UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

BUILDING FOR THE FUTURE THROUGH ELECTRIC REGIONAL TRANSMISSION PLANNING AND COST ALLOCATION AND GENERATOR INTERCONNECTION	**) Docket No. RM21-17-000**

COMMENTS OF THE UNITED STATES DEPARTMENT OF ENERGY TO ADVANCE NOTICE OF PROPOSED RULEMAKING

I. INTRODUCTION

Pursuant to section 405 of the Department of Energy Organization Act,[1] the United States Department of Energy ("DOE" or the "Department") files these comments with the Federal Energy Regulatory Commission ("FERC" or the "Commission") in response to the Commission's Advance Notice of Proposed Rulemaking ("ANOPR") issued in the above captioned docket.[2]

DOE commends the Commission and its staff on this crucial and timely undertaking, and appreciates the opportunity to comment. As the Commission notes in the ANOPR, the U.S. power system is undergoing a critical transition. A rapidly changing generation resource mix, deployment of new energy technologies, and changing consumer preferences and loads due to clean energy preferences and electrification of the transportation, buildings, and industrial sectors

[1] 42 U.S.C. § 7175.

[2] 86 Fed. Reg. 40266 (July 27, 2021).

are creating new challenges for the Nation's transmission system.[3] In the face of these challenges, strengthening and expanding existing transmission infrastructure, particularly the development of regional and inter-regional transmission projects, is key to continued access to reliable, resilient, lower-cost, and clean electricity for all. However, achieving a cost-effective, efficient, and broadly beneficial build out of such transmission requires reform to the existing planning and cost allocation rules.

Transmission is also key to managing the risks that climate change-induced extreme weather, cyber and physical security, and other vulnerabilities pose to our energy system. Strengthening our transmission networks is necessary not only for rapidly and cost-effectively decarbonizing the power sector to avoid the worst impacts of climate change, but also for improving the reliability and resilience of our Nation's power grid to increasingly frequent events that can cause large-area, long-duration outages. Expanding the existing transmission infrastructure is not just about lessening the likelihood that these outages occur but also about limiting the scope and impact of the outages when they do occur. At a time when outages caused by extreme weather events are devastating communities all over the country, and supply disruptions are threatening the reliability and the resilience of the Nation's energy system, reform of transmission planning, cost allocation, and generation interconnection could not be more timely.

The Commission has recognized that transmission planning must take account of public policy in ensuring a cost-effective and reliable grid with just and reasonable rates. As the Commission explained in Order No. 1000, "[t]he transmission planning process and the resulting transmission plans would be deficient if they do not provide an opportunity to consider

[3] ANOPR P 3.

transmission needs driven by Public Policy Requirements."[4] The reforms the Commission pursues related to planning, cost allocation, and interconnection processes should ensure that the regional transmission planning processes are adaptable to public policy objectives with the speed and scale needed in a way that can benefit all electricity consumers by reducing costs, increasing reliability and resilience, and reducing climate and environmental harms. One such public policy objective that the Administration has established is a whole-of-government effort to decarbonize the electric system, and effective and efficient transmission planning will play an important role in the success of this effort. This effort will be used to achieve the Administration's ambitious goals: a carbon pollution-free power sector by 2035, and a net-zero greenhouse gas emissions economy by 2050.[5]

As detailed below in answers to specific questions posed by the ANOPR, the National Laboratories and other researchers have identified several structural limitations of the current regional and inter-regional planning processes that hinder cost-effective and efficient transmission development. Addressing these structural barriers, improving planning frameworks to include a consistent and comprehensive set of benefits, and considering a longer time-horizon with forward-looking analyses, are all necessary steps for building out the transmission network of the future. At the same time, improving cost allocation methods and reducing undue burdens on

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[4] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 109 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC,* 762 F.3d 41 (D.C. Cir. 2014).

[5] *See* Exec. Order No. 14008 of Jan. 27, 2021, Tackling the Climate Crisis at Home and Abroad, 86 FR 7619 (Feb. 1, 2021), https://www.federalregister.gov/documents/2021/02/01/2021-02177/tackling-the-climate-crisis-at-home-and-abroad; *Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies* (Apr. 22, 2021), https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.

interconnection applicants are necessary to speed up the deployment of both transmission and generation resources.

It is also important to highlight that energy, environmental, and climate justice require participatory processes that consider community perspectives on transmission development, the impact that existing and new transmission can have on new and existing generation resources, and the cumulative environmental and infrastructure burdens faced by historically overburdened and underserved communities. Thus, planning processes must have procedures to consider and incorporate input to address both national and community needs and potential harms, and how to mitigate those harms. A process that ensures a just allocation of risks and costs is important for advancing the environmental justice goals of the Commission.

II. ORGANIZATION OF COMMENTS

Presented below in Part III are the Department's comments on the questions posed in the ANOPR. In preparing these comments, the Department worked closely with experts at the National Laboratories, including the National Renewable Energy Laboratory (NREL), the Pacific Northwest National Laboratory (PNNL), and Lawrence Berkeley National Laboratory (LBNL). As part of that effort, DOE is providing Appendix A which contains an analysis of the Texas Competitive Renewable Energy Zone (CREZ) Model with specific lessons learned that should be considered in addressing the issues raised by the ANOPR. Appendix B contains additional analysis and technical information from the National Laboratories related to questions raised in the ANOPR and provides citations to relevant publications and other resources.

Part IV details comments specific to the Department's four Power Marketing Administrations (PMAs): the Bonneville Power Administration (Bonneville), the Western Area

Power Administration (WAPA), the Southwestern Power Administration (SWPA), and the Southeastern Power Administration (SEPA). The PMAs were established by Congress, and their roles and responsibilities were set in their respective enabling statutes. Three of the four PMAs own and operate transmission facilities. Specific reforms that arise out of this ANOPR should take into account the unique circumstances under which the PMAs operate. In particular, reforms should ensure that any provisions to which the PMAs are subject do not impose requirements that conflict with their statutory obligations.

III. DOE's RESPONSES TO QUESTIONS PRESENTED IN THE ANOPR

A. Transmission Planning

1. Question: *Do current transmission planning processes result increasingly in transmission projects that are mostly local or intra-regional in scope, while failing to identify larger, more efficient or cost-effective projects needed to accommodate anticipated future generation?* (ANOPR PP 37 and 44.)

DOE comment: The available evidence shows clearly that existing transmission planning processes fail to identify and provide support for regional or inter-regional high-voltage transmission projects. These regional and inter-regional transmission projects – and perhaps networks of them – will be necessary under a range of plausible future conditions to maintain system reliability and resiliency and provide service to end-use customers at just and reasonable rates. Section 206 of the Federal Power Act requires that transmission rates be just and reasonable, and not unduly discriminatory.[6] FERC's authority and responsibility under section 206 includes

[6] 16 U.S.C. 824e.

rules and practices "affecting" wholesale rates,[7] including transmission planning and cost allocation. As FERC explained in Order No. 1000, its authority under section 206 includes "correct[ing] deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential."[8] Addressing transmission planning and cost allocation as reflected in Order No. 1000 and to be strengthened through the current proceeding will advance the Administration's goals of a carbon pollution-free power sector by 2035, and a net-zero greenhouse gas emissions economy by 2050. Success in this effort is important to ensure that the nation's electric infrastructure can deliver reliable, resilient, lower-cost, and clean electricity for all.

DOE supports consideration of reforms that would result in better information to support regional planning efforts, promote flexibility, and build upon FERC's existing framework. Under current planning practices, hundreds of local or sub-regional transmission projects are typically approved annually for construction, as compared to a few regional and inter-regional projects, if any.[9] The FERC Office of Energy Projects monthly *Energy Infrastructure Updates* show a clear

[7] Fed. Energy Regulatory Comm'n v. Elec Power Supply Ass'n, 136 S.Ct. 760, 773-774.

[8] Order No. 1000 at P 99.

[9] For example, of the 49 new transmission line projects approved in the 2020 MISO Transmission Expansion Plan (MTEP), none is more than 50 miles long. Of the 229 new transmission lines approved in any past MTEP that are still under construction, less than 1% are greater than 50 miles long. *See* MTEP , Approved Plan (Appendix A) Quarterly Status Report through July 30, 2021 (August, 2, 2021) https://www.misoenergy.org/planning/planning/mtep-quarterly-status-reports/#t=10&p=0&s=&sd=.

drop-off in the construction of new lines, especially high-voltage lines, over the last 5-10 years.[10] These conclusions are also supported by analyses prepared by transmission experts.[11,12]

The failure of existing planning processes to advance regional and inter-regional projects can be attributed, in part, to the failure of those processes to fully take into account all relevant benefits of such lines. A number of structural limitations of current transmission planning processes limit the ability to value all the benefits of transmission lines. Specifically, the siloed and reactive nature of current transmission planning practices limits their ability to fully recognize the value of transmission investments, and hence fail to identify larger, more efficient, or cost-effective projects in the following ways:

(1) Limited estimation of benefits: Current planning processes focus on only a limited number of benefit categories. Categories crucial to the planning of a reliable, resilient, and cost-effective grid of the future are often omitted in the planning process.[13] Furthermore, even when estimating what are more traditionally considered "economic" benefits, planners frequently use production cost models to gauge the effects of an additional transmission asset under various scenarios. Such models, however, typically assume a static generation fleet; this limited approach may reveal some benefits, but it may not identify others, such as those gained through the use of

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[10] https://ferc.gov/staff-reports-and-papers.

[11] Joskow, P. L. (2021) "Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector." http://ceepr.mit.edu/files/papers/2021-009.pdf.

[12] Pfeifenberger, J. (2021) "Transmission Planning and Benefit-Cost Analyses." https://brattlefiles.blob.core.windows.net/files/22086_transmission_planning_and_benefit-cost_analyses.pdf.

[13] *See id.* at 11.

the new asset to make trades outside the region, the asset's contribution during possible contingencies, or the value of transmission capacity freed up through reduced congestion.

(2) Disincentives for regional projects: Some regions distinguish between "regional" and smaller transmission projects in ways that create a disincentive for incumbent transmission operators to support regional projects.

(3) Short-term planning horizons: Regional planners currently look ahead 5 to 15 years, which is not long enough to anticipate and support decarbonization of the energy mix over the next 20-30 years. A 10- or 15-year transmission planning horizon will fail to capture the long-term benefits of enabling those goals to be achieved in the most efficient manner possible by establishing a more efficient transmission infrastructure.

(4) Reliability screening of economics-based projects: While transmission development can produce substantial reliability benefits -- benefits that should be incorporated into the planning process -- not all net-beneficial projects worthy of selection necessarily will meet reliability screens. Yet, some regions impose preliminary reliability requirements before projects are considered eligible for study based on their economic merits. In the California Independent System Operator (CAISO) region, economic project proposals are subject to a feasibility review by CAISO staff to determine whether the proposal addresses an identified constraint on the system. In New York, the New York Independent System Operator (NYISO) limits the economic analyses to the three most congested areas of the state as determined by the Independent System Operator (ISO). Such requirements may preclude the study of projects that are of merit primarily on the basis of economic and other benefits rather than reliability.

(5) The benefits of allowing "headroom" in transmission planning: Few planners would favor planning only to meet known future capacity or reliability/resilience requirements; some headroom has to be built into the system to be able to cope with potential growth, unanticipated trends, and contingencies. Also, given economies of scale, it is likely to be less expensive to build one line with headroom than two smaller lines on a just-in-time basis. Further, in an era of rising uncertainties, it is reasonable to assert that the amount of headroom to be maintained should be increased. A recent example of benefits received from available headroom include the economic efficiencies enabled by the Energy Imbalance Market in the West, which were feasible only because existing transmission capacity was available.[14] Similarly, Florida utilities have seen benefits recently from storm-hardening investments made after the severe storms in the mid-2000's. In the latter case, when the investment decisions were made, the issue was whether or when such storms would recur – *i.e.*, whether such headroom would ever be needed. Such challenges to the planners are even more acute today, given the increasing risks of more frequent and more severe extreme weather events.

See Appendix B, Item III, for additional discussion of some of the structural limitations of transmission planning processes that limit their ability to fully value transmission system benefits.

[14] "The EIM allows participants to buy and sell power close to the time electricity is consumed, and gives system operators real-time visibility across neighboring grids. The result improves balancing supply and demand at a lower cost. The EIM platform balances fluctuations in supply and demand by automatically finding lower-cost resources from across a larger region to meet real-time power needs. EIM also manages congestion on transmission lines to maintain grid reliability and supports integrating renewable resources. In addition, the market makes excess renewable energy available to participating utilities at low cost rather than turning the generating units off." EnergyImbalanceMarketFAQs.pdf (caiso.com).

2. Question: *Should transmission providers in each planning region amend their regional transmission planning and cost allocation processes to plan for the transmission needs of anticipated future generation?* (ANOPR P 44.)

DOE comment: Yes, such amendments are needed. The development of needed new generation capacity typically proceeds at a significantly faster pace than the development of associated new transmission capacity.[15] Further, new transmission has both a long operational life and significant economies of scale. As a result, if transmission is not planned far enough ahead to take the needs of likely new generation into account, the lack of appropriately sited and sized transmission capacity will impede the timely development of needed new generation and lead to higher costs of generation and transmission in the long term – with adverse implications for system reliability, resilience, consumers' electricity rates, and the achievement of clean energy goals.[16]

3. Question: *Does the failure to plan for anticipated future electric generation result in inefficient transmission investment and cause customers to pay unjust or unreasonable rates for transmission service?* (ANOPR P 44.)

DOE comment: Relying on successive small transmission expansion projects to meet foreseeable long-term needs may lead to the need for expensive retrofits (at customers' expense) at a later date. Economies of scale and network economies suggest that an initial larger-scale buildout will often represent a lower-cost solution. Moreover, a long-term expansion plan can usually be designed to be implemented in stages, thus minimizing front-end costs and preserving latitude for mid-course

[15] PJM Interconnection Queue https://www.pjm.com/planning/services-requests/interconnection-queues.aspx.

[16] Brinkman, G., et al. (2021) "The North American Renewable Integration Study: A U.S. Perspective." https://www.nrel.gov/docs/fy21osti/79224.pdf.

corrections in the design if unexpected changes occur. One recent assessment finds that investing in large-scale transmission could save $1 trillion in electric-system costs under a 95% clean energy future, relative to the same scenario without those grid investments.[17] Another study concluded that inter-state coordination and transmission expansion would reduce the system cost of a 100% clean power system by 46% compared with a hypothetical state-by-state approach.[18] A study from NREL estimated benefit-to-cost ratios of around 2-to-1 for large-scale inter-regional transmission expansion under higher clean power futures.[19]

Planning for anticipated future development is also highly relevant to aiding efficient use of emerging renewable energy technologies, such as offshore wind.[20,21] Generation development in the U.S. has relied upon generation-tie interconnections, which are inefficient transmission investments compared to more integrated regional alternatives. Transmission planning is already a multi-year process. Failure to consider future generation could stall development and lead to delayed and reduced benefits for consumers and other stakeholders. Regional transmission planning and commissioning will also facilitate competition for transmission project development, yielding potential transmission cost savings.

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[17] Clack, C. (2020) "Transmission Insights from *ZeroByFifty*." ESIG Transmission Workshop.

[18] Brown, P. and Botterud, A. (2021) "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System." *Joule* 5(1): 115-134 https://www.cell.com/joule/fulltext/S2542-4351(20)30557-2.

[19] Brinkman et al. (2020) "Interconnections Seam Study." https://www.nrel.gov/analysis/seams.html (DOE Note: This is likely an underestimate because many non-production benefits of transmission expansion, such as reliability, GHG and air pollution reduction, are not quantified in the study.)

[20] NationalGridESO (2020) Offshore Coordination Phase 1 Final Report. https://www.nationalgrideso.com/document/183026/download.

[21] Pfeifenberger, J. (2020) "Offshore Wind Transmission: An Analysis of New England and New York Offshore Wind Integration." https://www.brattle.com/wp-content/uploads/2021/06/21229_offshore_wind_transmission_-_an_analysis_of_options_for_new_england_and_new_york_offshore_wind_integration.pdf.

4. Question: *How could the Commission structure and implement a framework for considering the transmission needs of anticipated future generation in the regional transmission planning and cost allocation processes?* (ANOPR P 44.)

DOE comment: FERC should support the development of a common modeling framework to maintain consistency and comparability in regional transmission planning and cost allocation processes. If more capable and inter-compatible simulation tools become available, insights gained can inform better grid architecture, planning, and operations approaches, as well as relevant regulations and standards. As part of a framework, the Commission should consider the need to standardize, as appropriate, the following items:

- **Planning and Modeling Time Horizon** – Focusing on near-term system conditions (10 years) can result in suboptimal investments in the long-term. The Commission should consider a 30-year planning time horizon (or longer, depending on circumstances), with interim results reported for 10- and 20-year dates.
- **Modeling Input Assumptions** – Standardizing input assumptions can increase consistency and comparability across planning processes. Potential inputs the Commission could consider include:
    - Macro-economic and regional growth;
    - Electricity demand, including the impacts from expected distributed energy resource (DER) adoption, the availability of demand-side flexibility, and the electrification of end-use technologies for heating and transportation;
    - Customer demand for clean energy (as distinct from generic electricity demand);

- Existing utility scale generators (including extra-regional capacity accessed via imports) and existing transmission assets;
- Technology costs and performance characteristics for relevant types of new generation and new transmission, including non-wires alternatives. FERC should ensure that the process and parameters for new technologies affecting the grid are made available by the vendors and users so that they can be incorporated into the analytical and simulation tools;[22]
- Fuel prices and availability, including availability of water needed for hydroelectric and other generation resources;
- Weather conditions, including extreme events that may be more frequent and pose a significant threat to the electricity system;
- System contingencies consistent with the North American Electric Reliability Corporation (NERC) reliability requirements;
- Federal, state, and local policies, especially related to decarbonization, renewable portfolio standards, distributed energy resources (DERs), demand-side resources, clean energy standards, energy storage, greenhouse gas emissions, and climate change; and
- Other variables the planners consider relevant to their region.

- **Model Formulation, Physics, and Network Assumptions –** Tools used to assess the operational (*e.g.,* power flow/stability) impacts of a given transmission asset in a larger network should use consistent optimization equations, physics-based constraints, and

[22] National Academy of Sciences, *Future of the Electric Power in the United States,* Rec. 5.6.

model formulations. The Commission should require that all text file formats used for the exchange of power flow cases be publicly available, and that descriptions of all models used in system-wide transient stability studies be fully public.[23]

- **Core Scenarios** – Besides considering standardizing assumptions, the Commission should also consider the adoption of standardized core scenarios. Examples of these core standardized scenarios include business-as-usual, high/med/low load growth, high/med/low reliance on DERs and demand response, and decarbonization of the electric system. Planners could develop additional scenarios, but a core set of standard scenarios that takes into account current Federal and state public policy goals could make evaluating regional plans and assessing the costs and benefits of inter-regional projects easier.
- **Sensitivities** – Given uncertainty in the economy, consumer behavior, policy, climate, power sector evolution, and regional constraints, the Commission should consider requiring a multitude of additional sensitivities in planning processes aimed at identifying variables that strongly affect the need for new transmission, new generation, and reliability risks.

Use of a common modeling framework will also facilitate determination of benefits and allocation of costs among regions for inter-regional projects consistent with section 206 of the Federal Power Act. A cornerstone of just and reasonable rates is the "cost causation principle" which holds that rates charged for electricity should reflect the cost of providing it.[24] The cost causation principle ensures that "burden is matched with benefit, so that FERC generally may not

[23] *See* Chapter 3, "Analytic Research Foundations for the Next-Generation Electric Grid," National Academies, 2016. https://www.nap.edu/read/21919/chapter/3.

[24] *Ala. Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982).

single out a party for the full cost of a project, or even most of it when the benefits of the project are diffuse."[25] Compliance with this principle is evaluated "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[26] As FERC has determined in another context, and the court in *ODEC* recognized, it is "undisputed" that "high-voltage power lines produce significant regional benefits"[27] and a cost sharing mechanism that ignores the regional benefits of a project would be inconsistent with section 206. At the same time, it is important to recognize that cost causation does not require that benefits be calculated "to the last penny."[28] Shared modeling practices across regions as DOE recommends above will promote a common set of analyses that provide a sound evidentiary basis for approval of cost allocation for transmission projects in accordance with the principle of cost causation.

5. Question: *What factors shaping the generation mix should be considered, including: (1) federal, state, and local climate and clean energy laws and regulations; (2) federal, state, and local climate and clean energy goals (not enshrined into law); (3) utility and corporate climate and energy goals; (4) trends in the use of electricity-related technologies and their costs, including increasing electrification, DERs, and the use of grid-enhancing technologies; and (5) generation resource retirements? With regard to each factor that should be considered, show the basis for*

[25] *Old Dom. Elec. Coop. v FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018) (internal quotations and citations omitted) (*ODEC v. FERC*).

[26] *Illinois Commerce Com'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (internal quotations and citations omitted) (*ICC v. FERC*). As discussed in DOE's response to Question 17(1) *infra*, other physical criteria in addition to voltage may support a finding of shared interregional benefits.

[27] *ODEC v. FERC* at 1260.

[28] *ICC v. FERC* at 477 (citations omitted).

asserting that the Commission has authority to require that the factor be incorporated into regional transmission planning and cost allocation processes. (ANOPR PP 46 and 48.)

DOE comment:

(1) The modeled generation mix should of course reflect all current federal, state, and local laws and regulations affecting the provision and end-use of electricity, including such provisions related to the environment, climate, greenhouse gas emissions, clean energy, reliability, infrastructure resilience, and public health and safety. State-approved utility integrated-resource plans should be considered similarly.

(2) Federal, state, and local climate and energy goals, even if not reflected in law, are indicative of important concerns among policymakers, utilities, the public, and other stakeholders that planners should consider in their analyses. The fact that many of these goals now point in the same general direction – the need to deploy more clean energy and reduce carbon emissions – gives additional emphasis to the importance of taking them into account. Regional transmission planning processes must be adaptable to public policy objectives with the speed and scale needed in a way that can benefit all electricity consumers by reducing costs, increasing reliability and resilience, and reducing climate and environmental harms. Moreover, where climate and energy goals reflect a response to market inefficiencies (such as the failure to address externalities that impede welfare maximizing transactions and the insufficient provision of public goods such as reliability and resilience), FERC should enable transmission planning and cost allocation to address the market inefficiency, much as FERC has acted to recognize the externality of congestion

through the use of locational marginal prices that reflect the true cost of delivering electricity to a particular location.[29]

(3) Corporate climate and energy goals should be considered, to the extent that they will affect future supply of and demand for clean electricity in the region. Utility and corporate climate and energy goals should be taken as indicative of expectations by informed stakeholders of long-term objectives and trends that are relevant to transmission system planning. Utility goals, in particular, should inform transmission planners, as they represent future clean energy development and purchase commitments that will have to be met by a future transmission system. Consideration also should be given to the cost allocation implications of any additional transmission infrastructure investments associated with corporate energy goals.

(4) Consideration should be required of trends in the use of electricity-related technologies and their costs, including the precipitous declines in the cost of wind, solar, and energy storage, increasing electrification, deployment and integration of DERs, and the use of grid-enhancing technologies. Consideration of such factors is fundamental to established planning practice, even though the suite of technologies to be considered will continue to change.

(5) Consideration should be required of announced or expected generation capacity retirements, including appropriateness of continuing to maintain transmission facilities that served retired generation. Some retired generation sites may be suitable for development of new

[29] *See, e.g.,* Bethany A. Davis Noll & Burcin Unel, Markets, *Externalities and the Federal Power Act: The Federal Energy Regulatory Commission's Authority to Price Carbon Dioxide Emissions*, N.Y.U. Environmental Law Journal 1, 39 (2019).

generation capacity. However, announced retirements are not a comprehensive representation of likely generation fleet changes over the relevant planning horizon.

In addition, planners should take into account the likelihood of more frequent and more intense extreme weather events, given that the cost-effective and welfare maximizing responses to such events may require additional grid investments to maintain reliable and resilient electric service to end users.

6. Question: *Commenters are requested to address whether or how such requirements could shift additional costs to end-users, and whether the status quo allocates costs roughly commensurate with benefits, or whether it leads to rates that are unjust or unreasonable.* (ANOPR P 46.)

DOE comment: Inadequate planning for long-term system needs and the failure to fully consider the benefits of strong, networked power systems can lead to negative reliability impacts and result in rates and rules affecting rates that are not just and reasonable. By contrast, analysis of prior transmission investments shows that customer retail rates can decrease with well-planned transmission investments that enable access to lower cost generation sources and enable balancing over larger regions. In today's context, this latter point has particular weight given that to a large extent the incremental generation sources thus accessed will be producing at near-zero marginal cost.

Transmission system investments can also help achieve the public policy objectives of states or regions as well as lead to lower customer rates. For example, a survey of aggregate indicators suggests that after the Texas Competitive Renewable Energy Zones (CREZ) buildout (a) transmission charges to customers increased between 2007-2020, (b) wholesale energy costs fell, and (c) retail electricity rates in Texas fell while rates in the rest of the country increased. A rapid increase in wind installation and a decrease in natural gas prices drove wholesale power prices in the Electric Reliability Council of Texas (ERCOT) lower after 2014.[30] Please see Appendix A for a discussion of the Texas CREZ, including the impact on customer rates following implementation.

7. Question: *Should the Commission require greater use of probabilistic transmission planning approaches? Should planners aim to be reasonably well prepared for a broader range of possible future conditions? Would these approaches facilitate co-optimization of generation siting and transmission development? Are such requirements needed to ensure just and reasonable rates?* (ANOPR P 49.)

DOE comment: The electricity sector has changed considerably in the past few years, and there is little indication that the scope and rapidity of change will diminish. Transmission planners must consider a broader number of fundamental, uncertain variables (*e.g.*, behind-the-meter generation and storage and electrification of the transportation sector) affecting the demand for electricity. Thus, the planner's job has become more difficult, but it has also become more important, given that our economy and our national security are increasingly dependent on reliable and resilient electricity supplies.[31]

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[30] Additional analysis would be needed to disaggregate and apportion the factors that drove the net cost reduction in wholesale power prices.

[31] Larsen, P., LaCommare K., Eto, J., and Sweeney, J. (2016) "Recent trends in power system reliability and implications for evaluating future investments in resiliency." *Energy* 117(1): 29-46. Available at https://www.sciencedirect.com/science/article/abs/pii/S0360544216314979?via%3Dihub.

In light of these concerns, the increased use of probabilistic planning, the use of methods that co-optimize generation siting and transmission development, and the consideration of the likely strategic behavior of market participants are all likely to contribute to development of a transmission grid that reliably meets system needs at just and reasonable rates. It may be advisable for regions to use both probabilistic and deterministic approaches for several years before switching fully to probabilistic models in order to gain experience with probabilistic methods, refine their application, and better understand the implications of differences in the results.

As part of the need to prepare for a broader range of possible futures, rising uncertainties require that our electricity systems be designed to perform adequately during and after a variety of high-stress events.[32] Such requirements are needed to ensure just and reasonable rates in the future. Traditional planning methods are not likely to lead to the robust and resilient systems needed to provide reliable and cost-effective service to consumers under a wide range of plausible future conditions, leading to avoidable future costs.[33] Probabilistic approaches would inform planners about potentially different system needs under different scenarios and would help select projects that are most beneficial even with some level of uncertainty, preventing costly future upgrades or revisions.

8. <u>Question:</u> *Given the prospect of increasing percentages of renewable or other new generation technologies in the generation mix, should the Commission require planners to include considerations concerning actual performance, such as active power frequency control, reactive*

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[32] Novacheck, J. et al. (2021) "The Evolving Role of Extreme Weather Events in the U.S. Power System with High Variable Generation Penetrations." https://iceds.anu.edu.au/files/Joshua%20Novacheck%20-%20NREL.pdf.

[33] Baik, S., et al. (2021) "A Hybrid Approach to Estimating the Economic Value of Enhanced Power System Resilience." Available: https://eta-publications.lbl.gov/sites/default/files/hybrid_paper_final_22feb2021.pdf

power voltage control, and fault ride-through capabilities to ensure that the resulting planning solutions will result in operating reliability? (ANOPR P 50.)

DOE comment: Yes, such requirements are needed, although this question pertains more to reliability planning than transmission planning. As new technologies penetrate the generation mix, particularly inverter-based resources, it will become necessary to plan for the production of grid-support services in non-traditional ways. Further, planners will need to ensure that enough ancillary services will be procured during all times of year and the amount of ancillary services needed to secure the grid should be planned on a more granular temporal scale than annual. The impacts of daily and seasonal weather patterns on both generation and demand will increase under a high electrification and high renewable energy future. At a minimum, planners should consider the amount of ancillary services needed to meet seasonal conditions on the grid. Provision of some types of system services may be ensured through technology standards and other means. Planning processes should fully consider the technical capabilities of all resources to ensure just and reasonable outcomes. [34,35]

9. Question*:* *Should the Commission adopt principles or set minimum requirements to ensure that planners consider a sufficiently wide range of scenarios?* (ANOPR P 52.)

DOE comment: To be prepared for a more uncertain future, planners need to consider a wide range of scenarios. Direction from the Commission is needed to ensure greater consistency in the approaches used by the regional planning entities. Otherwise, a "wide range of scenarios" may

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[34] Milligan, M. (2018) "Sources of grid reliability services." *Available at*: https://www.sciencedirect.com/science/article/pii/S104061901830215X

[35] Ela, E, Hytowitz, R.B., (2019) "Ancillary Services in the United States: Technical Requirements, Market Designs and Price Trends." *Available at*: https://www.epri.com/research/products/000000003002015670

mean appreciably different things to different planners. As suggested in DOE's response to Question 4, such minimum requirements could also be crafted to ensure that planners in adjacent regions are studying a set of similar scenarios and using the same or compatible assumptions. Doing so can reduce barriers to building beneficial interregional transmission lines. The number of scenarios to be considered should not be onerous for the planner, but the range of scenarios considered should be sufficiently broad to capture multiple realistic futures. The planner should have ample latitude to devise and analyze region-specific scenarios not included in the Commission's set.

Planners should adopt a principle of transparency in the communication of the adopted scenarios. Consumers should know what scenarios (particularly those concerning extreme events) are considered in transmission plans. This principle of transparency is important not only as a procedural justice mechanism, but also to set expectations about what catastrophic events the planned transmission system will and will not be prepared to withstand.

10. <u>Question:</u> *What requirements should the Commission set to ensure that planners obtain appropriate inputs from stakeholders, particularly state and local officials?* (ANOPR P 52.)

<u>DOE comment</u>: Active participation by state and local officials and community members is essential to the success of the transmission planning process, although no participant should be accorded the privilege of a veto on matters that have regional or inter-regional implications. State and local officials can provide critical input on consumer, land use, and public policy interests and objectives, among other things. By understanding how planners' models work, state and local officials and community members will be better positioned to provide meaningful inputs and to

have confidence in the results. The results must inform decisions by regulators and others about approval of new transmission facilities and allocation of their costs.

DOE congratulates the Commission and the states in the creation of the Joint Federal-State Task Force on Electric Transmission. DOE expects the Task Force will contribute useful suggestions about ways to facilitate participation by non-federal public officials in these processes and to make them more collaborative. We look forward to further attention to this topic.

DOE also congratulates the Commission on establishing the Office of Public Participation (OPP). DOE expects the coordination of assistance to the public through OPP will allow for increased public participation in Commission proceedings to ensure all interests are adequately represented. The Commission should ensure OPP is included in these processes.

11. Question: *Should the Commission establish a minimum set of potential benefits from transmission projects that planners should incorporate into their planning decisions, and would this list have to be updated regularly?* (ANOPR PP 53, 93, and 94.)

DOE comment: The Commission should establish a minimum set of potential benefits (and costs) to be considered, to ensure that they are taken into account in both project selection and in the allocation of costs for selected projects. This practice would help ensure that benefits not currently fully valued will be more appropriately incorporated in the planning process and foster consistency among planning regions. Such a list should be updated regularly to ensure previously unidentified, or unplanned, benefits could be incorporated into the planning process.

It is important to note that, to be able to build the transmission lines that our Nation needs in an efficient and cost-effective way, this minimum set of potential benefit (and cost) categories should go beyond what is in current practice. The minimum set should include categories of benefits that accrue more broadly such as reduced emissions, resilience to extreme weather events, and reduced costs of meeting federal and state public policies. Categories listed in Johannes Pfeifenberger's presentation to FERC Staff provide a good starting point for discussion.[36] Additional or more detailed categories may be needed to account for important policy considerations such as energy, climate, and environmental justice.

12. Question: *Should the Commission require regional planners to identify geographic zones that have the potential for large amounts of renewable generation, and plan transmission that would facilitate integration of the generation from those zones?* (ANOPR P 54.)

DOE comment: The resource-rich areas are now well known, and the end-use market areas to be served are also well known. Designation of zones would be a step in the right direction, but by itself would not accomplish what is most needed, which is agreement on which generation resources would actually be developed, to serve which market areas, and the transmission facilities needed to connect them reliably and efficiently. The Texas CREZ model is instructive in that it shows the importance of coordinated planning of generation and transmission, and of demonstrating that if specific transmission lines were developed, the identified generators would use them, and the lines would thus become used and useful. However, the CREZ model is fundamentally a single-state model, whereas the challenges we now face are regional or inter-regional in scope – *i.e.*, multi-state. The emphasis now should be on the development of regional

[36] Pfeifenberger, *supra* n. 12, at 11.

vehicles through which groups of states can devise the solutions needed to enable coordinated planning to go forward.

The planners will be ready to follow guidance provided by such regional bodies, but they will not be able to lead the resolution of these challenges on their own. Identification of resource-rich areas and the likely market areas they could serve would be relevant inputs to decisions that under present law will have to be made by groups of collaborating state officials.[37] Effective action by groups of states on these matters will be of the highest importance to our economy and national security. DOE and its National Laboratories look forward to providing technical assistance as needed to facilitate this vital work.

13. Question: *To make planning for such zones more effective, should the Commission institute reforms to the current interregional coordination process? Is full-scale inter-regional planning needed? Would such reforms be consistent with Section 206 of the FPA?* (ANOPR P 57.)

DOE comment: Yes, the Commission should consider reforms to the current interregional coordination process. Development of generation and transmission in a resource-rich area may have implications for more than one region or the area may span the seams between adjacent planning regions. In such cases, at a minimum, interregional coordination would be critical to efficient development of the area's potential. Full-scale interregional planning is appropriate when there is a need to align the goals of affected states, coordinate lead times for generation and

[37] The planning of Competitive Renewable Energy Zones by the Texas Public Utility Commission yielded production cost savings of $1.7B per year and $5B in incremental economic development. Appendix A presents an analysis of Texas' CREZ as an example of successful coordination of generation and transmission development. Appendix B, Item I, discusses other regional planning efforts to assess generation development zones, including the Western Renewable Energy Zone Initiative, California's Renewable Energy Transmission Initiative, and the energy zones Mapping Tool developed for the Eastern Interconnection States' Planning Council.

transmission projects, and address cost allocation. Here, as elsewhere, ample consultation with stakeholders will be essential.

Because reliability and resilience are public goods,[38] and because there are both network and emission externalities that result from transmission planning outcomes, interregional and perhaps even national planning is necessary for developing cost-effective transmission networks. Thus, reforming interregional coordination is consistent with ensuring efficiency and cost-effectiveness principles, and with the Commission's authority to ensure just and reasonable rates.

As described in our responses above, the status quo does not lead to sufficient and cost-effective interregional transmission. By implementing needed reforms, the Commission could ensure transmission rates that are just and reasonable and thus consistent with its authority under section 206 of the Federal Power Act.

14. Question: *Are there potential best practices, analyses, models, or metrics that could be used to identify such zones?* (ANOPR P 57.)

DOE comment: A zone should be large enough that a single developer or group of developers cannot control enough generation sites to limit market entry by competitors. Public officials must also evaluate whether development in all or part of an energy zone would conflict with other high-value uses of the specific land (such as a park area, critical wildlife habitat, sacred tribal lands, and national defense). Engagement of stakeholders, including planners, state

[38] *See* Larsen *et al.*, *supra* n. 31.

officials, local communities, and environmental justice groups, in the development of such zones will be crucial.

When identifying these areas, planners should consider barriers to land development, transmission provider competition, elimination of transmission bottlenecks, cost allocation, coordination of regulatory processes and technical planning analyses, sufficiency of system resources to balance variable generation, and broad stakeholder collaboration. DOE's National Laboratories have developed an array of tools for identifying high-value areas for renewable energy development. Many of the capabilities have been consolidated in NREL's reV model,[39] which provides highly granular analysis and indicators of high-value generation resources. For additional details on these tools and their application, see Appendix B, Item I.

15. Question: *How can transmission providers and planners assess the level of commercial interest in developing potential generation in such zones? How can the Commission ensure that transmission is built for expected needs and not to serve overly speculative commercial interests?* (ANOPR P 57.)

DOE comment: Commercial interest could be gauged by the number of generators and the amount of generation (MW) in a region's generation interconnection queue, although some caution would be warranted because at times some interconnection queues have become saturated with speculative projects. Executed interconnection agreements or progression of applicants' past facilities' studies should be scrutinized when considering the interconnection queues. Also, unmet

[39] Maclaurin, G., et al. (2019) "The Renewable Energy Potential (reV) Model: A Geospatial Platform for Technical Potential and Supply Curve Modeling." https://www.nrel.gov/docs/fy19osti/73067.pdf.

state renewable portfolio standard (RPS) or equivalent requirements may drive commercial interest.

Overbuilding of transmission due to generator speculation can be minimized by considering the level of financial commitment made by developers to new generation projects in the zone. Commitments such as signed interconnection agreements, leasing agreements with landowners, letters of credit from funders, and other objective evidence can help confirm that transmission capacity built to serve such generation would be "used and useful."

In addition, "headroom" for additional generation development should be allowed by constructing transmission capacity greater than that confirmed by generators' commitments. As the experience of the Public Utility Commission of Texas with its CREZ program demonstrated, the demand for clean energy continued to grow and additional generation came forward to meet the demand in Texas and was served by transmission facilities sized to serve the increased demand. See Appendix A for more details.

16. <u>Question:</u> *As the generation resource mix evolves, will it be appropriate for planners to consider the transmission requirements associated with energy storage facilities in a zone?* (ANOPR P 58.)

<u>DOE comment:</u> It is appropriate for planners to consider the potential of storage facilities to reduce transmission capacity requirements in a variety of locations, not just high resource potential zones. Transmission lines are typically sized to meet peak demand needs plus a reliability margin, with the result that most lines are used well below their maximum capacity except under unusual conditions. Today, flexible and scalable storage facilities can be sited near load centers (either as

distributed energy resources or as transmission assets) and charged during low demand hours and discharged during peak periods, thus facilitating the safe use of transmission lines at higher loadings, delaying the need for transmission expansion, and adding a buffering capability that enhances system resilience. See Appendix B, Item V for more details on the potential synergies between transmission and distributed energy resources, including storage technologies.

17. Question: *The Commission asks whether:*

> *(1) eligibility thresholds or criteria (e.g., voltage levels, amount of new generation located within a given geographic area or load zone, etc.) would be appropriate to determine whether a proposed regional transmission facility should be considered as part of the regional transmission planning and cost allocation process for transmission facilities built for anticipated future generation?* (ANOPR P 59.)

DOE comment: Voltage level thresholds can be applied as a simple method for guiding cost allocation within a region. In DOE's SWPA, for example, the eligibility of a transmission project to be considered as part of regional cost allocation is based on voltage level and the location of the generation with respect to the load being served. If a transmission upgrade associated with generation is 300 kilovolt (kV) or above, SWPA assumes that it provides benefits to the entire region and the costs should be allocated 100% to the region. If the transmission upgrade is above 100 kV and below 300 kV and the transmission upgrade is in the same zone as the load being served, SWPA assigns 33% of the costs to the region and 67% to the load zone; or if the transmission upgrade is not in the same zone as the load being served, 67% to the region and 33% to the transmission customer. This approach could be applied in other regions, with modifications if appropriate for the region.

Cost allocation methods based on the underlying physics of the transmission network, rather than a simple voltage threshold, may also be just and reasonable. DOE urges the Commission to continue to consider the appropriate use of linear shift factors (power transfer distribution factors, generation shift factors, line outage distribution factors, and outage transfer distribution factors) for cost allocation purposes. Please see response to Question 5 for a discussion regarding the allocation of costs among regions for inter-regional projects consistent with section 206 of the Federal Power Act and the principle of cost causation.

> *(2) whether the CREZ, MISO MVP, CAISO approaches, or other processes for identifying and planning for the needs of anticipated future generation are models for any potential requirements and, if so, which aspects of those initiatives the Commission should consider requiring transmission providers to implement, for example, the CREZ model of requiring future generation to financially commit in advance of construction?* (ANOPR P 59.)

<u>DOE comment:</u> The CREZ and Midcontinent Independent System Operator (MISO) multi-value projects (MVP) processes have common features that appear essential to their success: 1) requirements that generators show major financial commitments as a precondition for the approval and initiation of transmission construction; and 2) the premise that designing, approving, and building an integrated set of generation and transmission facilities in a zone produces synergistic benefits such that the value added by the whole is greater than would be added if the projects were pursued piecemeal. Additionally, the MISO MVP process of engaging the States throughout the planning process in cost allocation, planning principles, and modeling assumptions and results should be required by the Commission. Credibility of the planning process could be further ensured by review by an independent team of transmission planners, helping to assure stakeholders that planning results align with agreed upon principles and assumptions.

> *(3) whether there is a need for mechanisms to limit the risk to customers from planning for anticipated future generation, such as CAISO's use of an ex ante cap on the total cost exposure to transmission customers in addressing generation resource interconnection, as one potential approach?* (ANOPR P 59.)

DOE comment: As noted above in response to Question 2, it is prudent to adopt such mechanisms, and we welcome discussion of the merits of various options. Environmental justice concerns and disproportionate impacts on low-income customers should also be considered.

18. Question: *The Commission asks whether regional transmission planning processes could be structured in such a way that is more collaborative, relying on the knowledge and experience that transmission providers, project developers, state commissions, and other stakeholders have regarding optimal locations, the topography of the transmission network, and Public Policy Requirements, among other factors that will influence the location and amount of future renewable resources.* (ANOPR P 60.)

DOE comment: Making transmission planning processes more collaborative will pay important dividends by making the results more transparent and legitimate in the eyes of affected stakeholders, which will in turn help to facilitate cost allocation and transmission siting decisions. FERC recognized in Order No. 1000 that "in the absence of coordination between transmission planning regions, public utility transmission providers may be unable to identify more efficient or cost-effective solutions to the individual needs identified in their respective local and regional transmission planning processes, potentially including interregional transmission facilities."[40] The current rulemaking process presents an opportunity to establish a formal, streamlined process that promotes interregional transmission planning. The Department hopes that the recently established

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[40] Order No. 1000 at P 81.

Joint Federal-State Task Force on Electric Transmission will provide useful suggestions on what measures are needed to foster such collaboration with and among the states. The Department further encourages FERC to engage the broader community, including affected localities, in transmission planning activities as a means to address environmental and energy justice concerns, and is itself ready to provide technical assistance where appropriate.

19. Question: *Should the Commission offer incentives (such as an ROE adder) applicable only to regional transmission facilities? Should such incentives be limited to regional facilities shown to be more cost effective than local alternatives?* (ANOPR P 61.)

DOE comment: Given how few regional transmission facilities have been added in recent years and the growing need for them, it may be appropriate for the Commission to consider incentives for new regional transmission facilities that would produce significant customer benefits. However, it is not readily apparent that a lack of sufficient return is a major factor inhibiting the construction of regional facilities. In any case, a transparent means of identifying eligible facilities would be needed. If ROE incentives are provided, they should be conditional on showing superior cost-effectiveness of the proposed facilities as compared to alternatives.

20. Question: *At present, an inter-regional project must first be selected in each of the neighboring regions' planning processes in order to be eligible for selection in the inter-regional process. Does this impede the selection of cost-effective inter-regional projects? Are joint planning processes required, rather than simply joint coordination between neighboring regions?* (ANOPR PP 62 and 63.)

DOE comment: The current practice impedes the selection of cost-effective inter-regional projects because the initial regional prioritization of projects based on benefits to one region's ratepayers may exclude potential solutions that may offer superior aggregate benefits to the ratepayers across more than that one region. Further, adjacent regions often use different analytic models and/or assumptions, leading to non-convergence on the merits of interregional projects. As discussed below in response to Questions 22 and 23, the Commission should institute a process for the development of a common analytic framework to be used by transmission planners. That, along with the use of common assumptions and scenarios, would greatly facilitate better interregional coordination and the selection of meritorious projects. If adjacent regional planners come to different conclusions about the merits of a proposed interregional line, despite the use of a common model and common assumptions, further analysis should be done to explain such differences and resolve them if possible.

21. Question: *How might regional states' committees or other organized bodies of state officials participate in the development of assumptions or criteria pertinent to the development of inter-regional transmission capacity?* (ANOPR P 64.)

DOE comment: Regional states' committees could provide input to regional and inter-regional transmission planning processes. Here, as in our responses to some of the preceding questions, we look forward to the work of the Joint Federal-State Task Force on Electric Transmission.

22. Question: *Should the Commission require transmission providers to operate their regional transmission planning and cost allocation and generator interconnection processes on concurrent, coordinated time frames and with the same or similar assumptions and methods? Would this lead to more cost-effective transmission solutions?* (ANOPR P 65.)

DOE comment: Yes, alignment across different ISOs/RTOs in model building, coordinated transmission studies, and interconnection study process timelines will result in a more cost-effective optimized transmission buildout. As discussed in response to Question 4, the use of a common planning model, with common concepts, definitions, and methods could facilitate more productive regional and interregional dialogue about transmission needs and more cost-effective solutions.

There are important disadvantages to the current processes. First, the planning processes that exist currently are not designed to optimize over-all costs and benefits. Second, the planning and interconnection processes used by the ISOs/RTOs and vertically integrated utilities are not synchronized within an ISO/RTO footprint. The misalignment of the generator interconnection study timelines between regions creates uncertainties about network upgrades and introduces delays that may negate efforts to make planning and interconnection processes more holistic and efficient. Optimizing transmission investment while ensuring access to low cost and high benefit generation requires integrated transmission planning across regions and investment in backbone transmission systems.[41]

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[41] Americans for a Clean Energy Grid. (2021) "Disconnected: The Need for a New Generator Interconnection Policy." https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf.

23. Question: *How could the regional transmission planning, cost allocation, and generator interconnection processes be better coordinated? Could they be integrated into a single process?* (ANOPR P 66.)

DOE comment: The Department suggests that FERC develop specific guidelines for cost allocation of large interregional lines that meet a predetermined set of criteria (*e.g.*, minimum voltage level, and operating in multiple balancing authorities). Neighboring regions could be given a timeline by which to submit a tariff agreement on cost allocation for lines that cross their seam. This would allow for flexible cost allocation agreements between neighboring planning authorities to account for regional differences.

More generally, as noted in response to Question 4, the Commission should develop a common analytic framework to maintain consistency and comparability in regional transmission planning and cost allocation processes. Greater commonality with respect to analytic tools, methods, and assumptions will aid inter-regional coordination and collaboration. Leadership and guidance from the Commission will be essential to achieving such commonality. This could be done without limiting the latitude of the regional planners to apply region-specific concepts or methods in a supplementary manner.

B. Estimation of the Benefits of Transmission Expansion Projects and the Likely Distribution of the Benefits

24. Question: *The current regional transmission planning process considers transmission needs driven by reliability, economics, and Public Policy Requirements. The Commission seeks comment whether, by separating transmission facilities into types, transmission planning processes may fail to consider the full range of benefits of multi-faceted projects for the purposes of cost allocation.* (ANOPR P 70.)

DOE comment: Any given proposed transmission facility can provide a range of short- and long-term benefits. Benefits can include improving system reliability, decreasing the cost of power, enhancing resilience, and achieving public policy -- and other utility and customer preference -- objectives (such as renewable portfolio standards, clean energy standards, and decarbonization goals). Separating transmission facilities into "types" hinders a comprehensive assessment of system impacts and the ability to measure benefits relative to cost, potentially resulting in suboptimal investments and outcomes. The full value stack provided by each transmission facility should be compared against other counterfactuals to optimize transmission networks and equitably allocate benefits and costs. See Appendix B, Item III, for a discussion of obstacles that limit the ability of transmission planners to fully recognize the value of transmission investments, and Appendix B, Item V, for a discussion of the need to consider the value of distributed energy resources to the bulk power system in transmission planning.

There is a strong body of literature that analyzes the multiple benefits transmission facilities can provide to the electricity system.[42,43,44,45,46,47] Research at DOE's National Laboratories also supports the conclusion that transmission can provide significant economic and resource adequacy benefits relative to costs.[48,49] Current grid operators also have experience quantifying the multiple benefits of transmission projects, including public policy objectives.[50,51,52,53] The subject of the

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[42] Joskow, *supra* n. 11.

[43] Pfeifenberger, *supra* n. 12.

[44] Van Horn K., Pfeifenberger, J., & Pablo Ruiz, P. (2020) "The Value of Diversifying Uncertain Renewable Generation Through the Transmission System." http://www.bu.edu/ise/files/2020/09/value-of-diversifying-uncertain-renewable-generation-through-the-transmission-system-093020-final.pdf.

[45] Pfeifenberger, J., Chang, J. & Sheilendranath, A. (2015) "Toward More Effective Transmission Planning: Assessing the Costs and Risks of an Insufficiently Flexible Electric Grid." https://brattlefiles.blob.core.windows.net/files/5950_toward_more_effective_transmission_planning_addressing_the_costs_and_risks_of_an_insufficiently_flexible_electricity_grid.pdf.

[46] Pfeifenberger, & Chang, J. (2016) "Well-Planned Electric Transmission Saves Customers Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future." https://brattlefiles.blob.core.windows.net/system/publications/pdfs/000/005/295/original/well-planned_electric_transmission_saves_customer_costs_-_improved_transmission_planning_is_key_to_the_transition_to_a_carbon_constrained_future.pdf?1465246946.

[47] Chang, J., Pfeifenberger, J., & Hagerty, J.M. (2013) "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments." https://cleanenergygrid.org/uploads/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf.

[48] Brinkman, G., *et al*. (2021) "The North American Renewable Integration Study: A U.S. Perspective." https://www.nrel.gov/docs/fy21osti/79224.pdf.

[49] Bloom, A., *et al*. (2020) "The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnection Seam Study." https://www.nrel.gov/docs/fy21osti/76850.pdf.

[50] New York Independent System Operator. (2019) "AC Transmission Public Policy Transmission Plan." https://www.nyiso.com/documents/20142/5990681/AC-Transmission-Public-Policy-Transmission-Plan-2019-04-08.pdf.

[51] California Independent System Operator. (2017) "Transmission Economic Assessment Methodology (TEAM)." http://www.caiso.com/documents/transmissioneconomicassessmentmethodology-nov2_2017.pdf.

[52] Southwest Power Pool. (2016) "Regional Cost Allocation Review (RCAR II)." https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.

[53] Midcontinent Independent System Operator. (2012) "Multi Value Project Portfolio Results and Analyses." https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf.

underestimation or omission of potential benefits is also addressed above in response to Question 11.

25. Question: *The Commission seeks comment on best practices for identifying the beneficiaries of a transmission facility.* (ANOPR PP 71 and 72.)

DOE comment: Transmission investments can produce benefits for a wide variety of stakeholders. In Order No. 1000, the Commission expressed the cost allocation principle that "[t]he costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions."[54] The current rulemaking process is an opportunity to establish a common methodology to be applied, thus giving greater definition and guidance to transmission planners and other stakeholders. Some benefits accrue to the immediate investors and market participants attached to a specific transmission investment (*e.g.*, reduced congestion on a specific node), while other portfolio-level benefits accrue to all system participants (*e.g.*, reduced costs and improved reliability and resilience). Any methodology used for assigning benefits should be comprehensive and take a system-level approach. Any methodology used for assigning benefits should incorporate a socio-demographic dimension to disaggregate the impacts and capture the specific benefits (economic, resilience, environmental and public health) to historically underserved communities. Such methodologies should also identify the communities directly harmed by the installation of transmission lines in their territories, utilizing a cumulative impact analysis. Finally, the methodology should include transparent communication with communities concerning the

[54] Order No. 1000 at P 622.

positive and negative impacts of transmission expansion projects. For best practices, please see literature cited in the response to Question 24.

C. Allocation of the Costs of Network Upgrades in Proportion to Benefits Received

26. Question: *In principle, FERC believes that the costs of transmission expansion should be allocated to its beneficiaries, and in proportion to the benefits they receive. Do current practices appropriately allocate these costs, particularly with respect to interconnection-related network upgrades?* (ANOPR P 38.)

DOE comment: Interconnection of a new generator may require one or more upgrades to the transmission network that would benefit parties other than the initial generator-applicant. That is, such upgrades, once built, may facilitate access to the network by subsequent generators. They may also benefit downstream load-serving entities (LSEs) and the end-use customers they serve. So, it may be unfairly burdensome to require the initial applicant to shoulder the full of the costs of such upgrades where broader benefits are likely to be created. This is even more the case if they are not reimbursed later for such expenditures. Being required to do so may also induce some applicants to withdraw their interconnection requests, and lead to delays in the development of generation and transmission capacity needed to serve the public interest.

The frequency with which interconnection requests require upgrades that could benefit other parties and related questions are under study now by analysts at DOE's LBNL. Past work, at a minimum, demonstrates that network upgrades represent a sizable fraction of total interconnection costs.[55]

Another relevant question is how large the cost of a typical upgrade that would benefit multiple parties usually is in relation to the overall front-end investment required of the generation developer/interconnection applicant. Recent work by ICF shows that some interconnection-related network upgrades provide substantial system-wide benefits -- suggesting that the current participant funding approach may not fairly allocate the cost of such investments to the full set of beneficiaries.[56] See Appendix B, Item IV, for a discussion of options available to manage and allocate interconnection costs, including cost sharing among benefitting projects.

27. <u>Question:</u> *Under a portfolio approach to regional transmission cost allocation, multiple transmission facilities are considered together, and the collective benefits of the transmission facilities are measured. The Commission seeks comment on whether a portfolio approach recognizes that a regional transmission planning process that considers a group of transmission facilities that collectively provide multiple benefits, including reliability, economic, and Public Policy Requirements benefits, among others, may be able to better identify more efficient or cost-effective transmission facilities when compared to a process that focuses only on individual transmission facilities or individual benefits. Further, would a portfolio approach be more accurate, or less likely to lead to anomalous results?* (ANOPR P 91.)

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[55] Gorman, W., Mills, A., & Wiser, R. (2019) "Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy." Available at: https://emp.lbl.gov/publications/improving-estimates-transmission.

[56] ICF Resources, LLC (2021) "Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits." https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf.

DOE comment: Most individual proposed transmission expansion projects would confer benefits of several kinds, spread somewhat unevenly across the electricity users in a wide area. Although some of these benefits (and their likely distribution) can be estimated quantitatively, other types of benefits are either difficult to quantify or such quantitative estimates are subject to major uncertainties. These uncertainties about how individual projects will affect stakeholders can be eased by addressing future transmission needs on a larger geographic scale; this enables planners to think holistically and develop plans for a portfolio of synergistic facilities that will meet the area's needs efficiently and provide some mix of benefits for all users. A given user may not see significant net benefits from every project in the portfolio, but they would receive significant net benefits if the portfolio were to be adopted as a whole. Thus, a portfolio approach is more likely to fully and accurately account for benefits, by allowing planners to solve multiple problems at once through one coherent design. By comparison, a series of less coordinated projects may leave important needs unmet and require costly retrofits at some later date.

28. Question: *The Commission asks whether the use of planning criteria beyond reliability and economic considerations may place the burden for the costs driven by Public Policy Requirements of one state on customers of load serving entities in non-participating states.* (ANOPR P 92.)

DOE comment: Today's policy challenges are often regional in scale, such as coping with the impacts of climate change (including wildfire threat and rising sea levels) or regional air pollution, and they frequently require interregional-scale solutions. Many considerations are relevant here, including:

(1) Just because one state in a region has a policy does not necessarily mean that citizens in other states without the policy will not see benefits. As a result, it would not necessarily meet

beneficiary-pays principles to allocate costs of transmission used to meet a certain state's policy to only the ratepayers in that state;

(2) Requiring consensus among states in a region may yield significant underbuilding (as it does today) of regional/interregional projects, particularly if there are substantial unquantified benefits that accrue outside of the immediate state; and

(3) The need for a strong, robust, and efficient transmission system is national, and such a system would provide benefits to all citizens.

DOE and the National Laboratories look forward to providing technical assistance to groups of states that wish to consider their energy policy goals and transmission planning from regional and interregional perspectives.

29. Question: *The Commission asks whether there is a tradeoff between facilitating the construction of transmission facilities that are needed to connect anticipated future generation, and ensuring against the risk of building more transmission than is necessary. If so, how should the Commission manage that tradeoff?* (ANOPR P 99.)

DOE comment: The obstacles to building new high-voltage transmission lines are substantial, although the barriers may be less severe for upgrades of smaller existing lines. Consequently, it is not likely that a given region will become overinvested in high-voltage transmission capacity. On the contrary, being chronically underinvested in such facilities is a more likely condition. Several recent studies show that at present the need for more regional-scale transmission investment has become widespread.[57,58,59] The same may not be the case for local projects and replacement of existing lines. The Commission could reasonably change its approach to these facilities, subjecting them to additional scrutiny before determining that investment is prudent.

As discussed above in responses to Questions 15 and 17, there are ways to ensure that new transmission facilities will be "used and useful" before becoming fully committed to their construction. If the cost-benefit analysis framework properly accounts for future generation and uncertainty, the risk of overbuilding would be mitigated to a large extent if the projects are selected on the basis of expected net benefits.

30. Question: *The Commission asks:*

(1) Whether costs allocated to interconnection customers pursuant to participant funding approaches have increased over time, and if so, why. (ANOPR P 114.)

DOE comment: The data currently available do not permit conclusive answers to these questions. Analysts at DOE's LBNL have a study under way that we hope will offer useful insights.

(2) Whether this increase in costs is evidence that regional transmission planning processes are not building adequate transmission system capacity. (ANOPR P 114.)

DOE comment: There are indications that current transmission planning processes are impeding the development of needed transmission capacity. The present transmission planning and

[57] Wood Mackenzie. (2020) "US Renewable Energy and Infrastructure Policy Scenario Analysis." *Available at*: https://www.woodmac.com/our-expertise/focus/Power--Renewables/us-renewable-energy-policy-scenario-analysis/?utm_campaign=pandr&utm_medium=article&utm_source=gtm

[58] Brown and Botterud, *supra* n. 18.

[59] Pfeifenberger, *supra* n. 12.

interconnection processes were largely developed when there were fewer interconnection requests per year. NREL analysis of interconnection queues in ISO-NE, PJM, and NYISO found that in the early 2000s, there were about 150 interconnection requests total. At present, there are about 1,000 new requests per year.[60] The increasing number of requests has also led to an increase in the time that projects spend in the interconnection queue.

A LBNL analysis of four ISOs found that the time projects spent in queues before being built increased from approximately 1.9 years for projects built between 2000-2009 to approximately 3.5 years for those built between 2010-2020.[61] Moreover, interconnection costs of proposed and constructed projects are different. Interconnection costs of proposed wind projects in PJM and MISO are higher than the interconnection costs of previously constructed wind projects.[62]

(3) *Whether the Commission's policies on participant funding have impacted the interconnection queue, e.g., through late-stage withdrawals, and if so, how and to what degree. In the case that there are late-stage withdrawals from the interconnection queue, it seeks comment on the ability of transmission providers to efficiently process interconnection requests from other interconnection customers affected by the withdrawal.* (ANOPR P 114.)

<u>DOE comment:</u> The motives for decisions to withdraw from the queues are not apparent from the available data. In any event, late-stage withdrawals can be disruptive to the efforts of transmission

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[60] *See* Appendix B, Item II.

[61] Rand, J., et al. (2021) "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2020." Available: https://emp.lbl.gov/publications/queued-characteristics-power-plants

[62] Gorman, Mills & Wise, *supra* n. 55.

planners to administer an efficient process, and to decisions by transmission providers and other generators impacted by those withdrawals.

> *(4) Finally, whether uncertainty regarding interconnection costs drives up the cost of developing supply resources and thereby ultimately increases the cost of electricity supply for customers.* (ANOPR P 114.)

DOE comment: Uncertainty inherently slows the pace of making business decisions, fosters delay, and increases the risks of making poorly informed decisions, all of which will increase electricity supply costs.

31. Question: *The Commission seeks comment on whether it is appropriate to eliminate or reduce participant funding for interconnection-related network upgrades in RTOs/ISOs and whether any specific proposed changes to interconnection funding mechanisms allocate costs in a manner roughly commensurate with benefits and are otherwise consistent with the Commission's authority under the FPA and do not unjustly or unreasonably shift costs to customers of load serving entities.* (ANOPR P 119.)

DOE comment: It may not be appropriate to require a generator seeking interconnection to provide all of the upfront funding for a transmission network upgrade that once built, would provide benefits for others (*e.g.*, low-cost transmission access for additional generators or lower power-supply costs for load-serving entities). Such a requirement could be unfairly burdensome to the initial interconnection applicant (whether or not reimbursement is provided at some later date) and could be an economic disincentive to the development of needed transmission capacity. However, a relevant question is how large the cost of a typical network upgrade that would benefit multiple parties usually is in relation to the overall front-end investment required of the generation developer/interconnection applicant. If the cost of a typical upgrade is not large in this sense, this issue may not be as important as it first appears.

32. Question: *The Commission seeks comment on whether eliminating participant funding may reduce the queue backlogs that plague many regions because interconnection customers would have less incentive to submit multiple interconnection requests in an attempt to lower their interconnection costs, and may drop out of interconnection queues at late stages due to unforeseen interconnection-related network upgrade cost increases. To these points, the Commission seeks comment on the number of interconnection requests that have withdrawn from the queue because the direct assignment of significant interconnection-related network upgrade costs made otherwise viable interconnection requests uneconomic.* (ANOPR P 126.)

DOE comment: DOE understands that interconnection applicants may file multiple requests to gauge whether interconnecting at one site would be lower in cost than at another, and that the prospect of paying substantial costs for network upgrades may be a significant driver behind late-stage withdrawals from the queue.

One option that should be considered is to require the planners to publish information about their respective networks indicating areas where interconnection could be achieved without creating the need for substantial network upgrades, injection capacity availability at a certain substation or line on their system, detailed heat maps showing available capacity, planning models availability, and other information that would allow project developers to make better informed decisions in siting generation and reduce the incentive to file multiple interconnection requests.

This approach would be similar in concept to distribution utilities publishing DER hosting capacity maps of their networks.

33. Question: *The existing alternative to participant funding is the "transmission service crediting" method, under which interconnection customers provide upfront funding for interconnection-related network upgrades and receive reimbursement through transmission service credits or a balloon payment after 20 years. Today, this approach may also impose an unjust and unreasonable burden on the interconnection customer, given that an upgrade may benefit a variety of other parties.*

The Commission seeks comment on whether to eliminate both participant funding and transmission service crediting, and instead require each transmission provider to provide upfront funding for all the interconnection-related network upgrades on its transmission system. Then, once such an interconnection-related network upgrade is in service, the transmission provider would be able to include the cost of that interconnection-related network upgrade in its transmission service rate base and recover a return on, and of, the network upgrade capital costs through the cost-of-service transmission rates in its OATT. Thus, interconnection customers that take transmission service on a transmission system would still pay for a portion of interconnection-related network upgrades through transmission rates. The Commission seeks comment on this approach and how it could be implemented in a just and reasonable manner.

The Commission also presents for comment several variant approaches for shifting portions of the upfront costs of network upgrades to the transmission providers. (ANOPR PP 120 and 132.)

DOE comment: Shifting an appropriate portion of the front-end costs of interconnection-related network upgrades to the transmission provider may be more equitable than requiring the interconnection applicant to pay all of those costs, whether through participant funding or the transmission service crediting approach. The cost share paid by the applicant should be in proportion to the likely share of the benefits that it would receive. DOE looks forward to discussion by stakeholders of the variant approaches suggested by the Commission.

D. Other Subjects

34. Question: *The Commission asks whether transmission providers, in the conduct of their interconnection studies, should be required to consider the possible use of "grid-enhancing technologies" as a way of reducing the costs of network upgrades.* (ANOPR P 158.)

DOE comment: Consideration of grid-enhancing technologies should be required in regional transmission planning studies and in interconnection studies. This will facilitate the more efficient use of existing transmission assets and reduce or delay the need for transmission expansion.[63]

35. Question: *The Commission believes that stakeholder participation in regional transmission planning processes is important to the legitimacy of the results, and transparency is essential to stakeholder participation. The Commission asks whether additional measures are needed to ensure such transparency, particularly in non-RTO/ISO regions.* (ANOPR P 162.)

[63] Tsuchida, T., Ross, S., & Bigelow, A. (2021) "Unlocking the Queue with Grid-Enhancing Technologies." https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

DOE comment: Here, as elsewhere, DOE expects that the Joint Federal-State Task Force on Electric Transmission will have valuable insights and suggestions to offer. Stakeholder engagement should include local community participation to address environmental, climate, and energy justice concerns. However, no single individual or participating entity should be accorded the privilege of a veto on matters that have regional or inter-regional implications.

36. Question: *Given the rising importance of regional transmission planning, interconnection, and cost allocation, the Commission asks whether it should require the establishment of independent regional transmission monitors. The Commission also presents for discussion several variants of how the monitor's functions could be defined and limited.* (ANOPR PP 163-175.)

DOE comment: DOE supports the Commission's exploration of the concept of independent regional transmission monitors. Transmission planning, interconnection, and cost allocation all involve issues of great importance to the public, often with conflicting interests among participants. As a result, there is an ongoing need for independent and informed oversight of these activities. A case in point is the conduct of interconnection studies by the transmission provider, who may not be seen by the interconnection applicant as a disinterested party. Interconnection applicants should have the option of calling for review of such studies by an independent entity, such as a regional transmission monitor. The Department welcomes discussion of how the monitor's functions should be defined.

IV. COMMENTS SPECIFIC TO THE FEDERAL POWER MARKETING ADMINISTRATIONS

A. Introduction

In this section, DOE identifies certain statutory limitations and other considerations applicable to the four PMAs that operate within the DOE and which may require accommodation within the structure established in a possible final rule promulgated by FERC as part of the process initiated by the ANOPR. The four PMAs are Bonneville, SEPA, SWPA, and WAPA. Originally administered by the Department of Interior (DOI), the Department of Energy Organization Act[64] transferred the DOI's power marketing duties to DOE.

The PMAs market power produced by Federal dams.[65] The Army Corps of Engineers (Corps), DOI's Bureau of Reclamation (Reclamation) and the International Boundary and Water Commission constructed and now operate and maintain the Federal dams. The PMAs sell the resultant hydropower, giving preference to statutorily defined customers "at the lowest possible rates to consumers consistent with sound business principles…."[66] FERC does not have jurisdiction over the PMAs under section 205 or section 206 of the Federal Power Act (FPA).[67]

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[64] *See* Pub. L. No. 95-91, 91 Stat. 565 (1977).

[65] *See The Power Marketing Administrations: Background and Current Issues* at 1.

[66] 16 U.S.C. § 825s; *see also id.* § 832c; 43 U.S.C. § 485h(c).

[67] *See* 16 U.S.C. § 824(f). *See also* 42 U.S.C. § 16431(b) ("The appropriate Federal regulatory authority may enter into a contract, agreement, or other arrangement transferring control and use of all or part of the transmission system of a Federal utility to a Transmission Organization.")

However, under applicable statutes and a DOE delegation order, FERC oversees the PMAs rates to ensure the rates recover Federal power costs.[68]

Congress created Bonneville under the Bonneville Project Act of 1937.[69] Bonneville operates and maintains over 15,000 circuit-miles of transmission lines in its service territory, which includes Idaho, Oregon, Washington, western Montana and small parts of California, Nevada, Utah, Wyoming, and eastern Montana.[70] Bonneville markets wholesale electricity from 31 Federally owned hydropower facilities, one non-Federal nuclear plant, and several small non-Federal powerplants in the Northwest. These resources provide about 28% of the electric power used in the Northwest. Bonneville differs from the other three PMAs in that it is self-financed: it receives no annual Federal appropriations. Bonneville covers its operating costs through power and transmission rates to customers or customer classes that are set to ensure repayment to the U.S. Department of the Treasury (Treasury) of capital and interest on funds used to construct the Columbia River power system.[71] Bonneville also has permanent Treasury borrowing authority, which it may use for capital on larger projects.[72] This money is repaid with interest from its wholesale power sales and transmission services.[73] Bonneville is registered for multiple functions

[68] *See id.;* 42 U.S.C. § 16431(d); *see also DOE Delegation Order No. 00-037.00B,* https://www.directives.doe.gov/delegations-documents/037.000bhttps://www.directives.doe.gov/delegations-documents/037.000b/@@images/file.

[69] 16 U.S.C. § 832.

[70] *See The Power Marketing Administrations: Background and Current Issues* at 2.

[71] *See id.* and 16 U.S.C. § 839e(i).

[72] *See id.*

[73] *See id.*

under the North American Electricity Reliability Corporation (NERC) registry, including as a Balancing Authority, Transmission Owner, and Transmission Operator.[74]

Congress created SWPA under Section 5 of the Flood Control Act of 1944 (P.L. 78-534).[75] SWPA markets hydroelectric power in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas from 24 Corps dams with a combined capacity of over 2,000 megawatts (MW).[76] SWPA manages nearly 1,400 miles of high-voltage transmission lines.[77] SWPA serves over 100 preference customer utilities, who, in turn, provide power to over eight million end-use customers.[78] SWPA is the only Balancing Authority in the U.S. supported solely by hydroelectric generation, and its use of the reservoirs and river systems within the SWPA marketing area must be balanced with flood control and other required uses so the power needs of its customers can be met.[79] SWPA is registered for multiple functions under the NERC registry, including as a Balancing Authority, Resource Planner, Transmission Operator, Transmission Owner, and Transmission Planner.[80]

Congress created WAPA under the Department of Energy Organization Act.[81] WAPA is the largest PMA in terms of service area.[82] WAPA's service area covers 1.3 million square miles

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[74] *See* NERC Compliance Registry *available at:* https://www.nerc.com/pa/comp/Pages/Registration.aspx.

[75] *See The Power Marketing Administrations: Background and Current Issues* at 2.

[76] *See id* at 5 and 16 U.S.C. § 839e(i).

[77] *See The Power Marketing Administrations: Background and Current Issues* at 5.

[78] *See id.*

[79] *See id.*

[80] *See* NERC Compliance Registry *available at:* https://www.nerc.com/pa/comp/Pages/Registration.aspx.

[81] *See The Power Marketing Administrations: Background and Current Issues* at 6

[82] *See id*.

and serves customers in 15 central and western states.[83] Its system includes over 17,000 miles of high-voltage transmission that WAPA uses to market and transmit hydropower from 57 federal dams.[84] Together, these powerplants have an installed capacity of more than 10,000 MW. In addition to the types of public entities traditionally served as preference customers by the other PMAs, WAPA has developed a policy to give preference to Native American tribes regardless of their utility status. WAPA serves approximately 700 customers, who, in turn, provide power to more than 40 million consumers.[85] WAPA is registered for multiple functions under the NERC registry, including as a Balancing Authority, Transmission Owner, Transmission Operator, Transmission Planner, Resource Planner, and Planning Authority/Planning Coordinator.[86]

The PMAs have interconnected significant quantities of renewable resources under their *pro forma* tariffs. For instance, Bonneville has approximately 6,000 MW of wind generation interconnected to its transmission system, with approximately 2,800 MW of wind generation in Bonneville's balancing authority area. With a peak balancing authority load of 10,500 MW and a minimum light load of 4,000 MW, the wind penetration in the Bonneville balancing authority is among the highest in the nation. Similarly, WAPA has added more than 500 MW of wind generation and more than 200 MW of solar generation.

Given the unique circumstances and constraints that the PMAs face, the PMAs' ability to participate in the regional transmission planning process that follows from the ANOPR will depend

[83] *See id.*

[84] *See Annual Report 2020 Western Area Power Administration* at 11 https://www.wapa.gov/newsroom/Publications/Documents/FY-2020-annual-report.pdf.

[85] *See id.* at 2.

[86] *See* NERC Compliance Registry https://www.nerc.com/pa/comp/Pages/Registration.aspx.

in part on that process being consistent with the PMAs' statutory requirements. Of particular importance to DOE is that in developing a proposed rule FERC should accommodate voluntary participation by the PMAs without exposing them to cost responsibilities for regional transmission facilities and interconnection-related network upgrades that are inconsistent with their statutory authority. Further, given the geographical breadth of the PMAs' service territories, each PMA also has unique elements and regional issues that affect its operations, and, thus, the reforms should be crafted to accommodate regional differences. As FERC considers changes to regional transmission planning, cost allocation, and generator interconnection policies and processes, it should take into consideration the diversity of all electricity providers, including investor-owned utilities, PMAs, municipalities, rural electric cooperatives, public utility districts, merchant generator owners, and merchant transmission developers.

B. FERC rulemaking should respect the requirement for the PMAs to comply with statutory responsibilities.

1. The PMAs must comply with their statutory responsibilities.

Although the PMAs are distinct entities subject to legal obligations specific to each, in general, the PMAs are bound by their obligations to safely provide reliable, cost-based hydropower and transmission to their customers and communities. Congress authorized construction of the Federal transmission system to reliably deliver Federal resources to statutorily authorized project uses and preference customers. Federal Reclamation law identifies specific costs and methodologies under which the PMAs provide Federal power and transmission service.[87] Any

[87] *See, e.g.,* 43 U.S.C. § 485h(c).

new FERC rule should provide room for the PMAs to participate in regional initiatives while at the same time maintaining their ability to meet their statutory duties. This flexibility has been used in the past, and can be used in the future, through an interactive contractual process whereby the PMAs work to find solutions with other regional stakeholders and market operators. For example, WAPA actively participated in the formation of the WestConnect planning region and joined as a Coordinating Transmission Owner.[88]

Of particular significance are reforms addressing cost responsibility for regional transmission facilities and interconnection-related network upgrades. Federal laws limit Federal agencies' ability to use Federal funds.[89] As an example, WAPA, SEPA and SWPA may only use appropriated funds for the purposes for which Congress appropriated it.[90] WAPA and SWPA submit their budgets to Congress based on their currently anticipated costs. After Congress approves their budgets, they serve project uses and customers with Federal resources within the amounts appropriated by Congress. WAPA and SWPA do not issue bonds or take out loans from private banks. Therefore, in order for WAPA and SWPA to cover any upfront costs of transmission network upgrades for future generation interconnections of third-party generators, they must first have authorization and appropriations from Congress. As a result, any final rule

[88] *See Pub. Serv. Co. of Colo., et al.*, 142 FERC ¶ 61,206 (2013), *order on reh'g and compliance*, 148 FERC ¶ 61,213 (2014), *order on reh'g and compliance*, 151 FERC ¶ 61,128 (2015), *reh'g denied*, 163 FERC ¶ 61,204 (2018). (While there are challenges to this original planning region filing, WAPA is part of ongoing settlement discussions and the agreement in principle whereby the parties intend to file a settlement agreement for Commission approval that will result in just and reasonable rates within the WestConnect planning region. *See* Unopposed Joint Motion to Continue Abeyance, filed by the parties in *El Paso Electric Company v. FERC*, 5th Cir. Case No. 18-60575 on November 15, 2019, Document: 00515201626.)

[89] 31 U.S.C. § 1301.

[90] *See id.*

issued by FERC should recognize WAPA's and SWPA's authority to only spend funds that are authorized and appropriated.

The PMAs also must be cognizant of their duties to ensure they are providing power to preference customers at the lowest cost possible consistent with sound business principles.[91] Federal Reclamation laws identify costs that the PMAs include in their rates.[92] As Federal agencies, the PMAs must approve these costs. States, local governments, and private entities cannot mandate what costs the PMAs include in their rates. Congress has delegated to Reclamation and the PMAs the requirement to determine the costs to include in their rates.[93] As such, there is no room for state or local regulation of the PMAs' rates. While the PMAs have and will continue to work with states, local governments, and regional planning groups, Federal law requires the PMAs to ultimately determine which projects provide a benefit to the Federal transmission system and which costs to include in their rates. On the other hand, FERC has been delegated by DOE a limited role in confirming and approving PMAs rates on a final basis.[94] However, this limited role does not allow FERC to require that specific costs be included in the PMA rates. Therefore, any final rule should permit PMA participation without the risk that the reforms could result in allocating inappropriate costs to the PMAs without their approval.

As another example, the National Environmental Policy Act (NEPA) may impose additional requirements before Federal agencies can fund or build a project. Federal agencies,

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[91] 16 U.S.C. § 825s.

[92] *See, e.g.,* 43 U.S.C. § 485h(c).

[93] *See, e.g.,* 43 U.S.C. § 485h(c).

[94] *See DOE Delegation Order No. 00-037.00B.*

such as DOE acting through the PMAs, must comply with NEPA requirements and may not commit to fund or build projects until after complying with the requirements of NEPA.

Congress may limit Federal agencies from undertaking certain activities. For instance, the Pacific Northwest Consumer Power Preference Act prohibits the Federal Government from constructing transmission lines between the Pacific Northwest and Southwest except for those facilities authorized in a June 24, 1964 report.[95]

Additional statutory requirements applicable to the PMAs could impact their ability to participate in any FERC reforms. The PMAs must be able to comply with *all* Federal laws, regulations, and policies. In developing any proposed rule, FERC should be cognizant of such restrictions and provide the PMAs with enough flexibility to ensure they can meet their statutory duties while following through with the PMAs' commitments to follow FERC policies.

2. FERC should respect the PMAs' commitment to follow FERC policy

Although the PMAs are generally not subject to FERC's jurisdiction under sections 205 and 206 of the FPA,[96] the PMAs have committed to aligning their open access transmission tariffs (Tariff) consistent with FERC's *pro forma* open access transmission tariff subject to certain limitations.[97] If FERC creates any new *pro forma* requirements for regional transmission planning

[95] 16 U.S.C. § 837g.

[96] *See* 16 U.S.C. § 824(f); 42 U.S.C. § 16431(d).

[97] For example, Bonneville has adopted provisions in its Tariff following the procedural requirements of Section 212(i)(2)(A) of the FPA, 16 U.S.C. § 824k(i)(2)(A), in establishing generally applicable terms and conditions for transmission service. In doing so, Bonneville "committed to aligning with the Commission's *pro forma* tariff to the extent possible." Administrator's Final Record of Decision, TC-20-A-03, at P-1 (Mar. 2019); *see also* Administrator's Final Record of Decision, TC-22-A-03, at 6 (July 2021) ("BPA's strategy and policy are to maintain a tariff consistent with the Commission's *pro forma* tariff and industry best practices to the extent possible and consistent with applicable law.").

and generator interconnection processes, the PMAs that offer wholesale transmission services will need to address those requirements in their Tariffs and adopt changes consistent with their statutory duties and other applicable legal requirements. Thus, it is important that any FERC reforms accommodate legal and regional differences and retain sufficient flexibility so the PMAs can make appropriate Tariff modifications consistent with their applicable statutes.

FERC seeks comment on a number of potential reforms that would relate to regional transmission planning.[98] As FERC considers adopting reforms to regional planning processes, FERC should allow flexibility in its final rule to accommodate the regional efforts already underway. With respect to regional planning, Order Nos. 890 and 1000 have offered latitude for utilities to gather into regions and develop processes suitable for the particular jurisdictional makeup of those regions.[99] Flexibility for regional variations has been particularly important for utilities that operate in a bi-lateral market in the West. This is evidenced by the recently formed NorthernGrid region.[100] Bonneville participates in regional planning through NorthernGrid, which includes member utilities located in the Northwest and some Rocky Mountain states. NorthernGrid achieves benefits of coordinated and transparent regional planning for members with a diverse jurisdictional makeup. It strikes a balance between addressing compliance needs of utilities subject to FERC's jurisdiction and the legal constraints related to non-jurisdictional

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[98] ANOPR PP 44–99.

[99] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009); *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[100] *See PacifiCorp*, 170 FERC ¶ 61,298 (2020). Attachment K to Bonneville's Tariff reflects Bonneville's participation in NorthernGrid.

utilities. Its structure works because the process respects the need for non-jurisdictional utilities to exercise their decision-making authority in a manner that is consistent with their legal obligations, including applicable statutes and decision making of governing bodies such as their boards, councils, or the Bonneville Administrator.

As previously discussed, certain of the PMAs may be unable to pay upfront costs for any future network upgrades for third-party developers. DOE supports improvements to the generator interconnection process and urges FERC to ensure that any reforms related to the funding of network upgrades help to advance needed generator interconnection requests while mitigating the risk of stranded costs to the transmission provider and network customers. Currently, consistent with FERC's *Open Access* policies, the PMAs require any generator interconnection customer to advance fund the costs of any necessary network upgrades. The PMAs then provide appropriate credits in future billings to the interconnection customer. While the PMAs may not be able to pay upfront costs in the normal course, there is flexibility under existing policies. For example, WAPA may be able to provide certain developers with alternative financing mechanisms. In certain circumstances, developers may seek funds for their project under the WAPA Transmission Infrastructure Program (TIP), authorized by section 402 of the American Recovery Reinvestment Act of 2009 (ARRA). WAPA has more than $3 billion in borrowing authority for the purpose of constructing, financing, facilitating, planning, operating, maintaining, or studying construction of new or upgraded electric power transmission lines and related facilities with at least one terminus within WAPA's service territory, to deliver or facilitate the delivery of power generated by renewable energy resources constructed, or reasonably expected to be constructed. TIP provides WAPA with the ability to provide funds to assist in financing and constructing transmission infrastructure that touches WAPA's service territory; it does not provide independent authority for

WAPA to allocate costs of such projects to WAPA's rate payers. A future generation interconnection customer that is constructing renewable generation may apply for funds under TIP to support third-party transmission network upgrades. WAPA has been and continues to be ready to work with FERC, states, local governments, and developers to ensure they have the ability to interconnect to WAPA's transmission system.

3. *FERC should craft reforms that allow for the PMAs' participation in a manner that respects the characteristics of the Federal transmission system.*

DOE supports the principle that those that benefit from a system upgrade should pay for their share of the cost of those upgrades allocated on the basis of the benefit received. As a result of limitations on how certain PMAs operate, system upgrades may not be necessary to provide Federal hydropower, which is generally already constructed, to load. Moreover, while one of the principal factors affecting the need for future system upgrades is the requirement to address load growth, the PMAs serve statutorily defined customers and so generally have very little load growth. Of course, external factors such as neighboring load growth and weather events such as drought do affect PMA transmission systems and can influence both the benefits and harms borne by the PMAs and their customers. The transmission reforms contemplated by FERC should take care to address both the costs and benefits of transmission development on transmission operators like the PMAs and on their customers.

The PMAs acknowledge that certain regional projects may have benefits to Federal transmission systems and Federal project use and preference customers. In such cases, for WAPA and SWPA, it is up to Congress to ultimately determine if they can participate and fund such projects. For instance, Congress has authorized WAPA to participate in many transmission projects that provide regional benefits, *e.g.*, the Pacific Northwest Southwest Intertie, the California Oregon Transmission Project, and the Path 15 Upgrade. In addition to receiving Congressional approval, specific laws also may place limitations on the ability of the Federal Government to participate in certain transmission construction.[101] As a result, any FERC rulemaking should recognize that Federal agencies must operate within the funding and authority constraints established by Congress.

C. FERC should consider regional differences

FERC should recognize the diversity and regional differences that make up the systems in the West. FERC should not adopt a one-size–fits-all rule, where the regional differences make application of the rules impractical or uneconomical. As discussed above, there are many regional differences among the PMAs. The PMAs serve a variety of different geographic areas, and within those areas, they have adopted their practices with other utilities that accommodate the regional differences. Bonneville's service territory spans the northwestern United States. WAPA's service territory spans from California to North Dakota. SWPA's service territory spans from Texas to Missouri. Spanning the Western and Eastern Interconnections, the PMAs must operate their systems in a variety of environmental and geographic conditions. The PMAs operate Balancing Authority areas and sub-balancing authority areas within their service territories. They deal with wide ranging and diverse weather patterns. Constructing, operating, maintaining, and planning transmission lines in the mountains of Montana is much different than in the farmlands of South Dakota, which, in turn, is different than in the deserts of Arizona and the agricultural and

[101] *See* 16 U.S.C. § 837(g) (prohibiting the government from constructing transmission lines between the Pacific Northwest and Southwest – except for those facilities authorized in the June 24, 1964 report).

mountainous Central Valley in California. Within this large geographic area, the PMAs participate in various energy markets and coordinate with many different utilities including investor-owned utilities, regional transmission organizations, independent system operators, municipal utilities, rural electric cooperatives, public power, merchant generator owners, and merchant transmission developers. Utilities in the West have developed their systems to take into account these broad differences. From the water in the Northwest, to the sunshine in the deserts, to the wind from the mountains, utilities have developed systems to maximize the available resources and to serve customers in the most efficient and reliable manner.

D. Summary of Comments Relating to the PMAs

As discussed above, it is important that any final rule issued by FERC provide the PMAs with sufficient flexibility to ensure they can voluntarily participate in future reforms and continue to meet all of their responsibilities under Federal law. The PMAs will need to comply with their legal obligations, follow their Tariff processes, and work with customers and stakeholders to adopt and implement reforms. Further, the final rule should permit the PMAs to work within their regions to continue to build on solutions that evolved following Order Nos. 890 and 1000. To the extent any part of the rules is applied by third parties, such as regional entities, independent system operators, planning monitors, or the like, any final rule should allow for appropriate provisions to ensure that such third-party entities cannot improperly impose new obligations upon the PMAs relying on FERC rules.

V. CONCLUSION

DOE appreciates the opportunity to submit comments and looks forward to continuing collaboration on the important issues raised in the ANOPR.

Respectfully submitted,

/s/ Kathleen Hogan

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Appendix A

The Texas Competitive Renewable Energy Zone Model

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This technical memorandum explains the salient features of the Texas CREZ model.

The Texas CREZ model includes:

1. A clearly defined regulatory pathway to transmission cost recovery that expands the criteria for demonstrating whether proposed transmission facilities are likely to be used and useful, consistent with applicable law and appropriate to the characteristics of renewable energy development.[102]

2. A market-wide assessment of near- and long-term clean energy demand across many load-serving entities (LSEs) simultaneously, with the objective of identifying a combination of new transmission facilities and low-cost renewable energy zones that can reasonably be expected to meet the combined demonstrated demand and future demand in the most beneficial way.

3. Renewable energy zones that are large enough to promote competition among developers.

The CREZ model arose from characteristics unique to the Texas market. Nevertheless, there are lessons and insights from the CREZ experience that can inform questions raised in the ANOPR. After a background discussion on the origins, features, and outcomes of the CREZ model, we will discuss how the model applies generally to some of the questions FERC posed in the ANOPR.

[102] For example, a large central station power plant and its long-distance transmission lines both take years to build. Reviewing and approving both in tandem make answering the "used and useful" question straightforward. This expedient approach seldom fits the characteristics of wind and solar power, however, because generating plants are smaller and can be brought on line faster than a large central station plant. Moreover, if a wind or solar project's ability to secure financing is conditioned on transmission availability, such conditionality would complicate the inclusion of that project as proof that a new transmission line would be used and useful.

Background

The CREZ model does not create commercial demand for renewable energy.[103] Rather, it directs demand that is already extant to places where investment will be most productive due to natural characteristics: consistently high wind speeds, consistent sunshine, and few obstacles to development. The CREZ model also relies on competition among developers. A CREZ should be large enough so that no single developer or group of developers acting in collusion can control enough sites to limit transmission access by competitors. These two factors—good natural resources and competition—ensure that LSEs and their customers will be able to get wind and solar power at the lowest reasonable cost.

The successful application of the CREZ model begins with an assessment of LSEs' demand for utility-scale wind and solar power—demand that is likely to occur with or without a CREZ transmission plan but might be pent up or met at an unnecessarily high cost due to insufficient transmission. Even so, extant commercial demand for clean energy will not cause new transmission to be built unless its existence and magnitude are proved to the satisfaction of applicable law. This was the key problem that the CREZ model addressed and resolved in the Electric Reliability Council of Texas (ERCOT) transmission region. The Texas utility code requires the Public Utilities Commission of Texas (Texas Commission) to ensure that rates are just and reasonable,[104] and it permits a transmission utility to earn a reasonable return on the utility's invested capital that is used and useful in providing service to the public.[105] Prior to 2005, however, there was no regulatory standard for proving "used and useful" if the generators that would connect to a proposed transmission line were not yet known. Filings in a 2002 Texas Commission informational project, where the CREZ concept was first proposed, indicated a strong likelihood of additional demand for renewable energy resources based on state mandates, the performance of voluntary green power retail programs, and other market trends.[106] But because the indicators of

[103] The CREZ model has sometimes been mischaracterized as an "if you build it, they will come" approach. An accurate description would be "they're coming, put them in the best place."

[104] Tex. Util Code §36.003.

[105] *Id.* §36.051.

[106] *Proceeding to Address Transmission Constraints Affecting West Texas Wind Power Generators*, Project No. 25819.

future demand were not traceable to specific LSEs, specific developers, and specific wind project sites, case law could not establish that a proposed line would be used and useful.

The CREZ concept lay dormant at the Texas Commission for three years until changes in the law created an alternative path for satisfying the used and useful standard. In 2005, the Texas Legislature directed the Texas Commission to designate CREZs and to develop a transmission plan for them.[107] CREZ designation had to take into account the level of financial commitment by generators, and the transmission plan approved by the Texas Commission had to work "in a manner that was most beneficial and cost effective to customers." Other provisions of the utility code were amended so that facilities that were in a CREZ transmission plan approved by the Texas Commission were deemed "used and useful to the utility in providing service … and are prudent and includable in rate base, regardless of the extent of the utility's actual use of the facilities."[108] The Texas Commission could set aside normal statutory requirements to consider "the adequacy of existing service" and "the need for additional service."[109] These would be determined by the Texas Commission in the CREZ proceeding consistent with the directives of the CREZ law.

The Texas Commission's rule enacting the CREZ legislation was adopted Dec. 1, 2006.[110] The rule states that in determining whether to designate an area as a CREZ, the Texas Commission shall consider the level of financial commitment by generators.[111]

> A renewable energy developer's existing renewable energy resources, and pending or signed [interconnection agreements] for planned renewable energy resources, leasing agreements with landowners in a proposed CREZ, and letters of credit representing dollars per MW of proposed renewable generation resources, posted with ERCOT, that the developer intends to install and the area of interest are examples of financial commitment by developers to a CREZ. The commission may

[107] Tex. Util Code §39.904(g) required the Texas Commission to "(1) designate CREZs in which renewable energy resources and suitable land areas were sufficient to develop generating capacity from renewable energy technologies; (2) Develop a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that was most beneficial and cost effective to customers, the output from renewable generators in CREZs; and (3) consider the level of financial commitment by generators for each CREZ."

[108] *Id.* §36.053.

[109] *Id.* §37.056(c)(1) and (2), set aside by §39.904(h) with respect to an application for a certificate of convenience and necessity for a transmission project intended to serve a CREZ designated by the Texas Commission.

[110] Tex. Admin. Code 25.174.

[111] *Id.* 25.174 (b)(4).

> also consider projects for which a TSP, ERCOT, or another independent system operator is conducting an interconnection study; and any other factors for which parties have provided evidence as indications of financial commitment.[112]

The rule required ERCOT to provide a study of wind energy potential statewide. It also invited the Texas Department of Parks and Wildlife to provide an analysis of wildlife habitat that might be affected by renewable energy development in a candidate CREZ, along with recommended mitigation measures.

The docket to select CREZs and an associated transmission plan began in January 2007, after ERCOT had submitted its study estimating wind potential across Texas and providing an initial assessment of transmission issues.[113] The ERCOT study was a prominent reference document in the CREZ docket. On a parallel track, as options for CREZs and transmission plans became more apparent, the Texas Commission opened another docket for a settlement conference addressing who should build elements of the transmission plan. The Texas Commission issued its order designating CREZs and deciding a CREZ transmission plan on Oct. 6, 2008 (Figure A-1), and it assigned transmission utilities' responsibilities on May 15, 2009. The last CREZ transmission element was completed and placed in service in December 2013.

In 2009 the commission amended the CREZ rule to allow re-testing of CREZ financial commitments after the designation of CREZs and before transmission utilities began construction.[114] Commitments in CREZs where most of the state's wind development had taken place (McCamey, Central, and Central West in Figure A-1) were deemed sufficient in the amended rule itself. The two CREZs in the Texas Panhandle were subject to special provisions applied in a single special proceeding.[115] The Panhandle is outside ERCOT's historical transmission footprint, but developers in these zones indicated a stronger interest in access to the ERCOT market than to

[112] *Id.* 25.174(c)(1).

[113] *Commission Staff's Petition for Designation of Competitive Renewable-Energy Zones*, Docket No. 33672.

[114] *Project to Establish Policy Relating to Excess Development in Competitive Renewable Energy Zones*, Project No. 34577, Order (October 8, 2009).

[115] *Commission Staff's Petition for Determination of Financial Commitment for the Panhandle A and Panhandle B Competitive Renewable Energy Zones*, Docket No. 37567.

Southwest Power Pool markets.[116] Before approving certificates of convenience and necessity for the Panhandle CREZ lines, the Texas Commission evaluated existing wind capacity, wind capacity under construction, and planned wind projects with signed interconnection agreements. Developers of projects not in any of these three categories had the option of posting collateral with the transmission utility. The amended rule required that the capacity represented by these four types of demonstrations amount to at least 50% of the CREZs' estimated generating capability.

On July 30, 2010, the Texas Commission accepted a settlement agreement that financial commitments for the Panhandle CREZs were sufficient.[117] As of September 2021, wind capacity installed in the Panhandle had exceeded the thresholds by 11%.[118]

[116] The Panhandle lines in the CREZ transmission plan do not connect electrically with the Southwest Public Service (SPS) network even though they cross many of the same Texas counties. SPS serves Amarillo, most of the Texas Panhandle, and parts of northeastern New Mexico. SPS is a member of the Southwest Power Pool and is in the Eastern Interconnection.

[117] *Commission Staff's Petition for Determination of Financial Commitment for the Panhandle A and Panhandle B Competitive Renewable Energy Zones*, Order, Docket No. 37567 (July 30, 2010).

[118] Energy Information Administration, Form EIA-860M database.

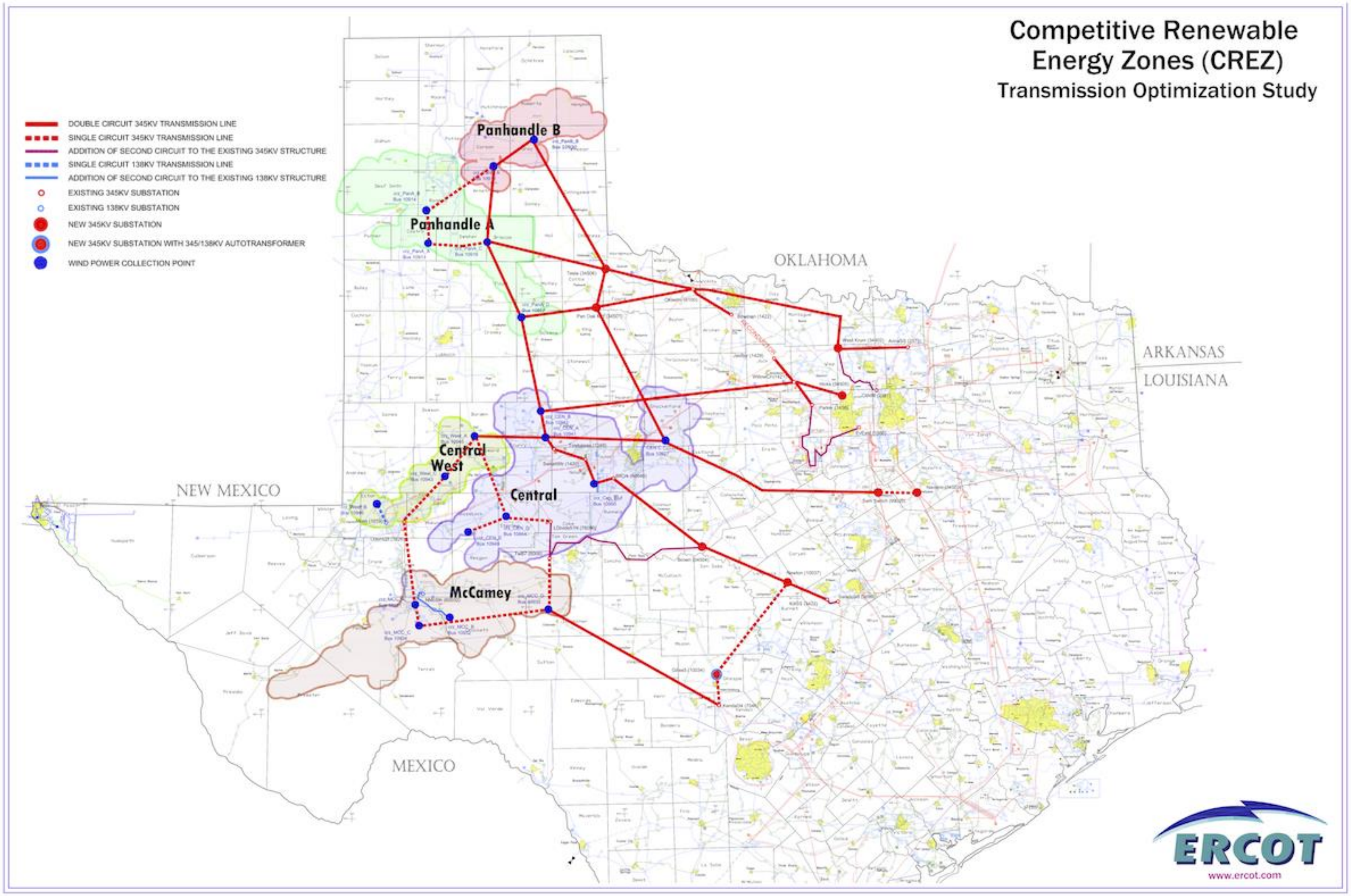


Figure A-1. CREZs and transmission development plan approved by the Texas Commission

CREZ outcomes

State law requires use of the postage stamp method to collect ERCOT transmission costs from load.[119] All end-use customers in ERCOT bear the cost of CREZ transmission facilities, as they do for other transmission. A CREZ transmission facility's cost was added to the provider's transmission cost of service (TCOS) once it was completed, and in turn, nonbypassable transmission charges paid by all retail customers in the ERCOT region were adjusted.[120]

Transmission charges to residential customers in the Oncor, CenterPoint, and AEP distribution territories (which include Dallas, Fort Worth, Houston, and Corpus Christi) increased from an average of $0.007/kWh at the beginning of the CREZ buildout to $0.013/kWh at the end of the buildout as CREZ transmission costs were added to utility rates (Figure A-2).[121] These figures include CREZ buildout costs as well as new TCOS unrelated to the CREZ buildout.[122] Meanwhile real-time wholesale energy prices in ERCOT, which averaged $0.046/kWh from 2007 to 2013, averaged $0.033/kWh from 2014 to 2020.[123] The drop was due to lower natural gas prices and to the growth in wind power as developers expanded in the CREZs. All

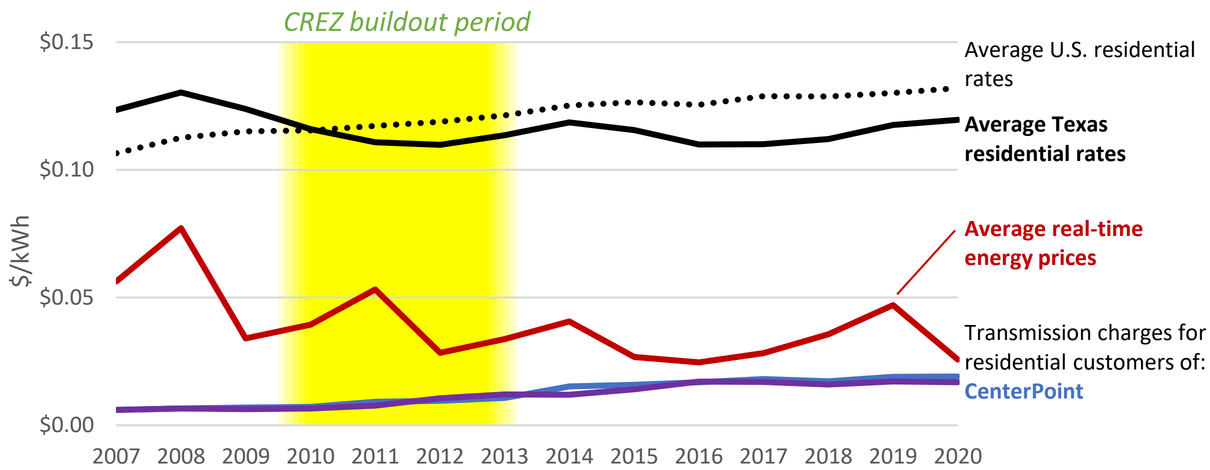
[119] A transmission provider's rate is its approved transmission cost of service divided by the average of ERCOT coincident peak for the months of June, July, August, and September (excluding load attributable to energy storage). Tex. Util Code §35.004(d); Tex. Admin. Code §25.192.

[120] In most of ERCOT, distribution and retail service are unbundled. Distribution is regulated as a monopoly in five service territories. Customers may choose from among dozens of retail electric providers, but every customer's bill contains a commission-approved non-bypassable charge for transmission and distribution costs.

[121] Oncor and CenterPoint serve 35% and 26% of ERCOT load. AEP's Texas Central and Texas North distribution utilities together serve 9%. ERCOT, 2020 Four Coincident Peak Load Calculation.

[122] Non-CREZ TCOS is also recovered from all load via the postage stamp method. A precise estimation of CREZ-related TCOS would require a detailed examination of all transmission service providers' filings from 2009 through 2013, and to NREL's knowledge such a study has not been done. It is reasonable to conclude, however, that CREZ-related TCOS did not exceed $0.006 per kWh for customers in the Oncor, CenterPoint, and AEP distribution service areas, which make up 70% of ERCOT load.

[123] Based on annual averages of real-time settlement prices during the period of nodal market operation after December 2010, and on annual average balancing energy prices for the years prior to nodal market operation. Potomac Economics, *State of the Market Report* (ERCOT), years 2008 through 2020.



Source: ERCOT, Fuel Mix Reports, 2007-2020

Sources: (residential rates) Energy Information Administration, EIA Form 861 database; (ERCOT wholesale energy prices) Potomac Economics, State of the Market Reports, 2007-2020; (transmission charges) Texas Commission, "Transmission and Distribution Rates for Investor Owned Utilities," http://puc.texas.gov/industry/electric/rates/TDR.aspx.

Figure A-2. Transmission component of residential rates during and after CREZ buildout

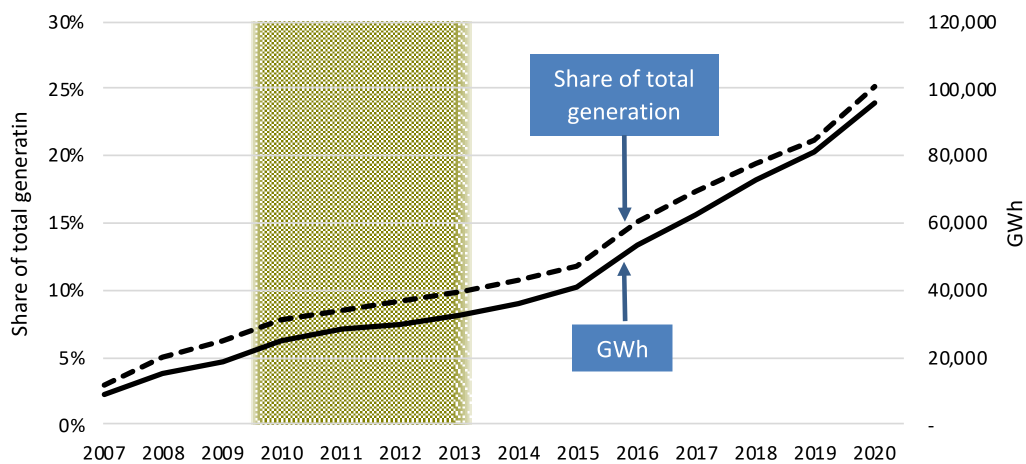


Figure A-3. Growth in wind, solar generation in ERCOT during and after CREZ buildout

told, the average residential customer in Texas paid less for electricity than the US average after 2010, and after the CREZ buildout the difference grew larger.[124]

To NREL's knowledge, a detailed analysis measuring the degree to which CREZ wind producers affected wholesale prices in ERCOT has not been done. Declining natural gas prices from 2014, one year after completion of CREZ transmission build-out, reduced the marginal cost of combined cycle plants and other generators fueled by natural gas, which *ceteris paribus* would reduce wholesale prices if natural gas generators are typically on the economic margin. However, adding wind capacity (which has near-zero marginal cost) would expand the ERCOT supply curve in a way that would also reduce wholesale prices, holding all other considerations unchanged. Thermal units with high heat rates that would otherwise be on the economic margin would be squeezed out, causing a lower-cost unit to be on the margin setting prices. Although each phenomenon's precise contribution to lower wholesale prices is uncertain without further analysis, one observation can be made: the effect of CREZ wind development was limited to Texas while the effect of natural gas prices was nationwide, and retail rates in Texas fell as rates increased in the rest of the United States as a whole.

CREZ development had collateral effects that became evident after the transmission buildout had been completed. One was utility-scale solar growth. Very few solar developers provided demonstrations of financial commitment during the CREZ proceeding. Nevertheless, there was a general recognition that daily production profiles for solar would be complementary to those of wind, so that the selected CREZs could accommodate solar resources once the economics of solar power improved. When solar costs fell, much of the first wave of development went to the CREZs in West Texas (Figure A-4).

Shortly after the CREZ buildout in 2014, wind development accelerated in South Texas. Although ERCOT's initial study of statewide wind potential had identified this area as a candidate zone, the Texas Commission declined to include it as a CREZ due to insufficient indications of developer interest. This area has seen the retirement of about 2 GW of natural gas capacity since 2006[125],

[124] Energy Information Administration, Form EIA-861M database.

[125] Energy Information Administration, Form EIA-860M database.

making more transfer capability available on the existing transmission network without a CREZ-like buildout.

ERCOT's growth in renewable energy has been entirely market-driven since the completion of the last CREZ transmission element. The state mandate was for 5 GW of new renewable energy capacity, achieved in 2008 (seven years early).[126] Texas also had a statutory planning target of 10 GW, reached in 2010 (15 years early). As of August 2021 Texas had 36 GW of wind capacity and 9 GW of utility-scale solar capacity, which for the 12 months ending August 2021 provided 27% of ERCOT's total generation. [127]

Identifying Geographic Zones That Have Potential for High Amounts of Renewable Resource Development

Texas' experience with the CREZ model suggests that identifying renewable energy zones works best once there is a clear regulatory path for addressing need and cost recovery *en masse*, as opposed to project-by-project. In Texas, the key was resolving the "used and useful" requirement. While each wind developer had the burden of demonstrating its own financial commitment to a candidate CREZ, it was the aggregate of all demonstrations that revealed which candidate CREZs had the greatest tangible commercial interest. This in turn built greater confidence in the practicality of a multi-element transmission plan connecting all the final CREZs to load. A financial demonstration by one transmission utility proposing one transmission project would not have had the same weight.

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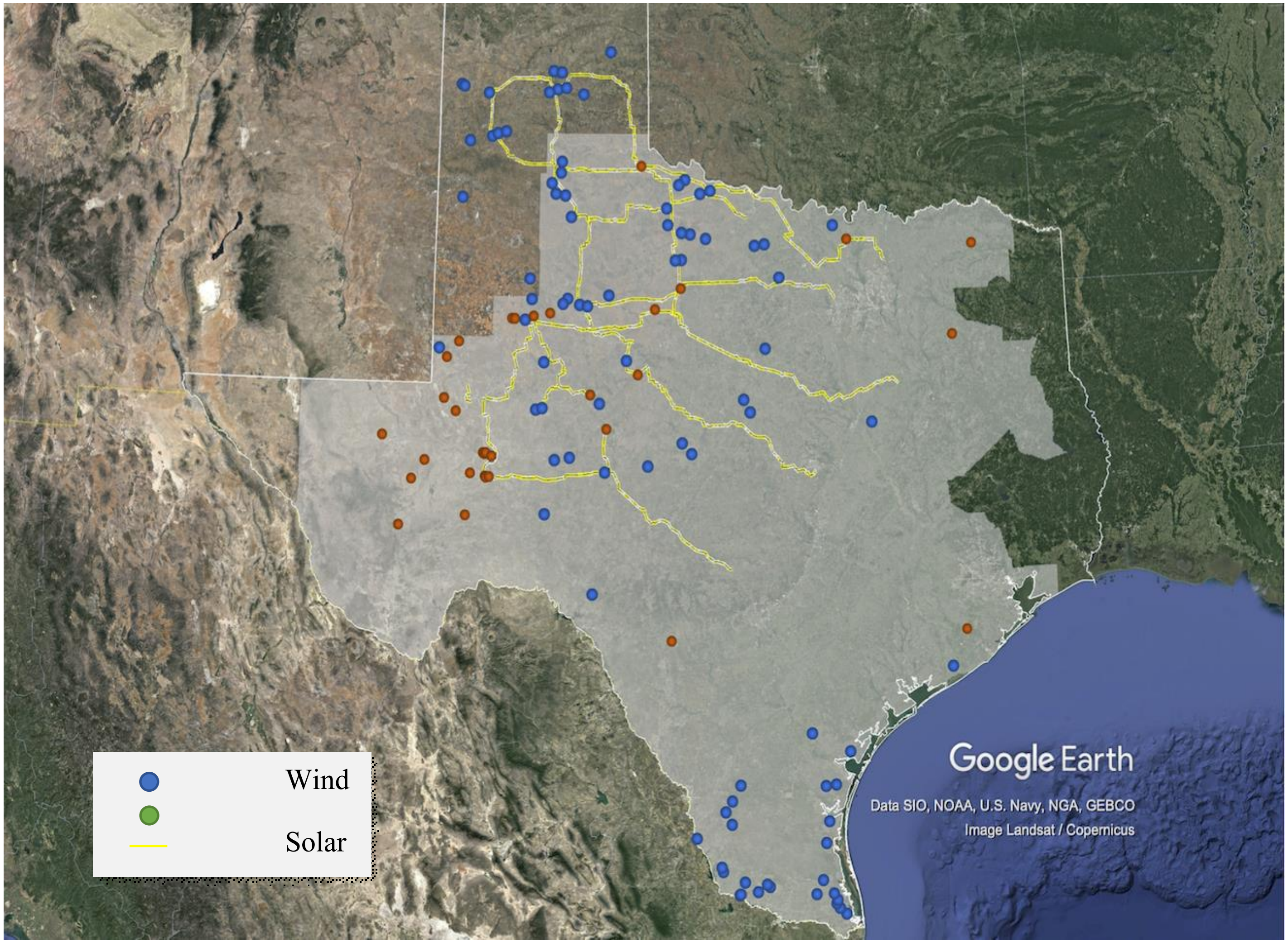
[126] Tex. Util Code §39.904(a).

[127] ERCOT, *Annual Report on the Texas Renewable Energy Credit Trading Program*, various years, available at https://sa.ercot.com/rec/public-reports; and Interval Generation by Fuel reports through August 2021.



Eastern CREZ lines terminate at substations connecting to the rest of the ERCOT grid.

Figure A-4. New renewable energy development after CREZ buildout (placed in service after 2013)

The CREZ model anticipates that future development will consist of (a) firm projects to meet demand by LSEs that are ready to secure PPAs today, plus (b) projects that would be responsive to long-term market drivers but are too far into the future for counterparties to manage the commercial risk bilaterally today. When the Texas Commission was evaluating options for transmission plans for the final CREZs, it rejected a minimal option that would have satisfied only the demand firmly established at the time of the proceeding, noting that "[t]ransmission plans with lesser transfer capacity than [the selected plan] would leave little room for expansion, thereby not providing transmission resources ahead of renewable generation as directed by the legislation."[128] At the same time, the Texas Commission rejected two larger buildout options because of cost and the lack of sufficient evidence that the capacity could be integrated reliably if fully developed. Also, the criterion for its re-test of the Panhandle CREZs was commitments for half of the zones' estimated capacity, leaving a margin for future development that was beyond commitments that could be demonstrated at the time of the Texas Commission's determination.

The risks of future generation projects development are different when considering a large transmission plan. With a large plan, the consequences of one or a few proposed projects failing are smaller. One project built on speculation takes on project-specific risks, one of which is being replaced in the market by a competitor. When considering future demand on a larger scale, the market is indifferent as to whether one developer replaces another. Macro trends and policies are measurable and entail different species of risk: supply chain disruptions, impacts related to climate change, technological shifts such as electric vehicles.

Potential insights from the CREZ model for this ANOPR

This experience suggests a number of related points for FERC to consider with regard to the Texas CREZ model.

1. <u>A forum for aggregating demand</u>. To maximize net benefits and economies of scale, FERC will need visibility into a single interregional planning event for LSEs and transmission providers covering a broad geographical market. Abstracting from the CREZ model, the

[128] *Commission Staff's Petition for Designation of Competitive Renewable-Energy Zones*, Docket No. 33672, Order on Rehearing at 46.

important parts of the process would be (a) a quantitative assessment of aggregate demand across the target market that would pass muster under the Federal Power Act, and (b) linking that aggregated demand with renewable energy zones that would deliver electricity at the lowest reasonable cost. FERC could enhance confidence and participation by providing guidance for the constitution and conduct of an interregional forum. It could also enumerate examples of financial indicators that it would consider in any subsequent transmission filing. A conference could be convened under the good offices of DOE or another reputable agent with no financial interest in the outcome.

2. The role of stakeholders. Stakeholder participation in the Texas CREZ process was robust due to confidence that it had regulatory weight and would therefore result in new transmission for new renewables. The CREZ docket had many intervenors and many types of interests, but two especially important groups were transmission providers and wind developers. Transmission providers were central because they were the ones who filed applications with the regulator for construction and cost recovery once the process was complete. Wind developers were crucial because they provided the financial demonstrations that what was technically possible was also commercially feasible. Developers—specifically, their prospects for securing power purchase agreements with LSEs and their willingness to shoulder financial risk—were a proxy for load's demand for renewable energy resources. Placing the burden on them, however, was to some extent an artifact of how the ERCOT market operated.[129] In other markets where vertically integrated utilities provide most of the retail service, demonstrations of commitment by the utilities would provide the same insight into the depth of demand. Regardless of how it is measured, evidence of commercial demand is crucial to the success of the CREZ model. Approaches to measuring commercial demand should be appropriate to the target market and need not be done the same way it was in ERCOT.

[129] Today more than 120 retail electric providers are registered with the Texas Commission. These LSEs may compete for retail customers in Dallas, Fort Worth, Houston, and other parts of ERCOT that are open to retail competition. Texas Commission, Numeric Directory of Retail Electric Providers.

3. The balance between firm and future demand. A CREZ-like transmission plan that is built to meet firm demand and nothing more risks being undersized and oversubscribed by the time the new transmission facilities are complete. At the same time, under the Federal Power Act, rates to recover the cost of transmission must be just and reasonable with respect to current demand as well as future demand. In the Texas CREZ proceeding, the Texas Commission used reliability and cost criteria for determining how much future demand to accommodate in the transmission plan. The issue for FERC in replicating this aspect of the CREZ model is to identify criteria it may use in estimating a reasonable level of future demand.

4. The role of technical analysis. In the Texas CREZ model, the threshold issue was resolution of cost recovery for transmission improvements, which in Texas turned on the "used and useful" question. Resolving this issue was crucial to the model's success, but it is often overlooked in other analyses that have attempted to replicate the CREZ process. The tremendous improvements in wind and solar resource assessments since the 2006 ERCOT study do not obviate the need to clarify the regulatory path to transmission approval *before* simulating power system operations or renewable energy potential. DOE's National Laboratories have the technical capability to analyze transmission development options for linking renewable energy zones with the strongest demonstrations of national interest. In the end, however, success will depend on solving the legal questions, not the technical analysis.

These four areas might involve new applications of the Federal Power Act that are not contemplated in case law to date. NREL has no comment on the applicability or interpretation of any provision of the Federal Power Act. The aim here has been to provide additional clarity around the transmission planning questions that need to be answered in the context of the law, based on experience with the Texas CREZ model.

Conclusion

The success of the Texas CREZ model provides lessons that can guide FERC in addressing key issues raised in the ANOPR. NREL's aim in providing these comments is to provide FERC and all parties with an accurate description of the Texas CREZ model and to offer insights into what elements contributed to its success.

Appendix B

National Laboratories' Supplemental Information to Comments of Department of Energy to Advance Notice of Proposed Rulemaking (ANOPR)

Item I. Identification of High Value Sites for Renewable Resource Development

The National Laboratories have developed an array of tools for identifying and analyzing high-value zones for renewable energy development. Many of the capabilities used in the work described below have been consolidated in NREL's Renewable Energy Potential model (reV)[130], which provides high spatial granularity analysis and indicators to identify high value resources. The model takes into account tradeoffs such as resource quality, distance and cost to build transmission to interconnect into the bulk system, and potential land use (social and environmental) and other potential siting conflicts. reV estimates technical potential, technology cost, spur-line cost, plant performance, and detailed land characterizations that can be used to develop supply curves to inform siting and investment analysis. Such data is used in NREL's capacity expansion modeling, which can help inform future transmission needs – capabilities that exist and can be leveraged today.[131] Specifically for this task, reV does not have much visibility into where specific network upgrades are needed and the associated cost of those upgrades beyond connecting to the bulk system. By merging reV and existing nodal power flow modeling tools, either production cost modeling or power flow modeling, NREL could help identify needed network upgrades that would open up more high value locations to renewable investment. Partnering with LBNL would be beneficial to understand real world network constraints that have either constrained investment or were upgraded by developers wishing to interconnect to the bulk system.

The Western Renewable Energy Zone Initiative illustrates the process by which the various tools are applied.[132] In 2009 NREL led an assessment of renewable energy development areas in the Western Interconnection for the Western Governors' Association. The initiative was guided by a steering committee comprising state regulators and other energy officials appointed by the governors. The analysis started with state-of-the-art data on wind, solar, and biomass potential from NREL, supplemented with available data for geothermal and small hydro potential. Working groups agreed on criteria for minimum resource quality and for excluding some areas from development (protected areas, urbanized areas, lakes, and terrain that was too rugged to develop economically). A geospatial analysis combined the raw resource layers with the exclusion layers to identify tracts with high renewable energy potential that were also accessible and developable (illustrated in Figure B-1). The working group then developed clustering criteria for identifying high concentrations of developable potential. The resulting "hubs" represented theoretical points

[130] NREL, Geospatial Data Science, *reV: The Renewable Energy Potential Model*, available at https://www.nrel.gov/gis/renewable-energy-potential.html.

[131] Maclaurin, G., et al. (2021) *The Renewable Energy Potential (reV) Model: A Geospatial Platform for Technical Potential and Supply Curve Modeling.* NREL/TP-6A20-73067.

[132] Pletka, R., & Finn, J. (2009) *Western Renewable Energy Zones, Phase 1: QRA Identification Technical Report*, NREL/SR-6A2-46877.

for siting a 500kV substation such that it would have access to the maximum technical resource potential within a 100-mile radius, shown in the map in Figure B-1. The steering committee of state energy officials reviewed the final product.

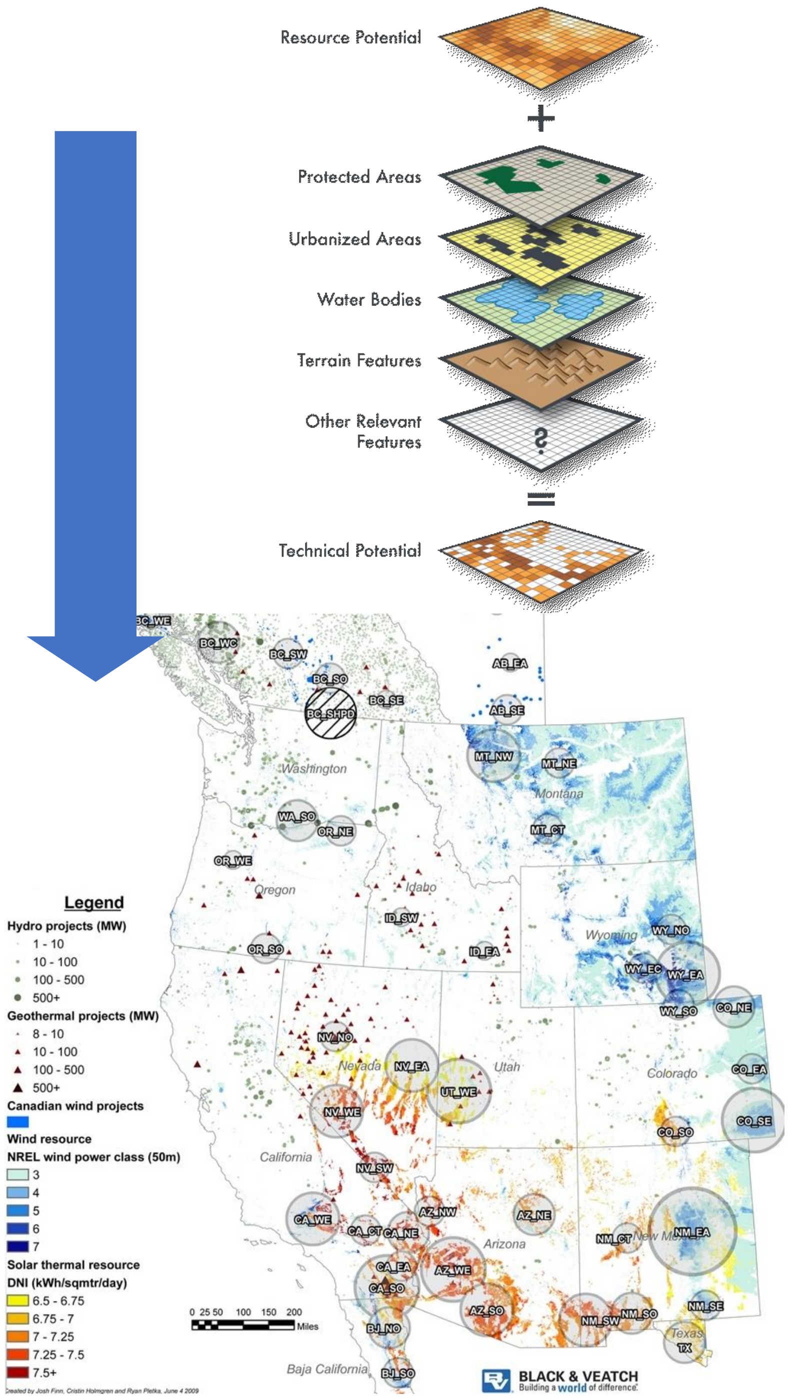
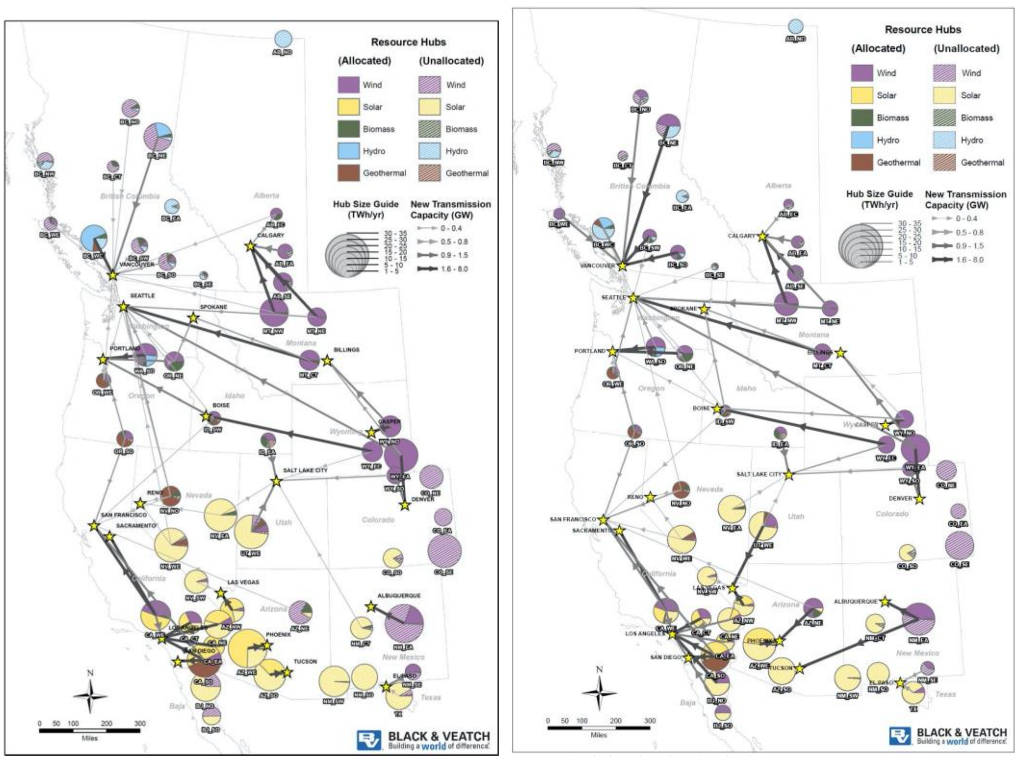


Figure B-1. Process used to identify Western Renewable Energy Zones

Analysis led by LBNL used tools from WREZ to identify transmission expansion associated with a hypothetical 33% renewable energy requirement.[133] One important finding was that the need for transmission expansion was, in some areas, highly dependent on assumptions about the relative cost trajectories of wind and solar. Assuming that wind costs would decline faster than other resources shifted the resource mix in southwestern states from locally-abundant solar to wind imported via transmission, Figure B-2.



(a) (b)

Figure B-2. Simple spreadsheet modeling of meeting a 33% RPS with renewable resource zones (circles) and load zones (stars), showed that transmission expansion decisions (arrows) in the southwest differed between a base case (a) and a case that assumed capital costs of wind would decline faster than other technologies (b).

[133] Mills, A. et al. (2010) *Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative.* https://emp.lbl.gov/publications/exploration-resource-and-transmissionhttps://eta-publications.lbl.gov/sites/default/files/report-lbnl-3077e.pdf.

A 2012 report for Western Governors Association[134] modeled the most economic WREZ hubs for 25 Western utilities and compared the results with their preferred areas for renewable resource development, as stated in interviews. Sixteen WREZ hubs were of common interest across two or more utilities, in many cases serving different states. Interviews also included 11 U.S. public utility commissions. Among other findings:

- Utilities are focused on developing renewable resources in or close to their service areas for many reasons — *e.g.*, to add resources incrementally, avoid pancaking charges, comply with in-state RPS requirements, ease siting, and reduce timelines and risks.
- Utilities are not interested in resources from WREZ hubs unless transmission to the hub already exists or there is a high degree of certainty for the timely completion of the line.
- Inconsistent and uncertain state and federal policies pose a barrier to efficient development of renewable resources — *e.g.*, differing RPS requirements, uncertainty in future tax credits.
- Transmission options are not thoroughly evaluated in integrated resource planning (IRP) processes, and most jurisdictions do not require utilities to submit separate transmission plans for review. At the same time, IRP has limited influence on transmission plans.
- Subregional planning groups should identify optimal transmission build-outs to WREZ hubs of common interest, rather than focus solely on system problems such as congestion.
- Most public utility commissions find it difficult to approve cost recovery for a transmission line sized beyond the definable future needs of their retail customers and the needs of transmission customers with signed service agreements.
- In most Western states, the framework for reviewing the public purpose of a proposed transmission line for siting and cost recovery does not address the economic benefit to the state for electricity serving other states.

The report includes 12 recommendations for consideration by states and regional bodies.

Texas CREZ model

The Texas CREZ model differs from other approaches described here in that it includes a final screening based on tangible indications of commercial interest from renewable energy developers themselves. Candidate zones were identified through technical analysis by ERCOT that included meteorological data, production cost modeling, and high-level estimates of transmission build-out costs.[135] Following that, the Public Utilities Commission of Texas (PUCT) conducted an open season during which developers submitted demonstrations of commercial interest in any of the

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[134] Schwartz, L. et al., (2012) *Renewable Resources and Transmission in the West: Interviews on the Western Renewable Energy Zones Initiative.* Prepared for Western Governors Association Executive summary: https://westernenergyboard.org/wp-content/uploads/2014/11/02-2012WGA-Renewables-Transmission-in-the-West-Interviews.pdf. Full report: https://www.raponline.org/wp-content/uploads/2016/05/rap-schwartz-wrez3fullfinalreport-2012-march.pdf.

[135] ERCOT (2006) "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas," http://www.ercot.com/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf

candidate zones. [136] If there was no evidence of commercial interest, a candidate zone was de-selected regardless of the technical analysis. As stated in the PUCT rules,

> A renewable energy developer's existing renewable energy resources, and pending or signed [interconnection agreements] for planned renewable energy resources, leasing agreements with landowners in a proposed CREZ, and letters of credit representing dollars per MW of proposed renewable generation resources, posted with ERCOT, that the developer intends to install and the area of interest are examples of financial commitment by developers to a CREZ. The commission may also consider projects for which a [transmission service provider], ERCOT, or another independent system operator is conducting an interconnection study; and any other factors for which parties have provided evidence as indications of financial commitment.[137]

The technical analysis was rudimentary at the time the CREZ process began at the end of 2006, and tools available today allow for more detailed analysis. Nevertheless, even with today's best tools, zones with high technical potential would have been de-selected in the CREZ process if there was no evidence of commercial interest that could be evaluated by the PUCT. (Additional information about the CREZ process is provided in Appendix A.)

Offshore wind development

NREL produces state-of-the-art wind resource data sets for land-based wind, offshore wind (OSW), and solar power. NREL is currently producing a new wind resource data set to replace the Wind Integration National Dataset (WIND) Toolkit for the outer continental shelf (OCS) for offshore wind. The WIND Toolkit has been the principal data set in the continental United States for wind resource assessment. The current update to the OCS wind resource assessment is part of a larger National Offshore Wind Research & Development Consortium (NOWRDC) project, leveraging funding from an earlier Bureau of Ocean Energy Management (BOEM)-funded project to update the cost model for floating offshore wind in the OCS. The new California OSW resource assessment data set has been published.

The National Laboratories works closely with BOEM, the federal agency that leases OSW areas for development, to identify the highest value sites for OSW. For instance, NREL completed a project for BOEM in recent years with recommendations on how to subdivide Massachusetts and Rhode Island OSW Call Areas auction to developers. Additionally, NREL has developed for BOEM a set of best practices for validating offshore wind resource assessments and drafted a technical report on cost trajectories and levelized cost of energy (LCOE) heat maps for five California OSW study areas. NREL is performing a project for BOEM to recommend how to subdivide the Humboldt and Morro Bay OSW Call Areas in California for auction to developers, determining the maximum OSW that could be deployed in Oregon without upgrading coast transmission, and performing a geospatial evaluation of LCOE of floating OSW in Hawaii. LBNL

[136] *Commission Staff's Petition for Designation of Competitive Renewable-Energy Zones*, Docket No. 33672.
[137] Tex. Admin. Code 25.174(c)(1).

used historical weather data and wholesale price data to identify offshore wind sites with the highest value net of costs on the eastern coast.[138]

Beyond cost of energy, PNNL has examined the capacity of existing transmission networks to integrate OSW in Oregon and have qualified the value to the grid stemming from geographic diversity, consistency of resource, and inherent complementarity with loads.[139] A pending study funded by NOWRDC and BOEM will analyze transmission extensions in Southern Oregon and Northern California.[140] This project will characterize the value of coordinated regional transmission to support OSW development in a large geographic area.

In addition to working with BOEM, NREL works with the Bureau of Safety and Environmental Enforcement, states, ISOs, and others to identify highest value OSW and other renewable energy sites to integrate them into the grid.

California's Renewable Energy Transmission Initiative

California's Public Utility Commission (CPUC),[141] Energy Commission (CEC),[142] and Independent System Operator (CAISO) identified potential renewable development areas and demand for renewables in the Renewable Energy Transmission Initiative (RETI).[143] Potential areas were ranked by a net resource cost metric composed of the generator bus-bar cost and transmission cost, less the system value of the resource.

Eastern Interconnection States' Planning Council (EISPC)

Argonne National Laboratory, in collaboration with NREL and Oak Ridge National Laboratory, developed the Energy Zones Mapping Tool for the Eastern Interconnection States' Planning Council (EISPC).[144] The tool provides EISPC members and stakeholders a web-based decision

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[138] Bolinger, M., et al. (2018) Estimating the Value of Offshore Wind along the United States' Eastern Coast, *Environmental Research Letters* 13, no. 9. https://eta-publications.lbl.gov/sites/default/files/offshore_wind_value_final.pdf.

[139] Bhatnagar, D. & Douville, T.C. (2021) Exploring the grid value of offshore wind energy in Oregon. *Energies*. https://www.mdpi.com/1996-1073/14/15/4435/htm.

[140] In concert with the 30 GW by 2030 national OSW target, NOWRDC announced two awards specific to OSW grid integration. *See* https://www.energy.gov/eere/wind/articles/national-offshore-wind-rd-consortium-announces-projects-totaling-8-million

[141] Transmission and renewable resource planning are now managed through the Integrated Resource Plan process at the CPUC. Dep't of Energy (2021) *National Offshore Wind R&D Consortium Announces Projects Totaling $8 Million*. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning.

[142] Cal. Energy Comm'n, Strategic Transmission Planning and Corridor Designation https://www.energy.ca.gov/programs-and-topics/topics/power-plants/strategic-transmission-planning-and-corridor-designation.

[143] Cal. Nat. Res. Agency (2017) Renewable Energy Transmission Initiative 2.0 Plenary Report. https://efiling.energy.ca.gov/getdocument.aspx?tn=216198.

[144] Argonne Nat'l Lab'y. https://www.anl.gov/es/energy-zones-mapping-tool.

support system with capabilities to identify and map areas with high suitability for clean power generation.

International Support on CREZ Development

Similar analysis was performed in the Philippines and in Africa with national lab support. NREL, with guidance with the Philippines Department of Energy and transmission planners from the National Grid Corporation of the Philippines, targeted new connections to CREZs in the Philippines National Transmission Plan.[145] LBNL worked with the International Renewable Energy Agency to identify renewable energy zones for the African Clean Energy Corridor.[146]

Item II. Analyzing Transmission Needs for Renewable Resource Development

Transmission planning in anticipation of generation development is challenging, although the alternative of reactively building transmission capacity in response to interconnection requests may lead to higher rates for consumers and impede competition in wholesale energy markets. The transmission planning and interconnection process was largely formed when there were less interconnection requests per year and quantifying results for future designs is challenging. NREL analysis of interconnection queues across ISO-NE, PJM, and NYISO found that in early 2000s, there were about 150 interconnection requests total. At present, there are about 1,000 new requests per year. The increasing number of requests has also led to an increase in the time that projects spend in the interconnection queue. Berkeley Lab analysis of four ISOs found that the time projects spent in queues before being built increased from ~1.9 years for projects built in 2000-2009 and increased up to ~3.5 years for those built in 2010-2020.[147] Moreover, interconnection costs of proposed and constructed projects are different. Interconnection costs of proposed wind projects in PJM and MISO are higher than the interconnection costs of constructed wind projects.[148] This could indicate a trend of increasing costs or it could reflect a selection bias, where only projects with inexpensive interconnection costs move forward.

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[145] Agustin, B., et al. (2020) *Ready for Renewables: Grid Planning and Competitive Renewable Energy Zones (CREZ) in the Philippines*, NREL/TP-7A40-76235.

[146] Ndhlukula, K., et al. (2015) International Renewable Energy Agency and Lawrence Berkeley National Laboratory, Renewable Energy Zones for the Africa Clean Energy Corridor (LBNL-187271).

[147] Bolinger, M., et al. (2021) Lawrence Berkeley National Laboratory, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2020. https://emp.lbl.gov/publications/queued-characteristics-power-plantshttps://eta-publications.lbl.gov/sites/default/files/queued_up_may_2021.pdf.

[148] Gorman, W., et al. (2019) Electricity Markets and Policy Group, Energy Analysis and Environmental Impacts Division, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*. https://emp.lbl.gov/publications/improving-estimates-transmissionhttps://eta-publications.lbl.gov/sites/default/files/td_costs_formatted_final.pdf.

ERCOT CREZ

A detailed analysis of outcomes has not been done, but a survey of aggregate indicators suggests that after the Texas CREZ buildout (a) transmission charges to customers increased between 2007-2020, (b) wholesale energy costs fell, and (c) retail electricity rates in Texas fell while rates in the rest of the country increased. A rapid increase in wind installation and a decrease in natural gas prices drove ERCOT wholesale power prices lower after 2014, although without further analysis it is not possible to disaggregate and apportion factors that drove cost reduction in wholesale power prices.

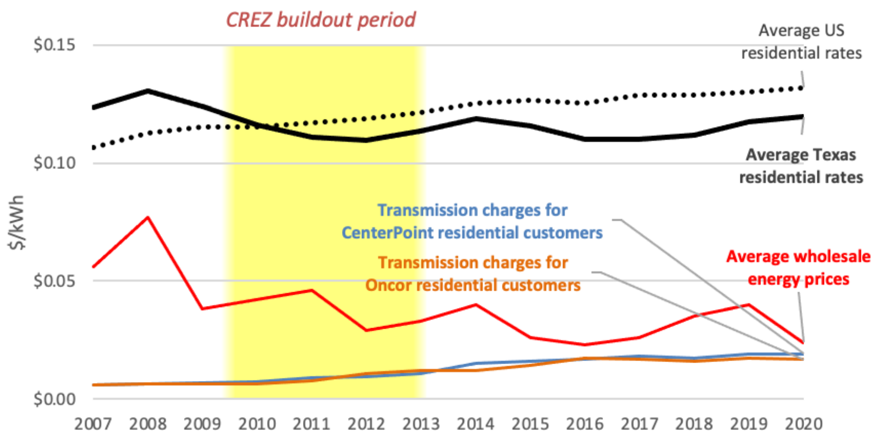

Figure B-3. Transmission and wholesale energy components of residential rates during and after CREZ buildout

Sources: (residential rates) Energy Information Administration, EIA Form 861 database; (wholesale energy prices) Potomac Economics, State of the Market Reports, 2007-2020; (transmission charges) Texas Commission, "Transmission and Distribution Rates for Investor Owned Utilities," http://puc.texas.gov/industry/electric/rates/TDR.aspx.

Possible Analysis

Capabilities exist to conduct studies that examine the broad impacts of continuing current transmission planning process versus other possible designs. These possible futures can be studied in different scenarios, such as looking at reinforcing interregional transmission corridors and expanding transmission based on "renewable energy zones" with high potential. As a first step, ISOs, industry and researchers use Capacity Expansion Models, Production Cost Models, and Resource Adequacy Models together or separately. Metrics that are used to examine the relative differences in scenarios are reliability, operations impact, transmission utilization, and resource adequacy. Some examples of past analysis include ISO-NE's Keene Road Market Efficiency Transmission Upgrades Needs Assessment[149] which used Production Cost Modeling to examine how transmission congestion could be relieved in a substantial wind generation and potential area.

[149] Henderson, M. I. (2016) ISO New England, *Keene Road Market Efficiency Transmission Upgrades Final Needs Assessment*. https://www.iso-ne.com/static-assets/documents/2016/12/2016_keene_rd_metu_needs_assessment_final_1.pdf.

Another example is the NREL Interconnection Seams Study[150] and North American Renewable Integration Study[151] where expanding national transmission based on renewable energy potential was examined.

Item III. Quantifying Benefits of Regional Transmission Projects and Obstacles in the Current Planning Process

Methods and tools to quantify additional benefits of transmission system investments are readily available and frequently used in other grid planning processes. For example, integrated resource plans frequently examine many of the benefits listed by Pfeifenberger—such as decreasing the volatility of variable resources, reliability margin needs, and emissions impacts—from the standpoint of the generation fleet. Fully quantifying the benefits of transmission investments in those areas would require coordinated expansion planning between the generation and transmission functions in a way that is not done at present. Quantification of these benefits, then, is less a question of having the right tool or model, and more a question of removing the structural barriers of the transmission planning process.

The National Laboratories have several active projects studying how to incorporate new objectives and different types of benefits into grid planning processes. However, the National Laboratories have not directly valued all of the listed additional benefits from a transmission planning perspective. As such, these comments will focus on work that the National Laboratories and other parties have done to document the structural limitations of transmission planning processes that limit their ability to value non-transmission benefits. The siloed and reactive nature of current transmission planning practices limits their ability to fully recognize the value of transmission investments in the following ways:

- Limited consideration of generation benefits
- Natural disincentives for regional projects
- Short-term planning horizons
- Subjective limitations for economic studies
- Failure to consider unplanned benefits from past transmission projects

These comments are not intended to criticize any region's specific practices or recommend a particular policy. Instead, they are intended to share the work done by the Department of Energy National Laboratories,[152] and other parties in identifying the limitations in current transmission planning practices and alternatives that FERC may want to consider.

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[150] Nat'l Renewable Energy Lab'y, *Interconnections Seam Study*. https://www.nrel.gov/analysis/seams.html.

[151] Bain, D., et al. (2021) Nat'l Renewable Energy Lab'y, *The North American Renewable Integration Study: A U.S. Perspective*. https://www.nrel.gov/docs/fy21osti/79224.pdf.

[152] Eto, J. (2016) Lawrence Berkeley National Laboratory, *Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans*; Eto, J. & Gallo, G. (2017) Regional Transmission Planning, A Review of

Limited estimation of benefits.
The models used by regional transmission planners to study the economic benefits of transmission investments vary in both scope and complexity. Some regions employ production cost models to evaluate the economic impacts of transmission assets on the generation fleet under multiple scenarios, while others may use a single scenario and others may not use a production cost model.

But even where a production cost model is used to study the impacts of a transmission investment, it may only capture some of the asset's economic benefits. Production cost models use a static representation of the generation fleet; they can capture how the addition of a new line would change the operation of the fleet and measure any resulting economic gains from reduced or more efficient dispatch of the generation fleet. This approach may fail to identify other economic benefits that may be realized from trades outside of the region, from the asset's contribution during contingency events, or the value of capacity freed up by reducing congestion.[153]

For a non-transmission alternative that can actively participate in generation markets, the production cost modeling approach is even less adequate. For example, FERC has indicated that energy storage assets may dually participate as both regulated transmission assets and competitive generation assets.[154] Identifying cost-effective opportunities to deploy storage in this manner requires a model that can forecast the value of an asset's market participation and include it in the cost/benefit assumptions used during the transmission planning process. This in turn requires a participation model for dual-use assets that forms reasonable assumptions for such a forecast. To date, no ISO has developed a participation model for dual-use assets, and only two regions have identified written processes for how energy storage will be considered in transmission planning processes.

A forthcoming national laboratory report on the topic of dual-use energy storage, which will be published later in 2021, found that regions have successfully included energy storage in the transmission planning process by creating an expectation for system planners to identify storage alternatives in one instance (CAISO)) and creating a transparent process for stakeholders to propose storage alternatives in another (MISO). Market participation models for dual-use assets can be flexibly created around three principles: establishing market participation windows in advance, creating flexible market products and resource definitions, and balancing cost recovery mechanisms to incent market participation.[155]

Disincentives to adopt regional projects.
Some planning regions connect the procurement of a transmission project to its size or timing in ways that may create a disincentive for incumbent transmission operators to support projects that

Practices Following FERC Order Nos. 890 and 1000; Eto, J. & Gallo, G. (2019) Interregional Transmission Coordination: A Review of Practices Following FERC Order Nos. 890 and 1000.

[153] Pfeifenberger, J. (April 2021) *Transmission Planning and Benefit-Cost Analyses*, Presentation to FERC Staff.

[154] "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost Based Recovery." FERC Docket No. PL 17-2-000, 158 FERC ¶ 61,051 (2017).

[155] Barrows, S.E., et al. Richland, WA: Pacific Northwest National Laboratory, *Enabling Principles for Dual Participation for Energy Storage as a Transmission and Market Asset* (forthcoming).

might be selected for regional cost-allocation (*i.e.*, "regional" projects). For example, in CAISO, regional transmission projects are defined as those that interconnect at larger than 200 kV or those that interconnect at less than 200 kV but include multiple service territories. Regional transmission projects are automatically subject to a competitive bidding process, while non-regional projects are assigned to the incumbent transmission operator in their area. This creates an incentive for incumbent transmission owners to push for smaller, localized projects—which may be less economic than larger, regional projects—that they can build and on which they can earn a FERC-authorized return.

Similarly, ISO New England (ISO-NE) conducts a competitive procurement for any transmission need that is at least three years in the future, while nearer-term needs are assigned to the local, incumbent transmission operator. While both near-term and long-term needs are eligible for regional cost allocation, the approach creates an incentive for incumbent transmission owners to push for near-term solutions, which given the speed at which they must be deployed, are less likely to be regional in scope.

Determining whether these practices have, in fact, resulted in fewer regional transmission projects being identified would require additional investigation. However, these powerful disincentives against regional transmission projects bear consideration.

Effects of short-term planning horizons.

One of the tightest constraints on a regional transmission plan's ability to fully value transmission investments is the short planning horizon that grid operators employ. Every planning region uses a planning horizon of 5 to 15 years, which fails to account for the rapid changes taking place in the generation fleet and may not capture the long-term benefits of a transmission asset that may have a useful life of 40 years or more.

At present, eight states and the District of Columbia have adopted mandatory 100 percent clean energy standards, while another 23 states have binding renewable portfolio standards of varying levels, including nine states with nonbinding goals to achieve 100 percent clean energy. Additional pressure for clean energy generation comes from individual utilities with voluntary decarbonization goals and municipalities and corporations with sustainability commitments. Deadlines for these various targets generally fall between 2040 and 2050, which makes their exact impact difficult to forecast. However, these policies collectively point to a rapidly decarbonizing energy mix over the next 20-30 years. A 10- or 15-year transmission planning horizon will fail to capture the long-term benefits of transmission infrastructure in enabling those goals to be achieved in the most efficient manner possible.

Longer term planning horizons would allow a cohesive evaluation of multiple factors, such as thermal plant retirements, changing loads brought on by transportation and end-use electrification, and generation needs to identify the most efficient transmission system topography. This type of long-term analysis would also enable the planning process to proactively identify optimal sites for new generation assets, rather than integrating individual project requests reactively on an ad-hoc basis.

The importance of considering longer planning horizons also raises the issue of what discount rate should be used. For example, the CAISO TEAM methodology uses a societal discount rate, which is lower than the weighted average cost of capital that is used in the majority of regional economic analyses.

Subjective limitations on economic studies.

Even where thorough economic studies are performed, some regions impose limitations on what proposals are eligible for study. In CAISO, economic project proposals are subject to a feasibility review by CAISO staff to determine whether the proposal addresses an identified constraint on the system. In New York , the NYISO limits the economic analyses to the three most congested areas of the state as determined by the ISO.

These limits on what economic projects may be proposed may serve a logical purpose in preserving staff resources by limiting the focus to only the most relevant projects. But they also illustrate a significant barrier to economic valuation of a broader portfolio of potential projects—a reactive approach that continues to study economic projects through a reliability lens. By requiring an economic project to effectively pass a reliability project screen before it is considered, some planning regions are potentially foreclosing analysis of economically viable projects.

Failure to consider unplanned benefits from past transmission projects.

The economic benefits of transmission projects depend on events and factors that are predicted to occur in the future. Future production cost savings (albeit based on a static fleet of generation and calculated using high discount rates over time periods that are short compared to the expected lifetime of transmission projects) are currently the only example of economic benefits for which such predictions are an accepted practice.

Pfeifenberger, among others, advocates for inclusion of additional predicted economic benefits. Their advocacy is challenged by those who maintain that these predictions are speculative, which, of course, cannot be denied. Given that the future can never be known or predicted with certainty, the issue is how or by what means can benefits that are initially considered speculative transition to become accepted practice.

One path toward increasing acceptance of predicted benefits that are currently less familiar and less widely accepted is to more systematically record and assess the circumstances under which unplanned benefits from past transmission projects have been realized. Southwest Power Pool and Electric Power Group are two examples of early efforts to articulate and measure these benefits.[156] The recent experiences of Florida utilities in reaping the resilience benefits of storm hardening efforts taken in the aftermath of devastating hurricanes in the mid-2000s are another example. It could similarly be argued that the significant economic benefits that have been realized by the creation of an Energy Imbalance Market in the West have depended on the availability of excess

[156] Southwest Power Pool (Jan 2016) *The Value of Transmission* Budhraja, V., et al. (2003) *Planning for California's Future Transmission Grid; Review of Transmission Grid; Electric Power Group for Cal. Energy Comm'n, Review of Transmission System Strategic Benefits, Planning Issues, and Response Policy Recommendations.*

transmission capacity built long ago but which is only now being utilized more fully and more economically through the creation of a formal market.

Item IV. Generator Funding of Network Upgrade Costs

Other jurisdictions have recognized the inequity of assigning all network upgrade costs to the project that triggered the need and have taken responsive steps. Some measures seek to more equitably allocate costs across all benefitting projects, while other measures seek to avoid the upgrade through flexible interconnection agreements.

In 2017, the New York Public Service Commission (NYPSC) established a cost sharing program that requires developers of projects benefitting from network upgrades built by a previous developer to reimburse that developer for its usage of the facilities. The NYPSC determined that large facilities installed at the substation level, such as voltage protection and transformer upgrades, costing $250,000 or more would be eligible for the cost-sharing program.[157] Under the program, each project that benefits from a network upgrade reimburses all previous projects that have paid for the upgrade in a manner that ensures that each project using the upgrade bears its share of the costs. The NYPSC recognized that better solutions may be available, and ordered a stakeholder working group to continue developing alternate cost-sharing proposals for the commission to consider. But the commission also ordered that the initial cost sharing proposal, which was initially planned to sunset in 2020, remain in place until an alternate approach is adopted.

Cluster interconnection study processes are another means by which network upgrade costs can be more equitably allocated. Already adopted in multiple ISOs, these processes evaluate many projects at once to identify common network upgrades whose costs can be distributed among all benefitting projects. Cluster studies are an improvement over traditional interconnection studies, which evaluate each project in isolation and identify network upgrades on a project-by-project basis.

In the United Kingdom in 2012-2014, UK Power Networks, an electric distribution company, conducted a pilot program called Flexible Plug and Play, in which it explored the usage of flexible interconnection agreements to avoid the need for system upgrades. The program focused on constrained distribution feeders that were out of interconnection capacity, allowing new generators to interconnect if they agreed to allow the utility to curtail them if necessary. Five projects totaling 6.75 MW connected during the pilot phase, and even after accounting for the curtailed energy, the

[157] N.Y. Pub. Serv. Comm'n (2017) *"Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings"* Case 16-E-0560. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={22BEAB22-7F9F-45B8-89FD-0E8AD84692B4}.

projects realized £36 million (about $55.4 million in 2015 dollars) in benefits by avoiding network upgrades.[158]

In a similar program, the Hawaii Public Utility Commission (HPUC) changed its interconnection requirements for distributed resources in 2015 to accommodate customer demands for more distributed solar on capacity-constrained feeders. The changes allowed new distributed generation to connect to the grid on the condition that the customer either allow the utility to curtail its output as necessary or consume all electricity onsite.

These policies and programs are indicative of the options available to FERC if it decides that changes to interconnection cost allocation processes are necessary. Instituting cost sharing among benefitting projects, as done in New York, is one option. Requiring cluster studies that allocate interconnection costs across benefitting projects on an upfront basis is another. FERC could also consider building on the increased interconnection flexibility it established in Order 845 by allowing project developers to avoid triggering network upgrades by agreeing to control their output through energy storage or some other means.

DOE is funding research at the National Laboratories that may help to answer these questions more completely in the future. One project is working with utilities and project developers to develop a benchmarking database of 150 interconnection studies for small hydropower facilities, with the goal of assessing how interconnection policies affect the development of such facilities. Anecdotally, there appear to be some incidents in which the high cost of necessary interconnection facilities resulted in the facility not being built. It is possible that in some cases, the construction of those interconnection facilities would have alleviated system congestion or provided benefits to other facilities. Evaluating whether interconnection cost allocation policies are preventing the construction of beneficial facilities in a widespread manner would require additional study.

Additional Discussion of Storage in Transmission Planning

Before studying how and where to expand the transmission system, it may be appropriate to study how the existing system may be used to its maximum efficiency. Because the transmission system must be designed and built to meet peak demand needs plus necessary reliability margins, the average transmission line's utilization is well below its nameplate capacity, even on fully subscribed and heavily utilized lines.

To illustrate this point, the Western Electric Coordinating Council's study of transmission system utilization in 2018 found that, on average, transmission lines in the region were only used at 75 percent or more of their rated capacity 6.2 percent of the time, and at 90 percent or more of their rated capacity just 1.3 percent of the time. In practical terms, this means that once peak loads were

[158] UK Power Networks(2015) *"Flexible Plug and Play Close Down Report."* https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2019/05/FPP-Close-Down-Report-Final.pdf.

met during a few hours of the year, the lines had abundant, unused capacity during the rest of the year.[159]

Flexible, scalable electricity storage technologies were not available when the electric grid was built, meaning that it had to be sized to meet the highest levels of demand. Now that those technologies are available, they can be sited near load centers and charged using excess transmission capacity during low-demand hours and then discharged to meet demand during high-demand hours, extending the life of existing transmission assets and delaying or displacing the need for additional transmission infrastructure. Embedding storage in the grid in this manner can create the missing buffer in the electric system, improving the grid's flexibility and resilience.[160]

However, there is no standard or policy to support this type of analysis. FERC may consider asking regional transmission planners to study how the targeted deployment of embedded energy storage may economically delay or eliminate the need for additional infrastructure and enable more flexible operations.[161]

Item V. Incorporating Distributed Energy Resources into Transmission Planning

Deployment of distributed energy resources (DERs), including energy efficiency (EE), demand flexibility (DF) and demand response (DR), electric vehicles (EVs), behind-the-meter storage, and distributed solar PV (DPV), has increased in recent years and are expected to grow significantly over the next decade, (*e.g.*, Muratori et al., 2021[162]; Barbose et al., 2020[163]; Goldman et al., 2020[164]). At the same time, the U.S. power system is currently undergoing transformational change with reduced generation from coal-fired generation and increased generation from wind, solar, and natural gas. As a result, utilities and states are considering DERs more comprehensively in their planning processes in order to more accurately forecast the impacts of DERs on future load growth as well as to incorporate the load shifting and load shedding capabilities of DERs. Extensive electrification has played a smaller role in planning processes throughout the U.S.; however, it has the potential to have significant impacts on the high-voltage transmission needs in

[159] Western Electric Coordinating Council (2019) *"2018 State of the Interconnection."* Transmission Adequacy module. https://www.wecc.org/epubs/StateOfTheInterconnection /Pages/Transmission-Adequacy.aspx. https://www.wecc.org/epubs/StateOfTheInterconnection /Pages/Transmission-Adequacy.aspx.

[160] Becker-Dippman, A., et al. (2019) Richland, WA: Pacific Northwest National Laboratory, *The Use of Embedded Electric Storage for Resilience, Operational Flexibility, and Cyber-Security*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-29414.pdf.

[161] Becker-Dippman, A., et al. (2021) Richland, WA: Pacific Northwest National Laboratory, *Regulatory Implications of Embedded Grid Energy Storage*. https://energystorage.pnnl.gov/pdf/PNNL-30172.pdf.

[162] Matteo, M. et al. (2021) The Rise of Electric Vehicles – 2020 Status and Future Expectations. https://iopscience.iop.org/article/10.1088/2516-1083/abe0ad/pdf.

[163] Barbose, G., et al. (2021) Lawrence Berkeley Nat'l Lab'y, *Tracking the Sun, Pricing and Design Trends for Distributed Photovoltaic Systems in the United States*. https://emp.lbl.gov/sites/default/files/2_tracking_the_sun_2021_report.pdf.

[164] Goldman, C. A., et al. (2020) Elec. Markets & Policy Energy Analysis & Env't Impacts Division, Lawrence Berkeley Nat'l Lab'y, *What Does the Future Hold for Utility Electricity Efficiency Programs?* https://eta-publications.lbl.gov/sites/default/files/preprint_w_cover_future_of_ee_elect_journal_20191220.pdf.

the future by changing both the timing of peak loads (*e.g.*, increased load from end-use electrification could shift some power system peaks from summer to winter) and increasing the deployment of dispatchable, flexible loads (*e.g.*, electric vehicles). Studies have shown electrification could lead to nearly double today's electricity demand (Mai et al., 2021)[165]. Adequately considering DERs and electrification in scenario planning for transmission could mitigate major cost increases to the future grid.

We describe and summarize recent National Lab research on DERs and electrification in transmission planning in three categories:

- Tools, models, and methods that can help assess the impacts of DERs and electrification on transmission planning;
- Analysis of the importance of these drivers; and
- Technical assistance to planning entities and/or synthesis of best practices.

Tools and Methods to Characterize the Growth in and Capabilities of DERs and Electrification

Many tools at the National Laboratories already consider the tradeoffs and implications of DER adoption and electrification on transmission planning. For example, the NREL Standard Scenarios[166] work leverages an iteration between the Regional Energy Deployment System (ReEDS) model and the Distributed Generation Market Demand Model (dGen) to optimize transmission around a variety of potential scenarios for DERs. ReEDS co-optimizes generation and transmission expansion to consider tradeoffs in a variety of future scenarios. The ReEDS model has also been extensively updated as part of the Electrification Futures Study (see "Analysis" section) to consider demand-side flexibility due to electrification of new loads, including transportation, space heating, water heating, cooking, and other end uses. The potential flexibility of these loads is treated endogenously within the ReEDS framework. dGen simulates customer adoption of distributed energy resources for residential, commercial, and industrial entities by applying an agent-based Bass diffusion model. dGen mixes resource data, population, zoning, building, rates, and policy information with LiDAR data on rooftop size, tilt, azimuth, and shading to understand the technical and economic adoption potential (see Figure B-4).

[165] Nat'l Renewable Energy Lab'y, *Electrification Futures Study: A Technical Evaluation of the Impacts of an Electrified U.S. Energy System*, https://www.nrel.gov/analysis/electrification-futures.html.

[166] Nat'l Renewable Energy Lab'y, *Standard Scenarios*, available at https://www.nrel.gov/analysis/standard-scenarios.html

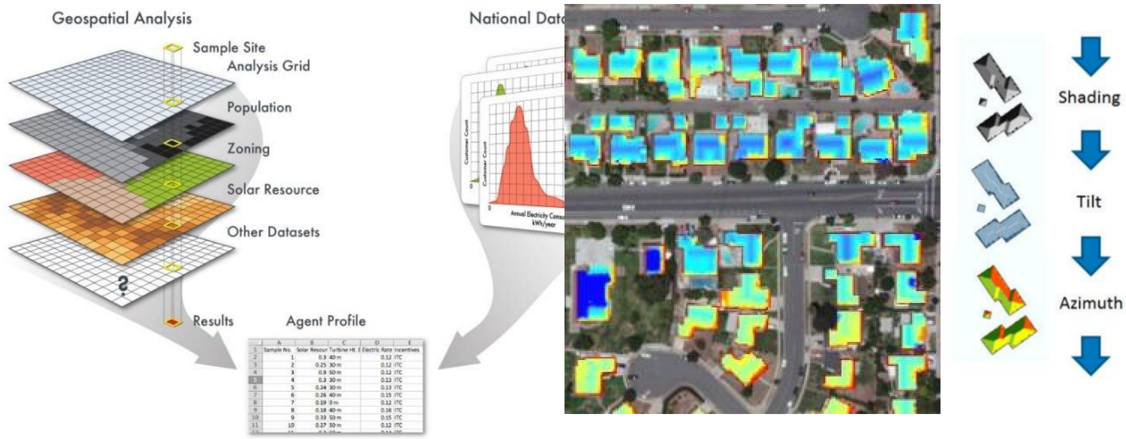

Figure B-4. dGen data layers

The labs have used production cost models (*e.g.*, Energy Exemplar's PLEXOS model) and resource adequacy tools (*e.g.*, NREL Probabilistic Resource Adequacy Suite [PRAS]) to further explore transmission implications and tradeoffs between these scenarios, as performed for several of the analysis studies mentioned.

DOE's Scout model is capable of estimating hourly impacts of residential and commercial building EE and DF measures. For example, Langevin et al. (2021)[167] used Scout to quantify the magnitude and distribution of building efficiency and flexibility as a grid resource across all regional U.S. power systems. Significant opportunities were found in the Southeast and Great Lakes regions and among residential pre-conditioning, heat pump water heaters, and commercial plug load management.

Models that can help analyze the potential changes to load patterns due to efficiency and electrification include ResStock,[168] ComStock,[169] and TEMPO.[170] ResStock and ComStock analyze the potential building efficiency and demand-side technologies and practices that could change energy use in residential and commercial buildings, respectively. TEMPO is a transportation demand model that could be used for transportation analysis and electrification of vehicles. Distribution network models also exist[171] to understand issues like voltage, power quality, resilience, and interplay between technologies.

[167] Langevin, J., et al. (2021) *U.S. Building Energy Efficiency and Flexibility as an Electric Grid Resource*. https://www.cell.com/joule/fulltext/S2542-4351(21)00290-7.

[168] *Available at* https://resstock.nrel.gov/

[169] *Available at* https://www.nrel.gov/buildings/comstock.html

[170] *Available at* https://www.nrel.gov/transportation/tempo-model.html

[171] Examples include Advanced Distribution Management System research (https://www.nrel.gov/grid/advanced-distribution-management.html) and GridLAB-D™ (https://www.gridlabd.org/)

Analysis

There have also been several analysis efforts that specifically inform the issues around DER and electrification impacts on transmission planning. For example, Deason et al. (2018)[172] studied the potential benefits and barriers to greater electrification in U.S. buildings and industry. Barbose et al. (2014)[173] analyzed energy efficiency impacts on load projections directly from western utilities and discuss the implications of including these types of projections in transmission planning (Figure B-5 shows the Compound Annual Growth Rate for load with and without high Demand Side Management (DSM) and DERs). This type of effort could be applied to electrification for planning scenarios, with the results potentially having a major impact on the results of the transmission planning process.

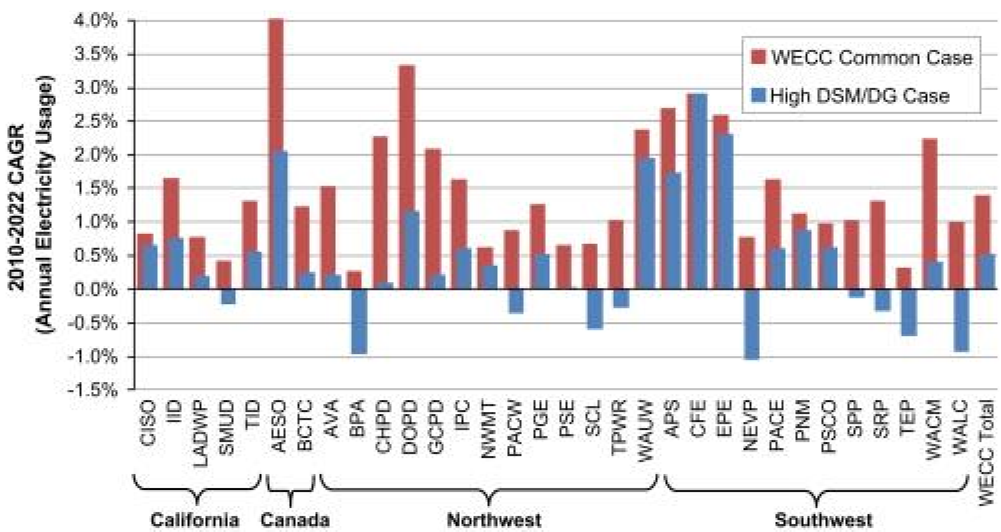

Figure B-5. Load growth with and without considering energy efficiency and distributed generation

Mills (2018)[174] describes drivers of DER deployment on the transmission system organized in four areas: DER economics (*e.g.*, influenced by rate design, electricity prices, state and federal incentives), public policy (*e.g.*, renewable portfolio standards), customer preferences (*e.g.*, interest in increased customer choice), and macro factors (*e.g.*, macroeconomic growth, cost and availability of complementary technologies). DER forecasting methods vary widely and

[172] Deason, J., et al. (2018) Energy Analysis and Environmental Impacts Division, Lawrence Berkeley Nat'l Lab'y, Electrification of Buildings and Industry in the United States. https://eta-publications.lbl.gov/sites/default/files/electrification_of_buildings_and_industry_final_0.pdf.

[173] Barbose, G., et al. (2014) Energy Markets & Policy, Lawrence Lawrence Berkeley Nat'l Lab'y, *Incorporating Energy Efficiency Into Electric Power Transmission Planning: A Western United States Case Study*, available at https://emp.lbl.gov/publications/incorporating-energy-efficiency-0

[174] *Available at* https://eta-publications.lbl.gov/sites/default/files/7._mills_forecasting_load_with_ders.pdf

combining several approaches with benchmarking to third-party forecasts may address uncertainty.

To demonstrate the importance of scenario planning, Gagnon et al. (2018)[175] showed the potential costs of inaccurately forecasting long-term DER adoption; these costs can be significant (and would potentially apply to transmission planning and drivers like electrification).

Several major analysis studies have recently performed large-scale analysis on electrification scenarios, and specifically looked at the impacts on generation and transmission planning:

- The Electrification Futures Study[176] was a multi-year, multi-lab study that explored the impacts of widespread electrification in all U.S. economic sectors. It provided insights through exploring supply-side scenarios, detailed grid modeling, demand-side modeling and scenarios, and developing foundational technology cost and performance data for electrification. Figure B-6 shows the transformational change that could occur in response to electrification and changing technology costs and performance.

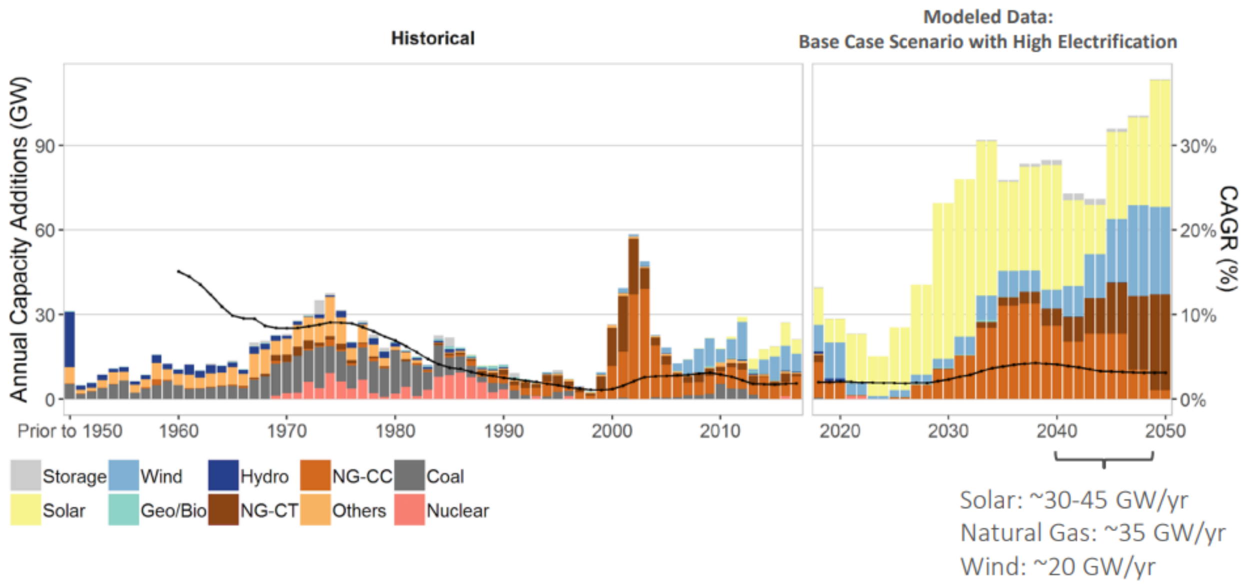

Figure B-6. Generation capacity expansion in a High Electrification scenario in the Electrification Futures Study

- The North American Renewable Integration Study[177] considered a suite of scenarios for future grid evolution, and specifically looked at inter-regional transmission. Core scenarios included a Business as Usual scenario and an Electrification scenario with nearly double the load. The transmission implications of the electrification are shown in Figure B-7. This study

[175] *Available at* https://www.nrel.gov/docs/fy18osti/71042.pdf

[176] *Available at* https://www.nrel.gov/analysis/electrification-futures.html

[177] *Available at* https://www.nrel.gov/analysis/naris.html

illustrated how electrification could lead to much larger transmission builds and demonstrated the highest value of transmission among all the scenarios.

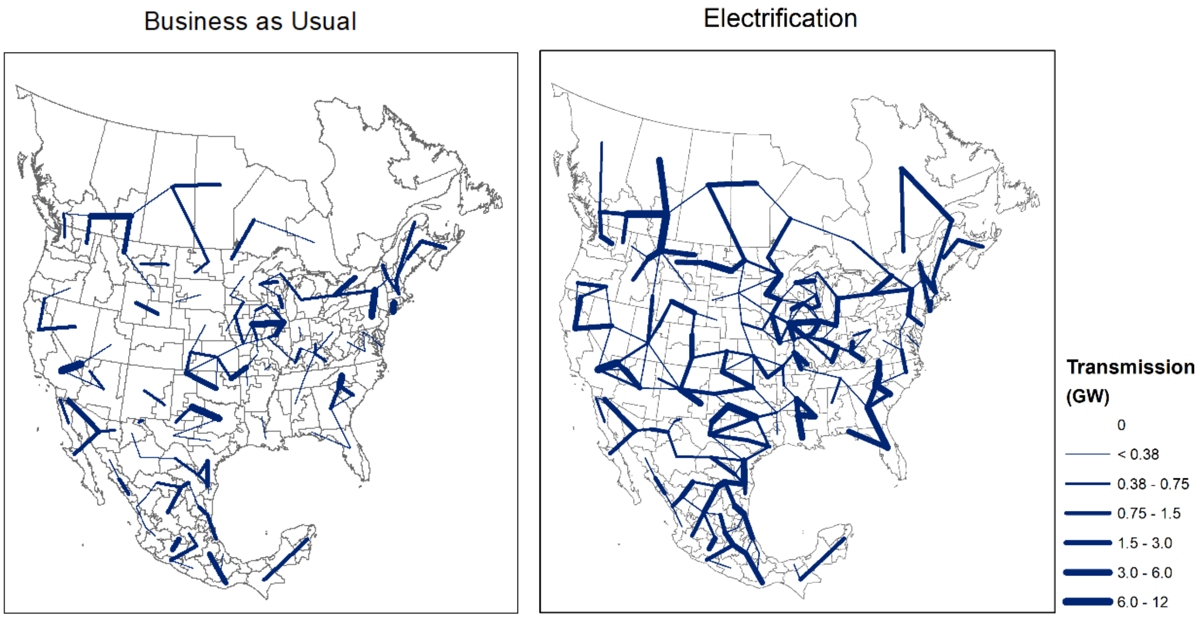

Figure B-7. Transmission expansion in the Business as Usual and Electrification scenarios in the North American Renewable Integration Study

Assistance to Planning Entities

Homer et al. (2020)[178] discuss distribution system planning with DERs. Many of the methods and conclusions in this work would also be relevant and important for transmission planning because the DERs and distribution network patterns have direct implications for the high-voltage transmission network. They note that "while load forecast approaches have been well established, the methodologies for forecasting DER adoption rates are still under development." Effectively forecasting DER adoption requires estimation of technical potential, economic potential, and customer adoption. The third component is the most challenging.

There have been fewer examples of direct assistance to planning entities for electrification. While utilities and states have been doing detailed load forecasting for many decades, the potential for a future with heavy electrification of new end uses creates major uncertainties that will require new methods and new scenarios.

[178] *Available at* https://gmlc.doe.gov/sites/default/files/resources/Distribution%20Planning%20Tools%20Report%20Final.pdf

LBNL provided technical assistance to the Western Electricity Coordinating Council on incorporating EE and DR in regional transmission and capacity expansion planning. For example, Satchwell et al. (2013a[179] and 2013b[180]) studied how demand response is and could be incorporated into grid planning in the west and throughout the country. More recently, Satchwell et al. (2020)[181] provided a detailed analysis of Integrated Resource Planning processes in Indiana, and how representation of DERs in these processes could be impactful and improved as part of a DOE-funded technical assistance project with the Indiana Utility Regulatory Commission.

Koebrich et al. (2018)[182] applied the dGen model to project adoption potential of DERs to help the Orlando Utilities Corporation understand the implications. Sigrin et al. (2020) applied dGen with building-specific detail for every building in the Los Angeles Department of Water and Power for the LA100 study[183], and these projections were incorporated into all of the scenarios for this major study. These types of projections can help utilities in their formal resource planning processes, ultimately improving regional and inter-regional transmission planning. The LA100 study as a whole considered a variety of scenarios with a range of DER, EE, DR, and electrification in a single framework.

Conclusions

It is important for transmission planning processes to take into account the dual impacts of DERs that make them a unique and valuable bulk power system resource, namely their ability to impact loads and also serve as dispatchable resources. There are several publicly available, DOE-funded tools developed by the National Laboratories that can forecast DERs and quantify hourly impacts. This can inform transmission planning scenarios and provide credible input assumptions for load forecasts and can help characterize dispatchable DER resources. Electrification of additional energy end uses could potentially transform the power grid by increasing demand substantially, affecting grid transmission needs in the future.

Further tool development and research can inform more precise estimates and reduce uncertainty, particularly regarding the interactions between technologies like DERs, efficiency, and electrification. Finally, bulk power system modeling tools themselves may not realistically represent the characteristics of DERs and electrification endogenously and should be enhanced to accommodate the growing size and importance of these technologies.

[179] *Available at* https://emp.lbl.gov/publications/analytical-frameworks-incorporate

[180] *Available at* https://emp.lbl.gov/publications/incorporating-demand-response-western

[181] *Available at* https://www.in.gov/iurc/september-2020-contemporary-issues-technical-conference-presentations/

[182] *Available at* https://www.nrel.gov/docs/fy21osti/77308.pdf

[183] *Available at* https://www.nrel.gov/analysis/los-angeles-100-percent-renewable-study.html

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing upon each of the parties shown on the official service list compiled by the Secretary of the Commission by depositing copies thereof in the first class mail, postage prepaid, and/or by electronic mail.

Dated at Washington, D.C., this 12thth day of October 2021.

/s/ Peter Meier
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