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Non-Transmission Alternatives

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Forthcoming in Harvard Environmental Law Review Volume 39, 2015

Sabin Center for Climate Change Law
Columbia Law School
September 2014

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Executive Summary

This article examines the reasons that "non-transmission alternatives"—including energy efficiency, energy storage, demand response, and distributed generation—have played a very limited role in meeting electricity grid constraints, despite their great potential. It argues that the predominant reasons for this failure lie in structural flaws in transmission planning, caused in part by questions over how far the jurisdiction of the Federal Energy Regulatory Commission (FERC) extends when it comes to these "non-transmission" resources. FERC has declared achieving "comparable consideration" for non-transmission alternatives to be an agency goal, but has limited the extent of its reforms to opening up the planning process to stakeholders. It has enacted these limited participatory reforms knowing that transmission planning is carried out by entities with expertise biases and financial incentives to build transmission, such that stakeholder participation is an unlikely remedy for the problem. This article illustrates why participatory reforms alone are likely to fail non-transmission alternatives, and then explores the jurisdictional limitations holding FERC back from creating transmission planning processes that fully and fairly incorporate non-transmission alternatives. In addition to suggesting ways that FERC can improve planning processes within its jurisdiction, this article argues that the Commission displays a harmful lack of candor by suggesting that it has implemented a mandate to treat non-transmission alternatives comparably, when in fact its reforms do little to accomplish this objective. I close by suggesting that FERC might be more honest about the shortcomings of its reforms in order to inform conversations among Congress, the Commission, states and stakeholders about options for progress on non-transmission alternatives.

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Introduction

The United States is approaching an electricity transmission crisis, at the same time that transmission has become the critical "fulcrum" on which the future of the U.S. energy mix may tip.[1] A recent headline succinctly described the problem: "Newly available wind power often has no place to go."[2] The challenge is one of geography. Whereas most U.S. electricity demand is on the densely populated coasts, most renewable energy resources are in the middle of the country.[3] For this reason, if we are to meet ambitious federal and state goals for transitioning our electricity system to one that relies far more on renewable power, and far less on fossil fuels, expanding transmission is critical.[4] Even absent these clean energy goals, new transmission will be important for maintaining the reliability of aging grid infrastructure to avoid costly and dangerous blackouts[5]—a challenge made more pronounced by the fact that climate change is increasing the frequency of storms and other disasters.[6] New transmission is also likely to be significant for helping states implement the major climate change regulations for power plants announced by the Obama administration in June 2014.[7]

At the same time, there is growing recognition that expanding transmission is not the only way—or necessarily the best way—to address all anticipated electricity constraints.[8] Transmission faces many well-documented challenges, including siting

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[1] PETER FOX-PENNER, SMART POWER: CLIMATE CHANGE, THE SMART GRID, AND THE FUTURE OF ELECTRIC UTILITIES 80 (2010).

[2] Trevor McClatchy, *Newly available wind power often has no place to go*, THE SACRAMENTO BEE, Aug. 4, 2013.

[3] *See, e.g.*, *Hearing on Legis. Regarding Electric Transmission Lines before the S. Comm. On Energy and Natural Resources*, 111th Cong. 2 (2009) (Statement of Jon Wellinghoff, now-former Chairman, Federal Energy Regulatory Commission); *see also* Ill. Comm. Comm'n v. FERC, 721 F.3d 764, 771 (7th Cir. 2013) ("The dirty secret of clean energy is that while generating it is getting easier, moving it to market is not . . . ." (internal quotation marks omitted)).

[4] *See Hearing on Legis.*, *supra* note 3 (explaining the need for the development of an extra-high voltage transmission infrastructure capable of transporting major quantities of renewable power); Stan Mark Kaplan, *Electric Power Transmission: Background and Policy Issues*, Congressional Research Serv. Report No. 7-5700, 9 (April 2009); Jim Rossi, *The Trojan Horse of Electric Power Transmission Line Siting Authority*, 39 ENVTL. L. 1015, 1016 (2009).

[5] *See* EXECUTIVE OFFICE OF THE PRESIDENT, ECONOMIC BENEFITS OF INCREASING ELECTRIC GRID RESILIENCE TO WEATHER OUTAGES 3, 7 (Aug. 2013) (observing that power outages cost the economy billions of dollars and disrupt millions of lives, and that seventy percent of transmission lines are over 25 years old); *see also* Alexandra Klass, *Takings and Transmission*, 91 N.C. L. REV. 1079, 1084-85 (2013).

[6] U.S. DEP'T OF ENERGY, U.S. ENERGY SECTOR VULNERABILITIES TO CLIMATE CHANGE AND EXTREME WEATHER i (July 2013).

[7] See, e.g. Debra Kahn, *Utilities: Western Officials Mull Regional Cooperation on EPA Rule*, E&E REPORTER, June 5, 2014 (explaining that one compliance challenge is "the dearth of transmission lines with enough capacity to take power from natural gas or renewable generation that would be called upon to compensate for ramped-down coal plants").

[8] *See, e.g.*, Rossi, *supra* note 4 (noting that transmission "can crowd out other desirable energy supply option programs").

battles and complicated questions about how to allocate the costs of new lines.[9] It also creates significant environmental impacts, which often lead to protracted litigation over the adequacy of environmental analyses.[10] If the end goal of transmission expansion is clean, affordable power in quantities adequate to meet demand, there are many means to this end. Often it may be easier, cheaper, and environmentally preferable to eliminate or shift demand, or to locate generation strategically, than it is to build new lines. As energy efficiency, demand response (the temporary cutting of demand during peak load periods), and distributed generation (e.g., roof-mounted solar) gain sophistication as a result of various policy drivers,[11] they are becoming increasingly viable alternatives to building new transmission.

However, as this article explains, there are persistent governance and jurisdictional hurdles that impede our ability to deploy these "non-transmission alternatives" even when they present superior solutions. Transmission development occurs through a complex web of federal and state processes and approvals.[12] States have taken some steps to evaluate alternatives to local transmission solutions, but transmission planning is increasingly an interstate, regional issue, carried out by bodies outside of state control.[13] And regional transmission planning processes fail to properly consider or promote non-transmission alternatives.

This failure has major ramifications. Much expensive new transmission will inarguably be necessary in the coming decades. One recent estimate suggested that U.S. utilities—and by extension, these regulated monopolies' customers—will spend around $50 billion *per year* on transmission and distribution system upgrades over the next two decades.[14] That is more than our current annual federal foreign aid and diplomacy

[9] *See, e.g.*, Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 VAND. L. REV. 1802 (2012).

[10] *See* THE NATIONAL COUNCIL ON ELECTRICITY POLICY, UPDATING THE ELECTRIC GRID: AN INTRODUCTION TO NON-TRANSMISSION ALTERNATIVES FOR POLICYMAKERS 1 (2009) [hereinafter "UPDATING THE GRID"].

[11] Several forces are driving the boom in these technologies, including state renewable portfolio standards, energy efficiency portfolio standards, and the ability of many of these resources to now participate in wholesale energy and capacity markets. *See, e.g.*, MATTHEW BROWN, THE ENERGY EFFICIENCY RESOURCE STANDARD: OBSERVATIONS ON AN EMERGING STATE POLICY (Harcourt Brown 2010); SANDY GLATT, STATE ENERGY EFFICIENCY RESOURCE STANDARDS ANALYSIS (Dep't of Energy 2010); Lincoln Davies, *Power Forward: The Argument for a National RPS*, 42 CONN. L. REV. 1339 (2010); Database of State Incentives for Renewables & Efficiency (DSIRE), http://www.dsireusa.org (last visited Aug. 19, 2013); Joel Fetter et al., *Energy Efficiency in the Forward Capacity Market: Evaluating the Business Case for Building Energy Efficiency as a Resource for the Electric Grid*, Paper presented at the ACEEE Summer Study on Energy Efficiency in Buildings (2012).

[12] *See generally* Ashley C. Brown & Jim Rossi, *Siting Transmission Lines in a Changed Milieu: Evolving Notions of the "Public Interest" in Balancing State and Regional Considerations*, 81 U. COLO. L. REV. 705, 710-713 (2010) (detailing the problems with the multi-layered approval process for transmission, including state and sometimes local approvals).

[13] *See, e.g.*, FERC Order 2000, Regional Transmission Organizations, 65 Fed. Reg. 810, 810 (Jan. 6, 2000) (codified at 18 C.F.R. § 35.24 (2012)) [hereinafter "Order 2000"].

[14] Chris Neme & Rich Sedano, *U.S. Experience with Efficiency as a Transmission and Distribution*

budget,[15] and more than five times the U.S. Environmental Protection Agency's annual budget.[16] About one-third of this investment is expected to be in high-voltage transmission lines that carry power over long distances.[17] Each of these lines will have to secure multiple state needs determinations, agreement on cost allocation, and state siting approvals. In the face of these challenges, the ability to understand when *not* to build transmission because other solutions out-perform it will be an important, complementary part of accomplishing U.S. energy goals.

The Federal Energy Regulatory Commission (FERC), the agency charged with regulating interstate transmission, has recognized that non-transmission alternatives deserve greater attention during transmission planning and has taken steps to better promote their consideration. First in 2007, in "Order 890," and then in 2011, in "Order 1000," FERC directed transmission planners to give "comparable consideration" to all types of solutions, in order to create "technology neutral" planning processes.[18] These orders also emphasized the need to open planning processes to greater stakeholder participation.[19] They stopped short, however, of giving transmission planners concrete instructions on how to achieve comparable treatment for non-transmission alternatives, leaving the details to be worked out at the regional and local levels. Unfortunately, planners at these levels are doing no more than making vague promises to "comparably consider" any non-transmission alternatives affirmatively proposed by participating stakeholders.

This article argues that such process-focused, participatory reforms are unlikely to do much to alleviate the challenges non-transmission alternatives face. I identify two impediments that will prevent FERC's participatory governance reforms from

System Resource, at i (Regulatory Assistance Project 2012).

[15] *See The U.S. State Dep't and U.S. A.I.D. Budget,* U.S. Dep't of State, http://www.state.gov/r/pa/pl/2013/207212.htm (last visited Aug. 16, 2013).

[16] *See* U.S. Envtl. Prot. Agency, Fiscal Year 2013 Budget in Brief, Pub. No. EPA-190-S-12-001, at 1 (2012) (requesting $8.4 million for the 2013 fiscal year).

[17] *See* THE BRATTLE GROUP, NATIONAL AND SPP ECONOMIC IMPACT ANALYSES FROM TRANSMISSION AND GENERATION INVESTMENT 5 (Dec. 2, 2011).

[18] *See* FERC Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12,266 (March 15, 2007) [hereinafter "Order 890"]; FERC Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842, 49,869 (Aug. 11, 2011) (codified at 18 C.F.R. pt. 35) [hereinafter "Order 1000"].

[19] *See, e.g.*, Order 1000, 76 Fed. Reg. at 49,842 (mentioning "stakeholders" 278 times, by my count). These reforms situate FERC within a broader movement towards "new governance" reforms, which emphasize flexibility, an enhanced role for private actors, collaborative decision-making processes, and robust stakeholder participation as critical components of administrative reform. *See* Douglas Nejaime, *When New Governance Fails*, 70 Ohio St. L.J. 323, 332 (2009); Karen Bradshaw Schulz, *New Governance and Industry Culture*, 88 NOTRE DAME L. REV. 2515, 2516 (2013); Orly Lobel, *The Renew Deal: The Fall of Regulation and the Rise of Governance in Contemporary Legal Thought*, 89 Minn. L. Rev. 342, 384 (2004) (utilizing the concept of "new governance" to unite many schools of thought that share these common concepts); Jody Freeman, *Collaborative Governance in the Administrative State*, 45 UCLA L. REV. 1 (1997) (tracing and endorsing the rise of collaborative governance regimes in place of the interest representation model).

facilitating "comparable consideration" in practice. First, we have ceded the function of transmission planning to transmission-focused entities, creating institutional biases and expertise in favor of building actual transmission that will be difficult to overcome via stakeholder participation. Second, non-transmission alternatives have societal benefits that are not being incorporated, and likely cannot be fully incorporated, into FERC-led transmission planning processes, making the pledge of "comparable consideration" ring somewhat hollow. I label these first two challenges as the "structural challenges" facing non-transmission alternatives. Third, non-transmission alternatives are ineligible to have their costs allocated among regional beneficiaries—a privilege that FERC accords to approved transmission projects.[20] I call this, quite simply, the "funding challenge," although as I explain, there is a larger jurisdictional problem at work. Without this guaranteed source of funding, companies will be unwilling to implement non-transmission alternatives, even when they do out-compete transmission solutions.

FERC's heavy reliance on participatory reforms to promote non-transmission alternatives pays lip service to these alternatives without meaningfully changing planning processes. To be sure, there may be some understandable reasons for moving slowly on non-transmission alternatives. As this article explains, FERC has taken relatively rapid steps to reform transmission planning in recent years and may feel that it has reached the edge of its institutional capital and jurisdiction in this sphere. Indeed, the D.C. Circuit recently read FERC's jurisdiction narrowly to strike one of its most innovative orders.[21] Nevertheless, FERC's reforms with respect to non-transmission alternatives are troubling for a lack of fit between rhetoric and action. FERC declares that it has created a process for "comparable consideration," but there are clear reasons that this process is likely to fail—making these reforms cosmetic rather than substantive.[22] If, instead, FERC truly intends to promote non-transmission alternatives to a place of parity, then it has more work to do. This article identifies several additional reforms could strengthen the stakeholder-oriented reforms now in place. However, it also shows where real jurisdictional limits exist to FERC's ability to promote non-transmission alternatives, and calls for more forthrightness from FERC on this point.

This article offers the first in-depth consideration of the legal and structural challenges faced by non-transmission alternatives. While the challenges of siting and paying for transmission have received ample scholarly attention in recent years,[23]

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[20] *See* Order 1000, 76 Fed. Reg. at 49,918 (requiring that "each public utility transmission provider have in its [tariff] a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan").

[21] Elec. Power Supply Ass'n v. FERC, --- F.3d ----, 2014 WL 2142113 (D.C. Cir. May 23, 2014) (discussed in detail *infra* Part IV).

[22] *See* Jaime Alison Lee, *"Can You Hear Me Now?": Making Participatory Governance Work for the Poor*, 7 HARV. L. & POL'Y REV. 405, 407 (2013) (noting several instances of "cosmetic" reform that appear to create more open processes but fail to deliver in substantive ways).

[23] *See* Rossi, *Trojan Horse*, *supra* note 4; Klass, *supra* note 5; Klass & Wilson, *supra* note 9; Brown & Rossi, *supra* note 12; Max Hensley, Note, *Power to the People: Why We Need Full Federal Preemption of Electrical Transmission Regulation*, 46 U. MICH. J.L. REFORM 1361 (2013); Elena P. Velikov, Note, *If It's*

transmission planning and non-transmission alternatives are important but underexplored related topics, given that planning is the critical antecedent to all siting and cost-allocation decisions.[24] The article unpacks the transmission planning process, showing how it suffers from bias and skewed incentives that will prevent recent reforms from operating as full solutions.

This case study of non-transmission alternatives also contributes to a broader discussion of agency action in the face of Congressional gridlock. Particularly in the environmental and energy spheres, where climate change presents an enormous problem unforeseen during the drafting of overarching statutes, agencies are struggling mightily to use old statutes to solve new problems.[25] In many cases, agencies are proceeding with an admirable combination of ingenuity and restraint.[26] And indeed, FERC has garnered deserved praise on this front in many regards.[27] However, I do not think that praise can be extended to the agency's handling of non-transmission alternatives. As this article shows, FERC likely knows that its participatory reforms standing alone are unlikely to achieve effective outcomes for non-transmission alternatives. Accordingly, I argue that an additional component of being a responsible agency working with outdated statutes is to admit where certain desirable actions are outside of agency powers, rather than declaring omnipotence where none exists.

This article proceeds in five parts. Part II provides background on the emerging concept of non-transmission alternatives and traces the history of FERC's reforms in transmission planning. Part III identifies and explores the limited efficacy of FERC's participatory reforms with respect to non-transmission alternatives, identifying key structural and funding challenges they continue to face. This part includes an examination of how regional transmission planners are implementing FERC's planning directives and the problems their interpretations present. Part IV discusses jurisdictional limitations—particularly those imposed by a recent D.C. Circuit decision—that constrain

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Broke, Fix It: Federal Regulation of Electrical Interstate Transmission Lines, 2013 U. ILL. L. REV. 695 (2013); Sandeep Vaheesan, *Preempting Parochialism and Protectionism in Power*, 49 HARV. J. ON LEGIS. 87 (2012); Ashira Pelman Ostrow, *Process Preemption in Federal Siting Regimes*, 48 HARV. J. ON LEGIS. 289 (2011); Drew Thornley, *The Federal Government's Authority to Site Interstate Electric Transmission Lines: How the Meaning of "Withheld" Is Withholding Clarity for Transmission Development*, 6 TEX. J. OIL GAS & ENERGY L. 385 (2011); Hoang Dang, *New Power, Few New Lines: A Need for a Federal Solution*, 17 J. LAND USE & ENVTL. L 327, 343 (2002).

[24] One recent article makes considerable headway into exploring transmission planning from the angle of whether FERC's reforms are legally permissible. *See* Alexander T. Dadok, Comment, *On the Pulse of America: The Federal Government's Assertion of Jurisdiction over Electric Transmission Planning and Its Effect on the Public Interest*, 91 N.C. L. REV. 997 (2013).

[25] *See generally* Jody Freeman & David B. Spence, *Old Statutes, New Problems*, XXX PENN. L. REV. XXXX (forthcoming 2014).

[26] *Id.* at 3; *see also* Sharon Jacobs, *The Administrative State's Passive Virtues*, 66 ADMIN. L. REV. (forthcoming 2014) (arguing that agency restraint is an "essential tool" in the strategic exercise of agency authority).

[27] *See* Freeman & Spence, *supra* note 25, at (forthcoming pages) (tracing how FERC has utilized the outdated Federal Power Act to manage changes in electricity markets).

FERC's ability to promote non-transmission alternatives. Part V then suggests how FERC might take a dual-pronged approach to non-transmission alternatives going forward, engaging in structural reforms within its jurisdiction that go beyond merely encouraging stakeholder input, while acknowledging where its reforms fall short in order to spark a broader conversation about potential solutions.

I. Non-Transmission Alternatives & Transmission Planning

A. Non-Transmission Alternatives

An article on non-transmission alternatives must begin by explaining what is meant by the phrase. Even when ordering that non-transmission alternatives receive "comparable consideration" in Order 1000, FERC never defines the term. The first clue that non-transmission alternatives may be at a disadvantage in the transmission planning process thus comes from their very characterization: as something *not* what the process traditionally focuses on. What, then, are these non-transmission alternatives?

Non-transmission alternatives are, most basically, any resource or configuration of resources that can replace or delay the need for additional transmission.[28] These alternatives include energy efficiency, demand response, distributed generation, energy storage, and centralized generation sited near load, each of which is described in more detail below.[29] A non-transmission alternative might also be a hybrid solution, employing some transmission capacity, but reducing the overall amount of new transmission by strategically utilizing some demand-side resources.[30] When utilized as a "non-transmission alternative," these alternative energy resources are weighed against a specific proposed transmission project as a possibly superior solution. Distributed energy resources also play a role in the antecedent process of projecting future electricity demand and consequent future transmission needs, but in this latter context, they are not functioning specifically as "non-transmission alternatives."[31]

Centralized (i.e., large) generation located close to load is the longest standing non-transmission alternative, dating back to the days before a transmission grid existed.[32] It negates the need for transmission by locating supply and demand alongside each other. Although elegantly simple in theory, this strategy is complicated by the real estate and

[28] *See* NEW ENGLAND STATES COMMITTEE ON ELECTRICITY, REGIONAL FRAMEWORK FOR NON-TRANSMISSION ALTERNATIVES ANALYSIS 2 (Oct. 2012); Elizabeth Watson & Kenneth Colburn, *Looking Beyond Transmission: FERC Order 1000 and the Case for Alternative Solutions*, PUB. UTILS. FORTNIGHTLY April 2013, 36 (2013).

[29] *See* Watson & Colburn, *supra* note 28, at 36.

[30] NEW ENGLAND STATES COMMITTEE ON ELECTRICITY, *supra* note 28, at 6 n.11.

[31] *Cf.* note 56, *infra* (describing the difference between "passive" and "active" deferral of transmission lines).

[32] See RICHARD F. HIRSH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM 12 (MIT Press 1999) (explaining that for Thomas Edison's original direct current power stations to work, customers had to be located within one mile of the plant).

environmental concerns raised by locating large power generating facilities near major urban demand centers.[33]

The other non-transmission alternatives—energy efficiency, demand response, distributed generation, and storage—are often lumped together under the moniker "distributed energy."[34] However, each has the potential to replace transmission in slightly different ways.[35] Energy efficiency entails "doing the same with less," and thus cuts overall electricity demand.[36] Typically, energy efficiency is implemented through utility- or third-party run programs that contact consumers and offer them incentives to take steps to increase the efficiency of their homes and appliances.[37] Quintessential examples include improving weatherization, replacing incandescent light bulbs with newer lighting technologies, and swapping out older appliances for newer, more efficient versions.[38] By permanently reducing electricity load, intelligently targeted energy efficiency can replace the need for a transmission line that is driven by a predicted increase in overall energy demand.[39]

Demand response refers to the practice of cutting energy demand during peak periods, either through switching to an on-site back-up generator or through energy saving measures like temporarily reducing air conditioning, dimming lights, etc.[40] Accordingly, demand response does not reduce long-term energy demand, but does reduce demand during the periods when the grid is under the most stress. It therefore might serve as a viable alternative to transmission in those situations where additional transmission capacity is needed to ensure adequate supply during peak times.[41]

Distributed generation consists of small-scale resources that are located near the load they are serving. These can be renewable or non-renewable.[42] Historically, much distributed generation has been diesel generators, which are often heavily polluting.[43] More recently, roof-mounted solar photovoltaic panels are gaining popularity, reaching one percent of electricity supply in leading markets and projected to grow to four percent in the next decade.[44] When considered as an alternative to transmission, distributed

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[33] *See* UPDATING THE GRID, *supra* note 10, at ii.

[34] *See* Travis Bradford, Anne Hoskins, & Shelley Welton, *Valuing Distributed Energy: Economic and Regulatory Challenges, Event Summary & Conclusions from the Princeton Roundtable,* at 4 (April 26, 2013).

[35] See PETER FOX-PENNER, *supra* note 1, at 46.

[36] UPDATING THE GRID, *supra* note 10, at 2.

[37] *Id.*

[38] *Id.*

[39] *See* Neme & Sedano, *supra* note 14, at 3-4.

[40] *See* Kaplan, *supra* note 4, at 12.

[41] *See id.*

[42] *See* FOX-PENNER, *supra* note 1, at 110-11; *see also* MIT, *Chapter 5: The Impact of Distributed Generation and Electric Vehicles*, in THE FUTURE OF THE ELECTRIC GRID 109, 109 (2011).

[43] *See* UPDATING THE GRID, *supra* note 10, at 5.

[44] *See* Anne C. Mulkern, *Utilities Challenge Net Metering as Solar Power Expands in California*, CLIMATEWIRE, April 2, 2013 (noting that small solar now makes up 1% of California's energy supply, and that it is projected to grow to four percent over the next decade).

generation functions differently depending on the type. Diesel- and natural gas-fired generators are often used as demand response resources—that is, they are deployed at peak times when it is cheaper to use these back-up sources than to purchase power from the grid. In contrast, solar panels and other renewable distributed generation technologies cannot cut load at a particular, pre-determined time. Instead, they cut load when the sun is shining (or wind is blowing, etc.), but their owners may require grid-supplied power at other times.[45]

Finally, there is the promising alternative of energy storage, which is often considered the holy grail of energy technologies and is still not widely commercially available.[46] Energy storage could replace transmission in several different ways. Similar to demand response, it could store energy off-peak and then release it during periods of peak demand.[47] Or it could serve as a complementary "balancing" resource for distributed renewables (or large-scale renewables), storing energy while the sun is shining or wind is blowing and releasing energy during periods when these renewable resources lag.[48] Finally, FERC has at times considered energy storage to itself *be* transmission, in those instances where the equipment "mimic[s] a wholesale transmission function."[49]

In addition to their potential to serve as cost-effective substitutes for transmission, non-transmission alternatives have several "co-benefits." By subjecting transmission to competition, non-transmission alternatives may help lower the future price of transmission itself, as well as reduce the need for subsidiary investments in distribution infrastructure.[50] The distributed energy solutions described above will also cut the overall amount of power flowing through the system, thereby easing congestion and further lowering electricity bills.[51] Depending on the resources utilized and resources replaced, distributed energy solutions also often reduce air pollutants, water usage, land usage, and carbon emissions when compared to a transmission solution.[52]

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[45] *See* MIT, *supra* note 42, at 109-110; Timothy P. Duane & Kiran H. Griffith, *Legal, Technical, and Economic Challenges in Integrating Renewable Power Into the Electricity Grid*, 4 SAN DIEGO J. OF CLIMATE & ENERGY L. 1, 4 (2013).

[46] *See* Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance and Accountability of Regional Transmission Organizations*, 28 ENERGY L. J. 543, 550 (2007); UPDATING THE GRID, *supra* note 10, at ii. Pumped storage at hydroelectric facilities is one economically viable form of storage (and 40 pumped storage projects in the U.S. provide over 22,000 megawatts of storage), but opportunities for expansion are limited. PUMPED STORAGE DEV. COUNCIL OF THE NAT'L HYDROPOWER ASS'N, CHALLENGES AND OPPORTUNITIES FOR NEW PUMPED STORAGE 3 (2012).

[47] *See* PUMPED STORAGE DEV. COUNCIL, *supra* note 46, at 3.

[48] *Id.*

[49] *See* Western Grid Development, LLC, 130 FERC ¶ 61,056 (2010).

[50] *See* Scott Hempling, *Order 1000: Can We Make the Transmission Provider's Obligation Effective and Enforceable?*, at 7 (paper prepared for the Sustainable FERC Project, March 2012), *available at* http://www.scotthemplinglaw.com/files/pdf/ppr_ntas-pprs_hempling0312.pdf.

[51] *Id.* at 7.

[52] However, the details matter in analyzing this potential benefit. If the transmission project would allow significant amounts of renewable energy to come on-line, or if the distributed energy solutions

And finally, utilization of non-transmission alternatives in place of transmission can help grow the marketplace for these relatively new technologies, thereby helping their own costs fall as well.

To state that each of these resources is theoretically capable of replacing transmission and bringing additional benefits invites the question of why they are not already doing so on the basis of market forces alone, even absent promotion by regulators. In fact, centralized generation sited near load regularly does replace transmission, as utilities and merchant generators have ample experience and incentives to propose generation solutions.[53] For this reason, transmission planning processes likely do not need to further promote centralized generation as a transmission alternative, as it does not face the same challenges as the other non-transmission alternatives. Often, however, the most cost-effective non-transmission alternatives employ a combination of centralized generation and distributed energy resources, such that centralized generation may form an important component of many broader non-transmission proposals.[54]

As for distributed energy resources, there are two primary reasons that they have not independently gained a major foothold as a viable alternative to transmission. The first is historical: these rapidly growing resources are still scaling up, such that many transmission planners may have dismissed them in the past as not reliable enough, or deployable at a significant enough scale, to replace transmission. There is now, however, growing evidence that these resources can indeed displace or defer transmission and distribution in meaningful ways.

In a 2012 study, the non-profit Regulatory Assistance Project catalogued the growing instances of energy efficiency substituting for, or deferring the need for, transmission and distribution.[55] It identified ten instances where planners have used energy efficiency to defer or displace transmission or distribution investments, with varying degrees of success.[56] These projects range from large-scale, region-wide

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proposed included significant small-scale diesel-fired generation, the non-transmission alternative might not produce an environmentally superior solution. *Cf.* MIT, *supra* note 42, at 100 ("[T] he benefits of [distributed generation] are highly dependent on the characteristics of each installation and the characteristics of the local power system.").

[53] In fact, utilities that own both generation and transmission have been accused of attempting to forestall needed additions to transmission in order to tamp down competition from outside generators, thereby keeping prices for their self-owned generation higher. *See* Order 890, 72 Fed. Reg. at 12,318 (observing that transmission providers "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").

[54] *See, e.g.*, Neme & Sedano, *supra* note 14, at 12.

[55] See Neme & Sedano, supra note 14. Comparable analyses are not available for the use of distributed generation or demand response in deferring/displacing transmission and distribution. Neme and Sedano note that these other resources have occasionally been used as a transmission substitute in the past, but do not analyze the matter in detail. *Id.* at 2.

[56] Neme & Sedano, *supra* note 14, at ii. *See also* UPDATING THE GRID, *supra* note 10, at 21-26. As Neme and Sedano explain, displacement can occur in two ways: passively, when already-planned energy efficiency (or demand response, or distributed generation) reduces loads and thus negates the need for new

endeavors, such as the federal Bonneville Power Administration's consideration of alternatives to transmission investments over $5 million, to much smaller-scale, such as NV Energy's initiative to obviate the need for a new transmission line and substation into Carson City, Nevada.[57] The authors reached positive tentative conclusions about energy efficiency's ability to defer transmission and distribution investments, finding that it can indeed be more cost-effective than traditional solutions.[58]

This study provides a hint that when considered, non-transmission alternatives may often be able to play a role in meeting grid constraints. The sheer volume of distributed energy opportunities available across the United States similarly suggests that non-transmission alternatives might be a potent strategy for helping to address future grid constraints. For example, there may be over 100 gigawatts of economic demand response capacity available nationwide—an amount "equivalent to the capacity of hundreds of new fossil fuel-fired plants."[59] Similarly, a now-famous report by the consulting firm McKinsey found that the U.S. could save $1.2 trillion through 2020 by investing in cost-effective energy efficiency options, cutting the country's projected energy usage by 23 percent.[60] And as noted above, distributed generation seems poised for a meteoric rise, at least in states with generous promotional policies.[61] All of these factors suggest that non-transmission alternatives might *often* provide superior solutions, if properly incorporated into grid planning.

But to a certain extent, it is impossible to estimate how large a role non-transmission alternatives might play in solving our national transmission crisis until they are systematically evaluated alongside transmission solutions. This observation brings us to the second, more pervasive reason that non-transmission alternatives—despite their promise—have not yet gained traction as a viable alternative to transmission, which

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transmission; or actively, when programs are specifically, geographically targeted to respond to an identified need that would otherwise be filled by a transmission or distribution system upgrade. This is an important distinction for purposes of this article, which is concerned specifically with the *active* consideration of non-transmission alternatives that might respond to an identified transmission need.

[57] Neme & Sedano, *supra* note 14, at ii-iii.

[58] *Id.* at iii, 18.

[59] Joel B. Eisen, *Who Regulates the Smart Grid? FERC's Authority Over Demand Response Compensation in Wholesale Electricity Markets*, 4 SAN DIEGO J. OF CLIMATE & ENERGY L. 69, 76 (2013) (citing ELEC. POWER RESEARCH INST, ASSESSMENT OF ACHIEVABLE POTENTIAL FROM ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS IN THE U.S. (2010-2030) 7 (2009)).

[60] *See* Kate Galbraith, *McKinsey Report Cites $1.2 Trillion in Potential Savings from Energy Efficiency*, N.Y. TIMES, July 29, 2009.

[61] Forty-three states currently use some version of "net metering"—wherein owners of distributed generation are allowed to "net" the energy they produce against the energy they draw from the grid—to promote these nascent technologies. *See* Database of State Incentives for Renewables & Efficiency, Net Metering, *at* http://www.dsireusa.org/userfiles/image/summarymaps/netmeteringmap.gif (last visited Jan. 10, 2013). However, these policies are under assault in many states where utilities are alarmed about the potential effects of rapid distributed generation growth. *See, e.g.*, Suzanne Goldenberg & Ed Pilkington, *ALEC calls for penalties on 'freerider' homeowners in assault on clean energy*, THE GUARDIAN, Dec. 4, 2013, *available at* http://www.theguardian.com/world/2013/dec/04/alec-freerider-homeowners-assault-clean-energy.

forms the crux of this article's argument: transmission planning processes are flawed in ways that prevent fair consideration of non-transmission alternatives.

B. States and Non-Transmission Alternatives

Before turning to examine federal transmission planning—the focus of this article—it may be helpful to explain briefly the state role in transmission planning and why I am looking beyond it. States are involved in transmission planning in several ways. First, state Public Utility Commissions (PUCs, or similarly named entities) oversee the rates charged by transmission and distribution utilities operating within their states to ensure they are "just and reasonable."[62] Furthermore, prior to undertaking a new transmission project, most states require transmission providers to obtain a "Certificate of Public Need" from the PUC, wherein a developer must demonstrate that the project is not "wasteful."[63] States also control transmission line siting, ultimately approving the final location of a line. These processes persist despite criticism that they allow parochial concerns to block much-needed interstate transmission lines.[64]

States have also long controlled decisions about how much energy efficiency, demand response, and renewable energy to require their utilities to procure or produce. They do this in several ways, the most prominent of which are "integrated resource planning" (IRP) and state procurement mandates. IRP, which is required in 28 states, forces utilities to plan for how to meet future anticipated demand through the most efficient resource mix, including generation, transmission, and distributed energy resources.[65] State procurement mandates, including "Renewable Portfolio Standards" (RPS) and "Energy Efficiency Resource Standards" (EERS), require utilities in a state to, respectively, source a certain percentage of their electricity supply from renewable energy and obtain a certain level of energy savings annually (generally from energy efficiency, but also sometimes from demand response). Twenty-nine states now have in place mandatory RPS, and twenty-four have EERS.[66] Through these processes, utilities

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[62] Regulators engage in a "prudence review" to determine whether or not a utility's investment should be deemed prudently incurred such that it can obtain rate recovery. *See* Jonas J. Monast & Sarah K. Adair, *A Triple Bottom Line for Electric Utility Regulation: Aligning State-Level Energy, Environmental, and Consumer Protection Goals*, 38 COLUMBIA J. ENVTL. L. 1, 60 (2013). However, states cannot disapprove cost allocations already approved by FERC in areas where FERC has jurisdiction over rates. *See* Entergy Louisiana, Inc. v. Louisiana Pub. Serv. Comm'n, 539 U.S. 39, 47 (2003) ("The filed rate doctrine requires 'that interstate power rates filed with FERC or fixed by FERC must be given binding effect by state utility commissions determining intrastate rates.'" (quoting Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 962 (1986))).

[63] *See* Klass, *supra* note 5; Rossi, *supra* note 4, at 1019; Klass & Wilson, *supra* note 9, at 1807.

[64] *See generally* Rossi, *supra* note 4; Klass & Wilson, *supra* note 9; Brown & Rossi, *supra* note 12.

[65] *See* Klass & Wilson, *supra* note 9, at 1807.

[66] *See* Database of State Incentives for Renewables & Efficiency, RPS Data Spreadsheet (March 2013), *available at* http://www.dsireusa.org/rpsdata/ (showing that 29 states plus the District of Columbia have mandatory RPS); *Energy Efficiency Resource Standards*, American Council for an Energy Efficient Economy, http://aceee.org/topics/eers (last visited Nov. 1, 2013). (finding 24 states with EEPS as of

may be discouraged from building transmission where distributed energy solutions appear abundant and inexpensive, although explicit consideration of non-transmission alternatives as a solution to identified transmission constraints is typically not required.[67] At least two states, Vermont and Maine, have passed specific laws requiring that any transmission proposed for construction within the state consider whether non-transmission alternatives could solve the same transmission constraint more effectively.[68] Connecticut has taken this requirement one step further, empowering the state's Energy Advisory Board to solicit requests for proposals for non-transmission alternatives to transmission projects that utilities have submitted for siting approval.[69] The Commissions of many other states administratively require consideration of non-transmission alternatives during transmission line approval processes, although with varying degrees of rigor.[70]

Prior to recent reforms, these state regulations constituted the primary oversight of transmission planning. Such plans occurred utility by utility, with each planning for the resources necessary to meet its internal customer needs.[71] Today, these state levers continue to exert force over individual utility plans and the siting of particular lines. However, utilities and their state oversight bodies are no longer the primary locus for transmission planning because, as the next section explains, FERC has regionalized the process to match industry reforms and an opening of the grid. For this reason, FERC has become the key regulator of transmission planning. State regulation continues to have relevance for injecting non-transmission alternatives into individual utility planning processes and individual line siting decisions, but federal attention to non-transmission alternatives is now critical to ensure that regional planning incorporates these options. The next two subsections explain further how regional transmission planning, overseen by FERC, has come to function in practice, in order to lay the groundwork for understanding how these processes treat non-transmission alternatives.

C. An Introduction to Transmission Planning

Transmission planning is a complex endeavor, involving layers of private entities

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September 2012).

[67] *See* Elec. Advisory Comm., Memorandum to Honorable Patricia Hoffman, U.S. Dep't of Energy, re: Recommendations on Non-Wires Solutions, at 14-15 (Oct. 17, 2012).

[68] *See* State of Vermont, Public Service Board Order, Docket No. 6290 (2003). These requirements were codified in 2005. *See* 30 VT. STAT. ANN. § 218C (2012). Since this time, Vermont has created a "System Planning Committee" that is responsible for "independently reviewing transmission plans and screening for non-transmission alternatives." *See* UPDATING THE GRID, *supra* note 10, at 25. Maine requires any person filing a petition for approval of a proposed transmission line to include "results of an investigation by an independent 3rd party . . . of nontransmission alternatives to construction of the proposed transmission line." 35-A Maine Rev. Stats. § 3132 (2014).

[69] *See* Conn. Gen. Stat. § 16a-7c (2014); *see also* UPDATING THE GRID, *supra* note 10, at 22-23.

[70] *See* Elec. Advisory Comm., *supra* note 67, at 11-12.

[71] *See* Brown & Rossi, *supra* note 12, at 721-22.

and regulators. 200,000 miles of high-voltage transmission lines across the United States carry electricity from power plants to demand centers.[72] These lines interconnect in historical rather than optimal patterns, and hundreds of individual utilities own portions of this larger system.[73] However, although technically under the ownership of hundreds of utilities, "from an electrical engineering perspective [the transmission system] operates as a single machine."[74] Transmission planning attempts to coordinate these entities in order to build the additional transmission necessary to maintain reliability, reduce congestion, and connect new resources to load.[75] It is a critical part of maintaining a functioning electricity grid, given the grid's disparate ownership patterns but inherent interconnectedness.[76]

I use "transmission planning" in this article to mean the exercise of projecting future needs for new transmission and selecting projects to meet those needs. In this way, I distinguish between this concept and the later processes of siting and paying for particular lines, as well as day-to-day management of lines.[77] I do so because for purposes of addressing non-transmission alternatives, it is important to unpack the particular problem of how needs are identified and potential responses considered. Indeed, some of the promise of non-transmission alternatives lies in their ability to avoid later siting battles.

From a technical perspective, there are two types of transmission planning:

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[72] *See* Kaplan, *supra* note 4, at 2-4.

[73] Klass & Wilson, *supra* note 9, at 1805, 1808; *see also* Jonathan Thompson, *The power grid may determine whether we can kick our carbon habit*, HIGH COUNTRY NEWS July 30, 2013 (describing the grid as growing "in an organic fashion, with new components welded on to the old ones, like additions slapped on to trailers in the rural West").

[74] *See* Order 2000, 65 Fed. Reg. at 817. Actually, the U.S. grid is more like three machines, because the entire grid is not interconnected. There is a western interconnect, an eastern interconnect, and a separate grid in the state of Texas that is not overseen by FERC because it is not considered sufficiently "interstate." *See* Klass & Wilson, *supra* note 9, at 1808; *see also* Kaplan, *supra* note 4, at 3. As of 2009, investor-owned utilities (IOUs) owned 66% of the U.S.'s high voltage transmission; the federal government, cooperatives, and other public power providers owned another 27%; and independent transmission companies owned 4%. Kaplan, *supra* note 4, at 4. Outside of the Upper Plains and the West, IOUs own approximately 80% of the grid. *Id.* Unlike IOUs, public power providers are not typically subject to the full panoply of state and federal regulation discussed in this article; instead, they are self-regulated by their governing boards. *Id.* at 6.

[75] *See* Kaplan, *supra* note 4, at 19 (citing Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, at 40, prepared by the Brattle Group for the Edison Electric Foundation (Nov. 2008)).

[76] *See Hearing on Legis. Regarding Electric Transmission Lines Before the S. Comm. On Energy and Natural Resources*, 111th Cong. 2, 7 (2009) (Statement of Jon Wellinghoff, now-former Chairman, Federal Energy Regulatory Commission); Order 1000, 76 Fed. Reg. at 49,848-49 (noting that the Department of Energy has recognized that "the electricity industry faces a major long-term challenge in ensuring an adequate, affordable and environmentally sensitive energy supply and that an open, transparent, inclusive, and collaborative process for transmission planning is essential to securing this energy supply").

[77] *Cf.* Klass & Wilson, *supra* note 9, at 1847 (explaining that while regional authorities engage in transmission line *planning*, authority for siting remains with the states).

reliability planning and economic planning.[78] For reliability planning, transmission planners—typically specialized electrical engineers—begin by assessing current electricity supply and demand, planned future generation and merchant transmission projects,[79] and projected future demand, typically over a long time horizon such as ten years.[80] The primary aim is to determine whether planned additions to, and subtractions from, the electricity grid will adequately protect the system's future reliability.[81] Where it is determined that planned additions will *not* ensure reliability, planners seek to identify where and what amount of additional resources are necessary.[82] After needs are identified, specific solutions are solicited and weighed against each other to choose the best option.[83] This latter process—the consideration of various potential solutions to an identified need—is where non-transmission alternatives can play a role.

Economic transmission planning focuses on saving consumers money by reducing grid congestion. Grid congestion, much like traffic congestion, can cost consumers hundreds of millions of dollars per year, as it limits the ability of the grid operator to deploy the cheapest power at any given time to the areas where it is needed.[84] Economic planning seeks to identify the places in the grid that are suffering most from

[78] *See* Eric Hirst & Brendan Kirby, *Key Transmission Planning Issues*, THE ELEC. J. OCT. 2001: 59, 60 (2001) (explaining these two types of planning, although noting that some grid planners believe that the distinction between these two categories is in practice quite blurry). As explained *supra*, FERC's Order 1000 added a third category of transmission planning—planning for "public policy requirements."

[79] Merchant transmission projects are those proposed by outside developers who, unlike traditional transmission providers, are not regulated as natural monopolies that can recover the costs of a project from captive retail customers. Merchant providers assume all market risk of their projects and have a right to charge for transmission at negotiated rates. *See* Heidi Werntz, *Let's Make a Deal: Negotiated Rates for Merchant Transmission*, 28 PACE ENVTL. L. REV. 421, 424-26 (2011).

[80] *See* FOX-PENNER, *supra* note 1, at 83; *see also, e.g.*, In re Long-Range Electric Resource Plan and Infrastructure Planning Process, Case No. 07-E-1507, N.Y. Pub. Serv. Comm'n, at 3 (Feb. 18, 2009) (describing the N.Y. Independent System Operator's transmission planning process) [hereinafter "In re Long-Range Planning"]; FERC Order on Compliance Filing, Cal. Indep. Sys. Operator, 143 FERC ¶ 61,057, ¶ 57 (April 18, 2013) (finding that ten years is a sufficiently long-term planning horizon for regional transmission planning processes).

[81] *See* Order 1000, 76 Fed. Reg. at 49,855; *see also, e.g.*, In re Long-Range Planning, *supra* note 80, at 2. Such analyses are informed by regional assessments undertaken by the North American Electric Reliability Corporation (NERC), the entity charged by FERC with ensuring the reliability of the grid. While NERC does not have the authority to actually order that any additional transmission or generation be built, *see Reliability Assessment & Performance Analysis*, NERC, http://www.nerc.com/pa/RAPA/Pages/default.aspx (last visited June 5, 2014), reliability standards filed by NERC and approved by the Commission become mandatory and enforceable against any "user or owner of the bulk-power system" that violates them. *See* 16 U.S.C. § 824o (2012).

[82] *See* In re Long-Range Planning, *supra* note 80, at 14.

[83] For simplicity's sake, this introduction glosses over the regional differences and nuances of how solutions are compared. Part III *infra* takes up this topic in more detail.

[84] *See* U.S. DEP'T OF ENERGY, TRANSMISSION BOTTLENECK PROJECT REPORT 20 (March 19, 2003). Although conceptually similar, the cost of traffic congestion is much higher: the U.S. Department of Transportation reports that it cost $121 billion in 2011. *Focus on Congestion Relief*, U.S. Dep't of Transp., http://www.fhwa.dot.gov/congestion/ (last visited Aug. 19, 2013).

congestion, or are likely to suffer from congestion in the future.[85] This exercise allows for the solicitation of new transmission projects that might reduce congestion enough to produce an overall net benefit to the system.[86] Here again, non-transmission alternatives can provide potential solutions.

This basic technical explanation of reliability and economic planning masks a convoluted set of actors. The next subsection explains the actors involved in transmission planning along with the ways FERC has recently sought to bring standardization and unification to transmission planning across the country.

D. The Evolution of Transmission Planning

In the past few decades, transmission planning has slowly been transforming from a utility-by-utility exercise into a more coordinated regional endeavor. FERC has actively promoted this transformation, interpreting its jurisdictional mandate in increasingly broad terms. In so doing, however, it has also emphasized regional flexibility, perhaps as a palliative to states and transmission providers none too excited about greater federal oversight. As a result, transmission planning processes vary considerably across the country. This subpart provides background on how FERC has worked to improve transmission planning over the past several decades.

Since the 1990s, the electricity industry has seen considerable changes in the form of "deregulation," or "restructuring."[87] This article does not treat in detail this history, as many others do this well.[88] It focuses instead on specific changes that restructuring brought to transmission planning. Traditionally, most utilities were "vertically integrated," meaning they each owned and provided generation, transmission, and distribution services. State regulators oversaw these utilities and established the rates that they could charge customers under traditional "cost of service" principles that

[85] *See* Hirst & Kirby, *supra* note 78, at 60-63; *see also, e.g.*, N.Y. Indep. System Operator, 2011 Congestion Assessment and Resource Integration Study 17 (2012), *available at* http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/Caris_Final_Reports/2011_CARIS_Final_Report__3-20-12.pdf

[86] *See* N.Y. Indep. System Operator, *supra* note 85, at 17.

[87] Because the movement in the electricity market from classically regulated monopolies to a more open market model that relies on competition to keep prices low occurred in concert with the deregulation of many other major U.S. industries, many refer to it "deregulation." *See* FOX-PENNER, *supra* note 1, at 9 (explaining that in 1990, the electric industry began to follow in the deregulatory footsteps of airlines, telephone companies, natural gas suppliers, and trucking firms). Others, however, prefer the term "restructuring" because the industry is still heavily regulated. *See* David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 CORNELL L. REV. 765, 765 & n.1 (2008).

[88] *See id.*; HIRSH, *supra* note 32; The Hon. Joseph T. Kelliher & Maria Farinella, *The Changing Landscape of Federal Energy Law*, 61 ADMIN. L. REV. 611 (2009); Richard J. Pierce, Jr., *Completing the Process of Restructuring the Electricity Market*, 40 WAKE FOREST L. REV. 451 (2005). For a thorough exploration of the history of deregulation as it relates to transmission, *see* Klass & Wilson, *supra* note 9, at 1804 *et seq.*

rewarded utilities an established rate of return on investments.[89] Utilities typically provided their services to customers as a "bundled" package, with a single charge for generation, transmission, and distribution.[90] Under this model, FERC had little role in regulating transmission planning, as utilities simply planned for their own transmission needs under state oversight.[91]

The Energy Policy Act of 1992 began to change this long-standing arrangement.[92] That Act gave FERC power to open up access to transmission,[93] and FERC used this authority to promulgate several landmark orders. In 1996, it issued Orders 888 and 889, which required all public utilities to allow outside parties to access their transmission lines at non-discriminatory rates.[94] This opening up of transmission lines, in turn, created a dramatic rise in the amount of electricity transferred inter-regionally.[95] Order 888 also encouraged the formation of "Independent System Operators" (ISOs) to manage regional grids to ensure open access.[96]

In the face of these changes, FERC grew concerned that transmission planning might "not be keeping up" with the regionalization of electricity flows.[97] Accordingly, it engaged in a series of reforms to update transmission planning to reflect the reality that transmission management could no longer be a utility-by-utility exercise with planning governed exclusively by a patchwork of state law requirements.[98]

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[89] *See Spence*, supra note 87, at 769 & n.21; *see also* Monast & Adair, *supra* note 62, at 11.

[90] *See* New York v. FERC, 535 U.S. 1, 4-5 (2002).

[91] *Id.* at 26.

[92] Pub. L. No. 102-486, 106 Stat. 2776, §§ 721-22 (1992) (relevant portions codified at 16 U.S.C. §§ 824j-k (2012)).

[93] *See* 16 U.S.C. §§ 824j-k.

[94] FERC Order 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21540 (May 10, 1996) (codified at 18 C.F.R. pts. 35, 385) [hereinafter "Order 888"]; FERC Order 889, Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct, 61 Fed. Reg. 21,737 (May 10, 1996) (codified at 18 C.F.R. pt. 37); *see also* Public Ut. District No. 1 of Snohomish County v. FERC, 272 F.3d 607, 610 (D.C. Cir. 2001).

[95] Snohomish County, 272 F.3d at 610; *see also* Order 2000, 65 Fed. Reg. at 813. Alongside these federal reforms, states experimented with deregulating their retail electricity markets. The state movement in this direction chilled, however, following the infamous meltdown of California's deregulated markets in 2001. *See* HIRSH, *supra* note 32, at 248-53 (reporting that by February 1996, thirty-six state legislatures had begun studying whether to adopt measures towards restructuring their electricity sectors); *see also* Timothy P. Duane, *Regulation's Rationale: Learning from the California Energy Crisis*, 19 YALE J. ON REG. 471 (2002); Peter Navarro & Michael Shames, *Electricity Deregulation: Lessons Learned from California*, 24 ENERGY L.J. 33 (2003). Several of the states that deregulated retail rates have since suspended or scaled back their reforms. *See* FOX-PENNER, *supra* note 1, at 10.

[96] *See* Order 888, 61 Fed. Reg. at 21,595; *see also* Joel Eisen, *Regulatory Linearity, Commerce Clause Brinksmanship, and Retrenchment in Electric Utility Deregulation*, 40 WAKE FOREST L. REV. 545, 551 (2005).

[97] Order 2000, 65 Fed. Reg. at 813.

[98] *Id.* at 814 (determining that regionalization was necessary to improve grid management and planning); *see also* Order 1000, 76 Fed. Reg. at 49,857; Rossi, *supra* note 4, at 1024 (explaining that while state models may have traditionally functioned well to attract investment for transmission, most have not

FERC first issued Order 2000 in 2000, which encouraged but stopped short of mandating the formation of regional transmission organizations (RTOs).[99] These RTOs would be "independent grid management organizations" that would run the grid's daily operations and plan for future grid expansions on a regionally efficient scale, unimpeded by private economic interests.[100] Transmission providers within an RTO would voluntarily delegate operational control of their transmission assets to these grid operators, in exchange for receiving fair compensation for the use of their lines by other providers.[101] Order 2000 also established "minimum characteristics and functions" that RTOs had to meet to gain FERC approval.[102] One such characteristic was "ultimate responsibility for both transmission planning and expansion within its region [to] enable it to provide efficient, reliable and nondiscriminatory service."[103]

Although Order 2000 explicitly sought to improve transmission planning and grid management by requesting placement of all transmission under RTO control,[104] its results were limited.[105] Only one additional RTO/ISO—the Southwest Power Pool—was created after its issuance.[106] These limited results are not surprising, as "the transfer of operational control or ownership over transmission systems was frequently against [utilities owning transmission systems'] self-interest."[107] During the early 2000s, the Commission considered taking more aggressive steps to mandate regional power

been updated to accommodate the increasingly interstate wholesale power market); James J. Hoecker, *Transmission Planning—A New Lever for FERC?*, NATURAL GAS & ELEC. AUG. 2007, 22 (noting that absent regional planning requirements, "transmission providers often made decisions to expand the transmission facilities within their system footprints with state-imposed service obligations and little else in mind").

[99] Order 2000, 65 Fed. Reg. at 834. Whether or not FERC's jurisdiction would have allowed it to order mandatory RTO participation was "unclear." *See, e.g.*, Robert J. Michaels, *The Governance of Transmission Operators*, 20 ENERGY L.J. 233, 236 (1999).

[100] *See* Order 2000, 65 Fed. Reg. at 815.

[101] Illinois Commerce Comm'n v. Fed. Energy Regulatory Comm'n, 721 F.3d 764, 764 (7th Cir. 2013). At the time FERC issued Order 2000, five ISOs already existed. In practice, these organizations functioned much like the envisioned RTOs, although not necessarily with the uniformity or at the regional scale FERC hoped. *See* Order 2000, 65 Fed. Reg. at 815; Eisen, *supra* note 96, at 551.

[102] *See* Order 2000, 65 Fed. Reg. at 811. The structure and governance of RTOs are discussed in more detail *infra* Part II.

[103] *See id.* at 909.

[104] *See id.* at 812.

[105] *Cf.* Eisen, *supra* note 96, at 552 (calling the "voluntary compliance" aspect of Order 2000 a "serious shortcoming"). Part of the reason that RTOs failed to gain traction is that California's electricity crisis occurred around this same time, leading many to question whether organized markets were the panacea they promised to be. *See, e.g.*, Mary Anne Sullivan et al., *Standard Market Design: What Went Wrong? What Next?*, THE ELEC. J. JULY 2003:11, 13-14 (2003). There were several unsuccessful efforts to create ISOs, the predecessors to RTOs, including in the Pacific Northwest and Rocky Mountain regions and the Midwest. *See* Order 2000, 65 Fed. Reg. at 816.

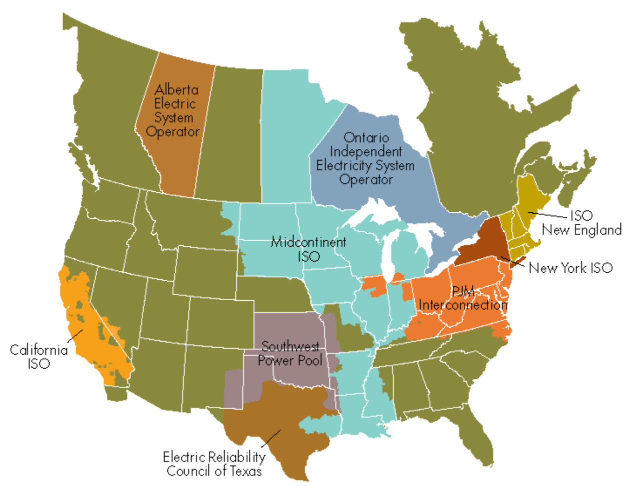
[106] *See Regional Transmission Organizations (RTOs)/Independent System Operators*, FERC, http://www.ferc.gov/industries/electric/indus-act/rto.asp (last visited Aug. 23, 2013).

[107] Eisen, *supra* note 96, at 553.

markets, but abandoned these proposals in the face of considerable state opposition.[108]

Accordingly, we are left with a patchwork of RTO and non-RTO regions in the U.S. RTOs serve approximately two-thirds of electricity customers, although their geographic coverage is more limited, as indicated in the map below.[109] Until recently, participation or non-participation in an RTO very much dictated how transmission planning occurred: either it occurred on the individual utility level, with limited voluntary collaboration; or it occurred at the RTO-level, where a regional scope prevailed.[110] As the next sub-section explains, however, FERC recently decided that RTO status should no longer determine whether regionalized planning occurs.

Figure 1. Map of U.S. and Canadian ISO/RTO Participation[111]



E. FERC's Change of Course

FERC has now moved beyond the RTO/non-RTO distinction in transmission planning to issue two major orders setting forth transmission planning parameters that apply to all transmission providers, whether organized into an RTO or not. In 2007, FERC issued Order 890 with the goal of "promot[ing] efficient utilization of transmission by requiring an open, transparent, and coordinated transmission planning

[108] *See generally* Sullivan et al., *supra* note 105; *see also* See James J. Hoecker, *Transmission Planning—A New Lever for FERC?*, NATURAL GAS & ELEC. AUG. 2007, at 21.

[109] Illinois Commerce, 721 F.3d at 764; Order 1000, 76 Fed. Reg. at 49,857*; see also* Dworkin & Goldwasser, *supra* note 46, at 544.

[110] *See* Order 1000, 76 Fed. Reg. at 48,856-87.

[111] Map reprinted from *ISO/RTO Operating Regions*, ISO/RTO Council, http://www.isorto.org/site/c.jhKQIZPBImE/b.2604471/ (last visited Aug. 27, 2013).

process" among transmission providers and stakeholders in a region.[112] Order 890 required each transmission provider[113] to submit a proposal for a "coordinated and regional planning process" that complied with several principles.[114] The order also made the first nod towards non-transmission alternatives, agreeing with commenters that customer demand resources should be considered on a comparable basis to transmission resources where appropriate.[115] As a functional matter, Order 890 typically resulted in the creation of bi-level transmission planning, particularly in non-RTO regions: transmission providers first plan at the local level, where they focus on meeting local customer needs; and then at the regional level, where local plans are amalgamated and compared for compatibility and effectiveness.[116]

Four years later, convinced that Order 890 had not gone far enough, FERC asserted further planning control in its July 2011 "Order 1000." Order 1000 enacts several interesting reforms. It specifically requires transmission providers to participate in regional processes that *produce regional transmission plans*—a more concrete planning requirement than Order 890's.[117] Order 1000 also creates new requirements for these plans: first, they (and local plans as well) must "provide for the consideration of transmission needs driven by public policy requirements."[118] This rather generic-sounding requirement is, in essence, FERC's attempt to make regional transmission planners build the lines needed to connect large wind farms and demand centers.[119] By being forced to take into account relevant policies—particularly state policies that require increasing percentages of power to come from renewables—planning processes should, at least in theory, identify those places where transmission constraints on renewables are most likely to arise and plan accordingly.[120] FERC also emphasizes in Order 1000 the consideration of non-transmission alternatives. The order requires "comparable consideration of transmission and nontransmission alternatives in the regional transmission planning process," although it leaves the details and metrics to be

[112] Order 890, 72 Fed. Reg. at 12,267.

[113] "Transmission providers" in this context means investor-owned utilities that own transmission lines and are subject to FERC and state public utility commission oversight. As described *supra* note 74, publicly owned transmission is largely (though not in every case) outside of the authority of federal and state energy regulators.

[114] Order 890, 72 Fed. Reg. at 12,320.

[115] Order 890, 72 Fed. Reg. at 12,326 ("[W]here demand resources are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis, they should be permitted to participate in that process on a comparable basis.").

[116] *See* Order 1000, 76 Fed. Reg. at 49,856.

[117] *Id.* at 49,845. FERC felt the need to take this additional step because even following Order 890, some regions merely used the regional process "as a forum to confirm the simultaneous feasibility of transmission facilities contained in their local transmission plans." *Id.* at 49,856.

[118] *Id.* at 49,876.

[119] *See* Klass & Wilson, *supra* note 9, at 1824.

[120] *See* Shelley Welton & Michael B. Gerrard, *FERC Order 1000 as a New Tool for Promoting Energy Efficiency and Demand Response*, 42 ENVTL. L. REP. 11025 (Nov. 2012); Watson & Colburn, *supra* note 28, at 36.

worked out by respective regions.[121]

Order 1000 contains two other noteworthy reforms. It requires an unprecedented level not just of regional planning, but also *inter*-regional coordination that will help regions work together to ensure that the most cost-effective solutions are chosen when lines cross more than one region.[122] And finally, it requires all regional plans to include a "regional cost allocation method" that spells out how the transmission providers will share the costs of regional transmission facilities selected during their planning procedure, although it leaves it to the regions to develop these methodologies.[123]

Many states have criticized these Order 1000 reforms as encroaching on their authority over planning and resource decisions. Particularly in non-RTO/ISO regions, transmission providers have had to form new regional planning processes that elevate regional interests above local ones and may lead to the rejection of providers' preferred solutions and substitution of mandatory alternative projects.[124] This perceived federal usurpation led several states and companies to file a lawsuit against the Commission, ongoing in the D.C. Circuit, alleging that FERC has gone beyond its jurisdiction in mandating regional transmission planning and cost allocation.[125]

Certain states and providers may balk at Order 1000's reforms, but both that Order and Order 890 contain a remarkable degree of regional flexibility. Pervading FERC's two recent transmission orders are emphases on stakeholder participation and collaboration among private transmission providers and other interested parties.[126] FERC also delegates considerable authority to regional planners—i.e., transmission providers and RTOs/ISOs—that operate in a quasi-governmental, quasi-private fashion, to shape the details of individual regional planning processes, including processes for giving non-transmission alternatives parity. This strategy represents a softer path for FERC, and one that pushes less forcefully against the bounds of its jurisdiction than mandating RTO participation might have.[127] In taking this softer path in regulating transmission planning, FERC is trusting that delegation, accompanied by procedural reforms including transparency and enhanced participation, and a few mandates to "consider" certain issues it deems important, will suffice to improve our critically

[121] Order 1000, 76 Fed. Reg. at 49,869.

[122] Order 1000, 76 Fed. Reg. at 49,900-01.

[123] Order 1000, 76 Fed. Reg. at 49,846. The order also requires transmission providers to adopt an *inter*-regional cost allocation methodology "for allocating the costs of a new interregional transmission facility that is jointly evaluated by the two or more transmission planning regions in their interregional transmission coordination procedures." *Id.*

[124] *See* Order 1000, 76 Fed. Reg. at 49,857.

[125] *See. e.g.*, Joint Initial Brief of Petitioners/Intervenors in Support of Petitioners Concerning Threshold Issues, S.C. Pub. Serv. Auth. V. FERC, Case Nos. 12-1232 et al., at 6 (D.C. Cir., filed May 28, 2013). As will be explored *infra*, this complaint is the latest in a long series complaining that FERC has overreached its jurisdiction in recent years. *See, e.g.*, Order 2000, 65 Fed. Reg. at 937.

[126] As noted *supra* note 19, one crude measure of the order's emphasis on stakeholder participation can be seen in the fact that order mentions stakeholders a total of 278 times.

[127] *See infra* Part IV for more discussion of these jurisdictional issues.

important, much maligned, and regionally diverse transmission planning processes. Is FERC right to place so much trust in these solutions?

II. Non-Transmission Alternatives' Persistent Challenges

I believe the answer to this question, with respect to the objective of giving parity to non-transmission alternatives, is no. FERC has over-relied on these participatory reforms to fix a process that is substantively hostile to non-transmission alternatives.

To understand why these reforms are failing non-transmission alternatives, it is necessary to look at the way that regions are implementing Orders 890 and 1000. It is in the translation from FERC's broad mandates to concrete planning mechanisms and incentives that the participatory, "comparable consideration" requirement may get thwarted. This section explores how two regions—one non-RTO/ISO region and one ISO—have implemented Order 1000's non-transmission alternatives reforms. It then examines the flaws in these processes.

A. Non-transmission alternatives in transmission planning today

As noted earlier, FERC's directives to regions with respect to non-transmission alternatives are relatively vague. FERC identifies Order 890 as the genesis of its "comparable consideration" requirement for non-transmission alternatives. In that order, FERC recognizes that "where demand resources are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis, they should be permitted to participate in that process on a comparable basis."[128] It its clarification order, Order 890A, FERC again reiterated that "advanced technologies and demand-side resources must be treated comparably where appropriate in the transmission planning process and, thus, the transmission provider's consideration of solutions should be technology neutral."[129]

Order 1000 builds upon these requirements to explicitly require "comparable consideration of transmission and non-transmission alternatives," although it then explains:

> [W]e will not establish minimum requirements governing which non-transmission alternatives should be considered or the appropriate metrics to measure non-transmission alternatives against transmission alternatives. Those considerations are best managed among the stakeholders and the public utility transmission providers participating in the regional transmission planning process.[130]

Given the regional flexibility thereby endorsed by Order 1000, regional implementation

[128] Order 890, 72 Fed. Reg. at 12,266.

[129] FERC Order No. 890-A, order on reh'g, Preventing Undue Discrimination and Preference in Transmission Service, 73 Fed. Reg. 2984, 3009 (Jan 16, 2008).

[130] Order 1000, 76 Fed. Reg. at 49,869.

of the "comparable consideration" mandate becomes key. As it turns out, most regions leave much to be desired in their implementation, as can be seen through examining a few representative operating tariffs and Order 1000 filings.[131]

(1) The Southeastern Regional Transmission Planning Process

The first example of how non-transmission alternatives are being integrated into transmission comes from the Southeastern Regional Transmission Planning Process, or "SERTP." Utilities across the southeast that are not members of RTOs formed this regional planning process in response to Order 890.[132]

SERTP transmission providers, as is typical of most regions, conduct both their own "local" transmission plans that are utility-specific, as well as participate in the broader regional planning effort required by Order 890 and strengthened by Order 1000. They operate on self-described "bottom up principles" – individual transmission owners' plans are presented to the regional group for inclusion in the broader regional plan.[133] At the regional level, transmission owners and non-incumbent transmission developers can submit proposed projects that they believe would more efficiently and effectively address regional transmission needs than projects proposed via individual utility plans. These proposed regional transmission projects are evaluated to determine whether they will provide significant benefits over solutions proposed by individual utility providers,[134] and to ensure that they will not increase the costs to any utilities that will be allocated some of the costs (as compared to the plans proposed by individual transmission owners).[135]

[131] Beginning with Order 888, when FERC required transmission providers to open their transmission lines up to competitors at competitive, non-discriminatory rates, it has required such utilities to "file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service." Order No. 888, 61 Fed. Reg. at 21,541. Utilities typically detail their transmission planning processes in attachments to their tariffs, and further explain how their procedures comply with new FERC requirements through "transmittal letters" that accompany the filing of their amended tariffs. *See, e.g.*, In re: Midwest Independent Transmission System Operator Inc.'s and MISO Transmission Owners' Compliance Filing for Order 1000, Regarding Regional Planning and Cost Allocation of Transmission Projects, FERC Docket No. ER13-187, Transmittal Letter (Oct. 25, 2012). Additional examples of how other regions are treating non-transmission alternatives can be found in Elec. Advisory Comm., *supra* note 67, at 6-8.

[132] *See Southeastern Regional Transmission Planning*, http://www.southeasternrtp.com/ (last visited Oct. 24, 2013).

[133] *See* Filing of Louisville Gas and Electric Company and Kentucky Utilities Company Transmission System, FERC Docket No. ER13-897, at 91 (filed Feb. 7, 2013).

[134] More specifically, regionally proposed solutions must have a "regional transmission benefit-to-cost ratio of at least 1.25." *See* Attachment K to the Filing of Louisville Gas and Electric Company and Kentucky Utilities Company Transmission System, FERC Docket No. ER13-897, at 91 (filed Feb. 7, 2013). The "benefit used in this calculation will be quantified by the transmission costs that the Beneficiaries [i.e., those whom the transmission line would serve] would avoid due to their transmission projects being displaced by the transmission developer's proposed transmission project." *Id.*

[135] *Id.* Projects must also obtain any necessary "jurisdictional authority/governance approval" – that is,

As part of its solicitation of regional solutions, the SERTP process allows for stakeholder proposals of non-transmission alternatives. Transmission owners are responsible for training stakeholders "regarding the underlying criteria and methodologies utilized to develop the transmission expansion plan."[136] Following this training, stakeholders are free to propose alternatives, including (although not explicitly mentioned) non-transmission alternatives, with the caveat that they must "perform analysis" prior to proposing the alternative.[137] The transmission owners then commit to analyzing proposed alternatives, taking into account "factors such as, but not limited to, the proposed alternatives' impacts on reliability, relative economics, effectiveness of performance, impact on transmission service (and/or cost of transmission service) to other customers and on third-party systems."[138] The analysis of proposed non-transmission alternatives would presumably mirror the benefit-cost analysis described above for transmission alternatives, although it is not clear whether the process for such stakeholder proposals contains additional criteria. Transmission owners then are responsible for reporting back to stakeholders "regarding the suggestions/alternatives."[139]

After the SERTP utilities submitted these plans in their Order 1000 compliance filings, a group of environmental non-profit organizations intervened to protest the paltry treatment given to non-transmission alternatives in this process.[140] The environmental interveners requested a more explicit explanation of "the qualification for, process of, and means of evaluating *non*-transmission alternatives," arguing that Order 1000 requires a more concrete process to ensure comparable consideration.[141] FERC declined to grant this request, explaining that it had already determined that the provisions complied with Order 890's comparability principle.[142] It thus chose to interpret Order 1000's "comparable consideration" mandate as adding no new substantive requirements with respect to non-transmission alternatives.

(2) The Midcontinent Independent System Operator

A second example of the regional treatment of non-transmission alternatives comes from the Midcontinent System Operator, MISO, which controls transmission

they must pass through necessary state reviews. *Id.*

[136] *Id.* § 13.5.3.2.

[137] *Id.* § 13.5.3.3. The tariff does not specify what this analysis must contain.

[138] *Id.* § 13.5.3.4.

[139] *Id.* § 13.5.3.5.

[140] Motion to Intervene and Protest of Four Public Interest Organizations, FERC Docket No. ER13-897-000, Kentucky Utilities Company and Louisville Gas and Electric Company (March 25, 2013).

[141] *Id.* at 13.

[142] *See* FERC Order on Compliance Filings, Louisville Gas & Elec. et al., 144 FERC ¶ 61,054, at ¶ 43 (July 18, 2013) ("With regard to Public Interest Organizations' assertion that the SERTP process does not treat transmission and non-transmission alternatives on a comparable basis, we note that, as described above, Filing Parties uniformly adopt the provisions that the Commission previously concluded comply with the comparability principle in Order No. 890.").

planning across fifteen states and one Canadian province.[143] MISO operates a combined "top-down/bottom-up" planning process. Local transmission entities create transmission plans that MISO evaluates to ensure compatibility and reliability, while at the same time MISO's "top-down planning process" examines "regional transmission drivers, including opportunities to relieve congestion."[144]

MISO made no amendments to its procedures for consideration of non-transmission alternatives following Order 1000.[145] And nowhere are non-transmission alternatives mentioned in its operating tariff. The tariff does, however, state that during "evaluation of alternatives," "inputs from stakeholders" will be "considered . . . in determining the solutions to be included in [the regional transmission plan]."[146] The potential alternatives proposed by stakeholders "may include transmission, generation, and demand-side resources," and MISO commits to "review and evaluate such alternatives on a comparable basis and select the most appropriate solution."[147] MISO asserts in its transmittal letter to FERC that this process fully satisfies the requirement to consider non-transmission alternatives comparably, but qualifies their consideration by explaining that "because resource adequacy is under the jurisdiction of the states, it is not appropriate for MISO to include in the regional transmission plan 'uncommitted' non-transmission alternatives (e.g., Generation Resources and Demand Response Resources)."[148]

Again, environmental groups intervened in the Order 1000 MISO filing process to voice their concerns over how non-transmission alternatives were treated. They noted that although MISO espouses comparability, there are no clear metrics and procedures provided for evaluating transmission and non-transmission alternatives comparably to select the most efficient and cost-effective solution.[149] Similarly, a filing by the Interstate Renewable Energy Council requested that FERC require MISO to develop a more detailed set of guidelines instructing stakeholders how to present non-transmission

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[143] *See About Us*, Midwest Independent System Operator, https://www.misoenergy.org/AboutUs/Pages/AboutUs.aspx (last visited Nov. 7, 2013).

[144] *See* MISO, *Level 200: Transmission Planning and Cost Allocation Course* (April 29, 2014), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Training%20Materials/200%20Level%20Training/Level%20200%20-%20Transmission%20Planning.pdf.

[145] *See* FERC Docket No. ER13-187, MISO, Inc., Tariff Filing for Order 1000, Tab A. Redlined Version of Tariff Sheets (filed Oct. 25, 2012); *see also* Motion to Intervene and Protest of Public Interest Organizations, FERC Docket No. ER13-187, MISO, Inc., Tariff Filing for Order 1000, at 21 (filed Dec. 10, 2012) ("MISO did not propose any tariff changes to address NTAs, because it believes that its planning process meets Order No. 890 (and therefore Order No. 1000), requirements for comparable treatment.").

[146] FERC Docket No. ER13-187, MISO, Inc., Tariff Filing for Order 1000, Tab A. Redlined Version of Tariff Sheets, at 25 (filed Oct. 25, 2012).

[147] *Id.* at 36.

[148] FERC Docket No. ER13-187, MISO, Inc., Transmittal letter for Order No. 1000 compliance filing, at 7 & n.28 (filed Oct. 25, 2012).

[149] Motion to Intervene and Protest of Public Interest Organizations, FERC Docket No. ER13-187, MISO, Inc., Tariff Filing for Order 1000, at 20 (filed Dec. 10, 2012).

alternatives and specifying how proposed non-transmission alternatives' costs and benefits would be measured.[150] Interstate Renewable also asked that MISO be required to conduct a study of at least one non-transmission alternative, whether stakeholders put forward a proposal or not.[151] FERC was no more receptive to these protests in the MISO proceeding than it was in the SERTP one, noting again that MISO's tariff was compliant with Order 890 and refusing to interpret Order 1000 to impose any additional requirements.[152]

In a few regions, FERC did push back against certain burdens imposed on non-transmission alternatives. It required, for example, that the WestConnect region reconsider its plans to subject non-transmission alternatives to the same information and fee requirements as transmission proposals, given their differing natures.[153] It also rejected language in ColumbiaGrid participants' proposed tariffs (in the northwestern U.S.) that would have required the study team to subject non-transmission alternatives alone to a determination that "such alternative has a reasonable degree of development."[154] But by and large, FERC accepted plans that gave little detail about how the particular features of non-transmission alternatives would be included in the comparability process, and that relied entirely on stakeholder proposals for non-transmission alternatives.

Because FERC thereby added little substance to the "comparability" principle announced in Order 890, the progress made on non-transmission alternatives since Order 890 is a fair measure of the likely success of non-transmission alternatives post-Order 1000. As public interest organizations note in their filings for multiple regions, the track record is poor: not only have non-transmission alternatives not been selected as superior to transmission solutions, they have not even been *proposed* for consideration.[155] It

[150] Motion to Intervene and Comments of Interstate Renewable Energy Council Inc, FERC Docket No. ER13-187, MISO, Inc., Tariff Filing for Order 1000, at 15 (filed Dec. 10, 2012).

[151] *Id.* at 16.

[152] FERC Order on Compliance Filings and Tariff Revisions, Docket No. ER13-87, MISO, Inc. et al., 142 FERC ¶ 61,215, at ¶ 48 (March 22, 2013).

[153] *See* FERC Order on Compliance Filing, WestConnect, Docket No. ER-13-75-000, 142 FERC ¶ 61,206, at ¶¶ 89-90 (March 22, 2013).

[154] *See* FERC Order on Compliance Filing, Clark Avista Corp. et al., Docket No. 13-93-000, 143 FERC ¶ 61,255, at ¶¶ 76-80 (June 20, 2013).

[155] *See, e.g.*, Motion to Intervene and Protest of Public Interest Organizations, FERC Docket No. ER13-187, MISO, Inc., Tariff Filing for Order 1000, at 22 (filed Dec. 10, 2012) ("[T]he virtually complete absence to date of stakeholder proposals for NTAs as solutions suggests that these principles may be falling short of ensuring the comparable consideration of NTAs . . . . The lack of proposals for NTAs in the planning process is especially disconcerting because most states in the MISO footprint have demand side management programs such as energy efficiency resource standards."); Motion to Intervene and Protest of Four Public Interest Organizations, FERC Docket No. ER13-897-000, Kentucky Utilities Company and Louisville Gas and Electric Company, at 14 (March 25, 2013).("[T]he virtual complete absence to date of stakeholder proposals for NTAs as solutions in the existing SERTP planning process suggests that KU/LG&E's tariff may be falling short of ensuring the comparable consideration of NTAs."); FERC Order on Compliance Filings, Docket No. ER13- 193, ISO-New England, Inc., at ¶ 44 (May 17, 2013) (noting movants' argument that "ISO-NE has not incorporated a single non-transmission

could be, of course, that non-transmission alternatives are not being proposed as superior solutions because there are, in point of fact, no non-transmission alternatives that present superior solutions to transmission. But reaching this conclusion first requires a determination that the regional filings described above create the "technology neutral" processes that FERC seeks for them to achieve.[156] As the next sub-section explains, there are numerous reasons to believe that these it is these processes—rather than the non-transmission alternatives themselves—that are not measuring up.

B. The Challenges Non-Transmission Alternatives Face

FERC's Orders 890 and 1000 create more open transmission planning processes, require clear indications of how and when stakeholders can participate in the process, and mandate the production of substantive regional transmission plans. The orders' focus on stakeholder involvement surely has some laudable effects, and may help avoid capture of the planning process by transmission providers.[157] But this mere opening up of the process to stakeholder participation is unlikely to result in non-transmission alternatives being proposed or constructed, even where they present cost-effective solutions. Below, I identify and explore two categories of problems that place non-transmission alternatives at a distinct disadvantage when compared to transmission alternatives and that are not likely to be remedied by bringing the "sunshine" of stakeholder involvement to the planning process:[158] structural challenges and funding challenges.

(1) Structural Challenges

Non-transmission alternatives first face what I term "structural" challenges. I mean by this the challenges that are created by the structure of the transmission planning process and its participating entities. The first structural challenge is that the process, as currently designed and implemented, relies on stakeholder proposals while creating no natural proponent or supplier of non-transmission alternatives. The second challenge stems from the nature of non-transmission alternatives as compared to transmission

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alternative into the regional system plan, raising the question whether 'comparable' consideration in compliance with Order No. 1000 has been achieved.").

[156] *See* FERC Order No. 890-A, order on reh'g, Preventing Undue Discrimination and Preference in Transmission Service, 73 Fed. Reg. 2984, 3009 (Jan 16, 2008) ("[A]dvanced technologies and demand-side resources must be treated comparably where appropriate in the transmission planning process and, thus, the transmission provider's consideration of solutions should be technology neutral.").

[157] *See* Hari M. Osofsky & Hannah J. Wiseman, *Hybrid Energy Governance*, 2014 ILL. L. REV. 1, 54 (noting that RTO stakeholder processes may help avoid capture by any one actor).

[158] *Cf.* E. Scott Adler & Thad E. Hall, *Ballots, Transparency, and Democracy*, 12 ELECTION L.J. 146, 151 (2013) (noting that the twentieth century saw a profusion of "sunshine" reforms "intended to make the process of government more open and bring the public and interested stakeholders into the governing process in a structured way").

alternatives—because, as described above, one of the major appeals of non-transmission alternatives is their "co-benefits,"[159] it is difficult to understand how a non-transmission alternative, if proposed, could receive "comparable consideration."

a. *Misaligned Expertise and Incentives*

The first structural challenge non-transmission alternatives face is that there is no one with the right match of expertise and incentives to act as a serious proponent of such alternatives. As detailed above, regional processes create no obligation on any party to put forth potential non-transmission alternatives. Instead, these processes rely on participants, including stakeholders, to generate voluntarily potential non-transmission solutions, which regional planners then commit to evaluate on a comparable basis. FERC has approved of these processes, suggesting that it interprets "comparable consideration" only to require comparability once several independently generated proposals are on the table. This version of comparability, however, is unlikely to ever result in non-transmission alternatives being proposed for consideration, because there is no stakeholder or provider likely to champion non-transmission alternatives.

It may be obvious why transmission providers themselves are unlikely to propose non-transmission alternatives. As a general matter, transmission providers make money from building more transmission. Transmission is still considered to be a natural monopoly,[160] meaning that most transmission providers earn their profits through traditional state rate regulation.[161] Under this system, states set a rate of return for capital invested in transmission, meaning that utilities increase their profits by increasing the amount of capital invested.[162] In contrast, investing in energy efficiency, demand response, and distributed generation—strategies that reduce electricity consumption—

[159] *See supra* notes 50-52 and accompanying text.

[160] Natural monopolies exist in situations where it is perceived that competition is impractical. In the case of transmission, it is generally thought that having multiple companies lay lines in the same area would be duplicative and unnecessarily expensive, such that transmission has remained a natural monopoly even as generation has not. *See* Jim Rossi & Thomas Hutton, *Federal Preemption and Clean Energy Floors*, 91 N.C. L. REV. 1283, 1322 (May 2013). However, "merchant transmission" providers are beginning to cast doubt on this assumption in the case of interstate transmission. *See* Werntz, *supra* note 79.

[161] This continued state rate regulation makes transmission different from electricity generation, which in many states has been deregulated. *See generally* Kelliher & Farinella, *supra* note 88; Klass & Wilson, *supra* note 9, at 1804 *et seq.*

[162] Jonas J. Monast & Sarah K. Adair, *A Triple Bottom Line for Electric Utility Regulation: Aligning State-Level Energy, Environmental, and Consumer Protection Goals*, 38 COLUMBIA J. ENVTL. L. 1, 52 (2013). This incentive to build out transmission may be less pronounced, or complicated, in states where utilities are still vertically integrated, such that the same entities own generation, transmission, and distribution. In these states, utilities' desire to build transmission is counteracted by a potential desire to keep generation prices higher by constraining. *See supra* note 53; *cf.* Brown & Rossi, *supra* note 12, at 731 (noting that "existing generators are likely to challenge proposed new generating plants or new transmission which will enable more generation to access more markets because of the fear that new entrants will drive down prices").

often *lowers* transmission providers' profits, to the extent that these are earned through volumetric charges to customers that vary depending on the amount of power consumed.[163]

To be sure, transmission providers in many states are nevertheless engaged in providing energy efficiency and demand response services, typically under state mandates and with the benefit of state incentives.[164] Often, utilities are rewarded for meeting state-mandated targets through payments that attempt to equalize investments in demand-side strategies with the earnings that would come from supply-side investments.[165] But these state-mandated investments are already taken into account when projecting future regional demand and supply during transmission planning. The pertinent question, when it comes to non-transmission alternatives, is whether more energy efficiency, demand response, and/or generation (distributed or otherwise)—*above and beyond what is mandated by state plans and laws*—would amount to a cheaper, better solution than a major regional transmission line.[166] And due to the incentives described above, transmission providers are unlikely to want to analyze or propose these solutions that cut against their bottom line.[167] Unfortunately, then, these entities that often have decades of experience in running energy efficiency and demand response programs and planning transmission are unlikely to connect these two areas of expertise.

In RTO regions, it might seem that the RTO itself could be a good candidate for proposing potentially lower-cost, more effective non-transmission alternatives as regional solutions. But here again, the nature of RTOs makes them unlikely to take on this role. RTOs are voluntary membership organizations, formed when transmission providers in a region decide to cede control to a non-profit entity to manage operations of their transmission lines.[168] This structure creates several challenges for non-transmission alternatives.

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[163] Some states are countering this incentive by engaging in "decoupling," which separates the determination of a utility's revenue from its volume of sales. *See* Shelley Welton et al., *Public Utilities Commissions & Energy Efficiency: A Handbook of Legal & Regulatory Tools for Commissioners and Advocates*, at 31-34 (Columbia Law School Center for Climate Change Law, Aug. 2012) (noting that fourteen states had implemented decoupling as of August 2012); *see also* Inara Scott, *"Dancing Backward in High Heels": Examining and Addressing the Disparate Regulatory Treatment of Energy Efficiency and Renewable Resources*, 43 ENVTL. L. 255, 264-65 (2013).

[164] Most states rely on their electric transmission and distribution utilities to implement energy efficiency programs, although a few have created independent state agencies to fill this role. *See* Welton, *supra* note 163, at 13.

[165] Many states now provide shareholder incentives, which award utility shareholders a percentage of the savings achieved by energy efficiency if they reach certain pre-agreed levels of implementation (and in some states, utilities are also penalized for falling short). *See id.* at 35-38; *see also* Edan Rotenberg, Energy Efficiency in Regulated and Deregulated Markets, 24 UCLA J. ENVTL. L. & POL'Y 259 (2006).

[166] *See supra* note 56 (drawing a distinction between "active" and "passive" deferrals of transmission).

[167] *See* Hempling, *supra* note 50, at 7 ("[N]on-transmission alternatives are not a profit source for a transmission company.").

[168] Public Ut. District No. 1 of Snohomish County v. FERC, 272 F.3d 607, 612 (D.C. Cir. 2001) (dismissing a challenge by utilities to FERC Order 2000 on several grounds, including the fact that RTO membership is voluntary).

First, although RTOs are non-profits, they have been observed to have a clear "transmission-first culture" given that their employees, charged with the crucial task of grid reliability and management, tend to have expertise in transmission development.[169] Indeed, transmission planners often view demand-side resources with some skepticism, concerned about whether their availability can be ensured at the instant it is needed in the same way that transmission capacity can.[170] Even where overt skepticism of demand-side resources is not present, RTOs are likely to have, at best, limited experience with these resources and virtually no experience with them in the context of transmission planning. This deficit of experience, combined with the "overriding importance attached to reliability concerns," creates strong incentives to favor—and perhaps overbuild—tried-and-true transmission solutions.[171]

Second, the voluntary structure of RTOs "has ended up leaving those entities [who can exit, including transmission owners] with disproportionate influence."[172] As scholars studying the rise of RTOs have noted, there are accountability questions raised by the structure of RTOs, as they are both the regional agents of FERC and the agents of

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[169] Hempling, *supra* note 50, at 20; *see also* Watson & Coburn, *supra* note 28, at 38.

[170] This distrust is manifested through the complex monitoring and verification requirements that RTOs and ISOs have established for energy efficiency and demand response resources that want to bid into their markets. As described by one industrial sector representative to the House Committee on Energy and Commerce, these processes erect a virtual barrier to anyone outside of large utilities participating because they are unnecessarily "cumbersome and expensive." Testimony of Paul N. Cicio, President, Industrial Energy Consumers of America, "Grid Reliability Challenges in a Shifting Energy Resource Landscape," Before the House Committee on Energy and Commerce, Subcommittee on Energy and Power, at 6 (Thursday, May 9, 2013). In spring 2013, FERC adopted a standardized, industry-endorsed monitoring and verification protocol that RTOs and ISOs will be required to use to help counteract the distrust that RTOs are apt to display towards demand side resources. *See* Final Rule, Standards for Business Practices and Communication Protocols for Public Utilities, 142 FERC ¶ 61,131, Docket No. RM05-5-020; Order No. 676-G, at 2 (February 21, 2013) (explaining that "the standards . . . facilitate the ability of demand response and energy efficiency providers to participate in organized wholesale electric markets, reducing transaction costs and providing an opportunity for more customers to participate in these programs, especially for customers that operate in more than one organized market").

[171] Mary Anne Sullivan et al., *Standard Market Design: What Went Wrong? What Next?*, THE ELEC. J. JULY 2003:11, 16. This article does not have as a goal the difficult task of determining to what extent RTOs are "captured" by the transmission industry, but it seems fair to note that the preceding observations suggest that RTOs may be at least "cognitively" or "culturally" captured by the industry they are regulating, in the sense that they have adopted a transmission-first mentality. *See, e.g.*, David Freeman Engstrom, *Corralling Capture*, 36 HARV. J. OF LAW & PUB. POL'Y 31, 32 (2013) (drawing a distinction between traditional regulatory capture and newer theories of "cognitive" or "cultural" capture, wherein interest groups capture the process "through the creeping colonization of ideas"). The notion of capture is particularly complex in the RTO context, as they operate at the public-private nexus. *See* Dworkin & Goldwasser, *supra* note 46, at 555-56. It is therefore unsurprising that these entities would be somewhat captured—and up to FERC to put in place safeguards to nevertheless ensure the kinds of technology neutral processes it desires. What these safeguards might look like is discussed *infra* Part V.

[172] Memorandum from Roy Thilly, President and Chief Executive Officer of Wisconsin Public Power, Inc. to Mariah Sotelino (Sept, 25, 2007) (quoted in Dworkin & Goldwasser, *supra* note 46, at 579 n.200 (alterations in Dworkin & Goldwasser)).

transmission owners who have ceded operational decision-making to the organizations.[173] Although FERC emphasizes RTOs' independence,[174] there are reports that transmission owners' influence filters into the design and functionality of stakeholder processes, and that it is impossible to create a knowledgeable governing board without drawing heavily from the transmission industry.[175] A desire to avoid the exit of participating transmission owners, coupled with their transmission-heavy culture, helps explain RTOs' limited engagement with considering non-transmission alternatives in their Order 1000 reforms.

It falls on stakeholders, then, to take up the mantle of non-transmission alternatives. But within the broad group that may qualify as "stakeholders,"[176] there is no entity appropriately positioned to propose viable non-transmission alternatives.[177] There are several sophisticated regional- and national-scale environmental non-profit organizations that have actively intervened in FERC Order 1000 compliance processes to encourage regions to create procedures receptive to non-transmission alternatives.[178] But

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[173] Dworkin & Goldwasser, *supra* note 46, at 555-58.

[174] RTOs and ISOs are required to possess certain hallmarks of independence, and the Commission has sought to enforce these requirements. *See, e.g.* Order 2000, 65 Fed. Reg. at 815 ("[T]he Commission rejected the original governance proposals for two ISOs: the New England ISO and New York ISO . . . [concluding] that the vertically integrated utility members of the ISO would have too much voting power in the various advisory committees that provide advice and recommendations to the non-stakeholder Boards."). However, FERC declined to prohibit passive ownership of RTOs by transmission utilities, explaining that so long as procedural and substantive safeguards were in place, permitting passive ownership "facilitates the formation of RTOs." Pub. Util. District No. 1 v. FERC, 272 F.3d 607, 620 (D.C. Cir. 2001).

[175] *See* Testimony of Lloyd Webb, Procurement Manager of Eastman Chemical Company, Technical Conference on Competition in Wholesale Power Markets, Docket No. AD07-7-000, at 211 (FERC May 8, 2007); *see also* Michaels, *supra* note 99, at 235 (predicting that "utility interests will be uniquely well-situated to dominate the internal politics of ISOs"); Dworkin & Goldwasser, *supra* note 46, at 568 ("[I]t is "impossible to find people who both have the expertise necessary to do their job as board members and managers and also have absolutely no connections in the industry in which they must have this expertise").

[176] In Order 1000, FERC defines the term stakeholder as "intended to include any party interested in the regional transmission planning process." 76 Fed. Reg. at 49,868 n.143.

[177] Moreover, as is the case in many administrative and judicial processes, stakeholders in RTOs are "outspent, outnumbered, and procedurally encumbered." Dworkin & Goldwasser, *supra* note 46, at 586.

[178] *See, e.g.*, Motion to Intervene and Protest of Public Interest Organizations, FERC Docket No. ER13-187, MISO, Inc., Tariff Filing for Order 1000 (filed Dec. 10, 2012); Motion to Intervene and Protest of Four Public Interest Organizations, FERC Docket No. ER13-897-000, Kentucky Utilities Company and Louisville Gas and Electric Company (March 25, 2013); Motion to Intervene of Eight Public Interest Organizations, FERC Docket No. ER13-103, Cal. ISO Tariff Filing for Order 1000 (Nov. 26, 2012). The groups participating in the public interest filings differed among regions, but generally consisted of several local groups along with a few national-level groups who participated across regions. For example, public interest organizations participating in California ISO's Order 1000 proceeding included Interwest Energy Alliance, Natural Resources Defense Council, Nevada Wilderness Project, Sierra Club, Sonoran Institute, Sustainable FERC Project, Vote Solar and Western Resource Advocates. *See id.* In the southeast, public interest participants included Natural Resources Defense Council, Sierra Club, Southern Environmental Law Center, and Sustainable FERC Project. *See* Motion to Intervene and Protest of Four Public Interest Organizations, FERC Docket No. ER13-897-000, Kentucky Utilities Company and Louisville Gas and

these entities have no experience with on-the-ground implementation of energy efficiency, demand response, or distributed generation, and have limited technical capacity to engage in the kind of large-scale modeling and studies that would be necessary. Instead, this capacity and experience rests primarily with the transmission providers themselves, as these utilities have historically been the ones charged with implementing state-driven distributed energy programs.

In some states, there also exist third-party implementers of such programs, often known as "Energy Service Companies" (ESCOs) or "aggregators" for their function in bundling together many small-scale projects for sale into regional energy and capacity markets.[179] These entities have the on-the-ground experience necessary to implement distributed energy and have devised ways of earning profits from doing so, but are unlikely to amalgamate their on-the-ground capabilities into a project that is specifically tailored to address a transmission need, for a few reasons. Most fundamentally, as discussed further in the next subsection's focus on cost allocation, there is not any financial incentive for them to gain by focusing on proposing a non-transmission alternative rather than on simply growing their core business. Beyond this, ESCOs and aggregators are confronted with geographic hurdles when it comes to the regional process. Transmission-scale non-transmission alternatives require operating at a geographical scale larger than the area most of these entities serve, making it unlikely that any of these entities acting without collaboration from several other ESCOs or aggregators could propose a project of the necessary scale.[180] Moreover, ESCOs and aggregators typically have the opposite expertise of RTOs, again creating an expertise gap: they have significant knowledge about energy efficiency and demand response implementation, but lack sophistication in transmission planning and understanding how to package their products to fill a transmission need.

The one powerful stakeholder that might seem best positioned to promote non-transmission alternatives is states.[181] But again, there is reason to doubt that states would

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Electric Company, at 1 (March 25, 2013).

[179] *See* Edna Sussman, *Reshaping Municipal and County Laws to Foster Green Building, Energy Efficiency, and Renewable Energy*, 16 N.Y.U. ENVTL. L.J. 1, 20 (2008) ("ESCOs generally develop, design, and finance energy efficiency projects, install and maintain the energy efficient equipment involved, measure, monitor, and verify the project's energy savings, and assume the risk that the project will save the amount of energy guaranteed."); *see also* Eisen, *supra* note 59, at 82 (explaining the role and expertise of aggregators, who work with customers to manage their electricity usage and assemble portfolios of businesses with demand response opportunities, which they then bid into wholesale electricity markets).

[180] *See* Watson & Coburn, *supra* note 28, at 39 (explaining that it is not clear that "aggregators of retail customers or third-party administrators of energy efficiency and demand response programs" have the expertise necessary "to implement [non-transmission] solutions at scale for transmission needs").

[181] Order 1000's treatment of states as stakeholders is best described as "first among equals" status. Several states requested a special role in regional transmission planning, but FERC declined to require this of regions. It did, however, note that states are in a particularly strong position to influence regional transmission planning given their authority over transmission siting and resource planning, such that regions are free to assign them a major role in planning. *See, e.g.*, Order 1000, 76 Fed. Reg. at 49,877-78 & n.189 (explaining that regions may choose to rely on a committee of state representatives as one avenue

take on this function in the regional process. As noted earlier, many states have adopted mandates and other mechanisms for promoting energy efficiency, demand response, and distributed generation within their state borders. However, what is useful for the purpose of regional transmission planning is whether coordinated activity across states might result in a decision to promote *more* distributed energy than any state has decided to do on its own, because it might avoid the need for building certain transmission infrastructure. Accordingly, it is unlikely that a single state would emerge as a champion of a regional non-transmission alternative, given that it would be taking on the task and expense of building the non-transmission alternative without reaping full benefits (a problem bound up in the cost allocation issues discussed *infra*). Ideally, a team of states might work together to examine the possibility of additional, cross-state distributed energy to function in place of transmission. This possibility is not farfetched; one region—the Northeast—is actively pursuing just such a collaboration.[182] But it is unclear whether this strategy will achieve success or spread across other regions. And indeed, it seems somewhat perverse that FERC-overseen regional planning processes, which were designed with the particular goal of ensuring coordination among different states and giving non-transmission alternatives parity, would necessitate the creation of yet another interstate, collaborative process in order to promote non-transmission alternatives. Because fair and full consideration of non-transmission alternatives is a goal of FERC's regional processes, the processes themselves should facilitate this aim.

b. The Comparability Challenge

Even if an entity could overcome the disincentives described above and put forth a reasonable non-transmission alternative for "comparable consideration," there remains a second structural challenge: it is far from clear how comparable consideration of non-transmission alternatives would or could be achieved in regional processes.

FERC has empowered transmission providers to work with stakeholders to develop "procedures by which the public utility transmission providers in the region identify and evaluate the set of potential solutions that may meet the region's needs more efficiently or cost-effectively."[183] In practice, when comparing two potential transmission projects, such procedures logically focus on economic metrics, although they do more than simply consider capital costs. For example, MISO explains that it considers "operating performance, initial investment costs, robustness of the solution, longevity of the solution provided, and performance against other economic metrics" in comparing multiple proposed transmission solutions.[184]

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of receiving input and weighing stakeholder proposals, and "strongly encourag[ing]" states to participate in regional planning).

[182] *See infra* Part V and New England States Committee on Electricity, Regional Framework for Non-Transmission Alternatives Analysis, at 1, 4 (Oct. 2013).

[183] FERC, Order on MISO Compliance Filing, at 14-15.

[184] MISO, *supra* note 144, at 49.

However, fitting non-transmission alternatives into these frameworks adds a layer of complexity that no region has yet grappled with. Although FERC has instructed regions to create "appropriate metrics" to compare non-transmission and transmission solutions, [185] details remain sparse at the regional level.[186] One reason that regions have likely been slow to act on this front (a reason no doubt compounded by the biases discussed in the previous subsection) is that non-transmission alternatives present a comparability conundrum: as explained below, regions appear unable *legally* to incorporate the full spectrum of non-transmission alternatives' benefits into the comparison process, creating a classic externality problem where public benefits are undervalued.

As described earlier, non-transmission alternatives often bring "co-benefits," which may include lowering air pollution, improving health and the comfort of homes, and reducing strain on the electric grid.[187] These benefits are real, meaningful, and capable of monetary estimate.[188] In many cases, the size of such benefits is likely to be substantial. For example, in 2003, Vermont's transmission utility, called "VELCO," proposed a transmission line upgrade known as the "Northwest Reliability Project." Vermont has a law requiring that alternatives to transmission be considered,[189] and VELCO submitted an analysis of five combinations of alternatives. That analysis showed that a non-transmission alternative using combination of centralized generation and energy efficiency would entail a capital cost of $314 million, as compared to $107.5 million for the cheapest transmission alternative.[190] However, when societal costs and benefits of the two projects were included in the calculations, the non-transmission alternative resulted in a total cost savings of $95 million.[191] As this example illustrates, the inclusion of co-benefits in comparability criteria may frequently be determinative of whether or not a non-transmission alternative prevails as the superior option.

However, there is a legal hurdle to performing a similar societal benefits analysis

[185] Order 1000, 76 Fed. Reg. at 49,869.

[186] *See supra* Part III(A).

[187] *See* Watson & Coburn, *supra* note 28, at 38; Neme & Sedano, *supra* note 14, at 18.

[188] *See, e.g.*, Christopher Williams et al., *International Experiences with Quantifying the Co-Benefits of Energy-Efficiency and Greenhouse-Gas Mitigation Programs and Policies* , Lawrence Berkeley Nat'l Lab. Pub. No. LBNL-5924E (Sept. 2012); *Co-Benefits Risk Assessment Screening Model*, U.S. Envtl. Protection Agency, http://www.epa.gov/statelocalclimate/resources/cobra.html (describing the EPA's free model that allows states to estimate the health and economic benefits of air quality policies) (last visited Nov. 3, 2013); JEREMY FISHER ET AL., CO-BENEFITS OF ENERGY EFFICIENCY AND RENEWABLE ENERGY IN UTAH (SYNAPSE ENERGY ECONOMICS, INC. 2010) (providing monetary estimates of the air quality, health, and water benefits that implementation of energy efficiency and renewable energy would bring to the state of Utah).

[189] *See supra* note 68.

[190] La Capra Associates, *Update to Alternatives to VELCO's Northwest Vermont Reliability Project*, at 10, Prepared for VELCO (2005).

[191] *See id.* at 3-4. "Societal costs" in this context included "emissions costs, as well as [demand-side management]-related benefits, such as avoided utility distribution upgrade costs, as well as a 10% discount to DSM program costs as a risk adjustment." *Id.* at 6.

at the regional level. FERC has based its regional planning reforms, including the requirement to afford non-transmission alternatives "comparable consideration," on its obligation to ensure "just and reasonable rates."[192] FERC and the courts understand this "just and reasonable" authority to extend only to economic interests, with a focus on balancing the needs of consumers and investors.[193] Accordingly, FERC has disclaimed any ability to consider environmental concerns within its "just and reasonable" grant of jurisdiction, unless the environmental concerns impose actual costs.[194]

For this reason, non-transmission alternatives face a comparability conundrum. Co-benefits are one of the reasons that such alternatives are so attractive, and ignoring them undervalues the full societal worth of the non-transmission alternative.[195] Clearly, society would be better off if regions selected non-transmission alternatives whenever their total societal costs were lower than the next best transmission alternative. Yet there is no legal basis for FERC to consider options that are rendered superior on the basis of overall societal benefits alone. More specifically, while certain "co-benefits" of non-transmission alternatives likely could be considered within regional comparability frameworks as economic in nature—such as non-transmission alternatives' ability to lower the amount of distribution infrastructure investment necessary—benefits like emissions reductions likely fall outside this framework, except to the extent that they impose real compliance costs.[196]

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[192] *See* 16 U.S.C. § 824(e) (2012) and *infra* section IV for a detailed discussion of FERC's jurisdiction and its boundaries.

[193] *See Grand Council of Crees (of Quebec) v. FERC*, 198 F.3d 950, 956-57 (D.C. Cir. 2000) (collecting cases and FERC decisions and finding that, "[u]nsurprisingly, the Supreme Court has never indicated that the discretion of an agency setting 'just and reasonable' rates for sale of a simple, fungible product or service should, or even could, encompass considerations of environmental impact (except, of course, as the need to meet environmental requirements may affect the firm's costs)"). It is worth noting that, contrary to FERC's current interpretation of its (in)ability to price in environmental externalities, some advocates and scholars believe that FERC *could* utilize its existing authority to reflect environmental costs. *See* STEVEN WEISSMAN & ROMANY WEBB, ADDRESSING CLIMATE CHANGE WITHOUT LEGISLATION, VOL. 2: FERC (U.C. Berkeley Center for Law, Energy & the Environment, July 2014) (urging FERC to, *inter alia*, adopt a "carbon adder" in wholesale electricity rates that accounts for the environmental costs of electricity produced from various sources and arguing that FERC's obligation to protect the public interest provides authority for assessing such an adder).

[194] *Id.* ("Following the judicial lead, the Commission has affirmatively forsworn environmental considerations."). Bonneville Power Administration, a federal non-profit utility operating in the Northwest, reports experiencing a similar comparability problem: according to BPA staff, "BPA, as a wholesale utility working through its transmission function, could easily count the transmission benefits of [non-transmission alternatives] and compare [non-transmission alternatives'] costs to the transmission benefits. But [non-transmission alternatives] also provide other benefits – avoided or deferred generation, emissions benefits, ancillary system benefits and the like that BPA could not take credit for or benefit from." *See* UPDATING THE GRID, *supra* note 10, at 21.

[195] Adding complexity, societal benefits would accrue unevenly across the region, benefitting the implementing state more than others.

[196] Therefore, certain RTO/ISOs in regions that have created greenhouse gas compliance obligations and trading markets likely could legally consider the climate change benefits of non-transmission alternatives during regional planning, whereas other regions could not. *See* Regional Greenhouse Gas

This conundrum diminishes the force of FERC's "comparable consideration" mandate, given that it will necessarily exclude some of what makes non-transmission alternatives attractive. Here, then, is one place where FERC might have recognized that there are limitations to what regions can do to incorporate these non-transmission alternatives. But instead, as described *supra*, FERC chose to pass the buck to regional planners to grapple with the challenge of designing comparability metrics,[197] and then approved regional plans that do nothing but make vague promises to treat stakeholder-proposed alternatives comparably.

FERC's decision to allow vague comparability frameworks is troubling for an additional reason beyond the comparability conundrum. In some cases, it may well be that a non-transmission alternative could outperform transmission solutions even on an economic basis, without consideration of those co-benefits that provide societal benefit but are not monetize-able. But regional processes do nothing to describe how non-transmission alternatives, which have very different characteristics than transmission projects, can demonstrate their economic superiority. FERC has therefore fallen short on its responsibility to ensure that "transmission providers . . . identify how they will evaluate and select from competing solutions and resources such that all types of resources are considered on a comparable basis."[198] Without an understanding of the framework for comparison, non-transmission alternatives are already at a disadvantage compared to transmission projects, which will proceed down what is for them a well-trod path. Moreover, without clearer metrics in place, transmission providers' concerns about non-transmission alternatives' reliability[199] are likely to be translated into comparability processes that may unfairly penalize these resources.

Of course, this lack of clear comparability frameworks remains for now a theoretical flaw. It has not been tested because, as noted above, no non-transmission alternatives have yet to be proposed. Thus, there remains the possibility that regions will at least, on an ad hoc basis, come up with metrics that work for measuring the benefits of non-transmission alternatives in a comprehensive, fair, transparent fashion. But it does

Initiative, http://www.rggi.org/ (last visited July 11, 2014) (website of the carbon dioxide cap-and-trade program covering nine northeastern states,); Cal. Reg. Code Subch. 10, Art. 5 (2014) (establishing a greenhouse gas cap and trade program for California). However, even in these regions the market value of greenhouse gas permits is generally much lower than the estimated societal benefit that would come from avoiding the emissions, making use of market prices a weak proxy for societal benefits. *Compare* CO_2 Allowances Sold for $5.02/ton in 24th RGGI Auction, Press Release, June 6, 2014, and California Carbon Dashboard, Climate Policy Initiative, http://calcarbondash.org/ (last visited July 11, 2014) (showing the CA carbon price was $11.90/ton as of July 4, 2014), *with* Interagency Working Group on Social Cost of Carbon, 'Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866', May 2013 (Technical Update), available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf (updating the federal government's central social cost of carbon from $22 to $36 for a metric ton of CO_2 emitted in 2013).

[197] *See* Order 1000, 76 Fed. Reg. at 49,869.

[198] *Id.*

[199] *See supra* note 170.

not bode well that no region has yet tackled the complexities of comparability or committed itself, on paper and in public, to a process that fairly addresses the issue. And indeed, if regions were forced to deal with these issues more transparently, it would likely serve to make overt the legal challenge of robustly comparing non-transmission alternatives to transmission solutions, which FERC has passed over without discussion through regional delegation.

(2) The Funding Challenge

The funding challenge facing non-transmission alternatives is likely more fatal than the structural challenges. Even if a non-transmission alternative were to emerge as superior from what has been shown to be a difficult comparability process, it is ineligible to have its costs of construction allocated among regional beneficiaries, unlike transmission projects. In Order 1000, FERC explicitly refused to extend cost allocation to non-transmission alternatives even while acknowledging that the previous lack of cost allocation for transmission had created "significant risk" of underdevelopment.[200] This decision presents similar "significant risk" for non-transmission alternatives.

To understand this problem, it is easiest to begin by explaining the way that cost allocation functions for transmission solutions, and the controversy it has provoked. Cost allocation is the methodology used to determine which customers must pay for the cost of building and operating new transmission lines in cases where a single utility builds a line that has benefits that extend beyond its customers alone.[201] In the case of major transmission lines, which often cross many states, it is rarely the case that a the constructing utility's customers reap the entire benefit of the line's contributions to grid reliability and congestion relief, making a mechanism to distribute these costs fairly a critical component of expanding the grid. However, as might be imagined, states and utilities have incentives to keep these costs from being foisted upon their ratepayers.[202] These incentives make cost allocation a fraught issue that has been plagued with lawsuits and disagreements about the best way to proceed.[203] In Order 1000, again emphasizing regional flexibility, FERC required each regional transmission planning process to include a regional cost allocation methodology for distributing costs of new transmission among participants, but left it for regions to establish the specifics of how they would

[200] Order 1000, 76 Fed. Reg. at 49,920.

[201] Kaplan, *supra* note 4, at 20. For intrastate lines, the common practice of state commissions is to include the costs of transmission assets in the "retail rate base" of the constructing utility, spreading out the costs among the utilities' consumers. *See* Brown & Rossi, *supra* note 12, at 726.

[202] *See* Vaheesan, *supra* note 23, at 88-89 ("State regulators are reluctant to authorize new transmission lines that increase rates for local ratepayers and impose aesthetic and environmental harms within the state, even if the lines yield net benefits to the larger region.").

[203] *See, e.g.*, Illinois Commerce Comm'n v. Fed. Energy Regulatory Comm'n, 721 F.3d 764, (7th Cir. 2013) (approving of MISO's latest cost allocation methodology), Klass & Wilson, *supra* note 9, at 1804; Rossi & Brown, *supra* note 12, at 764 (quoting the Center for American Progress calling cost allocation "protracted and contentious"); Kaplan, *supra* note 4, at 20.

allocate costs.[204] Instead of prescribing a methodology, FERC enumerated a set of principles that regions must adhere to in designing cost allocation methods, driven by the "cost-causation" principle that rates should reflect costs actually caused by the consumer who pays for them, or, put otherwise, that costs should be charged to those customers who actually benefit from a line.[205] The regional processes developed under Order 1000 will require transmission planners, in consultation with stakeholders, to determine processes for establishing the beneficiaries of a transmission project.

In turn, these cost allocation methodologies will allow regions to force beneficiaries of transmission projects selected in regional plans as cost-effective regional solutions to help pay for these projects.[206] For this reason, these rules have been a particularly controversial element of Order 1000, and comprise a major part of the current Order 1000 lawsuit. Opponents' argument, in brief, is that "[t]he FPA does not authorize FERC to mandate a broad assessment of charges by a transmission provider – in essence a tax – to entities that are not in a contractual or customer relationship with, or taking transmission service from, that provider."[207] FERC, of course, disputes this characterization, arguing that cost allocation methodologies are critical to ensure that the best regional solutions are proposed and implemented, and that no utilities "free ride" off the investments of others that improve overall grid functioning.[208] Without *ex ante* cost allocation methodologies, no developer will be incentivized to come forward with cost effective and efficient regional solutions.[209]

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[204] *See, e.g.*, Order 1000, 76 Fed. Reg. at 49,935. FERC's allowance of flexibility was popular among commenters, who "almost all . . . urge[d] the Commission not to adopt a 'one-size-fits-all' approach to cost allocation and to retain regional and interregional flexibility." *Id.* at 49,933.

[205] *See id.* at 49,932; *see also* Klass & Wilson, *supra* note 9, at 1825. FERC clarifies that the benefits that may be considered include "the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs." Order 1000, 76 Fed. Reg. at 49,932. A recent Seventh Circuit opinion endorsed a certain degree of leniency in assessing and assigning benefits among recipients, however, explaining that if a "crude" attempt "to match the costs and benefits" of transmission lines "is all that is possible, it will have to suffice." Ill. Commerce Com'n v. FERC, 721 F.3d 764, 775 (7th Cir. 2013).

[206] FERC deferred the question of how cost allocation methodologies will filter into utilities' cost recovery in front of state commissions, although it suggests that utilities should be able to recover these costs. *See* Order 1000, 76 Fed. Reg. at 49,928 (explaining that any complications arising in state jurisdiction over utility rates with respect to FERC's cost allocation reforms should be dealt with "based on specific facts and circumstances" rather than in that order); Order No. 1000-A, 77 Fed. Reg. at 32,279 ("In response to Alabama PSC's concern that the Commission's cost allocation reforms could lead to stranded transmission costs . . . we note that entities that receive benefits are subject to a Commission-approved transmission tariff. The existence of obligation [sic] arising under such a tariff is sufficient to ensure that there will be no stranded costs, and the question of specific recovery mechanisms is beyond the scope of this proceeding.").

[207] S.C. Pub. Serv. Auth. v. FERC, No. 12-1232, Doc. No. 1438224, Joint Initial Brief of Petitioners/Intervenors Concerning Cost Allocation, at 2 (D.C. Cir. Filed May 28, 2013).

[208] *See, e.g.*, Order 1000, 76 Fed. Reg. at 49,920; S.C. Pub. Serv. Auth. v. FERC, No. 12-1232, Doc. No. 1438224, Respondent's Brief, at 118 (D.C. Cir. filed Sept. 25, 2013).

[209] Order 1000, 76 Fed. Reg. at 49,921.

Despite recognizing that cost allocation is a critical incentive that drives the proposals received during transmission planning, FERC declared cost allocation for non-transmission alternatives "beyond the scope" of its Order 1000 reforms.[210] This decision effectively renders non-transmission alternatives infeasible, by denying non-transmission solutions a viable source of regional financing. No developer will propose a non-transmission alternative financed only by its customers, when much of the non-transmission alternative's benefit comes from its role in filling a regional transmission need. In contrast, developers will have ample incentive to put forth proposed transmission projects—even if less efficient and effective than a non-transmission alternative—given the guarantee that, if selected in a regional plan, costs will be apportioned among beneficiaries.

A return to the Vermont example from above may concretize the clear disincentives that non-transmission alternatives face given their inability to receive cost allocation. There, analysis showed that the non-transmission alternative had lower societal costs of around $95 million.[211] However, if Vermont chose the transmission solution, regional cost allocation rules provided that approximately 90% of the costs could be "socialized"—spread across all of the New England states—because of the regional benefits created by solving the reliability problem.[212] In contrast, the alternative solution would have to be funded entirely by Vermont ratepayers, even though it solved the same regional problem.[213] As a result of this rule and some misgivings on the part of the utility and regulators as to whether the forecasted energy efficiency improvements could be reliably delivered, the state opted for the transmission alternative.[214] Ultimately, then, ratepayers and citizens all over New England lost out because of a legal failure to treat alternatives to transmission equally to transmission solutions in allocating costs.

By refusing cost allocation to non-transmission alternatives in Order 1000, FERC has essentially ensured that such irrational outcomes will continue to be the norm across the country. However, as the next section explores, there are some understandable reasons for FERC's demurral on this point.

III. Cost Allocation and Jurisdictional Boundaries

FERC said nothing about why it chose to place cost allocation for non-transmission alternatives "beyond the scope" of Order 1000, but the most likely reason is that FERC was uncertain whether its jurisdiction extended to allowing cost allocation for

[210] *Id.* at 49,956 ("[W]e conclude that the issue of cost recovery for non-transmission solutions is beyond the scope of the transmission cost allocation reforms we are adopting here. . .").

[211] *See* La Capra Associates, *supra* note 190, at 3-4.

[212] *See* Neme & Sedano, *supra* note 14, at 12-13.

[213] *Id.*

[214] *See* Press Release, Vermont Public Service Board, "Board Approves Substantially Conditioned and Modified Transmission System Upgrade," January 28, 2005.

non-transmission alternatives. Allowing these distributed resources cost allocation would move RTOs and regional transmission planners closer to the traditional state domains of IRP and resource mix decisions. In essence, regions would be determining that certain states should engage in *additional* distributed energy, above and beyond state mandates, and that other states should help pay for it. Such determinations might cause some states and transmission providers to bristle, particularly when forced to pay for distributed energy programs in neighboring states (even though, under the beneficiary pays methodology, they would be paying based only on the benefits they received). However, the fact that cost allocation for non-transmission alternatives might prove politically unpopular is a distinctly different issue from whether FERC could, as a matter of jurisdiction, take this additional step. Until recently, there was a strong case that the agency could extend cost allocation to non-transmission alternatives. However, the May 2014 D.C. Circuit decision in *Electric Power Supply Association v. FERC* decidedly circumscribed this jurisdiction, in ways that this section explores.[215]

To understand FERC's jurisdictional bounds requires turning to the text of the Federal Power Act of 1935 ("FPA"), [216] which establishes the jurisdictional divide in electricity regulation.[217] FPA section 201 gives FERC jurisdiction over "the transmission of electricity in interstate commerce," as well as over sales "at wholesale in interstate commerce," but immediately caveats these grants of authority with a reservation that they "extend only to those matters which are not subject to regulation by the States."[218] Section 205 of the FPA charges FERC to ensure that all rates are "just and reasonable" and that no utility grants undue preference or unreasonably discriminates in its rates and charges.[219] Section 206 authorizes FERC to remedy any rate or "practice . . . affecting such rate" that it finds to be in violation of section 205.[220] The FPA thereby sets FERC up as the watchdog over interstate transmission and wholesale power rates, but maintains for the states considerable authority over other aspects of transmission.[221]

[215] --- F.3d ----, 2014 WL 2142113, at *1 (D.C. Cir. May 23, 2014).

[216] "As a federal agency, FERC is a creature of statute, having no constitutional or common law existence or authority, but *only* those authorities conferred upon it by Congress." Cal. ISO v. FERC, 372 F.3d 395, 398-99 (D.C. Cir. 2004) (internal quotation marks omitted, emphasis in original).

[217] *See* Public Utility Act of 1935, ch. 687, 49 Stat. 847 (codified as amended in scattered sections of 16 U.S.C.). Congress passed the FPA to respond to the famous "Attleboro Gap"—a vacuum in electricity regulation that was created when the Supreme Court found that Rhode Island could not regulate the rates charged by one of its companies selling into Massachusetts, as this imposed a "direct burden upon interstate commerce." Public Util. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83, 89 (1927). However, the Supreme Court has since clarified that the FPA does more than merely remedy the gap caused by its *Attleboro* decision. New York v. F.E.R.C., 535 U.S. 1, 21 (2002) ("It is . . . perfectly clear that the original FPA did a good deal more than close the gap in state power identified in *Attleboro.*").

[218] 16 U.S.C. § 824(a) (2012); *see also* New York v. FERC, 535 U.S. at 15.

[219] 16 U.S.C. § 824d.

[220] *Id.* § 824e.

[221] Klass & Wilson, *supra* note 9, at 1808; *see also* Vaheesan, *supra* note 23, at 97. Courts have consistently interpreted the FPA as creating a "bright line" between federal and state jurisdictional spheres. *See* Miss. Power & Light Co. v. Mississippi, 487 U.S. 354, 374 (1988); *see also* Steven Ferrey, *State*

Although still operating predominantly under this 1935 statute, FERC has generally been successful in stretching its jurisdictional authority to meet modern ends. Since the 1990s, as FERC has both precipitated and responded to the deregulatory trend in energy and transmission markets, it has effectuated a substantial enlargement of its jurisdiction.[222] In particular, FERC has brought a number of matters under its purview through use of its "affecting" jurisdiction under FPA sections 205 and 206, which allows it to regulate "practices affecting rates" in order to remedy any discrimination.[223] And by and large, as this section shows, the courts have approved, although the recent *Electric Power* decision may signal new limits on FERC's reach.

A. FERC's Jurisdictional Expansion and Its Bounds

Over the last several decades, states and utilities have frequently challenged FERC actions, and courts have often deferred to FERC's determinations of what it needs to do in order to remedy discriminatory rates. First, FERC quite expansively interpreted its "affecting jurisdiction" to remedy undue discrimination under FPA sections 205 and 206 when it issued Order 888 requiring transmission providers to open their lines to competitors at fair rates.[224] In a 2001 case challenging FERC's ability to expand its authority in this manner, the Supreme Court endorsed a broad reading of FERC's reach in our modern, transformed power markets (with the dissent arguing only that FERC should have regulated even more than it did).[225] In particular, the Court appeared quite deferential to FERC's determinations of what it needed to do under section 206 to remedy discrimination.[226] FERC has since utilized this broad authority to assert

Wars—The Empire Strikes Back: The Federal/State Constitutional Power Confrontation, 65 BAYLOR L. REV. 1, 41-42 (2013).

[222] *See, e.g.*, Ferrey, *supra* note 221, at 31 (asserting that there has been a "massive shift in regulatory jurisdiction from the states to FERC" during this time period).

[223] 16 U.S.C. § 824(e); *see also, e.g.*, Order 888-A, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 62 Fed. Reg. 12,274, 12,275 (Mar. 14, 1997) (codified at 18 C.F.R. pt. 35) ("Our authorities under the FPA not only permit us to adapt to changing economic realities in the electric industry, but also require us to do so, as necessary to eliminate undue discrimination and protect electricity customers.").

[224] *See* Order No 888, 61 Fed. Reg. at 21,541; *see also* Kelliher & Farinella, *supra* note 88, at 639. FERC's authority in this regard was clarified in the Energy Policy Act of 1992, which gave FERC explicit authority to order wheeling on a case-by-case basis. *See* Energy Policy Act of 1992, Pub. L. No. 102-486, § 711, 106 Stat. 2776, 2905-10 (wheeling authority codified at 16 U.S.C. § 824j).

[225] *See* New York v. FERC, 535 U.S. 1, 19 (2001); *id.* at 30 (Thomas, J., dissenting). More specifically, the Supreme Court considered whether FERC could require utilities to transmit other utilities' power over their lines at fair rates in those cases where the utility "unbundled"—i.e., separated—the cost of transmission from the cost of electricity in its billing. *See id.* at 3. It found that FERC had the authority to regulate even retail unbundled transmission, given that the FPA makes no distinction between retail and wholesale in granting FERC authority over transmission. *Id.* at 19.

[226] *See id.* at 26-28 (finding that FERC could properly determine that it wanted to regulate one type of retail transmission upon finding discrimination, but could decline to regulate another type of retail

jurisdiction on multiple occasions over practices or subject areas that states considered to be their traditional turf.

Two examples stand out as FERC's furthest forays into traditional state territory. The first is FERC's approval of "forward capacity markets" and "installed capacity requirements." In these cases, FERC allowed an ISO to require its utilities to purchase from generators a promise to supply power to meet their predicted demand three years in the future. Challengers in the D.C. Circuit alleged that this requirement intruded too far into state's control over generation, given that it forced utilities to buy a particular amount of generation capacity.[227] The D.C. Circuit disagreed. If found that these actions fell within the "heartland" of FERC's section 206 "affecting" jurisdiction to ensure just and reasonable rates, given the large impact that the availability of future capacity has on rates, and that because states still maintained their control over whether to build and operate particular generators, FERC had not intruded too far into state territory.[228]

These decisions suggested that even when FERC's regulations touch on matters traditionally under state control, the agency could have confidence in its jurisdiction where it could tie its actions fairly directly to transmission or wholesale electricity rates. This confidence no doubt inspired FERC's more recent actions both in Order 1000 and on the demand response reforms described below.

Shortly after FERC approved capacity markets and capacity requirements, the Commission turned its attention to improving wholesale markets by enabling demand response resources to compete alongside generators. FERC determined that as a matter of sound policy, entities providing demand response (i.e., temporarily cutting energy demand) should be paid for reducing demand just as generators are paid for providing electricity supply.[229] To accomplish this objective, FERC first issued Order 719 in 2008. That order required RTOs and ISOs to allow demand response to bid into organized energy markets just as generators are allowed to bid in.[230] A few years later, FERC further extended its jurisdiction over demand response in its 2011 Order 745, which required RTOs and ISOs to compensate demand response at the same rate as generation resources.[231] In setting what some viewed to be a generous rate for demand response

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transmission for which it had not yet found discrimination).

[227] *See* Maine Pub. Utils. Comm'n v. FERC, 520 F.3d 464, 468-69 (D.C. 2008), *reversed in part on other grounds sub nom* NRG Power Marketing, LLL v. Maine Pub. Utils. Comm'n, 558 U.S. 165 (2010); Conn. Dep't of Pub. Util. Control v. FERC, 569 F.3d 477 (D.C. Cir. 2009).

[228] *See* Conn. DPUC, 569 F.3d at 481, 483.

[229] *See* Order 719-A, Wholesale Competition in Regions With Organized Electric Markets, Order on Rehearing, 74 Fed. Reg. 37,776, 37,783 (July 29, 2009) [hereinafter "Order 719-A"].

[230] Order No. 719, Wholesale Competition in Regions with Organized Electric Markets, 73 Fed. Reg. 61,400 (Oct. 28, 2008).

[231] FERC Order No. 745, Demand Response Compensation in Organized Wholesale Electricity Markets, 76 Fed. Reg. 16,658, 16,658 (Mar. 24, 2011) (to be codified at 18 C.F.R. pt. 35) [hereinafter "Order 745").

compensation,[232] FERC explained that this rate reflected recognition that demand response faced numerous market barriers that made it difficult for it to compete with traditional resources.[233] And, the Commission explained, demand response's ability to compete in the wholesale market is important for market performance: it lowers market clearing prices, helps mitigate market power, strengthens reliability by putting downward pressure on peak demand, and relieves congestion on transmission lines.[234] These features of demand response, FERC concluded, mean that pricing rules that treat demand response comparably to generation in organized wholesale markets "directly affect wholesale rates."[235] FERC also, however, adopted a "cost-effectiveness" test providing that demand response would only be paid the mandated rate when the "net benefits" of including demand response in the market outweighed the costs, thereby ensuring that demand response's participation worked to lower electricity rates. [236]

In *Electric Power*, a group of electricity suppliers challenged Order 745 in the D.C. Circuit, arguing that FERC had exceeded its jurisdiction in setting a mandatory price for demand response in wholesale markets, given that demand response represents a foregone "retail sale" and therefore falls under state retail jurisdiction.[237] FERC countered by asserting that because demand response is the cutting of electricity demand, it is *neither* a "retail" nor a "wholesale" sale, and that its "affecting" jurisdiction should surely extend to demand response's pricing within the wholesale market, given that demand response has a demonstrable direct effect on lowering wholesale market rates.[238]

In May 2014, the D.C. Circuit sided with petitioners in a two-to-one decision that

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[232] Order 745 required that demand response be paid the same "locational marginal price" that generation receives. Opponents argued that demand response should be compensated at a lower rate, given that those who bid in demand response also were saved the expense of having to buy generation to meet their electricity needs. *Id.* at 16,659, 16,662-63.

[233] *Id.* at 16,659.

[234] *See id.* at 16,662.

[235] *Id.*at 16,676.

[236] *Id.* at 16,666.

[237] *See* Elec. Power Supply Ass'n v. FERC, --- F.3d ----, 2014 WL 2142113, at *1 (D.C. Cir. May 23, 2014).

[238] *See id.* at *3. The "direct effect" requirement comes from a 2004 case in which the D.C. Circuit considered whether FERC had acted within its jurisdiction when it ordered the California ISO to replace its board of directors upon a determination by FERC that they were not sufficiently independent of market participants. *See* Cal. Independent System Operator Corp. v. FERC, 372 F.3d 395, 398 (D.C. Cir. 2004). The court drew a line, explaining that FERC could not credibly consider the practice of dictating board composition to be a practice affecting rates. Instead, "practices affecting rates" must be limited "to those methods or ways of doing things on the part of the utility that *directly affect* the rate or are closely related to the rate, not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so." *Id.* at 403.

[238] 16 U.S.C. § 824(e).

[238] *See* Cal. Independent System Operator Corp. v. FERC, 372 F.3d 395, 398 (D.C. Cir. 2004).

[238] *See id.* at 403.

[238] *Id.* (emphasis added).

struck down FERC's Order 745 over a vigorous dissent.[239] Although agreeing with FERC that demand response compensation "affects the wholesale market," the majority found this a rationale without a limiting principle.[240] It reasoned that FERC's "affecting" jurisdiction cannot go so far as to "erase the specific limits of § 201"—that is, the section granting wholesale jurisdiction to FERC but reserving retail jurisdiction to the states.[241] And, it determined, demand response "is part of the retail market," as it involves retail customers and cutting levels of retail electricity consumption.[242]

The dissent found it hard to square these maneuvers with the deference required by *Chevron*.[243] The dissent argued that while the majority's interpretation of demand response as a wholly retail activity may be a *plausible* understanding of the concept of demand response, it is certainly not the only reasonable understanding.[244] In the dissent's view, because demand response resources participating in wholesale markets clearly and directly affect the wholesale price of electricity, and because they are not actual "retail sales" of electricity, it is perfectly plausible to place them on the wholesale side of the jurisdictional divide.[245] Under this view, *Chevron* deference would counsel for finding FERC's interpretation of its jurisdiction over demand response a reasonable reading of the FPA.[246]

I think the dissent has the stronger argument here, along with other scholars who had predicted that Order 745 would withstand judicial scrutiny.[247] The case law upholding FERC's authority to establish capacity markets and capacity requirements held that even if FERC must intrude somewhat into state regulatory territory, such intrusion is permissible when it is closely tied to a core FERC function like keeping wholesale prices just and reasonable.[248] And in the case of demand response, FERC could easily demonstrate that demand response's participation in wholesale markets helps lower rates. Whether this strongly divided opinion may lead to en banc review or a grant of certiorari remains to be seen. For the present time, *Electric Power* stands as an indication that the D.C. Circuit may be reigning in some of the leeway it has given to FERC during its market restructuring experimentation.

[239] *See* Elec. Power, 2014 WL 2142113.
[240] *Id.* at *3.
[241] *Id.* at *3-4.
[242] *Id.* at *4.
[243] *Id.* at *8 (Edwards, J., dissenting).
[244] *Id.*
[245] *Id.*
[246] *Cf.* City of Arlington v. FCC, --- U.S. ----, 133 S. Ct. 1863, 1874-75 (holding that a court must defer under *Chevron* to an agency's interpretation of the scope of its jurisdiction, in the face of statutory ambiguity).
[247] *See* Eisen, *supra* note 59, at 72; Richard J. Pierce, Jr., *A Primer on Demand Response and a Critique of FERC Order 745*, GEO. WASH. UNIV. J. OF ENERGY AND ENV. LAW 102, 104-05 (2012) (disagreeing with FERC's decision on how best to compensate demand response, but nevertheless arguing that it should be upheld on judicial review because FERC provided adequate reasoning and adopted the net benefits test to ensure reasonability of rates).
[248] *Cf.* Conn. Dep't of Pub. Util. Control v. FERC, 569 F.3d 477, 481 (D.C. Cir. 2009).

B. Implications for Non-Transmission Alternatives

Prior to *Electric Power*, there was a strong argument that FERC's proactive stance on pricing demand response in wholesale energy markets should have spurred it to take similar measures to allow cost allocation for non-transmission alternatives. Now that FERC's demand response reforms have been struck as extra-jurisdictional, it is likely that any attempt by FERC to extend cost allocation to non-transmission alternatives would be considered the same.

FERC's (losing) rationale behind Order 745 can be distilled to this: demand response's participation in wholesale markets, while not itself "energy," positively affects rates enough that the Commission felt warranted in setting pricing rules for this non-jurisdictional service as a "practice affecting rates." It would be a nearly identical rationale that might support extending cost allocation to non-transmission alternatives: because non-transmission alternatives lower costs (since they are only selected when cheaper than transmission solutions) and relieve congestion on transmission lines in ways that enhance the reliability of the grid,[249] they should be rewarded the same fair compensation as transmission solutions when they provide more just and reasonable options.[250] Without cost allocation for non-transmission alternatives, these resources face market barriers that make it difficult for them to compete, leading to overbuilding of transmission and unreasonably high transmission rates—*just as* demand response's market barriers lead to overbuilding of generation resources and unreasonably wholesale electricity high rates.[251]

Post-*Electric Power*, these arguments lose their force because they rest too heavily upon FERC's "affecting" jurisdiction in ways that the D.C. Circuit rejected. Now, a court would likely find that non-transmission alternatives, which are by definition *not* "transmission" but are instead localized generation, demand response, and energy efficiency, are appropriately categorized as part of state retail markets such that FERC cannot rope them into its jurisdiction via FPA section 206's broad "affecting" clause. *Electric Power*, then, affirms FERC's hesitance to extend Order 1000's scope so far as to include cost allocation for non-transmission alternatives, if the opinion stands.[252]

[249] *See supra* notes 50-52 & accompanying text.

[250] However, cost allocation for non-transmission alternatives would arguably rely on an even more attenuated relationship between pricing and rate affects than demand response in wholesale markets. One justification FERC uses for its assertion of jurisdiction over demand response in wholesale energy markets is that demand response is a "direct participant" in these markets. *See* Brief of Respondent FERC, Elec. Power Supply Ass'n v. FERC, Docket. No. 11-1486, at 39 (D.C. Cir. filed Aug. 28, 2013). Non-transmission alternatives, by contrast, are not market resources that can bid themselves in and then be dispatched at particular times when needed. Rather, they exist as an alternative at the transmission *planning* stage, where they might be designed to negate the need to build as much transmission.

[251] *Cf.* Order 745, 76 Fed. Reg. at 16,659.

[252] Conversely, should *Electric Power* be overturned en banc or by the Supreme Court, and if FERC's Order 1000 reforms survive judicial scrutiny, I would argue that FERC would be on solid legal footing in

Assuming that my arguments about the inefficacy of FERC's current reforms are correct, this leaves non-transmission alternatives in a sad position: championed on paper, but unlikely to ever emerge in practice. Is there a way forward?

IV. Meaningful Reforms, Honest Admissions

There is no doubt that FERC has taken some bold steps and legal risks in opening up and regionalizing transmission planning and access over the last twenty years. And it has done so by and large without Congressional guidance, forced to do what it can to adapt outdated statutes to the new challenges facing the transmission grid.[253] FERC has opened up transmission access, created ISOs/RTOs, and begun to integrate distributed resources into wholesale markets. Most recently, in Order 1000, it has attempted to an unprecedented degree to help states shape their energy resource mixes and promote renewable energy, through its requirement that regional transmission planning include consideration of those transmission needs that are created by "public policy requirements."[254] Similarly, FERC's insistence on regional cost allocation methodologies will hopefully ease the U.S. transmission bottleneck.[255]

These steps are commendable, and each required extending FERC's reading of its mandate into novel regulatory terrains.[256] But FERC has been decidedly less active when it comes to non-transmission alternatives. To be sure, there is now precedent to support FERC's previously silent conclusion that providing more robust support for non-transmission alternatives (particularly in the form of cost allocation) would stretch its jurisdiction too far. And FERC may be taking a step-wise approach to incorporating non-transmission alternatives that relies upon stakeholder proposals as a first step to incorporating these alternatives more fully into transmission planning. In this way, FERC's decision not to create a more robust framework for non-transmission alternatives feels like a weighing and parsing out of institutional capital. The Commission has decided that, for now, non-transmission alternatives are not high enough on its agenda to warrant further legal risks.

While institutional prudence is at times laudable,[257] FERC's approach to non-transmission alternatives is troubling because the Commission has lacked forthrightness about the poor fit between its means and ends. FERC continues to embrace publicly the position that it has created a process through which non-transmission alternatives are treated comparably, while rubber-stamping ineffectual regional plans. FERC has taken

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extending Order 1000's cost allocation requirements to non-transmission alternatives.

[253] Freeman & Spence, *supra* note 25, at (manuscript 31).

[254] Order 1000, 76 Fed. Reg. at 49,871.

[255] *See, e.g.*, Hari M. Osofsky & Hannah J. Wiseman, *Dynamic Energy Federalism*, 72 MD. L. REV. 773, 804 (2013) (describing previous FERC attempts to address the transmission bottleneck).

[256] For an excellent and more detailed exploration of how FERC has used its outdated statutory authority to innovate and update through regulation, see Freeman & Spence, *supra* note 25, at (manuscript 28-44).

[257] *See generally id.*; Jacobs, *supra* note 26.

this hands-off, stakeholder and delegation-focused approach despite knowing that there are significant risks of discrimination and bias across RTOs, ISOs, and unorganized regions—risks that have *driven* many of its reforms over the last twenty years.[258] Consequently, we are left with a situation where FERC's regional delegates can assert that FERC has approved their methodologies for according non-transmission alternatives comparable treatment, while in point of fact the structure of transmission planning offers nothing of the sort.

At the current juncture, the universe of actions that FERC might take to promote non-transmission alternatives has narrowed considerably, given that any attempt to extend cost allocation to these retail-level solutions is likely to run afoul of *Electric Power*.[259] But while cost allocation is a significant barrier, it is only one of the categories of barriers this article identifies. As explained in this section, there are several structural reforms that FERC could undertake to create more "comparable consideration" for non-transmission alternatives that should not push up against the bounds of its jurisdiction. And, I argue, it is time to pair these reforms with institutional honesty about what FERC can and cannot accomplish with respect to promoting non-transmission alternatives. Such honesty is crucial to send the appropriate message to stakeholders, Congress, and the states about how laws, policies, collaborations, and advocacy strategies may need to evolve to facilitate true "comparable consideration."

A. Structural Reforms

As discussed in Part III, non-transmission alternatives face a host of structural challenges that make it difficult for them to compete alongside transmission solutions in regional transmission planning processes. While non-transmission alternatives' cost allocation challenge appears currently unresolvable, the structural barriers to non-transmission alternatives—misaligned expertise and incentives and the comparability challenge—are more easily remedied.

FERC's weak mandate to regions to grant stakeholder-proposed non-transmission alternatives "comparable consideration" appears woefully inadequate in the face of what FERC has frequently documented as persistent self-interest on the part of transmission providers.[260] FERC knows that utilities are unlikely, without prodding, to provide services outside their core areas that lack guaranteed rates of return. Armed with this knowledge, there are several steps the Commission could take beyond asking politely for

[258] *See, e.g.*, Order 890, 72 Fed. Reg. at 12,273 ("As the Commission found in Order No. 888, it 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. Such an incentive can lead to unduly discriminatory behavior against third parties, particularly if public utilities have unnecessarily broad discretion in the application of their tariffs.").

[259] *See supra* section IV(b).

[260] *See, e.g.*, Order 888, 61 Fed. Reg. at 21,547 (explaining that the Commission had ordered wheeling because many public utilities "historically have declined to provide access to their systems, or have offered service only on a discriminatory basis").

comparability.

First, there is a relatively clear and easy solution available for the problem of misaligned expertise and incentives. In short, transmission providers themselves are in the best position to propose non-transmission alternatives, but have no incentive to do so. In this situation, an affirmative burden placed on these best-positioned entities to devise reasonable non-transmission alternatives seems appropriate. An obligation on transmission providers themselves accomplishes two objectives at once: first, it helps mitigate the transmission-first culture that dominates these entities by requiring them to look beyond their financially and technically preferred solution. And second, it puts the entity with the most knowledge and expertise in the position of primary evaluator of potential non-transmission alternatives.[261] In turn, stakeholders are relegated to their proper position: one of questioning assumptions and suggesting refinements in analysis based on their interests and knowledge, rather than coming up with potential solutions whole cloth.

A requirement on RTOs and transmission providers to make a good faith effort to design and evaluate non-transmission alternatives would also begin to unlock the comparability conundrum, as regions would be forced to design metrics and evaluation criteria to compare transmission and non-transmission alternatives. Different regions might treat externalities and resource assurance questions differently, in the experimental spirit endorsed by FERC, and this exercise might ultimately lead to a set of best practices. Similarly, a requirement on transmission providers and ISOs/RTOs to produce potential non-transmission alternatives would further our understanding of the true potential that these alternatives hold to serve as regional solutions. As certain regions found ways to analyze and utilize non-transmission alternatives, stakeholders might take these lessons and advocate for similar analyses in other regions.[262]

It might be argued that requiring such analysis would be an exercise in futility without also extending cost-allocation to non-transmission alternatives, given that there would be no one to pay for a non-transmission alternative that emerged from required analysis, rather than from an independent proponent. There are two responses to this criticism. The first is that the exercise of analyzing the potential superiority of non-transmission alternatives might prompt new creativity on the funding issue. Should a non-transmission alternative emerge from a required analysis as a clearly superior solution, states within the region might find the political capital necessary to create a cost-sharing arrangement, armed with evidence of its fiscal prudence. And second, even if cost allocation remains an impediment, requiring analysis would at least highlight the importance of the cost allocation problem facing non-transmission alternatives. If required analyses, responsive to stakeholder input, fail to find any cost-effective non-transmission alternatives, then cost allocation for these resources can be dismissed as a

[261] In practice, this obligation might be delegated to a third party entity (and perhaps this degree of distance from the transmission dominated culture would be preferable).

[262] One model for how such a requirement to analyze non-transmission alternatives might be crafted can be found in Vermont, which has explicitly required such analysis since 2006. *See supra* note 68.

non-priority. On the other hand, should such analyses prove that many non-transmission alternatives would be superior, perhaps Congress or the states may consider taking action to coordinate cost allocation for non-transmission alternatives.

There is a second, complementary step that FERC could take that might promote the funding of superior non-transmission alternatives. It could require regions to make clear that when a non-transmission alternative out-performs a transmission option, that transmission option *may not be included* the regional transmission plan for purposes of cost allocation. FERC alluded to this possibility in its Order on Rehearing for Order 1000, explaining that it "may be the case" that a region takes this step.[263] But it endorsed this idea only as permissible. If it were instead to make clear that the obligation to ensure reasonable costs precludes using regional cost allocation for a transmission project that has failed in comparison to a non-transmission alternative, regions, states, and/or providers might be more motivated to find funding solutions for these alternatives.

Finally, FERC could decide to be more rigorous in what qualifies as the appropriate elaboration of a regional "comparable consideration" methodology. As shown in the examples of SERTP and MISO, FERC has chosen to permit mere recitation of a promise to grant comparable consideration to suffice as proof of a sufficient, fair process. This leaves potential proponents of non-transmission alternatives little sense of how a proposed non-transmission or hybrid project would be evaluated against a transmission alternative. FERC could remedy this problem either by maintaining regional flexibility but asking for more detail in regional tariffs, or by elaborating its own requirements for what must be considered during a comparability evaluation.

There also exists the possibility that the procedural reforms needed to better promote non-transmission alternatives could occur outside the FERC-overseen regional transmission planning process. Most notably, states—although unlikely to champion and fund a regional non-transmission alternative individually for reasons discussed *supra*—could decide to create a process outside of FERC's planning to (1) identify viable regional non-transmission alternatives; and (2) develop methodologies for splitting the costs of these alternatives. One limited form of such collaboration is already underway in ISO-New England, where the participating states have a long history of cooperation in electricity and transmission markets. There, the states have developed a "Regional Framework for Non-Transmission Alternatives Analysis" that occurs outside of the formal RTO planning process.[264] The framework aims to bring together non-transmission alternatives analysis that is done within the various states in the region into

[263] FERC Order 1000-A, 77 Fed. Reg. at 32,216 ("It may be the case that non-transmission alternatives may result in a regional transmission planning process deciding that a proposed transmission facility is not a more efficient or cost-effective solution and, accordingly, that facility may not be selected in the regional transmission plan for purposes of cost allocation.").

[264] *See* New England States Committee on Electricity, Regional Framework for Non-Transmission Alternatives Analysis, at 1 (Oct. 2012), *available at* www.nescoe.com/uploads/NTA_Framework_October_2012_FINAL.pdf.

a larger regional analysis, and to encourage non-transmission alternative analysis to occur earlier in the planning process.[265] It will require transmission providers to estimate the economic potential for demand-side or hybrid solutions in areas of interest, and to conduct economic analyses comparing these solutions to transmission solutions.[266] The framework stops short, however, of providing a mechanism for regionally funding viable non-transmission alternatives.

This ISO-New England initiative may go some distance towards improving consideration of non-transmission alternatives and establishing them as viable options, and certainly deserves recognition as a worthy experiment. A separate regional framework is, however, an inferior solution as compared to FERC-driven transmission planning reforms. Because the New England framework occurs outside the ISO planning process, it does little to crack the transmission-first culture of our lead transmission planners. And while the framework calls for the use of ISO transmission needs analysis to inform the regional non-transmission alternative analysis,[267] those most knowledgeable about transmission needs and transmission planning are the ones within the ISO. The process then, while not necessarily duplicative, at least suffers from fragmentation. To the extent that the New England states are able to participate actively in ISO processes and have their results incorporated into ISO plans, this criticism may lose some force.[268] And given FERC's jurisdictional limitations, such outside processes may be one of the best short-term ways to explore the potential regional values of non-transmission alternatives, including their societal benefits. Accordingly, FERC might consider encouraging formation of such processes in other regions.

We are at a point in the structure of the electricity industry where RTOs and ISOs—agglomerations of transmission providers, agents of FERC, and non-profits, all in one—administer transmission planning for most people in this country.[269] And where they do not, transmission providers themselves continue to undertake this role. While these entities' expertise positions them as trustworthy stewards of the grid in some respects, their status as semi-private entities with their own set of incentives means there will always be issues of capture involved in delegating to them society-wide planning functions. FERC's duty, as the regulator of these entities, requires recognition that this administrative structure builds in and reinforces inherent biases against unproven, experimental, and unfamiliar options, including non-transmission alternatives. To ensure the comparable consideration the Commission espouses will therefore take more than merely opening the processes up for stakeholder input; it will take putting in place the type of reforms that begin to transform a transmission-first culture into one that weighs

[265] *Id.* at 4.

[266] *Id.* at 12, 17 (including "public benefits" as measured by various states).

[267] *See id.* at 5 (diagramming how the processes complement one another).

[268] See Dworkin & Goldwasser, *supra* note 46, at 587 (describing the informal collaboration between ISO-NE and the members of the northeastern committee of state representatives, in which federal regulators take state recommendations "extremely seriously").

[269] Ill. Commerce Com'n v. FERC, 721 F.3d 764, 769 (7th Cir. 2013) "(Control of more than half the nation's electrical grid is divided among seven Regional Transmission Organizations.").

all options equally for the good of the system and the good of ratepayers. The reforms suggested here—requiring RTOs/ISOs/transmission providers themselves to analyze possible non-transmission alternatives, refusing to allow a transmission project regional cost allocation if a non-transmission alternative appears superior, and requiring more detailed up-front comparison methodologies—will go some of the distance towards creating more resource-neutral planning.

B. Honest Admissions

At the same time, FERC faces real jurisdictional limitations when it comes to non-transmission alternatives. The FPA is proving an unwieldy tool to justify incorporating this set of solutions that its drafters could not have known to favor back in 1935—solutions that address transmission constraints alongside environmental problems in ways that give them an awkward place in the current energy regime. Given its limited mandate, FERC has some reasonable explanations for moving slowly on non-transmission alternatives. Its relatively aggressive actions on demand response have been rebuffed,[270] and its regional cost allocation requirements for transmission projects are under judicial attack.

But even if restraint may be understandable,[271] FERC's words and actions are misaligned. It has recognized that non-transmission alternatives may play an important role in helping ease grid constraints, and has said it wants to level the playing field for these resources. It has then claimed to do so by instituting a weak "comparable consideration" requirement coupled with reliance on stakeholder proposals—a set of reforms that shows few signs of imposing any real comparability framework at the regional implementation level. Moreover, when it comes to the major impediment of cost allocation, it has done no more than vaguely describe that issue as "beyond the scope" of current orders. These reforms so far have led to naught: seven years after Order 890 first instituted a requirement that transmission planners equally consider non-transmission alternatives, we have not seen non-transmission alternatives even proposed. This fact is neither surprising, given the barriers this article has identified, nor acceptable, given the pressures facing the grid and the need to intelligently consider all options.

If FERC believes (as it says) that non-transmission alternatives hold real potential, it is doing its mandate a disservice by pretending to have solved a problem where it has barely scratched the surface. If unable to implement more robust reforms, our policy process might at least benefit from the Commission airing some of the reasons for its hesitance more publicly. There are certainly limitations to this suggestion, the

[270] *See* Sharon B. Jacobs, *Bypassing Federalism and the Administrative Law of Negawatts*, IOWA L. REV. (PAGE) (forthcoming 2014) (critiquing FERC's efforts to bolster demand response by bypassing state programs and setting up its own wholesale program).

[271] *Cf. id.* at (manuscript 5) (arguing that agency restraint should be celebrated in certain instances as helping them to "remain true to legislative goals by controlling the timing and extent of their decisions").

most obvious being that FERC would want to avoid making any admissions that might come to haunt it in future litigation. This rationale most likely underlies FERC's decision to declare cost allocation for non-transmission alternatives "beyond the scope" of Order 1000, rather than make any more definitive statements about such action lying at the outer bounds of its jurisdiction.

Nevertheless, more signaling by FERC about the ways in which it believes it cannot go the full distance to achieving adopted aims would be beneficial for the deliberative democratic process.[272] For example, while FERC need not say explicitly that it has jurisdictional concerns about extending cost allocation to non-transmission alternatives, it might at least publicly recognize that the lack of cost allocation creates a major hurdle that it has not solved. It might even go so far as to suggest that states and Congress consider action in this regard. Similarly, in mandating "comparable consideration," FERC might acknowledge that its mandate leaves certain important benefits of non-transmission alternatives beyond incorporation, noting the incentive problems this creates and encouraging states to work collaboratively with other stakeholders to find solutions (as in the ISO-New England example explored above).[273]

By admitting those policy spaces where it feels unable to cope unilaterally with the burden of utilizing the grossly outdated FPA to solve modern day grid and transmission planning constraints, FERC could better advance a regional and national conversation about the best ways to address such challenges. Congress is unfortunately unlikely to listen in these polarized, partisan times,[274] but at least FERC can send the message that it needs support rather than acting omnipotent. That message may find receptivity at least with states that are eager to find ways to better incorporate non-transmission alternatives so as to save their regions money and hassle. Ultimately, such delineation of FERC's own fallibilities and legal constraints seems an important part of being a responsible agency working with a statute designed for a different technological and regulatory era.

Conclusion

Current transmission planning processes are unlikely to result in selection and implementation of non-transmission solutions, even where they are demonstrably superior. This shortcoming is obviously bad for proponents of distributed energy. It is also bad for those who hope to implement significant but thoughtful grid expansion in the coming decades. More transmission is critically needed to update infrastructure and to keep pace with renewable resource development, but each transmission line is also a

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[272] *Cf. id.* at (manuscript 49) (finding agencies not as well situated in the deliberative process as Congress for making reforms that shift jurisdictional boundaries).

[273] *See supra* note 264-266 and accompanying text.

[274] *See* Freeman & Spence, *supra* note 25, at (page) (arguing that Congress is in a particularly pernicious period of gridlock that is absenting it from updating statutes).

fractious, expensive, and environmentally damaging endeavor. Where transmission can be avoided, it should be. States and FERC know this, but as this article has shown, processes for truly integrating non-transmission alternatives into transmission planning suffer coordination and jurisdictional challenges. Some modest FERC reforms could shed light on the extent to which non-transmission alternatives present viable solutions. More will be necessary to achieve true parity, but more seems unlikely under current jurisdictional constraints. For this reason, it is also time for a more forthright FERC approach to non-transmission alternatives, one that recognizes the limitations of a stakeholder-driven "comparable consideration" mandate and seeks creative, collaborative solutions and reforms.