Relieving the Congestion: The Eastern Interconnection Planning Collaborative

by Michelle Bailey*

Congestion on the electric transmission grid, coupled with a shortage of transmission infrastructure, presents one of the most significant barriers to renewable energy integration and advancement of the transmission grid towards a more reliable, responsive, economical and efficient energy future. The transmission grid, which was historically organized around large stationary electric power plants located in close proximity to load centers (such as urban areas), must now be redeveloped to provide for the inclusion of renewable electricity into the grid. States are developing policies for renewable energy programs which are increasing demand for renewable sources of energy; particularly wind. These renewable energy sources are typically located far from load centers and require new transmission line development in order to connect with electric load centers. Efforts to address the inadequacies of the transmission grid, however, have been slow to develop. Moreover, the quality of the U.S. transmission system has long been declining, which intensifies the need for improvements and expansion.

Historically, transmission siting and permitting have been the domain of states and regional planning authorities. The types of bulk transmission lines required to address current transmission issues often cross multiple state and regional boundaries, requiring approval from each jurisdiction. The state and regionally-based transmission planning processes have been described as “protracted and difficult” This is due, in part, to state and regional behavioral patterns that favor projects “benefit[ing] their own jurisdictions, with less concern for potential adverse impacts in others, leading to delays and higher expenses in the siting process.” The complex nature of transmission siting and permitting procedures cause delayed transmission improvements and result in a general inability of transmission to keep pace with electricity demand.

With the Energy Policy Act (“EPAct”) of 2005, Congress signaled that it was turning its attention towards transmission siting and permitting. EPAct gave the Federal Energy Regulatory Commission (“FERC”) the authority

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4. Id. at 1803,
5. Id. at 1802.
9. Meyer & Sedano, supra note 8, at E-1 and E-42.
10. Id. at E-1.
12. See Meyer & Sedano, supra note 8, at E-1.
to provide “backstop” siting authority, where FERC may override state or regional permitting decisions, and approve siting transmission facilities in congested areas.15 Congress provided $11 billion under the American Recovery andReinvestment Act (“ARRA”) of 2009 for a “bigger, better, and smarter grid” that will move renewable energy from the rural places in which it is produced to the cities where it is mostly used.”16 That same year, Congress also considered five bills that would have expanded federal authority over siting transmission lines even beyond that granted in EAPAct.17

In 2007, the Joint Coordinated System Plan (“The JCS-Plan”) was created to provide the first-ever cross-jurisdictional analysis of projected wind development and transmission needs in the Eastern Interconnection (“EI”).18 Several planning authorities in the EI initiated this effort, and integrated its study scope with concurrent research the Department of Energy ("DOE") was conducting regarding transmission integration of wind energy resources.19 The final report produced by The JCSPlan, however, lost support of the East Coast planning authorities,20 diminishing its credibility as a broadly supported study. Although The JCSPlan implemented a more interregional planning process than ever before in the EI,21 it nevertheless suffered from the same fractured and regional thinking that previously characterized EI transmission planning.22

While The JCSPlan lost its broad support Congress was considering five bills that would have expanded federal siting authority,23 but received a vociferous push back.24 States and regional planning authorities pointed out that Congress’s proposals to increase federal authority over transmission planning were ill-conceived because states and regional planning authorities possess the expertise and technical ability to conduct the high-level transmission analyses required to identify where new transmission is needed most.25 Against this backdrop, planning authorities across the EI began to organize in a new manner. On April 8, 2009, the Eastern Interconnection Planning Collaborative (“EIPC”) announced its first meeting, stating that they intended to conduct “regionally based transmission system planning analysis” that had an “interconnection-wide approach.”26 EIPC was aiming to use a collaborative, transparent, and bottom-up process to address the specific inadequacies of projects such as The JCSPlan and the congressional proposals to increase federal authority.27

After applying for, and receiving, federal funding from DOE’s ARRA program, EIPC initiated a pioneering collaborative effort.28 Indeed, EIPC is the first transmission planning effort of its geographic size and scope in the United States.

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19 The JCS Plan was initially an agreement between the Midwest ISO, PJM, Southwest Power Pool, and the Tennessee Valley Authority to perform a coordinated transmission planning study. While these planning authorities were considering their study scope, the Department of Energy (“DOE”) was also implementing its Eastern Wind Integration Transmission Study (“EWITS”). It was decided that The JCS Plan would adopt the DOE’s EWITS study scope due to their similar schedules and objectives. The JCS Plan was also expanded to include additional EI planning authorities. From 2007 to 2008 multiple meetings and workshops were held to guide the study process, and analyze its results. See THE JCSP ’08, supra note 18, at 11–12.
21 THE JCS Plan ’08, supra note 18, at 1.
22 NYSO and ISO New England alleged that the JCSPlan analysis failed to consider regional renewable energy development and obligations under the Regional Greenhouse Gas Initiative (RGGI), and expressed concern that the plan relied on future midwestern coal development despite a possible national greenhouse gas control scheme. Letter to the JCSPlan, supra note 20.
23 See generally Benedetti, supra note 17, at 253.
26 Id.
27 See id.
28 See id.
States,\textsuperscript{29} bringing together a group of stakeholders and planning authorities that have previously never worked together. This Article seeks to highlight the significance of the EIPC’s formation for transmission planning and progress in the EI by discussing the structure it established, its significant lessons learned, and make recommendations for next steps that will carry its important lessons forward. Part I briefly discusses why transmission grid development is so important, the physical and regulatory constraints on the transmission grid, and the federal regulatory response to the stalled and piecemeal state of transmission development. Part II examines how the EIPC’s formation and structure addressed both federal and EI-wide concerns by including all relevant stakeholders and interest groups in the EI. Part III examines lessons that can be drawn from EIPC’s experience for future interregional and regional transmission planning, and provides suggestions for next steps that would carry its momentum forward.

I. A Brief Introduction to the Transmission Grid and the Regulatory Environment of Transmission Planning

This section discusses the complex web of challenges facing today’s transmission grid. It first describes how physical constraints within the electric transmission grid lead to a problem known as ‘congestion’, and the numerous issues that congestion introduces. Congestion imposes real economic costs on transmission providers and electricity consumers, and leads to reliability issues that can cause blackouts.\textsuperscript{30} Furthermore, it is the congestion and other physical limitations of the existing transmission grid that constrain our ability to realize renewable energy goals.\textsuperscript{31} Expansion and improvement of the transmission grid is therefore necessary for economic, reliability, and public policy reasons. The question then becomes, what is delaying development of the transmission grid? This section next examines answers to this question, namely the regulatory hurdles to transmission planning and siting. Attempts have been made to address some of the regulatory issues; however the central need remains for improved coordination in transmission planning and siting projects.\textsuperscript{32}

A. Physical Limitations on the Transmission System

The three regions of the transmission grid in the United States are the Western Interconnection, EI, and the Electric Reliability Council of Texas (“ERCOT”). These are functionally separate transmission systems that exchange electricity at only a few highly controlled locations.\textsuperscript{33} Within the Western Interconnection and the EI, a network of investor-owned utilities, electricity cooperatives, publicly owned corporations, Independent System Operators (“ISOs”), Regional Transmission Organizations (“RTOs”)\textsuperscript{34}, and the Federal Power Marketing Administration operate the transmission grid.\textsuperscript{35} ERCOT is different however, as it is almost entirely self-operated by one ISO/RTO, rather than a network of different organization types.\textsuperscript{36}

Most consumers assume that a light will always turn on when they flip a switch, but there are real limits to the transmission grid. Transmission lines, which are used to transmit bulk electric power, are restricted in the amount of energy that they can transmit at any given time and how they transmit that energy.\textsuperscript{37} Analogously, a water pipe can only allow as much water to flow through it as will fit within it. Further, if additional pipes connect to the system, water will distribute among the pipes along the path of least resistance, not to where water is needed most. In an ideal scenario, it would not matter whether electricity generators were near or far from population centers, because the electricity could be easily carried from the place of supply to the place of demand, regardless of the condition of the transmission lines. The transmission grid is far from ideal, however, and the physical limitations of the transmission grid lead to what is known as ‘congestion’ or ‘constraints’. Congestion results in significantly reducing the amount of electricity a given transmission line can carry, requiring transmission system operators to account for this imperfection.\textsuperscript{38}

The economic and reliability impacts from congestion are significant. DOE estimated that transmission congestion resulted in $8 billion in additional charges for the EI alone in 2008.\textsuperscript{39} Additional reliability costs accrue when transmission constraints are so severe that less energy can be delivered relative to consumer electricity demands, creating problems like blackouts.\textsuperscript{40} For example, the major blackout


\textsuperscript{31} CONGESTION STUDY 2009 U.S. DEPT OF ENERGY, supra note 1, at 13.

\textsuperscript{32} See Klass & Wilson, supra note 3, at 1873.


\textsuperscript{34} Independent System Operators and Regional Transmission Organizations organize and run the deregulated electricity markets in the United States and Canada. There are ten in the United States and Canada, providing electricity to more than two-thirds of the consumers in the U.S. and more than half in Canada. The ISO/RTO COUNCIL, \url{http://www.iso-rtcouncil.com/sites/cjkhQKZPBImE/h.2603295/k.BEAD/Home.htm} (last accessed July 23, 2012). These entities operate the centralized and spot power markets. These entities emerged in the mid 1990s to create a more competitive, transparent, and nondiscriminatory electricity market. See AM. PUB. POWER ASSOC., supra note 33, at 14–15.


\textsuperscript{36} U.S. DEPT. OF ENERGY, supra note 1, at 1.

\textsuperscript{37} Id.

\textsuperscript{38} David Cay Johnston, \textit{Grid Limitations Increase Prices for Electricity}, N.Y. Times (Dec. 13, 2006), \url{http://www.nytimes.com/2006/12/13/business/1power.html?pagewanted-all}.

in the Upper Midwest in 2003, caused fifty million people to lose power and $6 billion to be lost in economic activity. 41

Another cost of transmission constraints is the obstacle they pose to new energy development, particularly renewable energy projects. 42 Renewable energy projects must be sited where the resource exists—that is, where the sun shines and wind blows—and are necessarily limited to specific locations. 43 Wind resources are generally located offshore and in the middle of the United States, and the best solar development potential is located in the Southwestern United States. 44

Because the transmission system is responsible for moving the energy from these often-remote sources of renewable power to population centers, limitations on the transmission system play a key role in inhibiting the development of these projects. 45 A group of transmission providers wrote to FERC in 2009, warning that, “[t]he lack of transmission infrastructure is among the critical obstacles to the development of wind, solar, and other forms of renewable energy which are frequently located far from major electric load centers.” 46 It is widely agreed that increasing reliance upon renewable energy sources, “will be crucial both to increase energy security and attempt to mitigate effects of climate change.” 47 Despite policies encouraging, and in many cases requiring, renewable energy use, 48 development of these projects has been slowed due to capacity limitations on the transmission system or a complete lack of transmission in some areas. 49

The physical limitations of the transmission system have clear implications for increased electricity prices, reliability concerns, and renewable energy goals. However, addressing these clear physical constraints is not easy. 50 Efforts have been made at the federal level to remove the barriers to large-scale transmission projects, but they have had limited success to date. 51

B. Regulatory Hurdles to Transmission Planning and Building New Transmission Lines

As discussed, any effort to advance renewables development requires a massive expansion of transmission infrastructure due to congestion on the existing transmission grid, and the dispersed nature of renewable energy resources. 52 Yet, any effective planning, siting, or building of new transmission infrastructure that crosses multiple jurisdictions is constrained by a complex web of economic, political, environmental, legal, and regulatory implications at the state, regional, and federal levels. 53 Such complexity in the planning and development process is at the root of both the stunted pace of renewable energy development and the slow response to the congestion issues discussed in Section I.A. 54

Professors Klass and Wilson have identified three major barriers to transmission grid and renewables expansion: (1) transmission siting and permitting is primarily the domain of the states who frequently consider only in-state benefits for projects that address a regional or national need; (2) there is no central robust federal authority or regional coordinating authority that can plan and site transmission infrastructure, and; (3) the question of how to allocate costs for transmission infrastructure is extremely difficult, especially where transmission lines must cross state borders. 55 The resolution of each of these three hurdles is critical to the evolution of the current transmission regime. The significance of the EIPC is that by developing a process for conducting coordinated EI-wide transmission analysis, it has provided insights into what is possible within the existing regional planning processes, so that perhaps they could someday resolve these challenges. 56 This section will discuss the hurdles to transmission and renewables development by building off of the three challenges as presented by Professors Klass and Wilson above.

1. Transmission Siting and Permitting Structures

The authority to approve and permit major transmission projects has traditionally belonged to the states. 57 In theory, EPAct expanded federal authority for permitting transmis-

42. U.S. DEP'T OF ENERGY, supra note 1, at 13.
43. See Visualizing the Electric Grid, supra note 18 (showing wind, solar, and geothermal development potential in the United States by congestion area).
44. Id.
45. Id. (explaining that “the significant potential sources of renewable energy are constrained in accessing appropriate market areas by lack of adequate transmission capacity”).
47. Diamond, supra note 11, at 217. Note that while renewable power sources will play an increasingly critical role in addressing climate change and enhancing energy security, any solution must also address existing carbon sources of energy. Rossi, supra note 2 at 1016, n. 1.
49. U.S. DEP'T OF ENERGY, supra note 1, at 1.
50. See Jennifer E. Gardner & Ronald L. Leht, Wind Energy in the West: Transmission, Operations, and Market Reforms, 26 NAT. RESOURCES & ENV'TY 13, 13 (Winter 2012) (describing the “five primary obstacles inhibiting the development of a robust U.S. transmission system that can best utilize renewable energy [as]: (1) the location-constrained nature of renewables; (2) the need for improved electric grid flexibility; (3) the need for transmission expansion; (4) solving cost allocation issues related to transmission expansion; and (5) determining fair transmission access rates”).
51. See generally Diamond, supra note 11, at 218, 220 (describing the need for a broad, national approach to the grid and resistance to utilities’ eminent domain power in EPACT).
52. Id. at 217–218
53. See generally Klass & Wilson, supra note 3; Hurst & Kirby, supra note 7, at D-1, D-3.
54. U.S. DEP’T OF ENERGY, supra note 1, at 25.
55. Klass & Wilson, supra note 3, at 1804.
57. See Norris & Dennis, supra note 48, at 5 (“State regulators typically also have authority to approve the siting of electricity infrastructure within their state, including transmission . . . lines . . .”).
sion projects, however in practice the authority to approve or deny a permit for a transmission project that crosses state borders remains largely with the states.

The history behind state control of intrastate transmission projects is long and there are legitimate reasons why retention of state authority in this domain is important. At the same time, this lack of federal oversight has also fostered piecemeal transmission planning and the creation of roadblocks to projects with national importance. For instance, many state Public Utility Commissions are directed by state statute to look at a proposed transmission line’s benefit to in-state customers only, making it “extremely difficult politically, if not outright illegal, to site a line to export state power to nearby population centers.” By way of example, Clean Line Energy Partners proposed a transmission line that would transmit energy from Midwest wind farms to the Southeast, while passing through Arkansas and Oklahoma, but providing no energy to residents of those states. Arkansas authorities rejected the project in 2011 because the state determined that it did not meet the definition of a transmission utility because “it was not providing power to Arkansans.” Clean Line President Michael Skelly explained that companies like his often encounter barriers from State rules due to the inability to ‘fit’ regional projects like ours into the existing regulatory framework. A key reason behind a state’s refusal to permit projects without direct benefits to in-state customers may be the state’s failure to distinguish the questions of whether to site the line at all and whether to pass the costs of the line onto ratepayers in the state.

In an attempt to encourage interstate transmission siting, EPAct authorized states to use interstate compacts to create regional transmission siting agencies. This provision allows three or more contiguous states to create regional transmission siting agencies; these regional agencies would facilitate and administer the siting of transmission projects within the states. No states have yet taken advantage of this opportunity. If the EIPC results in long-term collaboration across the EI, however, it may serve as a model for future interstate compacts. Compacts have the potential to lead to more efficient and effective planning and construction of transmission infrastructure, especially with regional and interstate projects. In the absence of states creating such interstate compacts, however, transmission siting has been a piecemeal process in which states and organized electricity markets only consider their own transmission needs.

2. Federal Attempts to Expand Authority and Improve Coordination for Planning and Siting Transmission Infrastructure

Stronger federal authority to implement transmission projects is one proposed solution for overcoming the lack of interstate cooperation with transmission siting, and the slow pace of interstate transmission development. This section discusses actions taken by Congress and the Executive branch to increase federal involvement in transmission planning and siting, and by FERC to mandate improvement of the regional transmission planning processes. It will first look at the EPAct, which was Congress’s boldest move so far to expand federal oversight, and subsequent court rulings that have limited the extent of FERC’s statutory authority under EPAct. It becomes apparent that this congressional attempt has remained largely unsuccessful. The Executive Branch has taken efforts, however, that are expanding federal involvement in transmission planning and siting. Secondly, this section discusses FERC Order Nos. 890 and 1000, which are aimed at improving regional coordination for transmission planning.

59. 16 U.S.C. § 824p(b)(1)–(2) (2006) (giving FERC authority to issue permits when (1) the state does not have authority to approve the transmission facilities or consider the interstate benefits; (2) the applicant for the permit is a transmitting utility that must pass through a state, but does not serve customers in that state; (3) the state has withdrawn approval for not more than one year pursuant to applicable law or after the designation of the relevant interstate transmission corridor, whichever is later; or (4) the state conditioned approval in a way that the proposed project will not significantly reduce transmission congestion in interstate commerce or is not economically feasible).
60. Klass & Wilson, supra note 3, at 1819, 1850, 1854.
61. Benecheddi, supra note 17, at 256.
62. Id. at 270, 272 (discussing how national jurisdiction eliminates the opportunity for local expert input, while localities bear the brunt of the new lines’ impacts).
63. Norris & Dennis, supra note 48, at 4, 6. It is important to add, however, that it would be inaccurate to imply that there have been widespread examples of one state holding back a multistate project. Id. at 6. Nevertheless, “the potential for such project ‘veto’ by one state can unquestionably add to the uncertainty of developing such a project.” Id.
64. Klass & Wilson, supra note 3, at 1872.
66. Id.
67. Id.
70. Id. FERC shall not be able to issue a permit for a transmission project that is within a state in such a compact unless “the members of the compact are in disagreement.” § 824p(i)(4). However, if the Secretary of FERC, after notice and an opportunity for a hearing, finds that a State Commission or other entity with the authority to approve such facilities has withheld its approval for more than 1 year, or conditioned its approval of the project so much that the proposed project will not significantly reduce transmission congestion or is not economically feasible, then the FERC may also be able to issue a permit for a transmission project in such a state. § 824p(b)(1)(C).
72. Klass & Wilson, supra note 3, at 1817, 1868.
73. Katherine Ling, DOE Provides $60M For Transmission Planning, E&E Daily (Dec. 18, 2009), http://www.eenews.net/eenewspm/stories/85899/search?keyword=katherine-ling; see Meyer & Sedano, supra note 8, at 1 (reviewing transmission siting and permit process, and documenting a host of cases where agencies’ disparate priorities and failures to effectively communi- cate with one another have substantially impeded the construction of transmis- sion lines).
a. Congressional and Executive Branch Actions

EPAct, which amended the Federal Power Act, was Congress’s initial attempt to deliver a measure of federal authority to the transmission siting process, without taking too much power away from the states. In other words, it was an attempt to respond to the tension between local opposition to major electricity infrastructure projects, which is a frequent reason for state denial of siting permits, and the “need to expedite the construction of critical transmission lines.”

The revolutionary element of EPAct was its grant of increased responsibility to FERC. EPAct authorizes FERC to issue permits in DOE-designated National Interest Electric Transmission Corridors (“National Corridors”), provided that FERC determines that the state approval process has, in certain ways, hindered development of the project. After FERC acts, if the transmission permit holder cannot negotiate a right-of-way (“ROW”) across private property, the permit holder may take the ROW through eminent domain. Thus, it gives FERC “backstop” siting authority when the state approval process fails to generate a desired outcome.

Although the granting of backstop siting authority to FERC in EPAct has been described as “[o]ne of the federal government’s most assertive actions in the energy realm,” in subsequent years it has become clear that it did little to truly expand federal authority, in large part due to court decisions. In Piedmont Environmental v. Federal Energy Regulatory Commission, the Fourth Circuit struck down FERC’s interpretation of its backstop authority. At issue was FERC’s authority to issue a permit if a state has “withheld approval for more than 1 year after the filing of an application seeking approval pursuant to applicable law or 1 year after the designation of the relevant national interest electric transmission corridor, whichever is later.”

The court reasoned that “withheld” does not include “denied.” Rather, the court explained that the statute provides backstop authority to FERC only “when a state commission is unable to act on a permit application in a national interest corridor, fails to act in a timely manner, or acts inappropriately by granting a permit with project-killing conditions.” By specifying that FERC is allowed to use its backstop siting authority only in situations where the state has failed to take action, rather than when the state has acted and denied an application, the Fourth Circuit narrowed the potential scope of the EPAct.

Another judicially-imposed limitation to the federal power granted in EPAct came from the Ninth Circuit’s 2011 decision in California Wilderness v. Department of Energy. Here, the court found that the DOE’s 2009 Congestion Study and the resulting National Corridor determinations were invalid based on the DOE’s failure to adequately consult with states, as required by EPAct. Consequently, since the passage of EPAct, DOE has had limited ability to site National Corridors. Furthermore, within the designated Eastern and Western National Corridors, no other projects have applied for FERC to enforce its backstop authority.

While the EPAct aimed at expanding federal authority to plan and permit transmission projects in areas of national interest, thus far it has been severely constrained. Piedmont Environmental v. Federal Energy Regulatory Commission limited the circumstances in which FERC can utilize its backstop siting authority, and California Wilderness v. Department of Energy invalidated DOE’s previous National Corridor determination process. Congress’s attempt to develop a more robust federal coordinating authority through the EPAct has not been successful.

78. See 16 U.S.C. § 824p(b) (2006); see also Debbie Swanstrom & Meredith M. Jolivet, DOE Transmission Corridor Designations & FERC Backstop Siting Authority: Has the Energy Policy Act of 2005 Succeeded in Stimulating the Development of New Transmission Facilities?, 30 Energy L.J. 415, 431 (2009) (discussing § 824p(b) authority noting that FERC can site transmission lines within National Corridors under certain circumstances where, for example, a state withholds approval of the project for more than one year, or imposes onerous conditions which effectively destroy the economic viability or benefits of a project).
80. Diamond, supra note 11, at 217.
81. See Behr, supra note 65 (describing a proposal from the Obama administration to delegate to FERC the authority held by DOE under the EPAct to designate National Corridors. This would undermine the 2009 and 2011 Court of Appeals rulings that limited EPAct’s federal transmission siting authority, by giving FERC the ability to “conduct engineering reviews and oversee environmental assessments of transmission project proposals at the same time that these issues are under consideration by state authorities. Under the existing process, FERC begins its review after the state actions conclude.”).
83. Id.
86. Piedmont Envtl. Council, 558 F.3d at 315.
87. Dorsi, supra note 85, 596.
88. See generally Cal. Wilderness Coal. v. U.S. Dept. of Energy, 631 F.3d 1072 (9th Cir. 2011) (“The failure to consult was not some technical error, but resulted in a decision making process that was contrary to that mandated by Congress and one that deprived DOE of timely substantive information. We conclude that DOE’s failure to consult with the affected States, as directed by Congress, was not harmless error.”).
89. Id. at 1095.
90. See Behr, supra note 65.
91. Id. (only one project has applied for FERC to enforce its backstop siting authority, and it was subsequently withdrawn”).
92. See Dorsi, supra note 85.
93. Cal. Wilderness Coal., 631 F.3d at 1095.
94. In 2009 and 2011 Congress moved to empower the Executive branch initiated multiple efforts to expand federal authority in transmission planning and siting beyond that granted in EPAct (See Behr, supra note 65; See Benedetti, supra note 17, at 261–67), in part to specifically overcome the constraints of the Ninth and Fourth Circuit’s rulings. See id. The Congressional proposals considered in 2009 would have granted FERC dramatically increased authority to facilitate the development of interstate extra-high voltage transmission lines, to enable development of wind and solar energy to population centers. See Benedetti, supra note 17, at 261–67. However, these considerations were unsuccessful. See Klass & Wilson, supra note 3, at 1816–20. Additionally, in 2011 the Obama Administration created a plan that would have delegated the DOE’s authority under EPAct to designate National Corridors to FERC. See Behr, supra note 65. It was hoped that this strategy would revitalize FERC’s abilities under EPAct. See id. Due to the widespread criticism that erupted from state public utility commissions, however, the Administration quickly withdrew the proposed designation. See Lynn Garner, Energy Department Drops Plan to Cede Power to FERC for Siting Transmission Lines, 42 BNA Envtl. Rep. 2297 (Oct. 14, 2011).
An area that has seen expansion of federal oversight in transmission siting is in the Executive Branch. The Obama Administration created the Interagency Rapid Response Team for Transmission (“RRTT”) to “improve the overall quality and timeliness of electric transmission infrastructure permitting, review, and consultation by the Federal government on both Federal and non-Federal lands.” Nine federal agencies are working together to accomplish these goals, primarily by coordinating the permitting and review processes of the federal and state agencies involved. The RRTT has selected seven interstate transmission pilot projects, each of which come from projects suggested by the Eastern Interconnection States Planning Council (“EISPC”), which is the state entity working in conjunction with EIPC, and the Western Electricity Coordinating Council, which is the Western Interconnection’s corollary to EIPC. The RRTT will attempt to expedite the permitting and construction of these transmission projects, which traverse Arizona, Colorado, Idaho, Minnesota, New Mexico, Nevada, Wyoming, Utah, New Jersey, Pennsylvania, Oregon, and Wisconsin.

b. FERC Orders Aimed at Improving Coordination in Transmission Siting and Planning: Order Nos. 890 and 1000

In an effort to improve regional coordination in the transmission planning and siting process, FERC established Order Nos. 890 and 1000. Order No. 890 was issued in 2007, and required transmission providers to develop certain planning processes with the stated intent of making those processes more transparent and coordinated. By requiring each public utility transmission provider to develop a planning process that satisfied nine specific planning principles, Order No. 890 aimed at addressing the prior lack of specificity regarding treatment of stakeholders and the potential for undue discrimination. The nine planning principles are: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.

Order No. 1000 was issued in July 2011, and expands on Order No. 890 by establishing requirements that direct states and organizations to consider the benefits of interstate lines. Order No. 1000 does this by requiring transmission providers to comply with Order No. 890; identify transmission needs driven by public policy requirements established by state or federal laws or regulations and evaluate proposed solutions to those needs; and work with neighboring transmission-planning regions to identify mutual transmission needs and potential efficient or cost-effective solutions to these. One of the more significant elements of Order No. 1000 is that it has articulated “public policy benefits” as a new type of transmission-related benefit, and encourages transmission lines that serve renewable energy goals to be given priority and made more affordable. Together, Orders No. 890 and 1000 have attempted to improve coordination among states and transmission providers, so that transmission planning is more interregional and attentive to transmission needs that serve public policy goals.

3. Cost Allocation

One of the greatest challenges for interstate transmission projects is answering the question of who should pay for the costs of the project, which is generally known as “cost allocation.” Traditionally coast allocation has been governed by the “beneficiary pays” approach, where rates reflect the costs caused by the paying customer. The logic behind this is that customers who benefit from a new facility are seen as having contributed to the costs of that facility.

With the need for more interstate transmission lines, some of which cross state borders without providing electricity to customers in that state, the issues of transmission siting and cost allocation collide. For example, although customers in a hypothetical state may not directly benefit from the electricity traversing the line, they do reap the indirect benefits of a more reliable and efficient transmission grid overall. As the transmission grid ages and demand increases for renewable sources of energy in rural areas, the line begins to blur between who are and who are not the beneficiaries of interstate high voltage transmission lines.

FERC revised the cost allocation regime to address changing transmission needs in Order No. 1000. In Order No. 1000, FERC left the issue of cost allocation up to regional entities, but gave itself the authority to “step in” when a region cannot agree. FERC’s interest was to give regional planning authorities additional authority to spread transmission costs regionally, in an effort to facilitate the expansion of regional transmission projects that cross state borders.

96. Id.
97. See id.
98. See id.
103. Id.
In response to Order No. 1000 multiple regional entities have attempted to change the traditional cost allocation regime by developing novel regional cost allocation methodologies. One of the more promising of these recent attempts is the Multi-Value Project (“MVP”) methodology created by MISO. The MVP system is designed to allocate the cost of regionally oriented, and regionally beneficial transmission projects to the beneficiaries across the region. To be considered an MVP project, applicant projects must meet at least one of three criteria: (1) be developed through MISO’s transmission expansion planning project for the purpose of meeting energy policy mandates or laws; (2) provide multiple economic benefits across multiple regions, and have a total project benefit-cost ratio greater than 1.0 according to the MVP-defined benefit-cost methodology; or (3) resolve one issue related to a regional reliability standard and one economic-based issue that benefits multiple regions, and have a total project cost that is less than the total project benefits. In December 2010, FERC approved the MVP methodology. The MVP methodology recognizes that customers receive benefits from regional policy goals and mandates, such as Renewable Portfolio Standards, in addition to the more commonly understood reliability and economic benefits. “By expressly considering such goals, MVP pricing attempts to move beyond historical methods of allocating costs and better align transmission line planning and cost allocation with state-level renewable energy policies.” Critics have emerged, however, saying that it replicates the same deficiencies of previous cost sharing methods that courts have rejected because the benefits are not sufficiently correlated to the costs. Nevertheless, “[a]s it stands, all indicators are that MVP pricing may be the best plan to date to facilitate equitable transmission line buildup and to meet renewable energy needs.”

While regional cost allocation options are emerging which may foster transmission development, interstate transmission projects are still challenged by the state-by-state siting approval process, as discussed above in Part I.B. Without a regional, interconnection-wide, or national coordinating entity that can resolve cost allocation and transmission siting simultaneously, the transmission grid will likely continue to evolve in a slow and piecemeal fashion.

II. The Eastern Interconnection Planning Collaborative

Early 2009 was a perfect storm for the fate of the EI. This period saw the confluence of increased attention to the inadequate state of the transmission grid, growing demand for renewable energy due to state policies, a new Presidential administration, Congressional exploration of several options to strengthen federal authority in transmission siting, and dissatisfaction among some of the planning authorities in the EI over the JCSPlan process and results. The planning authorities and states within the EI recognized that in order to keep transmission siting and planning within their domain, action must be taken to address the grid’s reliability issues while demonstrating the potential for interconnection-wide coordination. It was from within this context that the EIPC was formed. This section discusses how the EIPC came together, the goals and project design of its original scope of work, and explores in depth the structure it created for ensuring robust stakeholder involvement. The unique structure of the EIPC is the heart of what it can offer to future coordinated transmission planning processes.

A. Initiating “Bottom Up” Transmission Planning

On April 8, 2009, seventeen planning authorities from across the EI, including ISOs/RTOs, investor-owned utilities, and municipal and cooperative systems, met for the first time to discuss EI-wide transmission planning and the creation of the EIPC. These planning authorities were aimed at promoting and improving bottom-up transmission planning in direct response to the potential top-down suggestions before Congress at that time. Between April and May, the number of planning authorities involved grew. An EIPC news release on May 22, 2009, announced that twenty-two planning authorities were now involved in the burgeoning effort to coordinate existing transmission plans, conduct reliability analyses of combined transmission plans, and study the impact of public policy goals on future transmission needs.
One of the group’s initial goals was to aggregate existing regional transmission plans, in order to “analyze, and as needed, enhance” their regional expansion plans that had been developed under FERC Order No. 890.\textsuperscript{130} This was important to the group because their intent was to “build upon, rather than substitute for” the existing planning processes developed by the planning authorities as required by Order No. 890.\textsuperscript{131}

In June, DOE announced a funding opportunity for interconnection-wide transmission planning in each of the three interconnections.\textsuperscript{132} This funding came from ARRA, which directed DOE to provide assistance for the development of interconnection-based transmission plans for the three interconnections.\textsuperscript{133} On September 9, 2009, EIPC applied\textsuperscript{134} and on December 18, 2009, received $16 million, which was the largest award from the DOE’s transmission planning grants.\textsuperscript{135}

The number of involved planning authorities continued to grow, showing that some entities across the EI took longer than others to join the process. By the time EIPC received funding from DOE, twenty-four planning authorities were involved.\textsuperscript{136} At the height of EIPC’s DOE-funded efforts it consisted of twenty-five planning authorities, collectively responsible for the regional planning of approximately 95% of the customer demand in the EI.\textsuperscript{137}

The tasks enumerated in the original DOE grant were completed at the end of 2012, with the results of its efforts described in the final Phase II Report.\textsuperscript{138} While the work of the EIPC continues, albeit with a slightly modified structure and number of involved planning authorities\textsuperscript{139}, this Article discusses the structure the EIPC had when carrying out the original DOE-funded scope of work because this is where its novel stakeholder process was most utilized.

B. Project Objectives

The two central objectives of EIPC’s original DOE-funded project were to: (1) develop a process for combining the modeling and regional transmission plans from across the entire EI, and conduct interregional analyses to identify potential conflicts and efficiencies between regional plans; and (2) analyze various potential transmission build-out scenarios based on broad stakeholder input and the consensus recommendations of the Stakeholder Steering Committee (“SSC”) in order to assess interregional options and policy decisions.\textsuperscript{140}

Underlying these goals were the central themes that had been articulated in the pre-DOE funding EIPC meetings between planning authorities: openness, transparency, collaboration, and building upon existing planning processes and projects so as to “[l]everage the existing planning expertise.”\textsuperscript{141} As further testament to EIPC’s commitment to having broad stakeholder involvement, its proposal to DOE explicitly included provisions for funding NGO involvement in the SSC and stakeholder Work Groups.\textsuperscript{142} The SSC ultimately decided to also reimburse some of the involved state consumer advocate offices for travel costs.\textsuperscript{143}

C. Project Phases I and II

In EIPC’s original proposal for DOE funding, the broader goals were distilled into a group structure, specific deliverables, project objectives, and a timeline.\textsuperscript{144} In order to accomplish their objectives and deliverables, EIPC created a two-phased approach. Phase I, which took place from 2010–2011,\textsuperscript{145} consisted of aggregating the existing regional transmission expansion plans into one “roll-up report”\textsuperscript{146}, performing interregional analysis across transmission plans to identify gaps and opportunities for efficiencies between regions, and establishing the SSC collaboratively with the planning authorities, stakeholders, and the project facilitator, The Keystone Center (“Keystone”).\textsuperscript{147} During this phase, the SSC decided on eight future policy scenarios to study and

\begin{itemize}
  \item \textsuperscript{130} Phase I Report, supra note 18, at 2.
  \item \textsuperscript{131} Project Narrative, supra note 128, at 5.
  \item \textsuperscript{134} See generally Project Narrative, supra note 128.
  \item \textsuperscript{135} See Ling, supra note 73.
  \item \textsuperscript{136} Comments to FERC, supra note 29, at 1.
  \item \textsuperscript{139} See Welcome to EIPC Website, E. Interconnection Planning Collaborative, http://www.epiconline.com/ (last accessed Jan. 29, 2014) (for the current list of involved planning authorities); See infra note 156, for a description of the EIPC’s current work and structure.
  \item \textsuperscript{140} Project Narrative, supra note 128, at 23–24.
  \item \textsuperscript{141} Comments to FERC, supra note 29, at 6.
  \item \textsuperscript{142} Project Narrative, supra note 128, at 13.
  \item \textsuperscript{144} Project Narrative, supra note 128, at 2, 15–19, 23–32.
  \item \textsuperscript{146} The aggregation of regional transmission expansion plans are called “roll-up reports” because these reports roll each transmission plan into one interconnection-wide analysis.
  \item \textsuperscript{147} The Keystone Center was subcontracted to provide assistance in both developing the EIPC’s proposal to the DOE and forming the SSC. Interview with Catherine Morris, now Sr. Mediator with Consensus Building Institute, Lead Convenor, E. Interconnection Planning Collaborative (July 11, 2012) [hereinafter Interview with Morris]; see also Phase I Report, supra note 18, at 9 (noting that Keystone was subcontracted to manage the stakeholder process). They also continued to provide facilitation assistance throughout Phase I and II. Project Narrative, supra note 128, at 6.
The scenarios studied in Phase I modeled how electric generation resources could expand under different policy futures. The intent of the original DOE-funded Phase II, which was completed in 2012, was to study in detail the additional high-voltage transmission facilities that would be necessary to support the generation expansion from the three selected scenarios. In Phase II, EIPC analyzed the transmission options for each scenario at the 230 kV level and above, studying their reliability and production cost implications, and estimating associated costs such as electricity generation and transmission. What Phase II and the EIPC process did not do is choose which types of generation should be built or pick specific routes for high-voltage transmission lines. In fact, even with the high level of detail analyzed in Phase II, the planning authorities in the EIPC made clear that “the results are indicative only and not representative of actual project solutions, which will be determined in regional level transmission planning processes as future resource requirements become more certain.”

The focus of Phase II was the analysis, and its results are not meant to suggest specific transmission project solutions, but rather provide general information about the transmission related impacts of different public policy options.

### D. The Structure of EIPC: Many Committees and Many Stakeholders

The two key bodies of the EIPC that carried out the work in the original DOE-funded project were the Stakeholder Steering Committee (“SSC”) and the Analysis Team. The SSC is a multi-stakeholder body, and in the original DOE-funded project it provided consensus input on what analysis should be conducted by the Analysis Team during Phase I and II. The Analysis Team was made up exclusively of the initial twenty-five planning authorities and was responsible for performing the technical modeling and analysis in conjunction with modeling subcontractors. Within the SSC and Analysis Team were numerous working groups, task forces, and committees.

1. Analysis Team

The Analysis Team was comprised of the twenty-five planning authorities, including the eight Principal Investigators, which are planning authorities that took on an additional

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148. The eight futures studied in Phase I were: (1) business as usual; (2) a significant reduction in carbon dioxide in the near term, a forty-two percent reduction by 2030, and an eighty percent reduction by 2050; (3) assumes the same goals as defined in (2), except “Super-Regions” will be designated to encourage selection of local resources first; (4) assumes overall energy demand is drastically reduced through energy efficiency, demand response, distributed generation, and universal deployment of smart grid advanced metering infrastructure; (5) assumes a national RPS is established requiring each load serving entity to obtain 30% of its electricity from renewable resources by 2030; (6) assumes the same goals as defined in (5), except Super-Regions will be designated to encourage selection of local resources first; (7) assumes there will be a significant number of nuclear facilities developed in the Eastern Interconnection, including the small modular nuclear facilities under the sensitivity run, and extension of existing plant life and the construction of new large facilities; and (8) assumes carbon constraint goals are a 42% reduction by 2030 and an 80% reduction by 2050, with the electricity sector responsible for 60% of the total emission reductions; this future also assumes the same RPS goals as defined in (5), except Super-Regions will be designated to encourage selection of local resources first. Press Release, E. Interconnection Planning Collaborative, Eastern Interconnection Grid Planning Authorities to Study Set of Stakeholder-Identified Electric System Futures (May 23, 2011) [hereinafter Press Release, May 23, 2011], available at http://www.eipconline.com/uploads/EIPC_to_Sudy_Electric_System_Futures_05212011.pdf.

149. The three scenarios selected for further study in Phase II were: (1) “Nationally-Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response; (2) Regionally Implemented National Renewable Portfolio Standard; and (3) Business As Usual.” Phase I Report, supra note 18, at 69–73.

150. Phase I Report, supra note 18, at 37.

151. Id. at 76.

152. Id. at 76; Phase II Report, Part I, supra note 138, at 2. In addition, a number of sensitivities were studied in relation to each scenario. The sensitivities included analyzing the amount of wind curtailment in scenario 1, as well as high loads and high gas prices in scenario 3. Id. at 24–25.


156. PROJECT NARRATIVE, supra note 128, at 18. The deliverables described in the original scope of work that DOE funded in 2009 were completed by the end of 2012. However, the work of EIPC continues in two directions. The first direction, referred to as “the non-DOE grant activities” because it is funded solely by the planning authorities now, is similar to what was conducted in Phase I and II with transmission planning “roll-up” analyses, scenario development, and transmission build-out analyses. There is one critical difference, however, between the current EIPC structure in the non-DOE grant activities, and the EIPC structure utilized in the original DOE-funded project: the SSC is no longer involved. Stakeholder involvement is only accomplished through the FERC-approved regional planning processes. EIPC STAKEHOLDER PROCESS DESIGN FOR NON-DOE GRANT ACTIVITIES (May 28, 2013), available at http://www.eipconline.com/uploads/EIPC_Stakeholder_Process_-2013-05282013.pdf. The second direction continues to be DOE-funded, because DOE provided EIPC an extension in order to study the interface between the natural gas and electric systems. The DOE-funded gas-electric interface study is also performed by the initial group of planning authorities, yet it does retain SSC involvement. However, the SSC is advisory only and has no decision-making authority. Thus, the scenarios are not being designed through the same consensus-based process utilized in the original DOE-funded project.


158. PROJECT NARRATIVE, supra note 128, at 24.

159. E. Interconnection Planning Collaborative, Eastern Interconnection Planning Collaborative Analysis Team Agreement 31 (rev. Dec. 22, 2009) [hereinafter Analysis Team Agreement], available at http://www.eipconline.com/uploads/EIPC_Planning_Authority_Agreement_Revision_2_-_122209.pdf. The modeling subcontractors are the Charles River Associates and Oak Ridge National Laboratory, who work with the Analysis Team to develop the modeling capabilities required to conduct the analysis. PROJECT NARRATIVE, supra note 128 at 6.

160. See discussion infra Parts II.D.1.–II.D.2.
leadership role.\textsuperscript{160} The Analysis Team’s primary responsibility was to “[develop] interconnection-wide transmission system models and [conduct] the technical analyses consistent with regional plans,” in collaboration with a body of stakeholders.\textsuperscript{161}

The planning authorities that were involved in the Analysis Team are entities listed on the North American Electric Reliability Council (“NERC”) compliance registry as Planning Authorities representing the entire EI.\textsuperscript{162} The Analysis Team was further structured to include an Executive Committee, which addressed governance and managed finances.\textsuperscript{163}

The eight Principal Investigators within the Analysis Team acted as treasurer for funds received from DOE, and were financially responsible for budget over-runs.\textsuperscript{164} In addition, each Principle Investigator agreed to provide their own internal resources to support a designated individual within their organization to carry out the responsibilities of EIPC and the Analysis Team.\textsuperscript{165}

2. Stakeholder Steering Committee (SSC)

Forming the SSC was a “significant milestone” for the future of the EI.\textsuperscript{166} Never before had stakeholders from all major interest groups in the EI come together to consider future transmission scenarios and needs.\textsuperscript{167} Additional pioneering aspects of the SSC are the model it developed for interregional stakeholder involvement, and the use of consensus-based decision making for stakeholder input in a field that is most accustomed to involving stakeholders through either “majority rule” or in an advisory capacity only.\textsuperscript{168}


161. Comments to FERC, supra note 29, at 1.

162. Phase I Report, supra note 18, at 2; Project Narrative, supra note 128, at 2.

163. Project Narrative, supra note 128, at 19.

164. Analysis Team Agreement, supra note 158, at 3, 12–19.

165. Project Narrative, supra note 128, at 20.

166. Phase I Report, supra note 18, at 9.

167. Id.

168. The regional planning processes that planning authorities have developed in accordance with FERC Order No. 890 and 1000, while each unique, in general more closely follow Robert’s Rules of Order in their formality and use of majority-rule, rather than consensus-based decision making. Interview with Morris, supra note 147. Robert’s Rules of Order is a formalized process of decision making “based on the rules and practices of Congress”, and which presumes “that parliamentary procedures (and majority rule) [offers] the most appropriate model for any and all groups.” The important distinction is that rather than seeking broad support on decisions in the form of consensus, Robert’s Rule uses majority rule. Lawrence Susskind, An Alternative to Robert’s Rules of Order for Groups, Organizations, and Ad Hoc Assemblies That Want To Operate By Consensus, in The Consensus Building Handbook 5 (Lawrence Susskind et al. eds., 1999) [hereinafter Susskind et al., The Consensus Building Handbook].

a. The Composition of the SSC and Process for Selecting Participants During the Original DOE-Funded Phase I and II Project\textsuperscript{169}

The SSC is fairly complex, with numerous elements built in to ensure representation of the diversity of interests in the EI and sufficient regional representation, while simultaneously maintaining a small enough group of core representatives so that consensus decisionmaking was possible. There were eight stakeholder “sectors” in the SSC, each with representatives, for twenty-nine SSC representatives in total.\textsuperscript{170} The stakeholder sectors, and the number of seats in the SSC allotted to each, were as follows\textsuperscript{171}:

1. (3) Transmission Owners and Developers
2. (3) Generation Owners and Developers (minimum 1 renewable, minimum 1 non-renewable)
3. (3) Other Suppliers (e.g. power marketers, energy storage, distributed generation, demand-side resources) (minimum 1 demand-side resources representative)
4. (3) Transmission-Dependent Utilities, Public Power, and Coops (e.g. municipal utilities, rural coops, power authorities) (minimum 1 public power or coop transmission-dependent utility representative)
5. (3) End Users (e.g. small consumer advocates, large consumers) (minimum 1 state consumer advocate agency)
6. (3) Non-Governmental Organizations (e.g. climate change and energy, land and habitat conservation)
7. (10) State Representatives (chosen by the Eastern Interconnections States’ Planning Collaborative)\textsuperscript{172}
8. (1) Canadian Provincial representative

169. The EIPC planning authorities made significant changes to the structure and role of the SSC when Phase II was extended beyond 2012 to include the gas-electric interface study, after the original Phase I and II tasks were completed. These changes included the transformation of the SSC from a consensus-based decision-making body to an advisory body, and the planning authorities’ recommendation for the SSC to include natural gas representatives to its membership. See generally Stakeholder Process Enhancements for the EIPC Gas-Electric System Interface Study for Portions of the North American Eastern Interconnection DE-0000343, Recovery Act Topic A, E: Interconnection Planning Collaborative (June 6, 2013), http://www.epionline.com/Gas-Electric_Documents.html.


171. Id.

172. The states had more representation and a different stakeholder selection process than the other sectors. The state representatives were selected by the Eastern Interconnection States’ Planning Collaborative, which is the state entity that received DOE funding to participate in the process and conduct independent research. Early on, DOE stipulated that the states must get at least one-third of the seats on the stakeholder steering committee. Project Narrative, supra note 128, at 18. The states originally proposed that states hold closer to half of the seats on the SSC, but eventually settled for ten out of the twenty-nine seats. Interview with Morris, supra note 147.
The stakeholders that made up each sector were representatives from “industry, state regulatory commissions, regional transmission organizations, environmental groups and consumer advocate organizations.” A relevant stakeholder was defined broadly to include anyone “that has an interest in the outcomes of the EIPC project.” Although the criteria for being considered a stakeholder may be broad (with the exception of the Transmission Owners and Developers sector), there was a specific set of criteria for being an SSC member. These criteria included elements such as seniority and credibility within one’s organization and sector, and a demonstrated ability to work collaboratively with others.

Four of the sectors created subsectors. The sectors for Generation Owners and Developers, Other Suppliers, Transmission-Dependent Utilities, and End Users all reserved one or more seats for a particular stakeholder subsector; for example, End Users reserved a seat for state consumer advocate agencies. Transmission developers wanted to receive a reserved seat on the Transmission Owners and Developers sector, but they did not succeed.

In addition to the SSC Members, each sector had a twenty-seven-member Sector Caucus, and the process for selecting both groups was accomplished in a two-step method. In the first step, the stakeholders in each sector selected twenty-seven caucus members through a transparent online candidate-registration and voting process. Sectors listed above as one through four used a Regional Nomination Process for dividing themselves, where the EI was split into the nine regions already defined by regional planning processes consistent with FERC Order No. 890. Each of these nine regions selected three caucus members for the sector, totaling twenty-seven caucus members for the entire sector. The End Users and NGO sectors used a different process because they do not divide themselves along the regional boundaries established in Order No. 890. Instead, they selected caucus members through an interconnection-wide process, each choosing twenty-seven individuals as well. Finally, the Eastern Interconnection States’ Planning Collaborative (“EISPC”), which is the state entity that received DOE funding to facilitate collaboration among the states and conduct independent research, chose the state representatives to the state sector caucus, and Eastern Canadian provincial governments chose the Canadian provincial representatives.

The final step in the SSC Member selection process was for each Sector Caucus to elect the three SSC Members who would serve on behalf of the entire sector. The selection of Sector Caucus members occurred in late June 2010, and in early July the caucus members voted on the three SSC Members. In addition to selecting the SSC Members, Sector Caucus members were expected to continue to provide advice and input to the SSC Members, and gather input from the broader EI-wide pool of stakeholders. The SSC Members’ responsibilities were to deliberate and decide on the assumptions and tools used in modeling, participate in the work groups and task forces, and ultimately make consensus decisions on the future resource scenarios to analyze.

Another unique component of the SSC structure was the specific table arrangement the stakeholders developed through negotiation, in order to ensure that each sector had interest-based and regional representation at the SSC meetings. Each sector’s caucus selected seven Sector Caucus members that would accompany the three SSC Members at the table. This resulted in the table arrangement used at each subsequent SSC meeting, where each sector sat at a round table with ten chairs. The Transmission Owners’ sector table elected to use their ten seats to have regional representation as well, appointing an individual from each region to a seat, including their three SSC Members. At each SSC meeting the non-SSC members seated at the tables were given the first opportunity to speak on a topic during the Open Discussion Period, after which others attending the meeting could speak during the remaining time.

A final important element of the SSC structure was the decision to have a Chair and Vice-Chair, and that these individuals would not be SSC Members. At the October 12–14, 2010 SSC meeting, the SSC selected the Chairs by closed ballot. The SSC agreed that after 12 months it would revisit and consider altering the system for choosing or retaining Chair leadership. However, at the end of 12 months the SSC did this, and “decided that the Chair/Co-Chair system works well and should be retained.” Initially there was concern that the Chairs would bias the process

173. See Behr, supra note 126.
174. SSC Description, supra note 143, at 1.
175. Id. at 2–3.
176. Id.
177. Id.
178. Interview with Morris, supra note 147.
179. SSC Description, supra note 143, at 3; Phase I Report, supra note 18, at 11–12; Phase II Report, Part 2–7, supra note 138, at 94. The Eastern Interconnection States Planning Council and the State Representatives’ sector did not have to follow the process described herein, but established their own processes. SSC Description, supra note 143, at 4.
180. Id. at 4.
181. Id. at 6.
182. Id. at 6.
183. Id. at 4–5.
184. Id. at 6.
towards their interests, however this proved to not be an issue.\textsuperscript{200}

\textbf{b. Decision-Making In the SSC During the Original DOE-Funded EIPC Project}

The use of consensus decisionmaking to reach the SSC’s decisions was a central element of DOE’s requirements for the EIPC process.\textsuperscript{201} This helped ensure that all guidance coming from the SSC was “consensus guidance”\textsuperscript{202} and reflected broad stakeholder support from across the EI’s regions and interest groups. Consensus was defined by the SSC in the SSC Charter “as none of the [twenty-nine] members objecting to a proposal moving forward. Unanimity and complete agreement are not required to achieve consensus—consensus means that all the parties can live with a particular decision and the ultimate outcomes of the SSC process.”\textsuperscript{203} Additionally, the SSC decided that all consensus decisions of the SSC were final.\textsuperscript{204}

Wanting to adhere to consensus-based decisionmaking, the DOE was initially reluctant to allow the SSC to develop a backstop voting mechanism, to be used in the event that consensus was not possible on a given decision.\textsuperscript{205} Nevertheless, the SSC Charter ended up including an alternative to consensus, and this turned out to be useful in encouraging consensus.\textsuperscript{206} The alternative voting mechanism was designed so that no one sector could either unilaterally initiate the voting, or block agreement on a proposal.\textsuperscript{207} The backstop voting method could be invoked if nineteen SSC Members agreed that consensus could not be reached on a decision, at which point “the SSC [would] strive to reach an agreement that [was] supported by at least [twenty-three] members.”\textsuperscript{208}

\textbf{c. Work Groups in Project Phases I and II}

“The first challenge of the SSC [was] to define eight ‘Futures,’ or EI-wide versions of future energy resource ‘worlds,’ and use the analysis of these Futures, including a high-level transmission analysis, to develop three final scenarios for detailed transmission build-outs and reliability assessment.”\textsuperscript{209} To accomplish this task, the SSC created three work groups and one task force in Phase I:

1. The Roll-Up Work Group focused on coordinating with and providing feedback to the EIPC planning authorities in the Analysis Team as they aggregated the regional plans.\textsuperscript{210} Additionally, the Roll-Up Work Group worked in close coordination with the Scenario Planning Work Group, to ensure that the conclusions and results of the roll-up study effort were understood in relation to the futures development and scenarios planning conducted in Phase I.\textsuperscript{211}

2. The Scenario Planning Work Group fully developed and recommended to the SSC a set of eight diverse macroeconomic futures, and nine sensitivities within each.\textsuperscript{212} They also coordinated with the subcontractor conducting the modeling, to ensure that these macroeconomic futures and the corresponding sensitivities met their needs.\textsuperscript{213}

3. The Modeling Work Group aided the SSC and all stakeholders in understanding the requirements and capabilities of the macroeconomic and production cost models used in the project.\textsuperscript{214} They “developed the values and inputs needed to model the agreed-upon Futures, sensitivities and Scenarios; and provided post-processing analyses as requested by the SSC.”\textsuperscript{215} This work group advised the Scenario Planning Work Group on the input requirements, outputs, processes, and limitations of the macroeconomic models that would analyze the eight futures.\textsuperscript{216}

4. The Scenario Task Force consisted of only SSC Members, although their meetings were open to other stakeholders and all interested SSC Members.\textsuperscript{217} Its duty was to make recommendations to the entire SSC for the three scenarios to be studied in Phase II.\textsuperscript{218}

The tasks of Phase II were considerably different from Phase I. With the requisite decision-making accomplished during Phase I regarding which future policy scenarios to analyze, Phase II focused on completing the transmission-build-out analyses of the three scenarios chosen by the Scenario Task Force and the SSC in Phase I.\textsuperscript{219} To accomplish this very technical analysis, the EIPC and SSC continued

\textsuperscript{200} Phase II Report, Part 2-7, supra note 138, at 99.
\textsuperscript{201} Project Narrative, supra note 128, at 14.
\textsuperscript{202} Id. at 24.
\textsuperscript{203} SSC Charter, supra note 170, at 5.
\textsuperscript{204} Id.
\textsuperscript{205} Interview with Morris, supra note 147.
\textsuperscript{206} Id.; Phase II Report, Part 2-7, supra note 138, at 98.
\textsuperscript{207} SSC Charter, supra note 170, at 5.
\textsuperscript{208} Id.
\textsuperscript{213} Phase I Report, supra note 18, at 15.
\textsuperscript{215} See Phase I Work Groups, supra note 210.
\textsuperscript{216} See Modeling Work Group, supra note 214.
\textsuperscript{218} See id.; Phase I Work Groups, supra note 210.
the work of the Modeling Work Group, described above, and established one task force:

The Transmission Options Task Force is the group that held the most responsibilities for Phase II, in conjunction with the Analysis Team.220 The task force was a forum for stakeholders to review and comment on the planning authorities’ development of the transmission build-out alternatives in Phase II.221 Its purpose was to provide an opportunity for information sharing and idea exchange; it was not a decisionmaking group.222 Each sector in the SSC was allowed one to two members on the task force (except for the states, which were allowed three to six members), and some planning authorities were also on the task force.223

III. Next Steps: Carrying the Coordinated Planning Momentum Forward

“Overwhelmingly, stakeholders found the overall [original DOE-funded EIPC] process to be very worthwhile”, and agreed that the objectives of the original project had been met.224 Furthermore, they suggested that elements of EIPC should continue into the future, and that aspects of their stakeholder experience may be worth adapting into future planning efforts.225 This section first looks at the lessons that EIPC and SSC provide for future transmission planning efforts, including both elements that could be improved upon, and factors that made the SSC’s success possible. The work of EIPC continues, although the role and structure of the SSC has been modified, and in part replaced entirely by the FERC Order No. 890-approved regional level planning processes.226 Thus, this section looks secondly to the regional planning processes, and the questions that must be asked if they are to provide a sufficient format for resolving today’s transmission issues.

A. EIPC and SSC Process Lessons to Consider in Future Coordinated Planning Structures

The SSC structure that was developed and utilized in the original DOE-funded project was a pioneering format, which conducted EI-wide consensus-based stakeholder engagement at an unprecedented breadth and depth. Its success speaks for itself: consensus was used to make all decisions, stakeholders felt the process was valuable, and the SSC recommended that future efforts replicate some of its structure.227 However, there are also areas for improvement. This subsection looks to four critical lessons learned from this experience, and highlights what is worth replicating or adapting, and what is worth improving.228 The first lesson is that the SSC design created the opportunity for broad regional and sector input, and funding provisions for certain sectors helped ensure their consistent participation. Future efforts, however, should pay even greater attention to supporting balanced participation across sectors in the SSC, and within each sectors’ individual stakeholder engagement processes. Secondly, the SSC showed the transmission planning field that consensus-building is not only possible, but in fact adds value to planning processes. Thirdly, building EI-wide relationships across both sectors and regions also adds value to planning processes. And finally, an important element to improve upon is the method for involving planning authorities’ expertise and input in the development of the planning scenarios.

1. Maintain Broad and Consistent Stakeholder Involvement

The SSC was carefully designed to foster broad sector and regional stakeholder representation.229 Its success, however, hinged on consistent and committed participation on the part of SSC Members and Sector Caucus members. Towards this end, the NGO sector, and state consumer advocate offices in the End Users sector were reimbursed for travel costs and expenses for their SSC Members and some of their Sector Table Representatives as well.230 Participants from within these sectors commented that this funding was critical to making their effective participation possible,231 and the SSC Chair noted that the financial resources also enabled a higher level of professional involvement from these sectors.232 Despite these strengths of the SSC model and noted positive outcomes, “the balance built into the structure of the SSC did not always materialize in practice.”233 The Other Suppliers sector—which included Power Marketers, Energy Storage, Distributed Generation, and Demand-side Resources representatives234—were not able to maintain a continual presence.235 Time constraints, lack of resources,

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222. Id.
223. See Transmission Options Task Force, supra note 220.
224. PHASE II REPORT, PART 2-7, supra note 138, at 91, 93.
225. Id. at 93, 100.
226. See supra note 156, for a description of the EIPC’s current work and structure.
227. PHASE II REPORT, PART 2-7, supra note 138, at 91, 93, 96, 98.
228. There are additional factors that supported the success of the SSC that will not be discussed in detail here, but were noted by stakeholders to have been critical in supporting the process: the use of work groups; the selection of effective and unbiased Chairs who were capable of and willing to develop straw proposals for contentious or complex decisions; face to face meetings to build relationships and trust; and the use of an unbiased facilitator who could ensure the rules of governance were followed towards the aim of transparent and broad participation. PHASE II REPORT, Part 2-7, supra note 138, at 99–100.
229. See discussion supra Part II.D.2(1) (describing how the SSC structure designed its sector and SSC Member selection process to ensure interest-based and regional representation).
230. PROJECT NARRATIVE, supra note 128, at 13 and 16; SSC Description, supra note 143, at 12; E. Interconnection Planning Collaborative, Comments from SSC Chair Roy Thilly 1 (Nov. 21, 2012), available at http://www.epiconline.com/Phase_II_Documents.html.
231. PHASE II REPORT, Part 2-7, supra note 138, at 96.
232. Comments from SSC Chair Roy Thilly, supra note 230.
233. PHASE II REPORT, Part 2-7, supra note 138, at 96.
234. SSC Charter, supra note 170, at 170.
235. Interview with Nachmias, Vice President, Energy Policy & Regulatory Affairs at Con Edison (July 18, 2012) (he noted that certain sectors were more active than others; the demand response and energy efficiency community was not well represented as a group, and the generation sector was mainly represented by a renewable representative and not a more traditional generator); Meeting Summary, Mar. 6, 2012, supra note 219 (noting that none of the “other suppliers’ representatives were present at that meeting).
and “waning interest” affected the ability of some Sector Caucuses to actively support the SSC Members, and even some SSC Members were not able to be as involved.\textsuperscript{236} “Almost inevitably, different regions and different sectors were better represented than others, particularly at the working group level.”\textsuperscript{237} This unevenness in participation did concern stakeholders, and was noted to have affected the outcomes of some deliberations by the simple fact that certain stakeholder interests were well represented, and others less so.\textsuperscript{238}

Additionally, there is the question of how well the SSC Members and Sector Caucus members stayed in connection with their EI-wide stakeholders, and thus how well EI-wide interests, concerns, and expertise filtered into the sector and the SSC. The SSC Charter encouraged, but did not require SSC Members to regularly consult with their sector caucuses.\textsuperscript{239} Further, the sectors were free to designate their own procedures for governing coordination between the SSC Members, Sector Table representatives, and keeping their EI-wide stakeholders informed.\textsuperscript{240} While the SSC Charter encouraged each sector to establish communication plans, it did not provide guidance or requirements to aid the sectors in achieving this goal.\textsuperscript{241}

Notable differences existed between sector methodologies for maintaining stakeholder involvement. The Public Power sector addressed stakeholder involvement by holding meetings with stakeholders prior to SSC meetings, but after the agenda for the SSC had been released, so that the SSC Members could discuss the agenda and gather input.\textsuperscript{242} The Transmission Owners and Developers sector took a more formal approach by holding regular ongoing calls in which they discussed key issues and upcoming decisions.\textsuperscript{243} The SSC Member interviewed from this sector stated that, “[a] nything I discuss at the SSC has been vetted. All folks have been heard and had their input.”\textsuperscript{244} Stakeholders observed that some sectors were overall more successful than others at ensuring communication and information-sharing, and that funding, time, and access to support staff needed to perform these functions were the main causes for sector differences.\textsuperscript{245}

Ensuring effective stakeholder representation is critical to thorough information sharing; and this is the heart of why broad and consistent stakeholder engagement matters.\textsuperscript{246} Furthermore, it is important for the credibility and utility of a processes’ results. In future coordinated transmission planning processes that aim to adopt the SSC’s model, an element that could be improved upon is attention to each sectors’ stakeholder engagement process. Future efforts may consider establishing best practices or guidelines.\textsuperscript{247} It may also be helpful to have more oversight on SCC members’ efforts towards this end, and to actively encourage information sharing between sectors on successful communication strategies.

2. Trust that Consensus-Based Stakeholder Decisions Are Possible

To the surprise of the participants interviewed for this article, consensus was used to reach all of the SSC’s decisions.\textsuperscript{248} The stakeholders became more focused on the larger picture and the common interests—a reliable and robust transmission system that can accommodate various potential future scenarios, with consideration for the environment and the cost to consumers.\textsuperscript{249}

The Phase II Report agreed, noting that, “Over time, consensus became the norm for Sector decisionmaking as well, even though EISPc and [Transmission Owners/Transmission Developers] set up voting as the expected method for developing Sector-based positions.”\textsuperscript{250}

Without DOE’s mandate that the stakeholder process be driven by consensus, stakeholders would have never chosen to attempt it due to its perceived impossibility.\textsuperscript{251} Elements that made consensus-based decisionmaking possible were noted as the consistency of stakeholder participation, the Chairs’ use of straw proposals to resolve difficult decisions, and the existence of the backstop voting mechanism.\textsuperscript{252}

\begin{thebibliography}{99}
\bibitem{236} Phase II Report, Part 2-7, supra note 138, at 96.
\bibitem{237} Id. at 96.
\bibitem{238} Id. at 99.
\bibitem{239} SSC Charter, supra note 170, at 9.
\bibitem{240} Id. at 7, 10.
\bibitem{241} Id. at 10.
\bibitem{242} Interview with Maryam Sharif, Program Manager, N.Y. Power Auth. (July 6, 2012).
\bibitem{243} Interview with Nachmias, supra note 235.
\bibitem{244} Interview with Nachmias, supra note 235.
\bibitem{245} Phase II Report, Part 2-7, supra note 138, at 97.
\bibitem{246} “A lack of communication between a representative and his or her constituents is problematic because it obscures not just the fact that a particular package may be unacceptable to a stakeholder group but also why this is so.” Sarah McKearnan & David Fairman, “Producing Consensus, in Susskind et al., The Consensus Building Handbook, supra note 168, at 347.
\bibitem{247} Sarah McKearnan & David Fairman, “Producing Consensus”, in Susskind et al., The Consensus Building Handbook, supra note 168, at 347 (noting that to ensure representatives clearly understand their role, “[a] group’s ground rules should always clearly spell out representatives’ responsibilities for keeping their constituencies informed and testing the acceptability of the group’s proposals).\textsuperscript{248}
\bibitem{249} Interview with Sharif, supra note 242; Interview with Nachmias, supra note 235; Interview with Morris, supra note 147; see also Phase II Report, Part 2-7, supra note 138, at 98. Deciding on the first eight scenarios ended up being the most complex. The Scenario Planning Work Group reached consensus on six futures, but could not on the last two. They presented four futures for consideration to the SSC, and took a “straw poll.” The two futures that received the most votes were then selected by the SSC through consensus. This was aided by making the realization that the two futures not selected could be captured by adding certain sensitivities to other future scenarios. Phase II Report, supra note 18, at 29–30. There was also concern that consensus would be difficult to reach when it came time to choose the three scenarios for Phase II. See Peter Behr, Testing 8 different scenarios for a future power grid, E&E News (May 19, 2011), http://www.eenews.net/climatewire/stories/1059949243/search?keyword=peter+behr, however, this decision did not prove to be a sticking point either. The Phase I Report notes that when deliberating the final three scenarios the Scenario Task Force debated between selecting Future 1 and Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid. “Once it was clear that the policy goals of Future 4 could be accommodated within Scenario 1, [Scenario Task Force] members coalesced around using Future 1 as a reference case for scenario analysis.” Phase I Report, supra note 18, at 73. Once the Scenario Task Force reached consensus on the three (3) scenarios to recommend to the SSC, the SSC then approved these three recommended scenarios at its meeting on September 26–27, 2011. Id. at 68.
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voting method was intended as a last resort option if consensus was not possible. Its “high threshold for...invocation” often led people to realize that they would not be able to get the requisite votes to initiate it, and thus had to make use of the consensus process. Even though the backstop voting process was never used, its existence was important, especially at the outset of the stakeholder process, because it gave stakeholders “some confidence that they would be able to avoid stalemate”. Ultimately, stakeholders found that the process of building consensus entailed its own benefits, including fostering a deeper understanding of the concerns across sectors and stakeholders, generating creative solutions when disagreement emerged, and providing the basis for developing trust within and across sectors.

3. Build Relationships Across the EI

One of the positive outcomes of the original DOE-funded EIPC project that is noted repeatedly in EIPC documents is the significance of the EI-wide relationship-building and information-sharing that this process fostered. Further, stakeholders commented on the importance of maintaining these EI-wide relationships going forward. The design of the SSC created a forum for exchange of information among regions where they could consider the respective priorities within and between regions. SSC Member Stuart Nachmias added to this by stating that simply getting to know the other parties in his sector, the Transmission Owners and Developers, and across other sectors, was one of the most important outcomes for him. Additionally, the planning authorities and EISPC participants in particular strengthened their working relationship, and developed a “greater understanding of the states’ interests and better understanding of the various sub-regional planning processes.” The EIPC and SSC structure made it possible for different interest groups and regions to develop stronger relationships, share information and expertise, and cultivate a deeper understanding of one another’s priorities and concerns.

4. Involve Planning Authorities in Scenario Development

The initial twenty-five planning authorities that spearheaded the EIPC were only utilized in the original DOE-funded project through the Analysis Team, which conducted analysis as advised by the SSC; they were not part of the SSC’s scenario development decisions. This appears to have been beneficial for this initial EI-wide transmission planning effort, because it helped the planning authorities gain trust and credibility among the stakeholders. Overtime, stakeholders increasingly turned to the planning authorities for advice and input on scenario development, showing that this trust and credibility did develop. Nevertheless, the planning authorities are the entities most familiar with transmission planning and the transmission grid, and limiting their involvement in the SSC’s decisions may have deprived the scenario development process of their expertise and experience.

As such, the Phase II report suggests that future EI-wide analyses consider giving the planning authorities a greater voice, and perhaps decision-making power, in scenario development “while maintaining a robust collaborative process in which stakeholders’ views are fully considered.” To do so effectively, however, it would be critical for the process to maintain transparency in order to maintain planning authority credibility.

B. Are the Existing Regional Planning Processes Sufficient?

After EIPC’s completion of the original DOE-funded project, the planning authorities within EIPC continued their efforts in a two-pronged fashion, modifying the involvement of the SSC along the way and returning to the FERC Order No. 890-approved regional planning processes. One of the continued directions of EIPC’s work is the gas-electric system interface study, which remains DOE-funded through an extension of Phase II. For this effort the EIPC planning authorities reduced the SSC’s input to advisory only, and suggested changes to the SSC structure, including adding natural gas system stakeholders. Secondly, EIPC continues its interregional transmission analyses by producing “roll-up reports” where all regional level transmission plans are aggregated, similar to what occurred in Phase I, and also continues to conduct future scenario analysis. The EIPC has completely removed involvement of the SSC in this work, and instead elected to rely on the existing stakeholder engagement processes within the Order No. 890-approved regional planning processes. Moreover, the planning authorities made clear that they were not advocating for nor intending to include SSC components into the existing regional planning processes.
The EIPC planning authorities’ decision to reduce the weight of the SSC’s involvement in the gas-electric system interface study, and to solely use the existing regional planning processes for their continued transmission planning shows that the consensus-based and EI-wide model for stakeholder input has not yet been embraced in the transmission planning field. The choice to depend on the regional planning processes highlights that these are currently the planning authorities’ preferred conduits for information exchange and stakeholder involvement. As such, it is important to take a closer look at them to ensure they are up to the challenge of producing thoughtful transmission solutions to the complex limitations of today’s transmission grid. This Article leaves the opportunity for detailed analysis of the regional planning processes to future research, however noted potential limitations of these processes are introduced below.

The stakeholder participation mechanisms in regional planning processes are currently too onerous for consistent involvement, seem to overlook important stakeholders, and do not provide enough benefit to make the cumbersome task of participation worthwhile. Catherine Morris, facilitator for the EIPC, observed that stakeholders in the End User sector who also attend regional planning processes tend to be large industrial users, and not the consumer advocacy groups who typically lack the time and resources to participate.273 Additionally, NGOs are invited to attend the regional planning meetings, but rarely do so because the meetings are time consuming, bureaucratic, and the voting process utilized often leaves them in the minority and thus without decision-making power.274 These observations lead to another limiting element of regional planning processes, which is their use of majority rule.275 Majority voting processes “[l]eave many stakeholders (often something just short of a majority) angry and disappointed, with little or nothing to show for their efforts.”276 The use of majority rule can ostracize whole groups of stakeholders by overtime becoming a disincentive to participation since the input of the minority never informs final decisions.

This Article suggests that it is imperative to carefully examine the regional planning processes in order to assess their strengths and shortfalls. Do they foster truly broad and consistent stakeholder involvement? Do they adequately incorporate and utilize stakeholder input? Do they promote thorough information-sharing and relationship-building across each region and interregionally? Do they result in creative problem-solving and thoughtful analysis? Transmission planning can only lead to wise and long-term solutions if it utilizes a robust stakeholder involvement process. Thus, the regional planning processes must be scrutinized to see if they measure up, and if not, to see what needs to change to make them more useful.

IV. Conclusion: Finding A Path Towards Congestion Relief

Resolution of today’s congestion issues and utilization of our nation’s renewable energy potential will largely be addressed through interstate and interregional transmission projects. These projects will inevitably continue to encounter the challenges of cost allocation, coordinated planning, and state-by-state transmission siting, which have largely caused the stalled and piecemeal process of transmission development to date. This Article leaves the question available for further research as to whether the FERC Order No. 890-approved regional planning processes are sufficient for conducting thoroughly-considered and wise transmission planning, let alone some day addressing the more complex challenges of siting and cost allocation.

Those in the energy field have understood for years that “[f]inding and implementing solutions will require cooperation by, not confrontation among”, the relevant interest groups.277 This is exactly what EIPC has done. The SSC proved that consensus-based transmission analysis is possible. The model created and utilized by the SSC for conducting coordinated planning is unprecedented in the energy field, particularly when one considers its regional and sector scope. Consensus was not only possible, but in fact the process of building consensus was noted as fostering a deeper understanding across stakeholders, and generating more creative solutions to complex or contentious issues. Thus, perhaps regional planning processes could aim for more than mere cooperation.

If the regional planning processes do not result in wise transmission projects in the near term that address congestion’s reliability and economic impacts, as well as the constraints to renewable energy expansion, the nation may some day look again to expanding federal oversight in order to relieve the congestion. Thus, regional planning processes may have only a limited window of opportunity within which to prove what they are capable of. It behooves planning authorities to consider the adequacy of their existing processes, and whether elements of the SSC’s structure should be incorporated, such as the use of consensus-based decisionmaking, mechanisms for ensuring broad and consistent stakeholder involvement, intentional region-wide and EI-wide relationship building and information sharing, and direct involvement of the planning authorities and stakeholders guiding scenario development together. If the EIPC’s lessons can be further utilized to enhance future regional and EI-wide planning processes, then it may indeed mark a new beginning for the transmission grid.

273. Interview with Morris, supra note 147.
274. Id.
275. Id.