THE LAW AND ECONOMICS OF TRANSMISSION PLANNING AND COST ALLOCATION

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Synopsis: This Article considers how to allocate the costs of transmission when states, utilities, or other classes of customers adopt different clean energy policies. It explains that the beneficiary pays approach to cost allocation does not result in some customers being forced to pay for their neighbors' benefits and is therefore consistent with the Federal Power Act's (FPA) prohibition on undue discrimination. In fact, beneficiary pays is likely the *only* approach to cost allocation that does not result in some customers free riding off their neighbors' transmission investments. For that reason, every federal court that has reviewed methods for allocating the costs of regionally planned transmission lines has required FERC and transmission planners to use the beneficiary pays approach. The Article also summarizes the last hundred years of federal interventions in transmission and natural gas markets to demonstrate that this view is consistent with decades of judicial, congressional, and regulatory policy, and it explains how beneficiary pays can be implemented when different states and classes of customers adopt different energy policies.

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I. INTRODUCTION

In May 2024, the Federal Energy Regulatory Commission (FERC) issued an Order—Order No. 1920—that aims to improve the processes for planning and allocating the costs of transmission investments.[1] Order No. 1920 imposes two important new requirements on transmission planners. First, it requires forward-looking, long-term regional planning that considers at least seven types of benefits of proposed lines.[2] Second, it instructs transmission planning entities to allocate the costs of new lines and upgrades such that customers pay their share of the benefits.[3] This approach to cost allocation, known as beneficiary pays, stipulates that customers cannot be charged for benefits they do not receive, and they cannot free ride off their neighbors by benefitting from new lines without having paid their share.

In a sharp dissent, Commissioner Mark Christie argued that the Order forces states to pay for neighboring states' clean energy programs.[4] The Federal Power Act (FPA) gives states authority over their generation facilities, and it prohibits electricity rates that are "unduly discriminatory or preferential."[5] The dissent appears to think that, if a new line helps some states meet their clean energy goals, then spreading the costs of the line across multiple states amounts to ordering all states to pay for their neighbors' clean energy policies. On this view, states should not have to pay for any part of a new line if any of the line's benefits are tied to another state's clean energy policies.

As an alternative to the approach adopted by Order No. 1920, the dissent proposes that transmission planners respond to individual needs—reliability or congestion or emissions reductions—and then allocate all the costs of new lines to the customers on the basis of only those benefits.[6] This is essentially a form of

1. Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068, 89 Fed. Reg. 49,280 (2024) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 1920].

2. *Id*. at P 3 ("This final rule also requires transmission providers to measure and use at least the seven specified benefits to evaluate Long-Term Regional Transmission Facilities as part of Long-Term Regional Transmission Planning.").

3. *Id*. at P 1305 ("[A]ny cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent.").

4. *See* Order No. 1920, at P 67 (Christie, Comm'r, dissenting).

5. 16 U.S.C. § 824e(a) (2005).

6. *See* Order No. 1920, at P 67 (Christie, Comm'r, dissenting) ("For each identified reliability problem, there is an optimal solution that solves the reliability problem at the least cost to consumers. For an economic

single-value planning. If a line is categorized as a reliability upgrade, then the customers who benefit from reliability improvements pay the entire cost of the line—even if the line also reduces the price of electricity or makes it easier for a state to meet its decarbonization targets.[7]

The debates surrounding Order No. 1920 thus raise important questions about how to allocate the costs of transmission, especially when states do not all share the same clean energy priorities. In our view, the most pressing questions have to do with what the FPA requires in terms of transmission planning and cost allocation, and how the beneficiary pays approach works when multiple states benefit from a new line but only a subset of states have adopted binding clean energy plans.[8] As we explain,

1. The FPA requires multi-benefit planning in which FERC and transmission planning entities consider the many factors that influence what transmission lines get built.
2. The FPA prohibits any approach to cost allocation that would require states to pay for benefits they do not receive, and it also prohibits cost allocation that allows states to free ride by benefitting from lines they do not pay for.
3. The beneficiary pays approach to cost allocation is the *only* approach that meets this standard.
4. The FPA therefore requires the beneficiary pays approach to cost allocation, which, though not a precise science, requires that the costs of new lines and upgrades be allocated in a way that is at least "roughly commensurate" with their benefits.[9]
5. The beneficiary pays approach to cost allocation does not involve states paying for energy policies they do not share (if it did, it would not be permissible under the FPA).
6. An alternative cost allocation approach that responds to individual needs such as reliability, congestion, or state decarbonization policies would increase costs and force some states to cross-subsidize their neighbors.
7. The Commission's approach to transmission planning and cost allocation is consistent with over sixty years of regulatory and judicial precedent.

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project, consumers should receive the maximum reduction in congestion costs relative to the cost of the project, or put in another way, for a given reduction of congestion costs, consumers should pay the least costs for the project").

7. *See* Request for Rehearing, *supra* note 5, at 12. It also urges courts to find that the Commission has strayed beyond its jurisdiction or, in the alternative, strike the Order down under the Major Questions Doctrine *see also id.* at 14. Because Order No. 1920 fits comfortably within the historic cost allocation framework within which FERC and its predecessor have long operated with judicial blessing, we do not believe the MDQ is implicated by that order. The broader impact of the MQD is beyond the scope of this article.

8. For prior work on how to implement beneficiary pays approach, *see* Han Shu & Jacob Mays, TRANSMISSION BENEFITS AND COST ALLOCATION UNDER AMBIGUITY (2024); *see also* William Hogan, *A Primer on Transmission Benefit and Cost Allocation*, 7 ECON OF ENERGY & ENV. POL'Y 25, 25-46 (2018).

9. Courts accept that this is not a perfect science. The costs of new lines must only be "roughly commensurate" with the benefits. Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 477 (7th Cir. 2009) (ICC I).

8. The Commission has relied on the same cost allocation principles—nondiscrimination and opposition to free ridership—since the FPA was passed. In fact, FERC used the same principle to restructure the natural gas industry. Overturning Order No. 1920's approach to cost allocation would thus open the door to relitigating gas restructuring.

In short, Order No. 1920 does not turn FERC into a national grid planner; it does not require that any particular transmission line or type of generation be built; and it does not force any state to pay a share of other states' clean energy policies. To the contrary, the beneficiary pays approach is the only way for the Commission to avoid cross-subsidization when allocating the costs of lines across states, regions, or utility services territories that do not share energy goals.

The specific reason Order No. 1920 avoids cross-subsidization is that costs are assigned to the customers who benefit from the line. If a line provides economic benefits to Ohio while facilitating emissions reductions in New Jersey, then Ohio pays for economic benefits in Ohio but only New Jersey pays for the environmental benefits in New Jersey. By contrast, under the dissent's proposed approach, if a line is built to address a one-off need—say to improve reliability in Ohio—then Ohio is saddled with all the costs of a line that also provides economic or clean energy benefits to New Jersey. Similarly, if New Jersey builds a line to support offshore wind that happens to improve reliability in Ohio, New Jersey pays the full costs of the line even though the line improves reliability in Ohio, since the costs are assigned based on the ostensible purpose the line serves. In other words, New Jersey would be forced to pay for—or cross-subsidize—Ohio's reliability benefits.

The converse is also true. Under the dissent's approach, if Ohio builds a line to support coal-fired generation in Ohio, and the line reduces congestion in New Jersey, Ohio would pay the full costs of a line that also benefits customers in New Jersey. In other words, the single-value approach results in cross-subsidization, since states are assigned costs based entirely on the individual benefits—economic, reliability, or decarbonization—that justify the line. States that benefit for other reasons therefore free ride off the states that pay for the line. As we discuss in Part IV, concerns surrounding precisely this type of free ridership have prompted courts to consistently require the use of the beneficiary pays approach when allocating the costs of transmission lines.

Finally, although we do not directly address how much deference courts should afford FERC, or the possibility that Order No. 1920 implicates the *Loper Bright* or the Major Questions Doctrine, our analysis is nevertheless relevant to potential *Loper Bright* and Major Questions challenges. As Part IV explains, Order No. 1920 fits comfortably within the historic cost allocation framework within which FERC and its predecessor have operated. In fact, much of the judicial precedent cited in Part IV predates the Supreme Court's *Chevron* decision or is based on *courts'* preferred reading of the FPA. When FERC or grid operators have tried to deviate from the beneficiary pays framework, courts, not FERC, have insisted that beneficiaries pay for gas and electricity infrastructure that benefits them.[10] For that reason, Order No. 1920 appears to be consistent with decades of judicial, congressional, and administrative practice.[11]

This Article proceeds in three parts. Part II provides a history of FERC interventions in transmission planning and cost allocation. Part III summarizes Order No. 1920 and the dissent. It also explains how to implement beneficiary pays cost allocation when states disagree about climate policy. Part IV describes the law of transmission planning and cost allocation and argues that Order No. 1920's approach to planning and cost allocation applies sixty years of judicial precedent to markets in which states have adopted different clean energy policies.

II. History of FERC Regulation of Transmission Planning and Cost Allocation

For decades, FERC has tried to address three persistent issues that have contributed to ballooning electricity rates and undermined system reliability. First, transmission planners often build lines in response to one-off issues such as reliability, congestion, or expected future load growth.[12] Doing so causes them to overbuild (and overpay) for small lines when larger lines could have addressed multiple needs simultaneously. Second, some utilities have used their influence over planning to push for lines that favor their own generating facilities and allow them

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10. Even under *Loper Bright*, when Congress has given a regulatory agency authority to determine what is "reasonable" or "appropriate," it can thereby indicate a direct Congressional intent to give the agency considerable discretion in interpreting such terms. See others empower an agency to prescribe rules to "fill up the details" of a statutory scheme, Wayman v. Southard, 23 U.S. 1, 43 (1825), or to regulate subject to the limits imposed by a term or phrase that "leaves agencies with flexibility," Michigan v. EPA, 576 U.S. 743, 752 (2015), such as "appropriate" or "reasonable." *See* Loper Bright Enters. v. Raimondo, 144 S. Ct. 2244, 2263 (2024). The Court continued, "In a case involving an agency, of course, the statute's meaning may well be that the agency is authorized to exercise a degree of discretion. Congress has often enacted such statutes. For example, some statutes "expressly delegate[]" to an agency the authority to give meaning to a particular statutory term. Batterton v. Francis, 432 U. S. 416, 425 (1977) (emphasis deleted). When the best reading of a statute is that it delegates discretionary authority to an agency, the role of the reviewing court under the APA is, as always, to independently interpret the statute and effectuate the will of Congress subject to constitutional limits. The court fulfills that role by recognizing constitutional delegations, "fix[ing] the boundaries of [the] delegated authority," Henry Monaghan, *Marbury and the Administrative State*, 83 COLUM. L. REV. 1, 27 (1983), and ensuring the agency has engaged in "'reasoned decisionmaking'" within those boundaries, Michigan, 576 U. S., at 750 (quoting Allentown Mack Sales & Serv., Inc. v. NLRB, 522 U. S. 359, 374 (1998)); *see generally* Motor Vehicle Mfrs. Assn. of U.S., Inc. v. State Farm Mut. Auto. Ins. Co., 463 U. S. 29 (1983). By doing so, a court upholds the traditional conception of the judicial function that the APA adopts.

11. Moreover, *Loper Bright* clarified that courts would not revisit prior decisions that were based on *Chevron*. *See* Loper Bright Enters., 144 S. Ct. at 2247 (2024) ("By overruling *Chevron*, though, the Court does not call into question prior cases that relied on the *Chevron* framework. The holdings of those cases that specific agency actions are lawful—including the Clean Air Act holding of Chevron itself—are still subject to statutory stare decisis despite the Court's change in interpretive methodology"). Since FERC in Order No. 1920 is adopting the same approach to cost allocation it has adopted in the past, then it can at the very least rely on past decisions and stare decisis to support the approach adopted in Order No. 1920.

12. *See* Alexandra Klass et al., *Grid Reliability Through Clean Energy*, 74 STAN. L. REV. 969, 1028-31 (2022); see also Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 ENERGY L.J. 1, 50-58 (2021).

to avoid competing with other developers.[13] This, too, results in excessive investment in local projects. Third, when the costs of new lines are not allocated to the beneficiaries of the line, regions can free ride off their neighbors, leading to underinvestment in the transmission system that would reduce congestion and improve system reliability.[14] Nearly every major FERC Order in the last thirty years has sought to address one or more of these issues.

A. Transmission Planning and Cost Allocation Before Order No. 1920

Federal authority to regulate transmission planning and cost allocation dates to the early years of the twentieth century. In fact, an influential 1921 federal report that urged Congress to pass national energy legislation—known as the Keller Report—pointed to the need to integrate transmission infrastructure as one of the primary justifications for federal regulation of the electrical grid, explaining that the "lack of flexible and capacious interconnections between adjacent power systems" had made it "virtually impossible to reduce [a coal] shortage by taking advantage of the diversity factor and by releasing for active use part of the installed reserves which interconnection would have rendered safely available."[15]

To that end, Congress instructed FERC's predecessor, the Federal Power Commission (FPC), to make sure that transmission rates are "just and reasonable" and not "unduly discriminatory."[16] Section 202 dealt specifically with the need to expand the transmission system, authorizing the FPC to order interconnection when doing so was "necessary or appropriate in the public interest."[17] At the time, policymakers assumed that regulated monopolists would build generation and

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13. *See* Joshua C. Macey, *Outsourcing Electricity Market Design*, 91 U. CHI. L. REV. 1243 (2024).

14. *See* Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011) [hereinafter Order No. 1000] ([T]he risk of the free rider problems associated with new transmission investment is particularly high for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development."); El Paso Elec. Co. v. FERC, 832 F.3d 495, 502 (5th Cir. 2016) (explaining that if certain transmission owners did not have to pay for benefits their customers receive, they "would become the subsidized free riders that Order No. 1000 sought to reduce or eliminate").

15. CHARLES KELLER, THE POWER SITUATION DURING THE WAR at 18 (1921). We are grateful to Benjamin Rolsma for drawing our attention to the relevance of this report. For a description of the Keller Report and the larger role concerns about reliability played in the passage of the FPA, *see* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. (forthcoming 2025) (manuscript at 12-16).

16. Public Utility Act of 1935, ch. 687, § 205(a), 49 Stat. 803, 851 (codified as amended at 16 U.S.C. § 824d(a)).

17. *Id*. § 202(b) (codified as amended at 16 U.S.C. §824a(b); *see id.* at §824a(a) ("[T]he Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnection and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts.").

transmission, subject to regulatory oversight, to meet their service territories' electricity needs. From the start, federal regulation in the electricity industry recognized the need for forward-looking planning.[18]

A few decades after the FPA was enacted, the technological and economic underpinnings of rate regulation had come under attack,[19] most notably from free market economists who published several influential and damning critiques of rate regulation.[20] In 1978, perhaps in response to these developments, Congress added section 211 to the FPA to give FERC the authority to order electric utilities to provide transmission service to independent power producers.[21] Fourteen years later, Congress further expanded FERC's authority over transmission by passing the Energy Policy Act of 1992.[22] Congress recognized that, because regulated monopolists could use their control over transmission to discriminate against their

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18. *See* Horace M. Gray, *The Integration of the Electric Power Industry*, 41 AM. ECON. REV. 538, 538 (1951) ("By 1935, fifteen years of intensive criticism, beginning with the Keller report and terminating with the National Power Survey, had exposed the defective organization of the electric power industry and delineated the essential features of an integrated power system" (footnotes omitted)); 1 FED. POWER COMM'N, NATIONAL POWER SURVEY INTERIM REPORT 54 (1935) (concluding that "studies . . . have gone far enough to show that interconnection as it exists today in the United States is not the result of any definitely planned program. Its growth has been relatively haphazard, handicapped by intercompany rivalry and prejudices and by artificial barriers"). As one Senate Report explained, "'In recent years the growth of giant holding companies has been paralleled by the rapid development of the electric industry along lines that transcend State boundaries. To a great extent through the agency of the holding company, local operating units have been tied together into vast interstate systems. As a result the proportion of electric energy that crosses State lines has steadily increased. While in 1928, 10.7 percent of the power generated in the United States was transmitted across State lines, the percentage had increased by 1933 to 17.8. The amount of energy which flowed in interstate commerce in 1933 exceeded the entire amount generated in the country in 1913 . . . The necessity for Federal leadership in securing planned coordination of the facilities of the industry which alone can produce an abundance of electricity at the lowest possible cost has been clearly revealed in the recent reports of the Federal Power Commission, the Mississippi Valley Committee, and the National Resources Board. . . . The new part 2 of the Federal Water Power Act seeks to bring about the regional coordination of the operating facilities of the interstate utilities . . . '" Jersey Cent. Power & Light Co. v. Fed. Power Comm'n, 319 U.S. 61, 68, at n. 7 (1943) (quoting S.Rep. No. 621, 74th Cong., 1st Sess., at PP 17).

19. *See* GILBERT M. MASTERS, RENEWABLE AND EFFICIENT ELECTRIC POWER SYSTEMS 6-7 (2d ed. 2013) (describing how technological and regulatory changes made it possible "small, on-site generators" cost-competitive); Severin Borenstein & James Bushnell, *The US Electricity Industry After 20 Years of Restructuring*, 7 ANN. REV. ECON. 437, 438 (2015).

20. Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962). For work building on their theory, see *also* William J. Baumol & Alvin K. Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, 3 BELL J. ECON & MGMT SCI. 162 (1970); Alvin K. Klevorick, *The Behavior of the Firm Subject to Stochastic Regul. Rev.*, 4 BELL J. ECON & MGMT SCI. 57 (1974).

21. Public Utility Regulation Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended at Pub. L. 113-23).

22. *See* Energy Policy Act of 1992, Pub. L. No. 102-486, § 711, 106 Stat. 2776, 2905-88 (1992) (repealed 2005) (authorizing exempt wholesale generators to sell electricity to utilities). *Id*. at §721 ("Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant.") (to be codified at 16 U.S.C. 824(j)); *see also* 18 C.F.R. § 366.1 (2019) (defining "exempt wholesale generator").

competitors, federal oversight was necessary to prevent transmission owners from having sole discretion to determine which transmission lines get built.[23]

In the period between 1978 and 1992, FERC relied on case-by-case adjudication to make sure that independent power producers enjoyed non-discriminatory access to the bulk power system.[24] By the mid-1990s, however, the Commission recognized that this case-by-case approach had not resolved the systemic problems with transmission planning. As part of its larger effort to restructure the wholesale power markets, FERC enacted a series of reforms designed to improve the processes for planning and allocating the costs of transmission investments.

FERC's first major intervention came in 1993, one year after Congress passed the Energy Policy Act of 1992, when the Commission issued a Policy Statement urging utilities to join Regional Transmission Groups (RTGs) that would coordinate to plan transmission investments. As FERC explained:

> Since RTGs bring together both transmitting utilities and their customers (and potential customers) in a region, they can provide a means for companies to coordinate their transmission planning more effectively, avoid costly duplication of facilities, and, in conjunction with their respective state commissions, find more efficient solutions to region-wide problems.[25]

The Commission felt that coordinated transmission planning would lead to more efficient transmission investment.[26]

FERC's next reforms focused on reducing barriers to competition in wholesale markets. In the late 1990s, FERC issued two landmark Orders—Orders No. 888 and 2000—to prevent transmission owners from discriminating against independent power producers.[27] While these Orders primarily concerned barriers to

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23. Congress again recognized the importance of opening up the transmission system in 2005, when it gave FERC authority to require "on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential." Energy Policy Act of 2005, Pub. L. No. 109–58, § 211A, 119 Stat. 955 (2005).

24. *See* Policy Statement, *Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41626, 41627-31 (1993) (to be codified at 18 C.F.R. pt. 2). FERC started down the same road a decade earlier in the gas industry. *See* Order No. 436, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 50 Fed. Reg. 42,408 (1985) [hereinafter Order No. 436]; Order No. 636, *Pipeline Service Obligations and Revisions to Regulation Governing Self Implementing Transportation Under Part 284 of the Commission's Regulations*, 59 FERC ¶ 61,030 (to be codified at 18 C.F.R. pt. 284) (1992); Final Rulemaking, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 57 Fed. Reg. 13,267, at 13,268 (1992) (to be codified at 18 C.F.R. pt. 284).

25. 58 Fed. Reg. 41626 at 41628. *See* 18 C.F.R. 2.21 (1993) ("An RTG agreement should require, at a minimum, the development of a coordinated transmission plan on a regional basis and the sharing of transmission planning information, with the goal of efficient use, expansion, and coordination of the interconnected electric system on a grid-wide basis"); *see also* 58 Fed. Reg. 41626, at 41628 ("Properly functioning RTGs will enable[e] the market for electric power to operate in a more competitive, and thus more efficient manner, and provid[e] coordinated regional planning of the transmission system to assure that system capabilities are adequate to meet system demands").

26. *See generally* 58 Fed. Reg. 41626, at 41627-31.

27. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996) [hereinafter Order No. 888] (FERC ordered utilities to functionally unbundle—to sep-

competition among electric power producers, both Order No. 888 and 2000 recognized that open, independent, and forward-looking planning were important features of a healthy electricity industry. For example, in Order No. 888-A, the Commission encouraged utilities to coordinate with other utilities and their customers and consider the needs of all affected parties when conducting transmission planning.[28] In Order No. 2000, FERC announced that, when deciding whether to certify RTOs, it would consider whether the region had developed a transmission planning process that would keep costs down while preserving system reliability. The Commission explained that "a single entity must coordinate these [transmission planning] actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability."[29] FERC also recognized that proper planning would require RTOs to "address[] many specific design questions, including who decides which projects should be built and how the costs and benefits of the project should be allocated."[30] Both Order No. 888 and 2000 were thus justified by FERC's concern that utilities would use their control over the transmission system to favor their own resources.[31]

At the time, FERC repeatedly emphasized that regional planning could not simply aggregate or roll up plans submitted by individual transmission owners. For example, in the Order approving PJM's request for RTO status, FERC "emphasize[d] that RTO regional transmission expansion plans must be more than a collection of traditional expansion plans developed by individual TOs and assembled by the RTO after confirming that they serve reliability needs."[32] FERC ob-

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arate the transmission and generation functions into separate subsidiaries—and to provide nondiscriminatory service to independent power producers). Order No. 2000, *Regional Transmission Organizations,* 89 FERC ¶ 61,285 (1999) [hereinafter Order No. 2000] (encouraged utilities to join Regional Transmission Organizations (RTOs) that would control regional power systems).

28. *See* Order No. 888-A at 30,311.

29. Order No. 2000, *supra* note 27, at P 486. *Id.* at P 255 ("[T]ransmission expansion would be more efficient if planned and coordinated over a larger region."). *Id.* at P 485 ("the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities"). *Id.* at P 63 ("The traditional use of regional coordination through study groups and planning committees is no longer effective because these entities are usually not vested with the broad decision making authority needed to address larger issues that affect an entire region.").

30. Order No. 2000, *supra* note 27, at P 486.

31. *See* New York v. FERC, 535 U.S. 1, 8 (2002) ("The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions"); Transmission Access Pol'y Study Group v. FERC, 225 F.3d 667, 684 (D.C. Cir. 2000) ("[T]ransmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers"); Order No. 888, *supra* note 27, at 21,546 ("The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive ownership of the facilities.").

32. *Order Provisionally Granting RTO Status*, 96 FERC ¶ 61,061, at p. 30 (2001).

jected that PJM's proposed approach to transmission planning "details a significant role for TOs in the planning process as members of the Planning Committee, which appears to conduct all the required analyses" while "provid[ing] little opportunity for comparable involvement of other parties."[33] Once again, FERC expressed concern that piecemeal planning would allow existing transmission owners to control which projects the PJM Board would review: "Although the Board has final approval of the plan, it appears that the Board has an opportunity to review only those projects that survive a study process significantly influenced by TOs."[34] To mitigate incumbents' influence over transmission planning, FERC required that transmission planning "include meaningful participation by third parties, and provide all interested parties an opportunity to participate."[35] FERC imposed the same requirements in other regions.[36]

But it quickly became apparent that FERC's open access orders had not removed all the barriers to competition in electric power markets. Over the next decade, FERC sought to further limit the ability of transmission owners to use their control over transmission planning to favor their own generation facilities.[37] To that end, in 2007 the Commission issued Order No. 890 to increase transparency in transmission planning. Order No. 890 required "each public utility transmission provider . . . to submit . . . a proposal for a coordinated and regional planning process."[38] Once again, FERC worried about incumbent self-preferencing. As the Commission explained:

> We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner. Although many transmission providers have an incentive to expand the grid to meet their state-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.[39]

33. *Id*.

34. *Id*.

35. *Id*.

36. *Southwest Power Pool*, 106 FERC ¶ 61,110 at P 188 (2004); *New York ISO et al.*, 96 FERC ¶ 61,059, at p. 61,203 (2001); *Carolina Power & Light Co*., 94 FERC 61,273, at p. 62,009 (2001); *Alliance Cos.*, 96 FERC ¶ 61,052, at p. 61,144 (2001); PJM Interconnection, *supra* note 32, at p. 61,240-41; *Translink Transmission Co.*, 101 FERC 61,140 at P 58 (2002); *ISO-NE*, 106 FERC ¶ 61,280 at P 213 (2004). For a discussion of these requirements, *See* Ari Peskoe, *Is the Transmission Syndicate Forever?*, *supra* note 12, at 38-40.

37. *See*, *e.g.,* Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, 104 FERC ¶ 61,103 at P 12 (2003) (to be codified at 18 C.F.R. pt. 35).

38. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, 118 FERC ¶ 61,119 at P 437 (2007) (to be codified at 18 C.F.R. pts. 35, 37) [hereinafter Order No. 890].

39. *Id.* at P 422; *see also id*. at P 39 ("[I]t is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide to themselves."); see also *id.* at P 57 ("[V]ertically-integrated utilities do not

One of Order No. 890's primary concerns was that existing transmission planning processes created collective action problems. As FERC explained "there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it."[40] While FERC did not insist on a particular approach to cost allocation, it explained that "cost allocation proposal[s]" should "fairly assign[] costs among participants, including those who cause them to be incurred and those who otherwise benefit from them," and "provide[] adequate incentives to construct new transmission."[41]

A few years later, FERC issued Order No. 1000, which required utilities to develop regional planning processes that allowed non-incumbent developers to compete with incumbents on a non-discriminatory basis. Once again, FERC worried that transmission owners were favoring their generation assets, and that piecemeal planning processes were causing regions to make inefficient transmission investments.

To address these issues, Order No. 1000 set out six cost allocation principles for regional planning, two of which instructed transmission planners to use the beneficiary pays approach.[42] The first principle required that "[t]he cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits."[43] The second clarified that "[t]hose that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities."[44]

In other words, FERC has consistently justified the need for holistic transmission planning and beneficiary pays cost allocation by pointing out that transmission owners have incentives to exercise market power and protect their generation facilities.[45] Note that the Commission has used the phrases "cost causation"

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have an incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors.").

40. Order No. 890, *supra* note 38, at P 561 (FERC also expressed concern that incumbent control over transmission planning would impede economic growth.); *see id.* at P 58 ("Our concern over this flaw is heightened by the critical need for new transmission infrastructure in this Nation. . . . [T]ransmission capacity is being constructed at a much slower rate than the rate of increase in customer demand.").

41. *Id.* at P 559.

42. Order No. 1000, *supra* note 14, at P 586.

43. *Id.*

44. *Id*.

45. New York v FERC, 535 U.S. 1, 8 (2002) ("The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions."); Transmission Access Pol'y Study Group, 225 F.3d at 684 ("[T]ransmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers"); Order No. 888, *supra* note 27, at 21,546 ("The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive ownership of the facilities."); Order No. 890, *supra* note 38, at P 422 ("We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner."); Order No. 1000, *supra* note 14, at P

and "beneficiary pays" interchangeably, and it apparently did so because it understood cost causation to mean beneficiary pays. Citing to D.C. Circuit case law, FERC explained that "the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits that are expected to accrue to it."[46] Despite the Commission's somewhat confusing terminology, beneficiary pays was now required for regional planning across the country, and it was justified because the Commission recognized that "a departure from cost causation principles can result in inappropriate cross-subsidization. This is why cost causation is the foundation of an acceptable cost allocation method."[47] As we explain in Part IV, this approach to cost allocation followed decades of judicial precedent in electricity and gas markets that pushed FERC to use this approach.

B. Problems with Transmission Planning and Cost Allocation

Unfortunately, Order No. 1000 appears to have inadvertently created incentives for some transmission owners to overinvest in small projects at the expense of regional solutions. It is worth clarifying that regional projects are those in which a regional planning entity allocates the costs, typically to more than one utility.[48] Local projects, by contrast, are those that are paid for by a single utility.[49] Since Order No. 1000 went into effect, transmission spending has more than doubled.[50] Yet during this period, the United States has significantly slowed the building of high-voltage transmission lines,[51] and most transmission investment that has occurred has been made outside of the regional process, with spending on local reliability upgrades increasing dramatically in the past decade such that they now account for a majority of spending in many regions.[52] Consumers are therefore spending a great deal of money on transmission projects for which there is no

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256 ("It is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities").

46. Order No. 1000, *supra* note 14 at P 504; *see also id.* at P 505 ("The Commission explained that, while costs generally have been allocated through voluntary agreements, the cost causation principle is not limited to such arrangements. If it were, the Commission could not address free rider problems associated with new transmission investment and could not ensure that transmission rates are just and reasonable and not unduly discriminatory").

47. *Id.* at P 626.

48. *Id.* at PP 63-64.

49. *Id*. at PP 62-64.

50. Johannes Pfeifenberger & John Tsoukalis, *Transmission Inv. Needs and Challenges* 2, BRATTLE (June 1, 2021), https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Investment-Needs-and-Challenges.pdf.

51. *See* Jay Caspary et al., *Fewer New Miles: The U.S. Transmission Grid in the 2010s*, GRID STRATEGIES LLC 1, https://gridstrategiesllc.com/wp-content/uploads/grid-strategies_fewer-new-miles.pdf ("[T]he U.S. dropped from installing an average of 1,700 miles of new high-voltage transmission miles per year in the first half of the 2010s, to averaging only 645 miles per year in the second half of the 2010s").

52. *See* Claire Wayner, *Increased Spending on Transmission in PJM - Is It the Right Type of Line?*, RMI (2023), https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/; Ohio Consumers Initial Comments at 5 (''Since 2017, in Ohio, less than 25% of the new investment in transmission has been associated with large regional transmission projects needed for reliability or economic efficiency'').

regulatory or market check to ensure that new investments cost-effectively address economic and reliability needs. The basic problem, which has been the subject of considerable commentary, is that incumbent utilities have both the incentive and ability to arbitrage around regional planning.

1. Rate Basing Local Projects

Economists have long understood that rate regulated utilities have misaligned incentives. Because utilities earn a return on capital investments, their profits increase when they spend more. They care that regulators authorize a return on the investments they make but do not necessarily have strong incentives to ensure their investments promote the public good.[53] This is known as gold-plating or the Averch-Johnson effect.

While Order No. 1000 required that regionally planned lines be open to competition, it authorized exemptions for certain projects planned outside the regional process. One example of this is Baseline Reliability Projects, which are projects that "are not cost shared and are generally developed by Transmission Owner(s), via their role as the NERC Transmission Planner (TP), to address localized Transmission Issues and reliability-related Transmission Issues."[54] Even within the regional planning process, some lines, such as those that respond to immediate reliability needs, are not required to undergo competitive solicitations.[55] These types of projects receive little, if any, scrutiny from regulators.[56] Still, not only are incumbent utilities legally entitled to build these types of projects in their service territories; they also typically establish the criteria for determining whether to build these projects. There may be good policy reasons for this. After all, certain reliability upgrades may be time sensitive or involve upgrades to assets the utility

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53. *See* Harvey Averch & Leland L. Johnson, *supra* note 20, at; *see also* Stanislaw H. Wellisz, *Regulation of Natural Gas Pipeline Cos.: An Economic Analysis*, 71 J. POL. ECON 30, 31 (1963) ("The pipeline companies are restricted to a "fair return" on the investment ascribed to jurisdictional sales. It is therefore in their interest to apportion to the regulated sales as much investment as possible.); *see also* Robert M. Spann, *Rate of Return Regulation and Efficiency in Prod.: An Empirical Test of the Averch-Johnson Thesis*, 5 BELL J OF ECON & MGMT. SCI. 38, 39 (1974) (describing the Averch-Johnson effect as "The overcapitalization in regulated firms hypothesized by Averch and Johnson is a direct result of a model which starts with the premise that the regulated firm maximizes profits subject to an effective rate-of-return constraint" and confirming the effect by studying data from electric utilities). For a discussion of the governance implications, see Aneil Kovvali & Joshua Macey, *The Corp. Governance of Pub. Utils.*, 40 YALE J. REG. 569, 582-97 (2023).

54. MIDCONTINENT IND. SYS. OP., TRANSMISSION PROJECT CATEGORIES & TYPES § 2.3, at § 2.3.1.1, https://cdn.misoenergy.org/DRAFT%20BPM-020%20Section%202.3%20Edits%20for%20INRP561844.pdf.

55. *See id.* at 2.3.2.3 ("Facilities comprising Market Efficiency Projects approved by MISO's Board after December 1, 2015 are subject to MISO's Competitive Developer Section Process unless such facilities: (1) are subject to a law granting a right of first refusal to the incumbent Transmission Owner; (2) qualify as upgrades to existing transmission facilities; or (3) qualify as an Immediate Need Reliability Project as described under Appendix I of this BPM. . . . Facilities that are exempt from the Competitive Transmission Process are assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement.").

56. *See Asset Condition Projects and Process Improvements*, NEW ENGLAND STATES COMM. ON ELEC. *2-3* (2023) https://www.iso-ne.com/static-assets/documents/2023/02/2023_02_08_nescoe_asset_conditions_letter.pdf (observing that spending on Asset Condition projects do not undergo competitive solicitations, grew from $58 million in 2016 to nearly $800 million in 2023, and pointing out that these projects "are subjected to materially less regional review and scrutiny").

already owns.[57] Nonetheless, these and similar exemptions to Order No. 1000's competitive process have allowed utilities to invest in transmission upgrades without being forced to compete with other developers. As Ari Peskoe has shown, utilities appear to have turned to non-regional processes to avoid being forced to compete with other transmission developers.[58] FERC appears to agree, observing that "incumbent transmission providers, as a result of those [Order No. 1000] reforms, may be presented with perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint."[59] In other words, the shift to non-regional planning in response to Order No. 1000 is likely due in part to the fact that utilities prefer to gold plate local projects rather than compete with other developers.

2. Protecting Generators' Market Power and Justifying Investment in New Generation

Another reason utilities prefer to invest in local projects is that, when utility holding companies own both generation and transmission assets, they can protect their generators' market power and justify the need to invest in new power plants by focusing on small projects that do not increase transfer capacity between regions or utility service territories. FERC never forced transmission owners to divest themselves of their generation assets.[60] The Commission's open access orders required functional unbundling, which means that their generating units must receive transmission service on the same terms as everyone else, but FERC continues to allow holding companies to own both generation and transmission assets.[61]

57. *See* Order No. 1000, *supra* note 14, at P 263 ("Given that incumbent transmission providers may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation to comply with their reliability and service obligations, delays in the development of such transmission facilities could adversely affect the ability of the incumbent transmission provider to meet its reliability needs or service obligations. To avoid this result, in section III.B.3 below, we require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those the incumbent transmission provider proposes, to ensure the incumbent can meet its reliability needs or service obligations.").

58. *See* Peskoe, *supra* note 12, at 50-58; FERC Docket No. ER20-2054-000 (Jan. 31, 2024) ("Maine's concern is that at least some New England utilities may be taking advantage of this lax review process to the benefit of their shareholders. Are they building replacement projects prematurely? If so, such practices can contribute to significant and unnecessary rate increases. Could the projects be more targeted and smaller? Are there less expensive alternatives to large transmission replacement projects? Do the NETOs adequately keep track of the condition of their current transmission assets? Do they have processes for maximizing the timing of replacements or the evaluation of non-transmission or hybrid alternatives?").

59. Order No. 1920, *supra* note 1, at P 1548.

60. Order No. 888, *supra* note 27, at P 59 ("In the absence of evidence that functional unbundling will not work, we are not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time").

61. Order No. 2000, *supra* note 27, at P 47; Order No. 1000, *supra* note 14, at P 818.

To be clear, FERC has developed standards of conduct and affiliate purchase rules that do not ignore the affiliate favoritism issue altogether,[62] but the Commission's unwillingness to fully quarantine rate regulated affiliates nevertheless left in place incentives for transmission owners to avoid investing in regional and interregional lines that reduce congestion.[63] Increasing regional and interregional transfer capacity allows load serving entities to import power from generators located outside the utility's service territories. A utility that invests in these lines may therefore expose its existing generation facilities to competition from low-cost power producers that are located outside the utility's service territory.[64]

There are two reasons that overinvesting in local projects can be seen as an exercise of vertical market power. The first is that it increases the price of energy by preventing low-cost suppliers in neighboring regions from competing with the utilities' generation. The second is that utilities can cite transmission constraints to convince regulators to authorize cost-recovery for new generation investments. As one of us has described in previous work, utilities in the Midcontinent Independent System Operator (MISO) have used the lack of regional transmission lines to justify spending hundreds of millions on new generation facilities.[65] The financial stakes are often significant. According to a recent study by Catherine Hausman, transmission constraints in MISO and the Southwest Power Pool (SPP) caused $2 billion in allocative inefficiencies in 2022.[66] Hausman estimates that reducing transmission congestion in MISO would have caused Entergy Arkansas and Entergy Louisiana to lose $930 million in revenue in that year.[67]

3. Avoiding Regulatory Oversight

A final problem is that local projects receive little scrutiny from state and federal regulators.[68] RTOs and other regional planners typically provide only a cursory review of transmission investments made outside the regional process. In some regions, transmission planners make sure non-regionally planned lines do not cause the region to fall out of compliance with reliability standards but do not

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62. *See* Order No. 717, *Standards of Conduct for Transmission Providers*, 125 FERC ¶ 61,064 (2008).

63. *See* Kovvali & Macey, *supra* note 53, at 2164-67.

64. *See id*.

65. *See id*.

66. *See* Catherine Hausman, *Power Flows: Transmission Lines, Allocative Efficiency, and Corp. Profits* 2 (Nat'l Bureau of Econ. Rsch., Working Paper No. 32091, 2024), https://www.nber.org/system/files/working_papers/w32091/w32091.pdf.

67. *See id*. at 25.

68. *Id.; see* FERC Docket No. ER20-2054-000 (Mar. 4, 2024) ("[T]he TOs do not actually specify any significant state level scrutiny [for asset condition projects]. And while they dispute Maine's concern that there is 'limited review of asset management projects,' their own internal documents say something else entirely. In rejecting consideration in two separate instances of building a parallel line to address the reliability concerns about an existing line, Eversource was concerned that that 'constructing a new line parallel could potentially trigger a more formal and lengthy regulatory review process.' The Identified TOs cannot truly believe to be "false" Maine's characterization of asset condition project cost review as, at best, limited. On the contrary, they have touted their cooperation with NESCOE in increasing the transparency of their processes. Their claim that they have agreed to 'increased notice and opportunities for stakeholders to submit written feedback' is an implicit recognition that the current review process is indeed limited.'" (citations omitted)).

consider whether alternative investments would provide greater aggregate benefits.[69]

Nor have state regulators filled this regulatory gap. State utility commissioners may lack jurisdiction to assess the benefits of multi-state lines,[70] and many states do not require a certificate of public convenience and necessity for lines that either fall below a certain kV threshold or are constructed on existing rights of way.[71] As a result, many transmission lines receive automatic rate recovery and undergo virtually no scrutiny from state or federal regulators.

All else equal, utilities prefer to avoid regulatory red tape. And because customers in rate regulated markets have limited ability to protect themselves—after all, there are no competitors to turn to if the incumbent provides costly or subpar service—their only recourse is diligent and effective regulatory oversight. Unfortunately, the lines that receive the least regulatory scrutiny are also the ones whose costs are not checked through competition or third-party planning.[72]

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Thus, in the past ten years, transmission investment has shifted away from regional-scale projects subject to competitive procurements and toward smaller local projects over which incumbents exercise greater control.[73] By avoiding the regional process, utilities ensure that they—not their competitors—build the line. And when utilities remain vertically integrated—when utility holding companies own both generation and transmission assets—they prefer to build small projects to obviate the need for regional and interregional lines that would expose their generation to additional competition.[74] Finally, local projects often receive little, if any, review from state and federal regulators. The result is a piecemeal process in which lines are built in response to one-off needs and in which incumbents steer investment towards projects that protect their financial interests but do not provide the most cost-effective approach to meeting the country's transmission needs.

Unfortunately, a piecemeal planning process in which a region's transmission needs are met through small, local projects reduces the need for regional and interregional solutions. That would not be a problem if local projects were cost-

69. For an explanation of these review processes, *see* Macey, *supra* note 13, at 1265.

70. *See* Matthew R. Christiansen & Joshua C. Macey, *Long Live the Fed. Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1381-1407 (2021); Jim Rossi, *The Brave New Path of Energy Federalism*, 95 TEX. L. REV. 399, 443-61 (2016) (even if state regulators had jurisdiction to do so, it is unclear why a regulator in one state would be motivated to consider out-of-state benefits).

71. *See, e.g.*, Gen. Order No. 131-D, Pub. Util. Comm'n of the State of Cal.§ III.A, at 2 (Sept. 10, 1995), https://docs.cpuc.ca.gov/PUBLISHED/Graphics/589.PDF (requiring a finding of "public convenience and necessity" for "major electric transmission line facilities which are designed for immediate or eventual operation at 200kV or more," but authorizing exemptions for replacements, relocations, or conversions or upgrades of existing lines); Testimony of Simon Hurd, Program & Project Supervisor, FERC Docket No AD22-9-00 (Oct. 6, 2022) (stating that 63% of transmission capacity in California built between 2019 and 2021 was self-approved and did not undergo regulatory review by a California energy agency).

72. *See, e.g., Maine Power Link*, 179 FERC ¶ 61,215 (2022) (describing the lack of regulatory supervision over projects in New England).

73. *See* Peskoe, *supra* note 12; Hausman, *supra* note 66.

74. *See* Hausman, *supra* note 66; Macey, *supra* note 13, at 1294-95.

effectively meeting the country's transmission needs. But because utilities and regulators do not consider whether these lines are more cost-effective compared to regional or interregional solutions, we are skeptical that utilities have stumbled on the most cost-effective investments.[75]

III. ORDER NO. 1920

While the underlying regulatory challenges remain the same as they were fifteen years ago, the stakes have grown considerably as a result of a changing resource mix and increasingly ambitious state clean energy policies. Wind in particular relies on transmission to connect the best resources with load centers and smooth variability across different sources. Along these lines, academic and national lab studies consistently observe that expanding regional and inter-regional transfer capacity would lead to significant economic benefits. The gains from improved coordination are even more significant when one accounts for state and federal decarbonization policies.[76] Heightening the tension, states participating in the same regional planning process often have significantly different decarbonization policies. Order No. 1920 reflects both FERC's most recent attempt to address market power issues that have long beleaguered U.S. electricity markets, and to do so in a manner that fairly and cost-effectively allocates costs of a changing grid.

A. Planning and Cost Allocation in Order No. 1920

At a high level, Order No. 1920 requires a transparent process for evaluating and selecting projects and the creation of an *ex ante* cost allocation method that meets the beneficiaries pay standard.[77] The Order requires the use of transparent processes for developing inputs into planning models, evaluating their outputs, and allocating the cost of any projects selected as a result. As such, the Order is consistent with the traditional regulatory goals of (1) selecting projects that maximize economic surplus while ensuring reliability and (2) allocating the cost of shared projects commensurate with benefits.

A significant portion of the text of the Order sets out minimum requirements that should be included in the transmission planning process.[78] In a regional process, transmission planners consider a set of potential projects and examine the possible consequences that could arise once the projects are built. These consequences include altered generator investment and retirement decisions, effects on

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75. In fact, a large amount of research has documented the economic and reliability benefits of regional and interregional transmission investments.

76. *See* Alexander E. MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on US CO_2 Emissions*, 6 NATURE CLIMATE CHANGE, 526, 526-31 (2016); *See also* Patrick R. Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 JOULE 115, 115-34 (2021).

77. The order also discusses issues connected to construction work in progress incentives, rights of first refusal, and local transmission planning inputs that have cost and modeling implications but are less salient to the present discussion.

78. Since including all relevant benefits is straightforwardly a best practice, most comments related to this item had to do with whether it makes sense to include relevant but difficult-to-model benefits beyond the required seven (e.g., increased liquidity and reduction of market power).

local transmission processes, and changes to operational decisions such as which generators would be dispatched. Planners also encode constraints that prevent the model from recommending a system configuration that would lead to an unacceptably low level of reliability, be inconsistent with physical constraints governing power system operations, or result in the region falling out of compliance with environmental laws. In this context, Order No. 1920 requires that:

> 1. Planners must construct at least three scenarios in developing a regional transmission plan.[79]
> 2. Planners must develop at least one "sensitivity," akin to a "stress test," for each scenario to study the benefits of the proposed plan during extreme weather events in which there are "multiple concurrent and sustained generation and/or transmission outages."[80]
> 3. The model should cover at least twenty years past the in-service date of potential projects.[81]
> 4. The model should reflect the impact of seven listed *benefits* related to cost and reliability.[82]
> 5. Planners should use the best available data when constructing the scenarios, in particular incorporating seven required categories of *factors*.[83]
> 6. Transmission planners should consider certain projects identified in generator interconnection processes.[84]
> 7. Transmission planners should consider grid-enhancing technologies.[85]

These requirements can be straightforwardly interpreted in the context of the models used in transmission expansion planning. In a standard optimization framework, planners attempt to maximize the present value of expected surplus subject to reliability constraints and applicable laws.[86] The first requirement is aimed at ensuring some representation of uncertainty in the system. The second ensures that model results will be tested against a broader range of potential futures

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79. Order No. 1920, *supra* note 1, at P 559 ("We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to develop at least three distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning. In implementing this requirement, transmission providers must develop, at least once during the five-year Long-Term Regional Transmission Planning cycle, at least three distinct Long-Term Scenarios that, at a minimum, incorporate the seven categories of factors listed in the Categories of Factors section above.").

80. *Id.* at PP 494, 593-95.

81. *Id*. at P 3.

82. *Id.* at PP 1505-08.

83. Order No. 1920, *supra* note 1, at P 231.

84. *Id.* at PP 7, 472.

85. *Id.* at P 1198 ("We . . . require transmission providers . . . to consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes, dynamic line ratings and advanced power flow control devices for each identified transmission need.").

86. For a more comprehensive discussion of optimization modeling for transmission expansion planning, *see generally* Shu & Mays, *supra* note 8.

than those used directly in development of the plan. Given the outsized role that extreme weather can play in the value of transmission,[87] the specific inclusion of such events in the analysis is consistent with techniques of importance sampling used for variance reduction in optimization and simulation. The requirement to evaluate benefits over a twenty-year time horizon intends to strike a balance of ensuring proactive identification of regional solutions that cost-effectively resolve needs that today are being addressed outside the regional process, while also preventing overoptimism about benefits that may accrue beyond the first twenty years of the project's life. Requiring the consideration of seven different benefits ensures that planning does not underestimate benefits by examining only a subset of potential benefits; in optimization terms, these can be thought of as ensuring that certain parameters are included in the model. The seven categories of factors are meant to ensure that planners use the best possible information when developing estimated values of parameters used in the model.[88] The sixth requirement elaborates on a particularly important source of information: the interconnection queue process. Lastly, requiring the consideration of grid-enhancing technologies ensures that the set of feasible solutions is as large as possible.[89] In our view, all these principles follow from FERC's central mission of preventing undue discrimination.

By defining a minimum set of benefits, the planning requirements are necessarily connected to the Order's approach to cost allocation. Order No. 1920 encourages states to reach an agreement about how to allocate the costs of regionally planned transmission facilities, but, if the state agreement approach fails, transmission planners must use a backstop cost allocation method.[90] Though the Order leaves specific details regarding implementation to transmission planners, it does require a transparent process for evaluating and selecting projects and the creation of an *ex ante* cost allocation method that meets the beneficiaries pay standard. Thus, although FERC will consider whether a region has complied with the beneficiary pays approach by looking at the record before it in specific proceedings, Order No. 1920 makes clear that "any cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent."[91]

One proposed method of meeting the beneficiary pays standard is to use the outputs of the planning models themselves.[92] Planning models attempt to measure the cost of projects against the discounted benefits that are projected to accrue years in the future once the lines are built. The benefits estimated in these models

87. Dev Millstein et al., *Empirical Estimates of Transmission Value using Locational Marginal Prices*, ENERGY MKTS. & POL'Y: BERKELEY LAB 3 (2022) https://emp.lbl.gov/publications/empirical-estimates-transmission.

88. Order No. 1920, *supra* note 1, at PP 314-15.

89. *Id.* at PP 842-43.

90. *Id.* at P 228.

91. *Id.* at 1305.

92. *See, e.g.*, Hogan, *supra* note 8, at 25-46.

can be disaggregated into estimates for each of the market participants included in the model. Accordingly, a "direct benefits modeling" approach offers the potential to "allocate the costs of transmission facilities selected [in the regional plan] to meet those transmission needs in a manner that is at least roughly commensurate with [the facility's] benefits."[93] The benefits of regional lines include, among other things, improved reliability, reduced congestion, and reducing the costs states face in meeting their energy goals. It is worth noting that in an optimization modeling context, different benefits are all translated into a common unit, namely dollars, for purposes of computing tradeoffs. Certain physical laws and reliability standards may be expressed as hard constraints, violation of which will not be allowed in the transmission plan or in any valid counterfactual against which benefits might be calculated. Other constraints, e.g., a state renewable portfolio standard that includes an alternative compliance payment provision, may be coded as soft constraints that the model will violate if the cost becomes excessive. One consequence of this common unit is that a direct benefits modeling approach does not distinguish between separate categories of economic, reliability, and public policy benefits; to the extent such a distinction is needed for accounting purposes, it would require additional calculations.

A virtue of the direct benefits modeling approach is that no cost is allocated to a state on the basis of a different state's clean energy policies. Consider a region that consists of New Jersey and Ohio. Planners have identified a new line that costs $40 and would create $100 of benefits across the two states. Each state would receive $20 in benefits for reliability improvements and $20 in benefits for reduced congestion. That yields $80 in total benefits—$20 for Ohio reliability, $20 for suggestion reduction, $20 for New Jersey reliability, and $20 for New Jersey congestion reduction. The remaining $20 in benefits arise because the line reduces the costs of meeting New Jersey's clean energy goal. New Jersey thus receives $60 in total benefits ($20 for improved reliability, $20 for reduced congestion, and $20 in clean energy) whereas Ohio only receives $40 in benefits ($20 for improved reliability and $20 for reduced congestion). Under the direct benefits modeling approach, New Jersey pays $24 (sixty percent of $40 is $24) and Ohio pays $16 (forty percent of $40 is $16). Table One Presents such a case:

Table 1: Direct Benefits Modeling Approach

	New Jersey	Ohio	Total
Reliability Improvement	$20	$20	$40
Reduced Congestion	$20	$20	$40
Clean Energy Goal Attainment	$20	-	$20
Total Benefits	$60	$40	$100
Share of Benefits	$60/100	$40/100	
% of Costs Allocated	60%	40%	
Costs Allocated	$24	$16	$40

93. *Id.* at 114.

Note that Ohio customers pay only for benefits they receive.[94] While the line makes it less expensive for New Jersey to meet its clean energy goals, Ohio is not responsible for paying for those benefits. When calculating the percentage of costs that are allocated to Ohio, planners only consider direct and measurable benefits to Ohio electricity consumers—here, improved reliability and reduced congestion.

Now imagine a situation in which regional planners did *not* consider region-wide benefits of some lines when allocating the costs of new transmission. In that case, a state with a clean energy policy—New Jersey, in our hypothetical—would need to make additional investments to meet its clean energy goals. To do so, New Jersey would likely either pay for additional carbon-free generation or additional transmission lines that are planned outside the regional process. Those assets would create benefits for Ohio customers. For example, the cost of energy in Ohio might go down or the line might allow Ohio utilities to import power during extreme weather events. Because New Jersey has paid the entire costs of these upgrades, New Jersey has provided a subsidy to Ohio customers. As we discuss in the next subpart, the dissent appears to endorse this siloed approach for *all* new transmission lines—not simply for resources that support state clean energy policies.[95]

The primary challenge in this regard is the uncertainty inherent in long-term transmission planning.[96] Suppose that in this example, transmission planners compute benefits by state in each scenario used in the planning model, with the results shown in Table 1. The hypothetical is constructed to maximize contrast between the scenarios. In Scenario 1, benefits accrue entirely to New Jersey, while in Scenario 2 they accrue entirely to Ohio. Scenario 3 exhibits the same 60/40 split in benefits as before, but the overall benefits are substantially lower ($25 instead of $100). The average across the three scenarios reflects the $60 and $40 of expected benefits in the original example. Further, it should be understood that the three scenarios chosen for study are a small subset of the potential futures that may arise.[97]

94. *See* Order No. 1920, *supra* note 1, at P 1510 (acknowledging New Jersey's concerns about free ridership and explaining that the beneficiary pays approach will address those concerns).

95. *See id.* at P 67 (Christie, Comm'r, dissenting) ("For each identified reliability problem, there is an optimal solution that solves the reliability problem at the least cost to consumers. For an economic project, consumers should receive the maximum reduction in congestion costs relative to the cost of the project, or put in another way, for a given reduction of congestion costs, consumers should pay the least costs for the project").

96. It is worth pointing out that the direct benefits modeling approach described here has not been implemented in any region, nor is it required by Order No. 1920.

97. For an example with more extensive out-of-sample tests, *see* Shu & Mays, *supra* note 8.

Table 2: Example with Different Benefits by State in Different Scenarios

	New Jersey	Ohio	Total
Scenario 1	$165	$0	$165
Scenario 2	$0	$110	$110
Scenario 3	$15	$10	$25
Average	$60	$40	$100

Order No. 1920 does not require that the project in this example is selected. Despite the expected benefits of $100, a region could decide that the presence of a scenario with only $25 of benefits implies too much risk for ratepayers. Similarly, it does not require that allocation be based on the expected value of benefits. Given the uncertainty in the calculation, states may decide that a different method of allocating costs would be preferable. Instead, Order No. 1920 requires a transparent process by which the transmission planner constructs scenarios and sensitivities, as well as a default method by which costs can be allocated. In the context of the direct benefits modeling approach, this transparency is a significant advantage. If cost is allocated in a way that diverges significantly from modeled benefits, it is reasonable to reevaluate whether the method leading to that allocation is consistent with the beneficiary pays standard. Such a reevaluation is only possible if the relevant model outputs are available.

It should also be noted that Order No. 1920's approach to cost allocation is resource agnostic. Ohio remains free to pass a "Coal Energy Law" that would keep its coal-fired power plants online. If Ohio passed such a law, multi-benefit regional planning would incorporate Ohio's preference for coal and allocate costs accordingly. In that scenario, if a new line reduced the costs of keeping an Ohio coal-fired power plant online, perhaps by increasing the market available to the coal-fired power plant, Ohio customers would benefit. New Jersey customers would pay for the economic and reliability benefits they receive but would not be responsible for the cost savings Ohio receives on account of the fact that the line reduces the costs of meeting its energy policy.

It is of course possible that *transmission* costs would be lower if planners did not consider state clean energy policies, but that would not result in lower *electricity* rates.[98] An alternative planning process might look at reliability benefits

98. Congress stressed the importance of this distinction in the Energy Policy Act of 2005, when it instructed FERC to "establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 315, 1283; *see* Federal Power Act 219(a), 16 U.S. Code § 824s(a). In other words, Congress has required FERC to adopt rules that encourage utilities to invest in transmission that reduces congestion and the cost of delivered power. FERC promulgated incentive-based rates in 2006. *See also* Order No. 679, *Promoting Transmission Investment through Pricing Reform*, 116 FERC ¶ 61,057 at P 34 (2006) (to be codified at C.F.R. pt. 35) ("[A]ny investment made in, or costs incurred for, transmission infrastructure after August 8, 2005 that ensures reliability or lowers the cost of delivered power by reducing transmission congestion will be eligible for incentive-based rate treatments under this Rule.").

while ignoring state energy policies. But consider what happens if transmission planners blind themselves to state energy policies in this way. New Jersey would still need to make additional investments to meet its clean energy targets.[99] Because planners, by definition, only select projects if the projected benefits exceed the costs, a line will not be selected if the aggregate costs of meeting system needs would be lower with an alternative portfolio of investments.[100] In other words, transmission planning that ignores state policies can be expected both to cause total costs to increase and force states that have adopted clean energy policies to subsidize states that have not.[101]

When utilities join an RTO or transmission planning region, they (or state or federal regulators) decide that the scale benefits of participating in a regional market—improved reliability, lower energy prices, more efficient transmission investment—are worth giving up some amount of control over transmission planning. If a state or utility is unhappy about this trade-off, it should exercise the remedy negotiated for when it joined an RTO, which may include the ability to leave an RTO.[102] But it cannot enjoy the benefits of regional integration while insisting that its neighbors pay for the economic and reliability benefits it receives from participating in an integrated system.

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99. These investments would also, as discussed, provide direct economic benefits to Ohio customers.

100. Because there is considerable uncertainty in future investments and policy decisions, planners will not be able to do this perfectly.

101. Alternatively, if PJM or Ohio refused to build lines that support New Jersey's clean energy policies, they could thereby prevent New Jersey from meeting its own clean energy goals. But The FPA is very clear that states retain authority over their generation facilities. *See* 16 U.S.C. § 824(b) (2000). Ohio and PJM would, in effect, be making decisions about what generation New Jersey can build. Incorporating state policy decisions is therefore needed to preserve state authority over generation facilities.

102. Whether, and under what circumstances, a utility can leave an RTO has not been fully resolved. RTO tariffs and operating agreements outline the procedures under which utilities can leave RTOs, though FERC has authority to review exit decisions to make sure that they do not result in unjust, unreasonable, or unduly discriminatory rates. *See, e.g.*, *American Transmission Systems, Inc.*, 129 FERC ¶ 61,249 (2009), order on reh'g; *see also Order Addressing Expedited Partial Requests for Clarification and Rehearing*, 130 FERC ¶ 61,171 (2010) (approving American Transmission System's request to leave MISO and join PJM). Moreover, the Energy Policy Act of 2005 gives FERC untested preemption authority where FERC finds that state law is inhibiting voluntary coordination efforts by the utilities they regulate. In addition, Section 205(a) of PURPA provides that "[t]he Commission may, on its own motion, and shall, on application of any person or governmental entity, after public notice and notice to the Governor of the affected States and after affording an opportunity for public hearing, exempt electric utilities, in whole or in part, from any provision of State law, or from any State rule or regulation, which prohibits or prevents the voluntary coordination of electric utilities, including any agreement for central dispatch, if the Commission determines that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area." 16 U.S.C. § 824a-l (2000). Section 205 contains two exceptions. However, the Commission may not grant an exemption if it finds that the relevant provision of state law, rule, or regulation is either: (1) required by Federal law; or (2) designed to protect public health, safety, or welfare, or the environment or conserve energy or is designed to mitigate the effects of emergencies resulting from fuel shortages. *See id.*; *See also The New PJM Companies*, 105 FERC ¶ 61,251 (2003) (considering the question whether FERC can enforce a merger condition obligating a utility to join an RTO where the utility also requires, but has not received, the approval of a state commission before it can turn control of its transmission assets over to an RTO).

B. The Order No. 1920 Dissent

The dissent's primary critique of Order No. 1920 is that the Order's approach to cost allocation forces some states to pay for other states' clean energy policies in what he calls a "dereliction of the Commission's duty under the [Federal Power Act] to protect consumers."[103] In arguing that the "final rule ignores the principle of the optimal solution in transmission planning," the dissent makes two arguments about how cost allocation should work.[104] First, under the dissent's preferred approach, transmission planners would consider needs individually and not look at the aggregate benefits of new lines.[105] If FERC adopted this approach, developers would build "reliability lines" in response to reliability needs, allocating the costs to regions that experience reliability benefits and ignoring the other benefits these lines provide. They would build "economic lines" to lower energy market prices, allocating the costs to regions in which the price of energy goes down and ignoring the other benefits of the line. And they would build "clean energy lines" in response to state decarbonization needs, allocating the costs to states that have adopted clean energy policies and ignoring reliability and economic benefits. Second, the dissent also urges planners to pursue a "cost minimization" approach that meets reliability needs at the lowest cost rather than maximizing the cumulative benefits of new lines.[106]

1. Multi-Value Projects

The dissent endorses an approach to cost allocation that considers benefits individually by identifying solutions to one-off needs. The dissent states that:

> [f]or each identified reliability problem, there is an optimal solution that solves the reliability problem at the least cost to consumers. For an economic project, consumers should receive the maximum reduction in congestion costs relative to the cost of the project, or put in another way, for a given reduction of congestion costs, consumers should pay the least costs for the project.[107]

In other words, Christie prefers an approach to transmission planning in which planners identify a single problem and determine the least-cost means of addressing that problem.

The problem with this approach is that it does not in fact identify the globally optimal solution. It instead endorses pursues solutions that are optimal only when assessed against individual benefits.[108] Suppose planners have identified a reliability violation and decide to consider two candidate solutions to the violation. Both potential solutions will resolve the issue. Option A costs $20 million, and option B costs $25 million but is projected to lead to economic (not climate) benefits of $10 million in present value terms. Option B is clearly globally optimal.

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103. Order No. 1920, *supra* note 1, at P 21 (Christie, Comm'r, dissenting).
104. *Id.* at P 101.
105. *Id.*
106. *Id.*
107. Order No. 1920, *supra* note 1, at P 101 (Christie, Comm'r, dissenting).
108. *Id.*

It costs $5 million more but produces an additional $10 million in economic benefits. However, the reliability-focused analysis the dissent endorses will select option A. It is the least-cost solution, and the dissent argues that planning should be based on individual needs—here, the reliability need that originally justified the line.

The dissent elsewhere acknowledges that "[a]s we know from basic transmission planning, any transmission built is going to bring some reliability and economic benefits," yet the approach it endorses would not allow transmission planners to include these benefits in cost allocation.[109] In a modeling context, even if the primary purpose of a project is to resolve a reliability issue, it will inevitably alter power flows and consequently have some impact on congestion, losses, and nodal prices. The Order requires an approach that considers those benefits in cost allocation, whereas the dissent seems to wish to preserve an artificial distinction between different project types. This amounts to "ignor[ing] the principle of the optimal solution" that it claims to be defending.[110]

In fact, FERC itself recognized that a siloed approach to transmission planning would increase system costs and allow certain states and classes of customers to free ride off their neighbors. As the Commission explained in Order No. 1920:

> [A]llocating costs based on . . . project types would result in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Allocating costs based on these project types could, for example, encourage the selection of transmission facilities based on either their economic or reliability benefits alone rather than based on an evaluation of the wider range of benefits that they may provide. This dynamic results in, among other things, transmission customers paying more than is necessary or appropriate to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments. We further find that permitting the use of such project-type-limited cost allocation methods for Long-Term Transmission Facilities would not allocate costs in a manner that is at least roughly commensurate to estimated benefits.[111]

In addition to suggesting suboptimal solutions, the siloed approach to transmission planning has created significant disagreements regarding cost allocation—specifically about how to categorize transmission investment decisions under the single-value approach. Commissioner Christie drew attention to this challenge in a recent proceeding in which PJM selected several transmission projects that were needed to resolve reliability violations that arose after the deactivation of the Brandon Shores coal plant in Maryland.[112] Since the projects were classified as reliability projects, PJM applied the cost allocation method in place

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109. *Id.* at P 64 n. 238.

110. *Id*. at P 67.

111. Order No. 1920, *supra* note 1, at P 1508.

112. *PJM Interconnection, L.L.C.*, 185 FERC ¶ 61,107 at P 3 (2023) ("PJM notes the urgent need to upgrade the PJM Transmission System to address the reliability violations caused by the deactivation of Brandon Shores.").

for reliability projects.[113] Commissioner Christie described the challenge with the resulting allocation as follows:

> [I]f the resulting transmission projects under protest in this [Regional Transmission Expansion Plan] filing are caused more by Maryland's policy choices than by organic load growth and economic resource retirements, then a salient question that may be asked is whether these transmission projects are more accurately categorized as *public policy* projects . . . . And if they are more accurately categorized as public policy projects, should such projects be regionally cost-allocated, potentially to consumers in Pennsylvania, West Virginia, Ohio, *et al.*?[114]

The problem Christie identified is that it can be unclear whether the benefits provided by a given portfolio of projects should be considered as belonging to reliability, economics, or public policy. Differentiating between the categories requires a model that includes all relevant reliability and economic benefits, as well as the public policy factors that enter the planning process. As described above, this is precisely the modeling approach set out in Order No. 1920. Without such a model, it is not clear how to answer the question raised by Commissioner Christie in the context of Brandon Shores.

2. Least-Cost vs. Highest Surplus

At other points, the dissent argues that system planners should pursue cost minimization over other priorities, asserting, for example, that "the fundamental principle historically embedded in utility regulation in the United States is to provide consumers with reliable power at the least cost under applicable law."[115] While this principle is framed as a cost minimization problem, the planning approach adopted in Order No. 1920 is posed as a maximization problem—it pursues transmission solutions that provide the highest possible value.

When customers all have the same preferences, the cost minimization formulation and surplus maximization formulation are synonymous. Customers want the cheapest solution that addresses their needs. The difference between these two objectives arises when customers in the system do not share the same preferences. For example, in the context of reliability, it has long been recognized that assuming a shared reliability target for all customers implies a cross subsidy from customers who might place a lower value on reliability to those that place a higher value on it. Presumably the more salient concern in the context of the Order is the different preferences that many states and corporate buyers have for low-carbon generation. At a high level, modelers have three options when incorporating the effect of these different preferences on relevant parameters: (1) incorporating customer- or state-specific values, (2) computing a market-wide average value, or (3) assuming no preference for low-carbon generation.

Only option 1 avoids cross-subsidization. Option 2 would lead to cross subsidies between different states or customers, and option 3 explicitly overrides the preferences of some states or customers, which, as discussed in the previous sub-

113. *See id*. at P 2.
114. *Id*. at P 7.
115. Order No. 1920, *supra* note 1, at P 2 (Christie, Comm'r, dissenting).

part, also results in cross-subsidization, since states would make additional investments that would benefit their neighbors. Option 3 may also be inconsistent with the FPA's mandate that states retain authority over their generation mixes. At the very least, it is in tension with the dissent's stated belief that FERC and transmission planners should in general defer to state priorities. Accordingly, the order's pursuit of option 1 is the most consistent with the "principle of the optimal solution."[116]

To understand this, it is worth returning to the Ohio-New Jersey example above, though using different numbers. Suppose for simplicity that the two states have equal electricity consumption. New Jersey has clean energy policies that could be included in the planning process, while Ohio does not. The regional planner is analyzing a transmission project with a cost of $5/MWh when amortized over the consumption of one of the states over the evaluation period. Suppose the planner conducts the analysis two times, once accounting for the policies and once without accounting for them, and calculates the following average cost per MWh in each state under the different scenarios, with no differences in reliability:

Table 3: Prices in Two States With and Without Transmission Expansion. "Base" refers to a price per MWh without including the cost allocated due to transmission expansion. Total transmission cost is allocated proportional to modeled benefits.

		New Jersey			Ohio		
		Base	Allocated	Total	Base	Allocated	Total
No policy	No expansion	$50	--	$50	$50	--	$50
	With expansion	$48	$2.50 (50%)	$50.50	$48	$2.50 (50%)	$50.50
With policy	No expansion	$60	--	$60	$50	--	$50
	With expansion	$54	$3.75 (75%)	$57.75	$48	$1.25 (25%)	$49.25

Without transmission expansion, the addition of policy-related constraints increases the expected cost of electricity in New Jersey from $50/MWh to $60/MWh. When evaluated without the effect of the state policy, the line would fail to be selected: total cost rises from $50/MWh to $50.50/MWh in both states with the expansion. When evaluated after accounting for the policy, however, the total benefit amounts to $8/MWh ($60/MWh-$54/MWh=$6/MWh for New Jersey and $50/MWh-$48/MWh=$2/MWh for Ohio). Since this benefit exceeds the cost of $5/MWh, the line is selected. The model suggests a cost allocation of 75% to New Jersey and 25% to Ohio, after which both states see a lower total cost than they would have without the line. As previously described, the planning study would not compute a separately specified "public policy" benefit within the

116. *Id.* at P 101.

model: the benefits are computed as "economic." By performing the planning analysis two times, it is possible to define such a public policy benefit as the difference ($8/MWh−$4/MWh = $4/MWh). However, this accounting change does not affect the recommended solution or the overall benefits calculation.

It is worth repeating one point for emphasis: Ohio sees its costs go down because the line has direct economic benefits for Ohio customers—it reduces congestion. Ohio customers only pay for those economic benefits. In this context, it is not clear how to interpret the dissent's allegation of "a mismatch between planning criteria and benefits."[117] One potential source of confusion has to do with the relationship between the "benefits" that must be included in the transmission planning process and the "factors" that planners must consider when constructing scenarios. In this example, the relevant benefit is production cost savings, while the relevant factor is New Jersey's policy-related constraints. In a modeling context, omitting these policy constraints would both lead to a suboptimal solution and make it impossible to correctly assess the split of benefits between Ohio and New Jersey.

The dissent argues that Ohio should not be included in the analysis and cost allocation at all, claiming that this approach "shoehorn[s] the broadest group of beneficiaries possible for projects that do not remotely relate to reliability and economic needs"[118] and that "[t]he result of this shell game is to ensure preferential policy and corporate-driven projects are selected with the widest group of beneficiaries possible, so as to socialize the costs across the widest group of consumers."[119] The implication is that the dissent would prefer to exclude some beneficiaries and allocate all of the project cost to New Jersey. Since New Jersey nevertheless would see net benefits from the transmission project, it may be willing to do so in this example. But that, of course, would result in New Jersey subsidizing Ohio's electricity consumption, violating the beneficiary pays principle and contradicting the dissent's stated goal of avoiding cross subsidies.

It is possible that some projects may "not remotely relate to reliability and economic needs."[120] Suppose that the transmission planner performs the same analysis as in Table 2 but on a different project. Suppose the outcome for New Jersey is an $8 reduction in cost when policy is included but $0 if it is not, and the outcome for Ohio is $0 in either case. The direct benefits modeling approach, supported by the multi-value planning approach required by Order No. 1920, would suggest an allocation of 100% of the project's cost to New Jersey. More generally, a multi-value model can be applied even if some benefits are not relevant for a given project. Single-purpose models, by contrast, will not necessarily contain the information required to compute the other, non-modeled benefits. Rather than shoehorning the broadest group of beneficiaries possible, a multi-value model is the only plausible way to assess the distribution of total benefits that might arise.

117. *Id*. at P 45.

118. *Id.* at P 98.

119. Order No. 1920, *supra* note 1, at P 98

120. *Id.* at P 98 (Christie, Comm'r, dissenting).

It is also worth noting that Order No. 1000 is technologically and politically neutral. If Ohio adopted a policy intended to facilitate access to coal-fired generation, transmission planners would have to consider whether transmission lines reduce the costs Ohio faces in meeting its coal-fired generation standard, and they would have to allocate the costs accordingly. Again, in such circumstances, only Ohio customers would be responsible for paying the costs associated with keeping coal-fired generation online, and New Jersey customers would be responsible for the economic and reliability benefits they receive.

It is therefore difficult to understand the dissent's allegation that "[t]he final rule's goal is to socialize the costs associated with preferential policy and corporate-driven projects across the multi-state regions, even when the states have never consented for their consumers to pay for such projects."[121] As we have explained, the most straightforward way to calculate public policy benefits, differentiate them from reliability and economic benefits, and assign them to particular states or customers is to explicitly include them in the planning model formulation. Without including the influence of public policy in the planning process, there is no straightforward way to identify the related benefits and beneficiaries. In other words, Order No. 1920 supports an approach wherein customers are allocated cost commensurate with the benefits they are projected to receive, whereas the dissent seems to make such an allocation impossible.

3. Practical considerations

Given the straightforward interpretation of Order No. 1920 as consistent with best practices in modeling and cost allocation, it is worth describing in more general terms how the planning processes it envisions might nevertheless lead to some states paying for other states' clean energy policies. To start, given the irreducible uncertainty involved in long-term planning, some mismatch between allocated costs and realized benefits is guaranteed to occur when regional projects are evaluated *ex post*, no matter what processes for planning and cost allocation are implemented. Returning to the example with the three scenarios described in Table 1 above, assume that an *ex ante* cost allocation method assigns 60% of the cost to New Jersey and 40% to Ohio based on the expected value of benefits across the three scenarios. If an *ex post* analysis were to find that the benefits accrued entirely to New Jersey, then it would turn out to be the case that Ohio subsidized New Jersey in this instance. With sound planning and cost allocation practices, however, this type of cross-subsidization would cancel out over the course of many projects and planning cycles.

Accordingly, we must instead look for the possibility that planning and/or cost allocation processes will be biased in such a way that the resulting allocations will lead to persistent cross subsidies. Suppose that the planner in this example used an allocation method that differed from the distribution of benefits projected in the planning model, e.g., assigning 50% of the project cost to each state. If the true expected distribution of benefits is indeed 60% to New Jersey and 40% to Ohio, and this imbalance holds for many projects, then over time the cost allocation method would embed a cross subsidy. Since Order No. 1920 does not specify

121. *Id.* at P 86.

a cost allocation method, it will only be possible to evaluate the potential for such a cross subsidy in the context of individual compliance filings. However, it does not seem to be a major concern for the dissent, which asks "in what reality will a transmission provider seeking to comply with today's final rule identify different beneficiaries from those identified in the planning process?"[122] As discussed above, the planning process laid out in Order No. 1920 identifies beneficiaries in a way that accounts for public policy and assigns their associated costs to the states or groups that have enacted them, enabling for their straightforward inclusion in an allocation consistent with the beneficiary pays standard.

The dissent raises two possible exceptions to this more general expectation that the beneficiaries will correspond to benefits. First, the dissent argues that including information from generator interconnection processes as a factor when modeling transmission needs will lead to cost shifts, with costs that would otherwise be borne by interconnecting generators instead of being paid by consumers.[123] Here, the dissent presumes that planners will suggest a cost allocation method that excludes generators from cost allocation, even if those generators have been identified as beneficiaries. Since Order No. 1920 allows for the possibility that generators will be included in cost allocation, it is not clear how to assess any potential cost shift in advance of compliance filings. The second, potentially more challenging case arises in the case of corporate demand for clean energy resources, also included in Order No. 1920 as one of the factors influencing transmission needs.[124] As explained above, it is appropriate in an optimization context to incorporate the different preferences of different customers when seeking a solution that maximizes overall surplus. However, inclusion of corporate demand as a factor in the parameterization of models will imply that the relevant corporations can be identified as beneficiaries by the models. As argued in the dissent, inclusion of such entities in cost allocation may present challenges in compliance and implementation. In this context, the dissent observes that "[n]othing in the final rule will prevent transmission providers from discounting these commitments one hundred percent."[125] To ensure compliance with the beneficiary pays standard, it is possible that planners will take this approach.

Rather than occurring in the step of mapping planning model benefits to beneficiaries, the most challenging source of potential cross subsidies arises in the construction of the scenarios and sensitivities used in the planning models themselves. In this context, the dissent argues that "[w]hile the final rule insists that it is not mandating *outcomes*, when you manipulate the *inputs* of transmission planning, you are effectively mandating outputs."[126] While "mandating" is too strong, both the Order and the dissent agree that it is possible to manipulate outcomes through the development of scenarios or sensitivities that will be more likely to lead to desired outputs. Indeed, a major motivation for the Order is the belief that

122. *Id*. at P 65.

123. *See* Order No. 1920, *supra* note 1, at P 71.

124. *Id*. at P 314.

125. *Id*. at P 73 (Christie, Comm'r, dissenting).

126. *Id*. at P 12 (Christie, Comm'r, dissenting).

current processes implicitly underestimate the expected benefits of regional projects. It is therefore possible that a different planning regime could instead lead to overestimates. While the dissent is right to be concerned about this possibility, there is no *a priori* reason to think that the potential for such manipulation will increase under Order No. 1920. In our view, the question should therefore be addressed in individual compliance filings, when it is possible to assess the specific scenarios and sensitivities transmission planners adopt. Similarly, it is not clear why such manipulation would necessarily favor states with clean energy goals as opposed to other parties.

IV. Legal Principles of Transmission Planning and Cost Allocation

Given their disagreement about how to allocate the costs of new transmission, it is somewhat surprising that both the Order and the dissent agree on the legal principles that should guide cost allocation. Notably, they agree that FERC cannot force some states to subsidize others, and that states retain authority over their generation mixes. Disagreement is primarily about how to meet this legal standard when states have adopted different clean energy policies. As we explained in the previous Part, the beneficiary pays approach prevents free ridership and does not force states to subsidize other states' energy policies. As we explain here, the beneficiary pays approach is also consistent with decades of judicial precedent.

A. Post-Order No. 1000 Cases

FERC's authority to regulate transmission planning and cost allocation is based on the text of the FPA, which gives FERC jurisdiction over "the transmission of electric energy in interstate commerce" and instructs FERC to make sure that transmission rates are "just and reasonable" and not "unduly discriminatory."[127] This is a clear grant of authority. In fact, courts have acknowledged that FERC's legal authority is strongest in the context of transmission[128] and, over the past sixty years, have emphasized that the FPA allows—and may even require—multi-factor planning in which the costs of transmission are allocated to the customers who benefit from the line.

Courts most clearly articulated this standard in the wake of Order No. 1000, when some utilities challenged the beneficiary pays approach to cost allocation. Order No. 1000, like Order No. 1920, "require[d] each planning process to have a method for allocating costs *ex ante* among the beneficiaries of new transmission facilities in the regional transmission plan."[129] The D.C. Circuit first considered challenges to this approach in *South Carolina Public Service Administration v.* FERC, where the Court held that FERC has "authority under Section 206 [of the

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127. Federal Power Act, § 201, 16 U.S.C. § 824p(b); *Id.* § 205, 16 U.S.C. 824d; *Id.* § 206, 16 U.S.C. 824f; New York v. FERC, 535 U.S. 1, 1 (2002). FERC's authority to regulate transmission rates perfectly mirrors its authority to regulate pipeline rates.

128. S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 63 (D.C. Cir. 2014) ("[T]he Commission possesses greater authority over electricity transmission than it does over sales.").

129. *Id*. at 48.

Federal Power Act] to require the *ex ante* allocation of the costs of new transmission facilities under beneficiaries."[130] The Court pointed out that "the deficiencies in transmission planning and cost allocation practices were well-understood and not based on guesswork" and recognized that forward-looking planning based on beneficiary pays cost allocation were the proper remedy to the free rider problem that had led to ineffective transmission planning.[131]

In *South Carolina Public Service Administration*, the D.C. Circuit also described the evidentiary burden FERC faces when reforming transmission planning and cost allocation. FERC must identify "existing planning and cost allocation practices that could thwart the identification of more efficient and cost-effective transmission solutions."[132] Historically, FERC has met this burden through generic findings showing that existing processes can be expected to impede competition, reduce reliability, or allow transmission owners to favor their own affiliates and discriminate against competitors.[133] Courts have not required that the Commission precisely quantify the costs and benefits, especially when it is not feasible to do so.[134]

After *South Carolina Public Service Administration*, courts continued to emphasize that, at least in most circumstances, FERC *must* assign the costs of new transmission to the customers that benefit from new lines.[135] One of the first challenges to Order No. 1000's approach to cost allocation—*Illinois Commerce Commission v. FERC* (*ICC 2*)—concerned multi-value projects in MISO. Some utilities argued that they were being charged for benefits they would not receive, and utilities outside MISO argued that they should not be forced to pay for lines that are planned to address MISO's transmission challenges. Both state regulators and utilities therefore accepted that beneficiary pays cost allocation was now the legally required standard and argued that MISO and FERC applied this standard incorrectly. The question, in other words, was not whether the FPA authorized a beneficiary pays approach, but whether FERC and MISO had marshaled enough evidence to show that certain customers would in fact see benefits from these lines. In upholding MISO's approach to cost allocation, the Court made clear that costs must be assigned on the basis of benefits, explaining that since the lines "will benefit electricity users in PJM, those users should contribute to the costs."[136]

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130. *Id.* at 49.

131. *Id.* at 65; *see* FirstEnergy Serv. Co. v. FERC, 758 F.3d 346, 346 (2016) ([A] 'beneficiary pays' approach is a just and reasonable basis for allocating the costs of regional transmission projects, even if it leads to reallocating sunk costs."). .

132. S.C. Pub. Serv. Auth., 762 F.3d 41 at 66.

133. *See generally* Order No. 888, *supra* note 27; Order No. 2000, *supra* note 27; Order No. 890, *supra* note 38; Order No. 1000, *supra* note 14.

134. *See id.*

135. *See* Ill. Commerce Comm'n v. FERC, 721 F.3d 764, 779 (7th Cir. 2013) (ICC II); *see also id.* at 779; *see also* Old Dominion Elec. Coop. v. FERC, 898 F.3d 1254 (D.C. Cir. 2018); *see also* Entergy Arkansas, LLC v. FERC, 40 F.4th 689, 692 (D.C. Cir. 2022); El Paso Elec. Co. v. FERC, 76 F.4th 352, 366 (5th Cir. 2023).

136. Ill. Commerce Comm'n v. FERC, 721 F.3d 764, 779 (7th Cir. 2013).

The Seventh Circuit also weighed in on the evidence planners need to produce to support cost allocation decisions. The Court observed that MISO had produced "voluminous evidentiary materials, including MISO's elaborate quantifications of costs and benefits" and explained that FERC and transmission planners need not quantify costs and benefits perfectly when it is not feasible to do so:[137]

> As we explained in *Illinois Commerce Commission v. FERC*, if FERC 'cannot quantify the benefits [to particular utilities or a particular utility] . . . but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in [the] region, then fine; the Commission can approve [the pricing scheme proposed by the Regional Transmission Organization for that region] . . . on that basis. For that matter it can presume [as it did in this case] that new transmission lines benefit the entire network by reducing the likelihood or severity of outages.[138]

The Court was emphatic on this point: "[i]t's not enough for Illinois to point out that MISO's and FERC's attempt to match the costs and the benefits of the MVP program is crude; if crude is all that is possible, it will have to suffice."[139]

The Seventh Circuit confirmed this position a year later, when it reviewed a challenge to cost allocation in PJM. In that case, also called *Illinois Commerce Commission v. FERC (ICC 3)*, utilities argued that FERC acted arbitrarily and capriciously because it failed to respond to allegations that utilities in western PJM were being forced to pay for lines that would not provide benefits to their customers.[140] This time, the utilities won, and they did so because PJM failed to rebut the charge that utilities in western PJM were paying for benefits that went to utilities in eastern PJM. PJM allocated costs "in proportion to each utility's electricity sales, a pricing method analogous to a uniform sales tax."[141] The problem with this approach, according to the Seventh Circuit, was that utilities had introduced evidence showing that most of the economic and reliability benefits went to customers in eastern PJM. Rather than respond to this concern, "[t]he Commission defended its approach by appealing to the difficulty of measuring the benefits that the western utilities would derive from the new lines."[142] This, according to the Court, was "a feeble defense. . . . FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members."[143] The Court therefore struck down PJM's cost allocation methods because "charging costs greater than the benefits would overcharge the utilities, and charging costs less than the benefits would undercharge them."[144]

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137. *Id.* at 775.

138. *Id.*

139. *Id.*

140. Ill. Commerce Comm'n v. FERC, 756 F.3d 556, 558 (7th Cir. 2014) ("The question presented by the petition for review is the extent to which the members of PJM in its western region (we'll call these the "western utilities") can be required to contribute to the costs of newly built or to-be-built 500–kV lines (we'll call these the "new transmission lines") even though the lines are primarily in the eastern part of PJM").

141. *Id.*

142. *Id.*

143. *Id.* (citing Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 476 (7th Cir. 2009)).

144. Ill. Commerce Comm'n, 756 F.3d at 558.

The two *ICC* cases establish that customers should not be charged for lines that do not benefit them. Nor should they escape cost responsibility for lines that do benefit them. Both cases accept FERC's use of the beneficiary pays approach but insist that transmission planners show that costs are actually being allocated to beneficiaries. These cases are especially relevant to Order No. 1920, since they explicitly state that it is not sufficient to ensure that costs are only being assigned to beneficiaries. One most also ensure there are no significant beneficiaries escaping cost responsibility. The dissent's preferred single-value approach would meet the first criterion—as all those assigned costs would in fact be beneficiaries—but it fails the second criterion because it leads to other beneficiaries escaping cost responsibility, and thus assigns the costs of transmission infrastructure on an unduly small group.

As courts have continued to review transmission cost allocation, they have continued to require system planners to use beneficiary pays cost allocation. For example, in *El Paso Electric Company v. FERC*,[145] the Fifth Circuit struck down cost allocation in the WestConnect planning region that did not allocate costs to non-jurisdictional utilities. The Court was concerned that the transmission planner did not "apply that foundational principle of cost causation for about half of the utilities in the WestConnect region" and emphasized that the Commission failed to "provide a reasoned explanation for why the non-jurisdictional utilities have incentive or obligation to participate in binding cost allocation when they can get many of the same benefits at the jurisdictional utilities' expense."[146]

El Paso recognized that failure to use beneficiary pays cost allocation "creates a 'free rider' problem that Order No. 1000 sought to reduce or eliminate" and, as a result, "unlawfully violates the principle of cost causation."[147] Importantly, the Court expressly connected the beneficiary pays approach to the text of the FPA, concluding that FERC's "Compliance Orders fail to adequately explain how the mandates in those orders do not ensure unjust and unreasonable rates as between jurisdictional and non-jurisdictional utilities (and their customers) in the WestConnect region."[148]

The D.C. Circuit reinforced the need for planners to use beneficiary pays cost allocation in 2018, in *Old Dominion Electric Cooperative v. FERC.*[149] *Old Dominion* concerned FERC's decision to approve an amendment to the PJM tariff

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145. *See generally* El Paso Elec. Co. v. FERC, 832 F.3d 495 (5th Cir. 2016).

146. *Id.* at 505.

147. *Id.* at 504. The facts of El Paso were complex, largely because the WestConnect region includes non-jurisdictional utilities that, under some circumstances, can opt out of the regional planning process and binding cost allocation. Under WestConnect's proposed approach, transmission plans could only proceed if the benefits to the utilities that paid for the lines exceeded their costs. FERC felt that this would reduce non-jurisdictional utilities' incentive to free ride. *See* Joint Brief of Intervenors in Support of Respondent at 14, El Paso Elec. Co. v. FERC, No. 18-60575 (5th Cir. 2022) ("[A]s FERC found on remand, if substantial numbers of non-public utilities choose not to accept cost allocation for a project that benefits them in the hopes they would get a free ride they would be taking a major risk that the project would not proceed at all") (citing Order on Remand, 161 FERC ¶ 61,188 at P 47).

148. *Id.* at 504.

149. *See id.*

that denied cost sharing for projects "undertaken only to satisfy an individual utility's planning criteria."[150] Because these projects result in significant regional benefits, they had historically been funded through cost sharing.[151] The Court held that the beneficiaries of new lines must pay their share and reversed FERC's decision on the ground that it forced customers to pay the entire costs of certain new lines even when those lines benefited customers in neighboring regions.

Old Dominion clarified two questions about the beneficiary pays approach. First, the Court explained that beneficiary pays was required even when lines do not go through the regional planning process, and second, that beneficiary pays was based on the FPA, not Order No. 1000. The Court emphasized that "compliance with Order No. 1000 does not necessarily ensure compliance with the cost causation principle."[152] To the contrary, the Court described cost causation as "a pre-existing, more general rule that, in order to ensure just and reasonable rates, FERC must make some reasonable effort to match costs to benefits."[153] Despite the fact that the lines at issue in *Old Dominion* did not go through Order No. 1000's regional planning process, the Court held that FERC exceeded its statutory authority by forcing a subset of customers to pay for lines that created region-wide benefits:

> [W]e fail to see how a categorical refusal to permit any regional cost sharing for an important category of projects conceded to produce significant regional benefits can be reconciled with the background principle [of beneficiary pays cost allocation]. To the contrary, the cost-causation principle prevents regionally beneficial projects from being arbitrarily excluded from cost sharing—a necessary corollary to ensuring that the costs of such projects are allocated commensurate with their benefits.[154]

Another point the *Old Dominion* court made, or at least implied, is that the benefits a project produces matter more for cost allocation purposes than the planning criteria the project was originally built to satisfy. As the Court explained, "the cost-causation principle focuses on project benefits, not on how particular planning criteria were developed."[155] This suggests that, if a project produces significant secondary benefits (e.g., reliability or economic benefits for a project built primarily to support a state's policy goal), then allocating the cost of a project solely based on the primary planning purpose for which it was built runs afoul of the FPA's just and reasonable requirement.

In the last few years, courts have continued to require beneficiary pays cost allocation. For example, in 2022, the D.C. Circuit said that "[i]n assessing whether a rate is 'just and reasonable,' FERC and the courts determine . . . whether the rate comports with the 'cost-causation principle' which requires that the rates charged

150. Old Dominion Elec. Coop. v. FERC, 898 F.3d 1254, 1255 (D.C. Cir. 2018).
151. *Id.*
152. *Id.* at 1263.
153. *Id.*
154. Old Dominion Elec. Coop., 898 F.3d 1254 at 1263.
155. *Id*. at 1262.

for electricity reflect the costs of providing it."[156] As the Court explained, "[w]e often frame this principle as one that ensures burden is matched with benefit, so that FERC generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse."[157]

Since Order No. 1000, every court that has considered cost allocation has sanctioned FERC's use of the beneficiary pays approach, and every case striking down transmission cost allocation has done so either because the RTO allocated costs to customers who did not benefit from the line or failed allocate costs to customers who did benefit from the line. In short, judicial skepticism of cost allocation decisions has arisen when FERC and system planners allow cross-subsidies, force customers to pay for lines that do not benefit them, or allow customers to benefit from lines without paying. At the very least, planners cannot ignore evidence that costs are (a) being allocated to customers who do not benefit from new lines or (b) being allocated to customers who do benefit.

It is worth noting that some of these cases predate *Chevron* while others rest on the court's understanding of the text of the FPA—not an agency construction of vague or ambiguous statutory text. For example, *Loper Bright* does nothing to call into question cases like *Old Dominion*, where the court specifically overrode FERC's determination based on the court's own reading of the FPA. By definition, that means *Old Dominion*'s reasoning is in no way dependent on *Chevron* deference, as in overruling FERC, the court was clearly not showing deference to FERC. In our view, *Loper Bright* actually reinforces the beneficiary-pays principle as interpreted and set forth by the *Old Dominion*, *El Paso*, and other courts, as those cases suggest that the beneficiary pays approach is based on statutory text and thus reduce FERC's ability to re-interpret what statutorily rooted principle means. That supports an argument that FERC's approach to cost allocation in Order 1920 is the legally safest route it had, given courts' repeated determination that the FPA prohibits FERC from allowing significant free riding. Order No. 1920 thus appears to be adopting the standard courts have required for decades.

B. Early Cost Allocation Cases

But even before FERC promulgated Order No. 1000, courts required the use of the beneficiary pays approach.[158] This legal standard originated before the Supreme Court's *Chevron* decision, immediately after Congress passed the FPA and

156. Entergy Ark., LLC v. FERC, 40 F.4th 689, 692-93 (D.C. Cir. 2022).

157. *Id.* at 693.

158. *See, e.g.*, Western Mass. Elec. Co. v. FERC, 165 F.3d 922, 927-28 (D.C. Cir. 1999) ("The Commission's position with regard to assignment of costs is, so far as we can tell, part of a consistent policy to assign the costs of system-wide benefits to all customers on an integrated transmission grid. We have approved the underlying rationale of this policy. When a system is integrated, any system enhancements are presumed to benefit the entire system"); Pub. Serv. Comm'n of Wisconsin v. FERC, 545 F.3d 1058, 1067 (D.C. Cir. 2008) ("Our precedent requires only that 'all approved rates reflect to some degree the costs actually caused by the customer who must pay them.' . . . Moreover, [MISO's approach to cost allocation] is consistent with the "Cost Causation Rate Principles" FERC has embraced in previous decisions, notwithstanding the petitioners' claim to the contrary, *see* PSCW Br. pt. IV; ISO New England, Inc. v. New England Power Pool, 91 F.E.R.C. ¶ 61,311, at 62,076 (2000) ("Our general principle is to assign costs of various upgrades to those who benefit to the extent that they can be

Natural Gas Act (NGA), when FERC relied on parallel provisions of the NGA to allocate the costs of natural gas pipelines.[159] In fact, even before Congress passed the FPA and NGA, the Supreme Court used language in utility cases suggesting that utility principles of nondiscrimination required some version of beneficiary pays cost allocation.[160]

Before discussing these cases, it is important to clarify a semantic point. As we briefly explained in Part III, the language FERC and the courts use in these cost allocation cases is often confusing. Sometimes FERC has used the phrase "cost causation." At other times, it has used "beneficiary pays." The phrases have become synonymous. Regulators and courts use both interchangeably. This appears to be a result of the history of the gas and electricity industries. When utilities planned gas and electricity investments to serve local service territories, costs were allocated to the utility that planned the investment.[161] In that period, utilities

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identified"); Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 476-77 (7th Cir. 2009) ("To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed"); *id*. at 477 ("We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. Midwest ISO Transmission Owners v. FERC, supra, 373 F.3d 1361, 1369 (D.C. Cir. 2004) ("'we have never required a ratemaking agency to allocate costs with exacting precision'"); *Id.* at 1368 (The court describes MISO Owners' primary contention as being that "FERC's order does not comport with the 'cost causation principle.' We have described this principle as 'requir[ing] that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.' . . . Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party").

159. Fed. Power Comm'n v. Nat. Gas Pipeline Co. of Am., 315 U.S. 575, 584 (1942) ("The second [step of utility ratemaking] is the adjustment of a rate schedule conforming to that level so as to eliminate discriminations and unfairness from its details"); Battle Creek Gas Co. v. FPC, 281 F.2d 42, 46 (D.C. Cir. 1960) (authorizing cost allocation that "rolled [costs] into the rate base of all pipeline customers on the ground that "all customers enjoy the benefits"); Laclede Gas Co. v. FERC, 722 F.2d 272, 276 (5th Cir. 1984) (upholding the use of rolled in pricing). After *Chevron*, many Supreme Court cases do not appear to have relied on *Chevron* when requiring that beneficiaries be assigned the costs of gas infrastructure. *See, e.g.*, Associated Gas Distrib. v. FERC, 824 F.2d 981 (D.C. Cir. 1987) ("The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. . . . AGD demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access as a remedy for undue discrimination."); Pacific Gas & Elec. Co v. FERC, 373 F.3d 1315, 1317 (D.C. Cir. 2004) ("'It has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them'") (citing K N Energy v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

160. *See e.g.*, U.S. v. Ill. Cent. R.R. Co., 263 U.S. 515, 524 (1924) ("[T]he difference in rates cannot be held illegal, unless it is shown that it is not justified by the cost of the respective services, by their values, or by other transportation conditions."); Interstate Commerce Comm'n v. U.S. ex rel. Campbell, 289 U.S. 385, 387–88 (1933) ("The Commission found that the failure of the carriers to establish joint or group rates over the short line connections had the effect of an undue preference to lumber companies doing business within the group territory. . . .").

161. Some of the old cost allocation cases understand cost causation to mean the rate regulated utility that plans investments. *See, e.g.*, Ala. Elec. Coop., Inc. v. FERC, 684 F.2d 20, 27 (D.C. Cir. 1982) ("[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity").

made investments to serve customers in their franchise territory, and so it made sense to ask who the but-for cause of utility investments was.[162] As utilities expanded their systems and integrated with their neighbors, FERC recognized that the proximate cause of energy infrastructure should be understood, at least for cost allocation purposes, by looking at the beneficiaries. To that end, in 1992, the D.C. Circuit observed that:

> [T]he benefit principle may simply prove to be another prism through which to view the question of cost causation—one that admittedly extends the chain of causation further than FERC has done traditionally. That is, rather than focusing us on the most immediate and proximate cause of the cost incurred, the benefit principle may only ask us to look at a host of contributing causes for the cost incurred (as ascertained by a review of those who benefit from the incurrence of the cost) and assign them liability too. Simply, it may be a proxy for an extension of the chain of causation.[163]

It thus appears that, as system planners recognized the need for regional and interregional planning, they began to assert that cost causation requires the beneficiary pays approach. That is why FERC and courts have repeatedly accepted that "adoption of a beneficiary-based cost allocation method is a logical extension of the cost causation principle."[164] In our view, any terminological confusion results from the electricity industry's history of cost-of-service regulation.

Despite FERC's use of these different phrases, FERC and courts have consistently insisted that, when there is evidence that a class of customers benefits from the line, those beneficiaries should pay for the benefits they receive, and customers should not be able to free ride off their neighbors. In the years immediately following the passage of the Federal Power Act and Natural Gas Act, courts required energy regulators to assign costs based on who benefits. For example, in a series of orders in the 1940s and 1950s, the Federal Power Commission (the FPC, FERC's predecessor) consistently held that it would be discriminatory for a gas company to charge different rates to customers who received similar benefits and service.[165] Courts typically upheld these decisions, and, in rare cases where they

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162. *See id.*

163. K N Energy, Inc., 968 F.2d at 1302.

164. S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 85 (D.C. Cir. 2014). *See* Town of Norwood v. FERC, 962 F.2d 20, 25 (D.C. Cir. 1992) (allowing cost allocation "based upon that customer's proportionate use of existing capacity at the time of peak system demand" because this approach "ensures that the cost of new capacity is allocated to those who contribute to the need for adding it—an eminently sensible allocation, and one that we have endorsed before"); *see also* Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277, 1285 (D.C. Cir. 2007) ("But FERC has long taken the view that customer 'but-for' causation isn't dispositive of this issue. '[E]ven if a customer can be said to have caused the addition of a grid facility, the addition represents a system expansion used by and benefitting all users due to the integrated nature of the grid'"). In gas markets, they use the phrase "rolled in "rates to describe the beneficiary pays approach. *See* Battle Creek Gas Co., 281 F.2d at 47–48 ("We find that the Commission's basic conclusion that this partial expansion would be part of the integrated gas system was proper, and therefore affirm the use of the rolled-in allocation method. This conclusion is confirmed by, although it is not dependent upon, the later applications of Trunkline, clearly indicating an intent to utilize for the benefit of all customers the 'cheap expansibility' and new reserves made available through the facilities involved in this application").

165. In re City of Cleveland v. Hope Nat. Gas Co., 3 F.P.C. 150, 190 (1942); In re La. Pub. Serv. Comm'n v. United Gas Pipe Line Co., 3 F.P.C. 402, 404-05 (1943); In re Trunkline Gas Supply Co., 8 F.P.C. 250, 258 (1949); In re Colo. Interstate Gas Co., 11 F.P.C. 324, 353-54 (1952); In re United Gas Pipe Line Co., 14 F.P.C.

pushed back against the FPC, it was typically because the Commission failed to distinguish among differently situated classes of customers and assign costs accordingly.[166] In fact, James Bonbright's seminal treatise on public utility regulation, which was published in 1961, notes that ratemaking involves a "fair-cost apportionment objective, which invokes the principle that the burden of meeting the total revenue requirements must be distributed fairly among the beneficiaries of the service."[167] Utility regulators continue to rely on the Bonbright principles to guide utility regulation to support the proposition that "[t]he fundamental objective is to ensure that the revenue burden is being equitably shared amongst each customer class."[168] Both before and after FERC restructured the natural gas industry, courts and the Commission accepted something called rolled-in pricing as the proper approach to pricing for gas pipelines. Under that approach, the costs of pipeline expansions are allocated across the system to reflect the fact that the pipeline creates system-wide benefits.[169]

Cases upholding rolled-in pricing have repeatedly cautioned that it would be discriminatory for FERC to approve a rate structure that forces customers to pay for benefits they do not receive.[170] In fact, when the Commission began to accept alternative cost allocation approaches for gas pipelines, it did so because there was evidence that some customers were *not* benefitting from the additional pipeline capacity. In 1981, for example, the Fifth Circuit upheld a FERC decision not to use rolled-in pricing for "emergency-gas costs."[171] The pipeline expansion was being built to ensure that high-priority customers received uninterrupted service. FERC found, and the Fifth Circuit agreed, that "the method of pricing United uses

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353, 391-400 (1955); Cf. In re Colo. Interstate Gas Co., 19 F.P.C. 1012, 1021 (1958) (authorizing an exemption to rolled in rates when doing so would harm existing customers and raise prices).

166. Miss. River Fuel Corp. v. Fed. Power Comm'n, 252 F.2d 619, 626 (D.C. Cir. 1957) (remanding an FPC rate decision for charging different prices to similarly situated ratepayers); Order No. 436, *supra* note 24, at 42,415 ("The Commission has generally followed rolled-in treatment for new facilities except where the costs of the new facilities are more appropriately assigned to a particular customer or group of customers. Thus, new pipeline construction or looping of some portion of a mainline transmission system in order to provide increased services to some particular customer downstream has been granted rolled-in treatment on the grounds that the new looping will also benefit all system customers through greater reliability of service").

167. JAMES C. BONBRIGHT, PRINCIPLES OF UTILITY RATEMAKING 292 (1961).

168. ARTHUR ABAL ET AL., TARIFF TOOLKIT: PRIMER ON RATE DESIGN FOR COST-REFLECTIVE TARIFFS 12 (2021).

169. Battle Creek Gas Co., 281 F.2d at 47 (D.C. Cir. 1960) ("We find that the Commission's basic conclusion that this partial expansion would be part of the integrated gas system was proper, and therefore affirm the use of the rolled-in allocation method. This conclusion is confirmed by, although it is not dependent upon, the later applications of Trunkline, clearly indicating an intent to utilize for the benefit of all customers the 'cheap expansibility' and new reserves made available through the facilities involved in this application.").

170. Michigan Gas & Elec. Co. v. Fed. Power Comm'n, 290 F.2d 374, 376 (D.C. Cir. 1961) (upholding rolled in pricing and rejecting a utility proposal that "would unduly discriminate in its favor and would impose an undue burden upon the other customers of Michigan Wisconsin").

171. Laclede Gas Co. v. FERC, 722 F.2d 272, 274-75 (5th Cir. 1984) (stating that "[t]raditionally, the Commission has endorsed the practice of rolled-in pricing unless it would lead to an unfair result." But explaining that, "[d]uring the natural gas shortages of the 1970's, FERC allowed an exception to the rolled-in pricing practices for emergency gas purchases.").

(to recover the cost of emergency gas) is unjust, unreasonable, unduly discriminatory, and preferential, in violation of section 5 of the Natural Gas Act."[172] The Court explained that FERC can use rolled in pricing if "there is a direct benefit to all classes of customers."[173] But that is not the case when a pipeline expansion is built for the sole purpose of providing uninterrupted service to high-priority customers. In such circumstances, requiring non-priority customers to pay a share of those costs would force them to subsidize benefits that redound entirely to other customers.

Both FERC and courts continue to insist that cost allocation must prevent customers from free riding off their neighbors' investments. As in the electricity industry, courts have connected cost causation to the NGA's "just and reasonable" requirement. In *BNP Paribas*, for example, the D.C. Circuit stated that:

> The Natural Gas Act requires that rates be just and reasonable and not unduly discriminatory. 15 U.S.C. § 717c(a)-(b). The Commission has 'added flesh to these bare statutory bones' through adoption of the 'cost causation' principle, which requires that rates 'reflect to some degree the costs actually caused by the customer who must pay them.' *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992). This typically translates into a process of 'comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.' *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004). The flip side of the principle is that the Commission generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse.[174]

The court emphasized that "the cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit)."[175]

Thus, in both the gas and electricity industry, courts have long allowed FERC to allocate costs to the customers who benefit from new infrastructure. This approach to cost allocation has been used in the natural gas industry since at least the 1960s. Alternative approaches allow some customers to free ride off their neighbors in violation of the FPA and NGA's prohibition on undue discrimination.

V. CONCLUSION

As the previous Part explained, the beneficiary pays approach to cost allocation is consistent with decades of judicial precedent. Order No. 1920 therefore adopts the approach to cost allocation that courts have required for decades. Courts have repeatedly suggested that alternative cost allocation approaches are not consistent with FERC's mandate to ensure rates are just and reasonable and not unduly discriminatory. At various points, the Order No. 1920 dissent appears to agree with this legal interpretation, arguing, for example, that the FPA prohibits cost allocation approaches that allow some classes of customers to free ride off

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172. *Id*. at 276 (quoting United Gas Pipe Line Co. v. FERC, 649 F.2d 1110, 1113 (5th Cir. 1981)) (upholding use of rolled in pricing when FERC showed all customers benefited from pipeline expansion).

173. *Id.*

174. BNP Paribas Energy Trading GP v. FERC, 743 F.3d 264, 267-68 (D.C. Cir. 2014).

175. *Id.*

their neighbors. The dissent thus accepts, at least as a doctrinal matter, the beneficiary pays approach that FERC and courts have endorsed for decades.

But the specific proposal outlined in the dissent does not meet the standard it endorses. The dissent argues, for example, that "the cost causation principle cannot, and should not . . . require that the ratepayers of a non-consenting state pay costs of other states' public policies where there is mismatch between planning criteria and benefits."[176] The dissent appears to envision a separate category of "public policy" lines in which all costs should be allocated to states that have adopted clean energy policies. It is true that, when only a subset of states in a region adopt clean energy policies, states and customers without decarbonization goals will be forced to pay for projects that support the policy goals of other states and customers.

The reality of an interconnected transmission system is that essentially every line will produce some economic benefits, some reliability benefits, and some climate benefits. As we explained in Part II, if the Commission forced states that have adopted clean energy laws to pay all the costs of such lines, it would force those states to pay for economic and reliability benefits they do not enjoy. As a result, the siloed cost allocation approach the dissent proposes would result in precisely the type of cross-subsidization to which he objects. Of course, in Order No 1920's compliance filings, transmission planners could propose an approach to cost allocation that would force states to pay for energy policies they have not adopted. But that is not a reason to reject beneficiary pays cost allocation, since it would plainly violate the beneficiary pays standard and thus be vulnerable to legal challenge.

176. Order No. 1920, *supra* note 1, at P 67 (Christie, Comm'r, dissenting).