UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through	)	**RM21-17-000**
Electric Regional Transmission	)	
Planning and Cost Allocation	)	
and Generator Interconnection	)	

REPLY COMMENTS OF
THE AMERICAN COUNCIL ON RENEWABLE ENERGY

Pursuant to the Federal Energy Regulatory Commission's ("FERC" or "Commission") July 15, 2021 Advance Notice of Proposed Rulemaking and the September 3, 2021 notice issued in the above-captioned proceeding, the American Council on Renewable Energy ("ACORE") submits these reply comments.[1] As set out in ACORE's initial comments, current transmission planning processes have not led to increased transmission investment other than by interconnection customers required under participant funding models to fund significant system expansions as if they essentially were the expansion's sole beneficiary, which is discriminatory against all new generation, not just renewables. In turn, this has both led to piecemeal, inefficient and in some cases virtually no transmission investment, *and* slowed the deployment of low-cost renewable generation, oftentimes because the participant funded interconnection costs become unacceptably high and/or because queue delays caused by impossible to predict restudies make the development process unacceptably long.

Reforms, then, are not just badly needed, but essential if this country ever can meet its clean energy aspirations. Hence, participant funding should be eliminated as soon as possible and planning processes required to comprehensively consider and simultaneously evaluate the

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[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (2021) ("ANOPR").

full benefits, costs (including avoided emissions costs) and resilience capabilities of both existing *and* potential transmission projects, and the planners required to plan, proactively, for both future load *and* future generation and virtual generation in the form of storage.

Numerous commenters support eliminating participant funding and reforming transmission planning as ACORE has suggested, agreeing that the status quo is no longer maintainable. Opposing commenters, for the most part, contend the Commission doesn't need to do anything, arguing that participant funding is necessary to incentivize efficient generation siting, that directing transmission planning reforms is likely not within the Commission's authority, or that, in any event, the Commission should back off and let the disparate planning processes imbued with regional differences be left to gesticulate. They are wrong. They provide zero evidence that participant funding is necessary to incentivize efficient siting, and no serious analysis in support of their arguments that transmission planning reforms are outside the Commission's authority – at least no argument that has not already been addressed and rejected by the courts in upholding Order No. 1000.[2]

[2] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 57 (D.C. Cir. 2014).

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I. REPLY COMMENTS

A. The Commission Must Eliminate Participant Funding For Interconnection Upgrades.

Participant funding imperils the timely development of economically beneficial generation and no longer should be deemed to meet the just and reasonable requirement of the Federal Power Act.[3] Hence, ACORE has urged the Commission to proceed expeditiously to eliminate participant funding and to require transmission providers to adopt the Commission's crediting policy or possibly an alternative cost allocation rule such as one that would impose a non-refundable fee based on some reasonable, objective metric.

Indeed, numerous commenters from across the industry agree or are at least open to meaningful reforms.[4] International Transmission Company states there have been "massive increases" in generator interconnection-related network upgrade costs, yet these upgrades will provide benefits broadly to customers throughout the region, not simply the generators who are currently forced to bear their full capital costs.[5] Tenaska illustrated how, in practice under the current rules, interconnecting generators may be required to fund significant upgrades to transmission facilities already overloaded though unaddressed in any regional planning process.[6]

[3] "Comments of the American Council on Renewable Energy," at 6-14, Docket No. RM21-17-000 (Oct. 12, 2021) ("ACORE Comments").

[4] *See e.g.*, "Comments of the California Independent System Operator Corporation on Advance Notice of Proposed Rulemaking," at 91-95, Docket No. RM21-17-000 (Oct. 12, 2021) ("CAISO Comments"); "Comments of Eversource Energy," at 11-13, Docket No. RM21-17-000 (Oct. 12, 2021); "Comments of Tenaska, Inc. on the Advance Notice of Proposed Rulemaking," at 9-10, Docket No. RM21-17-000 (Oct. 12, 2021) ("Tenaska Comments").

[5] "Comments of International Transmission Company d/b/a ITC*Transmission*, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC," at 36, Docket No. RM21-17-000 (Oct. 12, 2021) ("ITC Comments").

[6] Tenaska Comments at 7-9.

CAISO suggests a participant financing procedure, under which the customer generally would be reimbursed for upgrade costs after five years.[7]

On the other hand, NYISO, for instance, opposes reforms arguing that generator-funded network upgrades in fact usually do benefit only the generator.[8] And ISO-NE claims the participant funding interconnection customers are fairly compensated for these upgrades.[9] And the North Carolina Commission argues that all transmission providers – not simply those in RTOs and ISOs – should be allowed to adopt participant funding.[10]

These arguments are misplaced. Even if an interconnection upgrade would not have been needed but for its being required by an interconnection customer, this does not mean only that customer is benefitted by that upgrade. Actually, the Commission rejected this "sole beneficiary" argument long ago, noting that "the Transmission System is a cohesive, integrated network that operates as a single piece of equipment, and that network facilities are not 'sole use' facilities but facilities that benefit all Transmission Customers," and for that reason the Commission's general policy does not permit directly assigning network upgrade costs.[11] Unquestionably, if anything, this is even more true today.

Indeed, it is increasingly common that the directly-assigned network upgrades are substantial new transmission lines that clearly benefit a broad array of system users and not just

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[7] CAISO Comments at 91-99.

[8] *See e.g.,* "Comments of the New York Independent System Operator, Inc.," at 38-40, Docket No. RM21-17-000 (Oct. 12, 2021) ("NYISO Comments").

[9] *See e.g.,* "Initial Comments of ISO New England Inc at 27-30, Docket No. RM21-17-000 (Oct. 12, 2021) (" ISO-NE Comments").

[10] "Comments of the North Carolina Utilities Commission," at 15-19, Docket No. RM21-17-000 (Oct. 12, 2021).

[11] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003–A, 106 FERC ¶ 61,220, at P 585, *order on reh'g*, Order No. 2003–B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003–C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

the interconnection customer.[12] In a study of 12 significant network upgrades recently identified in MISO and SPP and to be directly assigned to generators, ten showed production cost savings and favorable benefit-to-cost ratios (even under very conservative modeling assumptions),[13] and were found to:

> provide benefits to the system by enabling more low-cost renewable output, which leads to reduction in fossil-fired generation and associated emissions attributed to those generators. … The network upgrades also eased existing chokepoints in SPP and MISO, which is beyond their primary purpose of integrating renewables.[14]

Contrast the evidence used above to substantiate ACORE's position with ISO-NE's entirely theoretical assertion offered to substantiate its suggestion that under participant funding, customers are adequately compensated. To the contrary, in its comments, ACORE stated that to its knowledge, *no* project *ever* received meaningful compensation under participant funding rules.[15] Presumably, commenters would have presented at least some examples to the contrary, if indeed there were any. What we do see, though, is evidence of the opposite. Recently, SPP removed from its Tariff this hypothetical compensation mechanism whereby customers received credits for funded network upgrades.[16]

Some commenters argue that returning to the Commission's crediting policy would be unworkable in RTOs, and that network upgrade costs could be allocated unfairly to the resource

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[12] *See e.g.,* ACORE at 20, Exhibit 2 at 16 ("[l]arge new transmission additions create broad-based regional benefits by providing customers with more affordable and reliable power, so charging only interconnecting generators for this equipment requires them to fund infrastructure that benefits others.").

[13] ACORE Comments, Exhibit 5 at 7 ("[T]he economic benefits evaluated and described in this report are conservative and may understate the full benefits of the projects to consumers].")

[14] *Id.* at 4-7.

[15] ACORE Comments at 9.

[16] *See Southwest Power Pool, Inc.* 166 FERC ¶ 61,160 (2019); *Southwest Power Pool, Inc.*, 171 FERC ¶ 61,272 (2020).

zones, rather than to load zones, resulting in unfair benefits.[17] But CAISO's current crediting model clearly rebuts this claim.[18] And whether interconnection customers in RTOs do or do not take transmission service to facilitate crediting, there is always the option for customers to receive a lump sum payment as allowed under the current crediting policy. And as to the concern that the related costs might be allocated unfairly within the RTO, there is no basis for concluding that upgrade costs always would be allocated solely to a single zone, nor any reason to believe that rules could not be developed to prevent any unfair allocation. Indeed, the Commission has recognized that such arrangements might very well be appropriate.[19]

The fact that adopting a different cost allocation model could, hypothetically, present a challenge provides no grounds for avoiding reforms, particularly given that network upgrade costs actually *are* being unfairly allocated under current participant funding models. Tenaska's Clear Creek project mentioned above provides but one stark example of a generator being assigned the full costs of substantial system additions, where certain facilities across the SPP/MISO/AECI seam were already overloaded. There, instead of these overloads being addressed in a regional or interregional planning process, Clear Creek was told it would have to pony-up the approximately $66 million required to construct the upgrades necessary to redress these preexisting conditions.[20] By definition, *any* network upgrades required to ameliorate pre-existent overloads necessarily benefit pre-existent customers and not merely the interconnection customer.

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[17] *See e.g.,* "Comments of Transmission Access Policy Study Group," at 41-44, Docket No. RM21-17-000 (Oct. 12, 2021) ("TAPS Comments"); "Initial Comments of Ameren Services Company," at 15, Docket No. RM21-17-000 (Oct. 12, 2021) ("Ameren Comments"); NYISO Comments at 42-43.

[18] CAISO Comments at 73-75.

[19] ANOPR at P 129.

[20] Tenaska Comments at 7-9.

Some commenters claim that doing away with participant funding could undermine incentives for efficient siting.[21] They further argue that the oftentimes enormously high cost increases that generators increasingly bear under the participant funding rules does not mean participant funding is necessarily flawed, but suggest those increases could be attributable to other factors such as labor costs or siting choices.[22] Aside from being completely unsupported with facts, these arguments don't even have a credible theoretical underpinning. These commenters misunderstand the relevant cost incentives.

As an initial matter, the Commission's crediting policy still requires interconnection customers initially to fund assigned network upgrades and, to the extent upgrade costs incentivize efficient siting, the crediting policy reflects this incentive. But there are many other factors that influence siting decisions, particularly in regard to wind and solar projects where siting decisions depend most critically and, therefore, first and foremost, on resource availability. ACORE challenges any proponent of participant funding to provide a single example of a situation when, in an area where crediting *did* apply, a renewable developer would not have purchased or optioned a site but for that fact.

One commenter asserts that participant funding is not causing queue delays given that non-RTO queues are backlogged as well.[23] MISO argues that the large number of interconnection requests in its queue is evidence that costs imposed under its participant funding model are not a barrier to interconnection and notes that while upgrade costs may have increased

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[21] *See e.g.,* "Comments of the National Rural Electric Cooperative Association," at 29-30, Docket No. RM21-17-000 (Oct. 12, 2021); "Comments of American Municipal Power, Inc.," at 20-22, Docket No. RM21-17-000 (Oct. 12, 2021) ("AMP Comments"); TAPS Comments at 44-45; "Comments of Southern Company Services, Inc.," at 39, Docket No. RM21-17-000 (Oct. 12, 2021) ("Southern Comments").

[22] *See e.g.,* Ameren Comments at 17-18.

[23] "Motion to Intervene and Initial Comments of the Entergy Operating Companies," at 22-23, Docket No. RM21-17-000 (Oct. 12, 2021) ("Entergy Comments').

in its earlier studies (i.e., Phase 1 and 2 studies), they have not in Phase 3.[24] This is irrelevant. The costs imposed on customers under a participant funding regime are unjust and unreasonable; they neglect the significant benefits to other parties of the lone customer-funded upgrades; and they make it all the more difficult for customers to start constructing their projects until every last iterative study is completed because otherwise they would have no idea as to how much money they might have to put up and never see again. The fact that there might also be issues with non-RTO queues does not change this one.

MISO is also incorrect to equate the large number of pending interconnection requests and wide cost fluctuations between the early and later stages of its study process with a functioning interconnection process. For instance, an experienced developer recently had to abandon a project that was in late stage PPA negotiations after being allocated over $70 million in upgrade costs;[25] and it now has effectively abandoned development efforts in large portions of the MISO footprint due to "the combination of lengthy study timelines with high-cost allocation risk and ineffective interconnection policies."[26] Interconnection customers intend to pursue the requests they submit, and the fact that through the study process, many requests are rendered unviable due to delays and unreasonable interconnection costs does not mean that the process is working; it means it is not and is in need for reform.

1. **<u>Placing additional burdens on "serious" interconnection customers in order to discourage or disadvantage "speculative" projects does not</u>**

[24] "Comments of the Midcontinent Independent System Operator, Inc.," at 90-94, Docket No. RM21-17-000 (Oct. 12, 2021).

[25] "Comments of EDP Renewables North America LLC," at 9, Docket No. RM21-17-000 (Oct. 12, 2021) ("EDPR Comments").

[26] *Id.* at 8-9.

address, much less justify, the cost uncertainty that is hindering all interconnection efforts.

Certain commenters advocate for reforms to advantage certain interconnection requests, often those the interconnecting utility owns or has contracted with. Some support fast tracking "ready" projects."[27] It is unclear how, exactly, any request could be deemed "ready" at the outset of the interconnection process. But it is clear that implementing a separate, faster interconnection track -- with the "off-track" projects left to languish in the primary interconnection queue while waiting on the results of years-long, and iterative study processes -- would create an unacceptable opportunity for undue discrimination, particularly when the fast track criteria almost certainly would end up favoring the owner(s) of the transmission system. This would be the case, for example, if fast-tracking required the interconnection customer to show it already had been selected in an RFP or already had executed a PPA before even having ascertained it would be able to execute an LGIA.[28]

Other commenters focus on limiting the number of permitted requests[29] or imposing additional readiness criteria to discourage "speculative" projects.[30] But here, too, they provide no rationale for why an arbitrary limit on the permitted number of interconnection requests is justified; and, aside from it being per se unreasonable – and quite possibly anticompetitive in certain service territories. Additional readiness requirements should also be rejected. Readiness

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[27] *See e.g.,* "Initial Comments of Avangrid, Inc.," at 18-19, Docket No. RM21-17-000 (Oct. 12, 2021) ("Avangrid Comments"); "Motion to Intervene and Comments of the National Association of Regulatory Utility Commissioners," at 35-36, Docket No. RM21-17-000 (Oct. 12, 2021); Southern Comments at 7-8, 40-42.

[28] Because most potential offtakers require a project to have an executed interconnection agreement before executing an offtake agreement, a fast-track option would only realistically benefit projects that the interconnecting utility had already selected in its RFP process and with which it may have already contracted with.

[29] *See e.g.,* "Comments of WIRES," at 19, Docket No. RM21-17-000 (Oct. 12, 2021); ITC Comments at 49-50.

[30] *See e.g.,* "Comment of Southern California Edison Company," at 6-8, Docket No. RM21-17-000 (Oct. 12, 2021); "Initial Comments of the Edison Electric Institute," at 37-38, Docket No. RM21-17-000 (Oct. 12, 2021) ("EEI Comments"); "Initial Comments of the American Public Power Association on Advance Notice of Proposed Rulemaking" at 26-27; Southern Comments at 40-42; Avangrid Comments at 18-19.

requirements can impose enormous burdens for customers. For instance, EDPR described how it secured full site control for a project (as required under SPP's rules) before entering the queue in 2017; but now, over four years later, SPP's study process is still not complete and EDPR continues to incur costs of maintaining site control.[31] Moreover, imposing these additional burdens on customers in order simply to enter and proceed through the queue clearly has not and will not address the underlying issues, principal among which is the uncontested fact that iterative study processes almost invariably take several years to complete. This alone would render "readiness" demonstrations all the more unreasonable, and only serve to exacerbate the uncontrollable cost uncertainty with which customers still would have to contend throughout the study process – indeed, oftentimes even after their having executed an interconnection agreement.

To its credit, one commenter, American Electric Power, while proposing a fee to "discourage speculative projects from entering the queue," and a bond that would be forfeited for failure to timely proceed and begin construction,[32] at least acknowledged the need to address the cost uncertainty issues developers face, particularly as to affected system costs. It proposes making the costs identified at the conclusion of the study process final costs, and requiring that affected systems complete studies sooner.[33] But as previously noted, additional fees and deposits subject to forfeiture already have been implemented in many interconnection queues, yet have done little to reduce queue delays because they do not address the processes' primary ailment,

[31] EDPR Comments at 10-12.

[32] "Initial Comments of American Electric Power Service Corporation," at 37-38, Docket No. RM21-17-000 (Oct. 12, 2021) ("AEP Comments").

[33] AEP Comments at 38-40.

the iterative study delays and cost uncertainties developers presently face.[34] However, AEP is correct that developers should receive additional information at the outset about available capacity at given points on the system and provided greater cost certainty, including as regard to affected system issues. These, indeed, are some measures that finally could begin to address the current queue delays and its oftentimes calamitous results.

2. **Transmission owner self-funding proposals already have been rejected.**

Some transmission owners insist they should be entitled to recover a return on network upgrades funded by interconnection customers.[35] The Commission has already ruled on these self-funding arguments and there is no reason to revisit those findings here.[36] Moreover, if transmission owners wish to recover a return on network upgrades, the solution is simply to eliminate participant funding and implement the Commission's crediting policy which, upon reimbursing the interconnection customer, permits the transmission owner to recover as high a return as it could justify.

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[34] ACORE Comments, Exhibit 2 at 17 ("Queue reform has attempted to reduce queue length and dropouts with larger financial deposits from interconnecting generators, yet queue backlogs continue to grow because queue reform has not addressed the fundamental problem of requiring interconnecting generators to pay for large network transmission elements that benefit the entire region.").

[35] *See e.g.,* "Comments of Louisville Gas and Electric Company and Kentucky Utilities Company," at 10-11, Docket No. RM21-17-000 (Oct. 12, 2021) ("LGE Comments"); "Initial Comments of National Grid Plc," at 38, Docket No. RM21-17-000 (Oct. 12, 2021) ("National Grid Comments"); EEI Comments at 35-37; "Comments of the Indicated PJM Transmission Owners," at 37-38, Docket No. RM21-17-000 (Oct. 12, 2021) ("PJM TO Comments").

[36] *New York Independent System Operator, Inc.*, 176 FERC ¶ 61,143 (2021), *reh'g denied*, 177 FERC ¶ 62,068; *Central Hudson Gas & Electric Corporation v. New York Independent System Operator, Inc.*, 176 FERC ¶ 61,149 (2021), *reh'g denied*, 177 FERC ¶ 62,067.

B. A More Comprehensive And Proactive Transmission Planning Approach Is Needed.

The current regional planning processes are not meeting the nation's transmission needs, hindering new generation and, ultimately, hurting consumers.[37] The Department of Energy ("DOE") was clear about the consequences of failing to act, noting that:

> [I]f transmission is not planned far enough ahead to take the needs of likely new generation into account, the lack of appropriately sited and sized transmission capacity will impede the timely development of needed new generation and lead to higher costs of generation and transmission in the long term – with adverse implications for system reliability, resilience, consumers' electricity rates, and the achievement of clean energy goals.[38]

And DOE was similarly frank in stating that the currently siloed planning procedures:

> hinder[] a comprehensive assessment of system impacts and the ability to measure benefits relative to cost, potentially resulting in suboptimal investments and outcomes.[39]

ACORE strongly supports a more proactive, comprehensive and, to a reasonable degree, generic transmission planning process, and was pleased that a wide range of commenters – including some transmission owners and state representatives – support similar objectives.[40] Specifically, it is critical that the Commission establish a planning framework that more comprehensively assesses project benefits and system requirements, including the need for, or at a minimum, the projected presence of, future generation. As noted by National Grid, this could

[37] *See generally* ACORE Comments at 13, 18-23.

[38] "Comments of the United States Department of Energy to Advance Notice of Proposed Rulemaking," at 10, Docket No. RM21-17-000 (Oct. 12, 2021) ("DOE Comments").

[39] DOE Comments at 36.

[40] *See e.g.,* "Comments of the Solar Energy Industries Association," at 5-6, Docket No. RM21-17-000 (Oct. 12, 2021), "Comments of Advanced Energy Economy," at 12-18, 24, Docket No. RM21-17-000 (Oct. 12, 2021); "Initial Comments of the New England States Committee on Electricity," at 35-41, Docket No. RM21-17-000 (Oct. 12, 2021); PJM TO Comments at 3, 24-26; "Comments of the New York Transmission Owners," at 2-4, Docket No. RM21-17-000 (Oct. 12, 2021); ; "Initial Comments of Massachusetts Attorney General Maura Healey," at 5-7, Docket No. RM21-17-000 (Oct. 12, 2021).

include establishing specific planning criteria for clean energy, be it required to satisfy anticipated market demand, to preserve or enhance resiliency and reliability or to meet state and federal policies in regard to climate or clean energy in general.[41]

Some commenters oppose such requirements and advocate, instead, for regional flexibility.[42] But a general claim of regional differences is insufficient and little more than a shibboleth. The burden should be placed squarely on the transmission providers to justify with specificity why any deviation from the Commission's requirements would be necessary based on specific regional characteristics, and why any sought after allowance for regional variation reasonably could be expected to accomplish not simply the Commission's general policy, but the purpose for which each of the specific provisions in a Commission-created planning process pro forma was intended – section by section. If indeed nobody does it better than this or that region, it should be small potatoes to demonstrate why.

1. **Transmission planning reforms are within the Commission's authority to require.**

Some commenters question whether the Commission has jurisdiction to mandate transmission planning reforms, such as requiring planners to account for future generation.[43] It does, and it should.[44] One commenter describes how, among other things, the lack of uniform standards in regional planning processes provides transmission providers with excessive

[41] National Grid Comments at 5-8.

[42] *See e.g.,* EEI Comments at 15, 24-25; ISO-NE Comments at 17-24.

[43] *See e.g.,* "Initial Comments of Xcel Energy Services," at 4-8, Docket No. RM21-17-000 (Oct. 12, 2021); Southern Comments at 17-22, 27-29; Comments of the Alabama Public Service Commission, at 2, Docket No. RM21-17-000 (Oct. 12, 2021) ("Alabama PSC Comments"); "Comments of the Louisiana Public Service Commission," at 4-9, 13-17, Docket No. RM21-17-000 ("Oct. 12, 2021) ("Louisiana PSC Comments").

[44] This is consistent with precedent stating the while states retain authority over in-state generation, FERC, of course, has plenary authority over interstate wholesale rates. *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1298 (2016).

discretion and creates opportunities for undue discrimination and is, therefore, well within the Commission's jurisdiction to remedy.[45] Indeed it is; and the needed reforms would simply build on the actions already taken in Order No. 1000. The Commission concluded in Order No. 1000 that it had authority under Section 206 to adopt reforms "intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential."[46] And this was upheld in the courts.[47] Commenters' vague suggestions otherwise are unsupported. Indeed, in affirming Order No. 1000, the court expressly stated that "[r]eforming the practices of failing to engage in regional planning and *ex ante* cost allocation for development of new regional transmission facilities… involves a core reason underlying Congress' instruction in Section 206."[48] Moreover, planning for future generation would respect and, indeed, accommodate state authority over that generation, and as one commenter notes, the failure of the current transmission planning practices to account for clean energy policies is likely to result in rates that are not just and reasonable or are unduly discriminatory which the Commission is obligated to address.[49]

[45] "Comment of the Harvard Electricity Law Initiative" at 31-35, Docket No. RM21-17-000 (Oct. 12, 2021).

[46] Order No. 1000 at P 99.

[47] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils*., Order No. 1000, 136 FERC ¶ 61,051 (2011), order on reh'g and clarification, Order No. 1000-A, 139 FERC ¶ 61,132, order on reh'g and clarification, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom., S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[48] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 57 (D.C. Cir. 2014).

[49] *See* "Comments of PSEG," at 3-6, Docket No. RM21-17-000 (Oct. 12, 2021).

Some commenters argue that planning for future generation is too speculative,[50] or that more clarity is needed on how future generation will be measured.[51] Certain commenters do not support planning for future generation due to uncertainties in the quantity and location of that new generation and oppose requiring transmission planners to account for anticipated new generation.[52] But doing so already occurs in various types of plans. The suggestion that transmission planning should await absolute certainty would effectively ensure failure of any effective transmission planning. It is important that the Commission establish the procedures now so that regions can plan for future, which will be dictated by, among other things, the demands of businesses, consumers, and states. Planning for these changes through regional and interregional processes, rather than the current haphazard approach of relying on the generator interconnection queue, would be more cost-effective;[53] and to the extent parties may argue that planning now for the future may impose associated costs on consumers, the Federal Power Act does not require the lowest possible rate, particularly where those costs are tied to responsible planning for the future.[54]

As previously noted, the transmission planning and interconnection processes currently operate on different timelines and assess different time horizons.[55] The issue here is long-term

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[50] *See e.g.,* "Joint Comments of the Industrial Customer Organizations," at 22-23, Docket No. RM21-17-000 (Oct. 12, 2021); AMP Comments at 19.

[51] Entergy Comments at 10-15.

[52] "Comments of Potomac Economics, Ltd," at 2-4, Docket No. RM21-17-000 (Oct. 12, 2021) ("Potomac Economic Comments"); "Comments of the Independent Market Monitor For PJM," at 2-6, Docket No. RM21-17-000 (Nov. 1, 2021).

[53] "Potential customer benefits of interregional transmission," General Electric International, Inc., at 16 (Nov. 29, 2021) ("Interregional Benefits Memo") (attached hereto as Exhibit 7).

[54] *See e.g., Commonwealth Edison Co.,* 113 FERC ¶ 61,278 P 44 (2005) ("With respect to whether or not the proposal 'will result in the lowest price for customers,' we note that our standard for reviewing rates is whether those rates are just and reasonable."); *Potomac Elec. Power Co. v. Allegheny Power Sys*., 85 FERC ¶ 61,160 n.7 (1998) ("[T]he Commission's mandate is not to set the lowest possible rate.").

[55] ACORE Comments at 24.

transmission planning that does not depend on any particular facility or interconnection request. And there is already ample evidence that broader long-term trends and shifts in the generation fleet are underway. For instance, states and utilities serving millions of households and businesses have committed to transitioning to 100 percent clean power.[56] A number of states currently have a binding 100% clean or renewable energy standard or a binding net-zero requirement that applies to electric distribution utilities.[57] Furthermore, 232 individual utilities are subject to a 100% carbon-reduction target set by a state and 72% of customer accounts are served by an individual utility with a 100% carbon-reduction target, or a utility owned by a parent company with a 100% carbon-reduction target.[58] These trends toward renewable generation are only expected to increase, and transmission will be required to integrate this generation.[59]

Commenters' concerns that the precise location of any particular anticipated generation facility may be presently unknown, or that it is uncertain as to whether any particular project with a pending queue position ever will be constructed, in no way preclude moving forward with the much-needed reforms. If ever there was an example of the perfect being the enemy of the good, this is it. These arguments ignore that planning processes already generally account for future load, presumably based on modeling and assumptions about the future that are less than 100% certain, and commenters give no good reason why future generation could not also be accounted for within a similar framework. For instance, DOE proposes establishing a common

[56] "Race to 100% Clean," Natural Resources Defense Council (Dec. 2, 2020), available at: https://www.nrdc.org/resources/race-100-clean.

[57] "Utilities' path to a carbon-free energy system," Smart Electric Power Alliance, available at: https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.

[58] *Id.*

[59] *See* Interregional Benefits Memo at 4-5.

modeling framework to maintain consistency and comparability in regional transmission planning and cost allocation processes and standardizing, as appropriate, model inputs and assumptions, scenarios and time horizons.[60] These planning models and standardized inputs could also reflect relevant policy goals and other factors such as state-approved integrated resource plans and retirements.[61]

Some commenters suggest that accounting for future generation or geographic energy zones would be inconsistent with the Commission's general cost causation principles.[62] The Alabama Public Service Commission asserts that the benefits of such an approach are "possibly unquantifiable."[63] ACORE does not support, nor does it understand the Commission to contemplate, imposing transmission facility costs on entities that do not benefit from them. But a system of planning for only very specific constraints[64] and taking a narrow view of project beneficiaries has demonstrably contributed to the piecemeal, dysfunctional planning observed today. And a common modeling framework that accounts for relevant policy goals, including state-approved IRPs, and that comprehensively identifies the true benefits and beneficiaries of these projects could more effectively identify transmission needs as well as associated beneficiaries. Can there be any doubt that *if* one were to assume that the purpose of a new transmission line was to deliver clean power from a point just outside the western border of a state to a point just outside its eastern border, and that this power would displace power from a coal plant at that same location, that everyone in that state would benefit from this reduction in

[60] DOE Comments at 12-15.

[61] *Id.* at 16-18.

[62] *See e.g.,* Louisiana PSC Comments at 13-17; Alabama PSC Comments at 2; AMP Comments at 19.

[63] Alabama PSC Comments at 2.

[64] Potomac Economics Comments at 3.

emissions regardless of who comes to pay for that power. It is folly not to include the avoided costs of carbon in any determination as to who benefits from the asset, and any reasonable carbon value assigned should clearly demonstrate substantial benefits. How could we not, and yet claim to be planning for a clean energy future.

Planning reforms that will finally begin to produce regional and interregional transmission projects are badly needed. Recent legislation emphasizes the importance of advancing these projects and even expands the Commission's backstop siting authority.[65] Given that backstop siting is a two-step process under which DOE has a role in identifying National Interest Electric Transmission Corridors and the Commission has a role in siting approvals, the Commission and DOE should collaborate to make this process as efficient as possible, while understanding the role for states in this process.[66]

1. **There are already models for identifying and planning for geographic energy zones.**

ACORE supports identifying and planning for geographic energy zones, and do many other commenters.[67] Some, however, oppose this approach. Some utility commenters claim they are not experts in identifying geographic energy zones.[68] Stipulated. But utilities were not experts in offering non-discriminatory transmission services either, or in identifying and paying for ancillary services, or in separating their transmission and generation services – until, that is, they were required to do so. Moreover, there is no reason that stakeholders should not be able to assist here, or why an expert could not be retained for this task; and just as planning for future

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[65] Infrastructure Investment and Jobs Act, Pub. L. No. 117-58 § 40105, 135 Stat 429.

[66] *See id.*

[67] *See e.g.,* National Grid at Comments 18-20; "Comments of EDF Renewables, Inc.," at 6-7, Docket No. RM21-17-000 (Oct. 12, 2021).

[68] LGE Comments at 12.

load is done without knowing with certainty just how that load might vary, as is planning for future transmission, as is planning even in the context of integrated resource planning at the state level, planning for future generation should not require any more certainty than these other efforts. It all is a question of who is permitted to supply the inputs, and how.

Commenters also argue that identifying geographic energy zones could potentially attract speculative developers.[69] Some suggest requiring a signed interconnection agreement or lease or other evidence of commitment.[70] Others propose an "open season" concept where planners hold procurements for transmission or upgrades and interconnection customers could sign up similar to how anchor shippers would.[71] As an initial matter, though, while there may well be some degree of uncertainty in the planning process, and in identifying appropriate geographic energy zones, the resource rich areas are already generally well-known, as are the end-use markets.[72] Moreover, stakeholder engagement, such as state or RTO-level committees, may be a helpful forum for identifying these zones. And requiring a signed lease or interconnection agreement at the outset of this process, which require projects to already be relatively advanced in the process, would hamstring any ability for long-term and strategic transmission planning. Similarly, requiring developers to commit at the outset through an "open season" would do nothing to address the cost and timing uncertainty endemic to the interconnection process that ultimately renders so many requests unviable. Moreover, there are already examples of transmission planners identifying and planning for geographic energy zones, including the CAISO model

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[69] "Comments of the Electric Power Supply Association," at 10-12, Docket No. RM21-17-000 (Oct. 12, 2021) ("EPSA Comments").

[70] DOE Comments at 27-28, 30.

[71] *See e.g.,* EPSA Comments at 8-10; "Comments of Vistra Corp.," at 12-13, Docket No. RM21-17-000 (Oct. 12, 2021).

[72] DOE Comments at 24.

discussed in ACORE's initial comments, Texas's Competitive Renewable Energy Zones initiative and MISO's Multi-Value Projects noted in the ANOPR.[73] In contrast, commenters cite no evidence of those models attracting "speculative" developers or necessitating the additional obstacles proposed here, such as an open season.

C. **At A Minimum, A Common Analytic Framework And A Pro Forma Process Is Needed To Ensure Efficient And Effective Interregional Planning.**

ACORE strongly supports reforms to better coordinate interregional planning processes.[74] There needs to be a functional interregional planning process, so there is some consistency between regions, even if there is also some regional variability.[75] Some commenters suggest this is unnecessary.[76] But while it may be the case that new interregional development is not needed in every single region of the country, this cannot be known without a coordinated process for identifying these needs where they exist. This is particularly important given that recent studies modeling the benefits of interregional transmission across the Western and Eastern Interconnects have demonstrated significant cost savings for consumers.[77]

Some commenters propose establishing a minimum interregional transfer capability.[78] Another commenter proposes that interregional planning should be done by an "Independent System Planner" entity.[79] These may be worthwhile approaches. As commenters note, one of

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[73] ACORE Comments at 26; ANOPR at PP 55-60.

[74] ACORE Comments at 27; *see also* "Comments of Amazon Energy LLC," at 2-4, Docket No. RM21-17-000 (Oct. 12, 2021).

[75] DOE Comments at 35.

[76] "Initial Comments of PJM Interconnection, L.L.C.," at 69-75, Docket No. RM21-17-000 (Oct. 12, 2021) ("PJM Comments").

[77] Interregional Benefits Memo at 4.

[78] *See e.g.,* PJM Comments at 69-75; AEP Comments at 21-24; "Comments of LS Power Grid, LLC to the Commission's Advanced Notice of Proposed Rulemaking," at 63, Docket No. RM21-17-000 (Oct. 12, 2021) ("LS Comments").

[79] LS Comments at 79-84.

the main barriers to effective interregional planning is establishing a "need" for the project through all three processes.[80] And establishing a minimum interregional transfer capability proposal could address that barrier by affirmatively defining a need and allowing transmission planners to move beyond the current focus primarily on coordination procedures to focus on addressing the defined need. Indeed, the current cost of failure to invest in adequate interregional transfer capability may itself lead to unjust and unreasonable results.[81] At a minimum, there needs to be a common analytic framework for interregional planning and this could include assessing the operational, adequacy and stability benefits of interregional transmission capacity and determining an appropriate interregional transfer capability requirement based on a comprehensive assessment of all three areas.[82] Given the importance of interregional development, the Commission should establish a common interregional planning process and continue stakeholder discussions of establishing a minimum interregional transfer capability.

[80] *See e.g.,* AEP Comments at 19-20.

[81] *See* ACORE Comments at 22, *citing* Resilience Report at 2 (stating that "during the February 2021 Winter Storm Uri, each additional GW of transmission between ERCOT and the Southeast could have saved nearly $1 billion; and in parts of the Central U.S. consumers could have avoided power outages and saved over $100 million for each GW of transmission ties to power systems in the East.").

[82] Interregional Benefits Memo at 19-20.

II. **CONCLUSION**

For the foregoing reasons, ACORE respectfully requests that the Commission accept these reply comments and issue a notice of proposed rulemaking including the reforms proposed in the ACORE Comments and herein, as soon as practicable.

Respectfully submitted,

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Counsel for American Council on Renewable Energy

November 30, 2021

EXHIBIT 7

Potential customer benefits of interregional transmission

Memo to

American Council on Renewable Energy (ACORE)

Submitted by:	General Electric International, Inc.
Revision No.	Final
29 November 2021	

FOREWORD

This memo was prepared by General Electric International, Inc. (GEII), acting through its Energy Consulting group, based in Schenectady, New York. Questions and any correspondence concerning this document should be referred to:

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Motivation

This memo is being provided to ACORE in support of their comments to FERC's Advance Notice of Proposed Rulemaking: *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*.

Summary: Interregional transmission can enhance grid reliability, enable consumer benefits

State governments, utilities, and large energy buyers are mandating a shift to carbon-free resources while grid reliability is simultaneously being challenged by extreme weather events. Given their cost-competitiveness compared to alternatives,[1,2] these new carbon free resources will likely be in the form of new wind and solar generation. Reliability can be maintained with high penetrations of variable renewable energy in three ways:

1) *Adequacy*: Long term supply-demand balance resilient to grid uncertainties (e.g. outages, weather)
2) *Operational*: Day-to-day supply-demand balance for all time periods
3) *Stability*: System strength to sustain voltage and frequency

California, Denmark, and SPP are examples of three regions achieving hours of renewable penetration >70% with significant ramping, and high reliance on inverter-based resources. Each of them are leaning into new reliability approaches by utilizing a menu of industry best practices. **One of the most technically impactful and cost-effective best practices they both utilize is regionalization**. Certainly, California remains challenged by the effects of extreme weather but without such regionalization, one could argue, the impacts of prior events would have been even more devastating.

GE Energy Consulting forecasts a 2035 United States that will look similar to the SPP, California and Denmark of 2020. The value of regionalization that has been validated for SPP, California and Denmark should be assessed for the broader US.

GE Energy Consulting has suggested a methodology to assess the incremental transmission requirement for a regionalized future US with higher renewables and extreme weather uncertainty. This incremental requirement would be based on a holistic assessment of three areas of reliability benefit:

1) *Operational:* Incremental interregional transmission can enable lower wind and solar curtailment which results in fuel cost savings.
2) *Adequacy:* Incremental interregional transmission can enable higher generation diversity in the face of uncertainties such as: generation, transmission or fuel outages or extreme weather events.
3) *Stability:* Incremental interregional transmission can enable greater system strength to avoid unintentional unit tripping due to fluctuations in voltage, frequency or unwanted oscillations.

[1] E.g. Lazard LCOE 15.0, https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf

[2] UT Austin, https://calculators.energy.utexas.edu/lcoe_map/#/county/tech (selecting for "availability zones" filter)

Today, there are limited practices in place for each region to evaluate the consumer benefits of interregional transmission on their own. Recent studies modeling the benefits of interregional transmission across the Western and Eastern Interconnects have demonstrated significant cost savings for consumers.[3,4] National-level guidance would help chart the path towards realizing the benefits of greater regionalization.

1 Decarbonization mandates are changing the energy mix

In the United States, and around the world, decarbonization mandates are driving a change in our energy mix. Countries, states, utilities, and companies are all taking on new mandates to decarbonize their operations. While the timing varies, many of these entities have some permutation of net zero carbon goals by 2050 at the latest. Indeed, many have announced more bold near-term goals by 2030 or 2040. We have summarized these goals in Figure 1 along with average electric generation mix.

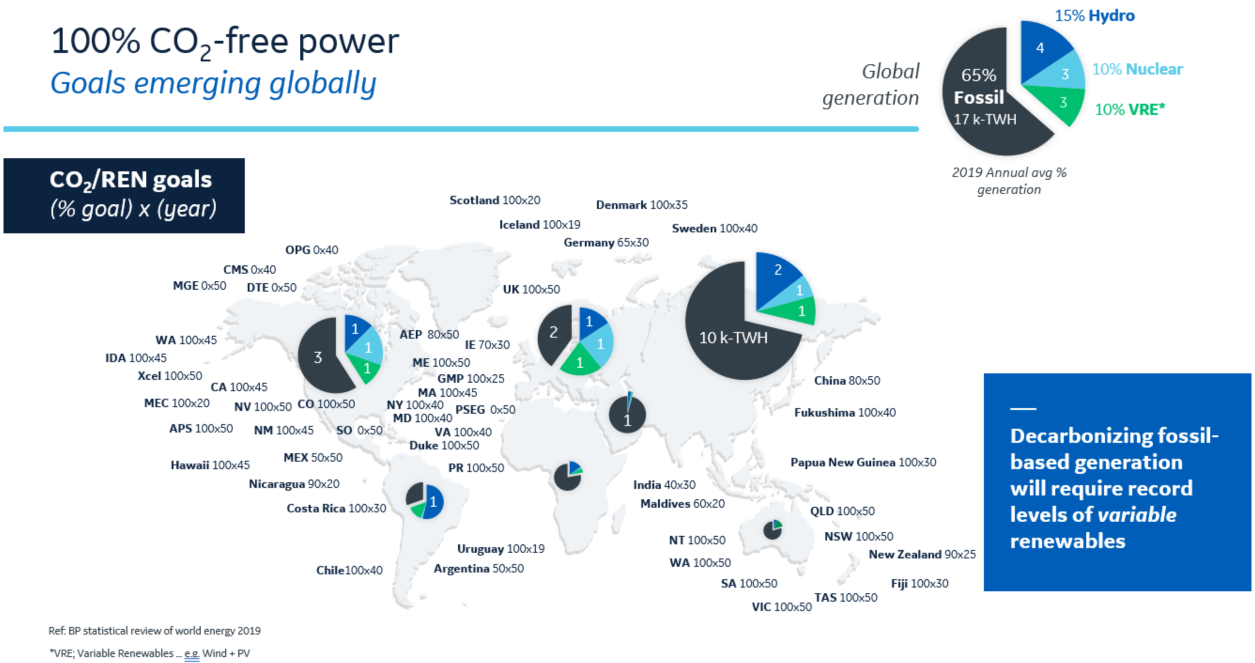


Figure 1 Global electricity generation mix along with decarbonization goals by various types of entities.

While hydro and nuclear form the majority of today's carbon-free forms of generation, given their limited availability, cost, permitting and siting challenges, the future generation mix will likely rely on

[3] Clack and Goggin, Consumer, Employment and Environmental Benefits of Electricity Transmission in the Eastern U.S., October 2020, (optimizing transmission build across the Eastern Interconnect would save consumers ~$105B through 2050), *available at* https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf

[4] Energy Strategies and the Western Interstate Energy Board, Western Flexibility Assessment, December 10, 2019 (noting that absent market coordination and increased regionalized transmission, achieving state policy targets in the 2020s becomes more difficult and costly), *available at* https://westernenergyboard.org/wp-content/uploads/2019/12/12-10-19-ES-WIEB-Western-Flexibility-Assessment-Final-Report.pdf

record amounts of new variable renewables … i.e. new wind and solar facilities. **New penetrations of wind and solar energy are central to achieving decarbonization mandates** in the electric power sector and for non-electrical carbon-emitting sectors like transportation and building heating and cooling.

2 Extreme weather events are challenging reliability

The U.S. power sector is increasingly feeling the effects of grid outages due to extreme weather. According to a recent analysis published by the US EIA, extreme events have been the main source of lost hours per customer in 2020.

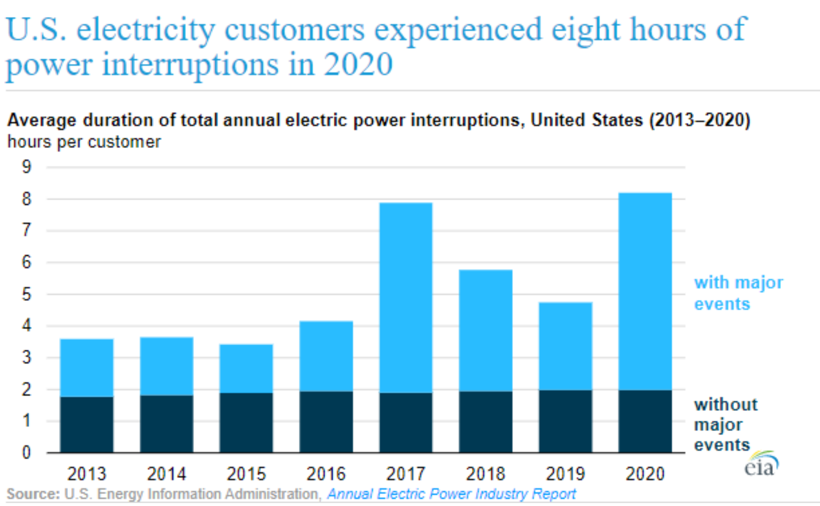


Figure 2 Analysis from the US EIA highlighting how major events accounted for six out of the eight outage hours per customer in 2020.[5]

According to the EIA, **2020 was the highest year of power interruptions since the agency began collecting data back in 2013**.[5] Notable recent storm-related outages included:

- August 2020: Louisiana & Texas—Hurricane Laura
- August 2020: Connecticut--Tropical Storm Isaias
- August 2020: Iowa derecho (extreme thunderstorm)
- August 2020: California heat wave
- October 2020: Oklahoma ice storm
- November-December 2020: Several winter storms in Maine
- February 2021: Texas freeze (Winter Storm Uri)

The key question is: **how do we continue to decarbonize our energy mix in a way that economically benefits consumers while also improving resilience to extreme weather events?**

[5] https://www.eia.gov/electricity/data/eia861/

3 Several regions are already achieving high variable renewable penetrations

While most of the world is currently below 20% variable renewables penetration, if we zoom in on the US and Europe as shown in Figure 3, we can see several examples of countries or regions that are achieving higher levels of renewables penetration.

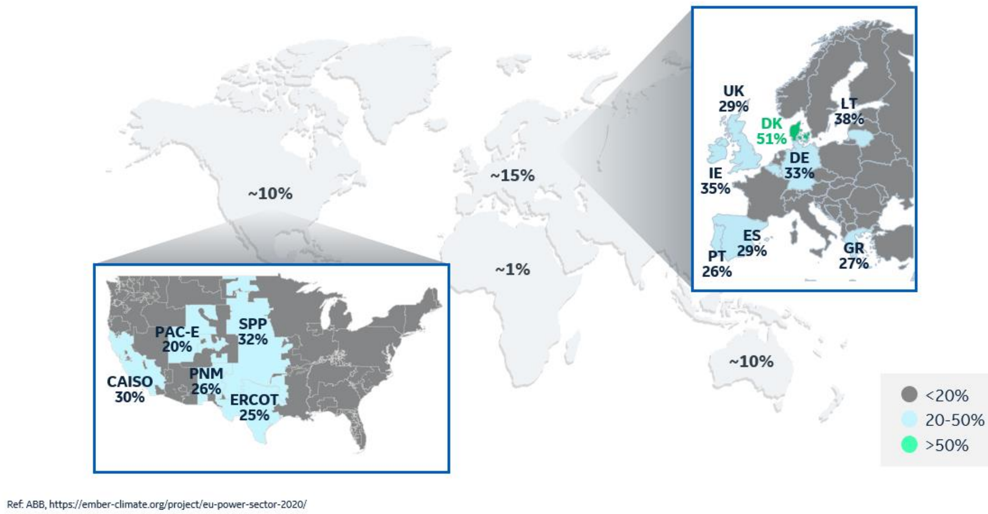


Figure 3 Average 2020 variable renewables penetration across the US and Europe.

In terms of regional penetration, Denmark has achieved 51% annual average variable renewable penetration, while several other regions across the US and Europe have achieved penetration levels in the 20-50% range. We present 2020 hourly penetrations and operations in Figure 4 for three example regions.

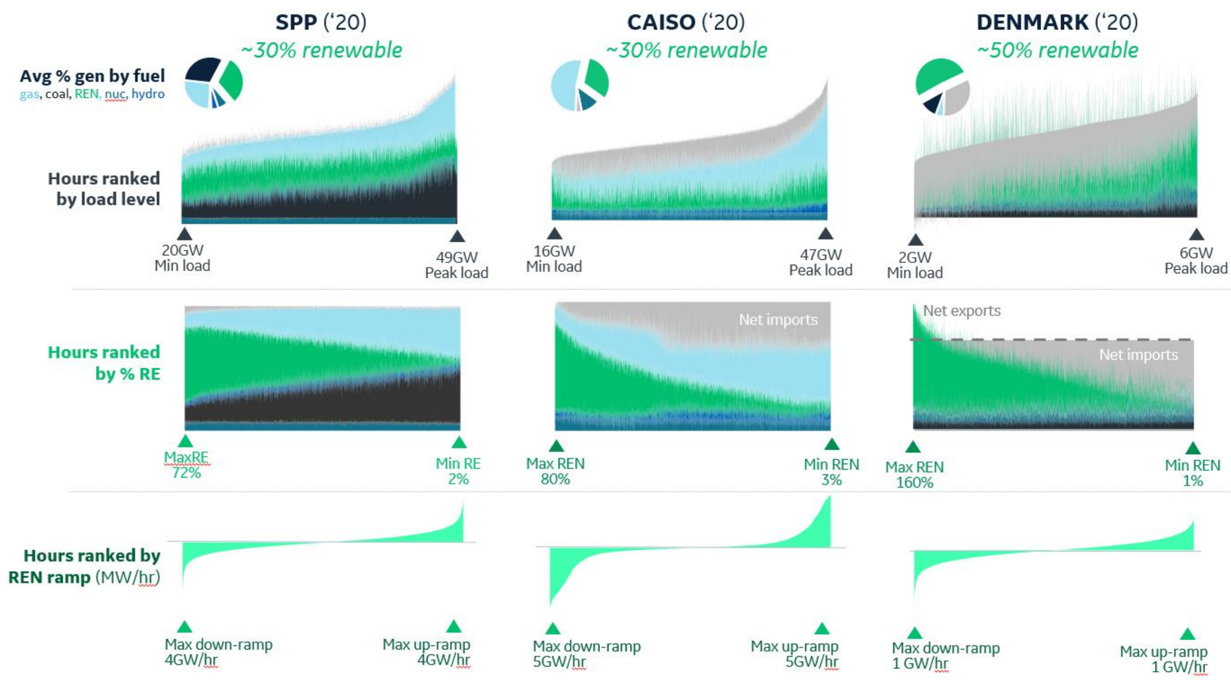


Figure 4 2020 hourly renewable penetration compared between SPP, CAISO, and Denmark.[6]

In Figure 4 and Table 1 we illustrate how hourly operations vary across systems with three different levels of variable renewable energy (VRE) penetration.

2020	PEAK LOAD	AVG %VRE	MIN HOURLY %VRE	MAX HOURLY %VRE	MAX RAMP-DOWN
SPP	49 GW	~30%	2%	72%	4 GW /hr (8% of peak)
CAISO	47 GW	~30%	3%	80%	5 GW/hr (11% of peak)
Denmark	6 GW	~50%	1%	16%	1 GW/hr (17% of peak)

Table 1 Summary of 2020 variable renewables (VRE) penetration levels across SPP, CAISO, and Denmark.[6]

Through this comparison we would like to highlight the following observations that have a direct impact on reliability:

1) **Hourly renewable penetrations can range from zero to over 100%.** In CAISO, hourly VRE penetration can be close to zero or as high as 80% while in Denmark, penetrations are even higher ranging from close to zero to ~160%.
2) **Ramping levels approach ~20% peak load levels.**

[6] ABB Hitachi

3) **Very high average VRE penetrations create periods of over/undersupply**. In the case of Denmark, we see that load levels exceed 100% or can be as low as 1%. In our forward-looking models of the US system, we see similar dynamics emerging within the next 15 years.

How do these systems maintain reliability given these new operating extremes? As we discuss further in this memo, across all three of these regions, **reliability and cost effectiveness in enabled by strong interconnections with their neighbors.**

4 Resilient decarbonization is based on three types of reliability

GE Energy Consulting has supported a wide variety of utilities and grid operators as they plan for reliable and cost-effective integration of renewables. Please see the Appendix for links to ~20 of our publicly available renewable integration study reports.

Given our broad renewable integration experiences, we observe three areas of reliability opportunity as we shift to variable renewables and maintain extreme-weather resiliency:

1. *Adequacy*: Operators are used to generators with fuel sources that are almost always available when needed. However, with the frequency of extreme weather events increasing this dynamic is changing for conventional fuel sources. Similarly, despite the availability of forecasts, wind and solar resource output is not a certainty either. How do we balance the need for adequacy and resilience with the costs to consumers? **In general, portfolio *diversity* benefits adequacy.**

2. *Operations*: Grids were designed assuming large centrally-located generation where power flows are generally flowing in a steady direction from generation centers to load centers. With the growth of highly distributed and variable wind and solar, there are reliability benefits associated with increasing flexibility. For SPP, CAISO and Denmark highlighted in Figure 4, we illustrate that the flexibility of their systems enabled renewables to reliably change their output quite dramatically in the course of one hour. **In general, resource *flexibility* provides reliability benefits to systems with higher variability.**

3. *Stability*: For the last 100 years of our electric system, stable frequency and voltage has been maintained by synchronous machines: rotating turbines that mechanically drive an electrical generator to create electricity. Wind turbines, solar panels, and batteries all drive power electronic, inverter-based electrical generators (i.e. inverter-based resources or IBRs) which provide new opportunities to maintain stable frequency and voltage. **In general, *grid strength* provides frequency and voltage stability benefits.**

5 Resilient reliability has a toolbox of solutions: cost-benefit drives choice

There is no one-size-fits-all solution. As we plan resilient decarbonized systems, **higher reliability is achieved via: 1) higher diversity; 2) flexibility; and 3) stronger grids**. Many times, a given solution can help address all three as we summarize in Table 2. In addition, implementing multiple forms of reliability enhancements can provide consumer benefits as renewable penetrations increase.

RELIABILITY ENHANCEMENTS	TYPE	ADEQUACY: *DIVERSITY*	OPERATIONS: *FLEXIBILITY*	STABILITY: *GRID STRENGTH*
Forecasting	PROCESS	✓	✓	✓
Regional coordination/visibility	PROCESS	✓	✓	✓
Geographic diversity	PROCESS	✓	✓	✓
Flexible demand	PROCESS	✓	✓	✓
Faster markets	PROCESS		✓	
Grid forming controls	PROCESS			✓
Interregional imports/exports	ASSET	✓	✓	✓
Storage	ASSET	✓	✓	✓
Lower minimum generation levels	ASSET	✓	✓	✓
Fuel-based synchronous generation	ASSET	✓	✓	✓
Synchronous condensers	ASSET			✓

Table 2 Examples of flexibility to improve diversity, flexibility and grid strength for resilient decarbonized electric systems.

The list in Table 2 represents the most common forms of reliability enhancements GE Energy Consulting recommends in our renewable integration studies. Determining which solutions are most advantageous for each region depends on the availability of solutions, their breadth of impact, along with their cost-benefit to consumers.

In general, process-related enhancements are frequently the lowest cost, and often provide all three types of reliability benefit. However, once process-related enhancements have been exhausted, exploring asset-related enhancements is imperative. Again, **implementation should be driven by the breadth of impact along with the cost to consumers.**

6 Today's best practices depend on interregional transmission & coordination

If we return to our three examples of increasing renewable penetration: SPP, CAISO and Denmark, as we show in Table 3, all three of these jurisdictions utilize reliability enhancements across the full menu of options and reliability types we presented in Table 2.

RELIABILITY ENHANCEMENTS	TYPE	SPP (~30% VRE)	CAISO (~30% VRE)	Denmark (~50% VRE)
Forecasting	PROCESS	✓	✓	✓
Interregional coordination /visibility	PROCESS	✓	✓	✓
Geographic diversity	PROCESS	✓	✓	
Flexible demand	PROCESS			
Faster markets	PROCESS	✓	✓	✓
Grid forming controls	PROCESS			
Interregional imports / exports (% of load)	ASSET	~1% (-10% -> +15%)	~40% (5% -> 70%)	~20% avg (-90% -> +80%)
Storage	ASSET		~2GW batteries[7]	

[7] https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/082621-feature-battery-storage-capacity-rapidly-rising-across-california-thermal-remains-strong

Lower minimum generation levels	ASSET	✓	✓	✓
Fuel-based synchronous generation	ASSET	✓	✓	✓
Synchronous condensers	ASSET	✓	✓	

Table 3 Examples of reliability enhancements utilized by SPP, CAISO, and Denmark.

Though this survey is not exhaustive, CAISO and Denmark represent examples of continental jurisdictions that benefit from regionalization to achieve their 2020 penetration levels. Regionalization includes:

- **Interregional transmission** build-out that is relied upon with neighboring jurisdictions. This does not necessarily imply a transfer capacity requirement.
- **Interregional planning**, coordination & visibility with neighboring jurisdictions.

Our work in Hawaii (see references in Appendix) demonstrates how island systems that are unable to regionalize can technically achieve similar levels of renewable penetration. However, such islands would have to rely on other forms of reliability enhancements in order to do so and these reliability enhancements would likely carry a higher cost versus regionalization.

6.1 California renewables expansion benefits from regionalization via the Western Energy Imbalance Market

In 2010, GE Energy and NREL identified the value of greater regionalization to support California's aggressive renewable penetration goals in our Western Wind and Solar Integration Study.[8] For example, Figure 5 shows the results of our analysis highlighting how greater interregional cooperation for 5 minute spinning reserves could save $2B.

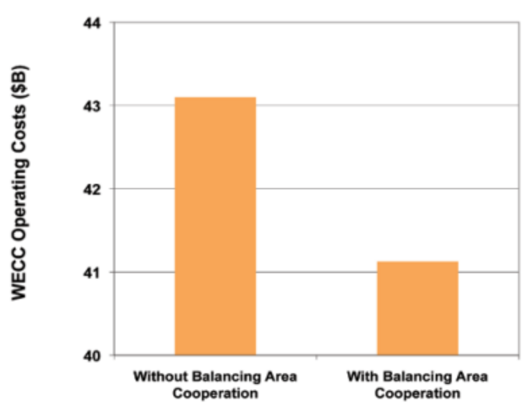


Figure 5 Results from 2010 GE-NREL WWSIS study illustrating the $2B in savings by holding spinning reserves as 5 large regions (right) versus many smaller zones (left).[8]

[8] NREL, "Western Wind and Solar Integration Study,"
http://www.nrel.gov/docs/fy10osti/47434.pdf
http://www.nrel.gov/docs/fy10osti/47781.pdf

This work helped support the 2014 launch of the Western Energy Imbalance Market that is operating today and enables California to benefit from operational flexibility at ~30% variable renewable penetration.[9]

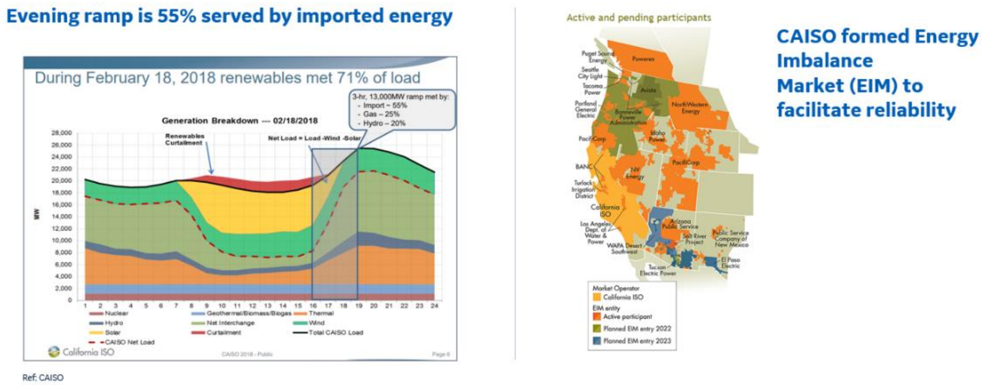
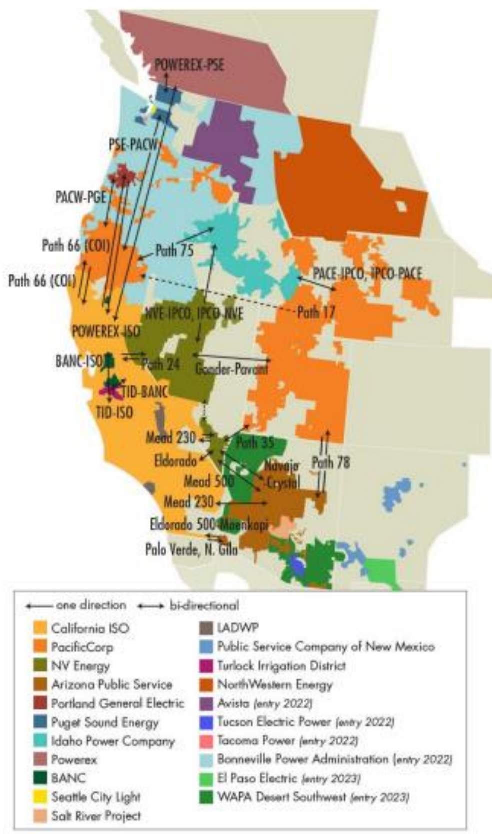


Figure 6 Data and map from CAISO illustrating how imports support the California "duck curve" or evening ramp in net load. These imports have been facilitated by the formation of the Western Energy Imbalance Market.



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400[1] [2]
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <-> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <-> PSE	150
Powerex <-> ISO	150
BANC <-> ISO	2,000-4,000
TID to ISO	1,400
TID to BANC	650

[1] Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.

[2] When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.

Current as of October 2021

Figure 7 Interregional transfer capability utilized by the Western Energy Imbalance market.[10]

[9] https://www.westerneim.com/

[10] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

The Western EIM would not be possible without the physical transmission infrastructure that enables power flows across the Western US. Figure 7 summarizes the inter-regional transmission capability across the EIM footprint. **For example, the largest inter-regional capacity outside California is ~3400 MW between CAISO and NV Energy.**

Benefits

$1.72 billion in gross benefits since Nov 2014 *(as of 10/28/2021)*

(millions $)

EIM PARTICIPANTS	2014-2019	2020	2021			TOTAL
			Q1	Q2	Q3	
Arizona Public Service Entered 10/2016	$140.32	$48.96	$15.01	$9.25	$24.58	$238.12
BANC Entered 04/2019	$15.86	$30.36	$7.53	$18.12	$72.52	$144.39
California ISO Entered 11/2014	$191.88	$62.04	$8.91	$27.58	$54.01	$344.42
Idaho Power Company Entered 04/2018	$55.11	$26.30	$12.54	$15.23	$17.76	$126.94
LADWP Entered 04/2021				$8.54	$23.57	$32.11
NV Energy Entered 12/2015	$89.03	$24.62	$14.14	$6.20	$18.04	$152.03
NorthWestern Energy Entered 06/2021				$1.06	$5.16	$6.22
PacifiCorp Entered 11/2014	$235.29	$40.63	$20.48	$15.05	$40.12	$351.57
Portland General Electric Entered 10/2017	$73.27	$31.76	$8.80	$7.45	$7.12	$128.40
PNM Entered 04/2021				$2.32	$6.77	$9.09
Powerex Entered 04/2018	$19.78	$4.03	$1.17	$1.01	$0.92	$26.91
Puget Sound Energy Entered 10/2016	$41.25	$13.68	$4.31	$4.16	$6.78	$70.18
Salt River Project Entered 04/2020		$36.06	$5.52	$12.61	$17.78	$71.97
Seattle City Light Entered 04/2020		$6.64	$2.60	$2.75	$3.92	$15.91
TID Entered 04/2021				$1.37	$2.13	$3.50
TOTAL	$861.79	$325.08	$101.01	$132.70	$301.18	**$1,721.76**

Figure 8 Summary of economic benefits from the Western EIM by participant.[11]

While the EIM is aimed at enhancing operational flexibility, it's a great example of how regionalization is an economically efficient form of flexibility—having realized almost $2B in gross benefits since 2014 as summarized in Figure 8. By leaning on a wider footprint across balancing areas to support grid services, this can substantially lower the operational and integration cost. Strengthening interregional ties and deploying capabilities across them via markets and requirements was shown in the above-mentioned GE and NREL studies.

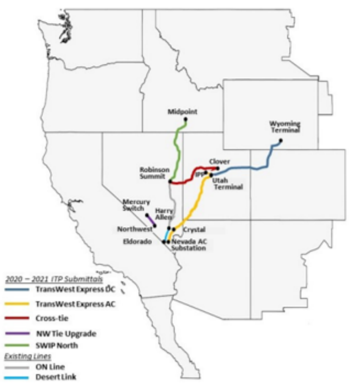
As the same time, **CAISO has been engaged in an interregional transmission planning process since 2015 to support all three areas of reliability.**[12] The CAISO and regional entities throughout the western interconnection collaborate during their transmission planning processes to ensure regional transmission stability and efficiency. These coordination efforts inform each entity's transmission plans. The interregional planning regions are WestConnect, NorthernGrid and California ISO.

[11] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

[12] http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

The CAISO interregional transmission planning process (ITP) is performed in a 2 year planning cycle covering all three areas of reliability that we previously outlined:

1) ***Adequacy***: extreme weather assessment (e.g. wildfires), localized capacity evaluation (e.g. storage, gas alternatives)
2) ***Operations***: flexible capacity deliverability
3) ***Stability***: frequency response assessment (e.g. potential tripping effects in case of Palo Verde nuclear outage)



Project Name	Sgmts	Company	CEII or Confidential Data Submitted	Project Submitted to	Relevant Planning Regions	Cost Allocation Requested From	Termination From	Termination to	In Service Date
Cross-Tie Transmission Project		TransCanyon, LLC	Yes	CAISO, NTTG, NG, WC	NG and WC	CAISO, NTTG and WC	Clover, UT (PacifiCorp)	Robinson Summit, NV (NV Energy)	2024
Northwest Tie Upgrade		GridLiance West	No	CAISO, WC	CAISO and WC	CAISO, WC	Innovation (VEA, GLW, CAISO)	Northwest, NV (NVE)	2024
SWIP-North`		Great Basin Transmission LLC	Yes	CAISO, NTTG and WC	NG, WC and CAISO	CAISO, NTTG and WC	Midpoint. ID (IPCO, PAC)	Robinson Summit, NV (NV Energy)	2023
TWE WY-IPP DC Project[149]	1	TransWest Express, LLC	No	CAISO and NTTG	Not an ITP	CAISO	Sinclair, WY (PAC)	Delta, UT (PAC)	2025
TWE WY-IPP DC + IPP-Crystal 500 kV AC Project	1+2	TransWest Express, LLC	No	CAISO and NTTG	NG + (WC)	CAISO	Sinclair, WY (PAC)	No. Vegas (NV Energy)	2025
TWE WY-IPP DC + Crystal - Eldorado 500 kV AC Project	1+3	TransWest Express, LLC	No	CAISO and NTTG	NA – segments not contiguous	CAISO			2025

Figure 9 Interregional transmission projects submitted to CAISO for their 2020-2021 interregional planning cycle.[13]

In Figure 9 we show **six interregional transmission projects that have been submitted to CAISO** as part of this holistic interregional planning process.

6.2 Southwest Power Pool (SPP) renewable penetration benefits from regionalization via continued expansion

The high levels of renewable penetration we observe from SPP has been enabled by their vast geographic footprint along with their continued interregional expansion. Though Table 3 seems to suggest that they do not have heavily reliance on interregional resources today, SPP has been steadily expanding their footprint since 2015 in order to incorporate the value of regionalization into their operations.

[13] http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf

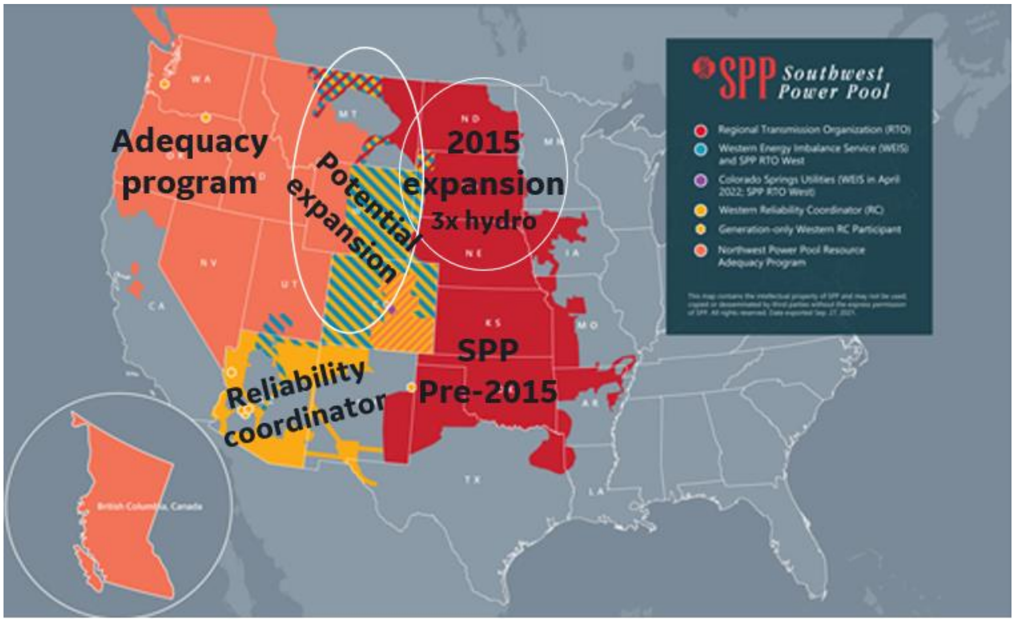


Figure 10 Southwest Power Pool map showing the current range of operational areas and services[14].

SPP is very transparent regarding the value that regionalization has brought to members in its territory. In its "2020 Member Value Statement,"[14] SPP shares that it has provided \$2B in savings to its members in 2020. **Of this \$2B in member savings, transmission was the largest component of value at ~\$770M. According to SPP, every dollar SPP directs toward transmission expansion returns at least \$3.50 in benefits** via:

- Higher reliability and deliverability
- Lower production costs
- Creating new revenue streams
- Reduced on-peak generation costs
- Reduced planning reserve margins
- Reduced resource adequacy requirements
- Improved siting of new generation
- Accelerated renewable integration

As SPP expands its services across the Northwest Power Pool, the cost-benefits of greater regional coordination are leading the efforts.[15] These benefits are projected to produce ~\$50M per year in savings and span all three forms of reliability that we have previously outlined as follows:

- Imbalance services
- Reliability coordination
- Planning coordination
- Unscheduled flow mitigation

[14] SPP.org

[15] https://spp.org/western-services/

6.3 Danish renewable penetration benefits from regionalization via ENTSO-E

The high levels of Danish renewable penetration also heavily rely on regionalization for all three types of reliability: 1) adequacy; 2) operational; and 3) stability via the ENTSO-E (European Network of Transmission System Operators for Electricity).

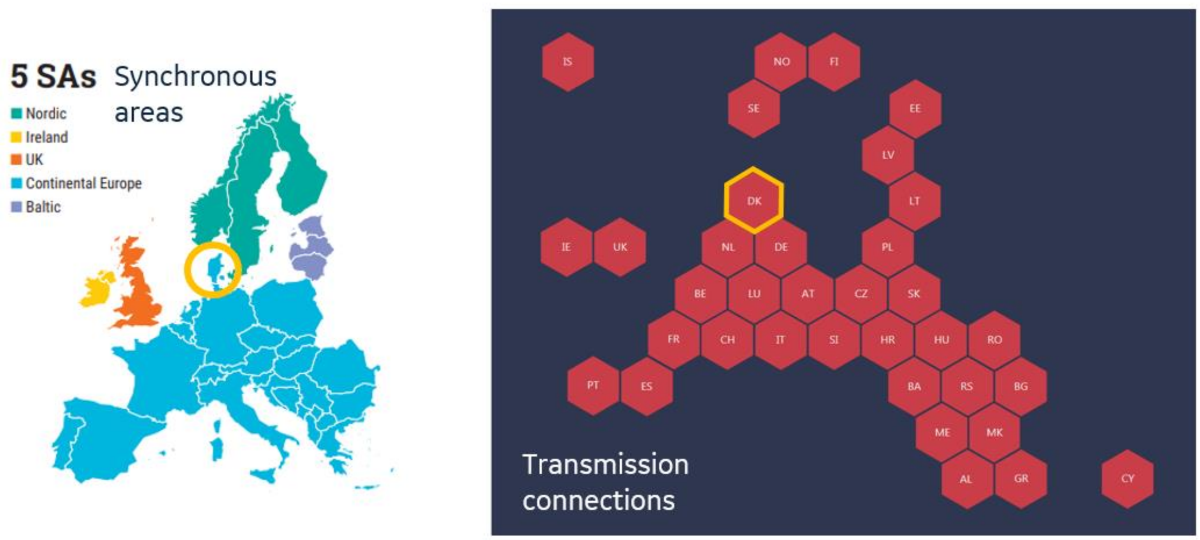


Figure 11 ENTSO-E maps showing the five synchronous areas and inter-country transmission coordination.[16]

The Continental European grid with coordination through ENTSO-E allows Denmark to rely on its neighbors for grid strength, balancing, and sharing of resources to manage uncertainty. Coordination of transmission interconnection and operation is done at the EU Commission level via ENTSO-E, and allows Denmark to achieve instantaneous variable inverter-based resource (IBR) penetrations well above 100%. Modeling and grid planning are coordinated across the EU regions by ENTSOE to maintain sufficient adequacy, resiliency and stability.[12]

The strength of this heavily regional approach is validated by the fact that the January 2021 "European Grid Separation" event did not result in significant blackouts.[17]

7 The rest of the US will need to reflect today's best practices

When we look at where the United States is headed with respect to variable renewables penetration, we see that much of the US in 2035 will look like California, the Great Plains region, and Denmark today.

[16] https://www.entsoe.eu/

[17] https://www.entsoe.eu/news/2021/07/15/final-report-on-the-separation-of-the-continental-europe-power-system-on-8-january-2021/

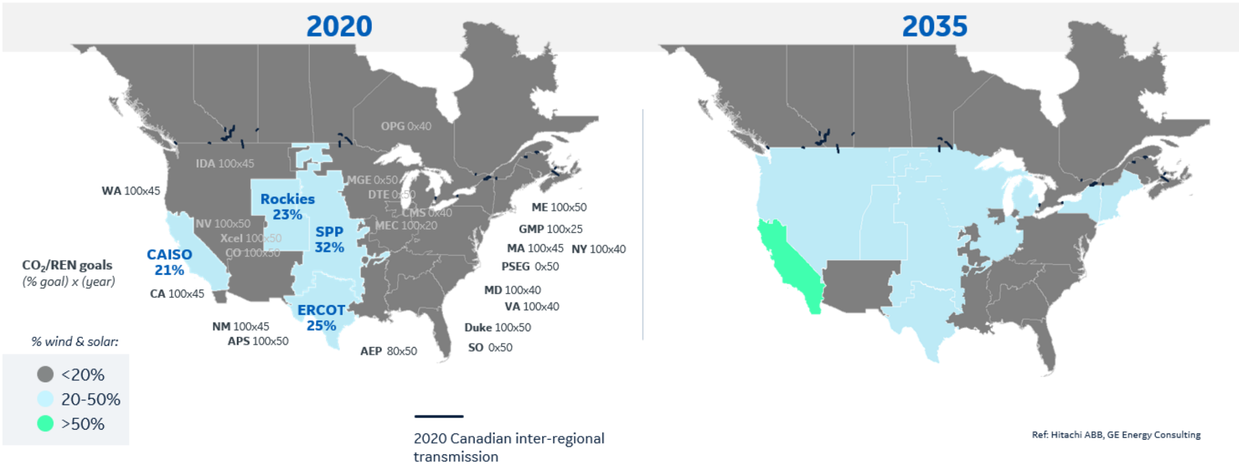


Figure 12 GE Energy Consulting forecast of regional variable renewables penetration in 2035 versus 2020.

In Figure 12, we show GE Energy Consulting's forecast of variable renewables penetration in 2035 versus 2020. Our forecasts are based on utility/grid operator load growth forecasts along with decarbonization policies spanning multiple layers of government. While much of the country is below 20% variable renewables today, **by 2035, much of the country will be between 20-50% VRE penetration**. This means that by 2035:

1. From an *adequacy* perspective: There will be hours where variable renewables within certain regions are close to zero coupled with the uncertainty of extreme weather. **The 2035 US will therefore benefit from the higher *diversity* enabled by regionalization.**
2. From an *operational* perspective: There will be hours where variable renewables approach or exceed 100% within certain regions along with intervals of high ramping. **The 2035 US will therefore benefit from higher *flexibility* enabled by regionalization.**
3. From a *stability* perspective: Each of the three US interconnections will be highly dependent on inverter-based resources to maintain voltage and frequency. **The 2035 US will therefore benefit from the higher *grid strength* enabled by regionalization.**

Given what we have shared regarding the potential reliability challenges, and potential mitigations for CAISO and Denmark today, we believe the rest of the US will need to increasingly leverage the reliability enhancement options we summarized in Table 2. Given the continental nature of the US systems along with our prior study work assessing the cost-benefit tradeoffs of the various solutions, **we contend that greater regionalization can be the most cost-effective mechanism for achieving resilient adequacy, flexibility, and stability in the 2035 US.**

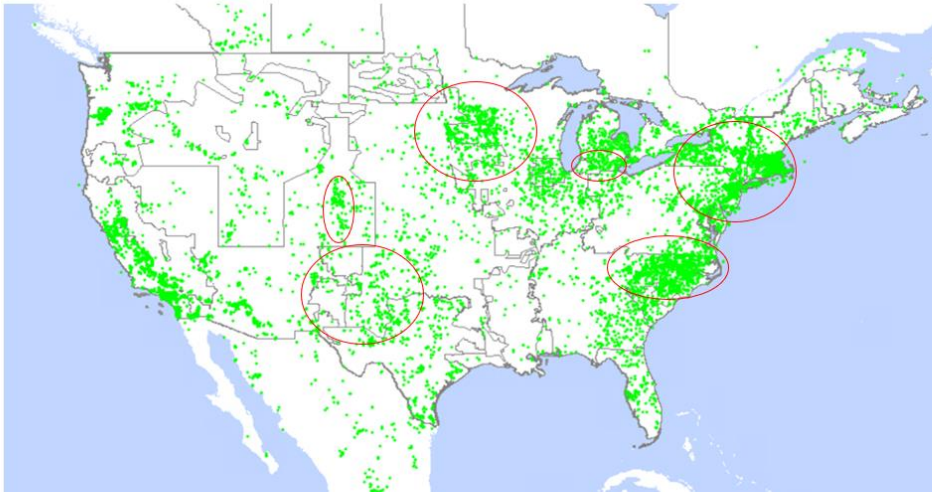


Figure 13 Regional map of the US showing siting of operating and planned wind and solar projects as of 2020. The circled areas highlight areas of high wind and solar siting along interregional interfaces. These are areas that could potentially benefits from greater interregional transfer capacity.[18]

At the same time, even looking at a current map of the US showing siting of wind and solar projects both in operation and under development, show how **projects are often located at the interfaces between two regions.** From our experiences interconnecting many of these projects, we observe that control stability of IBRs continues to be more challenging at regional interfaces. **Strengthening interregional transmission connections across seams where there are growing high-penetration pockets of IBRs can help ensure sufficient power flow during extreme weather events and, in certain cases, assist in resolving weak grid stability constraints** (e.g. between MISO and SPP). In addition, interregional sharing of services around balancing, frequency and voltage support, and managing variability and uncertainty of VER across stronger interregional ties has great benefit to reduce overall integration costs. Interregional assessment and interconnection is therefore also becoming more important as IBR penetration levels grow.

[18] ABB Hitachi

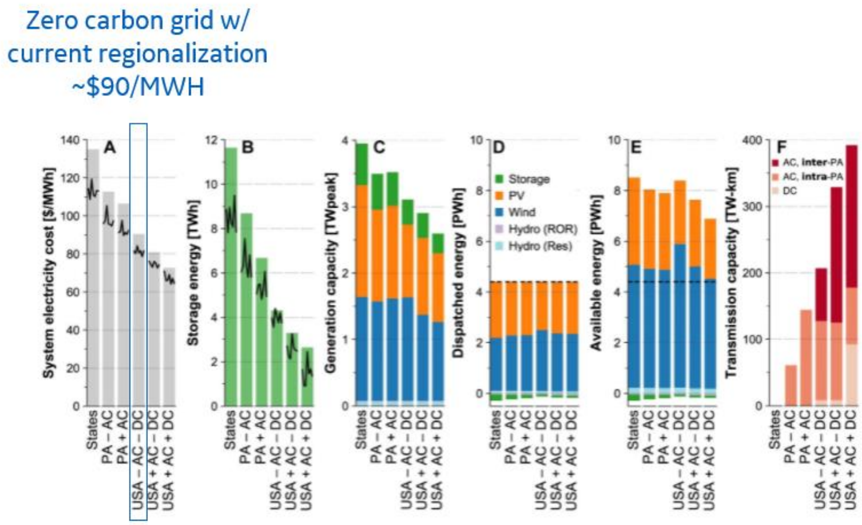


Figure 14 MIT study highlighting the economic benefit of higher regionalization to a zero-carbon grid.[19]

A recent MIT study also pointed to the benefits of higher transmission build-out to a future decarbonized US grid. In Figure 14 we show a summary of their analysis showing how a decarbonized US with higher transmission-enabled regionalization could lower average energy costs by ~$20/MWH (left graph). The areas of value are shown in the graphs to the right:

1. Lower long term storage requirement
2. Lower generation capacity requirement

One important implication of this work is that the economic benefit of greater transmission is higher than the economic benefit of greater storage in a zero-carbon electric mix.

8 Suggesting a requirement for incremental interregional transmission

For the future United States, **how can a minimum interregional transmission requirement be assessed** to reliably and cost-effectively support the anticipated renewables build-out while planning for new extreme weather events? GE team proposes the following *potential* approach to assess the operational, stability and adequacy benefits of increased transmission interconnection. This approach focuses on the technical benefits and should be used as part of a fuller analysis that considers the economics compared to alternatives.

[19] Brown and Botterud. The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity Grid. MIT. (Dec 2020)

8.1 Operational incremental interregional transmission requirement

In order to assess the operational benefits of increased interregional transmission capacity, we propose simulating the dispatch of the US system under the following two conditions:

1) *Condition 1:* **Unconstrained interregional imports/exports.** We suggest removing the MW limits associated with inter-pool transmission flows to determine the total power flow amounts between pools.

   Output: **Total transmission-unconstrained interregional power flow amounts between pools.**

2) *Condition 2:* **Constrained[20] interregional imports/exports**. We suggest simulating the same system after re-instating the existing/expected MW limits associated with the inter-pool transmission flows. This will allow the determination of the total power flow amounts between pools utilizing the existing/planned transmission system. We would expect renewables curtailment to be higher under this condition.

   Output: **Total transmission-constrained interregional power flow amounts between pools.**

Utilizing simulations under both the constrained and unconstrained EI conditions would allow us to calculate an "operational incremental interregional transmission requirement." These requirements could be calculated on a pool-to-pool basis for each pool across the United States. GE MAPS is an example of a software tool that could be used for this assessment.

8.2 Adequacy incremental interregional transmission requirement

In order to determine the incremental interregional transmission requirement to support future resilience and renewables uncertainty needs. We propose using a similar approach as described in Section 8.1 with the **addition of a stochastic dimension to test for the incremental transmission need given renewables uncertainty, outages, and extreme weather.** These requirements will be calculated on a pool-to-pool basis for each pool across the United States.

Given that recent grid events have highlighted adequacy risks across every type of resource (e.g. frozen cooling water, gas supply outages, transmission outages, extreme temperatures), we suggest:

- **Broadening the potential sources of failure** (e.g. non-electric sources of failure such as gas supply outage)
- **Testing new weather extremes** (e.g. extreme temperatures)
- **Testing coincidence of failures** (e.g. extreme temperatures during gas supply failure, or cyber attacks across multiple resources simultaneously)

GE MARS would be an example software tool that could be used for this assessment.

[20] Note on Constrained and Unconstrained in this section pertains to deliverability of MW based on thermal ampacity of transmission lines. It does not include stability constraints at this stage. Stability would be assessed as part of 8.3 via screening techniques.

8.3 Stability incremental interregional transmission requirement

In order to determine the incremental interregional transmission requirement to support stability needs. We suggest the following steps:

Step 1: Use the dispatch simulation results (see Section 8.1) and transmission maps to downsselect interregional areas of high IBR penetration and series compensation.

Step 2: For each of these areas, we suggest running a production cost (e.g. GE MAPS), stability and short circuit simulations (e.g. in PSSE or GE PSLF) under the following two conditions:

*Step 2.1--**Condition 1:*** Current system with current interregional ties and series compensation.
*Step 2.2--**Condition 2:*** Add in incremental interregional transmission (MW) and bypass series compensation.

Step 3: Under these two conditions, we suggest testing the following on a pass/fail basis:

- ☐ **Weak grid & voltage stability**: Was the short circuit current ratio acceptable (e.g. SCR>3) in both cases?
- ☐ **Frequency stability**: Was the headroom on committed synchronous units acceptable?
- ☐ **Small signal stability**: Were there unwanted resonances?

Step 4: If any of the tests in Step 3 fail, repeat Step 2.2 with additional incremental transmission until all stability tests pass. The total additional transmission is the interregional requirement.

8.4 Total incremental interregional transmission requirement

We propose that a total incremental interregional transmission requirement would encompass the three reliability benefit components described above. It is important to acknowledge that the technical value of greater interregional transmission may stem from any or all of the three areas of reliability. **In our experience, typical studies focus on one of these three reliability areas while missing the others.** Individual pools across the US may find value from differing areas of reliability given their existing infrastructure combined with their projected expansion.

9 Conclusion: Coordinated interregional transmission is a proven enabler for resilient decarbonization

GE Energy Consulting forecasts a 2035 United States that will look similar to the California, Great Plains region and Denmark of 2020 with high penetrations of variable inverter-based renewables. The value of regionalization for increasing adequacy, operational reliability, and stability, that has been validated for SPP, California and Denmark, should be assessed for the broader US.

GE Energy Consulting has suggested a methodology to assess the incremental transmission requirement for a regionalized future US with higher renewables and extreme weather uncertainty. This incremental requirement would be based on a holistic assessment of three areas of reliability benefit:

1) *Operational:* Incremental interregional transmission can enable lower wind and solar curtailment which results in fuel cost savings.
2) *Adequacy:* Incremental interregional transmission can enable higher generation diversity in the face of uncertainties such as: generation, transmission or fuel outages or extreme weather events.
3) *Stability:* Incremental interregional transmission can enable greater system strength to avoid unintentional unit tripping due to fluctuations in voltage, frequency or unwanted oscillations.

Today, there are limited practices in place for each region to evaluate the consumer benefits of regionalization on their own. National-level guidance would help chart the path towards realizing the benefits of greater regionalization.

APPENDIX: GE ENERGY CONSULTING RENEWABLE INTEGRATION STUDY REFERENCES

Most of GE Energy Consulting's wind and solar integration study work is publicly available at the following links:

- Australian Energy Market Operator, "Technology Capabilities for Fast Frequency Response," https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf
- Barbados Light & Power Company , "Barbados Wind and Solar Integration Study," http://www.blpc.com.bb/images/watts-new/Barbados%20Wind%20and%20Solar%20Integration%20Study%20-%20Exec%20Summary.pdf
- California Energy Commission's Intermittency Analysis Project Study "Appendix B - Impact of Intermittent Generation on Operation of California Power Grid," http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081-APB.PDF
- California ISO, "Frequency Response Study," Oct, 2011 http://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf
- CanWEA "Pan-Canadian Wind Integration Study," (PCWIS), 2016 https://canwea.ca/wind-integration-study/
- Electrical Reliability Council of Texas, "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements," http://www.ercot.com/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip (Note, this is a zip file that automatically downloads.)
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- NREL, "Western Wind and Solar Integration Study,"
- http://www.nrel.gov/docs/fy10osti/47434.pdf
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- PJM Interconnection, LLC, "PJM Renewable Integration Study," http://www.pjm.com/~/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx

CERTIFICATE OF SERVICE

I hereby certify that on this 30th day of November, 2021, a copy of the foregoing document has been electronically served upon each person designated on the official service list in this proceeding.

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