A Path Forward for the Federal Energy Regulatory Commission

Near-Term Steps to Address Climate Change

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Executive Summary

The Federal Energy Regulatory Commission (FERC) is an independent agency that regulates industries of fundamental importance to accomplishing clean energy transition: interstate transportation of oil, transmission and sale of natural gas, transmission of electricity in interstate commerce, wholesale sales of electricity, and hydropower. FERC is often overlooked as an important agency for climate policy, but swift regulatory reforms in FERC-jurisdictional sectors are crucial for cost-effective decarbonization.

FERC should take an active role in better aligning regulatory practices with climate policies, speeding up development of necessary transmission infrastructure, and reforming energy market rules. FERC's actions – or failure to act – in these three specific areas will help determine the success of the next administration's climate and clean energy policies.

FERC has the authority to undertake the reforms outlined below under either the Federal Power Act (FPA), the Natural Gas Act (NGA), or the National Environmental Policy Act (NEPA).

To enable a fast, cost-effective clean energy transition, FERC should:

(1) Revise its rules and regulations to properly account for GHG emissions by:

   a. Exploring carbon pricing opportunities in wholesale energy markets; and

   b. Quantifying and monetizing GHG emissions in interstate natural gas infrastructure reviews.

(2) Revise its transmission policies to enable cost-effective national decarbonization by:

   a. Improving the interregional transmission planning process to incentivize more interregional coordination, more competition, and a formal consideration of state public policy goals;

   b. Requiring the use of a comprehensive cost-benefit analysis in transmission planning, with requirements to consider societal benefits, including environmental benefits; to consider non-transmission alternatives and measures; and to rely on forward-looking analysis using the best available methodologies; and

   c. Adopting incentive- or performance-based regulation to improve regulatory incentives.

(3) Reform its electricity market rules to ensure effective participation of new technologies and high penetration of renewable energy resources by directing ISOs/RTOs to start a comprehensive evaluation of their market rules to enable technology-neutral participation of clean and renewable resources.

In addition, to ensure FERC can undertake these reforms quickly and effectively, the Department of Energy's should delegate its authority to designate National Interest Electric Transmission Corridors to FERC.

With these reforms, federal policymakers can take advantage of important opportunities energy markets can provide to combat climate change while ensuring an economically efficient and speedy clean energy transition.

I. Introduction

The Federal Energy Regulatory Commission (FERC) is an independent agency that regulates industries of fundamental importance to accomplishing the clean energy transition in the United States: interstate transportation of oil, transmission and sale of natural gas, interstate transmission and wholesale sale of electricity, and hydropower.[1] Because FERC is generally considered to be an "economic" regulator and not an "environmental" regulator, its crucial role in enabling climate change policy might not be apparent at a first glance. But a clean energy transition at the pace necessary to meet the nation's climate policy goals will require FERC to take an active role in better aligning current energy regulatory practices with climate policies, speeding up the development of necessary infrastructure, and reforming energy market rules. Consequently, FERC's actions – or failure to act – in these three specific areas will have significant consequences for the success of any climate and clean energy policies enacted in the coming years.

Not only would action by FERC be beneficial for climate goals, but *inaction* could be harmful to the pursuit of better-aligned energy and climate policy. For instance, several of FERC's rules and regulations that govern organized wholesale markets favor traditional electricity generation resources, which are typically fossil-fueled, and so can hinder the cost-effective deployment of newer and cleaner resources. This bias could persist even if federal climate legislation seeks to address emissions from the electricity sector. Thus, FERC eliminating market barriers and reforming market rules to ensure technology neutrality is necessary for achieving clean energy targets quickly and cheaply.

To enable a fast and cost-effective clean energy transition, FERC should:

1) Amend its regulations and market rules to properly account for greenhouse gas emissions in all sectors it regulates;

2) Revise its transmission policies to ensure better utilization of the nation's renewable energy resources; and

3) Develop a plan for making its market rules technology-neutral to facilitate participation of new energy technologies and thereby enhance the economic efficiency of FERC-jurisdictional markets.

FERC has the authority to undertake these reforms under the Federal Power Act (FPA), the Natural Gas Act (NGA), or the National Environmental Policy Act (NEPA). And, with these reforms, federal policymakers can take advantage of the important opportunities that energy markets can provide to combat climate change, while ensuring an economically-efficient and speedy clean energy transition.

II. FERC Should Revise Its Rules and Regulations to Properly Account for Greenhouse Gas Emissions

Economically, the ideal policy to combat climate change is a nation-wide, economy-wide carbon tax that can fully internalize the external damage greenhouse gases cause.[2] However, such a carbon tax would require new legislation, and might not be politically plausible. Until Congress can enact an economy-wide carbon tax, alternative policies and regulatory solutions are necessary.

Reforming FERC rules and regulations to properly account for greenhouse gases would be an important step for decarbonization. Not only could this help enable, or even speed up, implementation of a national climate agenda, but it could also serve as a back-stop mechanism to ensure that the sectors subject to FERC regulation internalize the external costs of greenhouse gases. Therefore, even if federal policymakers pursue comprehensive climate legislation or stricter greenhouse gas regulations under the Clean Air Act, they should also concurrently pursue FERC regulatory reforms that can help internalize greenhouse gases.

There are two main areas of FERC regulation that are ripe for this kind of reform: organized wholesale energy markets and natural gas pipeline approvals.

A. FERC Should Explore Carbon-Pricing Opportunities in Organized Wholesale Energy Markets

About two-thirds of the nation's electricity demand is served by organized wholesale energy markets.[3] These markets are operated by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), which are independent, non-profit organizations. The rules that govern these markets determine which generators in that market's footprint generate electricity and how much. Therefore, a sector-specific carbon price that applies to these organized wholesale markets could significantly reduce emissions in this sector. Such carbon pricing can leverage the power of competitive market forces to create efficient incentives for decarbonization and increase the effectiveness of existing state and federal clean energy policies. For these reasons, there is a growing consensus that wholesale electricity markets can play an important role in incentivizing a reduction of CO_2 emissions from electricity generation.[4]

Under a carbon-pricing market rule, a charge is added to the energy cost bids of emitting generators based on the amount of their emissions.[5] Then, the corresponding market operator makes its dispatch decisions based on these combined costs instead of just the energy costs. In this way, the rule incorporates the external cost of CO_2 emissions into dispatch decisions of market operators, better aligning market prices with the marginal social cost of electricity generation, just like a carbon tax would, without compromising the operational efficiencies of wholesale electricity markets.[6]

Carbon pricing in wholesale markets has many advantages. A carbon price would increase the cost of generation for emitting power plants. In this way, it would cause CO_2-emitting generators to directly internalize the climate change externality by ensuring that the energy prices reflect the social marginal cost of electricity. It would increase revenues

for cleaner resources and, hence, provide clear investment signals that would lead to efficient retention or entry of clean generators and efficient exit of emitting generators. It would be technology neutral, and so allow the market to select the lowest-cost emissions reduction opportunities, reducing the total cost of decarbonizing the electricity sector. It would provide regulatory certainty and uniformity, lowering the overall cost of achieving various state clean energy commitments and making it easier to achieve national ones. Furthermore, it could be designed to complement other state and federal carbon-pricing programs, reducing any potential conflict.

There are a number of potential approaches FERC can use to implement carbon-pricing rules in FERC-jurisdictional organized wholesale electricity markets based on its authority under the FPA.[7] The FPA provides two paths for changing ISO/RTO market rules, one under section 205 and the other under section 206.[8] Each section involves a different legal process and a different legal burden. However, as we explain below, each section gives FERC the authority to adopt carbon pricing.

1. Carbon Pricing Under Section 205 of the FPA

Under Section 205 of the FPA, FERC must approve a rule change filed by an RTO so long as it concludes that the change would yield rates that are just and reasonable and not unduly discriminatory or preferential.[9] As explained in Policy Integrity's recent report, a carbon-pricing rule can meet this legal bar if it would improve the efficiency of organized wholesale markets or if it would help harmonize those markets with state clean energy policies, protecting the integrity of both.[10] Depending on the goal of the program and its underlying legal theory, the type of evidentiary support needed to approve such a rule would be different.[11] However, as long as the economic and legal criteria described in the Policy Integrity report are met, FERC would have the authority to approve carbon-pricing rules under the FPA.[12]

Under section 205, FERC has a "passive and reactive" role to consider market rule changes that are filed by an RTO.[13] Therefore, implementing a carbon-pricing rule under section 205 would begin with a filing by an RTO. At the time of this report, carbon pricing discussions are underway in several ISO/RTOs. NYISO has developed, but not yet filed, a carbon-pricing rule to harmonize its wholesale market for electric energy with New York State's clean energy policies.[14] PJM is currently undertaking a stakeholder process to determine whether and what kind of carbon pricing should be implemented in its markets.[15]

POLICY RECOMMENDATION: If and when ISO/RTOs file tariff changes to implement a carbon-pricing rule, FERC should approve these changes, provided that the proposals meet the appropriate economic and legal criteria.

2. Carbon Pricing Under Section 206 of the FPA

Under section 206 of the FPA, FERC can compel a modification to market rules, either upon a complaint or on its own motion.[16] Directing ISO/RTOs under section 206 to implement carbon pricing would have a higher legal bar than adopting an RTO proposal filed pursuant to section 205. First, actions under section 206 require two substantive legal findings: (1) that the existing market rule is not just and reasonable, or is unduly discriminatory or preferential; and (2) that a replacement or modification of that rule (which could be proposed by FERC) will be just and reasonable and not

unduly discriminatory or preferential.[17] Second, the conclusion that the existing market rule is *not* just and reasonable, or is unduly discriminatory or preferential, must be based on a finding that current market rules produce wholesale rates that fall outside the "zone" or "range of reasonableness" that encompasses just and reasonable rates.

However, as described in Policy Integrity's report, basic economic principles can guide FERC to meet these legal requirements. FERC has regularly found existing market designs to be unjust and unreasonable when they fail to achieve economically efficient outcomes.[18] Here, FERC can similarly rely on economic principles to show that the existing rates are unjust, unreasonable, and unduly discriminatory or preferential because the uninternalized externality limits the efficient operation of organized wholesale markets. Alternatively, FERC can point to the detrimental effects of the current misalignment between market outcomes and state clean energy policies to make such a finding. Having made any of these findings, FERC can then determine that a carbon-pricing rule would remedy the problem.

Under section 206, once FERC makes these two findings, it would not need to specify a complete carbon-pricing rule on its own. Instead, FERC could establish high-level rules about the design, such as a carbon price floor, but leave specifics to each RTO and then review their compliance filings for consistency with the high-level rules. The resulting carbon-pricing rule could be applied to all wholesale sales within an RTO, or just to wholesale sales in states that opt in.

POLICY RECOMMENDATION: FERC should initiate a process that could lead to a requirement that ISO/RTOs implement carbon-pricing rules.[19]

B. FERC Should Quantify and Monetize Greenhouse Gases in Its Interstate Natural Gas Infrastructure Reviews

Recent technological advances, such as hydraulic fracturing and horizontal drilling, spurred a marked increase in natural gas production and low natural gas prices,[20] which in turn increased demand for new natural gas transportation infrastructure projects to connect newly productive areas with end users. Those projects include interstate pipelines, compressor stations, and related facilities. Natural gas pipelines and related infrastructure directly emit greenhouse gases that cause climate change.[21] Methane is emitted when pipelines leak and during safety tests, and CO_2 is emitted when natural gas is combusted in order to operate compressor stations and other enabling infrastructure.[22] Furthermore, new pipeline infrastructure enables new (upstream) production and (downstream) consumption of natural gas, leading to additional, indirect greenhouse gas emissions.

As explained in a recent Policy Integrity report, relying on FERC to evaluate and address the greenhouse gas emissions of these projects should be an important part of the federal energy policy agenda. FERC is responsible for reviewing all new interstate natural gas pipelines and facilities, and approving them if any of the projects are "or will be required by the present or future public convenience and necessity."[23] To meet this obligation, FERC must balance the need for additional natural gas infrastructure against the costs such infrastructure may impose, including costs associated with greenhouse gas emissions.[24] Because greenhouse gas emissions cause significant damages in the form of climate change, FERC should quantify and monetize these costs when reviewing potential interstate natural gas infrastructure projects.[25] Moreover, FERC should adopt a policy to incorporate *all* of the climate and environmental consequences of potential interstate natural gas infrastructure projects – including direct, upstream, and downstream emissions – in its decisionmaking.[26]

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There are two independent statutory bases for FERC to analyze and consider climate effects in pipeline approvals, one under NEPA and the other under the NGA. FERC can do separate analyses to meet its obligations under these two statutes, or can use its analysis under NEPA to strengthen its analysis for the NGA.[27]

1. Reviews Under the National Environmental Policy Act

NEPA requires all federal agencies to take a "hard look" at the environmental consequences of a proposed activity before taking action.[28] To satisfy this obligation, FERC must analyze the greenhouse gas emissions associated with any potential interstate natural gas pipeline projects, including both upstream and downstream emissions.[29] And a number of recent court decisions held that this inquiry requires an analysis of reasonably foreseeable emissions.[30]

To date, FERC has argued that, for the majority of pipeline projects where the upstream producer or downstream consumer of natural gas are not known with particularity, the emissions are not reasonably foreseeable, and so quantification of those emissions is not required.[31] But there are available methods and tools that FERC can use to reasonably analyze emissions consequences of potential natural gas infrastructure projects, and FERC should (and arguably must) do so.[32]

To meet NEPA's "hard look" requirement, FERC's greenhouse gas emissions analysis should include at least three steps: quantifying emissions, monetizing the quantified emissions, and analyzing the alternatives.

i. Quantifying Greenhouse Gas Emissions

FERC must first quantify greenhouse gas emissions associated with potential projects.[33] To quantify greenhouse gas emissions that can reasonably result from a given potential project, FERC should start requesting that applicants provide as much information as possible on the expected source, end use, and amount of natural gas to be transported through

a proposed pipeline.[34] FERC can then easily use this information to construct reasonable estimates of the potential greenhouses consequence of the proposed pipeline using established emission factors for each activity.[35] If project-specific data is not available, FERC should use reasonable default scenarios, available emission factor estimates, and, when possible, modeling to estimate the quantity of greenhouse gas emissions that will be enabled by new natural gas transportation infrastructure.[36]

POLICY RECOMMENDATION: FERC should quantify all greenhouse gas emissions that can reasonably result from a potential natural gas infrastructure project.

ii. Monetizing Greenhouse Gas Emissions

Once emissions consequences of a potential projects have been quantified, FERC should monetize them to help determine whether the emissions are significant under NEPA. Monetization places a dollar figure on how the emission of an additional unit of a greenhouse gas contributes to a variety of economic damages, including property damages, energy demand effects, lost agricultural productivity, human mortality and morbidity, lost ecosystem services and non-market amenities, and so forth.[37] Therefore, with this monetization, FERC can assess and disclose the actual climate consequences of its actions in a meaningful context.

In order to monetize greenhouse gas emissions, FERC should use the best available estimates for the monetized climate damages of greenhouse gases that are consistent with science and economics. Currently, the federal Interagency Working Group on Social Cost of Greenhouse Gasses (IWG)'s 2016 estimates of the Social Cost of Greenhouse Gases[38] reflect the best available science and economics of the monetized climate consequences of a marginal ton of greenhouse gases.[39] And they are widely used in federal and state policymaking.[40] Recently, a federal district court held that the Bureau of Land Management should have used the IWG's social cost of methane estimates instead of the "domestic only" value that was used by the Trump administration.[41] Therefore, FERC should immediately start using the IWG's Social Cost of Greenhouse Gases in its analyses.

However, FERC should also note that there is a broad consensus that the IWG's Social Cost of Greenhouse Gases are understood as a lower bound because they ignore many important costs traceable to greenhouse emissions, such as extreme temperatures and changes in precipitation patterns.[42] If, in the future, the IWG re-convenes and updates these numbers according to scientific and economic principles, for example based on the recommendations of the National Academies of Sciences, Engineering, and Medicine,[43] FERC should start using those updated values.

POLICY RECOMMENDATION: FERC should monetize greenhouse gas emissions using the best available estimates of the Social Cost of Greenhouse Gases.

iii. Alternatives Analysis

NEPA requires agencies to consider a broader range of alternatives than only the proposed project including, minimally, taking no action. Therefore, FERC's obligation under NEPA is not merely to evaluate the reasonably foreseeable environmental consequences of the project proposed in a certificate application, but also to analyze the environmental consequences of potential alternatives that meet the purpose and need of the project.[44] One of those alternatives must be the "no action alternative."[45] Other alternatives could include requiring applicants deploy more aggressive methane leak mitigation or operational limits. This analysis of alternatives can also help inform the analysis FERC must do for its Public Convenience and Necessity Test under the NGA.

With these additional analyses, the climate consequences of a potential project can be evaluated for each of the various reasonable alternatives such as the project with operational limits, the project with methane leak mitigation that exceeds regulatory requirements, and the no-action alternative. FERC can then balance each alternatives' public benefits against its potential adverse consequences and select the approach that is most in the public interest, whether it is approving the project, denying the project, or approving the project with additional requirements.

POLICY RECOMMENDATION: FERC should analyze a broader range of alternatives than just the proposed project under NEPA, including taking no action and requiring more mitigation measures.

2. *Public Convenience and Necessity Test Under the Natural Gas Act*

Under section 7 of the NGA, the construction and operation of all interstate natural gas facilities must first obtain a "certificate of public convenience and necessity issued by the Commission authorizing such acts or operations."[46] FERC is required to approve only those certificates that are "or will be required by the present or future public convenience and necessity."[47] And FERC establishes "such reasonable terms and conditions as the public convenience and necessity may require."[48]

FERC should incorporate climate damages into its process of determining "present or future public convenience and necessity," pursuant to the NGA. The public convenience and necessity standard has been interpreted to encompasses "all factors bearing on the public interest."[49] One factor that bears on the public interest is the environmental effects of a project.[50] Greenhouse gas emissions are environmental effects that must be analyzed by FERC to grant a public convenience and necessity certificate.[51]

FERC can incorporate greenhouse gas emissions into its obligations under section 7 of the NGA in several ways. The first, and potentially the easiest, way is to rely on the type of NEPA analysis as described above when making a public convenience and necessity determination. The second is to use a cost-benefit analysis to determine whether a project passes the public convenience and necessity test.

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i. Using NEPA Analysis to Inform the Public Convenience and Necessity Test

FERC's primary decision under section 7 is to approve or deny a certificate of public convenience or necessity.[52] Quantifying and monetizing emissions under NEPA analysis would give FERC sufficient information to assess the climate effects of a potential natural gas infrastructure project. FERC can incorporate this information into its decisionmaking process under the NGA for determining whether a project is meeting the public convenience and necessity test.

The consideration of alternatives of a particular interstate natural gas pipeline facility in NEPA analysis can also inform FERC as it exercises its NGA obligations. Under NEPA, FERC must analyze both the proposed project and the "no action alternative." If the analysis of the "no action alternative" shows that a new project is not necessary or convenient, including on the basis of excess emissions that are not justified by a project's benefits, the Commission can – and arguably must – deny the section 7 certificate.[53]

Similarly, if the other alternatives analyzed under NEPA show that it makes sense to require the applicant to make certain construction, operational, or other changes that would mitigate the extent of environmental damage, the NGA also allows FERC to establish "reasonable terms and conditions as the public convenience and necessity may require."[54] For example, if NEPA alternative analysis shows that more leak mitigation would reduce greenhouse gases significantly, FERC can require more aggressive methane leak detection and repair regimes.[55]

POLICY RECOMMENDATION: FERC should rely on its NEPA analysis to better inform its decisions under the NGA.

ii. Using Cost-Benefit Analysis to Inform the Public Convenience and Necessity Test

Cost-benefit analysis can provide FERC a useful framework for systematically evaluating certificate applications to assess whether a project is required by public convenience and necessity. FERC already balances different factors presented in particular applications, directly comparing the benefits of a project with at least some of the costs and proceeding to environmental review only if "the benefits outweigh" those costs.[56] However, currently, FERC does not make this determination using any formal or consistent methodology.

Even if it is not required by NEPA or the NGA, a cost-benefit analysis framework in which FERC balances the monetized benefits of additional pipeline infrastructure against the costs of constructing and operating that infrastructure, including greenhouse gases, is an appropriate decisionmaking framework.[57] As the Office of Management and Budget explains, "where all benefits and costs can be quantified and expressed in monetary units, benefit-cost analysis provides decision makers with a clear indication of the most efficient alternative, that is, the alternative that generates the largest net benefits to society (ignoring distributional effects)."[58] In other words, a cost-benefit analysis would allow FERC to rationally and transparently balance the tradeoffs inherent in any public convenience and necessity certificate proceeding.[59]

To adopt cost-benefit analysis as part of its process for issuing certificates under the NGA, FERC would have to anticipate, describe, quantify, and, when possible, monetize the positive and negative consequences of the project and relevant alternatives. Circular A-4 provides detailed guidance for how agencies can think about each of these steps.[60]

Cost-benefit analysis can also help FERC take into account greenhouse gas emissions in its certificate decisions. Because the climate damages by greenhouse gas emissions can easily be monetized using the IWG's Social Cost of Greenhouse Gases, FERC can explicitly consider these effects in its analysis.[61] This explicit consideration leads to more transparent and accountable decisionmaking by FERC when it is trying to balance potential environmental consequences of a potential project with its potential benefits such as the economic value that additional natural gas infrastructure projects brings to market.

POLICY RECOMMENDATION: FERC should adopt a holistic cost-benefit analysis framework to evaluate natural gas infrastructure projects under the NGA.

III. FERC Should Revise Its Transmission Policies to Enable Cost-Effective National Decarbonization

Cost-effectively decarbonizing the electric grid requires a robust federal policy for increasing transmission capacity. While our nation has a high potential for renewable resource generation, these resources are often location-constrained and located geographically far away from load centers.[62] For example, the technical potential for onshore wind is high in the Great Plains and the technical potential for solar is high in the Southwest.[63] As a result, building a network of long-distance transmission lines that can carry clean energy from remote areas to other areas when and where it would be useful – and would displace fossil-fueled generation – is necessary to fully realize the nation's renewable energy potential.

But realizing the goal of an efficient transmission network will require regulatory intervention and federal coordination for at least three reasons. First, it is substantially more efficient to build a single, high-capacity transmission line than to build multiple smaller lines. Given the large economies of scale involved, transmission is generally considered to be a natural monopoly.[64] And ensuring the appropriate quantity and quality of transmission investment by monopolist firms requires economic regulatory intervention.

Second, building transmission lines in one area could bring to broad regions of the country non-excludable benefits, such as reliability and reduced environmental impacts, that would not be recognized by local grid planning processes. Because local grid planning would not perceive the economic value of such "public goods" and so would likely not encourage or

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authorize projects that can capture them, leaving transmission planning to state and local authorities is unlikely to lead to an optimal transmission network. This potential inefficiency is made worse in cases where the relevant grid planning process does not take into account other important potential benefits such as reductions in greenhouse gas emissions. Therefore, interregional, even national, coordination is prudent.[65]

Finally, a transmission network designed optimally to enable decarbonization of electricity grids and other sectors of the economy would have to connect renewable-energy-resource-rich regions to high-load regions, potentially leading to an unequal distribution of costs and benefits among and between the regions. Because such inequities could lead states to prevent transmission lines essential to national decarbonization policy, federal regulatory intervention is imperative.

There are four main ways FERC can help enable the planning and development of a transmission system for cost-effective national decarbonization. Specifically, FERC should do the following: improve the interregional transmission planning process; use a forward-looking cost-benefit analysis framework that can incorporate broader benefits and alternatives into transmission planning based on state-of-the-art planning methodologies; improve regulatory incentives for cost-effective transmission investment using incentive-based regulation; and explore using its "backstop" authority for transmission siting.

FERC can undertake these measures based on its existing authority under the FPA. Under section 201 of the FPA, FERC has jurisdiction over "the transmission of electric energy in interstate commerce . . . [and] all facilities for such transmission."[66] Under section 205 of the FPA, FERC can approve "just and reasonable," and not "unduly discriminatory or preferential" rates for the transmission of electric energy in interstate commerce, proposed by the relevant transmitting utility and under section 206 it can prospectively modify such rates.[67] Under section 219 of the FPA, FERC can incentivize the development and construction of transmission facilities for "the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[68] The incentives issued pursuant to section 219 should "promote reliable and economically efficient transmission and generation of electricity,"[69] and "encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities."[70] There are also other provisions of the FPA that give FERC authority for transmission-related regulation and policy.[71] All these authorities are sufficient for FERC to adopt the reforms outlined below.

A. FERC Should Improve the Regional and Interregional Transmission Planning Process

In 2011, FERC issued Order No. 1000 to promote efficient transmission development.[72] Order No. 1000 was intended to improve regional and interregional coordination, and to create opportunities for non-incumbent transmission developers by requiring competitive development processes for certain regional transmission projects. Further, the Order directed transmission providers to "consider" public policy requirements such as renewable portfolio standards, and hence support the development of transmission facilities that would help meet those goals. However, transmission investment outcomes since Order No. 1000's adoption have been inadequate.

Quantitatively, transmission investment has grown significantly since FERC issued the Order, but there has been limited development of the regional and interregional projects that the Order was meant to encourage.[73] Furthermore, only 3% of post-Order No. 1000 transmission investments have been subject to competition.[74] In fact, currently, most transmission

investment occurs outside of the planning process prescribed by Order No. 1000 due to various exclusions allowed by transmission planning rules or ISO/RTOs.[75] Public policy projects have also seen limited success, partially because of the lack of specific requirements for how to "consider" public policy needs and allocate costs for projects that satisfy these needs.

A decarbonized power system requires significant investment in transmission lines that connect resource-rich areas with load areas, so investments in large interregional projects is a necessity. To ensure that such large-scale investment can be made as efficiently as possible, FERC should prioritize reform of the Order No. 1000 process for transmission planning to foster more interregional coordination, competition, and consideration of public policy needs.

First, FERC should adopt a more stringent and streamlined interregional planning process. A transmission facility that spans multiple regions may obviate multiple local transmission projects, while reducing congestion across the region, potentially at a lower per-unit cost due to economies of scale. FERC already 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."[76] However, FERC stopped short of creating a more structured process for such coordination, leading different regions to adopt their own process, so that a potential interregional project might now have to go through multiple region-specific processes that each use different metrics, sometimes referred to as a "triple hurdle." The lack of significant interregional transmission projects since Order No. 1000's adoption is a clear sign that the current, less formal, process is not working.[77] And, without interregional projects, significant cost savings and other benefits are being left on the table.[78] Therefore, FERC should revisit Order No. 1000 and establish a formal, streamlined interregional planning process that eliminates regulatory barriers to interregional project development.

Second, FERC should adopt a more prescriptive interregional cost allocation process. In Order No. 1000, FERC directed that costs related to interregional projects should be allocated "at least roughly commensurate with the estimated benefits."[79] FERC's goal with this order was to "induce the construction of interregional projects if such facilities address the needs of the transmission planning regions more efficiently or cost-effectively than regional projects."[80] This allocation principle, in theory, should avoid potential free-rider problems associated with public goods, and improve the transparency of the process. However, FERC left to individual planning regions details such as which benefits to include and decisionmaking criteria to employ, and allowed discretion in cost allocation methodologies for different types of transmission projects. The resulting discrepancies created the potential for situations in which an interregional project deemed cost-effective in one region is not deemed cost-effective in the other. Consequently, no interregional competitive transmission project has been built to date. Therefore, FERC should adopt a more prescriptive cost allocation methodology for interregional transmission projects, based on a uniform cost-benefit analysis framework that is applicable to all regions.

Third, FERC should review the competitive exemptions available in the current transmission planning processes and require more competitive transmission development whenever such competition can provide efficiency gains. For example, current planning processes provide exemptions from competitive procurement for local reliability projects or certain supplemental or end-of-life projects that are developed by existing transmission owners. These exemptions potentially harm the cost-effectiveness of transmission development by limiting competition even when it can lead to significant cost reductions (and thus cost savings to ratepayers). Currently about half of the transmission projects are developed outside of the full regional planning processes and hence are not subject to competition.[81] This number is bound to increase given the significant investment required to replace many transmission lines that are nearing the end

of their useful life, as the replacements are more likely to be developed as local projects that are currently exempt from competition. While there might be cases in which it would indeed be more efficient for an incumbent transmission owner to build such projects,[82] it is possible that some of these projects might be developed more efficiently if the incumbents face third-party competitors during the procurement stage. Evidence to date on potential efficiency gains from competition is "sufficiently promising to consider expanding the use of open competitive procurement solicitations for transmission projects."[83] So, FERC should take steps to ensure more projects can be developed through a competitive process, including project categories that have traditionally been exempt from competition.

Finally, FERC should mandate formal requirements and metrics on how to consider public policy goals in both regional and interregional transmission planning. FERC explained in Order No. 1000 that "regional transmission planning could better identify transmission solutions for reliably and cost-effectively integrating location-constrained renewable energy resources needed to fulfill Public Policy Requirements such as the renewable portfolio standards adopted by many states."[84] However, FERC declined to specify criteria for qualifying public policy objectives, either for the purpose of selecting or considering transmission projects. Again, the limited success of public policy projects to date in planning processes shows that FERC should reconsider its approach and require a more formal and standardized metric in relation to the public policy goals that inform some transmission planning.

POLICY RECOMMENDATION: FERC should initiate a process to reform Order No. 1000 transmission planning in a way that would result in more interregional coordination, more competition, and a formal consideration of public policy goals in regional and interregional planning processes.

B. FERC Should Require the Use of a Comprehensive Cost-Benefit Analysis in Transmission Planning

FERC has multi-faceted regulatory responsibility for transmission planning. Under the FPA, FERC has authority over rates for the transmission of electric energy in interstate commerce and all matters directly affecting those rates, such as planning, as well as authority over providing incentives for transmission development to promote reliable and economically efficient transmission and generation of electricity. Carrying out these responsibilities requires FERC to achieve multiple objectives. First, not only must FERC ensure that transmission rates are just and reasonable once transmission infrastructure is built, but it must also ensure that building a given transmission infrastructure project is economically justified in the first place, whether the investment is for the enlargement, improvement, maintenance, or operation of facilities used for interstate transmission. Second, as part of its mandate to encourage efficient transmission investment, FERC must also encourage "deployment of transmission technologies and other measures to increase the capacity and efficiency" of existing infrastructure and their operation.[85]

Requiring a more comprehensive cost-benefit analysis for transmission planning than what is currently used would give FERC a helpful framework for achieving both of these sets of objectives. First, a comprehensive cost-benefit analysis that incorporates broader benefits and costs at the planning stage, including benefits accruing to other parties (such as those resulting from interregional planning or decarbonization), would ensure projects selected *ex ante* for development and cost recovery are economically justified and otherwise prudent both at the time they were selected and over the

foreseeable future.[86] Because this analysis would maximize the expected net present value of total benefits minus total costs when viewed *ex ante*, it should lead to more economically-efficient, if not optimal, transmission investment.[87] Thus, such a cost-benefit analysis, in combination with the Order No. 1000 reforms suggested above, could address shortcomings of the current planning process and help ensure socially beneficial transmission development in accordance with decarbonization goals.

Second, a comprehensive cost-benefit analysis that compares different technologies, including alternative transmission technologies that can help reduce congestion and increase reliability, would ensure that those alternative technologies can compete with transmission infrastructure on a level playing field. Thus, using a cost-benefit analysis would encourage deployment of such technologies when it would be more economically efficient to do so.

Therefore, FERC should require that transmission planners conduct a more comprehensive cost-benefit analysis for transmission planning. Importantly, to ensure that the use of cost-benefit analysis helps FERC to achieve its regulatory mandate, FERC must require that cost-benefit analyses satisfy the following criteria. First, the analysis should include all costs and benefits related to a potential transmission project, including those that accrue to parties other than the consumers and producers of the region or regions in which that project will be located. Second, the analysis should compare proposals of transmission infrastructure projects, as well as proposals of alternative technologies and measures that can help achieve the same outcomes as traditional transmission infrastructure. And, third, this analysis should be done in a forward-looking manner using state-of-the-art planning methodologies and should take into account how the mix of generation resources will change as the grid is decarbonized.

1. Incorporating Broader Categories of Costs and Benefits, Including Environmental Costs and Benefits

Currently, in many regions, the transmission planning process already includes an economic analysis to assess the impacts of transmission solutions proposed to address reliability or economic needs.[88] The nature and the scope of this analysis varies across regions.[89] Most intuitive categories of benefits, such as production cost savings and reduced transmission losses, are included relatively consistently across ISO/RTOs. However, the consideration of societal benefits, such as reduced emissions or interregional reliability benefits, is currently inconsistent. Because decarbonization benefits accrue to more than just one region, failing to consider broader societal benefits will not lead to efficient transmission development.

FERC, therefore, should direct ISO/RTOs to explicitly account for broader societal effects in transmission planning, such as climate effects and other externalities.[90] ISO/RTOs should quantify and monetize greenhouse gas emissions and other pollutants associated with proposed projects, and incorporate those into their transmission planning analysis. Requiring transmission planners to consider these benefits, in combination with requiring interregional planning as suggested above, would lead to the development of cost-effective regional and interregional transmission projects that support nationwide decarbonization.

POLICY RECOMMENDATION: FERC should require a cost-benefit analysis that considers societal benefits, including environmental benefits, for transmission planning.

2. *Incorporating Alternatives to Transmission Infrastructure*

New technological options such as dynamic and adaptive line rating, advanced flow controls, or topology controls can improve the operation and efficiency of existing infrastructure.[91] However, current transmission planning processes and regulatory mechanisms put these technologies at a disadvantage, hindering cost-effective infrastructure development. As a result, FERC is not providing incentives that lead to efficient transmission infrastructure investment.

FERC could improve the incentives for deploying these technologies, and thereby increase the efficiency of transmission investments, by requiring the explicit consideration of these alternatives in the transmission planning process. Similar to the alternatives analysis required by NEPA, FERC could require ISO/RTOs to consider a no-action alternative, and a various-transmission-technologies alternative in the planning process. That way, these technologies would be prioritized if the cost-benefit analysis shows that they can help meet reliability, economic, and/or public policy needs in a cheaper manner than capital-intensive transmission lines, leading to cost-effective transmission infrastructure investment. FERC, as part of its prudence review, could also require a utility show that it has considered these alternatives in its decisionmaking.

In addition, non-transmission technologies such as energy storage, distributed generation, and demand response can also help replace or delay the need for transmission infrastructure.[92] FERC should direct ISO/RTOs to include such alternatives in their analysis to see if any of these technologies can provide cost-effective solutions instead of building additional transmission lines.

POLICY RECOMMENDATION: FERC should require a cost-benefit analysis that considers various transmission and non-transmission technologies and measures.

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3. *Forward-Looking Analysis Using the Best Available Methodologies*

Current analyses for proposed transmission projects look at costs and benefits mostly based on the current mix of generation resources, ignoring the large-scale changes needed in the generation mix to meet decarbonization goals. Most planners use "production-cost" models, which simulate optimal dispatch given a generation mix of existing and planned resources that are sufficiently far along in a region's interconnection process, and show how energy markets would behave under different transmission configurations, to assess the costs and benefits of predefined transmission and generation scenarios.[93] As a result, these analyses pick the best projects to reduce congestion and production costs given the production profile and location of existing and planned generation resources, of which the existing resources are mostly fossil-fuel-fired. Therefore, projects deemed net beneficial and selected with this kind of analysis, even if all costs and benefits are quantified and monetized, might not actually be economically "efficient" when considered from a long-run decarbonization perspective, because their selection will wrongly assume a resource mix that is largely static, and not sufficiently dynamic or adaptive to reflect rapidly changing conditions on regional grids.[94]

Furthermore, when analyzing projects, planners rely on model tools that look at outcomes under a limited number of predefined scenarios in which factors such as load growth and fuel prices vary. With this kind of modeling, a particular transmission plan is selected if it performs well under those well-defined scenarios. However, uncertainties arising from a clean energy transition–related not just to growing volumes of intermittent and variable renewable energy resources but also building electrification and deployments of distributed energy resources, electric vehicles, and other smart appliances–are more numerous and important than ever. Such deep uncertainties require transmission planning that can be adaptive and flexible.[95] And, transmission plans that can perform well under these uncertainties because they are flexible enough to provide a hedge against the uncertainties are unlikely to fare well when analyzed under only one of the specific scenarios alone, and hence, are unlikely to be chosen using today's planning tools.[96]

Therefore, FERC should require transmission planners to use forward-looking analysis that takes into account the types and locations of resources that are necessary to meet decarbonization goals, as well as the deep uncertainties that a rapid clean energy transition will bring.[97] A proactive transmission planning framework that co-optimizes transmission and generation investment, and considers the variability of renewable resources is essential to implementing meaningful climate policy. This type of analysis not only would help build a cost-effective transmission network that can enable decarbonization goals, but would also prevent building costly transmission lines that might be useful for only a limited period of time.

POLICY RECOMMENDATION: FERC should require use of forward-looking cost-benefit analysis that considers changes in generation resources consistent with decarbonization goals.

C. FERC Should Improve Regulatory Incentives to Achieve Cost-Effective Transmission Development

FERC mostly uses cost-of-service regulation to determine rates for the transmission of electric energy in interstate commerce. Under this type of regulation, transmission owners can charge rates and receive revenues intended to recover their costs plus a "reasonable" return on invested equity capital (ROE). FERC relies on financial models and risk analysis to calculate a "zone of reasonableness" for ROEs, and uses the mid-point of a particular risk category to set a just and reasonable ROE for a utility with a given risk profile.[98] Some transmission facilities might also use negotiated rates, but cost-of-service regulation predominates.

Cost-of-service regulation, however, creates two problems that are detrimental to cost-effective transmission development. First, it creates a moral hazard problem.[99] Because the costs of transmission facilities (including a return of and on invested capital) generally would be covered no matter what, the developers of projects have little incentive to take any action that would reduce their capital and operating costs. Second, it creates a bias toward high-capital projects.[100] Because the developers earn a return of and on their capital expenditures, they have an incentive to invest in more capital intensive projects, even when there is a less capital intensive project that can accomplish the same goal. As a result, there might be more than the efficient level of high-capital expenditures, and higher rates, under this type of regulation. FERC's apparent reluctance to question the prudence of utility capital investments only exacerbates this perverse incentive.

FERC, in order to satisfy its mandate to encourage economically efficient levels of capital investment in transmission, should reconsider the regulatory incentives it provides. One alternative is to move towards incentive- or performance-based regulation. While this kind of regulation can take many different forms,[101] shared-savings mechanisms can be especially important for developing efficient transmission. These kinds of mechanisms reward developers with a guaranteed share of cost savings compared to a baseline, aligning the developer's incentives with society's interest in finding the most efficient transmission solution for achieving policy goals. They also help mitigate cost overruns due to moral hazard problems. Similarly, FERC can encourage the use of cost-containment mechanisms or cost caps.

Another alternative is to rely on FERC's existing transmission incentives mechanisms, which provide ROE adders to certain types of projects[102] and bring their ROE to the upper range of the zone of reasonableness, to incentivize more competition and better project selection. For example, a "competition" ROE incentive awarded to projects selected through an open competitive process could lead to more competitive solicitations. Or, an ROE adder could be awarded if the selection process quantified all costs and benefits, if various transmission and non-transmission alternatives were considered, or the selected project had the highest net benefits among all proposed projects. Importantly, FERC can use this mechanism to also provide ROE disincentives if projects were not adopted using a robust and comprehensive societal cost-benefit perspective. For example, FERC can start adjusting the existing ROE-based incentives down so that inferior transmission solutions are allowed ROEs that are closer to the lower end of the zone of reasonableness. Even though the zone of reasonableness could be narrow and this downward adjustment could end up being only one percentage point or less, it could still lead to a significant behavior change given the high capital intensiveness of transmission projects.

POLICY RECOMMENDATION: FERC should improve regulatory incentives for cost-effective transmission development.

D. The Department of Energy Should Delegate Its Authority to Designate National Interest Electric Transmission Corridors to FERC

Section 216 of the FPA provides FERC with "backstop" siting authority for transmission lines to override state barriers to transmission siting.[103] However, this authority is conditional on the Department of Energy (DOE) identifying areas of the country that experience transmission constraints and congestion, and classifying these areas as National Interest Electric Transmission Corridors (NIETCs). Previous attempts for NIETC designations have been vacated for failure to adequately consult the states and failure to adequately consider environmental impacts as required by NEPA.[104] And that absence of a successful NIETC designation has prevented the exercise of federal authority over transmission siting.

Under section 216(a), DOE is required to conduct congestion studies every three years "in consultation with affected States."[105] After conducting a congestion study, DOE may decide to designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers" as an NIETC.[106] Before issuing a report that designates a NIETC, DOE must consider "alternatives and recommendations from interested parties (including an opportunity for comment from affected States)."[107] Failure to adequately consult states when conducting a congestion study could render the entire report invalid.[108]

DOE, under the Department of Energy Organization Act, has the authority to delegate its authority to designate NIETCs to FERC,[109] and should do so to increase the frequency and quality of NIETC designations. Designating new national corridors requires, at minimum, sufficient state consultation and a NEPA review. FERC staff already regularly navigate state and Indian tribe consultation requirements,[110] Endangered Species Act requirements,[111] and NEPA obligations[112] to complete infrastructure licensing projects. Further, because NEPA analysis is required at both the national corridor and project siting stages, delegation to FERC would allow the Commission to use the same staff, procedures, and information to complete both analyses. Thus, FERC would be better positioned than DOE to conduct the Congestion Reports and NIETC designations required by section 216.

POLICY RECOMMENDATION: DOE should delegate its authority to designate NIETCs to FERC to empower FERC to use its backstop transmission siting authority.

IV. FERC Should Reform Its Electricity Market Rules to Ensure Effective Participation of New Technologies and High Penetration of Renewable Energy Resources

Market rules in organized wholesale markets ensure reliability at lowest cost. To achieve this goal, market operators rely on carefully designed auctions, which optimize the operation of all generators based on generators' marginal costs and other operational characteristics to determine prices that would ensure economic efficiency and sufficient generation to provide reliable electricity service.[113] Yet, most wholesale market rules are designed with fossil-fueled resources in mind. And high penetration of renewable resources, which are low- or zero-marginal cost resources with intermittent and variable generation patterns, will require a rethinking of the design of organized wholesale electricity markets.

Fossil-fuel-fired resources are more dispatchable; they can generate electricity whenever needed, subject to their ramping requirements. As a result, grid operators can balance electricity demand and supply by mostly relying on changing the dispatch of these resources, without the need of additional price signals for being flexible in either the amount generators produce or the amount consumers demand. In addition, these resources have non-zero marginal costs because they require fuel for generation. And, because current market pricing rules aim to have prices equal marginal costs, a generation mix with high percentage of fossil-fuel-fired resources leads to energy prices that are high enough to create sufficient energy revenue opportunities for all power plants, without having to rely too much on additional remuneration mechanisms for capacity.[114]

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However, decarbonizing the electric sector will require high penetration of new and cleaner resources, which have different generation and cost profiles. Their generation is intermittent and variable depending on weather patterns, so they might not always be dispatchable. As a result, there is a greater and growing need for resources that can quickly change their supply or demand, or provide power for multi-day periods experiencing limited solar and wind output, to ensure that electricity supply and demand can be balanced at all times. Accommodating the deployment and operation of these resources will require changes to market rules such as enhancing scarcity pricing, incorporating fast start pricing, or thinking about new ramping products.

At the same time, renewable resources generally have an almost zero marginal cost of generation. As a result, it is a non-trivial task to figure out how to design energy or capacity markets to set economically efficient prices that would also be sufficient to incentivize the construction of new generation needed to meet peak demand.[115] Furthermore, because there could be significant variability in the output of these resources, market designs need to evolve to more accurately value services these resources provide, such as the ability to quickly increase or decrease production or to generate energy during scarcity periods. With the increased penetration of intermittent resources, ensuring that prices can reflect the economic value of energy and incremental reserves is critical to efficient market operation.[116] Similarly, because both the availability of renewable resources and the electricity demand might vary significantly throughout the year, the design of capacity markets must evolve to take seasonal variations into account.[117]

Not all wholesale market operators are thinking thoroughly about these issues or acting as swiftly as they should given the urgency and magnitude of needed changes. While there are some ISO/RTOs that have just started discussing market design for a high-renewables future, a consistent investigation across all market operators is lacking.[118] All ISO/RTOs should already be thinking about, and even moving forward with implementing, technology-neutral regulatory frameworks that can accommodate all new resources based on the value they bring to grid, including their external costs and benefits, and regardless of their scale. Further, many market operators look at one rule at a time, even though an effective overhaul will require consideration of the entire design in a comprehensive manner. Therefore, FERC should direct ISO/RTOs to conduct a comprehensive evaluation of their market rules.

POLICY RECOMMENDATION: FERC should establish principles for market rules that can enable technology-neutral participation of clean and renewable energy resources, and direct ISO/RTOs to ensure their market rules satisfy those principles.

V. Conclusion

Even though FERC does not generally receive immediate attention as an important agency for climate policy, implementing regulatory reforms in FERC-jurisdictional sectors is crucial to cost-effective decarbonization of the energy sector. To help meet the nation's climate policy goals, FERC should reform its regulatory practices to align better with climate policies, develop transmission infrastructure necessary for cost-effective decarbonization, and reform its energy market rules to enable technology-neutral participation of clean and renewable energy resources. And, as outlined above, FERC has the authority to undertake all of these reforms under existing law. With these reforms, federal policymakers can take advantage of important opportunities energy markets can provide to combat climate change while ensuring an economically efficient and speedy clean energy transition.

Endnotes

[1] *Frequently Asked Questions About FERC*, Fed. Energy Reg. Comm'n, https://www.ferc.gov/about/what-ferc/frequently-asked-questions-faqs/frequently-asked-questions-faqs-about-ferc (last visited Aug. 3, 2020).

[2] *See, e.g.,* Arthur Pigou, The Economics of Welfare (1920); *see also* Climate Leadership Council, https://clcouncil.org/ (last visited Aug. 3, 2020).

[3] Fed. Energy Reg. Comm'n, Energy Primer: A Handbook for Energy Market Basics 40 (2020), https://www.ferc.gov/market-assessments/guide/energy-primer.pdf.

[4] Request for Technical Conference or Workshop of the Interested Parties regarding Carbon Pricing in FERC-Jurisdictional Organized Regional Wholesale Electric Energy Markets, Docket No. AD20-14 (FERC) (Apr. 13, 2020), https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14851162 (filed jointly by American Council On Renewable Energy, American Wind Energy Association, Brookfield Renewable, Calpine Corporation, Competitive Power Ventures, Inc., Electric Power Supply Association, Independent Power Producers Of New York, Inc., Ls Power Associates, L.P., Natural Gas Supply Association, Nextera Energy, Inc., PJM Power Providers Group, R Street Institute, and Vistra Energy Corp); *see also* Carbon Pricing in Organized Wholesale Electricity Markets, Docket No. AD20-14 (FERC), https://elibrary.ferc.gov/idmws/docket_sheet.asp?docket=AD20-14&Subdocket=000.

[5] This can be done in multiple ways. For example, the market operator itself can add a charge onto the cost bids, or can ask the generators to include a charge in their bids.

[6] Matt Butner et al., Carbon Pricing in Wholesale Electricity Markets: An Economic and Legal Guide § I.B (2020), https://policyintegrity.org/publications/detail/carbon-pricing-in-wholesale-electricity-markets.

[7] *Id.* § III.

[8] *See* 16 U.S.C. §§ 824d, 824e.

[9] *See* City of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984); *accord* Cal. Indep. Sys. Operator Corp., 141 FERC ¶ 61,237, at 23 (2012); City of Winnfield v. FERC, 744 F.2d 871, 875 (D.C. Cir. 1984).

[10] Butner et al., *supra* note 6. *See also* Bethany A. Davis Noll & Burcin Unel, *Markets, Externalities, and the Federal Power Act: The Federal Energy Regulatory Commission's Authority to Price Carbon*, 27 NYU Envtl. L.J. 1 (2019).

[11] Butner et al., *supra* note 6, at 33-45.

[12] *Id.*

[13] Atlantic City Elec. Co. v. FERC, 295 F.3d 1, 10 (D.C. Cir. 2002) (quoting *City of Winnfield*, 744 F.2d at 876).

[14] *Carbon Pricing*, N.Y. Indep. Sys. Operator, https://www.nyiso.com/carbonpricing (last visited Aug. 3, 2020).

[15] *Carbon Pricing Senior Task Force*, PJM, https://www.pjm.com/committees-and-groups/task-forces/cpstf.aspx (last visited Aug. 3, 2020).

[16] *See* 16 U.S.C. § 824e.

[17] Emera Maine, 155 FERC ¶ 61,233, at 32-39 (2016); *see also Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,237, at 30.

[18] Davis Noll & Unel, *supra* note 10, at 26-41 (discussing examples).

[19] At the time of writing, FERC had scheduled but not yet conducted a carbon pricing technical conference. However, the scope of the scheduled technical conference was too limited to consider recommendations outlined in this document about FERC implementing a carbon-pricing rule under Section 206.

[20] Jack Perrin & Troy Cook, *Today in Energy: Hydraulically Fractured Wells Provide Two-thirds of U.S. Natural Gas Production*, U.S. Energy Info. Admin. (May 5, 2016), https://www.eia.gov/todayinenergy/detail.php?id=26112.

[21] *See, e.g., Mountain Valley Project and Equitrans Expansion Project Final Environmental Impact Statement*, Fed. Energy Regulatory Comm'n, Docket Nos. CP16- 10-000, CP16-13-000, ES-4-ES-16 (2017) (describing potential harms to safety, the community, and the environment of the Mountain Valley Project).

[22] *See* James Bradbury et al., U.S. Dep't of Energy, Greenhouse Gas Emissions and Fuel Sue within the Natural Gas Supply Chain – Sankey Diagram Methodology 8-9 (2015), https://www.energy.gov/sites/prod/files/2015/07/f24/QER%20Analysis%20-%20Fuel%20Use%20and%20GHG%20Emissions%20from%20the%20Natural%20Gas%20System%2C%20Sankey%20Diagram%20Methodology_0.pdf.

[23] 15 U.S.C. § 717(a); *see also id.* § 717f(c), (e).

[24] For a more detailed discussion see Jayni Hein et al., Pipeline Approvals and Greenhouse Gas Emissions (2019), https://policyintegrity.org/files/publications/Pipeline_Approvals_and_GHG_Emissions.pdf.

[25] *Id.*

[26] *Id.*

[27] *Id.*

[28] 42 U.S.C. § 4332(C).

[29] Hein et al., *supra* note 24.

[30] *See, e.g.,* Sierra Club v. Fed. Energy Regulatory Comm'n, 867 F.3d 1357, 1372 (D.C. Cir. 2017); WildEarth Guardians v. BLM, 870 F.3d 1222, 1237-38 (10th Cir. 2017); Mid States Coal. for Progress v. Surface Transp. Bd., 345 F.3d 520, 549-50 (8th Cir. 2003) ("Mid States"); Montana Envtl. Info. Ctr. v. U.S. Office of Surface Mining, 274 F. Supp. 3d 1074, 1090-91 (D. Mont. 2017); San Juan Citizens Alliance et al v. BLM, 326 F.Supp.3d 1227, at 1243-44 (D. N.M. 2018); W. Org. of Res. Councils v. BLM, No. CV-16-21-GF-BMM, 2018 WL 1475470 at *13 (D. Mont. Mar. 26, 2018); Wildearth Guardians v. Zinke, No. 1:16-cv-01724-RC, 2019 WL 1273181 (D.D.C. Mar. 19, 2019).

[31] *See, e.g.,* New Market Project Rehearing Order, 163 FERC ¶ 61,128 at 62-66; Broad Run Project Rehearing Order, 163 FERC ¶ 61,190 at 60-61 (rejecting the need for additional analysis of upstream and downstream analysis as part of an EA because Commission stated that upstream and downstream emissions were not reasonably foreseeable given the information before it).

[32] *See* Hein et al., *supra* note 24, at 12-20 (providing details about how FERC can quantify such emissions.)

[33] *Id.*

[34] *Id.* at 20-22.

[35] *Id.* at 22-28.

[36] *Id.*

[37] Interagency Working Grp. on the Soc. Cost of Carbon, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2010), https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/scc_tsd_2010.pdf.

[38] Interagency Working Grp. on the Soc. Cost of Greenhouse Gases, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2016), https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

[39] *See* Richard L. Revesz et al., *Best Cost Estimate of Greenhouse Gases*, 357 Science 6352 (2017).

[40] The Cost of Carbon Pollution, Inst. for Policy Integrity, https://costofcarbon.org/ (last visited Aug. 3, 2020).

[41] California v. Bernhardt, No. 4:18-CV-05712-YGR, 2020 WL 4001480 at *25-27 (N.D. Cal. July 15, 2020).

[42] *See* Institute for Policy Integrity, Issue Brief: A Lower Bound: Why the Social Cost of Carbon Does Not Capture Critical Climate Damages and What That Means for Policymakers (2019).

[43] Nat'l Acad. Sci., Eng. & Medicine, Valuing Climate Damages: Updating Estimates of the Social Cost of Carbon Dioxide 3 (2017).

[44] 40 C.F.R. § 1502.14(a) (calling the alternatives analysis "the heart of the environmental impact statement" because it "sharply defin[es] the issues and provid[es] a clear basis for choice among options by the decisionmaker and the public").

[45] *Id.* § 1502.14(d).

[46] 15 U.S.C. § 717f(c)(1)(A).

[47] *Id.* § 717f(e).

[48] *Id.*

[49] Atl. Refining Co. v. Pub. Serv. Comm'n of N.Y., 360 U.S. 378, 391 (1959).

[50] Hein et al., *supra* note 24, at 9.

[51] *Id.* at 8-12.

[52] 15 U.S.C. § 717f(e) ("a certificate shall be issued to any qualified applicant . . . if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed . . . and that the [project] . . . is or will be required by the present or future public convenience and necessity; *otherwise such application shall be denied*") (emphasis added).

[53] Hein et al., *supra* note 24, at 8-12 and 52-54.

[54] 15 U.S.C. § 717f(e).

[55] Hein et al., *supra* note 24, at 52.

[56] *1999 Policy Statement*, 88 FERC ¶ 61,227 at 61,746 ("Only when the benefits *outweigh* the adverse effects on economic interests will the Commission then proceed to complete the environmental analysis") (emphasis added).

[57] Hein et al., *supra* note 24, at 54-56; *see also* Avi Zevin, *Regulating the Energy Transition: FERC and Cost-Benefit Analysis*, 45 Colum. J. Envtl. L. 419, 487-516 (2020) (discussing opportunities and authority of FERC to apply cost-benefit analysis).

[58] Office of Mgmt. & Budget, Circular A-4, Regulatory Analysis 2 (2003).

[59] Even when some benefits or costs are difficult to quantify and monetize, the analysis should include any relevant quantitative and qualitative information, and a clear explanation of how these benefits and costs affect a policy choice. *Id.* 26-27.

[60] *See generally id.* at 14-42.

[61] Hein et al., *supra* note 24, at 37-52.

[62] *Renewable Energy Technical Potential*, Nat'l Renewable Energy Lab., https://www.nrel.gov/gis/re-potential.html (follow "Maps" hyperlink; then follow "United States Renewable Energy Technical Potential" hyperlink).

[63] *Id.*

[64] Academics have also analyzed "merchant" transmission projects that is funded solely through congestion rents and showed that this model can lead to desirable results under a set of assumptions. But they have also concluded that those conditions were not realistic. *See, e.g.,* Paul Joskow & Jean Tirole, *Merchant Transmission Investment*, 53 J. Industrial Econ. 233 (2005), https://economics.mit.edu/files/1179. However, there are alternative models of competition that could be compatible with the technical and institutional settings in the U.S. such as the "competitive transmission procurement model." *See* Paul Joskow, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, at 4, 6 (CEEPR WP 2019-004, 2019) [hereinafter *Competition for Electric Transmission Projects*], http://ceepr.mit.edu/files/papers/2019-004.pdf. There have also been some "merchant" projects which interconnect regional grids that have been built based on purely economic benefits to their participants (e.g., interregional differences in prices for electric energy and capacity). *Id.* at 24-26.

[65] Johannes Pfeifenberger & Judy Chang, The Brattle Group, Well Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future 8-10 (2016), https://www.eesi.org/files/WIRES-Report-Well-Planned-Electric-Transmission-Saves-Customer-Costs.pdf (showing the potential cost savings from interregional transmission planning approaches compared to using traditional approaches).

[66] 16 U.S.C. § 824(b)(1).

[67] *Id.* § 824(d), (e).

[68] *Id.* § 824s(a). Pursuant to section 219, FERC issued Order No. 679. Promoting Transmission Investment Through Pricing Reform, 116 FERC ¶ 61,057 (2006). Five months later, FERC issued amendments to Order No. 679 on rehearing, Order No. 679-A. Promoting Transmission Investment Through Pricing Reform, 117 FERC ¶ 61,345 (2006). Order No. 679 created a number of different incentives with the goal of encouraging new transmission investment or removing impediments and disincentives, such as the potential lack of recovery costs, to investment. These incentives include ROE-based incentives (e.g. ROE risk adder, transco adder, and RTO participation adder) and risk-reducing incentives (e.g. Abandoned plant incentive, construction-work-in-progress incentive).

[69] *Id.* § 824s(b)(1).

[70] *Id.* § 824s(b)(3).

[71] *See id.* § 824a(a) (establishing authority for FERC to establish voluntary regional districts for the efficient transmission of electricity); *id.* § 824j(a) (providing FERC authority to issue an order to an electric utility requiring wheeling of electric energy over that utility's transmission facilities); *id.* § 824o (providing FERC authority to establish minimum reliability standards for the bulk-power system, including standards related to transmission); *id.* § 824p (providing FERC authority to site interstate transmission facilities in certain circumstances). *See also id.* § 824p (giving FERC authority to "determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation" whenever it "upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any interstate service of any public utility is inadequate or insufficient." While there has been little precedent under this section, FERC has previously used its authority under this section to direct PJM and Potomac Electric Power Company "to develop and implement comprehensive long-term plans for the operation, planning and construction of transmission facilities to address the current reliability risks to the system." District of Columbia Public Service Commission, 114 FERC ¶ 61017, 61042 (2006).

[72] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051 (2011).

[73] Johannes P. Pfeifenberger et al., The Brattle Group, Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value 2-3 (2019) [hereinafter *Brattle Study*]. Note that Order No. 1000 required regional transmission planning outside of RTO regions. While all regions have submitted Order 1000-compliant plans, no competitive transmission project has been developed outside of RTO regions. *Id.* at 47. *See also* Joskow, *Competition for Electric Transmission Projects*, *supra* note 64.

[74] Pfeifenberger et al., *Brattle Study*, *supra* note 73, at 18.

[75] *Id.* at 20 fig.7.

[76] Order 1000, *supra* note 72, ¶ 81 (2011).

[77] Pfeifenberger & Chang, *supra* note 66, at 1 ("…seven years after FERC Order No. 1000, major regional investments have been limited and interregional projects are almost non-existent.")

[78] *Id.* at iii ("we estimate that the net savings associated with a proactive transmission planning and development process in the U.S. would range from (a) $30–70 billion of savings in total generation and transmission investment costs through 2030 for compliance with current regulations to (b) $47 billion/year of savings in annual customer bills under an even more environmentally-constrained future in which a well-planned grid significantly reduces generation investment and operating costs.")

[79] Order 1000, *supra* note 72, ¶ 622 (2011).

[80] Ameren Services Company v. Federal Energy Regulatory Commission, 893 F.3d 786, 789 (D.C. Cir. 2018) (internal quotation marks omitted).

[81] Pfeifenberger et al., *Brattle Study*, *supra* note 73, at 25.

[82] Joskow, *Competition for Electric Transmission Projects*, *supra* note 64, at 53.

[83] *Id.* at 60.

[84] Order 1000, *supra* note 72, ¶ 80 (2011).

[85] 16 U.S.C. § 824s(b)(3).

[86] In the past, FERC has refused to adopt a cost-benefit analysis related to transmission incentives. *See* Zevin, *supra* note 57, at 433. However, in that case, the analysis in question would have looked at whether providing additional incentives to an already-chosen project would pass the cost-benefit test. Our suggestion here is for an earlier step; which, if any, project should be chosen to satisfy a particular transmission need.

[87] William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, 7 Econ. Energy & Envtl. Policy 1, 26 (2018), http://www.iaee.org/en/publications/eeeparticle.aspx?id=202.

[88] Joseph H. Eto, Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans 18 (2nd ed. 2017), https://eta-publications.lbl.gov/sites/default/files/lbnl_1006331rev2.pdf.

[89] *Id.* at 24-28 tbl.4, 29-32 tbl.5.

[90] For a list of comprehensive benefits see Johannes Pfeifenberger, Improving Transmission Planning: Benefits, Risks, and Cost Allocation 13 (Nov. 6, 2019), https://brattlefiles.blob.core.windows.net/files/17555_improving_transmission_planning_-_benefits_risks_and_cost_allocation.pdf.

[91] T, Bruce Tsuchida & Rob Gramlich, Improving Transmission Operating with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives 5-20 (June 24, 2019), https://brattlefiles.blob.core.windows.net/files/16634_improving_transmission_operating_with_advanced_technologies.pdf.

[92] Shelley Welton, *Non-Transmission Alternatives*, 39 Harv. Envtl. L. Rev. 457, 464-65 (2015), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2497475.

[93] *See generally* Benjamin F. Hobbs et al., *Adaptive Transmission Planning: Implementing a New Paradigm for Managing Economic Risks in Grid Expansion*, 14 Inst. Electrical Electronics Engineers Power and Energy Mag. 30 (2016), https://ieeexplore.ieee.org/document/7491446.

[94] *Id.*

[95] *Id.*

[96] *Id.*

[97] For an example of this type of analysis see *Interconnections Seams Study*, Nat'l Renewable Energy Lab, https://www.nrel.gov/analysis/seams.html (last visited Aug. 3, 2020).

[98] *See* Ass'n of Businesses Advocating Tariff Equity, Order No. 569, 169 FERC ¶ 61,129 (2019).

[99] *See* Paul Joskow, *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks*, in Economic Regulation and Its Reform: What Have We Learned? 291, 295 (Nancy Rose ed., 2014).

[100] *See* Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 Am. Econ. Rev. 1052 (1962).

[101] *See generally* David E.M. Sappington et al., *The State of Performance-Based Regulation in the U.S. Electric Utility Industry*, 14 Electricity J. 71 (2001), https://www.sciencedirect.com/science/article/pii/S1040619001002408.

[102] *See supra* note 68.

[103] 16 U.S.C. § 824p.

[104] *See* California Wilderness Coalition v. DOE, 631 F.3d 1072 (9th. Cir. 2011).

[105] 16 U.S.C. § 824p(a)(1).

[106] *Id.* § 824p(a)(2).

[107] *Id.* § 824p(a)(2).

[108] *See California Wilderness Coalition* 631 F.3d at 1079.

[109] 42 U.S.C. § 7252 ("Except as otherwise expressly prohibited by law, and except as otherwise provided in this chapter, the Secretary may delegate any of his functions to such officers and employees of the Department as he may designate, and may authorize such successive redelegations of such functions within the Department as he may deem to be necessary or appropriate.")

[110] *See, e.g.,* Order No. 635, 104 FERC ¶ 61,108 (2003); 18 C.F.R. § 4.41 (1976).

[111] FERC provides applicants pre-filing assistance in order to comply with the Endangered Species Act. Fed. Energy Reg. Comm'n, Hydro powering Licensing And Endangered Species: A Guide For Applicants, Contractors, And Staff 14 (2001), https://www.ferc.gov/sites/default/files/2020-04/HydropowerLicensingandEndangeredSpecies.pdf.

[112] Department of Transportation v. Public Citizen, 541 U.S. 752 (2004) (requiring NEPA compliance from FERC).

[113] *See* Peter Crampton, *Electricity Market Design*, 33 Oxford Rev. Econ. Pol'y 589, 594-96, 598 (2017).

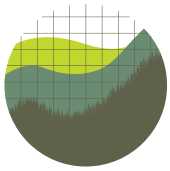
[114] Some wholesale markets have additional capacity markets that pay resources for being available during peak periods to help with ensuring resource adequacy. Even in those markets, energy markets currently provide the majority of the revenues for power plants. However, that percentage has been decreasing over the past years.

[115] *See Wind's Near-Zero Cost of Generation Impacting Wholesale Electricity Markets*, Dep't of Energy (May 8, 2018), https://www.energy.gov/eere/wind/articles/winds-near-zero-cost-generation-impacting-wholesale-electricity-markets; *see also Hydropower Upgrades to Yield Added Generation at Average Costs Less Than 4 cents per kWh – Without New Dams*, Dep't of Energy (Nov. 4, 2009), https://www.energy.gov/articles/hydropower-upgrades-yield-added-generation-average-costs-less-4-cents-kwh-without-new-dams (touting extremely low marginal cost of power produced by new hydroelectric technology); *Geothermal FAQs*, Dep't of Energy, https://www.energy.gov/eere/geothermal/geothermal-faqs (last visited Sept. 12, 2019).

[116] William W. Hogan & Susan L. Pope, PJM Reserve Markets: Operating Reserve Demand Curve Enhancements (2019), https://scholar.harvard.edu/whogan/files/hogan_pope_pjm_report_032119.pdf.

[117] *See* Sylwia Bialek & Burcin Unel, *Will You Be There for Me the Whole Time? On the Importance of Obligation Periods in Design of Capacity Markets*, 32 The Electricity Journal 21, 22 (2019), https://policyintegrity.org/files/publications/On_the_importance_of_obligation_periods.pdf.

[118] New York Independent System Operator's Grid in Transition work provides a good outline of the analysis that is needed. *See* New York Indep. Sys. Operator, Reliability and Market Considerations for a Grid in Transition (2019), https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf/61a69b2e-0ca3-f18c-cc39-88a793469d50.



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