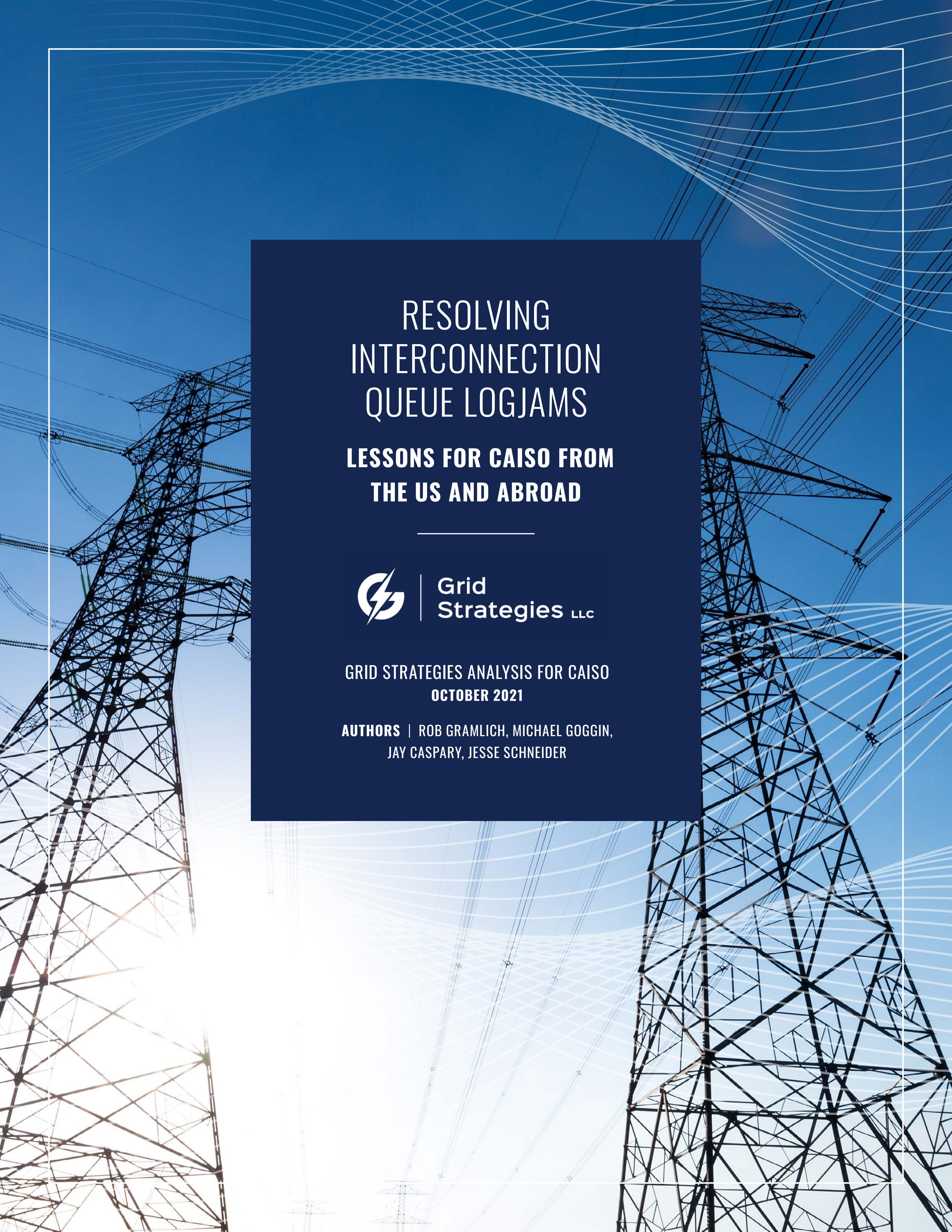

RESOLVING INTERCONNECTION QUEUE LOGJAMS

LESSONS FOR CAISO FROM THE US AND ABROAD

Grid Strategies LLC

GRID STRATEGIES ANALYSIS FOR CAISO

OCTOBER 2021

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I. EXECUTIVE SUMMARY

Interconnection queues are being overwhelmed in much of the country, and the California ISO's is no exception. The most recent queue cluster, Cluster 14, has ballooned with so many projects that it exceeds CAISO's ability to process it within its obligations under its tariff.

California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC) policies include best practices that improve queue management and the ability to connect new resources relative to other Independent System Operators/Regional Transmission Organizations (ISO/RTOs). In our opinion, the two main policy practices required for good queue management are:

1. Pro-active transmission planning to incorporate the future resource mix; and
2. Sharing some of transmission cost assignments with load rather than charging generators exclusively.[1]

California (CAISO, CPUC, and other entities) has routinely pro-actively planned network transmission, beginning with the Tehachapi trunkline project in the 2000s. CAISO developed an innovative policy for radial lines called Location-Constrained Resource Interconnection. CAISO also provides for sharing of transmission costs with load rather than assigning all costs to generators. These planning and cost allocation approaches have helped with the region's resource evolution and are generally much better practices than most ISO/RTOs.

Despite the solid foundation of CAISO's planning and interconnection practices, additional solutions are needed for Cluster 14. A number of small changes to study processes and various protocols are being discussed in CAISO interconnection stakeholder processes. We believe there are additional opportunities to reduce the queue logjam through greater use of "first ready, first served" type of approaches. More broadly, CAISO, CPUC, and

1 *See* Jay Caspary, Michael Goggin, Rob Gramlich, and Jesse Schneider, *Disconnected: The Need for a New Generator Interconnection Policy*, January 2021.

CEC will need to make changes to how resource adequacy, transmission planning and generator interconnection fit together. Specifically, we recommend:

- In the near-term, move more towards a “first ready, first served” model with milestones, potentially including Power Purchase Agreements (PPAs).
- Apply Grid-Enhancing Technologies where appropriate in the interconnection process to enable faster and cheaper integration.
- Use open seasons and subscriptions for interconnection, using lessons from transmission and gas pipelines.
- Longer term, conduct more pro-active transmission planning, which includes accounting for the resource adequacy contributions of diverse and geographically dispersed resources.
  - Plans should co-optimize energy, capacity, and transmission.
- Plans should include a broader set of benefits beyond production cost alone such as resilience and capacity reserve sharing in transmission benefit-cost assessments.
- Integrated Resource Planning should also co-optimize generation and transmission to find the lowest delivered cost resources accounting for the capacity value (contribution to resource adequacy) of geographically dispersed resources.
- CAISO should fast-track well-sited storage and review the operational assumptions used in interconnection studies, to avoid over-stating their impacts on the system.
- CAISO should develop more stable interconnection costs by electrical zone to reduce uncertainty on developers and procurement entities. Spreading this risk across ratepayers will likely reduce their costs in the long run.

II. INTRODUCTION

Interconnection queues around the country have become the focus of a great deal of public policy attention. The US Federal Energy Regulatory Commission (FERC) issued an Advance Notice of Proposed Rulemaking (ANOPR) on interconnection and planning in July 2021.[2] There have been bills and reports in Congress about interconnection queue reforms.[3] Fundamental questions have been raised about whether current approaches used by RTOs and ISOs work for the new resource mix, as current policy was established by FERC in 2003 when almost all the generation was natural gas fired.[4] Some Independent System Operators/Regional Transmission

2 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 86 Fed. Reg. 141, July 27, 2021.

3 *See* House Select Committee on the Climate Crisis, *Solving the Climate Crisis: The Congressional Action Plan for a Clean Energy Economy and a Healthy, Resilient, and Just America*, June 2020, and House Select Committee on the Climate Crisis, "Castor Introduces Bill to Expand Access to Clean Energy & Reduce Grid Congestion," June 22, 2021.

4 *See* Jay Caspary, Michael Goggin, Rob Gramlich, and Jesse Schneider, *Disconnected: The Need for a New Generator Interconnection Policy*, January 2021.

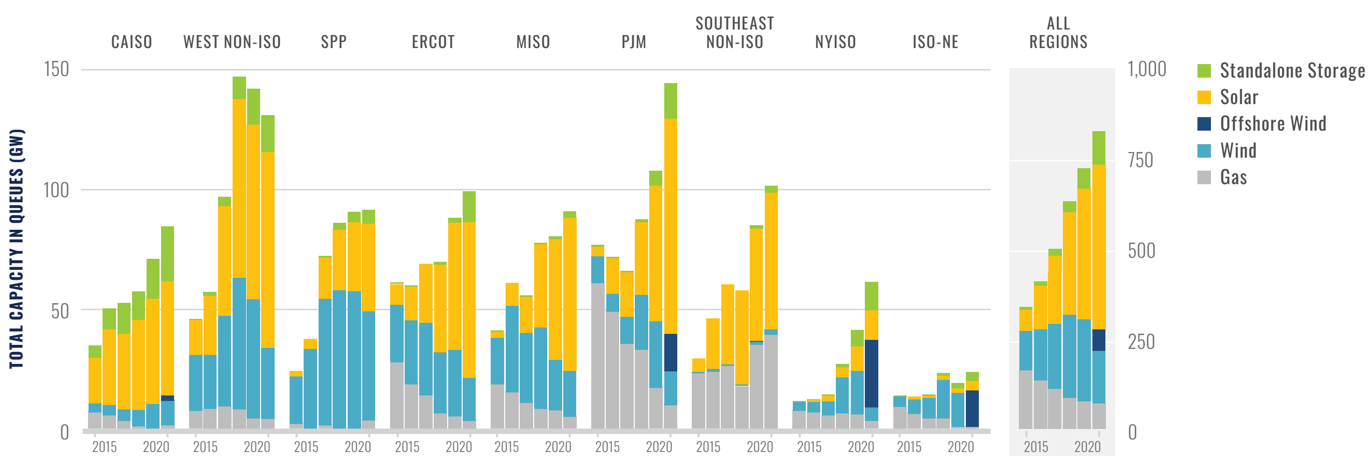
Some ISOs/RTOs are evaluating fundamental reforms to their interconnection policies.[5] These actions are responses to ballooning interconnection queues, partially driven by states and utility attempts to evolve their generating resource mix.

The new generation required for state and utility decarbonization goals is stalled for years waiting to connect to the grid. At the end of 2020 there were 755 Gigawatts (GW) of proposed generation waiting in interconnection queues across the country.[6] The average time to interconnect has risen to 3.5 years over the last decade, with longer times at the end of the decade, compared to about half that in previous decades.[7]

Delays harm open access and competition, hinder states from meeting their resource objectives, harm reliability, and can stifle innovation by adding years to the time it takes for new technologies to be brought to market.

Interconnection queue volumes are rising in all regions as shown below.

FIGURE 1. *Total Capacity in Queues by Type and Region (GW)*[8]



California has more than its share of interconnection challenges compared to other regions, driven in large part by faster retirements and capacity additions resulting from clean energy policies. Queue volumes and timelines in California have risen steadily over the last decade, largely from solar and solar/storage hybrid resources as the costs of solar photovoltaics (PV) and batteries have fallen and procurement has increased.

Interconnection policy is a balance between fairness and manageability.[9] Extremely stiff requirements on generators would thin out the queues and make them more manageable,

5 *See*, e.g., PJM, "Interconnection Process Reform Task Force," (n.d.). *See* MISO, "SPP Joint Targeted Interconnect Queue Study (JTIQ)," (n.d.). See SPP, "Strategic and Creative Re-engineering of Integrated Planning Team," (n.d.), which is proposing policies to 1) consolidate planning processes, 2) improve Tariff Services processes in terms of responsiveness and quality, as we as reduce independence on queue-driven analyses, 3) optimize transmission network, 4) improve decision quality, 5) facilitate beneficial energy transfers to address interregional needs and 6) improve cost sharing.

6 Rand et al., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2020*, at 3, May 2021.

7 *Id.*

8 *Id.*, at 12.

9 The challenges of managing a large queue are explained in chapter III of this paper.

but would in turn sacrifice fairness and open access objectives. On the other end of the spectrum, extremely lax requirements would facilitate easy entry of both large and small market participants, but would cause queue volume expansion to the point where it would be less manageable. ISO/RTOs and FERC need to find a balance of these objectives.

Interconnection policy is also closely tied to transmission planning and resource adequacy. In the old days of vertically integrated utilities, interconnection, planning, and resource adequacy were integrated into one process. In competitive markets today, they are three separate processes, and the challenge is to make them work together. While reforms have been instituted over the last 13 years within the interconnection process alone, and likely more could be done related to milestones to separate more vs. less viable projects, there is a limit to what can be accomplished within the interconnection process alone. At some point limited transmission capacity must be addressed in the transmission planning and cost allocation realm.

Similarly, at some point the resource adequacy benefits of a regionally diverse set of resources needs to be incorporated into transmission planning and reflected in interconnection rules. The capacity value (contribution to resource adequacy of the system) of any given resource type at any given location will tend to fall as penetration increases. Inversely, adding different technologies at different locations, connected via transmission, tends to add capacity value.

That incremental capacity value should be accounted for in transmission and interconnection processes to achieve an efficient overall portfolio that minimizes total delivered costs (generation capacity and energy plus transmission). FERC has recognized the need for coordination between planning and interconnection in its recent ANOPR:

> We seek comment on whether the Commission should require transmission providers to operate their regional transmission planning and cost allocation and generator interconnection processes on concurrent, coordinated timeframes, with the same or similar assumptions and methods, and whether such a potential requirement may identify more efficient or cost-effective transmission solutions that could address needs shared between the two processes. We seek comment on how the regional transmission planning and cost allocation and generator interconnection processes could be better coordinated or integrated.[10]

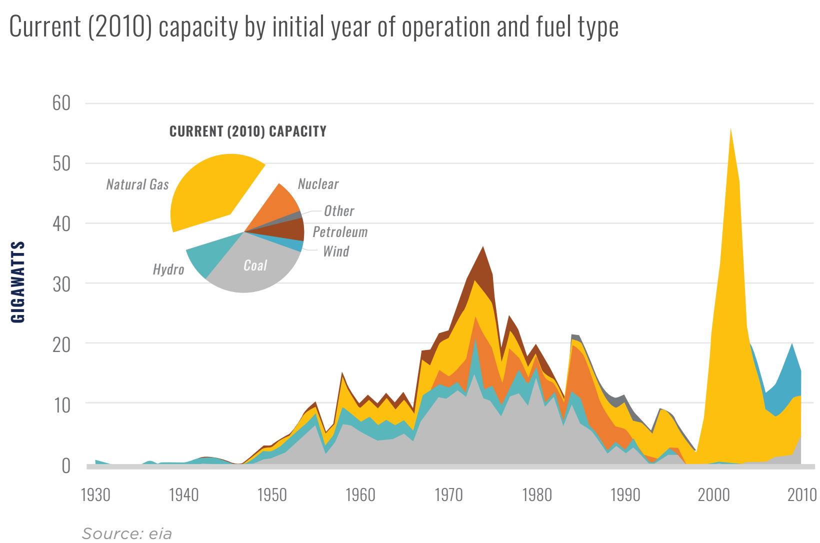
This paper begins by describing the problem of interconnection queue logjams and their contributing causes, then outlines the criteria against which to compare policy options, describes and evaluates interconnection policy options, compares CAISO's current approach relative to these practices, and finally makes recommendations for CAISO.

10 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 86 Fed. Reg. 141, at P 65-66, July 27, 2021.

III. NATIONAL AND SYSTEMIC INTERCONNECTION QUEUE CHALLENGES

Nationally, queue volumes and timelines have grown as shown in Figure 1. They started low in 2005 when Order 2003 had been implemented, in part because the gas generation boom of 1999-2004 had just ended. Figure 2, below, shows that the gas capacity addition boom peaked at close to 60 Gigawatts (GW) per year in the early 2000s, and by 2005 had fallen as the market adjusted to lower need for new capacity. Capacity surpluses, temporarily higher gas prices, and lower load growth forecasts caused by successful energy efficiency improvements as well as the 2008 financial crisis flattened gas generation development plans in the second half of the 2000s.

FIGURE 2. *New Capacity by Initial Year of Operation and Fuel Type (GW)*[11]



By the late 2000s, a new driver of generation had emerged—clean energy incentives. The Production Tax Credit (PTC) and state Renewable Portfolio Standards (RPS) caused growth in wind power, which at that time was the lowest-cost renewable resource. There were over 200 GW of new wind generation in interconnection queues by the end of 2007.[12]

The location of the new renewable generation has been driven by two major factors: proximity to RPS demand, and resource quality. Some areas like Texas and Oklahoma did not have RPS demand but had very high-quality resource areas, incentivizing development that was rewarded

11 EIA, "Most Electric Generating Capacity Additions in the Last Decade Were Natural Gas-Fired," July 5, 2011.

12 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions, at 11, January 2009.

with PTCs for each Megawatt-hour (MWh) of production. Other areas like the Bonneville Power Administration (BPA), which operates most of the transmission system for the Northwest, did not have the high resource quality of Texas but experienced requests to serve demand in Washington, Oregon, and California. In 2005, BPA received 11 generator interconnection requests worth about 2,300 MW. At the end of 2007, BPA had 52 active requests in its queue for a total of 12,580 MW.[13]

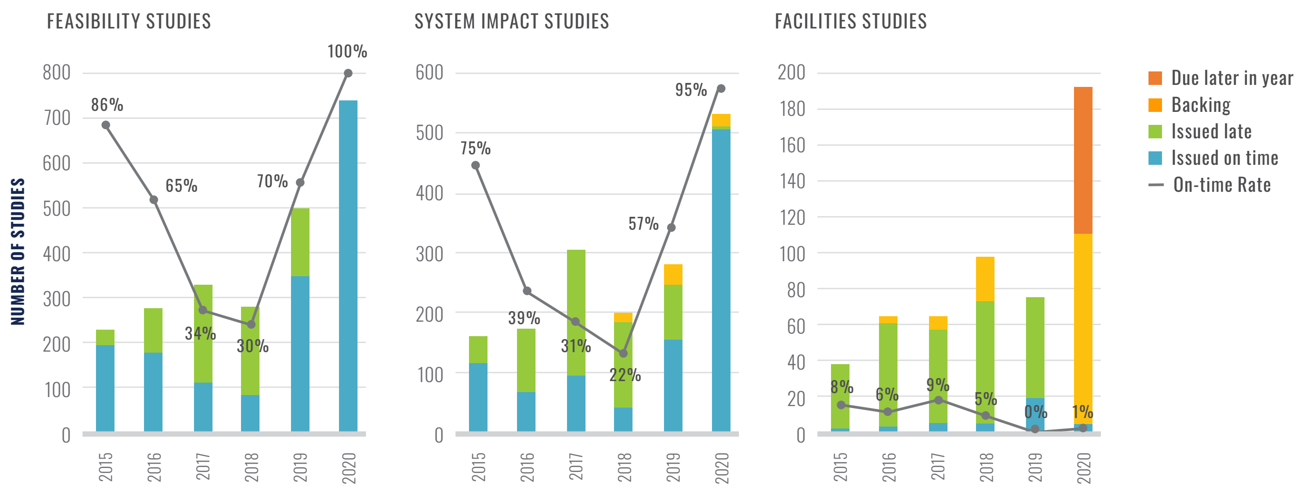
Another driver of proposed generation compared to the amount of load growth was the development of the independent generation industry. While there was a half dozen major developers of natural gas plants in the early 2000s gas boom, there were dozens of renewable energy developers in the late 2000s renewable energy boom, all working on projects hoping to receive contracts. This contributed to higher interconnection numbers in competitive areas compared to areas with vertically integrated utilities.

Transmission pricing policy contributed to the increase in proposed projects. Pricing in ISO/RTOs allowed full "participant funding" where all network upgrade costs could be assigned to generators. This policy was an "Independent Entity" variation allowed by FERC Order 2003. It provided for network upgrades that are not needed "but for" the interconnecting generator to be assigned to the generator. This pricing policy meant that each generator could receive a dramatically different cost assignment depending on the timing of requesting service, and it was difficult for the generator to predict what that charge might be. As a result, an incentive was created for generators to submit multiple interconnection requests at different locations. This dynamic was noticed early on, and termed "upgrade shopping" in Porter et al.[14]

Cost uncertainty remains an issue in most of today's queues. While initial studies can be informative, they are not bankable and can change dramatically. Generators must wait for final facilities studies before they have enough certainty to proceed. As queues grew, the on-time rates fell for these binding studies, and projects have an incentive to remain in queues to see about the final upgrade cost. The right side of the PJM table below shows that the on-time rate for the facilities study has fallen to around 1 percent as the number of studies climbed to over 150.

13 *Id.*, at A-1.
14 *Id.*, at 26.

FIGURE 3. *PJM Study Volume and On-Time Rates (as of Oct. 20, 2020)*[15]



The cost assignments described above, in combination with the relative ease of entering and exiting queues, led to churn, where projects that receive high network upgrade cost assignments drop out causing a need to re-study projects lower in the queue. This too was noticed early in the life of ISOs and RTOs. Porter et al noted "what may have happened is that generators, in an attempt to avoid or minimize incurring significant transmission network upgrade costs, choose to file multiple interconnection applications, which prompts restudies once those applications are suspended or withdrawn."[16] Queue churn has been a continuing problem.

RTO/ISO processing time has also been a contributing factor. The self-reinforcing cycle described above clearly puts a burden on limited staffing at ISO/RTOs. In theory, they could have enough staff and consultants to complete all studies on time. However, this is a very volatile process to manage, and the budgets and resources of experts qualified to conduct the studies are limited.

The location-constrained nature of renewable energy has also contributed to interconnection queue logjams. Many projects are proposed in the best resource areas, such that these areas experience limited transmission capacity as well as significant interactions among studied projects. When projects are electrically close to each other, as is the case with location-constrained resources, the interactions between projects, the effect of the order of interconnection requests on upgrade costs, and the impacts of one project dropping out affecting the need to re-study other projects is greater.

The resource mix of today and tomorrow is very different from the resource mix that was predominant at the time FERC's interconnection policy was established in 2003, when almost

15 Jason Connell and Susan McGill, "Interconnection Process Overview," at 31, 2020.

16 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, at 41, January 2009.

all new generation was gas. Gas units are much less location-constrained and the interactions between projects were less significant. This resource mix difference provides a strong justification for fundamental reassessments of interconnection policy for the new issues facing the grid today.

Limited transmission is perhaps the most significant contributor to interconnection queue logjams. If capacity is unconstrained, the studies are quick, network upgrade costs are low, and there is little incentive to submit multiple projects; the process can move forward easily. In many areas, the process worked well until a point when transmission capacity limits were reached.

As new generation interconnects in desirable locations for new renewable resources, the network upgrade costs rise as transmission capacity becomes more constrained. This creates a non-linear increase in interconnection costs, adding to the expense, uncertainty, processing time, and churn of projects entering and exiting.[17]

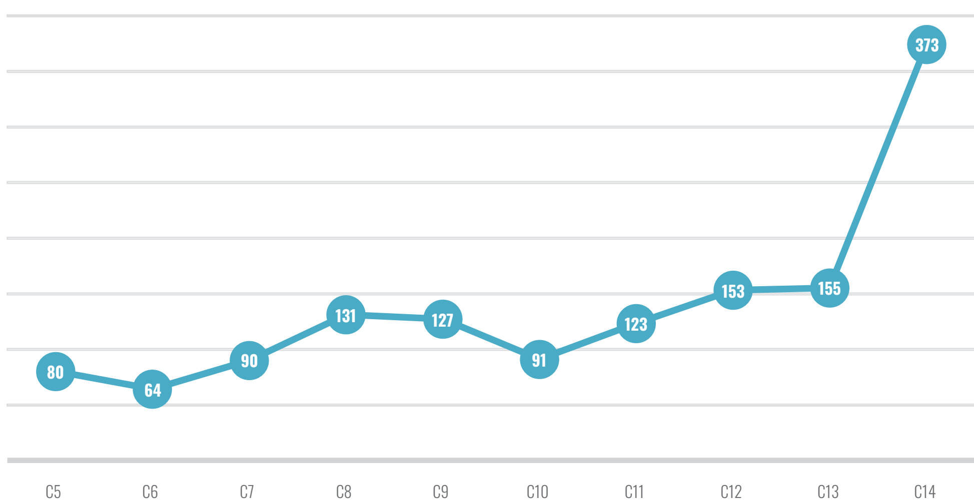
There are limits to what can be accomplished by reforms within the interconnection queue process. At some point planning and cost allocation policies need to be reformed.

17 *See* Jay Caspary, Michael Goggin, Rob Gramlich, and Jesse Schneider, *Disconnected: The Need for a New Generator Interconnection Policy*, January 2021.

IV. CAISO INTERCONNECTION QUEUE PROBLEM ASSESSMENT

CAISO has seen a sudden surge in interconnection requests that are overwhelming the current process. In the last decade, CAISO has received an annual average of 113 interconnection requests in each annual interconnection request window. In 2021, the ISO reported that it received a total of 373 requests in Cluster 14 — over 3 times the average in the previous 9 cluster request windows.[18] To accommodate such a large number of requests in this "supercluster," CAISO has proposed to extend the overall study process by roughly a year and modify study processes. The growth in cluster 14 ("c14") compared to previous clusters is shown in Figure 4 below.

FIGURE 4. *Interconnection Requests From CAISO Clusters 5 Through 14*[19]



A major factor contributing to the large amount of capacity in Cluster 14 is the CPUC's recent Resource Adequacy orders calling for increased procurement to meet peak and net loads.[20] The widely reported concerns about evening power needs and then the rolling blackouts in August 2020 also very likely added to market interest in adding capacity. The procurements have not only been large but have significantly changed the type of proposed resources, with much more storage needed to meet evening net load peaks.

18 Neil Millar, "Decision on Cluster 14 Interconnection Procedures," at 2-3, July 7, 2021.

19 CAISO, *Supercluster Interconnection Procedures: Final Proposal*, at 6, July 14, 2021.

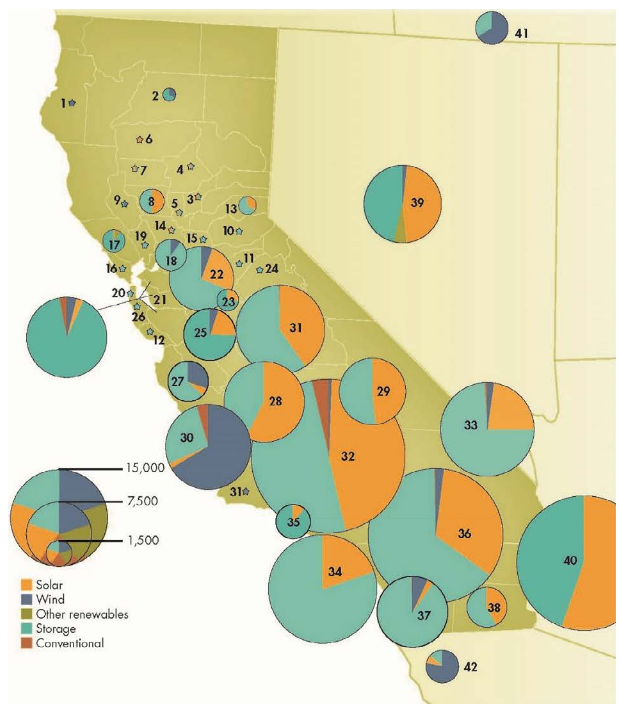
20 *Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements*, R. 16-02-007, ALJ/JF2/avs, November 7, 2019 . The CPUC kicked off a new IRP in May 2021: Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes, R.20-05-003, ALJ/ /mph, June 14, 2020, which produced modeling results calling for more procurement, and led to 2021 decisions: CPUC, "CPUC Orders Historic Clean Energy Procurement to Ensure Electric Grid Reliability and Meet Climate Goals," at 1, June 24, 2021.

There was already a large amount of generation in the queues through Cluster 13: 44 GW of renewables and 47 GW of storage. This amount was already adequate to meet current needs for clean energy and capacity. Thus, the primary near-term public policy problem is managing the queue to comply with ISO tariff requirements, not necessarily an inability to meet clean energy objectives.

Longer term there is a potential public policy problem with the interconnection queue approach undermining resource adequacy objectives. For example, if one capacity resource type can be placed anywhere, and another capacity resource type is location-constrained and deliverable only over a congested transmission path, the optimal system would have the location-flexible resource in the less transmission-constrained location and the location-constrained resource using the transmission path. Yet with open access rules, generation can propose to locate anywhere, whether an optimal location or not.

This seems to be happening in California. Unlike renewable resources, which are location-constrained, energy storage resources are able to interconnect nearly anywhere on the grid. Cluster 14 includes a massive increase in location-flexible energy storage, from 47 GW to 147 GW.[21] Storage and hybrid storage-PV developers have the same incentive other developers have to submit multiple requests for interconnection because they do not know what the cost assignment will be. One can see in the figure to the right that storage projects, shown in the teal color, are widespread.

FIGURE 5. *All projects in CAISO Queue (as of July 2021)*[22]



While storage can be located most anywhere, renewable resources are more location-constrained. CAISO has been studying certain transmission paths because of renewable energy impacts on them, shown below.[23]

21 Neil Millar, "Decision on Cluster 14 Interconnection Procedures," at 1-2, July 7, 2021.

22 The figure shows the general location, capacity, and resource type of all projects in the queue as of July 2021 on a full capacity basis. Bob Emmert, *"Briefing on Renewable and Energy Storage in the ISO Generator Interconnection Queue,"* at 4, July 15, 2021.

23 CAISO, 2020-2021 Transmission Plan, at 262, March 24, 2021.

TABLE 1. *Constraints Selected for Further Investigation*

Constraints	Cost (M$)	Duration (Hours)	Overview of congestion investigation
SDG&E DOUBLTTP-FRIARS 138 kV line	52.74	2,749	SDG&E Doublet Tap – Friars 138 kV line congestion has the largest congestion cost among congestions identified in this planning cycle. Both San Diego generators and IV/ECO generators may contribute to the congestion, including solar generators since congestion was observed during solar hours.
SCE Whirlwind 500/230 kV Transformers	22.91	295	About 4000 MW of renewable generators were modeled behind the Whirlwind 500/230 kV transformers constraint in the base portfolio PCM, including about 3000 MW existing or under construction generators, and the rest generators are under contract as shown in the CPUC's base portfolio.
COI Corridor	12.96	3.29	COI congestion slightly increased in this planning cycle compared with the congestion in the last planning cycle. The changes in transmission and renewable assumptions in the Northern Grid territory contributed to the COI congestion.
PG&E Fresno area constraints	8.64	4,520	Congestions were observed on multiple lines in the PG&E Fresno area, with relatively high congestion cost and duration. Some are recurring congestions.
Path 26 corridor south to north congestion	6.74	273	Path 26 congestion was mostly caused by the large amount of renewable generation in Southern CA identified in the CPUC portfolio

Another challenge to the current CAISO queue is the number of independent parties participating. While this reflects healthy competition, it makes coordination on transmission upgrades much more difficult than it used to be.

Projects have an incentive to stay in the queue to see if they win a contract in procurement. To be taken seriously, projects must have completed phases I and II of the interconnection process. As a general matter it is common for there to be 10 times more proposed projects than there is demand.

General CAISO interconnection queue policy and performance

In some regards, California, through the CAISO, CPUC, and CEC, has been utilizing better long-term queue management practices than other regions. CAISO pro-actively plans transmission for the future resource mix, which is the most important feature to have in place. California transmission planning at least intends to take into account future generation needs. CAISO plans note "the CPUC provided to the CAISO a renewable generation portfolio reflecting approximately 60 percent RPS for reliability, base policy and economic study purposes."[24] Just the fact that a future portfolio is incorporated as a standard practice has been unique to California among FERC-jurisdictional ISOs and RTOs. Some RTOs, such as the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP), have done that in the past, and the New York Independent System Operator (NYISO) is doing it now with their public policy transmission process, but it is not routine. The plans that have been developed

24 *Id.*, at 14.

over the years certainly contributed to the integration of new resources. For example, the Tehachapi set of transmission projects enabled 4,350 MW of new wind energy while expanding needed North-South capacity on the whole system.[25] CAISO Business Practice Manuals provide a process for policy driven transmission.[26] More detail on CAISO's planning process can be found in Appendix A.

Cost allocation

CAISO also has less cost assignment to individual generators than other regions. Under the Generator Interconnection Process (GIP), the Interconnection Customer payments for Network Upgrades are repaid to the customer by the Participating Transmission Owners (TOs), from revenues that come from TAC (the CAISO Transmission Access Charge). Accordingly, while an Interconnection Customer generally up-front funds the construction of needed Network Upgrades, the generator does not ultimately absorb these costs — ratepayers who pay the TAC do.[27]

Cost assignment depends on the categorization of the upgrades and type of service requested.[28] There is only "reasonable" cost reimbursement, and it is capped, so it is not the same for all locations, thus preserving some price signal to encourage more economical locations. Clustering has been utilized for a number of years in CAISO.[29] Various milestones are required for projects to proceed.[30] More could surely be done in these areas, but the principles are already ingrained in the CAISO approach.

Transmission planning

Transmission planning is likely not capturing all of the needs and benefits of the future resource mix. While plans do incorporate estimates of the future generation mix, the estimates may be understated due to conservative assumptions based on known changes to the resource fleet in a relatively short planning horizon. For example, the 2020-2021 CAISO transmission plan states, "Consistent with past studies, this transmission planning cycle did not reveal the need for major transmission expansion to achieve the 60 percent RPS goal set out in SB 100 for 2030."[31] That may have been true in the past, but the need is changing as higher renewable penetrations are required. As CPUC representative Karolina Maslanka said at a recent CEC workshop, the state is "beginning to see a shift from an era of available transmission headroom to one where transmission development will be necessary to accommodate the large amounts of resources expected to come online in the next 10-20 years to meet state goals."[32]

The benefits of diversification and contributions to resource adequacy from different resources in different locations likely have not been sufficiently incorporated into transmission plans. That

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25 CAISO, *"California ISO Board Approves Tehachapi Transmission Project,"* January 24, 2007.

26 *See* CAISO, *Business Practice Manual for Transmission Planning Process*, at section 4.6.1, June 30, 2020.

27 CAISO, *Business Practice Manual for Generator Interconnection Procedures (GIP BPM)*, at 16, Last Revised February 20, 2020.

28 *Order Conditionally Accepting Tariff Revisions*, 140 FERC ¶ 61,070, Docket No. ER12-1855-000, at 24-27, July 24, 2012.

29 CAISO, *Business Practice Manual for Generator Interconnection Procedures (GIP BPM)*, at 36, Last Revised February 20, 2020.

30 CAISO, *California Independent System Operator Fifth Replacement Tariff*, Appendix U: Standard Large Generator Interconnection Procedures, at 8 and 17-26, February 20, 2020.

31 CAISO, *2020-2021 Transmission Plan*, at 1, March 24, 2021.

32 CEC, "Joint Agency Workshop: Next Steps to Plan for Senate Bill 100 Resource Build — Transmission Session 1," Slide 19, July 22, 2021.

leaves value on the table and requires higher payments for resource adequacy than necessary. The Integrated Resource Plan (IRP), through which CAISO transmission planning was based, may not have incorporated capacity value diversity benefits among wind, solar, and storage, a concern stakeholders raised.[33] This can result in a less diverse generation fleet that provides less capacity value. At least one study shows significantly higher capacity contribution and carbon reduction impact from external resources that could serve California if these factors were incorporated into resource planning.[34]

Import limits in the IRP may also have been too tight, undervaluing external generation. As the CPUC documented, "Numerous parties were also concerned about the reduction in import limits for this IRP cycle, and how they were implemented both in the RESOLVE and SERVM models."[35]

Valuing diverse benefits

CAISO's economic planning seems to only be based on production cost savings, rather than integrating reliability, resilience, resource adequacy, and other values.[36] Few projects pass the benefit-cost test based on production cost savings alone, but more likely would with other values incorporated.[37] Out of 62 projects selected by CAISO for further economic planning analysis in the previous 5 transmission plans, only 5 upgrades were determined to have production cost benefits that were enough to support them as an economic-driven transmission projects.[38] Notably, in the 2020-2021 plan, CAISO determined SWIP-North and the Pacific Transmission Expansion were not sufficient on standalone bases to be economic-driven projects. With regard to SWIP-North, CAISO stated "The economic assessment for the SWIP-North project in this planning cycle identified that its benefit to cost ratio is 0.21, which indicates that the production cost benefit of this project likely cannot cover its total cost over its economic life. No other benefit was assessed for the SWIP-North project in this planning cycle, such as capacity benefit."[39] Benefits of transmission exist well beyond production cost alone so CAISO and the CPUC may be systematically under-valuing transmission.

Resilience benefits, based on the potential for extreme weather events, seems to be systematically under-valued. Recent challenges with extreme weather in and around California, as well as wildfires and drought, have stressed the bulk power network to conditions beyond traditional planning standards. This demonstrates the need to focus on the resilience and security benefits, as well as the insurance value, of a robust transmission network.

In August 2020, California experienced power outages and high prices when a high level of generator outages and derates coincided with record-breaking heat across many parts of the Western U.S. While this event was highly unusual in that the extreme heat affected much of the West at the same time, additional transmission capacity to other regions still could have helped

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33 CPUC, *2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning*, at 16, March 26, 2020.

34 Michael Hagerty, Johannes Pfeifenberger, and Evan Bennett, "SWIP-North Benefits Analysis," February 2021.

35 CPUC, *2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning*, at 12, March 26, 2020.

36 CAISO, *2020-2021 Transmission Plan*, at 8, March 24, 2021.

37 CAISO, *Transmission Economic Assessment Methodology (TEAM)*, August 8, 2017; CAISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004.

38 *See* CAISO, *2020-2021 Transmission Plan*, at 352, March 24, 2021, CAISO, *2019-2020 Transmission Plan*, at 342, March 25, 2020, CAISO, *2018-2019 Transmission Plan*, at 395, March 29, 2019, CAISO, *2017-2018 Transmission Plan*, at 264, March 22, 2018, and CAISO, *2016-2017 Transmission Plan*, at 195, March 17, 2017.

39 CAISO, *2020-2021 Transmission Plan*, at 298, March 24, 2021.

alleviate the outages and price spikes. CAISO calculated that congestion on transmission ties with other regions, mostly the Pacific Northwest, added around $45 million in consumer costs, while transmission congestion within California imposed an additional $37 million in costs.[40]

A lack of planning for reasonably predictable scenarios is taking place around the country. An extra GW of capacity into Texas would have fully paid for itself in winter storm Uri, and a GW between MISO and the Southeast would have saved consumers $100 million just during those few days.[41] Transmission planning should take into account reasonably foreseeable weather patterns even if they are outside of historical norms.

40 CAISO, "Bi-Weekly Performance Report," 8/05/2020-8/18/2020, (n.d.).

41 Michael Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, July 2021.

V. POLICY OBJECTIVES AND CRITERIA

Interconnection policy should attempt to achieve and balance multiple objectives, all of which have been elements of FERC Order 2003 and subsequent decisions.

Open access and non-discrimination

All generators should be treated on an equal basis to prohibit undue discrimination.

Reliability

The transmission system should meet all NERC criteria and provide redundancy and management of contingencies.

Generation resource adequacy should also be supported, as a separate area of reliability from transmission planning and operations. Resource adequacy improves with resource diversity and accessing resources that contribute capacity value.

Low barriers to entry

The policy should not be unnecessarily difficult or expensive for smaller entities or new entrants. The policy should be as simple and transparent as possible to enable ease of entry.

Speed and manageability

The process should be as fast as possible, with low implementation demands on the ISO/RTO, market participants, and TOs. Speed will allow innovative technologies to more quickly enter the market and bring their benefits to consumers.

Minimize total system cost

Total system cost to consumers should be minimized while complying with resource policies and other requirements. There can be a tradeoff between generation and transmission cost where generation closer to load can have higher generation cost but lower transmission cost. Similarly, there can be lower cost means of achieving resource adequacy despite some transmission cost to reach diverse resources. The overall interconnection, transmission, and resource adequacy policy should balance these costs to achieve lowest delivered costs to consumers.

VI. ALTERNATIVE APPROACHES AND ASSESSMENT

In this section we discuss alternative interconnection approaches from RTO and non-RTO areas, as well as other ideas that have been raised in the FERC ANOPR or elsewhere that may be relevant for California.

Pre-open access approach

Because interconnection queues were smaller before the open access requirements, it is worth reviewing that approach. Prior to FERC Order 888 requiring open access transmission service in 1996 and the associated Order 2003 applying the same approach to interconnection service in 2003, the process was simpler and more manageable. The vertically integrated utility would add generation into its rate base and incorporate transmission needs and access into the generation planning and development process in an integrated fashion. Resource adequacy, transmission needs, and interconnection were considered together in one process.

This approach, however, was not amenable to competition. Third party generation could only use the excess capacity available and negotiate with the transmission provider, who could utilize non-standard rates, terms, and conditions of interconnection service, which were generally not friendly to generation competitors. Interconnection queues were not large because there was not much of an opportunity for third party generation to serve load. This illustrates the trade-off between competition and manageability.

The pre-open access approach was on the extreme end of the spectrum with a manageable process that was not competitive or fair to all interconnection customers. Indeed, this is the reason for Order No. 2003 standardizing interconnection, as FERC stated in that order:

> …requests for interconnection frequently result in complex, time consuming technical disputes about interconnection feasibility, cost, and cost responsibility. This delay undermines the ability of generators to compete in the market and provides an unfair advantage to utilities that own both transmission and generation facilities. The Commission concludes that there is a pressing need for a single set of procedures for jurisdictional Transmission Providers and a single, uniformly applicable interconnection agreement for Large Generators.[42]

Open access models outside RTO/ISOs

Approximately one-third of the country follows open access rules but does not have an ISO or RTO. After Orders 888 and 2003, all transmission providers in the country were required to follow open, non-discriminatory access procedures for both transmission and interconnection. Outside of RTO/ISOs, FERC applied a default tariff and allowed minimal deviations. In this

42 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 11, July 24, 2003.

default set of procedures in the Order 2003 tariff, all generators can apply for interconnection on the same basis as all other generators, and follow the same terms and conditions as spelled out in FERC-approved tariffs. Order 2003 provided a standard Large Generator Interconnection Agreement (LGIA) and Large Generator Interconnection Procedures (LGIP). The procedures spell out how feasibility, system impact, and facilities studies are to be conducted and funded, how multiple requests are to be processed, and how any needed upgrades are to be performed and funded.

Order No. 2003 provided comparable interconnection service, but that is not the same as comparable transmission service. The LGIP/LGIA was "intended to provide the Interconnection Customer with an interconnection of sufficient quality to allow the Generating Facility to qualify as a designated Network Resource on the Transmission Provider's system without additional Network Upgrades."[43] Transmission service had to be reserved separately, and under Order No. 888 Open Access Transmission Tariffs, transmission service is provided to generation serving native load on a preferential basis. Thus, the combined effect of Orders No. 888 and 2003 blocked independent generators from gaining fully comparable access to both interconnect and deliver power. This less-than-open access has limited third party generation generally, and interconnection queue requests specifically in these areas. To further competition and more open access, FERC encouraged but did not require ISO/RTO formation in Order 2000 and other initiatives.

Initial standard ISO/RTO approach

When ISOs and RTOs formed initially in the late 1990s and early 2000s, they followed a similar approach to interconnection:

- Serial (generator by generator) process;
- Participant funding where interconnecting generator pays for network upgrades not needed "but for" the interconnection request;
- Interconnection customer pays for studies;
- ISO/RTO performs certain functions while the TO performs others, thus creating a three-way negotiation with the interconnection customer;
- Milestones and requirements apply to the ISO/RTO, transmission owner, and interconnection customer.

There were few but important deviations from the standard Order 2003 tariff. By 2009, most of the provisions were the same in ISO/RTOs on issues: request deposit, site control deposit, third party feasibility study, ability to waive facilities study, feasibility study timeline, cluster studies, system impact study deposit, permit applications, system impact study timeline, facility study deposit, sensitivity analysis, suspension rules, engineering and procurement agreement, and LGIA deposit.[44]

43 *Id.*, at P 768.
44 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, Table 1 at 11-12, January 2009.

In general, these initial ISO/RTO terms increased the ability of independent generators to enter each system with low barriers to entry. Implementation of Order 2003 in each region took place by 2005, just after a significant "boom" of new generation entry (almost all natural gas) around the country. By the end of 2007, there were 438 GWs of capacity in interconnection queues across the county, 51% of which was wind capacity.[45]

The more open access approach of Order No. 2003 contributed to the volume of requests as described above. In 2009, Porter et al said "Transmission providers contend that the low entry requirements and the ease of suspending applications leads to a congested interconnection queue; generators complain about uncertain transmission cost allocation, delays in processing interconnection applications, potential lost market opportunities, and multiple studies and restudies, among other things."[46] FERC began its first review and reforms with a technical conference in 2007 and direction to ISO/RTOs to file status reports in 2008.[47] MISO, PJM, ISO-New England, and CAISO all instituted initial reforms with their stakeholders and received FERC approval for them in 2008.

We discuss various approaches to manage interconnection queues below.

More clustering

The first and most obvious option to improve interconnection queues was to cluster project studies together. Each transmission provider quickly discovered that multiple projects connecting in the same area had many interactions such that any addition or withdrawal of any generator would reshuffle the needs and assignments of costs among other projects in the queue. In response to the 2007 FERC technical conference on interconnection queuing practices,[48] representatives from MISO,[49] SPP,[50] PJM,[51] ISO-New England,[52] BPA,[53] as well as the ISO/RTO Council,[54] noted the difficulties that this reshuffling presents in serial queues. The pure sequential process became unworkable. Clustering was "strongly encouraged" in Order No. 2003[55] as an option for the Transmission Provider. Some ISO/RTOs started with forms of clustering, others added it over time, and all use some form of it today. There are different approaches including the timing window (e.g., 90 or 180 days). Most allow for "electrically isolated" projects to be treated outside of clusters since they did not pose the same electrical interactions between projects.

45 Berkeley Lab Electricity Markets & Policy Group, "US Interconnection Queues 2020," Updated June 4, 2021.

46 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, at 2, January 2009.

47 *Order on Technical Conference*, 122 FERC ¶ 61,252, Docket No. AD08-2-000, March 20, 2008.

48 *See* FERC, *Technical Conference on Interconnection Queuing Practices*, Docket No. AD08-2-000, December 11, 2007.

49 *Prepared Remarks of Clair J. Moeller, Vice President of Transmission Asset Management Midwest Independent Transmission System Operator, Inc.*, Docket No. AD08-2-000, December 11, 2007.

50 *Prepared Statement of Charles Hendrix Senior Engineer, Southwest Power Pool*, Docket No. AD08-2-000, December 11, 2007.

51 Steve Herling, *Status of the PJM Queue: Overview Comments of PJM Interconnection*, Docket No. AD08-2-000, December 11, 2007.

52 Stephen J. Rourke, "FERC Technical Conference Interconnection Queuing Practices," Docket No. AD08-2-000, December 11, 2007.

53 *Prepared Comments of Elliot Mainzer, Manager of Transmission Policy and Strategy, Bonneville Power Administration*, Docket No. AD08-2-000, December 11, 2007.

54 *Comments of the ISO/RTO Council*, Docket No. AD08-2-000, December 11, 2007.

55 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 155, July 24, 2003.

California ISO shifted to a clustering approach in 2008.[56] ISO-New England,[57] NYISO,[58] SPP,[59] MISO,[60] Public Service Company of Colorado (PSCo),[61] and PJM[62] all have forms of clustering. Clustering reduced the volatility of the process such that the facility upgrade needs were much less influenced by the fate of any individual generator and more a function of a larger set — sometimes a few dozen generators studied together.

Clustering of projects by itself did not solve the long-term problem given the fundamental supply and demand for transmission access in certain areas. Wind energy in particular is very location-constrained, and in the late 2000s, wind energy was entering each ISO/RTO in large volumes. Generation markets had become very competitive such that many independent companies were developing projects in all RTO/ISO regions, hoping to secure both transmission service and PPAs for their power. ISO/RTOs had little basis to distinguish between all of the project proposals. Transmission service in the desirable development areas remained limited, and clustering did not address long-term grid capacity constraints.

Milestones and deposits

A theme of the first FERC review of interconnection logjams was that there needed to be ways to distinguish between "real" and "speculative" projects. Of course, every project developer believes their project is real, or has as good a chance of being viable as any other project in the queue. That said, it was generally recognized in the FERC proceeding that there were many more projects in the queue than would be developed in the near term, and that each project had a correspondingly low percent chance of being completed. Therefore, there was alignment of recommendations at the FERC conference including generation interests to increase the requirements on generators to allow more viable projects to proceed faster through the process.

In the 2008-9 timeframe, FERC, RTOs, and various stakeholders began to update requirements on generators. As stated by Porter et al in 2009, "Momentum has gathered around four particular options: (1) increasing the financial deposit requirements for receiving and maintaining a queue position; (2) eliminating the initial feasibility study or re-creating it as an optional screening phase; (3) greater limitations on project suspensions; and (4) moving away from a first-come, first-serve approach towards one that is more milestone-based."[63]

After the first round of interconnection reforms, processing improved for a period of time. The impact of the reforms are difficult to isolate from the effect of transmission expansion which occurred in the same 2009-2013 timeframe in multiple RTO/ISOs, in particular in CAISO,

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56 *Order Conditionally Approving Tariff Amendment*, 124 FERC ¶ 61,292, Docket No. ER08-1317, September 26, 2008.

57 ISO-NE, *Schedule 22: Large Generator Interconnection Processes*, at 53, Effective Date: July 20, 2021.

58 NYISO, *NYISO OATT*, Attachment X, at 196.

59 SPP, *Attachment V Generator Interconnection Procedures (GIP) Including Generator Interconnection Agreement*, at 42, Effective Date December 1, 2020.

60 MISO, *Attachment X Generator Interconnection Procedures*, at 64-65, Effective Date July 21, 2021.

61 Xcel Energy Operating Companies, *Open Access Transmission Tariff of Northern States Power Company, Northern States Power Company (Wisconsin), Public Service Company of Colorado, Southwestern Public Service Company*, Attachment N, Effective Date December 5, 2019.

62 PJM, *PJM Open Access Transmission Tariff*, section 36.2, Effective Date November 17, 2020.

63 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, at 36, January 2009.

SPP, Electric Reliability Council of Texas (ERCOT), and MISO which were the same areas experiencing the highest volumes of interconnection requests.

More can likely be done to move to a "first ready, first served" approach in place of a "first come, first served" approach and/or add financial commitment requirements. A variety of milestones have been utilized by now in ISO/RTOs around the country. These include:[64]

- Higher initial non-refundable application fees and security deposits than what is in place today (not just higher fees and deposits for later stages of the queue);
- Initial and/or continued demonstration of site control;
- Site exclusivity;
- Higher cost to withdraw and/or tiered decision points with higher portions of at-risk security as a deterrent to speculative entry;
- Completed application;
- Technical data submission;
- Proposed in-service date;
- Letters of Credit;
- Evidence of all necessary major permits;
- Initial payment of network upgrade cost assignments;
- The execution of a contract for the supply or transportation of fuel; execution of a contract for the supply of cooling water;
- Execution of a contract for the engineering, procurement of major equipment, or construction; execution of a contract for the sale of electric energy or capacity; or
- Application for an air, water, or land use permit.

FERC's ANOPR noted the up-front commitments, or financial collateral to pay for transmission upgrades, by generators in the ERCOT Competitive Renewable Energy Zones (CREZ) process and stated: "we seek comment on whether a fast-track generator interconnection process should be developed to facilitate interconnection of generating facilities that have firmly committed to connecting to new regional transmission facilities...We seek comment on whether such a process would constitute inappropriate "queue jumping," or instead would be more appropriately viewed as an extension of the previously approved first-ready, first-served queuing practice."[65] FERC's questions indicate the balance between manageability and open access. One guide to this balance might be the overall queue size—if it is very long, there may be a need to shift the balance towards more manageability through higher requirements and milestones.

Any of these options can be combined with others in the form of optional ways to meet certain

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64 See, e.g., MISO, "Generator Interconnection Process," and Xcel Energy Operating Companies, *Open Access Transmission Tariff of Northern States Power Company, Northern States Power Company (Wisconsin), Public Service Company of Colorado, Southwestern Public Service Company*, Attachment N, Section 7.7, Effective Date December 5, 2019.

65 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 86 Fed. Reg. 141, at P 155-156, July 27, 2021.

milestones, and often times additional security deposits may be accepted in lieu of more concrete milestones such as the initial or continued demonstration of site control.

PPAs as a milestone

A key factor in distinguishing between more vs. less viable generation projects is whether they have a PPA. In many regions there is one project that has a PPA for every ten that do not, and it is the one with a PPA that will most likely move forward.

This dynamic was recognized early on. Colorado PUC Chairman Binz suggested during the 2007 FERC technical conference that projects in state integrated resource plans or winning projects in bidding solicitations should be able to "jump the queue."[66]

A challenge with using PPAs as a milestone is the chicken-and-egg problem. Generators need to know their interconnection costs and transmission situation in order to form bids in solicitations at the same time as the interconnection process would be taking into account solicitation results. These are two separate processes with interaction between them.

Another challenge with using PPAs is the potential for discrimination, particularly where generators may be affiliated with the load-serving entity and/or transmission owner. TOs have a key role in interconnection even where an RTO/ISO is involved. Load Serving Entities (LSEs) clearly have a key role in selecting generation. In most cases the LSE is part of the same company as the TO. In many states, utilities are allowed to own generation, as well as transmission, and allowed to serve load. So, it is often the case that a utility that is both the LSE and TO is also competing with independent generation to secure the PPA. If the utility affiliate has an advantage to secure a PPA and if PPAs are used for preference in the interconnection process, then FERC would be presented with a policy that reinforces discrimination against third party supply.

FERC has approved the use of PPAs or winning a solicitation as a milestone. The PSCo tariff includes "reasonable evidence that the project has been selected in an approved Resource Plan or Resource Solicitation Process" as one of three "Readiness Milestones" required as part of a generator interconnection request.[67] PSCo's LGIP includes resource solicitation procedures that allow soliciting LSEs to request a queue position as agent for bidders participating in a resource solicitation process.[68] FERC approved PSCo's tariff modifications stating they consider the procedures to be "a reasonable approach to complying with a state-mandated resource solicitation process. It offers an innovative approach to queue management that will facilitate least cost planning without disadvantaging other generators in the queue."[69] FERC's acceptance was contingent upon the insulation of other interconnection customers from the effects of the resource solicitation process.[70]

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66 FERC, *Technical Conference on Interconnection Queuing Practices*, Docket No. AD08-2-000, at 38, December 11, 2007.

67 Xcel Energy Operating Companies, *Open Access Transmission Tariff of Northern States Power Company, Northern States Power Company (Wisconsin), Public Service Company of Colorado, Southwestern Public Service Company*, Attachment N, Section 7.7, Effective Date December 5, 2019.

68 *Order on Tariff Filing*, 169 FERC ¶ 61,182, Docket Nos. ER19-2774-000 and ER19-2774-001, at 5, December 4, 2019.

69 *Order on Rehearing*, 109 FERC ¶ 61,072, Docket Nos. ER04-419-001, ER04-419-004, and ER04-419-005, at 8, October 26, 2004.

70 *Id.*, at 10.

The extent of preference for affiliated generation is the subject of on-going litigation. As recently as June 2021, briefs were filed with the US Court of Appeals for the Washington DC Circuit in PSCo v FERC. In this case the company challenges FERC's determination that providing an easier path to interconnection for generators replacing retiring generation is discriminatory.[71] The Commission found that this two-tiered system would "disproportionately benefit replacement of [PSCo's] own generation.[72]

To address such potential for discrimination, FERC could allow PPAs to be used only in the case where the generation is unaffiliated with the transmission owner and LSE. In states without affiliated generation, this approach could potentially work to efficiently speed up interconnection queues without causing discrimination.

Open Season and subscription model

Offering interconnection capacity to all market participants and allowing voluntary subscriptions is a potential means of rationing scarce capacity in a fair and administratively efficient manner. The approach has lengthy precedent in energy markets and FERC regulation since it is the primary means of providing capacity on gas pipelines. It has also been used extensively now with merchant transmission providers.[73]

There is not a case of interconnection capacity itself being the subject of an open season and subscription as distinct from transmission service. But there are cases of transmission service solicitations that could be brought into the interconnection context, and the BPA Open Season example contained an interaction with the interconnection queue.

BPA utilized an open season for transmission in the late 2000s when it faced a shortage of transmission relative to requested transmission. Bonneville required entities to participate in the Network Open Season (NOS) for transmission service or else lose their position in the interconnection queue. "At the close of the 2008 NOS on June 16, 2008, BPA had 153 requests from 28 customers for 6,410 MW of new long-term firm transmission service."[74] Participants (generators) were asked to sign a Precedent Transmission Service Agreement, which included a security payment in return for the transmission rights that would be assigned, and BPA would then perform a cluster study of those willing to reserve capacity. This replaced the separate feasibility, system impact, and facilities studies. BPA was able to provide service to what was reported at the time to be 3,700 MW of new service through the process.[75] Other projects unwilling to make such financial commitments dropped out of the queue.

CAISO developed an innovative approach to transmission and interconnection in 2007 called Location Constrained Resource Interconnection Facilities (LCRIF).[76] CAISO filed, and FERC approved, an innovative rate treatment for these LCRIF facilities, in a policy often called the

71 *See* *Brief for Respondents, Xcel Energy Servs. Inc. v. FERC*, No. 20-1295 (D.C. Cir. 2021) (No. 14-1282), June 1, 2021.

72 *Order Addressing Arguments Raised on Rehearing*, 172 FERC ¶ 61,297, Docket No. ER20-1153-001, September 30, 2020.

73 *See* Joseph H. Fagan, Becky M. Bruner, and Natara G. Feller, "FERC Opens Door to Merchant Transmission Line Development—Expands Opportunity to Bring Renewables to Market," February 26, 2009; *Order Conditionally Authorizing Proposal and Granting Waivers*, 148 FERC ¶ 61,122, Docket No. ER14-2070-000, August 14, 2014.

74 *See* Letter from Stephen J. Wright with update regarding BPA NOS, at 1, February 16, 2009.

75 *Id.*, at 2.

76 CAISO, *California ISO Proposal for Location Constrained Resource Interconnection*, October 1, 2007.

trunkline policy.[77] The approach explicitly accounted for the location-constrained nature of renewable resources, while FERC was able to approve it as a technology neutral and non-discriminatory policy. While the exact transmission lines originally considered for LCRIF treatment were largely built and funded through separate transmission planning initiatives, the policy remains in the CAISO tariff and as a FERC precedent that can be used elsewhere. The policy provided for the construction and funding of radial transmission to serve a resource area experiencing a large volume of interconnection requests, paid for by existing network customers of CAISO, with payments by generators in the future as they took service.

The BPA NOS and CAISO LCRIF policies both enabled projects to move through the interconnection queue to completion and reduce the logjams, while avoiding discrimination and preserving open access. Critical to the success of these policies was the pro-active planning and building of transmission based on larger amounts of generation interested in an area than just what may have been in a queue cluster. The policies could have gone further to incorporate demand for transmission over a longer term, based on generation demanded in utility IRPs and state policy. As stated by Porter et al in 2009, "Above all, it is important to link queue reform initiatives with more proactive transmission expansion planning and addition of new transmission. Although the increase in generator interconnection applications has contributed to clogged interconnection queues, lack of transmission capacity also cannot be overlooked. Without new transmission, the queue reform initiatives may simply lead to a faster rejection of the generator interconnection application. Therefore, coupling queue reform initiatives with a re-examination of transmission cost allocation policies…is likely necessary to succeed in alleviating clogged generator interconnection queues."[78] That comment made in 2009 was made at about the time that MISO, SPP, and ERCOT produced significant pro-active transmission planning and cost allocation programs.

Relatedly, FERC approved an "anchor tenant" policy for merchant transmission in 2009.[79] The policy provides an exception to FERC transmission open access rules by giving the transmission developer the ability to use negotiated rates instead of market-based rates when an anchor tenant subscribes a large share of the line's capacity. This provides enough critical mass to allow a transmission project to move forward, helping to overcome the chicken and egg timing mismatch between generation and transmission discussed earlier. Due to reasons mostly related to transmission permitting, no transmission lines using this model have yet come online, though many are still in advanced stages of development and the policy can be used as a precedent.

A potential downside to solicitation approaches is the time and resources it takes to administer such programs. The timelines under the tariff for interconnection processing do not afford time for additional steps, so there would need to be a more comprehensive set of changes. For example, the competitive solicitation process for transmission in CAISO plans takes 9 months.[80]

77 *Order Granting Petition for Declaratory Order*, 119 FERC ¶ 61,061, Docket No. EL07-33-000, April 19, 2007.

78 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, at 42, January 2009.

79 *Order Authorizing Proposals and Granting Waivers*, 126 FERC ¶ 61,134, Docket Nos. ER09-432-000 and ER09-433-000, February 19, 2009.

80 CAISO, *Business Practice Manual for Transmission Planning Process*, Figure 5-1 at 52, June 30, 2020.

Favored zones

Another option that has not been used to our knowledge is to identify favored interconnection zones and allow faster, cheaper interconnection there. For example, if an RTO/ISO performs all the best practice pro-active planning, there may be a need to distinguish between future projects that are located in the places that were planned for versus those in other areas with less capacity available. FERC indicated its openness to an idea like this: “Another example of an interconnection request that demonstrates a higher degree of readiness could be one sited at a previously developed point of interconnection that can make use of existing interconnection facilities.”[81] A previously established interconnection point or a newly created interconnection point might be treated differently since the system impacts would likely be lower.

Higher fees

FERC’s ANOPR raised the idea of a fixed fee for interconnection requests as a way for interconnection customers to contribute to the upfront funding of interconnection-related network upgrades: “we seek comment on the potential establishment of a fixed fee applied to each interconnection request, which would be the same for all interconnection requests, irrespective of the generating facility’s capacity or project location.”[82] The Commission also asked about a variable fee, which ”could depend upon the generating facility capacity associated with the interconnection request and/or the identified interconnection-related network upgrades.”[83]

Limiting changes in cost estimates

In the current Cluster 14 discussions, CAISO has proposed that “...interconnection customers whose maximum cost responsibility goes up by 25 percent or more between Phase I and Phase II would be eligible for a 100 percent refund of their initial IFS posting if they withdraw before their second IFS posting is due.”[84] This approach may be an improvement that limits the uncertainty to generators, decreasing the incentive to submit multiple requests or stay in the queue longer.

Pro-active planning

Some amount of transmission planning is required for all transmission providers by FERC Orders No. 890 and 1000. Outside of RTOs, little planning is performed on a regional basis. Utilities tend to plan for their own native load needs. Inside RTOs, planning processes include a regional reliability assessment that identifies projects to meet reliability needs, a process designed to identify projects that will enhance the regional economic efficiency of the transmission system, a process for specific transmission or interconnection service requests,

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81 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 86 Fed. Reg. 141, at P 157, July 27, 2021.

82 *Id.*, at P 136.

83 *Id.*, at P 137.

84 CAISO, *Supercluster Interconnection Procedures: Final Proposal*, at 13, July 14, 2021.

and a process to consider public policy. These processes tend to operate in separate silos with minimal consideration of optimizing all of the needs together. Thus, both outside and inside ISO/RTOs, there tends to be little pro-active planning to incorporate the future resource mix or interconnection demands.

There have been exceptions to the rule above about minimal pro-actively planned and optimized transmission. We summarize the following approaches below: MISO MVPs, SPP Priority Projects, certain state initiatives such as Colorado's, ERCOT CREZ, NY public policy transmission, and the CAISO/CPUC transmission planning process.

MISO MVP:

In the late 2000s, MISO began a process along with states in the region called the Regional Generator Outlet Study (RGOS) to study pro-active plans to meet future generation resource plans.[85] The MISO Transmission Expansion Plan of 2009 (MTEP09) included the RGOS study scenarios.[86] These plans eventually became the MVPs, which unlocked a large amount of generation in the interconnection queues.

FERC approved the MVP portfolio despite the fact that MISO did not "determine the costs and benefits of the projects subregion by subregion and utility by utility."[87] While MISO now estimates subregional benefits, such an analysis could initially have bogged down MISO's approval of the portfolio, which MISO now projects to create average monthly benefits between $4.23 and $5.13 for the average residential customers over the next 40-year period, as compared to only $1.50 per month in average costs.[88]

The RGOS and subsequent MISO studies serve as a model for both co-optimized generation and transmission expansion planning while simultaneously assessing the multiple values of transmission. The study was multi-value in that it identified a transmission portfolio that simultaneously met reliability, economic, and public policy (through renewable generator interconnection) requirements. Co-optimization of generation and transmission means that the study attempts to minimize the total cost of generation plus transmission while meeting resource adequacy and other reliability criteria. For example, the following chart from the RGOS study shows how MISO attempted to minimize total generation plus transmission cost by evaluating different portfolios, ranging from building less transmission and using lower-quality local renewable resources on the left, to building more transmission to access higher-quality remote renewable resources on the right. The RGOS study found that a mixture of local and remote renewable resources, with a moderate transmission build, provided the lowest total cost for ratepayers.

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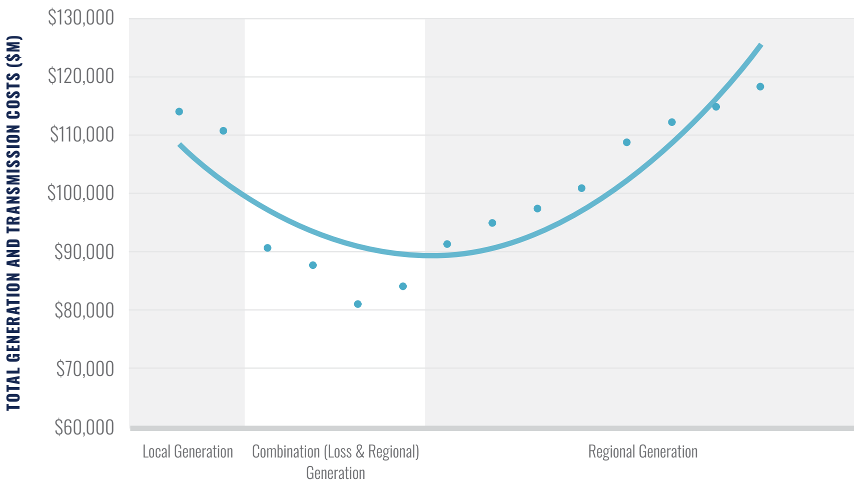
85 MISO, *Multi-Value Project Portfolio: Results and Analyses*, at 3, January 10, 2012.
86 *Id.*, at 15.
87 *Illinois Commerce Commission v. FERC*, 721 F.3d 764, 774 (7th Cir. 2013), ICC II at 774.
88 MISO, *MTEP19*, at 7, (n.d.).

FIGURE 6. *Generation and Transmission Capacity by Energy Zone Location*[89]



Subsequent MISO transmission planning efforts have also involved co-optimized transmission and generation expansion planning to some extent. Due to conflicts over cost allocation, these studies have not driven significant transmission expansion beyond the MVP projects, with most transmission upgrades paid for through participant funding by interconnecting generators. However, the studies provide a model for co-optimized generation and transmission expansion planning. Specifically, MISO has analyzed the location and type of optimal generation expansion across a range of futures,[90] based on high-resolution temporal and spatial representation of wind and solar output profiles as well as a simplified representation of transmission constraints.[91] These resource output profiles are used to assemble an optimal mix of resources that meets resource adequacy needs in every hour of the year. These generation expansion futures are then used as inputs in the MTEP transmission planning process. Vibrant Clean Energy and others have also conducted other studies in which transmission expansion is co-optimized with generation expansion.[92]

Co-optimized multi-value transmission planning offers significant advantages over transmission expansion driven by serial or even clustered interconnection studies. Using the generator interconnection process to drive transmission expansion inherently misses opportunities to address reliability and economic needs that can be more optimally solved through a multi-value planning process. Co-optimization better realizes economies of scale in transmission expansion and ensures the modeling captures globally optimal solutions, like expanding transmission into a remote area with superior resources, whereas incremental interconnection-driven expansion may miss these solutions by building more local upgrades.

89 MISO, *Multi-Value Project Portfolio: Results and Analyses*, at 17, January 10, 2012.

90 MISO, *MISO Futures Report*, April 2021.

91 Vibrant Clean Energy, *Detailed Siting Enhancement of MISO High Penetration Wind, Solar and Storage*, July 2017.

92 For example, *see* Aaron Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, October 2020; Christopher Clack, Michael Goggin, Aditya Choukulkar, Brianna Cote, and Sarah McKee, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, October 2020; Patrick Brown and Audun Botterud, "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System," January 20, 2021, Joule, Volume 5, Issue 1, at 115-134; Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, December 15, 2020.

Co-optimization becomes particularly important at high renewable penetrations when resource adequacy is an important constraint on the optimal generation portfolio, as is the case for CAISO. The incremental generator interconnection approach can account for the marginal Effective Load Carrying Capability (ELCC) of individual resource additions, but this misses large ELCC diversity benefits among wind, solar, and storage resources that emerge at higher renewable penetrations so that the total portfolio's ELCC is greater than the sum of its parts. By studying portfolios of resources instead of individual resource additions, co-optimized planning can identify the optimal mix of resources for meeting resource adequacy needs at least cost, as well as the transmission expansion necessary to enable that generation portfolio. This can include evaluating the value of inter-regional transmission for accessing diverse resources or loads in other regions.

While transmission expansion through centralized planning tends to drive better outcomes rather than relying on participant funding, there can be value in retaining some price signal and other market incentives for generation type, profile, and location. For example, generators can still opt to build farther away from the optimal transmission expansion, but they could face a higher interconnection cost for doing so. The elements of an Open Season process in which generators provide a binding indication of their willingness to pay for transmission interconnection, can also be used as a key input in the planning of transmission. For example, a resource with high economic value because it is located in a resource area with high productivity, particularly at times of peak net load, should have a higher willingness to pay for transmission interconnection than a resource with lower economic value. At a minimum, the transmission planning process should be informed by the current generator interconnection queue, which contains useful information about generators' interest in resource locations, as well as some indication of their expectations for grid upgrade costs (e.g. generators are less likely to apply to interconnect at points where they expect large upgrade costs). For example, the current interconnection queue was a key input into the planning of the CREZ and MVP transmission expansions.

PSCo:

Pro-active planning for a future resource mix is required by the state of Colorado. The CPUC requires electric utilities to submit bi-annual 10-year transmission plans as part of Rule 3627 for additional electric transmission projects in Colorado. In February 2020, Xcel Energy filed the latest 10-year transmission plan. In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policy initiatives[93] such as: Colorado House Bill 19-1261 (GHG abatement rules and regulations, including statewide goals to reduce pollution 26% by 2025, 50% by 2030, and 90% by 2050), Senate Bill 19-236 (includes mandatory retail utility clean energy plans for utilities > 500,000 customers), Senate Bill 16 19-077 (EV bill), Executive Order B 2019 002 (Zero emission vehicle mandate), Colorado's Renewable Energy Standard, Colorado Senate Bill 07-100 ("SB07-100"), and the U.S. EPA Affordable Clean Energy Rule. Two of the Companies, Black Hills and Public Service (one of four operating companies of Xcel), are subject to the requirements of SB07-100, which

93 Tri-State, Xcel Energy, and Black Hills Energy, *10-Year Transmission Plan for the State of Colorado to Comply With Rule 3627 of the Colorado Public Utilities Commission Rules Regulating Electric Utilities*, at 15-16, February 3, 2020.

requires Colorado's rate-regulated electric utilities to identify areas that have a high potential for beneficial resource development. As stated in SB07-100, Black Hills and Public Service are required to: a. designate energy resource zones (ERZs), b. develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones, c. consider how transmission can be provided to encourage local ownership of renewable energy facilities, and d. submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review.[94]

ERCOT CREZ

In 2005, the Texas legislature passed Texas Senate Bill 20, which ordered the Public Utility Commission of Texas (PUCT), in consultation with the Electric Reliability Council of Texas (ERCOT), to establish CREZs and develop a transmission plan to deliver renewable power to load.[95] The final selected transmission scenario constructed 3,600 right-of-way miles of 345 kV transmission at a cost of $6.8 billion. Since the completion of construction in 2014, the implementation of CREZ enabled the addition of more than 18 GWs of wind capacity to the Texas power grid. Generators paid a share of the upgrade costs as a commitment, which helped keep the queue manageable.

SPP Priority Projects:

In early 2009, the SPP Board of Directors approved a new report that recommended restructuring the organization's regional planning processes to create a new integrated planning process which focuses on regional, extra-high voltage (EHV) transmission expansion. SPP adopted a new set of planning principles that focused on the construction of a robust transmission system, large enough in both scale and geography to provide flexibility to meet SPP's future needs. These planning principles established a new Integrated Planning Process (IPP) that improved and integrated existing planning processes, which included an annual 10 year horizon reliability assessment to honor the delivery of committed transmission service, an aggregate transmission service study that determines expansion necessary to meet requests for new service, a generation interconnection process to determine expansion necessary to connect new resources to the grid, a balanced portfolio to assess economic expansion alternatives that provides more benefits than costs in each zone, and an EHV Overlay to assess EHV transmission needed within the next 20 years or more.

In this new process, SPP transitioned the EHV Overlay, Balanced Portfolio, and Reliability Assessment processes to the IPP. The Generation Interconnection and Aggregate Study Process were not integrated into the IPP, but were expected to be simplified. The IPP was intended to focus on regional needs and position SPP to prepare for and quickly respond to national energy priorities. A major objective was the design and construction of a transmission backbone to connect load centers to known or expected large generation resources. The backbone was expected to more strongly connect SPP's eastern and western regions,

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94 *Id.*, at 77.
95 Warren Lasher, "The Competitive Renewable Energy Zones Process," August 11, 2014.

strengthen ties to the Eastern Interconnection, and be strong enough to possibly connect to the Western Interconnection. It was recommended that SPP move to a "highway-byway" approach for funding transmission. The EHV "highway" would be funded with a regional rate, and lower-voltage "byways" would be funded with local rates. This method supports uniformity of customer costs, eases the administrative burden associated with current differing cost allocation methods, provides a basis for cost allocation across seams, and is more consistent with the "national transmission highway" being discussed at the federal level. Because it would take time to implement the new IPP and cost recovery recommendations, SPP has short term recommendations approved to identify, evaluate, and construct certain "priority projects" that continue to appear in system reviews as needed to relieve congestion on existing flowgates and connect SPP's eastern and western regions.

For projects that are identified in the transmission planning process, SPP uses the "Highway/Byway" transmission cost allocation methodology that assigns all costs to load. The Highway/Byway approach assigns 100 percent of all 300+ kV transmission upgrades to the SPP zones on a regional basis using the load ratio share (LRS) as a percentage of the whole of regional loads of each zone multiplied by the total annual transmission revenue requirement (ATRR) of the new upgrade. New upgrades in the 100 - 300 kV range are allocated 33 percent to all zones in the region on a LRS basis and 67 percent to the host or local zone; and 100 percent of upgrades under 100 kV are allocated to the local zone. The ATRRs assigned to the zones are collected from their respective transmission customers using the previous year's 12-month coincident peak LRS.[96]

NYISO public policy:

NYISO's Comprehensive System Planning Process (CSPP) analyzes expected changes in supply and demand on reliable operation over a ten-year period and includes the local transmission system planning process, reliability planning process, congestion assessment and resource integration study, and the public policy transmission planning process.[97] As New York public policies have changed in recent years, NYISO stated, "As part of the NYISO's Public Policy Transmission Planning Process, the New York State Public Service Commission (PSC) identified the need to expand the state's AC transmission capability to deliver additional power from generating facilities located in upstate New York, including important renewable resources, to the population centers located downstate."[98] Plans are underway to build these public policy transmission projects that would connect many projects in the interconnection queues.

Australia National Energy Market:

Similar to US RTO areas, the Australia market has an independent operator and planner and an independent generation sector. Each Transmission Network Service Provider must analyze the expected future operation of its transmission networks over an appropriate planning period, taking into account the relevant forecast loads, any future generation, market network service,

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96 Julie Lieberman, *How Transmission Planning & Cost Allocation Processes are Inhibiting Wind & Solar Development in SPP, MISO, & PJM*, at 37, March 2021.

97 NYISO, "Comprehensive System Planning Process (CSPP)," (n.d.).

98 NYISO, *2019-2028 Comprehensive Reliability Plan*, at 10, July 16, 2029.

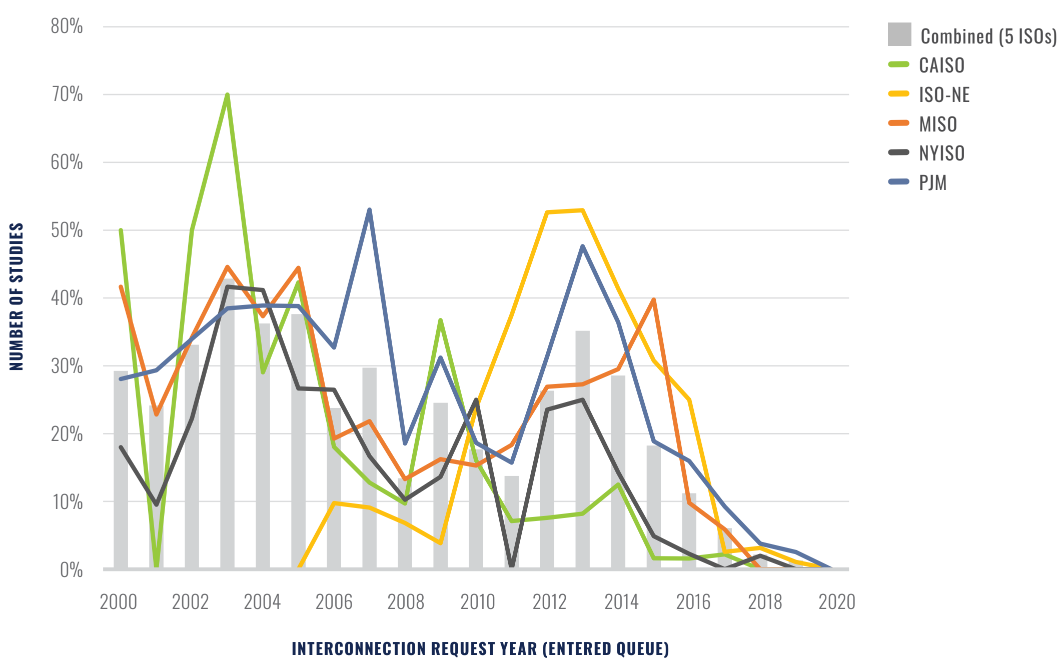
demand side and transmission developments and any other relevant data.[99] The "Integrated System Plan" (ISP) models a large range of options, and selects transmission projects that are commercially feasible, technically feasible, capable of meeting the system's physical requirements, able to balance resources, and able to unlock Renewables Resource Zones.[100]

Summary of pro-active planning models

These experiences with pro-active planning incorporating estimates of future generation all significantly alleviated interconnection queue logjams, at least for a period of time. Most of these plans were developed in the 2009-2013 timeframe, and relatively little has taken place since. In most cases, the desirable location of generation in the late 2000s remains a desirable area, and thus the transmission capacity built to serve these resources has largely been used up by now. With little regional or interregional transmission planned over the last decade, transmission capacity has become scarce again and queues are lengthening.

Generator completion rates rose for a few years in the 2012-2014 timeframe after these pro-active planning efforts opened up capacity, as shown below. However, as capacity filled up, completion rates fell again.

FIGURE 7. *Percentage of Completed Projects by ISO*[101]



99 AEMC, National Electricity Rules Chapter 5: Network Connection, Planning and Expansion, at 473, (n.d.).
100 AEMO, 2020 Integrated System Plan, at 13, July 2020.
101 Rand et al., Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2020, at 9, May 2021.

When transmission capacity has gotten ahead of generator interconnection, the interconnection queues have been quicker and cheaper for a period of time. In ERCOT, for example, interconnection queues have not been long or expensive. They are much simpler because transmission capacity is handled in the planning process, not the interconnection process.

Transition issues

It is one thing to identify a better policy than the one in place but quite another to shift to the new one without causing excessive impacts on projects in the queue. There are necessarily winners and losers among existing project owners if anything changes after they are already into the process. This has been a major hindrance to interconnection queue reform over the years. Making changes only prospectively is a way to avoid such disruption, but it may not sufficiently address the problem when there are years' worth of projects already in the queue.

VII. LESSONS FOR CALIFORNIA

We find no simple fixes for queue logjams from other examples.

One set of near-term changes, such as changing current deadlines and expectations, may be necessary because of staffing levels and the infeasibility of processing so many projects in Cluster 14.

A broader set of changes can likely be pursued in the category of moving towards more of a "first ready, first served" approach. The previous section listed a number of changes within the queue process which might be considered. Many of these types of changes are also currently being discussed by CAISO and its stakeholders in the "supercluster" process. For example, having PPAs can be used as a criterion for which projects may be more ready and viable, justifying faster processing in interconnection. Some market participants will likely prefer financial commitments over PPAs because they may have more confidence in their likelihood of success than the PPA status may indicate, and there are a variety of PPA types and terms so there is no black-and-white distinction between projects with and without PPAs.

There may also be an ability to speed up interconnection of storage projects given their flexibility and controllability. Certain applications and locations could be fast-tracked based on the system resource adequacy benefits they provide, and their operational flexibility which can avoid negative system impacts. Some solar-heavy locations are likely to be particularly good locations for storage to reduce solar curtailment and likely not trigger the need for large transmission upgrades because solar output is low during evening peak net load periods, unlike other paths that are much more congested during peak net load.

Similarly, adding storage to existing generation through greater flexibility in the Surplus Interconnection Service policy from FERC Order No. 845 would allow for the speedy interconnection of a lot of valuable storage on existing sites. In both cases, storage is so controllable that whatever reliability risks from its operation that may be possible can be avoided with appropriate agreements and controls. In most cases, storage's dispatch based on LMP should already ensure that storage is not exacerbating transmission congestion. Beyond the electrical studies, interconnection studies for transmission upgrade purposes can assume closer to "best case" rather than "worst case" operation given their controllability and dispatch according to price signals, and should therefore be relatively quick and easy to process.

As higher solar penetrations shift peak net load further into the evening, it is also important for CAISO to continue updating its interconnection study assumptions regarding solar's output during peak periods to fully capture the location-specific value of storage for reducing the need for grid upgrades to deliver remote resources.[102] While storage developers take into account the location-specific impact of transmission congestion when accounting for the energy arbitrage value of battery storage, the related value of storage for reducing the need for grid upgrades

102 CAISO, "Deliverability Assessment Methodology Straw Proposal Paper," August 5, 2019.

should be accounted for in the interconnection study process. For example, hybrid resources with large amounts of battery storage may be able to interconnect in a congested area with significantly lower upgrade costs than non-hybrid renewable resources. Similarly, additional renewable resources may be able to interconnect if they are installed on the same side of transmission constraints as battery storage.

As computer processing power increases, there will likely be benefits to moving away from interconnection studies based on snapshots of peak, off-peak, and shoulder periods to a more hourly approach that models renewable output patterns and the duration limits of storage. In the interim, CAISO should continue to update its study assumptions to account for how increased renewable penetrations are shifting the time periods of greatest transmission congestion and peak net load. For example, this can better capture the fact that storage resources located in solar-heavy areas can be deliverable at peak net load without causing a major need for grid upgrades because solar output has dropped off by the evening, while storage can also reduce congestion that limits the deliverability of solar resources midday by charging during that time period.

While fast-tracking storage that has minimal system impacts could provide benefits, similarly there may be benefits to providing access to resources that provide additional capacity value for the future on new or expanded transmission paths, as discussed below.

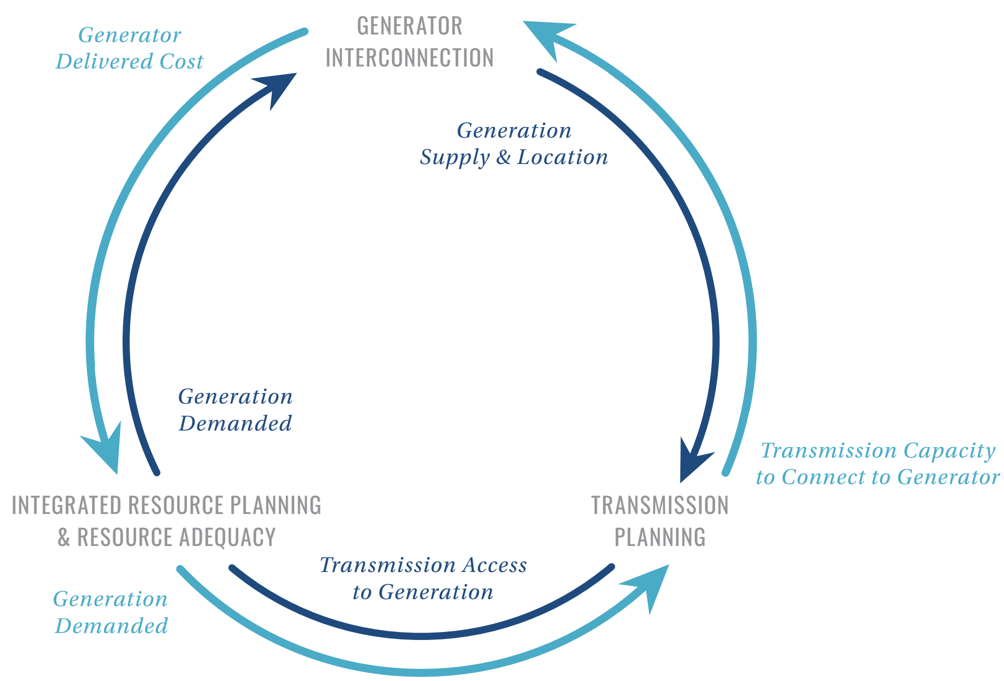
Another modest change within the interconnection process would be to allow greater use of Grid-Enhancing Technologies in the interconnection context. In some cases these technologies can solve transmission issues and are almost always cheaper and quicker to install than large new transmission lines.

Longer term, no changes within the interconnection process alone can be expected to solve queue logjams. At some point, the interactions between resource adequacy and transmission planning and cost allocation must be addressed head on and reforms must be considered in those areas to avoid dysfunctional interconnection queue processes. We offer some suggestions in these areas below.

General coordination of resource adequacy, integrated resource planning, generator interconnection, and transmission planning

There is significant overlap between these processes, which used to be integrated in the vertically integrated utility model. As the processes were separated, in many cases the interactions were lost. CAISO, the CPUC, and CEC can work towards better integrate to increase value to consumers.

FIGURE 8. *Interaction of Generator Interconnection, Transmission Planning, and Resource Adequacy/Integrated Resource Planning*



CAISO could incorporate capacity value into transmission planning

One of the largest values of transmission is the opportunity to reduce generation reserve margins, and save consumers money on generation capacity by aggregating diverse loads and resources. At higher renewable penetrations, California will have resource needs that cannot be met by short-duration storage alone and can most likely be met most cost-effectively with geographically remote resources that add diversity to the system. Marginal capacity value contribution (measured by marginal Effective Load Carrying Capability) tends to be high for resources with low penetration, but then decline rapidly because added resources have output that is correlated with existing resources. This has already occurred with solar and will eventually occur with battery storage.

Transmission can help offset this decline by offering both a greater diversity of resources type, and greater geographic diversity within each resource type. For example, wind energy from a different wind regime can often have low correlations with existing wind resources and therefore provide additional capacity value. Time zone effects can also marginally boost the value of solar from distant areas; e.g., New Mexico solar is available an hour earlier and thus can help meet the morning load ramp. Reports indicate that there are renewable resource diversity opportunities from California accessing out-of-state renewable resources.[103] CAISO's assumed marginal capacity values for different resources in 2030 are shown in the table below. It is appropriate to use future values such as these over the timeframe of transmission planning,

103 Johannes Pfeifenberger, "Transmission Planning and Benefit-Cost Analysis," April 29, 2021.

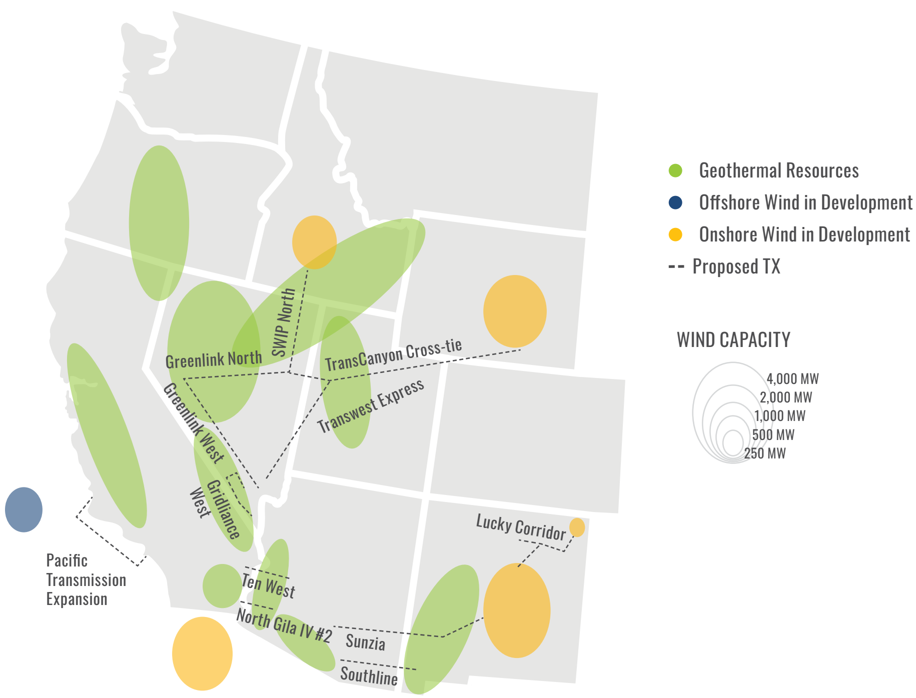
though it is also important for the resource optimization to dynamically account for how the capacity value of a resource changes based on the penetration of it and other resources.

TABLE 2. *CAISO 2030 Marginal Capacity Values in Effective Load Carrying Capability (ELCC)*[104]

High Capacity Factor External Wind	Solar	Geothermal	Storage
36%	9%	83%	93%

The map below shows the locations and types of external resources that could contribute substantially to California resource adequacy by providing energy at the times needed to meet high net loads in the state.

FIGURE 9. *Diversity-Increasing Resources and Proposed Transmission Projects*[105]



104 2030 ELCC average for July-September for each resource from CPUC, *Resource Data Template*, June 15, 2020, and using high capacity factor wind which is what is found in these other states. This is also the method used by Brattle here: Michael Hagerty, Johannes Pfeifenberger, and Evan Bennett, "SWIP-North Benefits Analysis," at 19, February 2021.

105 For descriptions of proposed transmission from Joint Agency Workshop, *see* CEC, "Joint Agency Workshop: Next Steps to Plan for Senate Bill 100 Resource Build — Transmission Session 1," Slides 39-109, July 22, 2021. For information on the proposed Greenlink transmission segments in NV, see Michael Goggin, Rob Gramlich, and Michael Skelly, *Transmission Projects Ready To Go: Plugging Into America's Untapped Renewable Resources*, at 8, April 2021. Wind resource size is based on projects in development that transmission developers state could be delivered on their lines, except for offshore wind and onshore wind in Mexico, which are from the CAISO generator interconnection queue, see CAISO, *The California ISO Controlled Grid Generation Queue for All: Active*, last accessed August 17, 2021. TransWest Express expected to deliver power from Wyoming's proposed Chokecherry and Sierra Madre wind projects (2,000-3000 MW), see Michael Goggin, Rob Gramlich, and Michael Skelly, *Transmission Projects Ready To Go: Plugging Into America's Untapped Renewable Resources*, at 8, April 2021. SWIP-North expected to deliver power from Idaho's Lava Ridge wind project (1,000 MW), see CEC, "Joint Agency Workshop: Next Steps to Plan for Senate Bill 100 Resource Build — Transmission Session 1," Slide 58, July 22, 2021. Sunzia expected to deliver 3,200 MW from the Sunzia wind project, see Id., Slide 77. Lucky Corridor expected to deliver 180 MW from the Don Carlos I wind energy project, see Id., Slide 102. Geothermal resource pockets are estimated from NREL's data, see Billy J. Roberts, "Geothermal Resources of the United States: Identified Hydrothermal Sites and Favorability of Deep Enhanced Geothermal Systems (EGS)," February 22, 2018.

CAISO could incorporate capacity value into interconnection policy

The ability of resources to increase overall system capacity value might be incorporated into interconnection policies. For example, offshore wind might be the highest and best use of the transmission between Diablo Canyon and the main system. That is one of very few places to bring offshore wind onto the system, and offshore wind provides significant and unique diversity that complements solar and storage by operating at hours when solar would not. Similarly, geothermal resources in Nevada or wind in Mexico or other states might provide the highest total value to consumers if those resources used the limited transmission capability on relevant paths between the resources and load. Interconnection policy could allow faster processing and higher queue priority for resources that add to resource adequacy in a future year such as 2030.

CAISO could adopt an Open Season and subscription model into interconnection

Whereas it used to be the case that there were a few companies who could coordinate on network upgrades, there are now dozens. A more manageable process would be an Open Season and reservation process to generators in the queue to subscribe to upgrades needed to interconnect them in common locations. The Open Season approaches from merchant transmission and gas pipeline contexts, which have been approved by FERC, could be used in the interconnection context. It could apply in areas where network upgrades could support many generators.

CPUC could incorporate resource diversity and geographically remote resources in IRPs

Related to the point above, resource procurement and resource adequacy, which are overseen by the CPUC, should include appropriate valuation of remote resources that provide diversity and capacity value. There are feedback loops between CAISO transmission planning and CPUC generation resource planning which will require tight coordination. CAISO likely cannot plan for transmission to resources that would not be considered in CPUC resource procurement.

CAISO co-optimization of generation and transmission

CAISO can adopt more co-optimized generation and transmission planning processes that minimize total costs and identify the optimal transmission build given the cost and resource adequacy of portfolios of resources. Greater co-optimized transmission and generation planning practices have been successfully used by other RTOs, such as the RGOS that led to the MVPs, as well as MISO's more recent MTEP. By studying portfolios of resources instead of individual resource additions, co-optimized planning can account for diversity benefits to better identify the optimal mix of resources for meeting resource adequacy needs at least cost, as well as the transmission expansion necessary to enable that generation portfolio.

Planning that incorporates total delivered cost, multiple benefits, and alternative scenarios is simply what would be called for in standard benefit-cost analysis from any economics textbook.

All benefits, appropriately adjusted for risk and time-value should be compared with the costs of any given investment.

Improved cost certainty for interconnection by zones

After a robust planning process plans transmission based on all benefits and connecting all new generation required, there will still be potential costs assigned to generators. For example, the generation proposing to interconnect in the area for which transmission was planned could be assigned a lower cost than generation in a new area that has more limited capacity. In this situation, it will still be valuable to consumers to provide greater certainty to generators up front so the process does not lead to the same issues of queue prospecting and churn. CAISO presently provides cost caps in phase I, and the cost caps in phase II might be lower but not higher. These limitations on cost are beneficial, and may be unique among ISO/RTOs. Still, more can likely be done to provide certainty. If the transmission owner does not wish to make the investment, the projects could be bid out to others.

CAISO and transmission owners could establish fixed interconnection prices by zone. These costs could be based on reasonable estimates of the cost. The risk of over- or under-forecasting those costs could be borne by ratepayers since in the long run this price certainty provides value to them in the form of a functional interconnection queue process.

VIII. CONCLUSION

CAISO has an interconnection queue problem. For better or worse, it is in good company with other ISOs and RTOs. The pace of the resource transition including the recent shift and acceleration of demand for storage resources has contributed to the ISO's queue backlog.

There is no easy fix for CAISO's interconnection queue logjam. A number of small changes to the process are being considered to make it more manageable and to come closer to meeting the tariff timelines. A set of broader changes to move towards a "first ready, first served" approach would likely improve the manageability of the process. PPAs and other milestones could be used to distinguish which projects to process faster than others. Grid-Enhancing Technologies should be considered as a faster and cheaper way to integrate projects.

CAISO should review Open Season and subscription models from other federal regulatory contexts for application in its interconnection queue process. This approach has successfully raised capital for needed infrastructure, provided market certainty to market participants, and fairly allocated scarce capacity.

Longer term, CAISO, CPUC, and CEC will need to work on the intersection and interaction between resource adequacy, transmission planning, and interconnection. Contributions to resource adequacy from geographically remote and diverse resources should be incorporated into both CAISO transmission planning and CPUC resource adequacy and integrated resource planning. Transmission and generation should be co-optimized. A broad set of benefits beyond just production cost should be included in the economic valuation.

CAISO should develop policies for greater cost certainty to the market for interconnection by electrical zone. Well-sited storage close to much of the solar development should be able to move through the queue faster and with less assessed impact if more appropriate operational assumptions are used.

APPENDIX A

CAISO'S TRANSMISSION PLANNING PROCESS

Each CAISO transmission plan includes a project list that identifies transmission found to be needed to meet reliability, public policy, and economic needs. CAISO states that transmission projects identified to meet public policy needs will help "interconnect new renewable generation via a location constrained resource interconnection facility project."[106] The transmission planning cycles are "recalibrated" each year to meet changes brought about by the aggressive pace of the electric power industry transformation in California, as well as renewable needs as identified through CAISO's policy-driven transmission studies based on the 60% RPS (and higher, potential sensitivities I.e. 70% RPS).[107] CAISO also states "integrated resource planning considerations need to focus not only on accessing renewable generation but also accessing the necessary integration resources to effectively operate the grid in a future of high volumes of renewable generation, and distributed energy resources and shifting customer needs necessitate a high degree of coordination in supply side and demand side forecasting."[108] Additionally, "the transmission plan is developed through a comprehensive stakeholder process and relies heavily on coordination with key energy state agencies — the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) — for key inputs and assumptions regarding electricity demand side forecast assumptions as well as supply side development expectations."[109] To identify transmission needed to meet transmission needs, CAISO uses CPUC-generated resource portfolios to capture the impact of renewable build out on transmission infrastructure and identify transmission upgrades or other solutions needed to ensure reliability, deliverability or alleviate excessive curtailment.[110] These portfolios have differing levels of renewable capacity, and are broken down by plausible forecasts of resource type and location.[111]

CAISO has also developed Generator Interconnection and Deliverability Allocation Procedures (GIDAP), which have important implications in facilitating the deliverability of the renewable generation forecast in the base renewables portfolio scenario provided by the CPUC: "In July 2012, FERC approved the GIDAP, which significantly revised the generator interconnection procedures to better integrate those procedures with the transmission planning process...The principal objective of the GIDAP was to ensure that going forward the CAISO would identify and approve all major transmission additions and upgrades to be paid for by transmission ratepayers under a single comprehensive process — the transmission planning process —rather than having some projects come through the transmission planning process and others through the GIP."[112]

106 CAISO, *2020-2021 Transmission Plan*, at 1, March 24, 2021.
107 *Id.*
108 *Id.*
109 *Id.*
110 *Id.*, starting at 161.
111 *Id.*, starting at 167.
112 *Id.*, at 40.