



ISSUE BRIEF

MAKING SENSE OF A WESTERN ISO: THE ROLE OF FERC IN TRANSMISSION SERVICE

The potential benefits of transforming California’s existing grid operator, known as the California Independent System Operator (CAISO), to include other western utilities—and therefore the states they serve—are significant. Although more study is necessary to demonstrate the specific benefits any given state may incur, a regional grid will also allow even more rapid and cost-effective integration of wind and solar power into the electricity mix than is already happening and will lower the cost of meeting state and federal environmental regulations. The change also provides an opportunity for power industry competition that has not existed previously across the Western Interconnection transmission grid. Failure to regionalize grid operations and incorporate a broader western footprint likely will cost consumers billions of dollars over time, require the development of duplicative infrastructure and generation because less resource sharing will be possible, and make regulatory compliance more difficult and expensive for states in the Western Interconnection region.

One important issue under consideration as part of discussions related to establishing a multistate grid operator concerns the jurisdiction of the Federal Energy Regulatory Commission (FERC)—the federal agency that regulates interstate transmission and wholesale sales of electricity—over utilities and regional grid operators. How might that authority change (and how would it impact state authority) if CAISO transforms into a regional grid operator? (A corollary question concerning the role of states in a western regional grid operator was addressed in our issue brief *Making Sense of a Potential Western ISO Governance: The Role of the States.*)

Recognizing that a significant number of stakeholders interested in regional expansion have questions about the role of FERC, this issue brief provides background on the federal agency, the role it currently plays in the West with regard to transmission development and service, and how its role would change if CAISO transforms into a multistate entity.

FERC BACKGROUND

FERC is an independent federal agency led by five commissioners who are appointed by the president and confirmed by the U.S. Senate. Typically three commissioners are from the president’s political party. FERC exists as a result of the Federal Power Act, which the U.S. Congress passed in 1935 to address states’ inability to regulate interstate sales of electricity. The agency has jurisdiction over transmission service in interstate commerce and wholesale sales of electricity. (Among other powers, FERC also has authority to approve interstate natural gas pipelines and license hydropower facilities.) FERC’s electricity-related jurisdiction can be divided into four general areas: interstate transmission system planning, transmission system reliability, wholesale market design, and operations (for example, establishing rules for grid interconnection).

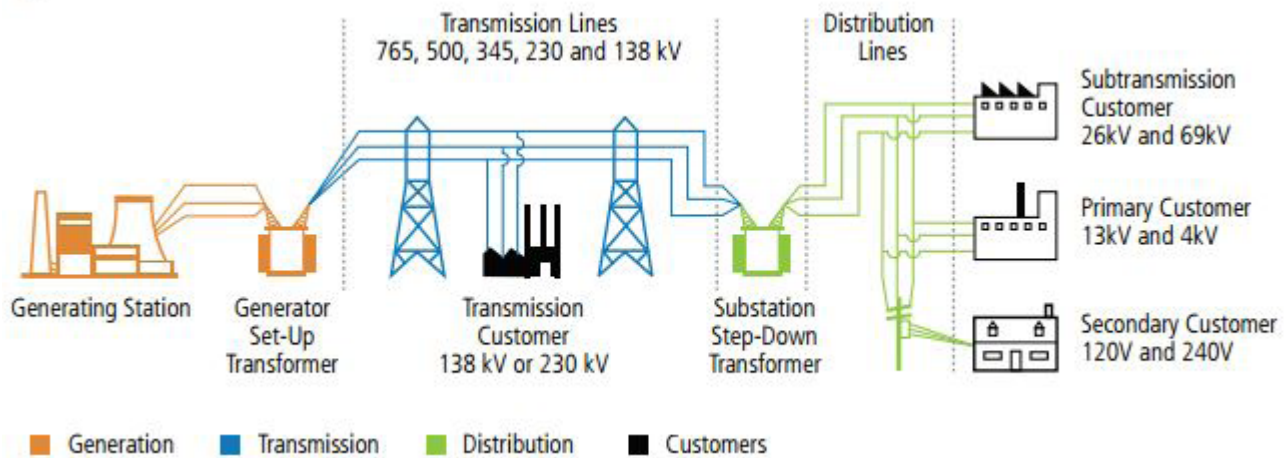
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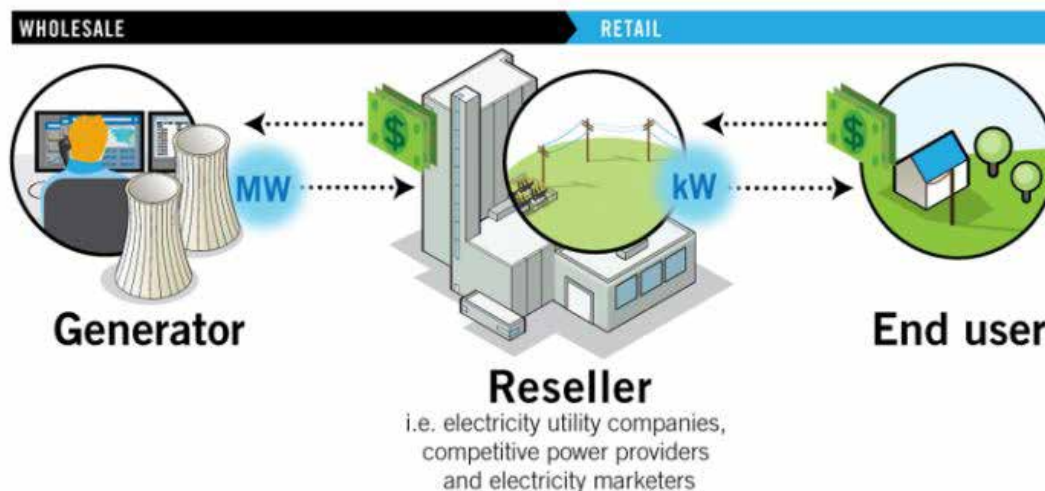
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In passing the Federal Power Act, Congress preserved a significant role for states in electricity regulation, leaving them with authority over issues including retail electricity rates and practices and “facilities used for the generation of electric energy.” With notable bumps in the road, this division of authority has worked relatively well for the past 90 years. States are responsible for generation resource planning and the approval of new power plants and transmission lines within their borders. On behalf of the federal government, FERC then regulates the rates for sales of power from the plants that generate it to wholesale customers (like retail utilities) as well as rates for transport of that power across the nation’s high-voltage transmission lines. States regulate rates for the sale of electricity from the utility or competitive suppliers to residential, commercial, industrial, and agricultural customers. At the center of this regulatory arrangement is FERC’s jurisdiction over transmission-owning public utilities—although use of the word public can be confusing because public utilities under the Federal Power Act are actually investor-owned. With exceptions, FERC does not have significant authority to regulate municipally owned or cooperative utilities.

The division between state and federal authority is not uniform across the country. Differing regulatory structures provide region-specific opportunities for grid integration. As discussed in more detail in Section III, authority over transmission service, resource adequacy, and wholesale electricity sales varies based on whether states are vertically integrated (i.e., a single utility controls generation, transmission, and distribution of electricity) or restructured (i.e., have introduced competition in the retail sale of energy) and whether the utilities are members of regional transmission organizations. For example, states that remain vertically integrated generally maintain their authority over planning processes and resource adequacy, regardless of whether their utilities are members of regional grid organizations. On the other hand, most restructured states have relinquished their authority to ensure resource adequacy; many no longer engage in robust integrated resource planning but rely on competition (via wholesale markets that exist within their regions) to ensure an adequate supply of electricity in the future.



The U.S. Department of Energy’s Quadrennial Energy Report: *Energy Transmission, Storage, and Distribution Infrastructure (2015)* provides a description of the various components of the electric grid. Courtesy of U.S. DOE, http://energy.gov/sites/prod/files/2015/04/f22/QR%20ch3%20final_0.pdf.



PJM, the grid operator for the Mid-Atlantic region, illustrates the distinction between wholesale and retail markets. Specifically, it shows the difference between wholesale customers or “resellers” and residential, commercial, industrial and other “end-use” customers. Courtesy of PJM, <https://learn.pjm.com/electricity-basics/market-for-electricity.aspx>.

The electric grid has changed rapidly over the past decade and more specifically over the past five years, in large part due to the significant growth in distributed energy resources (DERs) on the distribution system. DER growth is causing uncertainty, in some cases, about where to draw the line between state and federal authority.¹ DERs interconnect to the distribution system but have the ability to participate in wholesale power markets and involve FERC-jurisdictional transmission system planning.² States in the West are already dealing with jurisdictional questions related to DERs, and the western focus on DERs will only increase over time, regardless of whether any utility becomes part of a multistate regional system operator.

This lack of clarity around jurisdictional boundaries has even been tested in court (including in two U.S. Supreme Court cases that received significant attention), and it is likely that more legal challenges will arise.³ However, it remains possible to delineate most of the contours of the state-federal jurisdictional divide, especially for states that remain vertically integrated.

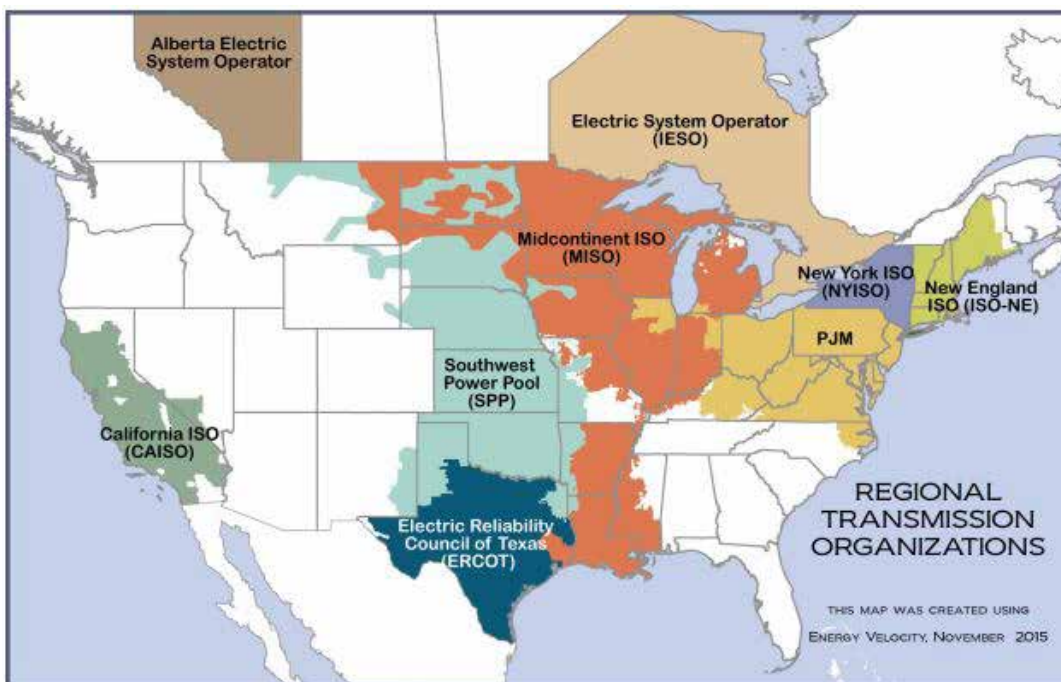
FERC'S AUTHORITY OVER REGIONAL TRANSMISSION ORGANIZATIONS AND INDEPENDENT SYSTEM OPERATORS

Starting in the late 1990s, FERC took actions to encourage competition in the provision of transmission service. In 1996 it issued a landmark rule called Order 888, which requires transmission-owning utilities to provide third parties access to their transmission lines, at the same price they charge their own retail utility affiliates.⁴ When Order 888 was issued, several transmission-owning utilities had already joined together voluntarily to capture efficiencies

of sharing energy reserves and coordinating power plant dispatch. In 1999, FERC built on Order 888 and issued Order 2000, which encourages and provides standards for the formation of regional transmission organizations (RTOs, sometimes referred to as Independent System Operators, or ISOs).⁵ This issue brief refers to existing regional grid operators as RTOs and ISOs, and to a potential multistate grid operator in western states as a Regional System Operator (RSO).

Order 2000 intends for RTOs and ISOs to act as independent third-party system operators that maximize efficiencies through regional transmission coordination and centralized power markets. Order 2000 and subsequent regulations have provided specific RTO and ISO responsibilities, including, among others:

- Development and of regional prices for transmission service and the rules by which market participants can access transmission lines and sell power;
- Centralized dispatch of the region's power plants;
- Responsibility to supply ancillary services (energy-related services that the grid needs as complements to the energy itself);⁶
- Administration of total available transmission capacity to transport power in the region and rules for unused transmission capacity that might be available to market participants;
- Establishment of sufficient independent market monitoring for the region's markets; and
- Engagement in local and regional transmission system planning, as well as interregional coordination.⁷



This map shows the regions that have formed regional transmission organizations and independent system operators. Courtesy of the Federal Energy Regulatory Commission, <https://www.ferc.gov/industries/electric/indus-act/rto.asp>.

Operationally, RTO and ISO functions generally require the involved utilities to hand over operation of their transmission systems and dispatch of their generating fleets to the RTO or ISO (independent transmission companies and power generators can also participate).⁸ FERC then regulates the RTO or ISO as a transmission operator on behalf of the member transmission owners. Transmission owners retain several Federal Power Act-related responsibilities themselves, and FERC maintains authorities over these responsibilities.

Several regions, most of which were already coordinating via power pools or independent system operators, went through FERC's process to establish RTOs. Some of these regions, like PJM (the grid regional operator for 13 mid-Atlantic states) and the New York Independent System Operator (NYISO), now consist mostly of restructured states. Other RTOs, such as the Mid-Continent Independent System Operator (MISO) in the Midwest and South, and the Southwest Power Pool (SPP) in the Great Plains, are largely made up of vertically integrated states.⁹ The roles of the states participating in these regional grid operators vary due to these regulatory differences, as well as political, institutional, economic, resource, and other varying regional factors. As a result, the experience of New Jersey as part of PJM is only partially relevant to the experience of Oklahoma as part of SPP, just as both are only partially relevant to the potential experience of a western state as a member of a western RSO. With this caveat, the experiences of other states are certainly informative when considered in the context of a western RSO.

FERC'S TRANSMISSION-RELATED AUTHORITY IN THE WEST—WITHOUT, AND WITH, A REGIONAL SYSTEM OPERATOR

FERC presently has authority over investor-owned utilities and independent transmission owners and operators in the West, including utilities like PacifiCorp and CAISO (on behalf of its member utilities).¹⁰ FERC's obligation under the Federal Power Act is to ensure "just and reasonable rates" and the avoidance of "undue discrimination" in the provision of interstate transmission service and the wholesale sale of energy. If any other transmission-owning utility joins a multistate RTO, FERC's obligation will not change—that obligation is equivalent across the entire country.¹¹ Of course, the ways in which FERC's obligation plays out will change from the strictly vertically integrated context to that of a more competitive regional transmission organization. The jurisdictional differences are important but are manageable and have worked in both the Midwest and the Great Plains regions, where utilities in vertically integrated states have joined RTOs.

This issue brief addresses these issues in the context of PacifiCorp's potentially joining with CAISO to form a regional system operator. PacifiCorp is a vertically integrated utility that owns generation, transmission and distribution across six operating

states: Washington, Oregon, Idaho, Wyoming, Utah, and a portion of California. The principles, however, can be applied in the case that any western vertically integrated utility considers joining an RTO or ISO.

Transmission Service

As a transmission-owning public utility, PacifiCorp is subject to FERC's regulations. FERC is obliged to ensure just and reasonable rates and to avoid undue discrimination in the provision of interstate transmission service. Relevant regulations can be considered in two parts: the formula rate and annual total revenue requirement, and transmission incentives.

Formula Rate and Annual Total Revenue Requirement

Currently, PacifiCorp is required to seek FERC's approval of the equation for its "formula rate"—the rate the utility uses to determine the amount of revenues necessary to recover the costs of its FERC-jurisdictional transmission capital investments and operations and maintenance costs.¹² PacifiCorp last filed a request to change its formula rate with FERC in 2011.¹³ This rate serves as the basis for PacifiCorp's annual total revenue requirement, which PacifiCorp files with FERC annually.¹⁴ The annual total revenue requirement includes both annual revenues necessary to recover costs and a FERC-approved return on equity (ROE) allowance. The ROE is determined through a specific analysis as part of the formula rate determination.¹⁵ PacifiCorp would need renewed FERC approval before materially adjusting its formula rate or modifying its allowable ROE by any amount.

It is helpful to examine the western states' corollary role in considering transmission rates. Since all of the states in PacifiCorp's territory remain vertically integrated, the utility provides its retail customers with a bundled electricity product. This means that customers pay one price for the generation, transmission, and delivery of electricity into their homes, all of which are provided together by PacifiCorp and not a competitive third party. Under the Supreme Court's established interpretation of federal and state authority over transmission rates, states retain responsibility for transmission rate review as part of the delivery of bundled electricity.¹⁶ State public utility commissions review the utility's transmission investments in a general rate case just as they do the utility's generation and distribution investments.

PacifiCorp's FERC-jurisdictional annual total revenue requirement serves as an input into its retail revenue requirement applications in each of the six states in which it operates. States cannot approve an amount of total transmission cost recovery that is less than their relative portions of this FERC-approved total revenue requirement. However, because PacifiCorp has wholesale transmission customers (separate from its retail customers) who pay for use of its transmission system, PacifiCorp is able to

recover at least a substantial portion of its FERC annual total revenue requirement via these third parties, known as “wheeling” customers. The revenues that PacifiCorp estimates it will receive from third-party wheelers are subject to consideration and approval by the state utility commissions, and then are applied as a credit against the FERC-jurisdictional transmission component of the utility’s retail annual revenue requirements.

Consideration of this “revenue credit” is part of state utility commissions’ retail rate review, which takes into account whether proposed costs, including transmission investments, meet each state’s specific prudence standards for approving retail cost recovery.¹⁷ States also consider whether new investment in transmission meets their prudence tests.

FERC’s traditional jurisdiction over transmission notwithstanding, PacifiCorp’s bundled service approach causes a multi-jurisdictional, somewhat disjointed rate-setting process for the transmission component of retail rates. One disadvantage of this disjointed review between states and FERC is that it can shift risk onto PacifiCorp ratepayers. For example, if wheeling revenues, and the associated revenue credit, are underestimated, PacifiCorp will over-collect transmission costs from its retail customers. (On the other hand, if wheeling revenues are overestimated, the utility may under-collect from retail customers). Also, this process may have negative impacts on cost efficiencies and risk mitigation that PacifiCorp customers could gain from the utility’s participation in more robust regional transmission system planning available via an RSO (discussed in Section III. B). The regional planning process is designed to avoid redundant transmission development by determining when regional transmission resources can more cost-effectively provide the service of one or more localized transmission resources. If retail consideration of transmission costs is disconnected from this broader perspective, these efficiencies may be lost.

If PacifiCorp joins an RSO, the regulatory treatment of its transmission service rates would most likely change. PacifiCorp would likely “unbundle” its transmission service from its delivery of electricity. Unbundling means that the transmission component of PacifiCorp’s retail electricity product would be separated out and integrated into the RSO process for transmission service. If unbundling occurs, FERC would assume jurisdiction over the rates and conditions of PacifiCorp’s transmission service, and states would no longer consider potential transmission investment costs as part of their review of PacifiCorp’s rates; those costs would instead be “passed through” as FERC-approved rates. Once the RSO determined PacifiCorp’s share of costs for new investments, PacifiCorp then would retain authority to determine how those costs are spread across its operating region, subject to approval by the states. PacifiCorp’s formula rate and annual total revenue requirement would change to the formula rate utilized by the RSO, but the

resulting total annual revenue requirement would continue to be passed through to PacifiCorp’s retail customers, as is done today.

Joining an RSO does not necessarily prohibit continuation of retail bundled electricity service, however. As part of Entergy’s joining MISO in 2013, for example, the Louisiana Public Service Commission instructed the company to maintain delivery of electricity in a bundled fashion at the retail level in order to maintain the state’s regulatory authority over the utility’s transmission investments. The legal aspects of the arrangement have not been tested in court.

If unbundling is the path taken as part of RSO membership, the change must be considered in the context of the other modifications that occur as part of RSO membership—including more efficient transmission infrastructure planning and the avoidance of redundancies, competition to test and improve the efficiency of PacifiCorp’s existing transmission infrastructure, the ability to take advantage of the distributed energy resources coming online across the region that collectively negate the need for some transmission infrastructure, and perhaps most important, states’ ability to influence transmission development outcomes through RSO processes.¹⁸ In other words, changes in state jurisdiction over unbundled transmission cost recovery may be outweighed by other considerations that benefit retail customers.

Specifically, states will continue to have several options for achieving cost savings and protecting customers against imprudent transmission investments. In states in which transmission lines are planned, certification processes offer the opportunity for in-depth review of proposed projects. Also, regardless of whether proposed projects run through a state, representatives from state agencies (utility commissions, state energy offices, governors’ offices) can influence inputs into regional planning processes by ensuring that their PacifiCorp utilities’ load forecasting processes, which are subject to state jurisdiction, are robust and accurate (especially that they account for the impacts of energy efficiency and other distributed energy resources on forecasting). States can also require PacifiCorp to meaningfully consider whether non-wires alternatives—like targeted energy efficiency, demand response, rooftop solar, and other clean generation—can avoid the need for transmission to address local reliability or congestion issues. In addition, representatives from states can participate in regional transmission planning processes at the RSO. Recognizing that resources are limited and these planning processes can be technical and time consuming, states can propose specifically targeted opportunities for participation in transmission planning review as part of agreeing to RSO membership. Committees of state regulators and officials, such as the currently proposed Western States Committee and similar existing entities in ISO-NE, PJM, MISO and SPP, provide good examples of ways to facilitate these opportunities.

In addition, it is worth noting that FERC rules dictate that only customers receiving benefits from new transmission pay the associated costs.¹⁹ As discussed in more detail in Section III. B, this “beneficiary pays” principle applies in all circumstances, including when states are interested in developing transmission infrastructure to facilitate their own public policies.²⁰ Courts have upheld and rejected proposed cost allocation based on this beneficiary pays principle, providing an additional check to ensure the principle works in practice.²¹

Moving from a bundled retail electricity product to one that unbundles transmission represents a change and it is one that holds opportunities for customers in PacifiCorp’s region. The change may simplify existing regulatory processes and, most important, increase customer savings in relation to future transmission investments—especially when considered together with changes in the transmission planning process, discussed in Section III. B.

Transmission Incentives

The second component of FERC’s regulatory authority over PacifiCorp (and all other jurisdictional utilities) is its ability to consider incentives that allow additional cost recovery for activities specific to new transmission project development. Pursuant to congressional encouragement of new transmission development in the Energy Policy Act of 2005, FERC can award transmission-owning utilities (and independent transmission companies) incentive (i.e., extra) rates of return on equity for new transmission projects if those projects demonstrate characteristics valuable to the development of an interregional transmission system.²² It can also award cost recovery for, among other things,

costs that utilities incur during the transmission project construction process and for all expenditures if utilities abandon projects because of failure to obtain regulatory approval.²³ In 2008, PacifiCorp applied for and received a 200 basis point (2 percent) return on equity incentive for segments of the Energy Gateway Transmission Expansion Project, an incentive still in place today. At the same time, FERC also awarded PacifiCorp the right to recover “prudently incurred development and construction costs if the Project is cancelled or abandoned, in whole or in part, as a result of its inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority, or regulatory agency, for any reason outside PacifiCorp’s control.”²⁴

The states in which PacifiCorp operates do not review FERC’s award of transmission incentives directly, and the value of the incentives are wrapped into PacifiCorp’s annual FERC-approved total revenue requirement (that serves as a non-rejectable input into PacifiCorp’s retail bundled electricity rate recovery requests).

The change from a vertically integrated system to RSO membership would not change FERC’s authority to award transmission incentives. Of course the actual transmission projects involving incentives will change—and significant transmission projects that are likely to qualify for incentive treatment at FERC will face increased competition in an RSO. Unlike the historical planning process whereby PacifiCorp considers only transmission options under its control, RSO planning also would consider potentially lower-cost options proposed by other utilities or third parties.

TABLE 1: SUMMARY OF JURISDICTIONAL CHANGES AND OPPORTUNITIES RELATED TO TRANSMISSION SERVICE IF PACIFICORP JOINS A MULTISTATE RSO

Issue	Jurisdictional change if PacifiCorp joins a multistate RSO	Opportunities for PacifiCorp states
Transmission formula rate and annual total revenue requirement	No change, OR unbundling of transmission means states remove transmission component from retail revenue requirement considerations	Follow Louisiana model, which successfully maintained bundled retail electricity after integration into MISO, OR states have opportunity to gain efficiencies from RSO regional planning process to offset changes in jurisdiction over transmission component of bundled product
FERC transmission incentives	No change	As precursor to award of incentives, regional PacifiCorp transmission projects will face competition with third-party alternatives before chosen as desirable and cost effective and more likely to qualify for incentive treatment
Cost allocation—existing transmission	No change (under current CAISO Transmission Access Proposal)	Proposal contemplates status quo treatment of PacifiCorp’s existing transmission system
Cost allocation—new transmission	No jurisdictional change (beneficiaries of a new line pay for the line), but the methodology for allocating cost of new transmission would shift from Northern Tier Transmission Group to RSO	<ul style="list-style-type: none"> • Current CAISO approach to identify benefits and beneficiaries of new transmission is more transparent, objective, and refined than the current Northern Tier Transmission Group (NTTG) process • A broader region provides the opportunity to reduce redundant development, which results in cost savings • Consideration of new transmission in CAISO is subject to more robust competition than exists in NTTG
Transmission siting	No change	States maintain full traditional CPCN and siting authority

Transmission Planning, Cost Allocation, and Siting

Transmission Planning

As part of FERC’s authority to ensure just and reasonable rates and avoid undue discrimination in transmission service, it requires all utilities to engage in local transmission planning (within the utility’s footprint), and, either on their own or via their regional transmission organization, to cooperate with neighboring utilities in performing regional transmission system planning.²⁵

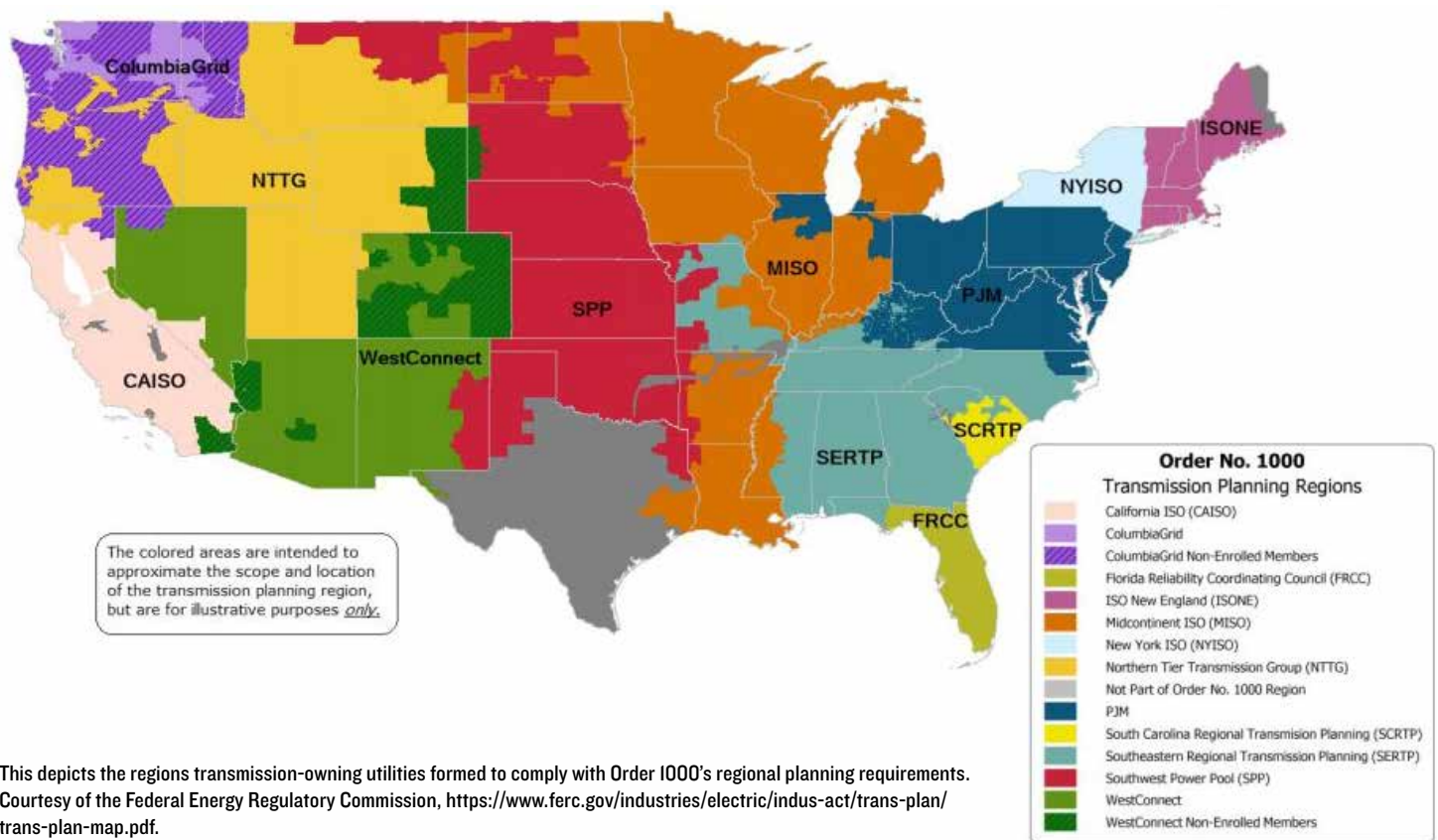
Local and regional transmission planning each involves a two-part process: identifying transmission system needs (future reliability or congestion issues, or public policy-driven needs) and then developing solutions to meet those needs. Grid planners take into account many different factors affecting the grid’s current and future operation to identify needs, including predicted customer demand; existing, planned, and retiring power plants; and environmental and clean energy standards. Based on these and other factors, transmission owners and grid planners determine whether they need to upgrade existing power lines and/or build new ones. Most regions plan on an annual or biannual basis, creating plans that look 10 years ahead.

PacifiCorp currently engages in its own local transmission planning and in regional planning as a member of the Northern Tier Transmission Group (NTTG). The rules for PacifiCorp’s local and regional planning processes,

as well as the local planning of the transmission-owning utility members of CAISO, and CAISO’s regional planning processes, have been reviewed, subjected to revision, and approved by FERC. FERC also has the authority to review any future proposed material changes to these processes.

If PacifiCorp joins a regional system operator, its local transmission planning process would not need to change materially. Its regional planning process, however, would change in that the utility would leave NTTG and join the RSO’s regional planning process (for which, under the current proposal, CAISO’s current planning process provides the basis). FERC’s role in overseeing the planning processes is equivalent in either case.

In its rules establishing this regional planning requirement FERC provided flexibility to regions to design their own processes that must meet FERC-mandated principles designed to ensure effective planning and transparency, among other traits. NTTG took an approach significantly different from CAISO’s. This issue brief is not intended as a venue for an in-depth comparison of NTTG’s and CAISO’s planning processes, but our anecdotal experience indicates that opportunities for meaningful stakeholder input into the design of grid studies, and analysis and transparency in the same process are stronger in CAISO than in NTTG. In addition, opportunities for true competitive bidding, so that necessary transmission infrastructure projects are built as affordably as possible, remain stronger in CAISO.



This depicts the regions transmission-owning utilities formed to comply with Order 1000’s regional planning requirements. Courtesy of the Federal Energy Regulatory Commission, <https://www.ferc.gov/industries/electric/indus-act/trans-plan/trans-plan-map.pdf>.

Cost Allocation

When it comes to new transmission infrastructure development, NTTG and CAISO each maintain one or more FERC-approved regional cost allocation methods for transmission investment driven by reliability, congestion, or public policy needs. FERC has deemed these methodologies consistent with its cost allocation principles, which include the following: (1) costs must be allocated in a way that is roughly commensurate with benefits; (2) costs may not be allocated involuntarily to those who do not benefit; (3) any minimum benefit-to-cost ratio must be below 1.25; (4) costs may not be allocated involuntarily to a region outside of the facility's location; (5) the process for determining benefits and beneficiaries must be transparent; and (6) a planning region may choose to use different allocation methods for different types of projects.²⁶

Similar to the transmission planning processes that these cost allocation methodologies complement, no change would take place in terms of FERC's authority over the methodologies if PacifiCorp were to join a multistate grid operator. However, the actual methodologies to which PacifiCorp is subject would change.

Modifications to CAISO's cost allocation methodology would be necessary to satisfy the broader group of stakeholders involved in an RSO and to continue to meet

FERC's requirement that, as a multistate grid operator, only beneficiaries of proposed projects pay for them. CAISO's Transmission Access Charge initiative has made significant progress in developing a proposal that meets the needs of PacifiCorp and CAISO stakeholders and continues to comply with FERC requirements.²⁷

Transmission Siting

FERC has no authority over states' transmission certification and siting processes. No change would take place if PacifiCorp joined a multistate system operator. States in which transmission projects are proposed as part of local or regional transmission planning processes would maintain full authority to review proposed projects for certification and siting purposes. As a result, plans coming out of regional planning processes are not mandates to build, but guides to hosting states that retain the final say.

CONCLUSION

When a vertically integrated utility joins an RSO, there are changes related to state and FERC authorizations over transmission. The incremental modifications provide states with opportunities to expand their influence in some areas and to mitigate the impacts of FERC authority in other areas, while still partaking in the benefits that a regional, integrated grid has to offer.

ENDNOTES

1 This brief defines DERs to include energy efficiency, demand response, rooftop solar, electric vehicles and other forms of energy storage, and smart grid technologies to support their integration.

2 More information on the evolving interaction of DERs and the transmission system is available here: <https://www.nrdc.org/experts/allison-clements/small-power-big-grid-part-1>.

3 The two cases are *FERC v. Electric Power Suppliers Association*, <https://www.nrdc.org/experts/allison-clements/us-supreme-court-decision-demand-response-forces-awaken>, and *Hughes v. Talen Energy Marketing*, <https://www.nrdc.org/experts/allison-clements/supreme-court-decision-striking-down-maryland-program-contains-good-news>.

4 Order 888, *Promoting Wholesale Competition Through Open Access; Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* (1996), <https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt>.

5 Order 2000, *Regional Transmission Organizations* (1999), <http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf>. FERC distinguishes between RTOs and Independent System Operators, or "ISOs." One key distinction between the two forms was the obligation of RTOs to engage in interregional coordination. In light of FERC's more recent Order 1000 regional planning requirements, the distinction between RTOs and ISOs is largely irrelevant for purposes of this brief and the brief either refers to both or describes the concept as a regional system operator or "RSO."

6 A basic primer on what ancillary services are and what they do for the grid is available at <http://greeningthegrid.org/integration-in-depth/ancillary-services>.

7 Order 2000 contains most of these functions as requisite to RTO formation. In 2007, FERC issued Order 890, *Preventing Undue Discrimination in Transmission Service*, <https://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf>, which contains local planning obligations for all transmission-owning utilities regardless of whether they are members of an RTO or ISO. In 2011, FERC built on Order 890 and issued Order 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, <https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf>, which requires all transmission-owning utilities, regardless of RTO or ISO membership, to engage in regional planning with neighboring utilities and interregional coordination with neighboring regions.

8 Utilities like PacifiCorp that self-supply much of their power needs may continue to self-schedule their dispatch, at least initially; a process that would be facilitated by the RSO. So, PacifiCorp's fleet may not initially face competition, but regulators will have the opportunity to compare PacifiCorp's cost of service rates with competitive locational marginal pricing that will exist across the RSO.

9 Of MISO's 16 states and one province, two—Michigan and Illinois—have some level of restructuring. The rest remain vertically integrated.

10 It does not have authority to regulate transmission-owning municipalities and public cooperatives, although some municipalities and cooperatives voluntarily subject themselves to FERC regulations in order to receive "reciprocity" that provides them with non-discriminatory access to transmission service in return for following FERC rules.

- 11 Federal Power Act, 16 U.S.C. §§ 824 *et seq.*, §§ 205 and 206.
- 12 See Order 888, 61 Fed. Reg. 21 at P 540. FERC's landmark 1996 ruling, which originally required all transmission-owning utilities to open up their transmission lines to use by third parties at non-discriminatory rates, provided a seven-factor test for determining whether specific lines constitute local distribution subject to state authority, or whether the lines are transmission subject to FERC's regulation. The factors include that local distribution lines are (1) close in proximity to retail customers and (2) primarily radial in character, and (3) power flows into but rarely flows out of the system, (4) power is not reconsigned or transported onto another market, (5) power flowing into the system is consumed in a relatively constricted geographic area, (6) meters are based at the interface of transmission and distribution to measure flows into the distribution system and (7) local distribution systems are of reduced voltage. Some of these factors risk becoming outdated in light of the changes taking place on distribution systems in response to the increasing penetration of DERs.
- 13 See *PacifiCorp*, Order Accepting and Suspending Proposed Rates and Establishing Hearing and Settlement Judge Procedures, 136 FERC ¶ 61,092 (2011), Docket No. ER11-3643.
- 14 See *PacifiCorp*, Docket No. ER11-3643.
- 15 See Order on Initial Decision, 147 FERC ¶ 61,234 (2014), available at <https://www.ferc.gov/whats-new/comm-meet/2014/061914/e-7.pdf>. Similar to states, FERC has a set methodology for determining a reasonable and therefore allowable return on investment for transmission-owning utilities. It applies a two-step discounted cash flow that involves both a short and long-term growth rate analysis.
- 16 *New York v. FERC*, 535 U.S. 1 (2002). It is worth noting that neither FERC nor the Supreme Court has suggested that FERC *cannot* assert jurisdiction over the transmission component of bundled retail sales; instead the Court agreed with FERC's view that it *did not need* to do so in 1996 to address the discrimination FERC aimed to solve. Therefore, the current arrangement is not totally immune from future legal challenge by entities interested in promoting FERC's jurisdiction in this area regardless of whether western utilities join RSOs.
- 17 The states in which PacifiCorp operates utilize different standards of review. For example, with some exceptions Utah reviews rates to determine whether they are unjust, unreasonable, discriminatory, preferential or otherwise in violation of the law (U.C.A. Section 54-4-4) while Wyoming statute calls for consideration of whether utility investments are "used and useful for the convenience of the public" (WS 37-2-119).
- 18 Specific avenues for states to participate in RTO processes are outlined in *The Role of States in a Western Grid Operator*, available here: <https://www.nrdc.org/experts/allison-clements/role-states-western-grid-operator>.
- 19 Order 1000 requires regions to have default cost allocation methodologies in place to determine how cost allocation for new transmission projects driven by reliability, economic and/or public policy needs will be made. These allocation methodologies must satisfy the cost allocation principles discussed in Section III. B of this issue brief.
- 20 One exception to the beneficiary pays principle is when consideration of non-wires alternatives to new transmission is considered, since most often those resources remain subject to state jurisdiction and even if customers in other states would benefit by the avoidance of expensive transmission investments, costs cannot be spread across state borders.
- 21 The U.S. Court of Appeals for the Seventh Circuit, for example, twice rejected attempts by PJM to charge customers in the Western part of the region for new transmission development in the Eastern part of the region (*Illinois Commerce Commission v. FERC*, 576 F.3d 470 (7th Cir. 2009); *Illinois Commerce Commission v. FERC*, (7th Cir. 2014)). The same court upheld challenges to a cost allocation methodology instituted by the Mid-Continent Independent System Operator that spread costs across the region for a set of "multi-value projects" demonstrated to provide benefits to the entire region (*Illinois Commerce Commission v. FERC* (7th Cir. 2013)).
- 22 Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1261 *et seq.*, 119 Stat. 594 (2005) ("EPAAct 2005"). Section 219 of EPAAct 2005 required FERC to develop incentives to "promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities." Congress also encouraged utilities to join RTOs or ISOs by including that FERC's incentive program should make an incentive available to transmission-owning members of these regional organizations.
- 23 FERC implemented Section 219 in 2006 by establishing a transmission incentive rule called Order 679, available at <https://www.ferc.gov/whats-new/comm-meet/072006/E-3.pdf>. It revisited its rule in a 2012 policy statement, available here, <https://www.ferc.gov/whats-new/comm-meet/2012/111512/E-3.pdf>, and its subsequent orders considering incentive applications demonstrate a trend of reduction in the overall generosity of incentive packages it is awarding.
- 24 *PacifiCorp*, 125 FERC ¶ 61,076 at P 8 (2008). Two segments of the Gateway Project have been canceled: Hemingway-Captain Jack (southwest Idaho to southern Oregon) and the "southeast loop" of Gateway South into the Wyoming wind area. Our understanding is that since both decisions were made by PacifiCorp and not due to regulatory impasse.
- 25 See endnote 8.
- 26 See Order 1000 starting at P 558.
- 27 See, for example, <https://www.caiso.com/Documents/StrawProposal-TransmissionAccessChargeOptions.pdf>.