QUARTERLY REPORT

June 2019

Introduction

As I write this missive, I am in Cheyenne, Wyoming, at the Western Conference of Public Service Commissioners. For anyone in our industry who must work on regulatory issues, this is a must-attend event regardless of where it is. However, it's always good to get away from the coastal part of the West and realize just how diverse the region truly is. A Wyoming state agency presented its ideas on "infrastructure" that would benefit Wyoming…this translated into "coal." Shortly thereafter, there was a panel with commissioners from Idaho, California, Oregon, Washington, and Montana, all sitting in comfortable wing chairs, comparing notes on what drives them. Talk about diversity!

Underlying the conference is a recognition of the changing nature of the Western generation mix—even in coal-embracing Wyoming. The discussion by industry, representing various business models, emphasized the need to count "capacity" and compensate it. Impressively, many of the regulators recognized this discussion as important, as the resource mix integrates more and more very-low-cost renewable assets. The desire for "regionalization" is once again in the air, but with an important difference: no longer is California seen as being attached to the cause of regionalization, even though California will be part of any market.

Perhaps the debate about a regional market has hit an inflection point because of the need to value capacity in this new environment. California has its very formalized and detailed capacity program, while the rest of the West is less formal. Because there is increasing consensus on the need for a regional network market to integrate resources efficiently, maybe it will be possible to form a market around the Energy Imbalance Market (EIM) Entities and let the California Independent System Operator (CAISO) have a separate but highly coordinated market. Maybe, but the lasting impression I have from observing this diverse group of regulators is that there is a desire to consider new ways to get to a market that will better integrate resources. We'll see where this goes.

Scott Miller

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Save the Date

2019 Summer General Meeting
Board Meeting July 24
General Meeting July 25-26
The Edgewood Resort
Stateline, Nevada

2020 Winter General Meeting
February 20-21
Park Hyatt Aviara Resort
Carlsbad, California

Check the WPTF website for all the details

WIDER WEST COMMITTEE (2WC)

Caitlin Liotiris

Caitlin Liotiris coordinates WPTF's Wider West Committee (2WC), which engages on market, policy, reliability and technical developments in the "wider West," generally outside of California. The 2WC is active in advocating for broader western energy markets, especially the EIM and other regional market expansion opportunities. The 2WC also follows important developments at Peak Reliability and the Western Electricity Coordinating Council. Caitlin has over a decade of experience in energy issues in the West and has spent most of those years actively engaged on market development efforts across the Western Interconnection footprint, including a major role in developing the policies for implementing the EIM. She is skilled in understanding and distilling the interaction of energy policy and energy market dynamics. In addition to her work with WPTF, Caitlin has worked on various energy policy and market related issues throughout the county. Caitlin is currently a member of Peak Reliability's Member Advisory Committee (MAC) and has also co-authored various reports exploring the benefits of proposed transmission facilities in the West.

Is It Time Western Stakeholders Considered an Independent Coordinator of Transmission?

The Western Interconnection has long been a region that necessitates unique approaches to electricity issues. Look no further than the novel proposal referred to as the Extended Day-Ahead Market (EDAM), which is being designed to provide some of the benefits associated with full Independent System Operator (ISO)/Regional Transmission Operator (RTO) development while meeting the unique needs of utilities in the West. Additionally, many non-ISO/non-RTO transmission providers are dealing with interconnection queue backlogs that will require innovative solutions. All at a time when there are increasing demands to interconnect new resources to meet growing clean energy policy goals of many Western states. Pondering some of the challenges facing Western utilities, particularly on the interconnection side, made me wonder whether the West should consider implementing its own version of an Independent Coordinator of Transmission (ICT). An ICT (described more below) might fit well in the West for several reasons. First, it could give non-ISO/non-RTO transmission providers more flexibility in the interconnection processes that the Federal Energy Regulatory Commission (FERC) allows them to implement. Second, it might help address some of the transmission concerns that have been brought up in preliminary discussions of EDAM. Lastly, it fits well with the West's incremental approach to market development. In short, the time might be ripe for Western utilities and stakeholders to give this framework more consideration.

Let's start by briefly exploring the role and history of an ICT. In 2005, Entergy sought FERC approval of an ICT, which is the only proposed implementation of an ICT that I am aware of. Entergy's ICT proposal, which was conditionally approved by FERC in 2006, was intended to improve the transparency of transmission information, enhance transmission access, and relieve transmission congestion by placing an independent entity (initially the Southwest Power Pool in Entergy's case) in charge of some aspects of transmission-related functions for the utility. Although the use of an ICT didn't solve all of Entergy's problems (nor did it prevent a Department of Justice investigation into Entergy for potentially anticompetitive practices), the ICT did provide some independent oversight and control over several transmission-related functions. During its existence, the ICT functions included preparing base transmission plans, granting or denying requests for transmission and interconnection service, and coordinating data inputs/criteria studies. The role of the ICT was somewhat limited in its role of granting or denying requests for transmission and interconnection service, as it was required to conform to Entergy-determined studies and criteria in performing these functions. Nevertheless, the ICT provided oversight of Entergy's transmission system and achieved a level of independence for granting transmission service requests and performing interconnection studies.

The concept of an ICT may be intriguing to Western stakeholders and utilities struggling with how to implement meaningful interconnection queue reform. PacifiCorp's interconnection queue has grown so large that the utility recently proposed a business practice that would allow it to deem certain interconnection queue requests "non-viable." Because PacifiCorp (and other non-ISO/non-RTO transmission providers) may have incentives to perform studies in a way that would benefit certain generators, some stakeholders met this proposal with skepticism and concern about potentially anticompetitive practices.[1] In addition to the challenges of PacifiCorp, Public Service Company of Colorado (PSCo) has been seeking reforms to its interconnection queue process to allow viable projects to move forward, but has failed multiple times to achieve approval. In each instance, FERC has noted that some of PSCo's proposals were not accepted because, unlike an ISO or RTO, PSCo does not qualify for the "independent entity variation." This variation allows ISOs and RTOs more flexibility in implementing generator interconnection procedures and interconnection agreements. Thus, the lack of an independent entity variation has appeared to cause problems for PSCo in implementing meaningful queue reform. PacifiCorp seems to believe that it, too, may have trouble securing FERC approval of meaningful queue reform (which appears to be one reason the utility put forward the business practice referred to above, rather than starting a stakeholder process to develop comprehensive tariff reforms). Though these transmission providers and others in the West might have options for meaningful queue reform, they might also continue to struggle without the independent entity variation. It may be worth exploring whether an ICT could help these providers secure the variation from FERC.

The potential development of EDAM presents another reason to explore an ICT. Advocates of competition in energy markets must be given pause by some transmission-related aspects of EDAM: how much transmission is made available to EDAM by the utilities, how transmission is reserved by utilities for EDAM, and whether EIM Entities might be able to influence or manipulate market outcomes by releasing differing amounts of transmission into EDAM and the EIM. These concerns might be at least partially mitigated by a framework that provides independent oversight and control of some of the transmission-related functions of the market, such as that provided by an ICT. Injecting some independence into the management of transmission might be worth thorough stakeholder consideration during EDAM market design discussions.

In some ways, Entergy's implementation of an ICT was an incremental step toward full participation in an ISO (though Entergy's entrance to an ISO was arguably driven more by the Department of Justice investigation). Implementation of an ICT, modified to meet the needs of the West, seems to fit nicely with the apparent preference of Western utilities to move toward markets through an evolutionary (not revolutionary) process.

While setting up an ICT may be a step beyond what EIM Entities are currently considering, it seems worthy of additional discussion, especially in light of the interconnection-related concerns that are piling up across the West and their continued and increased importance as markets evolve. It is certainly something the WPTF Wider West Committee will discuss more as we continue to engage in interconnection-related stakeholder processes across the West.

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1 The functional separation of transmission and merchant functions established in FERC Order 889 is intended to ensure that transmission providers do not unfairly favor their merchants. But some question whether that functional separation continues to work as well as intended.

CARBON AND CLEAN ENERGY COMMITTEE

Clare Breidenich

Clare Breidenich coordinates [WPTF's Carbon and Clean Energy Committee](). Clare has over 18 years' experience on greenhouse gas regulation and policy. In addition to her work with WPTF, Clare has worked on international climate issues with the Environmental Protection Agency, the Department of State, and the United Nations Framework Convention on Climate Change secretariat. She has also served on the Washington State Governor's Climate Action Team and on a National Academy of Science's Committee on monitoring of greenhouse gas emissions.

State Carbon and Clean Energy Programs Raise EIM Concerns

This may be a bellwether year for clean energy in the West. Two high-profile legislative efforts—the Washington clean energy standard and the Oregon cap-and-trade program—have garnered the most attention, but Nevada, New Mexico, and Colorado have also taken strong action.

The Washington 100% Clean Energy Standard Is Adopted

In early May, Washington Governor Inslee signed the state's clean energy standard into law. The legislation requires that 100% of electricity used to serve Washington load be carbon free by 2045. Between 2030 and 2044, 80% of electricity used to serve Washington customers must be carbon free, and utilities must use alternative compliance options to make carbon neutral any portion of electricity that is met by emitting sources. The alternative compliance options are retirement of unbundled renewable energy credits, investments in energy transformation projects, or payment of an alternative compliance fee.

Several important changes made during the House's consideration of the legislation remained in the final version:

- In response to concerns that a "once-size-fits-all" alternative compliance fee would not incent utilities to choose lower-emission resources over high-emission resources, the fee is now tiered: $150/megawatt-hour (MWh) for electricity sourced from coal-fired resources, $84/MWh for electricity from gas peakers, and $60/MWh for electricity from combined-cycle units.
- The legislation clarifies that renewable energy credits (RECs) used for I-937 compliance (the state's renewable portfolio standard) also apply toward compliance under the new clean energy standard.
- Unbundled RECs (where the REC has been separated from the underlying energy) may be used for compliance, provided that there is no double-counting of any nonpower attributes associated with RECs within Washington or programs in other jurisdictions.

The no-double-counting provision was added at the insistence of environmental groups, who wish to ensure that renewable electricity "deemed delivered" to California by the EIM under the cap-and-trade program cannot be used to comply with the Washington clean energy standard. Washington utilities, not surprisingly, object to this interpretation. The Department of Ecology and the Utility and Transportation Committee must now conduct rule-making for implementing the prohibition on double-counting of nonpower attributes (including, presumably, deciding what constitutes double-counting). Rules must also be developed for how utility load served by the EIM and other market purchases will be treated under the program.

Oregon Cap-and-Trade Bill Awaits Final Legislative Action

Down in Oregon, the Joint Committee on Carbon Reduction passed the cap-and-trade bill out of committee. There were several last-minute amendments to the bill, but the only significant change for the electric sector was the addition of a provision, advocated by WPTF, that allows the Carbon Policy Office to adopt additional rules for EIM imports. Such rule-making authority is necessary if Oregon is to align its rules for imports with California's.

The legislation now sits with the Joint Ways and Means Committee. With less than three weeks left in the 2019 legislative session, time is quickly running out. The reason for the delay is not clear, given that the tax and revenue package was adopted in late May. However, most observers still expect the bill to pass.

EIM Regional Issues Forum to Tackle Carbon and Clean Energy Policies

In light of Oregon's expected adoption of the cap-and-trade program, the Washington clean energy standard, and similar legislation enacted in New Mexico, Nevada, and Colorado, the interaction of state carbon policies and energy markets is a hot topic. Many market participants wonder how state policies to drive out fossil-fuel resources will affect resource adequacy over the next decade, and what impact the future glut of renewable energy will have on wholesale electricity prices. However, a more immediate question concerns the ramifications of these policies for the expanding EIM. On June 16, the EIM Regional Issue Forum will devote an entire day to examining Western states' carbon and clean energy policies and their implications for EIM design and on EIM Entities and participating resources.

A key issue at the forum will be the potential conflicts between market efficiency and state carbon and clean energy policies. While cap-and-trade programs can be accommodated in the EIM design because of the imposition of a carbon price (though not necessarily without unintended consequences, as the consternation over the EIM's "secondary dispatch" has demonstrated), programs that do not use carbon pricing or that result in divergent carbon prices across states could complicate EIM operations and undermine market efficiency.

For Oregon, the primary question is whether the cap-and-trade program will be linked to that of California. If not, and if Oregon imposes EIM import rules similar to those of California, then the California Independent System Operator (CAISO) would need to allow for separate greenhouse gas bids for the two programs. This would add complexity to the EIM dispatch algorithm and, if allowance prices differ significantly across the two states, could lead to some unusual bidding behavior from low-emission resources trying to get to the more profitable state. Even with program linkage, CAISO would need to modify its systems to distinguish the Oregon load of EIM Entities, such as PacifiCorp, whose balancing areas overlap state borders.

Clean energy programs that do not rely on carbon pricing, such as Washington's and the mandates adopted by New Mexico and Nevada, do not require changes to the EIM dispatch algorithm; regulators could implement the programs solely through retirement of RECs, as has been done so far under most state renewable portfolio standards. The risk is that concerns about potential double-counting of REC attributes could cause regulators to adopt rules that hamper market efficiency. For instance, Washington regulators could decide that renewable resources bid into the EIM must be deemed delivered to Washington in order for the associated RECs to be considered bundled, or that deemed delivery of the output of a renewable resource to California or Oregon constitutes a claim on the nonpower attribute of the RECs, thereby disqualifying those RECs for use under the clean energy standard. Such program rules could result in a strong disincentive for renewable resources to participate in the EIM. Or, they could lead to demands to modify the EIM algorithm to give EIM Participating Resource Scheduling Coordinators more control over where the output of renewable resources is deemed delivered to fulfill renewable contract requirements with Washington utilities. Neither outcome would be good for the EIM.

RESOURCE ADEQUACY (RA) COMMITTEE

Greg Klatt

Greg Klatt coordinates the Resource Adequacy Committee. Greg is a practicing attorney with over 20 years of energy industry experience. His practice focuses on state and federal regulation of the electric power and natural gas industries. He has represented clients in numerous ratemaking and rulemaking proceedings before the CPUC. He regularly advises energy companies regarding regulatory requirements applicable to their product and service offerings. He represents marketers and retailers in CPUC licensing, compliance and enforcement matters. He also commonly acts as regulatory counsel in energy-related transactional matters, including procurement contracting, resource development projects, repower projects, major asset acquisitions and related financing arrangements.

Greg received his J.D. from UC Berkeley's School of Law (Boalt Hall). He graduated magna cum laude with a B.A. in History from the University of San Francisco and is a lifetime member of the Alpha Sigma Nu honor society.

The Central Buyer Rubik's Cube

When the last quarterly report came out, the California Public Utilities Commission (CPUC) had just issued its final decision on Track 2 issues) in the resource adequacy (RA) proceeding). In that decision, the CPUC established three-year forward procurement requirements for local RA. However, the CPUC declined to adopt a "central buyer" framework for local RA procurement and instead directed the parties to hold a series of workshops, with one workshop to be facilitated by the investor-owned utilities (IOUs), a second by community choice aggregators (CCAs), and a third by electric service providers (ESPs). The CPUC's stated purpose in ordering the workshops is for the parties to develop a set of agreed recommendations for the CPUC to adopt. But, as was wryly observed at one of the workshops, trying to resolve the issues surrounding a central buyer is like trying to solve a Rubik's Cube.

First Workshop Fiasco

The first workshop, held on April 22–23, was facilitated by the IOUs. It did not go well.

The focus of the workshop was the scope of the local RA procurement to be undertaken by the central buyer (i.e., "full" versus "residual" procurement). However, much of the first day was squandered on an unsuccessful effort by the IOUs to get the parties to agree on definitions for the "stakeholder priorities" that had previously been identified. The remainder of the first day was taken up by the IOUs' presentations on their preferred procurement models for the central buyer or "central procurement entity" (CPE):

- PG&E favors the "full" procurement model, wherein the CPE procures all the local RA needed to meet local capacity requirements and charges the costs of that procurement directly to load-serving entities (LSEs) or to their customers based on each LSE's respective share of total load.
- SDG&E prefers the "residual" procurement model, wherein LSEs continue to be assigned local RA requirements and self-procure the local RA needed to meet their individual requirements, with the CPE's role being limited to procuring the local RA needed to meet any LSE-specific and collective procurement deficiencies. Under this approach, the CPE's procurement costs would be allocated first to LSEs (or the customers of LSEs) that had procurement deficiencies, with the costs of any CPE procurement in excess of LSE-specific deficiencies being

allocated among all LSEs based on load share.

- SCE advocates a "hybrid" model, wherein the CPE would be responsible for procuring all the local RA needed to meet local capacity requirements, but individual LSEs could reduce their allocations of CPE procurement costs by voluntarily procuring local RA and offering it to the CPE; the CPE's procurement would be reduced by the amount of such voluntarily "shown" local RA that it agrees to buy.

The second day was largely taken up by the IOUs presenting detailed numerical examples of how their respective preferred models worked. That was followed by a "panel discussion" that amounted to little more than PG&E and SCE representatives defending their utilities' preferred models. There was no time for a planned "all party discussion" at which non-utility parties could identify top priorities and preferences. Thus, at the end of the first workshop, there was no apparent progress toward a consensus proposal.

Second Workshop Sonata

The second workshop, held on May 15, was facilitated by the California Community Choice Association (CalCCA) and representatives from several larger CCAs. The focus of the workshop was "Selecting a Central Procurement Entity." The CCAs' presentations were more balanced and the discussion was more productive than at the first workshop. The second workshop's objectives, and the outcomes thereof, are outlined below.

Organizational options: Six alternatives were initially identified, but three were excluded from the workshop discussion for the following reasons:

- CAISO—Not interested, and there are jurisdictional concerns
- Joint Powers Authority—Can include only governmental entities and thus could not include IOUs or ESPs
- Utility Affiliate—Presents structural challenges and conflicts of interest

The discussion thus focused on these three alternatives:

- Not-for-profit corporation
- State agency
- Distribution utility (either single or one for each Transmission Access Charge [TAC] area)

(Interestingly, the CAISO's Karl Meeusen said that his organization, while categorically opposed to being designated the "jurisdictional entity" for centralized RA procurement, might be willing to "facilitate" centralized procurement in some fashion—if all the parties agreed and the CPUC approved.)

Organizational advantages and disadvantages: This topic received the most attention, resulting in general acknowledgement and agreement that the three main alternatives' capabilities are pretty much equal in terms of:

- Ensuring reliability
- Reducing CAISO backstop procurement
- Not being able to eliminate non-utility market power (because that's a federal issue)
- Time required for implementation
- Promoting state energy policies

The main advantages of a distribution utility CPE are: (1) new legislation wouldn't be required to confer procurement and cost recovery authority (unless one utility was going to be the CPE for all TAC areas); (2) existing staffs have requisite knowledge and expertise (but that, at the same time, gives rise to potential conflicts of interest not associated with the other alternatives); and (3) startup costs would be low. However, the IOUs either have or could soon have major creditworthiness issues. And, as PG&E acknowledged, startup costs could be just as high for the IOUs under this alternative as with the other alternatives, assuming the IOUs are required to wall off the CPE from other utility functions.

The perceived advantages of a state agency CPE include low startup and operating costs and no creditworthiness issues. The biggest advantage of both the state agency and not-for-profit corporation alternatives is that they would be competitively neutral (although having a CPUC-hired consultant do the resource selections and then having IOUs sign the contracts may provide competitive neutrality under the distribution utility CPE model). The biggest disadvantage of a not-for-profit corporation CPE is that its startup would likely entail the highest costs, with creditworthiness also being a potential problem.

The differences between the alternatives are most pronounced with respect to whether the CPE would be a regulated utility:

- Not-for-profit corporation—Could be set up as a CPUC-jurisdictional utility. Would be exempt from FERC jurisdiction if established and operated as an "instrumentality of the state."
- State agency—Would not be subject to CPUC jurisdiction (unless its authorizing legislation provided for such). Would be exempt from FERC jurisdiction as an "instrumentality of the state."
- Distribution utility—Would be subject to CPUC jurisdiction. Could be subject to FERC jurisdiction depending upon scope of responsibilities and activities.

Third Workshop's a Charm?

The third workshop, held on May 22, was facilitated by Shell Energy on behalf of the ESP community. The focus of the workshop was implementation issues associated with centralized procurement, and thus the discussion covered much of the same ground covered at the first two workshops. But, by some miracle, the discussion was much less contentious and even friendly at times. It's too early to predict how things will end, but it's fair to say that a negotiated settlement, among most if not all the parties, is not the impossibility that it appeared to be on day one.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) COMMITTEE

Dan Douglass

Dan Douglass has directed WPTF's legal efforts since helping to cofound WPTF with Gary Ackerman in 1998. On behalf of WPTF, he has been extremely active at the California Public Utilities Commission and assists Ellen Wolfe, Caitlin Liotiris, and Carrie Bentley with WPTF matters at the Federal Energy Regulatory Commission (FERC).

His firm, Douglass & Liddell, specializes exclusively in energy law issues, providing regulatory and transactional counsel to generators, suppliers, and end-users in the electricity and natural gas markets. This work has included the formation and representation of several influential regulatory advocacy organizations in addition to WPTF.

Prior to Douglass & Liddell, Dan was a partner with the national firm of Arter & Hadden, where he headed the firm's California energy practice; he previously was General Counsel of LG&E Power and President of Cook Inlet Energy Supply. Dan also spent 15 years at Southern California Gas Company and its affiliates and worked on several international and domestic gas supply and storage issues during that time.

PCIA Working Group 3—Why It's Important to WPTF

The Power Charge Indifference Adjustment, or PCIA, has been a topic of hot debate for many years. It is much despised by parties that support competitive retail electricity markets, and much adored by utilities and bundled customer advocates.

Today's PCIA originated in statute enacted during the California energy crisis, when the California Legislature passed Assembly Bill 1X. After finding that unforeseen shortages of electric power and substantial price increases were "an immediate peril to the health, safety, life and property of the inhabitants of the state," the Legislature authorized the state Department of Water Resources (DWR) to enter into contracts to purchase electric power for delivery to retail customers of the state's investor-owned utilities (IOUs).

It soon emerged that the new DWR contracts were extremely expensive relative to post-crisis electricity costs, which prompted many customers to move to direct access service. Therefore, AB 1X directed the CPUC to suspend the right of customers to enter into direct access transactions. The CPUC determined that DWR had made its purchases on behalf of all customers and that there would be a significant cost-shifting if energy crisis costs were borne solely by remaining bundled service customers.

For these reasons, the PCIA and related charges were developed. But the passage of time and the significant growth in community choice aggregation (CCA) have led to claims by all sides that the PCIA is outdated and needs to be revised. A lengthy and hard-fought proceeding last year resulted in rejection of both a consolidated utility proposal to increase the PCIA and a CCA proposal to reduce it. Instead, various changes were made to the PCIA calculation methodology by decision D.18-10-019.

In the wake of that decision, a Phase 2 Scoping Memo was issued on February 2, establishing three working groups (WGs) on the following topics:

1. WG 1—Issues with the highest priority: benchmark true-up and other benchmarking issues

2. WG 2—Issues to be resolved in early 2020: PCIA prepayment

3. WG 3—Issues to be resolved by mid-2020: portfolio optimization and cost reduction, allocation, and auction

WG 1 has had several meetings and rounds of comments. WG 2 has held two workshops and one round of comments, with more to follow.

WPTF members should be highly interested in WG 3, as the portfolio management and optimization issues could significantly change utility operations, with a concurrent impact on existing contract counterparties and future IOU contracting opportunities.

For example, WG 3 is tasked with answering the following questions:

1. What are the structures, processes, and rules governing portfolio optimization that the CPUC should consider in order to address excess resources in utility portfolios? How should these processes and rules be structured so as to be compatible with the CPUC's ongoing Integrated Resource Planning and resource adequacy program modifications in other proceedings?
2. What are the standards the CPUC should adopt for more active management of the utilities' portfolios in response to departing load in the future in order to minimize further accumulation of uneconomic costs?
3. If the CPUC were to adopt standards for more active management of the utility portfolios, how should the transition to new standards occur (timeframe, process, etc.)?
4. Should the CPUC consider new or modified shareholder responsibility for future portfolio mismanagement, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards? If so, are Energy Resource Recovery Account or General Rate Case proceedings the appropriate forums to address prudent management of portfolios?

The co-chairs of WG 3 are Southern California Edison and the California Community Choice Association. Also, there is an allocation and auction subgroup for which Commercial Energy is the chair.

So far, there has been one WG 3 workshop (April 29), with comments provided on May 10. More workshops and follow-up comment and input opportunities are planned. A first progress report is due June 24, and a second is set for September 26. A WG 3 report on consensus and non-consensus items is due January 30, 2020, with a proposed decision expected in the second quarter.

Why is this important? Put simply, it's all about the money (so what else is new?). Utility portfolios are larded with contracts that greatly exceed their bundled customer requirements. This situation is exacerbated as more and more CCAs are formed and make their own procurement arrangements. Plus, direct access will grow modestly in 2021, under the CPUC's recent implementation of Senate Bill 237. Further, the same legislation directed the CPUC to report by June 1, 2020, as to how the cap on direct access transactions could be eliminated for all nonresidential customers.

The dramatic increase in unbundled load, coupled with the possibility that some or all IOUs may attempt to become simply wires companies, means something has to give with regard to IOU power portfolios.

Will that mean IOU portfolio restructurings or sales of power contracts? Could it be a contributing factor in a Pacific Gas and Electric (PG&E) decision to use its bankruptcy as a pretext for rejecting contracts? How will all this tie into the Integrated Resource Planning and resource adequacy proceedings?

These and many more questions are yet to be answered. But the process has begun, and it would be prudent for WPTF to pay close attention. Some board members are already discussing the possibility of forming a PCIA committee.

In summary, the WG 3 process could result in significant changes to utility portfolio management, which should be of interest to many WPTF board and general members.

CALIFORNIA LEGISLATIVE COMMITTEE

Jesus Arredondo

WPTF Legislative Committee consultant is Jesus Arredondo. Jesus is the principal and founder of Advantage Government Consulting LLC and has over 19 years of experience in media and government relations, including concentrated experience in energy policy. Prior to launching Advantage Consulting, Jesus worked as a senior advisor for two major public relations firms in the United States and Mexico. Jesus also served as a policy advisor to a major California transmission project, principal advisor on an education effort in California concerning natural gas and on a national education campaign concerning the FERC's push for standard market design. Before launching Advantage Consulting, Jesus was a bilingual spokesman for two California governors and served five years as director of regulatory and government affairs for a fortune 250 independent power producer and two years at the California Power Exchange, where he served as director of corporate communications.

Fire Legislation and De-Energization of Transmission Highlight the Legislative Session

Fire Legislation Is Still in Play

As the first part of the legislative session came to a close in May, legislation to address utility vulnerability due to catastrophic wildfires remained the top energy policy priority. Specifically, key questions revolved around how the state should deal with the next fire while maintaining energy reliability, keeping consumers safe, and maintaining the financial health of the investor-owned utilities.

Hoping to offer guidance on how to address these questions, the five-member Commission on Catastrophic Wildfire Cost and Recovery, created last fall by the Legislature under Senate Bill (SB) 901, said in a draft report released May 29 that California should overhaul the legal doctrine known as "inverse condemnation," which holds a utility liable for wildfire costs if the company's equipment caused the fire, even if the company didn't act negligently.

Under the Commission's proposed overhaul, the utilities could bill ratepayers for "just and reasonable investments" that reduce the likelihood of fire. The Commission also called for the creation of a Wildfire Victims Fund to quickly pay claims to survivors of the 2017 wine country fires and the Camp Fire, which destroyed most of the town of Paradise last November. The Commission proposal stated that the fund would include financial contributions from shareholders as well as ratepayers, but did not address how large the fund should be. The Commission's recommendations are similar to proposals outlined by Governor Newsom's Wildfire Taskforce Report, released in April, and recognize the financial peril facing the state's three major utilities. In addition to PG&E's bankruptcy filing, the other two utilities, San Diego Gas and Electric (SDG&E) and Southern California Edison (SCE), have seen their credit ratings plummet as lenders fear they will get swallowed by wildfire liabilities as well.

The SB 901 Commission report came as state legislators continued to debate how to get funds to wildfire victims while keeping utility rates relatively low. Problematic is the fact that all three utilities have asked the CPUC for substantial rate hikes to deal with wildfire risks. In a joint statement with legislative leaders following the release of the Commission's report, Newsom pledged to work for a solution that treats everyone fairly, stating, "We must act now to stabilize the energy market and our utilities by addressing the liability faced by utilities after catastrophic wildfires." Senate President pro Tem Toni Atkins and Assembly Speaker Anthony Rendon in a joint statement added that they too are committed to “insisting on a culture of safety for utilities and on affordability for ratepayers.”

It is still unclear which bill will actually carry the language for whatever happens this year. Asked about the possibility of addressing a meaningful change to “inverse condemnation,” Newsom showed little appetite for tackling that kind of reform in the near future; he has many other (non-energy) issues that are also top priorities.

De-Energization of Powerlines during Dangerous Weather Conditions Approved

With the support of the Governor and the Legislature, the CPUC in May approved allowing utilities to cut off electricity to possibly hundreds of thousands of customers to avoid catastrophic wildfires like the one sparked by power lines last year, which killed 85 people and largely destroyed Paradise.

Because the utilities' liability can reach billions of dollars, and after several years of devastating wildfires, they had asked regulators to allow them to de-energize powerlines when fire risk is extremely high, mainly during periods of excessive winds and low humidity, when vegetation is dried out and can easily ignite. PG&E initially planned to de-energize power lines in at-risk rural areas, but has since expanded its plans to include high-voltage transmission lines. Precautionary outages could thus mean multiday blackouts for cities as large as San Francisco and San Jose, PG&E warned in a recent filing with the CPUC.

Though the CPUC approved de-energization with a unanimous vote, it also told the utilities that they must do a better job of educating and notifying the public (particularly those with disabilities and others who are vulnerable) of dangerous conditions and outages, and must ramp up preventive efforts, such as clearing brush and installing fire-resistant poles.

Governor Newsom asked the Legislature to approve a state budget expenditure of $75 million to help communities prepare, saying, “We're worried about it because we could see people's power shut off not for a day or two but potentially a week. This is high winds, severe weather, turn-off the electricity so it doesn't ignite a fire. It's a good thing—unless you're impacted.”

The Legislature is required to approve the state spending plan by June 15, and the Governor must sign it by July 1.

Key Bill Update

Of the nearly 2,600 bills that were introduced in 2019, only a few energy bills are worth mentioning for now. Bills that failed passage this year and are now two-year bills are SB 772 (Bradford), which would require CAISO to procure 2,500 MW of long-duration bulk energy storage; Assembly Bill (AB) 915 (Mayes), which would move the Renewable Portfolio Standard (RPS) from the current 60% to 80% by December 31, 2038; and SB 549 (Hill), which would subject PG&E electric rates to legislative approval.

These bills are still alive: AB 56 (Garcia) would establish a central statewide entity to procure electricity for all end-use retail customers in the state; AB 235 (Mayes) would create the California Wildfire Catastrophe Fund Authority; AB 740 (Burke) would establish the California Catastrophic Wildfire Victims Fund to ensure that victims of catastrophic wildfires are compensated in a timely manner; SB 350 (Hertzberg) would authorize a CPUC multiyear centralized resource adequacy mechanism; and SB 550 (Hill) would put parameters around a change of PG&E structure.

The legislative session concludes on September 13, 2019.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) COMMITTEE

Carrie Bentley

Carrie Bentley is the co-founder and CEO of Gridwell Consulting and has over a decade experience in the energy industry across the ISO/ RTO markets. Ms. Bentley currently provides analysis and strategic support on "all things California ISO," including transmission, interconnection, capacity, storage assets, and the energy markets. Prior to becoming a consultant, Ms. Bentley most recently had been acting as a lead market design and regulatory policy developer at the CAISO, leading design and stakeholder initiatives in critical areas such as flexible ramping, resource adequacy, and renewable integration. Prior to the CAISO, Ms. Bentley was a consultant for GDS Associates, an engineering and economics consulting firm where she specialized in power supply contracting, natural gas hedging, and energy market design for a large range of clients in ERCOT, PJM, MISO, and SPP.

Inside, Outside, Upside Down

Inside

A year ago, for the 2018 Second Quarterly Report, I wrote about the exciting new Day-Ahead (DA) Market Enhancements initiative. It included proposals to move toward a 15-minute DA market, develop a DA flexible ramping product, co-optimize the DA markets (the integrated forward market and residual unit commitment process), and reoptimize ancillary services in real time. If you recall, CAISO proposed to implement all these things in fall 2019 and then extend the DA market to EIM Entities in fall 2020. Of course, within a few months, the DA market was split into two implementation and policy phases; phase one being a 15-minute DA market and phase two being the other scoped items, with the 15-minute market moving full steam ahead.

Phase 1 came to an abrupt stop in May, when CAISO announced that it was "deferring consideration of day-ahead market 15-minute scheduling." To translate for those of you who don't speak CAISO, this means it is not moving forward with a 15-minute DA market, and phase 1 of the initiative is dead. I've been asked several times whether the DA can be extended to the EIM Entities without this enhancement. I think it was to CAISO's detriment that it tied the DA enhancements (in stakeholders' minds) to the extension of the DA market to EIM Entities. In fact, none of the proposed DA enhancements are technically needed. Some of the proposals, like the DA Flexible Ramping Product, may be good for the market and better set up resources for real time, but are not necessary for DA extension. The DA extension initiative—if it ever happens—will address needed policy changes to include the EIM in the DA market, and I expect most of these will be technical rather than product based.

The CAISO is holding a technical workshop on June 20 "to discuss proposed options for developing a new day-ahead product that will address ramping needs between intervals and uncertainty that can occur between the day-ahead and real-time markets."

Outside

Turning to current EIM rules, WPTF has been closely following an incredibly boring-sounding but important initiative, the Real-Time Market Neutrality Settlement. Instead of trying to describe it in an interesting way, I will quote from Powerex's comments, as they helped me grasp that this initiative is important for both internal and EIM Participants—and actually very interesting! On page 3, Powerex states, *Despite the potentially unfamiliar jargon, this [initiative] is not about faulty meter readings or the mishandling of particular billing determinants. Instead, what appears to be occurring is that the financial settlement process fundamentally mis-values the products and services transacted in the EIM, the result of which is to negate key pricing and associated incentives intended in the design of the EIM.*

Part of the current Real-Time Market Neutrality Settlement process concerns how the CAISO EIM places a financial value on transfers into and out of EIM Balancing Areas Bas that accounts for greenhouse gas (GHG) costs. The challenge is that not all transactions across the EIM should include a GHG component because they are not delivering to California. EIM settlements therefore must have a different accounting for transfers that are not going to a GHG-regulated area (e.g., transfers between two non-GHG-regulated EIM BAA).

Part of this initiative is to now value transfers between two non-GHG-regulated areas differently than transfers to a GHG-regulated area (e.g., the CAISO BAA). Specifically, transfers between two non-GHG-regulated areas will not reflect the GHG cost. And this is where things get complicated. Some stakeholders argue that the proposed method may not work, others note that it will work but be exceedingly inefficient, and yet others believe that the way GHG has been accounted for historically may not have been the original policy intent, nor consistent with the tariff.

Although some of these comments get very technical very quickly, the initiative is fundamentally about whether EIM Entities are being paid and charged (1) as intended in the initial EIM policy, and (2) in a fair and reasonable manner. In order to move forward with a more fair allocation, the CAISO has raced through this initiative with impossible speed, posting the first issue paper on April 25 and the draft final proposal a little over a month later, on May 30. While this speed is warranted to fix known issues, WPTF and other stakeholders have urged the CAISO to break the initiative into two parts. The first part would move forward with the CAISO's current proposal and the second part would holistically evaluate EIM settlements specifically pertaining to GHG allocation and other neutrality account issues. This is a topic I am sure the EIM Governing Body will investigate closely, with EIM member support. It is imperative that EIM Entities have confidence in the CAISO real-time market settlements, especially before moving forward with any DA market extension proposals.

Upside Down

The CAISO is asking stakeholders for their comments on an incredibly important topic in the issue paper stage—the question of what standards CAISO should use to determine local RA requirements. The Local Capacity Technical Study Criteria Update initiative kicked off at the end of May, and I highly encourage anyone with an interest in local RA to follow and comment on this initiative. Currently, the CAISO meets "mandatory standards" in its transmission plan and in its determination of whether a generator may retire or not; however, CAISO uses lower standards when determining the local RA requirement. This has several implications: first, it prioritizes transmission assets over local RA, because the transmission planning process will show a need in an area before the local RA area. Second, it makes planning hard, as the CPUC may approve local RA projects in order to eliminate a Reliability Must Run (RMR) contract for an existing resource, but these projects may not actually eliminate the CAISO determined need for the existing resource. Finally, the CAISO is depending on non-RA capacity to meet reliability needs at both the local level, which is not ideal.

Speaking of not ideal circumstances, I recently was able to confirm that when CAISO does its RMR check on whether a system resource may retire, it assumes full use of RA Import Allocation—in other words, the entire amount of Maximum Import Capability is counted as available for system capacity. I always wondered why CAISO allowed La Paloma to mothball when system capacity was clearly so tight, and this could explain it. My prediction is that the current RA prices will drive not only La Paloma but other resources back into the market, so I am less concerned about reliability at the moment. But generally, assuming that level of imports to maintain reliability is an incredibly shaky assumption. WPTF plans to ask for this topic to be included in the Local Capacity Technical Study Criteria scope.

MEXICO COMMITTEE

Rajan Vig

The WPTF Mexico Committee Consultant is Rajan Vig. Rajan started his career in strategy consulting with FTSE 100 companies, working at WPP Group in London before working at private equity firm, Hamilton Bradshaw, where he began his consulting focus on commodities. He moved to Houston in 2014 to found an energy human capital consultancy within Sir Peter Ogden's portfolio, where he oversaw the build-out of commercial energy businesses across oil, gas and renewables into emerging markets across the Americas, specifically Mexico and the Southern Cone. Most recently, Rajan started and ran BioUrja Trading's office in Mexico City, managing the company's implementation across trading and origination in Mexico across fuels, gas and electricity. Rajan has a BA (Hons) in Modern Languages (Spanish & Italian with Portuguese) from the University of Manchester and an MSc in Latin American Studies (Economics & Politics) from Oxford University.

New CRE Commissioners

It took nearly four months for the Regulatory Commission of Energy (CRE) to find its feet with Mexico's new administration. The CRE is perhaps the most important regulatory body in Mexico, responsible for issuing permits for the commercialization of oil, gas, and electricity. Along with the Secretary of Energy (SENER), the CRE had been at a standstill, preventing the progress of energy reform, because the previous commissioners had either left their posts or been asked to leave. Finally, at the start of April, four new commissioners were appointed after a calamitous review of some primary candidates that had little knowledge of the energy sector. The new candidates are Luis Linares Zapata, Norma Leticia Campos, Guadalupe Escalante Benítez, and Jorge Alberto Celestinos Isaacs.

Luis Linares has two degrees from University of Pennsylvania. He was a consultant to the Mexico Senate in 2002–2005, when energy reform was taken up by politicians. At the same time, Luis was in charge of policy development for Pemex. He also has experience working in the Ministry for Mining, Agriculture and Social Development.

Norma Leticia Campos is a specialist in the power sector and a professor at National Autonomous University of Mexico (UNAM). She has published subjective essays titled "The power reform in Mexico," "The resurgence of nuclear energy, an option for climate change and for emerging countries?" and "Electricity in Mexico City and the conurbated area: history, problems and perspectives."

Guadalupe Escalante Benítez is an industrial chemical engineer from the National Polytechnic Institute (IPN) and a business administration teacher at University of the Americas Puebla who specializes in investment projects. From 2003 to 2015, she worked in the management of Programming and Production Control of Pemex Petroquímica (as production control manager). She has also worked in the management of Petrochemical and Gas Operation in Pemex, and as head of balances in the petrochemical complex of Cangrejera.

José Alberto Celestinos Isaacs studied chemical engineering at the National School of Chemical Sciences at UNAM. He worked at Pemex as shift engineer at the Azcapotzalco refinery and at the central offices as a process engineer. Celestinos was the first general superintendent of process and development and headed the industrial district of Poza Rica. He was executive coordinator of Refined Production, deputy director in the Pemex Refining Production Division, and executive coordinator of Pemex's General Directorate.

In a statement, the Mexican Energy Council (Comener) said that, "The virtual commissioners may be good Mexicans, but they lack sufficient experience in professional activities related to the corporate purpose of the CRE, which will undermine the credibility of the resolutions adopted by this important body of the Mexican State and, thereby, weaken the incentives to invest in the energy sector."

New Energy Committee Meetings

In early May, the president of the National Center for Energy Control (Cenace), Alfonso Morcos Flores, debuted before the Senate Energy Commission to say that Mexico does not have the economic capacity to meet its commitments under the Paris Agreement to increase the generation of electricity from renewables. He told the senators that Mexico should evaluate the commitments because the goals are unattainable and that the country will be able to count on, at most, 20% of electricity generation from renewables in 2024. In addition, he said, Mexico does not have an impact on global emissions of greenhouse gases, because it contributes only 0.3% of the total.

Morcos Flores asked the Energy Commission to promote legislation that prevents CRE from liberally permitting wind and solar generation. Morcos Flores spoke at length of his dislike for the idea of additional renewable projects and the implied high cost of renewables. He stated that CRE had issued far too many renewable energy permits without consideration of the transmission network's ability to absorb them. He advocated for more coal plants and pointed out how much coal generation China uses compared to Mexico. He also advocated for the increased use of fuel oil provided by Pemex.

Morcos Flores also noted the proposal to the Secretariat of Energy to enable Petróleos Mexicanos and the National Refining System to cogenerate electricity that can be profitable for the country in the short term. He commented that AMLO's Program for the Development of the Electrical System (Prodesen), which will establish alternatives to the electric auctions that have been suspended since December, would also go into effect in late May.

PRODESEN Publication

The demand for electric power in the national electric system will grow between 2.8% and 3.6% on average over the next 15 years, according to the Development Program of the National Electric System (PRODESEN) 2019–2033, published by the SENER at the start of June.

The primary objectives underlined in the publication are guaranteed and reliable supply, sovereignty, energy security, and sustainability. The paper considers the reintegration and operational, financial, and technological strengthening of the Federal Electricity Commission (CFE) and aims to "correct the negative consequences" of the strict legal separation of the CFE.

PRODESEN emphasizes that all participants in the electricity market will be able to participate in an equitable manner and that the CFE Basic Services Provider will be able to enter into electricity coverage contracts under the same conditions as the rest of the market participants.
The document argues that the country's energy reform, via permits granted by CFE, incorporated private agents into the electricity industry in an inequitable manner, forcing the CFE to create a subsidiary to subsidize and do operative and administrative work for its competitors in the electricity market. It also states that "the universe of permits created a systemic disorder and imbalance for the planning of the national electric system, the demand for the closest and most efficient generation was disconnected and the construction of transmission and distribution infrastructure was subordinated." Now, however, the CFE will be allowed to participate on equal terms in the electricity industry.

PRODESEN 2019–2033 retains the goal of generating at least 35% of electric power using clean energy.