Transmission Planning for the Energy Transition

Rethinking Modeling Approaches

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Table of Contents

Executive Summary

Transitioning to a resilient and clean energy system is vital for confronting the challenges of climate change. While there is no doubt that a robust electric transmission system is key to this transition, there is less consensus on how to plan and structure the needed transmission investment.

Historically, transmission planning has been reactive and compartmentalized, with separate efforts focusing on reliability, public policy alignment, and economic needs. However, a cost-effective clean energy transition will require building the right transmission lines at the right locations, with the right capacity, and in the right order. This will only be possible with proactive and holistic transmission planning. And this kind of planning requires a paradigm shift in transmission planning models.

This report examines the critical role of modeling details and assumptions that planners frequently ignore. We first provide an overview of the wide array of choices planners have when designing traditional transmission planning models. We then discuss how planners need to rethink these choices to account for the rapidly evolving energy system and the additional uncertainties climate change brings. Finally, we present a modeling case study to show how important these modeling choices could be for transmission outcomes.

Our case study examines the effect of more holistic modeling designs on transmission planning for ISO-NE, the regional electric grid in New England. We ran a high-level transmission planning model for the region, and then updated the model to consider broader categories of costs and benefits, such as alignment with public policies, impacts from greenhouse gas emissions and local air pollution, and performance under extreme weather scenarios. Incorporating these factors yields different optimal plans for transmission buildout compared to those suggested by traditional models, and, consequently, would lead to different investment, generation, and environmental outcomes. Importantly, the cost to society will be different depending on the model specifications, with tradeoffs between operational and investment costs.

We also show that the geographic scope of transmission planning, including the ability to coordinate offshore wind connections, can affect optimal configurations for both onshore and offshore transmission. Further, we explain how planners' designs for their model objectives, and whether they include risk aversion or regret criteria, can alter modeling outcomes. Significantly, we find that ignoring extreme weather scenarios in the planning stage can lead to much costlier outcomes, as costs related to unserved energy and emissions in these scenarios are higher than the additional transmission investments needed to improve extreme-weather resilience.

Our work suggests that policymakers should reconsider the standard design of transmission planning models. Given these models' critical importance in ongoing policy discussions, regulators should provide specific guidance about model design.

As many federal, regional, and state policymakers are exploring transmission policy reforms, they should not gloss over the wonky details of transmission modeling. Guidance that promotes more proactive, holistic modeling to inform long-term regional transmission planning can help facilitate a cost-effective, resilient, and clean energy future.

Introduction

Managing and averting climate change's worst impacts require transitioning to a clean and resilient energy system, while at the same time making rapid changes in how we use electricity, how much of it we use, and how we operate our electric grids. A robust transmission system is critical for achieving this transformation cost-effectively.

Yet there is little consensus about the best strategies to plan for building transmission at the pace and scale necessary for the clean energy transition. Historically, transmission planning has been reactionary rather than proactive. Moreover, around most of the country, it has generally been compartmentalized, with separate processes to manage needs like reliability, alignment with public policy, and economic concerns.[1] But to achieve the transmission investment necessary to ensure cost-effective and reliable electric service in the face of climate change, proactive and holistic planning is key.

Given the unprecedented attention to transmission policy, the United States may be on the precipice of a massive transmission buildout that could more than double the current system.[2] The Department of Energy (DOE) is working in several ways to support this change, including studying transmission needs and transmission planning models, and working on rules for national interest electric transmission corridors.[3] FERC and independent system operators/regional transmission organizations (ISO/RTOs) are also working to reform transmission planning processes, focusing on how advances in scenario-based planning and cost allocation could better account for uncertainty and unlock financing in proportion to projects' benefits.[4] And states are signaling their intent to increasingly rely on RTO/ISO regional transmission planning efforts, as well as potential interregional planning collaboratives.[5]

While this increased attention to transmission planning is critical to the energy transition, the discussion often glosses over a component vital to transmission planning: the underlying modeling frameworks and assumptions. Appropriate modeling analyses with proper assumptions are critical for ensuring that the right transmission lines are built at the right locations with the right capacity and in the right order, all in a cost-effective manner. Similarly, the underlying models and the outputs they provide can affect the pace of clean energy integration and emission reductions, as well the planned

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1 Ams. for a Clean Energy Grid, Transmission Planning and Development Regional Report Card 10–11 (2023). One regional transmission operator, MISO, has done a better job of evaluating transmission modeling solutions with a multi-benefit lens, across portfolios of transmission project solutions. *Id.* at 33; *accord* Ams. for a Clean Energy Grid et al., Enabling Low-cost Clean Energy And Reliable Service Through Better Transmission Benefits Analysis: A Case Study Of MISO's Long Range Transmission Planning (2022).

2 E. Larson et al., Net-Zero America: Potential Pathways, Infrastructure, and Impacts 27–29 (2021). The size of the buildout also depends on how well we enable distributed energy resources, and other kinds of newer resources to soften peak loads as well as reduce overall energy footprint. Srishti Slaria et al., Resources for the Future, Expanding the Possibilities: When and Where Can Grid-Enhancing Technologies, Distributed Energy Resources, and Microgrids Support the Grid of the Future? 13 (2023) ("Overall, the zero-emission DERs described may . . . partially displace the need for transmission expansion in a renewables-dependent grid.").

3 U.S. Dep't of Energy, National Transmission Needs Study ix–x (2023); *National Transmission Planning Study*, U.S. Dep't of Energy, https://perma.cc/N2GQ-6X8X; *Notice of Intent and Request for Information: Designation of National Interest Electric Transmission Corridors*, 88 Fed. Reg. 30956 (Apr. 15, 2023).

4 *E.g., Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, at P 185 (2022) (FERC's Proposed Rule); PJM Interconnection, Long-Term Regional Transmission Planning (LTRTP) Update (2023), https://perma.cc/GU7D-7L6P.

5 *See, e.g.*, ISO-NE, EXTENDED-TERM/LONGER-TERM TRANSMISSION PLANNING PHASE 2 at 5 (Oct. 17, 2023) (noting that ISO-NE OATT has to change in order to accommodate state-identified requirements, and that cost-benefit factors will continue to change going forward); James Downing, *Northeast States Detail Early Efforts on Interregional Tx Collaborative*, RTOINSIDER (Nov. 15, 2023), https://www.rtoinsider.com/62163-aeu-interregional-transmission-policy-collaborative/.

system's resilience to extreme weather events. But there is little discussion and guidance around how these models need to change.

Traditional transmission planning modeling relies on capacity expansion models that minimize economic costs related to investment, operations, and maintenance, while ignoring other benefits that transmission investment can bring.[6] Even the most sophisticated transmission planning models, like the one being developed in conjunction with DOE's National Transmission Planning Study, rely on this kind of modeling, considering only a limited number of additional benefits and costs.[7] FERC's Proposed Rule, while recognizing the importance of modeling, leaves significant discretion to planners on what modeling scenarios to use, what benefits to include, how to calculate those benefits, and what selection criteria to use (minimize costs, maximize net benefits, no regrets, etc.).[8]

Designing the reliable, clean energy grid of the future, however, will require a paradigm shift away from this mindset. This report examines how these frequently ignored modeling details can be critical to the pace and cost-effectiveness of decarbonization efforts. When setting up transmission planning models, planners' choices on such topics as risk tolerance, whether to incorporate multiple policy goals like greenhouse gas and air pollution reduction, and how to account for resilience to extreme weather events will play a key role in determining modeling outcomes. Similarly, the geographic scope of their models—for example, whether or not offshore wind interconnection points are optimized—significantly affects their recommended transmission buildout. Accordingly, improving transmission planning models is critical for quickly and cost-effectively decarbonizing the energy system, while preparing the grid for climate change impacts.

In this report, we present a high-level modeling case study to highlight the need for updating existing modeling frameworks so they will better achieve a cost-effective, clean electric grid. Our analysis reveals several useful insights. First, our work supports the principle that incorporating more robust economic costs (like costs of air pollution and greenhouse gas emissions), as well as extreme weather scenarios, into the modeling frameworks will yield different optimal transmission solutions, compared to simply optimizing for investment and operational costs. Second, our work shows that the scope of transmission planning, including the ability to coordinate and optimize offshore wind connections, can affect both onshore and offshore transmission topology. Third, our work shows that how planners set up objectives, and how they think about risk aversion or regret criteria could affect modeling outcomes. Finally, our work highlights the need for more specific regulatory guidance on transmission planning model designs, given their critical importance to ongoing policy discussions.

With these high-level insights, our report illuminates an important missing piece in the ongoing dialogue regarding U.S. transmission planning: If planners rely on outdated models that fail to account for essential elements of the clean energy transition, creating a clean, resilient, and reliable electric grid will be more expensive than necessary.

This report proceeds in three parts. In the first section, we summarize the wide array of choices planners have when designing traditional transmission planning models. We expand upon this section in the Appendix, which is a more detailed primer delineating the decisions that go into transmission planning modeling. In the second section, we discuss how planners need to rethink transmission planning models to account for climate change. In the last section, we report the results of a working paper in which we applied some elements of this more expansive approach to integrating offshore wind in the ISO-NE grid.

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6 *See* Johannes Pfeifenberger & Joseph DeLosa, Brattle Group, Transmission Planning for a Changing Generation Mix 8 (2022); Johannes Pfeifenberger et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Cost 30–53 (2021).

7 Inst. for Pol'y Integrity, Comments to DOE on Designation of National Interest Electric Transmission Corridors 25 (July 31, 2023), https://perma.cc/68PN-NBW2.

8 Inst. for Pol'y Integrity, Comments to FERC on Building the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection (Aug. 17, 2022), https://perma.cc/PZC5-5V7F; Justin Gundlach & Sarah Ladin, Inst. for Pol'y Integrity, *What's in FERC's 500-Page Transmission NOPR?* (Apr. 27, 2022), https://perma.cc/RQ7W-S84E.

Transmission Planning Modeling Frameworks

Policymakers, developers, and grid operators use transmission planning models to simulate future power systems and optimize the time, location, size, and type of new investments over one or more planning years. These models are a fundamental predicate for grid expansion. In this section, we briefly summarize the nature of commonly deployed models and describe some complex choices transmission planning modelers must make when developing and running them, focusing on how climate change can and should factor in.[9]

Today, state-of-the-art transmission planning model frameworks typically focus on minimizing cost by co-minimizing investment and operating costs for transmission, generation, and storage.[10] They consider the costs of constructing new transmission lines, upgrading existing infrastructure, building new generation and storage facilities, and operating the electric system with existing and new generation and storage facilities.[11] These models also inform operating decisions for that set of investments by accounting for least-cost operation, as well as system reliability outcomes by identifying the amount of unserved energy or spillage.[12] These models typically measure benefits in production cost savings, avoided investment costs, and reduced expected energy losses.[13]

To date, transmission planners largely have not incorporated climate change (and policies designed to adapt to it and protect against it) into capacity expansion modeling, except in cases where climate policies directly affect economic cost parameters.[14] Yet climate change-related factors will impact many transmission modeling inputs and decisions, as described below. Modeling frameworks will help support sound transmission planning decisions only if they can account for a wider range of benefits, costs, and risk tolerances, given climate change's disruptive wake.

Technology Costs and Other Financial Considerations

For every technology in a modeling framework, modelers need to specify fixed costs (e.g., investment in capital) and variable operating costs, which encompass considerations like fuel, operations, and maintenance. Incentives for

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9 For a deeper dive into traditional planning model basic design and parameter choices, please see our Primer on the Elements of Transmission Planning Modeling, attached as an Appendix to this report.

10 *See, e.g.*, PACIFIC NORTHWEST NAT'L LAB'Y ET AL., NATIONAL TRANSMISSION PLANNING STUDY: MODELING SUBCOMMITTEE MEETING 20 (2022), https://perma.cc/VXW7-C9SS; Todd Levin et al., *Energy storage solutions to decarbonize electricity through enhanced capacity expansion modelling*, 8 NATURE ENERGY 1199, 1200 (2023); Venkat Krishnan et al., *Co-optimization of electricity transmission and generation resources for planning and policy analysis: review of concepts and modeling approaches*, 7 ENERGY SYS. 297, 298 (2015); Francisco D. Munoz et al., *An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainty: WECC Case Study*, 29 IEEE TRANSACTIONS ON POWER SYS. 307, 309–10 (2014).

11 In practice, transmission planners may use models that do not co-optimize; for example, they may optimize only transmission for a given portfolio of future generation and storage, *see, e.g.*, ISO NEW ENGLAND, 2050 TRANSMISSION STUDY: FINAL RESULTS AND ESTIMATED COSTS 9–10 (2023), https://perma.cc/BX97-F7FJ, or compute only the optimal mix of generation and storage and identify the resulting transmission needs, *see* PJM INTERCONNECTION, *supra* note 4, at 15.

12 The term "spilled" energy comes from the hydroelectric context, where water may be spilled so that it does not contribute to oversupply, rather than flowed through the hydropower plant. *See* Andrej Predin et al., *Lost Energy of Water Spilled over Hydropower Dams*, 13 SUSTAINABILITY 9119 (2021) (studying lost energy potential of spilled water). Planners now commonly use this term interchangeably with "curtailed," when referring to excess wind, solar and hydro generation that is simply let go, rather than fed into the grid. *See, e.g.*, Giles Parkinson, *Load shifting and energy spills: Secrets to smarter grid dominated by wind and solar*, RENEW ECON. (Apr. 5, 2023), https://perma.cc/Q6ES-F73Q.

13 PFEIFENBERGER ET AL., *supra* note 6, at 33.

14 Compare, for example, NEW YORK ISO, MANUAL 35: ECONOMIC PLANNING PROCESS MANUAL (2023), with NEW YORK ISO, MANUAL 36: PUBLIC POLICY TRANSMISSION PLANNING PROCESS MANUAL (2020).

developing and deploying clean energy technologies will affect cost metrics, as will time horizons for financing and building these resources.

Modelers must also decide on the number of decisionmaking stages, which help determine sequencing of buildouts and costs. In some models, the solution for meeting electricity demand in a given future year will include only a single investment stage and then an operations stage.[15] Such an approach provides the optimal system that could be built within the planning horizon, but little guidance on the process of how and when investments should occur during that time. In contrast, other models explicitly model multiple decisionmaking stages of investment, simulating the optimal buildout of the power system gradually, to meet demand as it changes over time. This alternative approach is more useful for understanding the best sequencing and timing of investments.

These multistage models have another important advantage: Modelers can incorporate technology-specific learning rates for investment costs relatively easily (e.g., falling costs of storage). This aspect is particularly important for emerging technologies, which typically become cheaper with deployment.

Energy Resource Representation

Transmission planning modelers must choose how to represent energy resources in their models. How modelers represent energy resources affects how much energy supply a grid operator may draw from, with a given grid configuration. Traditionally, firm, dispatchable generation resources (like thermal power plants) have been the most prevalent resource type. Climate change-related extreme weather events will affect these resources in different ways (e.g., extreme cold weather that freezes fuel supplies, droughts that affect the availability of water for cooling), necessitating model updates.

Modelers must also incorporate a growing list of energy technologies. Laws focused on decarbonization have diversified the existing and anticipated energy resource mix in many ways relevant to model construction, requiring more investment in zero-emissions technologies and/or the phase-out of fossil-fuel-fired generation. Other examples include more availability and kinds of demand-side resources, as well as a number of supply-side resources with increasingly diverse operating characteristics and reliability contributions. Modelers must ensure that they build frameworks flexible enough to reflect these changes. They must also choose how to represent storage technologies, which are energy-limited because their ability to provide power to the grid depends on earlier charging and discharging decisions. The cost and operational properties of transmission lines will vary significantly depending on the resource choice.

It is also important to note that, even when there is installed generation capacity, not every resource will be available to produce electricity at full capacity at all times. Consider a solar panel at night, or a natural gas plant during a severe cold snap. Accordingly, modelers select capacity factors, or distributions of capacity factors, that adjust the total energy generation assigned to each resource (or classes of resources).[16] It will be increasingly important for models to accurately capture resources' ability to serve the grid at given times and locations.

Climate change will affect capacity factors in several ways. For example, higher ambient temperatures will affect thermal power plants' efficiency, and should be reflected in updated capacity factors. These temperatures will also affect transmission line ratings, which are important for understanding transmission's contribution to energy adequacy.

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[15] *E.g.*, Hung-po Chao & Robert Wilson, *Coordination of electricity transmission and generation investments*, 86 Energy Econ. 1, 3.

[16] *See Glossary*, U.S. Energy Info. Admin., https://perma.cc/S924-QVRT ("Capacity factor: The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.").

Further, future regulations may also affect these factors when regulatory stringencies are tied to a plant's capacity factor, influencing incentives.[17]

Demand

Modelers must specify future electricity demand, which transmission planning models aim to meet at the least possible cost. Often, current models assume an inelastic demand (i.e., the level of demand does not change with prices, and the potential for demand shifting is not considered), and use a constant rate of demand growth based on historical demand. But increasingly severe extreme weather events make historical demand pattern projections unreliable.[18] At the same time, decarbonization policies will dramatically increase demand and change consumption patterns. Current climate models and climate projection scenarios reveal the need to adjust historical demand inputs for transmission models.[19] Modelers can proactively incorporate robust, forward-looking demand data that reflect climate change and extreme weather events. Additionally, as more distributed energy resources and demand-side resources come online in response to decarbonization policies, in order to produce accurate outputs sustaining grid reliability, modelers will need to include assumptions about consumers' ability to shift demand.

Accounting for Public Policy

Traditionally, regional transmission planners have addressed transmission capacity expansion planning in response to public policies (like state renewable portfolio standards and in-state resource siting requirements) separately from reliability and economic project planning. However, if a state within the modeled region has laws reflecting specific policy goals for different types of resources, it would be appropriate and necessary for its model to invest in, at a minimum, the required amount of those particular energy resources, regardless of whether the model would otherwise have chosen to "build" these resources. This principle holds regardless of the kind of planning, as planners should consider these policies as the baseline scenario for modeling. Not accounting for such policies in the baseline can produce inefficient transmission buildout, leading to unnecessary costs. Furthermore, because transmission planning is path-dependent, these suboptimal decisions could compound, resulting in even more significant but unnecessary consumer costs over the long term.

Value of Lost Load and Reliability

Another input that planners may consider—and which is entangled with the concept of reliability—is the value of lost load (VOLL). The VOLL represents the societal cost of the grid failing to serve a unit of energy demanded by consumers. While transmission planning models will strive to meet anticipated demand, by investing in transmission, generation and storage, they will do so only until the costs of meeting demand exceed the costs of failing to provide the demanded energy (the VOLL multiplied by the amount of missing energy). In other words, the models achieve the reliability level that is justified by the costs of serving electricity compared to the costs of failing to do so.

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[17] *See New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 88 Fed. Reg. 33,240 (2023) (proposing different systems of emission reduction for natural gas plants based on their capacity factors).

[18] *E.g.*, Energy Sys. Integration Group, Weather Dataset Needs for Planning and Analyzing Modern Power Systems 7–9 (2023); Nicholas Rivers & Blake Shaffer, *Stretching the Duck: How Rising Temperatures will Change the Level and Shape of Future Electricity Consumption*, 41 Energy J. 33 (2020).

[19] Inst. for Pol'y Integrity, *supra* note 8, at 11–12; Energy Sys. Integration Group, *supra* note 18, at 100–04.

There are few empirical studies on what the VOLL should be, but transmission modeling studies typically assume values range from $5,000 MWh to $10,000 MWh.[20] Some estimates for specific categories of customers and durations have been much higher.[21] Beyond this VOLL approach, modelers might instead require the model to meet demand at all times, implicitly assigning an infinite value to the VOLL. While an infinite value is unrealistic, as discussed in the section on Adapting Transmission Planning Models for the Clean Energy Transition, planners may have good reasons to adopt a more risk-averse mindset given how climate change will increase harms resulting from unserved energy, as well as the distribution of those harms. The fine line between involuntary load curtailment and a blackout (the latter would have catastrophic consequences, with cascading impacts that would likely leave portions of the country without power for a prolonged time) provides a compelling reason for selecting a more conservative (higher) VOLL.

System Representation

The U.S. electric grid has many fragmented but interconnected parts.[22] Models that incorporate higher spatial resolution and broader geographic scope will often be more effective at addressing grid challenges. Because new energy resources have operational characteristics that may depend, in part, on their physical locations, higher spatial resolution will be increasingly valuable for model precision. Moreover, extreme weather will have physical impacts on grid resources and increase the breadth and consequences of extreme weather impacts by producing correlated risks. For example, an extreme cold event can increase consumer demand, decrease renewable resource availability, cause fuel supply disruptions, and result in freezing or forced outages for thermal generators.[23] Using models with higher spatial resolution and broader geographic scope will be essential to ensure the reliability and resilience of an energy system relying more heavily on weather-dependent supply and lacking substantial seasonal storage capacity. These choices will be even more important for risk-averse planners and policymakers.

System planners must also tackle the complex interdependency between the bulk power system and the gas system, given the importance of gas-fired electric generation in the current resource mix. A holistic co-optimization model that considers all options, including the interaction of transmission and pipeline expansion, can provide more efficient and sustainable expansion solutions than would a decoupled approach that looks at transmission planning and pipeline expansion separately.[24] Several models have been developed to integrate or coordinate natural gas transportation and electric transmission capacity expansion, including ones that rely on open-source tools.[25] In the future, an expanded hydrogen system may raise similar coupling questions that will become important to model.[26]

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[20] *E.g.*, Ting Qiu et al., *Stochastic Multistage Coplanning of Transmission Expansion and Energy Storage*, 32 IEEE Transactions on Power Sys. 643, 646 (2017).

[21] Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii–xiii (2015); Lawrence Berkeley Nat'l Lab'y & Nexant, Inc., Public-Private Partnership to Update/Upgrade the ICE Calculator, ICE Calculator, https://icecalculator.com/recent-updates (last visited Nov. 29, 2023)(discussing a new tool in progress for valuing customer interruption costs); Julia Frayer et al., London Economics, Estimating the Value of Lost Load 7–8 (2013).

[22] Mathias Einberger, RMI, *Reality Check: The United States Has the Only Major Power Grid without a Plan* (Jan. 12, 2023), https://perma.cc/KY82-QNU5.

[23] *See* Energy Sys. Integration Group, Ensuring Efficient Reliability New Design Principles for Capacity Accreditation 11 (2023).

[24] Venkat Krishnan et al., *supra* note 10, at 314 & fig.3 (2015).

[25] *See* Kristina Mohlin, Env't Def. Fund, The U.S. Gas Pipeline Transportation Market: An Introductory Guide with Research Questions for the Energy Transition 31–32 (2021) (describing various models and platforms that allow planners to "analyze the relevant interactions and interdependencies between the sectors," including the National Energy Modeling System; the simultaneous steady-state natural gas and electric power optimization framework from Los Alamos National Laboratory; a market module being developed to pair with Switch 2.0; a cooperation platform that pairs the PLEXOS model for electricity with the SAInt simulation model of natural gas flows; and several others); Xin Fang et al., Nat'l Renewable Energy Lab'y, Linear Approximation Line Pack Model for Integrated Electricity and Natural Gas Systems OPF (2019).

[26] *See* Guannan He et al., *Sector coupling via hydrogen to lower the cost of energy system decarbonization*, 14 Energy Env't Sci. 4,635 (2021).

Time Resolution

One of the many peculiarities of power systems is that supply and demand must be matched at all times.[27] Although supply and demand change in real-time, the changes are typically minor within a 15-minute window or even within an hour. Modelers therefore typically choose to model power systems at the hourly (or sub-hourly) level for representative days, representative weeks, or full representative years.

Models' temporal resolution can have large impacts on a model's tractability and the optimal outcomes it reveals. Because policies and incentives promoting decarbonization will result in higher penetrations of many resources with variable profiles, modelers' selections of higher temporal resolutions will be even more important for accurately rendering optimal pathways.[28]

Uncertainties

Modeling uncertainties is one of the most challenging and important facets of transmission planning. Climate change impacts, as well as regulations and laws aiming for rapid decarbonization, all increase uncertainties in modeled variables, including: (1) the impacts of more frequent extreme weather on weather-dependent resources; (2) the location, type, and deployment pace of new renewable energy resources; (3) the retirement pace of dirtier generation resources; and (4) the efficacy of demand-side programs. Furthermore, the stringency of the laws and regulations depends on uncertain political factors. Some uncertainties can be easier to incorporate into transmission planning model frameworks, while others may require sensitivity analysis or constructing scenarios with corresponding probabilities. Ideally, stakeholders or experts should thoroughly vet the scenarios and their probabilities to achieve robust modeling input data. Modelers consider stochastic programming[29] and robust optimization[30] models to be the state-of-the-art techniques for dealing with uncertainty. Both techniques support a proactive approach to planning, and may be able to better account for and deal with uncertainty about anticipated future states of the world.[31]

Challenges for Updating Modeling Frameworks

Transmission planning models, especially if constructed well, are data intensive and computationally expensive. Because of the computational complexity of these models, planners make many choices to balance resource constraints and accuracy. Examples include reducing the time resolution; reducing the spatial resolution; focusing only on a few uncertainties; and/or using simplified assumptions about some uncertainties. While some of these tradeoffs were reasonable in the past, the evolving energy landscape and climate change significantly alter the modeling consequences of these choices.

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[27] *Compare Electricity explained: How electricity is delivered to consumers*, U.S. Energy Info. Admin. (Aug. 11, 2022), https://perma.cc/KGP9-2Z7Q (detailing grid time-matching), *with* Xin Fang et al., *supra* note 25 (modeling gas systems to reflect line pack).

[28] John E T Bistline, *The importance of temporal resolution in modeling deep decarbonization of the electric power sector*, 16 Env't Rsch. 1 (2021).

[29] *E.g.*, Krishnan et al., *supra* note 10; Munoz et al., *supra* note 10.

[30] *E.g.*, Álvaro García-Cerzo et al., *Robust Transmission Network Expansion Planning Considering Non-Convex Operational Constraints*, 98 Energy. Econ. 105246 (2021); Cristina Roldán et al., *Robust Transmission Network Expansion Planning Under Correlated Uncertainty*, 34 IEEE Transactions on Power Sys. 2071 (2019); Raquel García-Bertrand & Roberto Mínguez, *Dynamic Robust Transmission Expansion Planning*, 32 IEEE Transactions on Power Sys. 2618 (2017).

[31] Aharon Ben-Tal et al., Robust Optimization xv (2009) ("[B]oth Robust and Stochastic Optimization are aimed at answering the same question (albeit in different settings), the question of building an uncertainty-immunized solution to an optimization problem with uncertain data; . . ."). In stochastic programming models, some or all input parameters are assumed to be uncertain, but their probability distributions are known. Proponents of robust optimization argue that its primary advantage over stochastic programming is that it does not require knowledge of the probability distribution of uncertainties, which is difficult to obtain in practice, just a range of variation of the uncertain parameters. *See* R.A. Jabr, *Robust Transmission Network Expansion Planning with Uncertain Renewable Generation and Loads*, 28 IEEE Transactions on Power Sys. 4558, 4559 (2013).

Adapting Transmission Planning Models for a Clean Energy Transition

Above we reviewed components of typical transmission planning models and described how climate change impacts and policies will affect them. In this section, we will consider how modelers and planners could improve transmission planning model frameworks.

Climate change requires us to think differently about every aspect of transmission planning. First, given the significant market failures associated with energy generation and consumption, as well as the increasingly costly consequences of these market failures, planners must reconsider traditional planning objectives. Second, as consumers' electricity usage and needs are changing, planners should update traditional assumptions and planning targets related to electric demand. Finally, as the uncertainties related to both the evolving energy landscape and climate change are increasing, planners must reconsider how they incorporate risk in their modeling frameworks.

Planners must also reconsider traditional planning models' goals. Traditionally, economic theory teaches that a social planner—in this context the transmission planner—should aim to maximize social welfare (the sum of consumer and producer surplus). The implicit assumption behind this theory is that the costs of consuming and producing are all accounted for; there are no hidden or missing costs. But fossil-fuel-fired electric generators are responsible for significant health and climate costs that are unaccounted for in many analyses. In addition, other market failures, such as the societal costs of an unreliable grid, indicate that clinging to traditional definitions of maximizing social welfare may be a mistake.[32] Given that least-cost pathways to decarbonizing typically anticipate electrifying a broad array of end uses, the costs associated with future outages could increase significantly. As a result, transmission planners must broaden their analyses to truly maximize social welfare.

Additionally, planners should also update their assumptions related to electric demand. It is now outdated to assume price is inelastic in the short run, even though this assumption used to be largely correct.[33] Under that old assumption, the typical solution to a social planners' welfare maximization was equivalent to minimizing costs of the system, and the currently used cost-minimizing modeling framework works. But in our modern electricity systems, a larger share of the demand can flexibly react to prices, e.g., choosing when to charge electric vehicles,[34] operating smart appliances at times when energy costs are lower,[35] dispatchable industrial demand, or dispatchable commercial demand like datacenters.[36] Transmission planners, therefore, can no longer rely on traditional assumptions and planning goals.

Planners will also have to rethink how they incorporate risk into their modeling. Standard transmission planning paradigms assume that the planner is risk neutral. Put differently, the planner would care about the expected costs or social welfare metrics given a probability distribution of potential outcomes, and not about how potential realizations

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32 *See* FERC, NERC, & Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States (2021) (detailing the events of Winter Storm Uri, in which electricity losses led to hundreds of deaths).

33 *See* Paul J. Burke & Ashani Abayasekara, *The Price Elasticity of Electricity Demand in the United States*, 39 Energy J. 123 (2018); Raymond Li et al., *How price-responsive is residential retail electricity demand in the US? Author links open overlay panel*, 232 Energy (2021).

34 *E.g.*, *Electric Vehicle (EV) Time-Of-Use (TOU) Rate - National Grid*, U.S. Dep't of Energy, https://afdc.energy.gov/laws/12521 ("National Grid offers a TOU rate to residential customers that own or lease eligible EVs.").

35 Sanem Sergici et al., Brattle Group, Heat Pump–Friendly Cost-Based Rate Designs (2023).

36 Kibaek Kim et al., *Data Centers as Dispatchable Loads to Harness Stranded Power*, 8 IEEE Transactions on Sustainable Energy 208 (2016).

of the outcomes are distributed. Consider buying a lottery ticket that would pay you $1 million 50% of the time, and $0 the other 50% of the time. If you were risk neutral, you would be indifferent between buying that ticket and getting paid $500,000 with certainty.

But risks associated with climate change upend this paradigm. Given the importance of reliable electricity to modern life, few people would accept a grid that alternated between blackouts and excessively cheap energy, compared to a more balanced grid with moderate prices. With increasingly severe extreme weather events, a paradigm that explicitly incorporates risk aversion may make better sense. While this paradigm might lead to lower expected social welfare or higher expected costs, it would be likely to better protect society against extreme negative outcomes.

One way planners can be risk averse is aiming to minimize "regrets" instead of minimizing costs or maximizing social welfare, as alluded to in FERC's proposed rule.[37] But because planners may regret unserved energy, excessive cost, environmental damage, or all of the above, minimizing regrets could produce many different solutions depending how planners define regret. Another way to incorporate risk aversion into planning models is to use the Conditional Value at Risk metric—a method that is popular in finance for managing an investment portfolio's tail risk.[38] By using this metric, transmission planners can also protect against potential extreme negative outcomes.[39]

Overall, given these models' critical importance in ongoing policy discussions, it is important for modelers to adapt the standard designs and assumptions of traditional transmission planning models to the realities of the evolving grid and the necessities of climate change. While some of these factors might seem too technical and therefore easy for policymakers to gloss over, as we show in the next section, getting them right is a prerequisite for a cost-effective transmission planning.

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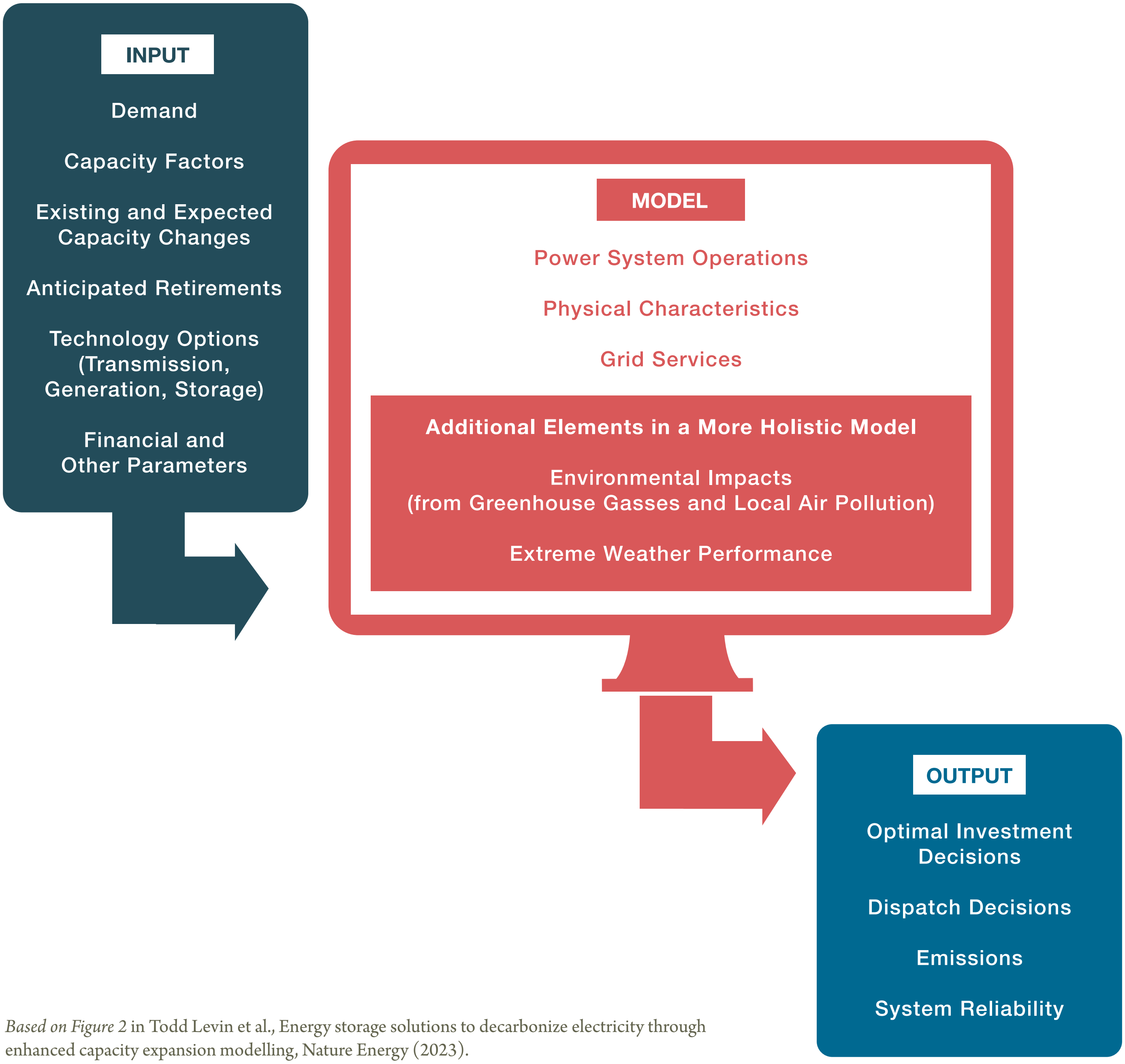
[37] In decisionmaking under uncertainty, regret is commonly defined as the difference between the actual outcome and the best possible outcome that could have been achieved. *See, e.g.*, David E. Bell, *Regret in Decision Making under Uncertainty*, 30 Operations Rsch. 961; *see also* 179 FERC ¶ 61,028, at P 251.

[38] In models with uncertainty, there will be a distribution of outcomes. And hedging against the tails of that distribution (representing low probability, high cost events) is a way to account for risk aversion. *See* R. Tyrrell Rockafellar & Stanislav Uryasev, *Optimization of conditional value-at-risk*, 2 J. Risk 1755 (2000).

[39] *See* Francisco D. Munoz et al., *Does risk aversion affect transmission and generation planning? A Western North America case study*, 64 Energy Econ. 213, 213–216.

FIGURE 1

Key Components of Transmission Planning Models



Based on Figure 2 in Todd Levin et al., Energy storage solutions to decarbonize electricity through enhanced capacity expansion modelling, Nature Energy (2023).

Case Study: A More Holistic Model for ISO-NE Transmission Planning

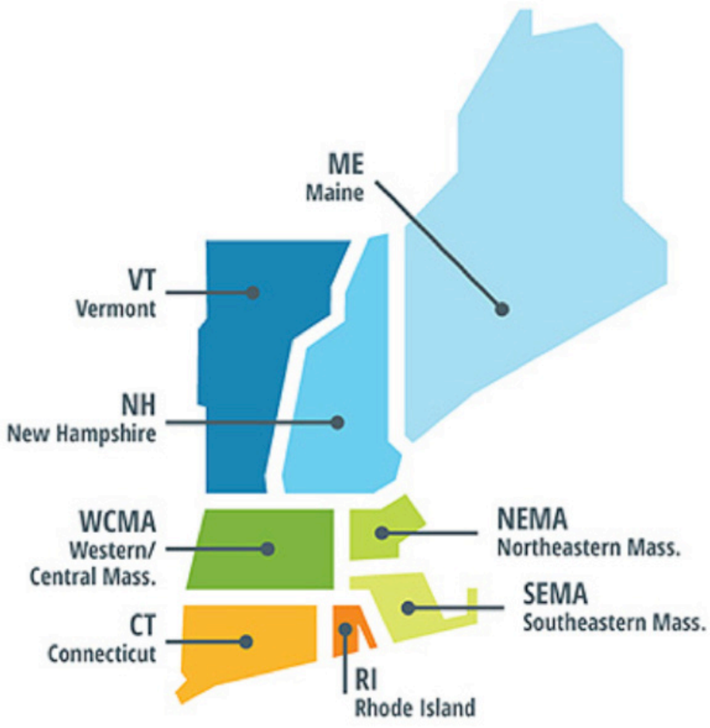
To illustrate the importance of adapting the factors we discussed in the previous section, we use a high-level case study to explore what outcomes a multi-objective planning model might produce when incorporating some of those changes (such as considering greenhouse gas emissions and air pollution, flexible demand, potential coordination on offshore wind interconnection, and extreme weather events).[40] In addition, we look at what thinking about "regret" could mean for the outcomes.

These modifications are not the only considerations missing in current transmission planning model frameworks, as we explained above. But we focus on them here because they are relatively simple to implement, and they demonstrate how a holistic planning model would yield different optimal transmission planning outcomes. Our exercise highlights how a transmission modeler's choices to better reflect the realities of the clean energy transition can play a crucial role in improving energy-system decisionmaking.

Our modeling work underpinning this case study used a representation of the ISO-NE system, which consists of eight load zones, as depicted in Figure 2: ISO New England's Eight Load Zones. ISO-NE presents an interesting test case, because there is significant offshore wind capacity planned in the region, requiring new ways of thinking about transmission planning and configurations. Our model co-optimized investment in transmission, generation, and battery storage with expected operational costs, as some planning models do.

FIGURE 2

ISO New England's Eight Load Zones



Source: https://www.iso-ne.com/markets-operations/market-performance/load-costs

[40] This case study is based on modeling presented in our working paper, Saroj Khanal et al., *Multi-Objective Transmission Expansion: An Offshore Wind Power Integration Case Study* (2023), https://perma.cc/EJU3-ZGN2 [hereinafter Working Paper].

But unlike traditional co-optimizing models, we also accounted for expected environmental costs in the model's objective function, alongside investment and operational costs, and we optimally integrate offshore wind into the ISO-NE onshore system. We also accounted for demand-shifting potential—a feature that is likely to become more important in the future when thinking of the flexibility potential of electric vehicles, smart appliances, or industrial load, including data centers. Finally, we examined performance under extreme weather scenarios. We explain the technical assumptions of the model specifications and our case study in more detail in our working paper, *Multi-Objective Transmission Expansion: An Offshore Wind Power Integration Case Study*.[41]

Technology Options and Assumptions

We allowed the model to pick among fossil-fuel-fired generators,[42] solar photovoltaic installations, and land-based wind, assuming offshore wind with offtake agreements proceed as planned.[43] We treated all existing generator retirement as exogenous for simplicity.[44] We directed the model to pick from the following transmission network investment options for new transmission capacity: inter-farm configurations of offshore wind farms,[45] points of onshore interconnection,[46] and onshore grid upgrades.[47] We also allowed the model to optimize inter-farm line configurations and export lines. Finally, our model allowed for demand shifting; consumers can shift a fraction of demand throughout the day at a certain cost.

Data

For our model, we used a "test bed" to reasonably represent the ISO-NE system.[48] Test beds are simple representations that modelers commonly use to observe how their planning model responds to different scenarios. While they are not fully reflective of existing power systems, they provide good indicators of how robust and reliable planning models will be.

Greenhouse Gases and Air Pollution

For the model specifications in which we considered greenhouse gas emissions and air pollution in the model's objective function, we monetized costs from each. Because we have carbon dioxide emissions factor data for existing thermal power plants, and because we can make reasonable assumptions about these factors for new thermal power plants, we

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41 *Id.*

42 For data availability consistency and simplicity, within the fossil-gas-fired thermal category, we included Natural Gas Combustion Turbine generation and Natural Gas Combined Cycle Carbon Capture and Sequestration units.

43 Although we excluded investment in any additional generation and storage resources in offshore nodes, we allowed the integration of the offshore wind projects presented in Table 1. We assumed that these offshore wind projects will be built and in service as planned, despite recent setbacks in the US offshore wind industry due to inflation and supply chain crunches.

44 We treated generator retirement as exogenous because existing power plants' future profits (or lack thereof) are a function of capacity and transmission additions; treating them otherwise would complicate the modeling exercise because these interdependencies would require the modeler to engage in many iterations until reaching some kind of convergence between additions and retirements.

45 We considered each offshore farm as a separate offshore node, requiring an investment in at least one candidate line to ensure offshore wind farm grid integration by their commercial online date. We used the developers' anticipated commercial online dates. We also permitted the model to choose three discrete cable types for the offshore grid: one high-voltage AC (HVAC) cable of 400 MW and two high-voltage DC (HVDC) cables of sizes 1,400 MW and 2,200 MW, reflecting current standard sizes in ongoing U.S. projects.

46 Additionally, given the prevailing uncertainties surrounding the eventual connection points of these offshore projects, we permitted a greater number of interconnection points on land than what the relevant offtake agreements specify.

47 We only considered grid reinforcement by doubling the existing line capacity.

48 We used ISO-NE's own test bed and enhanced it in several ways. Our Working Paper contains a detailed description of how we curated the operational input and cost data.

could easily calculate the emissions for any possible dispatch scenario. We then monetized these emissions using the social cost of carbon (SCC)[49] and added them to our transmission planning model's objective function.

Valuing local damages from reduced air quality is harder, because air pollution impacts from electric generators depend on many variables. These include: (1) operational dispatch; (2) wind direction and speed; (3) how close the thermal power plant is to population centers; and (4) the power plant's exact configuration, i.e., smokestack height, pollution control technology, etc. We took advantage of the Intervention Model for Air Pollution (InMAP)[50] to compute average marginal damages from volatile organic compounds, nitrogen oxides, ammonia, sulfur oxides, and fine particulate matter from each existing power plant.[51] We then used InMAP's source-receptor matrices[52] to estimate locational damages from air pollution without running a computationally demanding air quality model simulation.[53] We used those values for power plants with missing data, as well as for new investments.

In Figure 3: Average Marginal Damages from Local Air Pollution, we show the different estimates of the average (annual) marginal damages from local air pollution. The average values for each technology are as follows:

- Gas CCGT: 15.42 $/MWh
- Gas GT: 26.22 $/MWh,
- Gas Steam: 29.41 $/MWh
- Coal: 60.38 $/MWh
- Oil: 133.70 $/MWh

[49] We valued greenhouse gas emissions at the SCC, which is a dollar estimate of the damage cost from each additional ton of carbon (or carbon dioxide equivalent emissions). The latest Interagency Working Group estimate in the U.S. is $51 of damage per metric ton of carbon dioxide emissions. Interagency Working Group, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 at 5 tbl.3 (2021). In addition, we performed a sensitivity analysis with values in line with EPA's released draft update. *See* EPA, EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (2022).

[50] *See* Christopher W. Tessum et al., *InMAP: A model for air pollution interventions*, 12 PLOS ONE (2017).

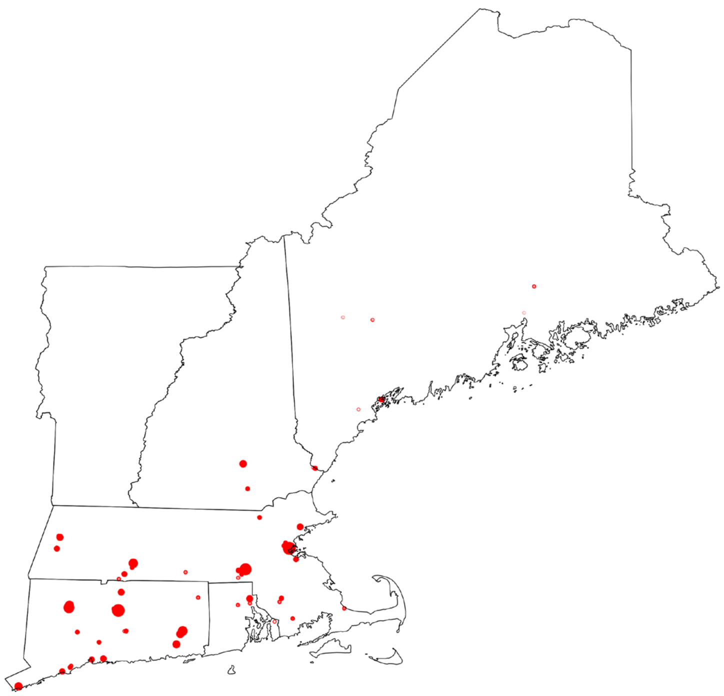
[51] We used 2016 annual emissions of these air pollutants, measured in short tons.

[52] InMAP uses air pollution source-receptor matrices to relate emissions at source locations to concentration at receptor locations. Andrew L. Goodkind et al., *Fine-scale damage estimates of particulate matter air pollution reveal opportunities for location-specific mitigation of emissions*, 116 PNAS 8775 (2019).

[53] We estimated locational damages from power plant air pollution by: (1) mapping the Air Emissions Modeling data to our ISO-NE+ test bed, by matching the power plant data to Clean Air Markets Program Data (CAMD) using the EPA-EIA-Crosswalk, *see Power Sector Data Crosswalk*, EPA (Sept. 5, 2023), https://www.epa.gov/power-sector/power-sector-data-crosswalk, (2) calculating air pollution damages according to InMAP's methodology, *see* Chris Tessum, *Working with source-receptor matrices using https://inmap.run and GeoPandas in Python*, InMAP (Apr. 20, 2019), https://perma.cc/FY89-WF6A. For details on our estimation procedure, *see* the Working Paper. To estimate each power plant's marginal emissions, we then repeated our estimation procedure adding additional emissions that would result from generating 1 MWh of electricity. The difference between these two estimates gave us an estimate of the average (annual) marginal damages from local air pollution for each power plant in the sample.

FIGURE 3

Average Marginal Damages from Local Air Pollution



Size of the red dots represents the $/MWh average marginal damages with a maximum value of 535.75 $/MWh and a minimum value of 0.31 $/MWh.

Accounting for Public Policy

All ISO-NE states have either clean energy standards or renewable portfolio standards (RPS),[54] which mandate a set percentage of demand to be supplied from renewable sources or from low- or zero-carbon emitting resources. We modeled these mandates with both a hard constraint, where the goals are met fully, and a soft constraint, where there is an alternative compliance payment if these goals are not met, reflecting states' implementation of these policies.[55] We present the results with hard constraints below.

54 *U.S. State Electricity Portfolio Standards*, C2ES (Feb. 2022), https://www.c2es.org/document/renewable-and-alternate-energy-portfolio-standards/ ("Thirty states and the District of Columbia require electric utilities to deliver a certain amount of electricity from renewable or other clean electricity sources."). The prevalence of RPSs makes updating transmission planning models to include greenhouse gas emissions reductions in their objective functions a pressing policy matter.

55 *See, e.g.*, Mary Fitzpatrick, Backgrounder: Connecticut's Renewable Portfolio Standard (2017), https://perma.cc/PK8D-AJRY ("By law, an electric company or supplier that does not meet the RPS must pay an alternative compliance payment (ACP) of 5.5 cents per kilowatt-hour for the shortfall.").

Main Results

To examine how transmission planning outcomes vary when different considerations are included in models' objective functions, we ran several model specifications and compared the results along the following criteria: transmission and capacity expansion decisions, costs, and environmental outcomes. The full set of outcomes can be found in the Working Paper.[56] In this report, we focus on our most important findings.

Our "*Baseline*" model's objective function included only the traditional considerations of investment costs and expected operational costs. For our "*Holistic*" model, we added monetized environmental externalities for air quality damages and carbon dioxide emissions to our objective function.[57] Finally, "*Holistic+*" refined *Holistic* by optimizing points of interconnection (POI) between cables connecting offshore wind hubs and onshore zones.

Figure 4: Optimal Onshore and Offshore Topologies Across Specification summarizes the optimal transmission expansion decisions for all three models (*Baseline*, *Holistic*, and *Holistic+*). Unsurprisingly, optimal transmission buildout is different under different cases. However, our results highlight an interesting dynamic. The *Baseline* output requires an onshore transmission line upgrade, while *Holistic and Holistic+* do not. In other words, accounting for a more comprehensive set of economic costs would not necessarily require onshore upgrades.

We also find that optimizing over the POI significantly affects the offshore topology. For example, rather than linking one of the offshore wind nodes to two separate points of interconnection in two different states, *Holistic+*'s solution is to connect this offshore wind node to an adjacent offshore wind node, where all the offshore wind is bundled and ready to be shipped into one point of interconnection. This result highlights the importance of thinking about coordination among states and regional transmission operators.

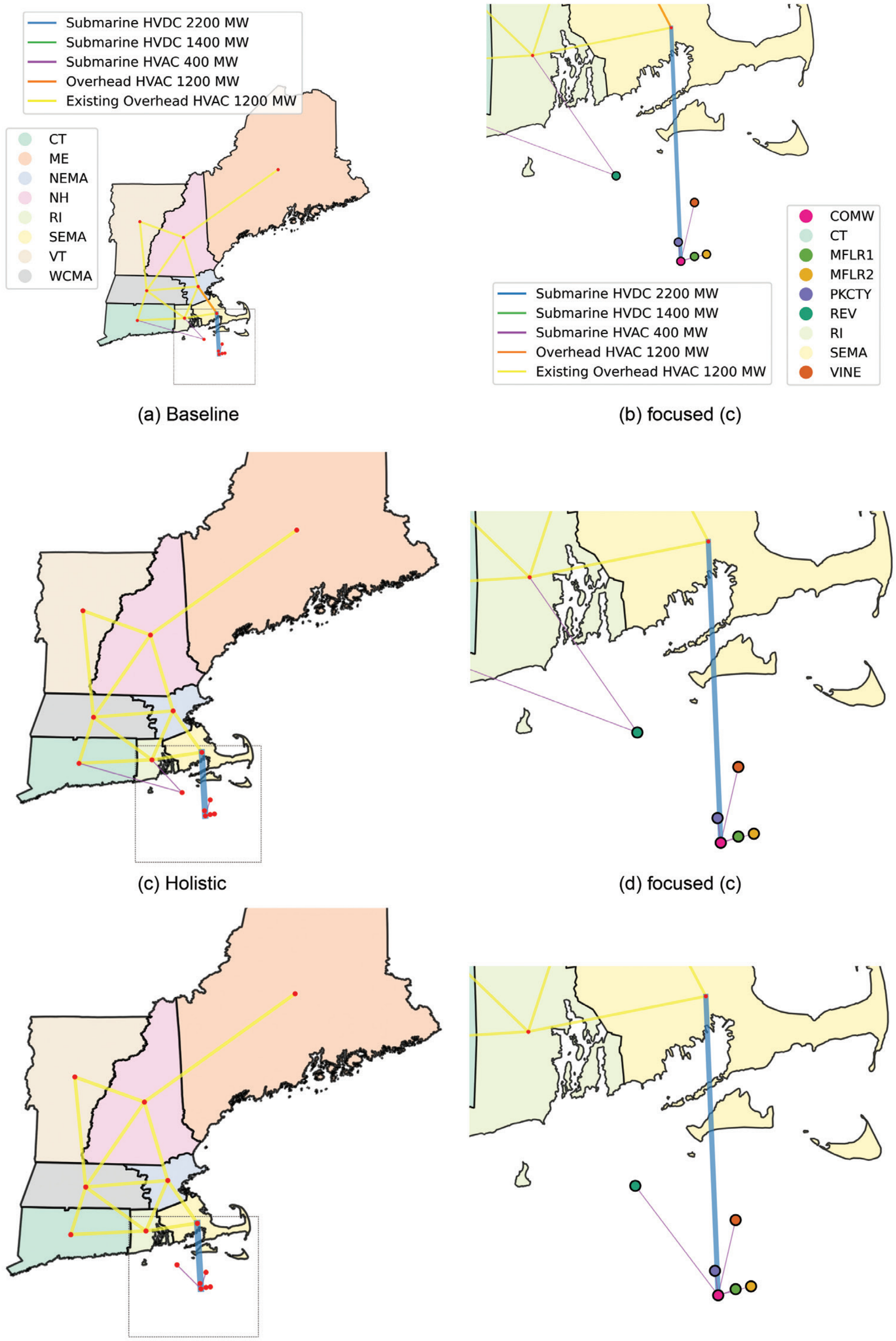
These differences in optimal transmission topology highlight the importance of considering multiple planning objectives in transmission models. Traditional planning models would not have identified the outcomes *Holistic* or *Holistic+* are able to identify, potentially resulting in less efficient decisionmaking.

[56] Working Paper, *supra* note 40.

[57] Going forward, planners may incorporate additional unpriced externalities to a model's objective function beyond the ones we selected for our Working Paper.

FIGURE 4

Optimal Onshore and Offshore Topologies Across Specification



(a) Baseline

(b) focused (c)

(c) Holistic

(d) focused (c)

(e) Holistic+

(f) focused (e)

Our modeling exercise also reveals tradeoffs between different model specifications. While the total investment costs and expected operating costs are the same order of magnitude in all three model specifications, *Holistic* and *Holistic+* end up with higher investment costs but lower expected operational costs, because both of these scenarios lead to more and earlier investment in mostly clean energy resources, which have lower operating costs. As a result, the higher upfront investment costs of *Holistic* and *Holistic+* come with two benefits: lower overall expected operational costs, and significant environmental benefits.

In addition, using holistic planning also increases the pace of the clean energy transition because it prompts more upfront investment in clean energy (see Figure 5: Total Capacity Expansion Decisions in the next 20 years Across Specification). Even though there are higher and earlier investment costs under *Holistic* and *Holistic+*, expected operational costs over the planning period are about 50% lower (see Figure 6: Total Cost Outcomes over 20 Years Across Specification). Similarly, because of this early investment in clean energy, there is also about an 80% reduction in monetized greenhouse gas and air pollution damages (see Figure 6: Total Cost Outcomes over 20 Years Across Specification). The lower expected operational costs and the lower expected environmental damages stem from a drastic increase in investment in onshore wind, which leads to lower dispatch from fossil-fuel-fired generation (see Figure 7: Total Generation over 20 Years Across Specifications). In other words, properly accounting for these values early in the transmission planning process can have tremendous effects on both the pace of decarbonization, and the societal benefits that come with it.

FIGURE 5

Total Capacity Expansion Decisions in the next 20 Years Across Specification

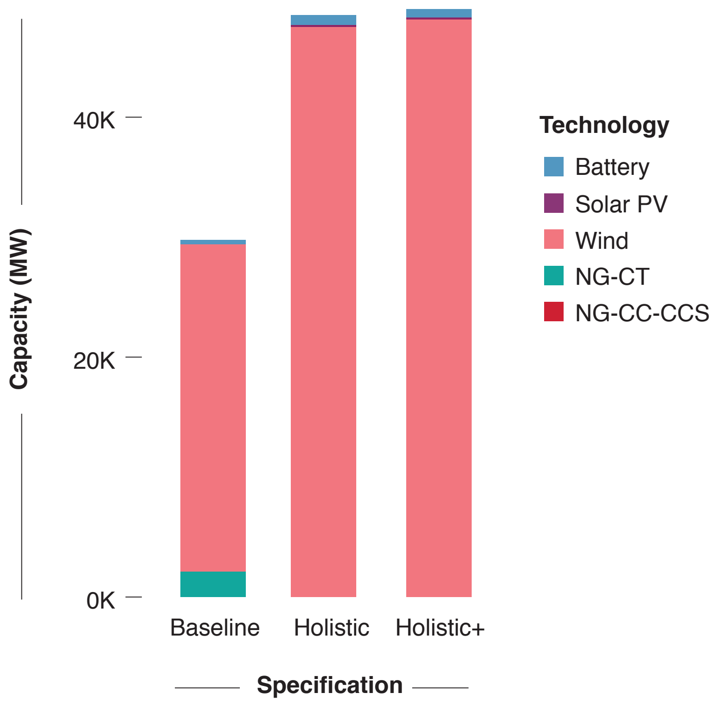


FIGURE 6

Total Cost Outcomes over 20 Years Across Specification

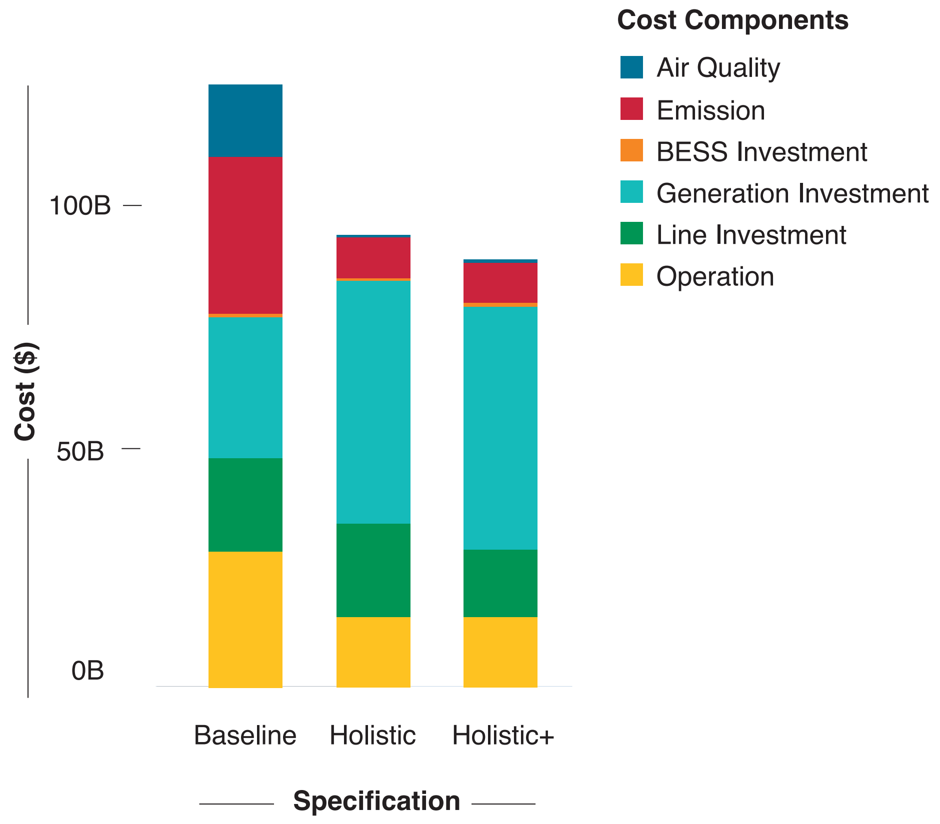
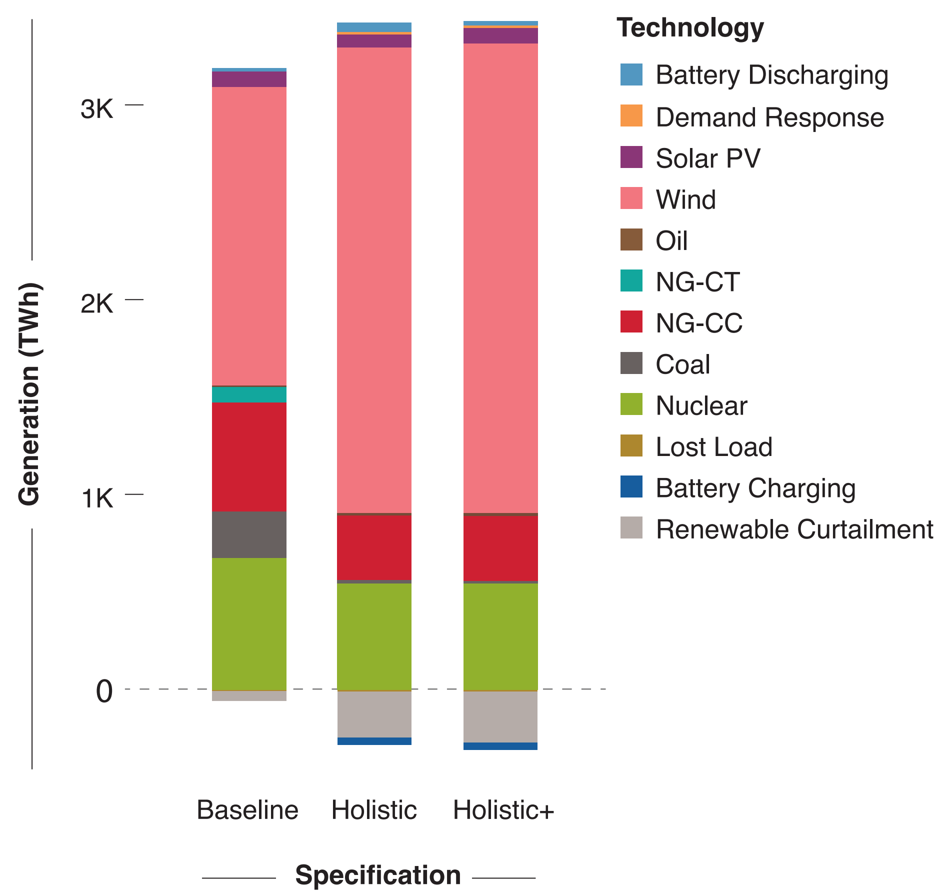


FIGURE 7

Total Generation over 20 Years Across Specifications



Extreme Weather Events

Reliability and resilience during extreme weather events are likely to become even more important given their increased frequency due to to climate change. Therefore, it is critical for transmission planners to include extreme weather scenarios in their models to better capture the full distribution of weather-dependent parameters like wind and solar generation, and demand. It is also important to consider different types of extreme weather, such as extreme heat and cold weather events, or droughts, as they all affect the power system differently.

Our results highlight that the need for transmission upgrades vary when accounting for extreme weather, regardless of the type of optimization we chose.[58] In addition, in each model specification, accounting for extreme weather scenarios also affected the optimal energy resource amount and mix, leading to more installed capacity of a diverse set of technologies, including renewables, gas-fired resources, and storage. However, the level of capacity addition for each technology, and hence emissions consequences, varied depending on the model specification. This finding also highlights the importance of considering climate change impacts when creating modeling scenarios.[59]

Risk Aversion

As discussed earlier, planners may be willing to trade off some expected social cost increase (or social welfare decrease) against some protection from extreme negative outcomes. One way to achieve that is to minimize regrets instead of costs when modeling. While we did not provide a full least-regret analysis in the Working Paper, our models show important consequences of not accounting for extreme weather events early in planning decisions.

One way to show the magnitude of the issue is by examining how a system optimized without considering extreme weather scenarios then performs under those scenarios. To do this, we plugged optimal transmission, generation, and storage investment decisions from our baseline model into a model that accounts for extreme weather operational scenarios. We then compared those outcomes to the ones produced by incorporating extreme weather directly into the planning model, as we reported in the sub-section *Extreme Weather Events*.

We find that, by failing to incorporate extreme weather events directly into the planning model, expected operational costs would increase by about $1 billion, almost 4%. About one-quarter of those costs would come from unserved energy costs, which are expected costs related to outages. Additionally, this outcome leads to higher greenhouse gas emissions and local pollution costs. In total, this planning outcome results in about $2.1 billion of additional expected costs over the planning horizon. But if the planners had accounted for extreme weather from the start, the additional infrastructure investment would have been only about $900 million.

This example demonstrates how important it is for policymakers to provide robust and clear guidance on transmission planning modeling frameworks. By encouraging or requiring planners to make changes necessitated by climate change, policymakers can spur better decisionmaking and an improved energy system.

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58 In fact, when accounting for extreme weather, we find that the onshore transmission upgrade would be the same as in *Baseline* without considering extreme weather (*see* Figure "Optimal Onshore and Offshore Topologies Across Specification").

59 *See* Inst. for Pol'y Integrity, *supra* note 8, at 11–12.

Caveats

Our goal in this report is to highlight the importance of considering additional factors in modeling, rather than provide specific empirical results. Readers should interpret the results of our case study directionally in terms of guiding principles on how to plan for transmission buildout in the face of uncertainties brought by climate change and consider public policies trying to address climate change. Similarly, including real-life constraints in planning, such as land-use and siting, will matter for determining the optimal resource mix and transmission topology, showing the importance of carefully modeling all significant constraints in a given system.

Of course, modeling outcomes will vary depending on context (e.g., different RTOs) and assumptions (e.g., parameterization of demand-side participation). But that fact does not take away from our basic finding: It is possible, necessary, and critical for transmission planners to account for factors beyond investment and operational costs in planning models' objective functions in order to plan the grid of the future.

Conclusion

This report, together with other transmission modeling framework analyses, highlights the critical importance of getting a transmission modeling framework right. As modeling efforts are starting to play a bigger role in policy discussions, policymakers should also be thinking about the critical role of modeling frameworks, and how new guidance could lead to improvements.

More holistic modeling will produce solutions that comport with modern grid planning goals and help address climate change. Our case study provides an example of how models that account for additional factors like extreme weather and pollution, as well as risk, result in meaningful changes to transmission planning outcomes. Broadening the suite of factors transmission planners consider, and improving the way they consider them, would help pave the way for more holistic, efficient investment decisions on the path to developing a reliable, clean grid.

Appendix: A Primer on the Elements of Transmission Planning Modeling

This primer elaborates further on the basics of transmission planning modeling discussed in the main report, and highlights some of the most important modeling choices.

Objective Functions

State-of-the-art transmission planning models minimize total cost, which requires designing their objective functions to co-minimize investment costs of transmission, generation, and storage, as well as the expected operating cost of the power system.[60] In contrast, some transmission planners use models that do not co-optimize these outputs together; for example, they may optimize only transmission for a given portfolio of future generation and storage,[61] or compute only the optimal mix of generation and storage and identify the resulting transmission needs.[62]

But co-optimization is important because generation, storage, and transmission are often substitutes.[63] Demand can be served by building local generation, or by building new transmission to deliver power from extant but remote generation. Similarly, building storage near a load area can substitute for transmission capacity through targeted charging and discharging. Co-optimization is appropriate also because transmission, generation, and storage operate interdependently. Transmission expansion decisions impact optimal generation and storage expansions, and vice versa, and co-location of generation and storage (e.g., solar and batteries) can improve a project's economic viability.[64] Accounting for these complex interactions in an integrated, co-optimized way leads to lower-cost solutions compared to a decoupled planning approach.

Because planners design transmission models in part to account for least-cost operating decisions (in addition to investment costs), outcomes also include optimal operating decisions for a given set of investments. These optimal operating decisions can be mapped easily to resulting emissions, although models do not currently co-optimize these emissions in the way that they do financial costs.[65] Both unserved energy (i.e., demand for electricity that would not be met) and curtailed excess energy supply will also be apparent as the transmission planning model run outcomes, providing additional useful data for system reliability planning assessments.

Technology Costs

For every technology included in a model, modelers will need to specify fixed costs (e.g., investment in capital) and variable operating costs, which could encompass considerations like fuel and operations and maintenance. To compare different options on an apples-to-apples basis, fixed costs need to be annualized so that they can be appropriately compared with total annual expected variable operating costs.

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60 *See, e.g.*, Pacific Northwest Nat'l Lab'y et al., *supra* note 10; at 20; Levin et al., *supra* note 10; at 1200; Krishnan et al., *supra* note 10, at 298; Munoz et al., *supra* note 10; at 309–10.

61 *E.g.*, ISO New England, *supra* note 11, at 9–10.

62 PJM Interconnection, *supra* note 4, at 15.

63 Krishnan et al., *supra* note 10, at 1.

64 *Id.*

65 *E.g.*, Qiu et al., *supra* note 20.

Thus, there are two critical and related modeling choices in this space: the time horizon and the discount factor the modeler will use to compute an investment's annuity (see *Discounting* below). It is appropriate to select a time horizon commensurate with the long useful lives of these assets to capture the economies of scale.[66]

Discounting

Discounting refers to the rate at which current and future costs and benefits are traded off. As such, choosing a larger discount rate devalues future costs and benefits relative to immediate costs and benefits. In the transmission and capacity expansion context, most existing academic works assume a private discount rate to capture real-world decision-making by private investors in the market. However, under the assumption of a social planner solution, the social discount rate, which is typically much lower than the private discount rate, is appropriate, as the goal is to find the socially optimal behavior.

Technology Operational Characteristics

Along with costs, inputs to transmission planning models include the operational characteristics of each technology. For example, thermal resources such as coal and natural gas can be constrained by various physical restrictions, such as minimum stable production levels, ramping limits, and minimum up and down times. For weather-dependent renewables, depending on their design, it may or may not be possible to ramp down generation below what the unit is capable of producing under the circumstances (e.g., solar panels that can angle away from the sun).

Generation resources—including both thermal and renewable—must also be assigned capacity factors. These reflect the amount of generation that the model should expect from a unit as a fraction of its maximum generation output. Capacity factors, which reflect both planned and unplanned outages, can vary hourly as well as seasonally, and they are also a function of location. Within a technology class, capacity factors can vary by design (e.g., natural gas plants with vs. without on-site storage). Although capacity factors are most commonly associated with intermittent renewable resources, they have become increasingly important for thermal resources, given the increased frequency of extreme weather events due to climate change.[67] Climate change will also affect renewable resources' capacity factors, such as by causing droughts that affect hydropower. Modelers will need to decide how to modify historical weather data to account for these changes. For example, they can replace a few historic "normal" years with data from historic extreme weather years, or change the frequency or duration of extreme weather events based on guidance from academic literature.

Turning from how modelers represent generation to how they consider storage, a key difference between the two is that the latter is an energy-limited resource. Storage not only has power limits on charging and discharging (i.e., limits on the rates at which energy can be transferred from the storage to the grid), but also energy limits depending on the storage's state of charge. It is therefore appropriate to model the state of charge, i.e., the amount of stored energy, at all times. The state of charge is a dynamic, intertemporal constraint, because the energy available during one time period depends on the charge and discharge decisions of all prior periods. For storage, model inputs could also include different power and energy limits of assorted storage technologies, as well as deterioration of the storage asset.

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66 P. Donohoo and M. Milligan, National Renewable Energy Laboratory, Capricious Cables: Understanding the Key Concepts in Transmission Expansion Planning and Its Models 4 (2014).

67 *E.g.*, FERC, NERC & Regional Entity Staff Report, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (2023).

The model can include costs and operating properties for different transmission technologies. These include: alternating current (AC) vs. direct current (DC), overhead vs. underground, single circuit vs. double circuit, and voltage level. AC and DC describe the two ways that current can flow on a transmission line, either back-and-forth (AC) or in one direction (DC). Most transmission lines are AC, but DC lines can carry large amounts of power over long distances with fewer losses. Underground lines cost more than overhead lines, but provide reliability benefits. Installing a double-circuit transmission line costs more than a single-circuit one, but the double-circuit option may be better overall given the increased power flows and the reliability benefits of having two parallel lines. Similarly, there is a tradeoff between investment costs and efficiency as the line's voltage increases. In principle, modelers also have the option to model the use of grid-enhancing technologies, such as dynamic line ratings and power flow controllers. Even for pipes-and-bubbles representations (see System Representation below), models include costs for expanding transmission through stylized transmission corridors, based on the extent of the expansion.

Beyond generation, storage, and transmission, it is also possible to model demand-side resources (which can overlap with storage). Demand-side resources are important for transmission planning modelers to include, because they can affect both the aggregate load on the electric grid and the shape of demand (load) curves. Consumers may adopt smart appliances, such as smart heating or cooling devices that shift demand by pre-heating or pre-cooling at off-peak times. As electric vehicles become more widely adopted, their batteries may be successfully integrated in ways that support the power system. Despite the significance of such demand-side resources, transmission planners and modelers sometimes neglect to consider them.[68] When they are included, modelers may specify inputs, such as the percentage of demand that can be shifted and the costs of doing so. Ideally, modelers would do so based on credible and robust estimates, accounting for future assumptions about the role demand-side resources will play in the future, evolving power system.

Demand

When transmission planning models minimize costs, they are specifically minimizing the costs of serving anticipated future load at all moments (with the exception of some unserved energy, as discussed in *Value of Lost Load* below), including its daily, weekly, and seasonal variations. Accordingly, modelers must specify inputs concerning electricity demand. During nights and weekends, consumers typically demand less electricity.[69] Some regions peak in winter and others in summer. Demand levels and patterns also vary by location. Generally, temperature is a good predictor of demand, especially if electricity is used for heating and cooling.[70] When models include a more granular approach to anticipating demand (both temporally and spatially), the resulting co-optimization of investment and expected operations of generation, storage, and transmission will lead to more realistic modeling outcomes. Because electricity demand decreases with the adoption of behind-the-meter distributed energy resources (e.g., rooftop solar) and increases with electrification of new end uses (e.g., electric vehicles), modelers will need to make assumptions about these parameters.

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[68] *E.g.*, Qiu et al., *supra* note 20.

[69] *Hourly electricity consumption varies throughout the day and across seasons*, U.S. Energy Info. Admin. (Feb. 21, 2020), https://perma.cc/ULG7-BXMD.

[70] Rivers & Shaffer, *supra* note 18.

Retirements

Modelers must also deal with the issue of which existing plants will retire, becoming unavailable to meet forecasted demand. Typically, planners will model retirements exogenously because doing so simplifies modeling.[71] However, simply relying on announced retirements may underestimate the need for new generation, as operators may not disclose an impending retirement until relatively close to the event.[72] Units may retire for reasons related to economics, public policy (e.g., state decarbonization goals), or the interaction of the two (e.g., state subsidies for renewable generation or federal pollution standards).

Accounting for Public Policy

For accuracy's sake, a transmission planning model should solve for a co-optimized solution for meeting future demand while also accounting for legal and policy constraints. For example, if a state within the scope of the modeled region has enshrined specific levels of offshore wind (or any other resource) deployment into its laws, it would be appropriate for the modeler to instruct the model to invest in, at a minimum, that amount of the resource, regardless of whether the model would otherwise have built these resources.

Modelers will also need to decide which public policies to model and how. Legal requirements with respect to generation, transmission, and storage can exist at the federal, state, and local level. These include pollution-control regulations that can affect costs, renewable portfolio standards, minimum procurement levels for specific technologies, and siting restrictions. Public policies can also affect demand, such as state rules that encourage electrification by incentivizing the adoption of electric vehicles or smart appliances, or policies that encourage the location of energy-intensive data centers. Modelers will also need to decide how to treat non-binding public policies, such as goals that are only aspirational but may indicate the direction in which binding policies will evolve over the study period.

Value of Lost Load

Another input that planners may consider is the VOLL, which represents the cost to society of the grid failing to serve a unit of energy demanded by consumers. When included, transmission planning models will strive to meet anticipated demand, but will allow energy shortfalls to occur when the cost of doing so would be less than the cost of preventing it through increased investments. The costs of failing to serve energy would be the VOLL multiplied by the amount of missing energy, and, depending on the selected VOLL and the amount of energy, this may be more or less expensive than the investments necessary to serve the missing energy. Some modelers do not include a VOLL and instead require the model to serve all energy. This kind of modeling is not a best practice because requiring the model to serve all demand under all circumstances implicitly places an infinite value on the VOLL and leads to inefficiently large investments.

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71 *E.g.*, Munoz et al., *supra* note 10, at 311.

72 *E.g.*, *PJM Interconnection, L.L.C.*, 185 FERC ¶ 61107, at P 16 (2023) ("PJM states that it received the deactivation notice of the Brandon Shores [coal-fired power plant] on April 6, 2023. PJM argues that it could not have foreseen or anticipated the June 1, 2025 proposed deactivation of Brandon Shores prior to April 6, 2023 . . . .").

System Representation

As power systems transition from large, thermal resources to increased penetration of renewable generation, defining the "system" scope (the size of the model's study area) becomes more critical. Given the increased weather dependencies of a system relying more on supply from solar and wind, the most efficient set of generation, storage, and transmission will tend to include interregional transmission capacity across geographies that are larger than individual weather patterns, if the weather patterns and correlation with load are different across regions.[73] Accordingly, how models treat the possibility of building interregional lines and the availability of power imports from other regions become important decisions. However, the wider the system scope, the higher the computational burden. To prevent intractability, modelers must carefully balance data scope and granularity against computational constraints.

Another important decision point when constructing a transmission modeling framework is choosing how to incorporate precise power flows. The simplest approach is to model power flows through "pipes and bubbles," meaning forgoing a sophisticated and realistic representation of transmission infrastructure and power flows in favor of stylized transfer ("pipes") between geographic areas ("bubbles") points. A more precise way to model power flows is using an AC load flow model or a linearized DC load flow approximation of actual high voltage transmission facilities. Like many modeling decisions, this choice involves a tradeoff between accuracy and computational burden.

Time Resolution and Decisionmaking Stages

Modelers must also choose whether to model power system operations at the hourly level for (1) representative days of a year, (2) representative weeks of a year, or (3) for representative whole years. In systems where inter-seasonal storage is available (e.g., large hydro reservoirs or perhaps through long-duration hydrogen), representing the power system operation for the whole year is important because it may be possible to store energy during one season to meet load in another.

Further, transmission planning models can have different numbers of decisionmaking stages. In some models, the co-optimized solution for meeting demand in a given future year will include only a single investment stage and then an operations stage.[74] Such an approach provides the optimal system to be built within the planning horizon, but little guidance on the process of how investments should occur over time. In contrast, other models explicitly model multiple decisionmaking stages of investment, simulating the optimal buildout of the power system gradually to meet demand as it changes over time. This alternative approach is more useful for understanding the best sequencing and timing of investments. Multistage transmission planning models can also accommodate changes in cost distributions over time to include learning curves for new technologies.

Uncertainties

One of the most important considerations in formulating robust transmission planning modeling frameworks is how the model will handle uncertainty. Operational uncertainties are relatively easy to factor into modeling frameworks. These include locational capacity factors for weather-dependent supply technologies such as solar, hydro inflows, or wind, as well as locational demand. Decades of data exist for these parameters, and there are methods to extrapolate from these past data to predict future trends. Accounting for these operational uncertainties is particularly important in

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[73] *See* U.S. Dep't Of Energy, *supra* note 3, at x.

[74] *E.g.*, Chao & Wilson, *supra* note 15, at 3.

a system that heavily relies on weather-dependent resources in combination with limited storage resources and demand-side participation.

Because transmission models typically try to approximate the power system operations for many years, usually decades ahead (20 years ahead is a commonly used time horizon), there are also many other uncertainties that are harder to address. These uncertainties encompass things like technological innovation, general demand growth, interest rates, fuel costs, public policy trajectories, local effects of climate change, and extreme weather phenomena—to name only a few. Conducting sensitivity analyses on the operationally robust solutions of the baseline transmission planning model is one way to deal with these deeper uncertainties. And, when modelers discretize the distributions of these deeper uncertainties, they can create scenarios and assign associated probabilities, which can be fed into transmission planning models as well.

Given the number of uncertainties, some modelers may build risk aversion into planning models. One way to achieve that is choosing to minimize regrets instead of costs. Another way is reducing exposure to extreme negative outcomes using the Conditional Value at Risk (CVaR) metric—a method that is popular in finance to manage tail risk of an investment portfolio, and that has been applied in the transmission planning context.[75]

[75] *See* Munoz et al., *supra* note 39, at 213–216.

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