over a multi-decade time horizon.

These research efforts will be successful if the model and computational improvements are adopted by vendors and transmission planners. Based on the response of researchers to the recent Advanced Research Projects Agency - Energy grid optimization competitions, a mix of basic research support and competitions may be a highly effective way to quickly move modeling enhancements into practice.

3.2.5 Adaptive TRP Under Profound Uncertainty

The power sector is more capital intensive than any other industry, and network investments can be expected to have lifetimes of many decades. These characteristics mean that uncertainty about the evolution of the structure, technology, costs, and growth of the industry present great risks of commission and omission. That is, there are significant risks both from constructing assets that then become stranded and provide far less value than their installation cost, and from missing opportunities for making timely investments that could yield significant economic, reliability, and environmental benefits well in excess of their costs of construction. To ensure that consumers gain the maximum value from their expenditures on electricity infrastructure while meeting reliability and achieving sustainability goals, it is necessary to understand and reckon with the many sources of long-run uncertainty (Munoz et al. 2015). In doing so, planners should identify all major sources of uncertainty, and distinguish the uncertainties that can be readily probabilistically modeled and quantified based on historical frequencies (load forecast, transmission and generation outages, etc.) from the uncertainties that are more difficult to probabilistically model and that require expert judgment (government policies, technology breakthroughs, investment behavior, non-stationary climate, etc.)

In order to ensure that consumers realize the full value of transmission investment, we recommend that DOE focus on the following research topics:

- *Multi-stage risk-based TRP models.* TRP models formulated as stochastic multi-stage optimizations can help define near-term investment plans that are robust in the face of long-run uncertainties because they diversify portfolios and preserve options. Multiple stages and possibilities are key to considering adaptability and option values. Especially for optimal management of grid resilience, integrated consideration is essential of both preventative actions, such as network design and positioning inventories of spare equipment, and corrective actions, such as post-event repairs and restoration. The ultimate objective is to develop TRP methods that consider resilience and multiple scenarios that are practical to solve using standard solvers on typical servers used by ISOs. This research topic will involve both fundamental research in stochastic and robust programming and careful tailoring to the particular needs of TRP.
- *Computational advances.* The curse of dimensionality, in which the number of possible futures that result from considering various sources of uncertainty grows exponentially, implies that computational power will never be sufficient to consider all interesting possible futures with the desired level of detail and fidelity in a single model. This reinforces the research priorities outlined above for enhancing production-cost models and using decomposition/coordination approaches to solve large-scale TRP models. Examples of particular research directions include cleverer formulations that may allow for more compact yet accurate characterization of the diversity of short-run conditions, including extreme events that stress system resilience, as well as the range of possible long-run economic, technology, and policy conditions that drive the diversification and option values of investments. Second, decomposition-by-scenario approaches, such as progressive hedging, hold particular promise for dealing with uncertainty.
- *Imaginative scenario definition.* Efficient computation is of little use if lack of imagination and foresight result in planners overlooking the most important risks to system efficiency and resilience. Approaches should be developed to define scenarios for short-run operating conditions and long-run policy, technology, and economic developments, for use in both

stochastic optimizations and non-probabilistic resiliency and robustness methods. These methods can benefit first from human-factors and cognitive psychology research on fostering creative and expansive thinking that avoids well-known biases. A second area of potentially beneficial research combines experimental design/sampling theory with optimization to address how the most information about the range and impact of possible scenarios can be captured by parsimonious samples of conditions and futures.

- *Improved forecasting methods and data.* Research should be conducted on forecasting methods and procedures that can help advance grid planning while minimizing risks to electricity ratepayers. First, new or improved forecasting methods should be identified and developed to support multiple energy sectors and integrated transmission and distribution grids. Second, there needs to be both assessment of currently available data and development of research strategies for collecting future data to use in advanced long-term forecasting methods, including methods for projecting the evolution of electrification technologies in the building and transportation sectors. Missing data will be a growing problem, so research on methods to estimate or create synthetic representations of missing observations will also be very useful. This work should consider how use of sensors that have already been deployed, such as consumer smart meters, could help identify uses and processing of the data that will produce benefits in the planning process. Security and confidentiality concerns must be addressed. Third, besides state-of-the-art forecasting methods, which can serve as a vision, we need more applied R&D with industry partners to recognize the data, skill, and computational limitations that industry faces when attempting to use improved forecasting methods. Research is especially needed into understanding and creating future 8,760-hour load profiles based on behaviors, usage, technology, and public policy assumptions (e.g., transportation and heating electrification), informed by empirical studies of how consumers use new technologies. Scaling up or down historical load profiles is inadequate for reflecting these potentially profound policy and consumption changes.
- *Robust cost allocation to promote cooperation.* Cooperative game theory has shown potential to identify win-win plans and cost allocations, and thereby to promote cooperation in planning and market design among neighboring balancing authorities. However, deep uncertainty about how trade patterns and costs will evolve in the future is a barrier to agreements because of the perceived risks that future patterns of benefit could diverge from cost allocations. There is a need to develop implementable approaches to allocating costs and financing large interconnections that is adapted to changing financial conditions and that is viewed as fair and reasonable to all parties. These methods should be informed by the multi-stage stochastic solution approaches that correctly assess the benefits of diversification and options. Representing cost allocation within planning models, together with how cost allocation might influence which transmission investments are made (Bravo et al. 2016), might be useful for gaining insight on potentially successful regional interconnection possibilities.

These topics connect tightly with several other recommendations in Section 3. Improvements in computational efficiency of production costing would strongly support several of this report's recommended tool improvements, including stochastic TRP (Section 3.2.4). Empirical investigations by social scientists of the factors driving inter-balancing authority mergers and cooperation (Section 3.2.3) would support definition of methods to allocate the costs of inter-regional interconnections that would encourage joint projects.

Like the previous subsection's recommendations, the proposed research into stochastic TRP models can be judged a success if, first, planners embrace the importance of quantifying the economic value of adaptability through explicit consideration of multi-stage decisions and options and, second, multiple vendors develop and successfully market tools that incorporate these concepts.

3.3 Recommendations for Priority and Time Frame

We believe that all of the above 23 topics are important for supporting improvements in transmission planning and, ultimately, the performance of our nation's electric power system. Some are more urgent than others, however, in that an immediate need is apparent (for instance, as a result of the ERCOT February 2020 events), and the time frame to develop the needed knowledge and technologies is relatively long. In Table 1, we highlight one or more topics in each of the five general areas as being especially deserving of immediate attention.

Some topics are relatively focused and would benefit from the cross-fertilization of having several teams of researchers intensely pursuing different approaches in parallel. Recent Advanced Research Projects Agency - Energy type competitions to create better optimal power-flow solvers are examples of efforts that could inspire research program designs for several topics in Section 3.2.4. In Table 1, we indicate that we believe that about half of the topics fall in this category. The table also highlights other topics that would benefit more from longer, sustained support that is not as intensive as the focused efforts. This could be, for example, because fundamental knowledge and data are required before theories can be tested, and new methods developed and tried out based on those theories. Our recommended research in workforce development (Section 3.2.2) and the social science foundations of consumer decision making (Section 3.2.3) are examples of such topics.

Table 1. Authors' R&D recommendations for the U.S. Department of Energy

Research Areas & Topics	Immediate Priority	Short-Term Focused Support	Long-Term Sustained Support
3.1 Multi-Value Planning			
· *Planning with multi-value objectives*	■	■	
· *Creating advanced scenarios & performing sensitivity analyses*		■	
· *Bridging and bonding transmission and distribution planning*			■
· *Investigating multi-sector interdependencies & planning*	■		■
3.2 Workforce Development			
· *Providing students & professionals with experience-building opportunities*	■		■
· *Supporting educational & outreach tool development*			■
· *Increasing accessibility to all*	■		■
3.3 Behavioral Underpinnings of Economic Valuation & Market Designs			
· *Researching how trading institutions have evolved*		■	
· *Researching market & non-market drivers of resource investment*		■	
· *Conducting on consumer & distributed resource decisions*			■
· *Researching market designs & software on deliverability of ancillary services*	■	■	
3.4 Market Simulation & Planning Models with Flexibility & Scalability			
· *Devising frameworks & practical tools for developing reliability/security requirements, & their integration into economic planning models*			■
· *Developing more realistic & larger-scale production-cost models*	■	■	
· *Identifying fidelity improvements that would most improve plans*	■	■	
· *Incorporating enhanced flexibility in models & tools*			■
· *Representing market inefficiencies & effects on transmission benefits*		■	
· *Researching decomposition for solving large-scale TRP models.*		■	
· *Modeling extreme events & resilience in TRP*	■	■	
3.5 Adaptive TRP under Profound Uncertainty			
· *Developing multi-stage risk-based TRP models*		■	
· *Developing computational advances*			■
· *Defining imaginative scenarios*		■	
· *Improving forecasting methods & data*	■		■
· *Developing robust cost allocation to promote cooperation*	■	■	

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