WPTF WESTERN POWER TRADING FORUM

QUARTERLY REPORT

January 2023

Welcome to the Casbah

If you ever have the misfortune of spending a lot of time with me, a couple of things may become apparent to you. Among these are that I am a bit of a history geek and I love old movies (I mean old, like 30's, 40's, 50's). So, it wasn't unusual that as I talk to people involved in the various efforts at regional market integration, I began to think of a Souk or marketplace. But marketplaces are fairly open affairs. There is an article I'm interested in; I ask the price. You tell me the price; I suggest another, etc.

When contemplating the discussions and what is motivating various players around the competing day-ahead market platforms, there is an element of intrigue in the air. Conversations between some parties that are not meant for other ears. Negotiations are carried on in secret and what is motivating this party, or another is not completely known. Hence, I began to think of an old movie from 1948 called "Casbah". As you will see from this link, it has nothing to do with "The Clash" (Rock the Casbah).

If you check in on the parties attending the numerous stakeholder meetings, put on by CAISO and SPP over the last year you would get various answers about where some were leaning in terms of favoritism. In the early days, this seemed to be somewhat of an academic exercise. We all were trying to figure out how transmission access in a day-ahead market was different in EDAM or Markets+? How did the "resource sufficiency test" of each affect Resource Adequacy? You know, common stuff.

But as the two offerings began to look the same, the conversation about which was better became less straight forward. Some utilities which seemed favorably disposed to one platform, now seem to prefer the other. But the reason was not about market design or tariff. There are conversations utilities are having amongst themselves that involve cost-benefit analysis. But what are the driving assumptions? Is transmission utilization based on historic flows or on assumptions about how a network dispatch would work - which would have quite different outcomes? You look for insights in body language, who is talking to whom… Hence, "Casbah."

There are plenty of other things going on in California, the Pacific NW, and with carbon. But interestingly, they all have implications on choices for regional market integration choices which, as you may have heard me say, is critical to future reliability and economic efficiency.

But you must excuse me, I must duck into the café, where some parties are sitting around a hookah, discussing the day, exchanging gossip. I bid you to read the contributions of my learned colleagues that follow and may your camel never be lame. Peace be with you.

Scott Miller

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Save the Date

Check the WPTF website for all the details.

CPUC COMMITTEE

Gregg Klatt

Gregg Klatt coordinates the CPUC Committee. *Gregg is a practicing attorney with over 20 years of energy industry experience. With a practice focused on state and federal regulation of the electric power and natural gas industries, Gregg has represented clients in numerous rulemaking proceedings before the CPUC, CEC and CARB. He advises energy companies concerning regulatory requirements affecting their product and service offerings. He represents generators, marketers and retail suppliers in licensing, compliance and enforcement matters. And he provides regulatory counsel in energy-related transactional matters, including procurement contracting, resource development and repower projects, asset dispositions, and related financing arrangements. Gregg received his J.D. from UC Berkeley's School of Law and has a B.A. in History from the University of San Francisco.*

Gigawatts Galore

In the last quarterly report, I wrote about a CPUC staff proposal for a new regulatory program wherein load-serving entities (LSEs) would be subject to binding procurement requirements for mid- to - long-term reliability, and clean energy resource needs identified through the Commission's Integrated Resource Planning (IRP) process.

The fundamental premise of staff's proposal is that it will obviate the need for ad hoc procurement directives, like the Commission's 2019 decision directing LSEs to procure 3.3 GW of incremental capacity to come online by August 2023. And its 2021 decision directing LSEs to procure 11.5 GW of qualifying capacity from new supply resources to come online by June 2026 (including 2.5 GW of clean energy and demand response resources to replace Diablo Canyon, which at the time was expected to cease operating in 2025.)

Stakeholders submitted comments on staff's proposal in December, followed by reply comments in early January. However, the ink on those comments had barely had time to dry when on January 13 the Commission issued a proposed decision (PD) in the IRP docket directing LSEs to procure yet more new capacity.

Under the January PD, LSEs would be required to procure an additional 4 GW of qualifying capacity from new zero-emissions, storage, and renewable energy resources to come online in 2026 and 2027. The PD asserts that the additional 4 GW is needed to meet higher forecast demand and mid-term reliability needs that are attributable to increasingly frequent extreme weather conditions. As well as, increasing penetration of electric vehicles, air conditioning needs, and building electrification; changes in consumption patterns; expected retirements of thermal generation units; and decreasing availability of seasonal imports due to the aforesaid factors also impacting other Western states.

The PD also identifies another important factor: "Accelerating goals for clean energy production and reductions in GHG emissions through 2045 and earlier." No kidding. The preferred resource portfolio adopted by the Commission last February shows that approximately 35 GW (nameplate) of new resources are needed by 2030 to maintain system reliability and meet California's GHG reduction targets. As the PD notes:

> *Even if all of the incremental resources ordered to date were to come to fruition, that procurement will only meet roughly half of the additional resources needed by the end of the decade to meet the expected portfolio being adopted later in this decision to be used for transmission planning.*

The GHG target used to develop the preferred portfolio adopted in February was 38 million metric tons (MMT) of CO2 equivalent. That resource plan was transmitted to the CAISO for study in the 2022-2023 cycle of its Transmission Planning Process (TPP). It was also used by LSEs to develop the individual resource plans they filed with the Commission this past November. For comparison, the GHG target used to develop the resource portfolio that the CAISO studied in the 2020-2021 TPP cycle and used by LSEs to develop their individual resource plans in 2020 was 46 MMT. Thus, notwithstanding the January PD and its 4 GW procurement directive, the odds favor the Commission moving forward with development of a formalized IRP procurement program.

But Wait, That's Not All!

In addition to yet another ad hoc procurement directive, the January PD adopts an updated resource portfolio for the CAISO to study in its 2023-2024 TPP. The GHG target used to develop that portfolio was 30 MMT by 2030, or a third less than the target used to develop the preferred resource portfolio adopted in 2020. According to the PD, the updated portfolio *"approximately 86 GW of new resources by 2035, on top of the existing resource mix on the electric grid of approximately 75 GW. This is more than a doubling of nameplate capacity on the system within 12 years."* (Emphasis added.)

Where will all those megawatts come from? Only time will tell. But for purposes of the CAISO's transmission planning, the Commission wants it to assume that the bulk will come from new solar (39 GW) and nearly a third will come from new battery storage (28 GW), while the remainder will come from out-of-state wind on new transmission (4.8 GW), offshore wind (4.7 GW), generic wind (3.9 GW), pumped storage (2 GW), geothermal (1.9 GW), demand response (1.1 GW), and small amounts of new biomass and natural gas generation. That should make just about everyone happy.

Let It Flow, Let It Flow, Let It Flow

Ultimately, the success of California's clean energy and GHG goals for the energy sector will depend on not just new generation but also new transmission being built. To that end, the Commission is proposing to establish a state level Transmission Project Review (TPR) process. The TPR will be a uniform process to review transmission projects proposed by PG&E, SCE, and SDG&E.

Under the new program, the utilities will submit semi-annual reports on transmission projects with capital additions to rate base in the last five years, and expected capital expenditures in the current year and future five years. The TPR process will encompass specific projects and programmatic project buckets that are CAISO-approved or utility self-approved, as well as network upgrades that are needed for generator interconnections.

Once the utilities submit their reports, CPUC staff and stakeholders will have the opportunity to submits questions and comments, to which the IOUs will be required to provide written responses. In addition, each utility will convene semi-annual stakeholder meetings to discuss project data, procedures, project alternatives, and other identified issues. Assuming the draft resolution in which the new program is outlined is adopted without major modifications, the TPR process will get underway in 2024.

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.*

Notwithstanding $22 Billion Deficit, Newsom Proposes $297 Billion Budget

Just days after taking the oath of office for his second and final term, Gov. Gavin Newsom on Jan. 10 presented a $297 million budget, with a glaring a $22 billion deficit.

The deficit was not a surprise. Newsom and state budget writers have been signaling for well over a year that California was sailing into economic headwinds.

The reversal of fortune is due to spiraling inflation and a weakening stock market, particularly in the California-based tech sector. The change has clouded the economic forecast for the state, which depends heavily on capital gains from its wealthiest residents. The Department of Finance now expects tax revenues will total $29.5 billion, or 9.6% less than what was assumed in last year's budget.

Notably, Newsom chose not to dip into the state's $35.6 billion savings account. And proposed no significant cuts to major programs and services. Whether that plan holds will depend on what the state's finances look like after April 15, when most residents file their state income tax returns. Newsom and legislative leaders don't have to approve a spending plan until the end of June.

Newsom appeared pessimistic about the future as he scaled back some of his ambitious climate proposals, cutting his much heralded five-year, $54 billion investment to $48 billion.

He tried to downplay that cut, arguing the $48 billion is still one of the largest climate investments in the world and the state would seek to recover some of that lost money from other sources.

Still, it was enough of a cut to anger some climate groups who had been heartened by the state's commitment to combating climate change in recent budgets.

More than half of the cuts for climate — $3.3 billion — would come from the state's clean transportation initiatives. Newsom is proposing to cut $2.5 billion from zero emission vehicle infrastructure build-out, and about $1.4 billion of that would be shifted to the state's cap-and-trade fund paid into by fossil fuel companies. The cuts from these programs would also affect the construction of heavy-duty vehicle infrastructure, a much-needed investment as the state considers another ambitious proposal to ban sales of diesel trucks and phase in zero-emission models. Another $2.2 billion in funds would be gutted from transportation that includes spending for rail and transit projects.

While Newsom hopes to offset those reductions with federal funds and a potential bond reserve, the move comes just five months after the state imposed a historic mandate for electrifying cars. Newsom, who has branded himself as a global climate leader, helped push a $54 billion climate package approved by the Legislature during last year's session. The massive clean energy investment aims to meet the state's aggressive decarbonization goals. But now, the budget deficit is getting in his way.

Democrats control all of state government in California, leaving Republicans with little influence on policy and budget decisions.

Key dates ahead: May Budget Revision from the Governor; June Budget Deadline for the Legislature; and July Fiscal Year (Budget must be in place by July). Between now and then, while other business will be in play, this is what will command the attention in the Legislature.

New Legislative Year, Energy Measures Trickle In

Barely a few days into the new Legislative Session, and already more than 100 bills have been introduced. But so far, not many energy bills.

Five bills have been introduced for the special session called by Gov. Newsom regarding higher California gasoline costs. Senator Nancy Skinner is carrying the Governor's windfall gasoline profits bill (SBX1-2). Also introduced are two bills that would suspend the gas tax, a report on the environmental impact of oil from out of state and making scheduled maintenance of refineries public information.

The special session bills, as well as the other bills, are missing most of the specifics, which will likely be added over the next two months.

Some of the other energy-related bills that were introduced include:

- SB 12 requires the California State Air Resources Board (CARB) to ensure that statewide greenhouse gas (GHG) emissions are reduced to at least 55% below the 1990 level by no later than December 31, 2030. This bill is similar to this year's AB 9 and last year's AB 2133, which died on the Assembly Floor.
- SB 49 provides tax incentives for the construction of solar canopies over large parking lots to post the local generation of clean electricity in urban and suburban areas.
- AB 3 accelerates offshore wind projects.
- AB 9 requires CARB to ensure that statewide GHG emissions are reduced to at least 55% below the 1990 level by no later than December 31, 2030. This bill is similar to this year's SB 12 and last year's AB 2133, which died on the Assembly Floor.
- AB 45 promotes blue carbon demonstration projects such as improving wetlands, tidal and marine ecosystems. The bill is similar to last year's AB2593 which died in Senate Appropriations.
- AB 50 improves communication between CEC, IOUs, CAISO, and CPUC, similar to discussions during the extreme heat event.
- AB 53 is a one-year suspension of the gas tax.
- AB 65 allows the CEC to certify nuclear fission thermal power plants.

The WPTF Legislative Committee will follow these bills and others as they proceed through the Legislature. Keep in mind that we are very early in the process. Last day for bills to be introduced is February 17. Also, this is the first year of a biennium. Anything introduced this year, could be "continued" into next year.

SACCWIS Recommend Extensions to OTC Facilities, Including Diablo

The Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS), which is composed of the CAISO, CCEC, and CPUC – filed a draft report to the State Water Resources Control Board (SWRCB) recommending that the once-through-cooled (OTC) facilities slated for retirement remain on-line for an additional 3 and 5 years.

Specifically, the report recommends that SWRCB allow three AES facilities - the 1,137 MW Alamitos Energy Center, 1,491 MW Ormond Beach Generating Station and 226 MW Huntington Beach Generating Station - to stay online another three years, to the end of 2026.

This would be the second three-year extension of these plants, with a combined capacity of 2,854 MW. Originally, they were slated for closure in 2010. SACCWIS did not propose keeping the fourth AES plant, the Redondo Beach plant, online for an additional three years.

SACCWIS also recommends keeping the Los Angeles Department of Water and Power's (LADWP) 324 MW Scattergood units 1 and 2 online for an additional five years, moving the closure date from December 31, 2024, to the end of 2029.

The proposed amendment would also include a change without regulatory effect to revise the compliance date for Diablo Canyon. This change will ensure the OTC Policy is consistent with the compliance date that was already extended by SB 846, which was approved by Governor Gavin Newsom on September 2, 2022, to support statewide grid reliability. Accordingly, the extension for Diablo Canyon would add 10 years, with the potential to add 10 more.

According to the proposal, *"extensions would be responsive to concerns regarding grid reliability and would bolster the electrical power supply that is essential for the welfare of the residents of the State of California."*

The Draft Staff Report and Draft Amendment will be released for public comment on or before January 31, 2023, and written comments must be submitted by noon on March 17, 2023. The hearing on this proposal is scheduled for March 7, 2023.

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..

Going into 2023

This is usually the time of year when the CAISO Committee starts gearing up for the year ahead. We review the stakeholder plan and begin to think about how the initiatives fit into WPTF priorities. And it makes for an easy January quarterly report, because there's lots of new material to discuss. Unfortunately, this year the initiative process has been delayed and the CAISO does not plan on presenting their initiative schedule for the year until February. So instead, this article will be focused on a rapidly approaching issue – the orderly retirement or repowering of the thermal fleet.

Currently there is a lot of focus on ensuring that sufficient capacity comes online to merely ensure reliability given the pending once-through-cooling retirements by end of 2026. This is already a hugely expensive endeavor and on Friday the CPUC put out yet another ad Hoc Proposed Decision to procure an additional 4,000 MW for 2026 – 2027. A lot will be written in the coming months on the stress this will put on load-serving entities and the upward pressure it will put on new resource contract costs.

But setting that aside for a moment, let's look further ahead and pretend we are in 2026. The ordered procurement is mostly online and by some miracle California is meeting an adequate reliability level. What then? In 2026 over 41 gas power plants will be 40 years or older, which is typically when we begin to see gas plants either need major investments or retire from the grid. In terms of policy creation and tariff changes, 2026 is basically around the corner. It is therefore very reasonable to start asking, what is the plan for the thermal fleet?

If anything, this winter has shown that California is completely dependent on the gas fleet to keep the lights on. Thermal resource production increased in 2022 by around 15% compared to 2020, despite an 25 % increase in renewables production of over this same time period. This can be largely attributed to the significant downward trend of available, low-cost imports coming into the CAISO. Imports into the CAISO decreased by a little over 10% in 2021, and by another 12.5% in 2022. This trend has put extreme pressure on the California thermal fleet and gas system this winter. As I write this, the thermal fleet is supporting 40% of the CAISO energy demand at 11 am – a "belly of the duck" hour – when renewables are doing the most work.

Policy makers have already realized 4-hour batteries cannot replace a thermal resource, but that certainly longerduration storage can replace a portion of the thermal fleet. The question is which portion? After the once-through-cooling resources retire, which resources will be next? Will older gas plants be incented to make major investments knowing the 60% clean energy goal is only 4 years away and escalates rapidly from there? Will load serving entities be willing to sign longer

term contracts to incent needed maintenance or major overhauls to lower gas resource carbon output. And finally, what happens when gas resources want to retire, but we know they will be needed for grid reliability? Does the CAISO have strong enough tariff authority to keep them from retiring?

I would argue that now is the time to start drafting policy to provide incentives for gas plants to create longer-term plans and now is the time for CAISO to consider whether their authority to maintain reliability is sufficient. The CPUC and CAISO should provide clear signals as to the benefits and need for technology upgrades like adding hydrogen, investing in carbon capture, hybridizing with battery. Likewise, there should be clear signals to gas resources that are ill-suited to provide a role in the green energy transition and in fact should retire because their interconnection is worth more than their resource. WPTF believes that transparency and competition lowers prices, but this is only possible when there are clear signals and rules that create a meaningful framework for evaluating costs and benefits, risks and rewards. We doubt this will be on the CAISO's initiative list, but we would strongly argue that now is the time to design policies for traditional thermal resources to be efficiently phased out to make way for the new low-carbon world.

WIDER WEST COMMITTEE (2WC)

Caitlin Liotiris

Caitlin Liotiris is a Principal at Energy Strategies, where she has more than 15 years of experience supporting a wide range of clients in the electricity sector, including supporting market analyses and transmission development activities. Caitlin 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, which includes active participation in the NorthWest Power Pool's Western Resource Adequacy Program (WRAP), and in coordination with the CAISO Committee on the EIM and EDAM, especially as they relate to tariff provisions and impacts outside of the CAISO. Caitlin brings her analytical, regulatory, policy and strategic expertise to bear in supporting 2WC members by providing information and advocacy on a wide variety of issues affecting the electricity industry.

Southwest Power Pool (SPP) Markets+ Effort Enters Next Phase of Development; WPTF Considering Formal Stakeholder Status in Phase 1

Over the last year or so, a variety of stakeholders in the West, including WPTF, have been working on day-ahead market designs. The incremental offering, which doesn't go as far as a full Regional Transmission Organization (RTO), is something Western utilities are clearly interested in pursuing, given that there are two day-ahead market proposals currently under development: SPP's day-ahead offering (Markets+) and the California Independent System Operator's (CAISO's) Extended Day-Ahead Market (EDAM) proposal.

At the end of November, SPP published the Markets+ "Final Service Offering." The document includes key details on the market's design and governance structure. Its release marked a notable new phase for Markets+, as SPP shifts efforts to "Phase 1." Phase 1 requires a $9.7 million funding commitment from interested parties to move forward, and is currently envisioned as a 21-month process that will culminate with a proposed tariff filing for Markets+ at the Federal Energy Regulatory Commission (FERC).

So far eleven entities have announced an intention to fund Phase 1 efforts.[1] Powerex has provided the most enduring commitment, announcing its plans to fund Phase 1 and its intentions to join the market at inception. These commitments and announcements are encouraging for Markets+, but SPP still needs to securing *signed* funding agreements. Securing these will be a key focus in the coming months. Thus, we anticipate a slowdown in the overall stakeholder meeting schedule for Markets+ through the end of Q1 2023.

Once that step has been completed, Phase 1 will begin in earnest. And while the Markets+ Final Service Offering outlines the broad framework for market design and governance, many details remain to be determined during Phase 1. Below, we outline some of the key elements of Markets+ design and governance that are known and review several key decisions that remain to be made in Phase 1.

For governance, a structure has been developed to help meet the unique interests of the West. The governance structure will, eventually, establish a five-member Markets+ Independent Panel (MIP). In many cases, MIP approval will be all that's required for SPP staff to automatically file proposals with FERC. But some items, namely those that may have a material adverse effect on SPP (including the Markets+ budget and MIP appeals) will require approval from the SPP Board. The MIP will

[1]These entities are: Arizona Electric Power Cooperative, Arizona Public Service Company, Avista, Bonneville Power Administration, Chelan County Public Utility District (PUD), Grant County, Powerex, Puget Sound Energy, Salt River Project, Tacoma Power, and Tucson Electric Power

not be fully established during Phase 1. But, to provide independent oversight during Phase 1, the MIP function will be performed by a three-member subcommittee of SPP Board Members.

The Markets+ stakeholder and governance structure will also include a Markets+ Participants Executive Committee (MPEC), Markets+ States Committee (MSC), and various other groups. Each of these groups will provide a forum for market participants, market stakeholders, and non-voting stakeholders to discuss issues relating to Markets+. WPTF is considering obtaining Markets+ Market Stakeholder (MMS) status for the Phase 1 effort. MMS status would allow WPTF to vote in the MPEC during Phase 1, as part of the "Independent" sector, providing greater influence over the ultimate market design.

The market design for Markets+ would generally automatically include all transmission as available for the market optimization. There will be provisions to remove transmission capacity. However, the specifics will need to be worked out in more detail during Phase 1. It seems likely that non-participating Transmission Owners will be able to remove their transmission from the market optimization. But whether Transmission Customers will be able to do the same remains to be determined.

Markets+ is intentionally being designed with a strong tie to transmission rights (as discussed more below), but it's unclear whether transmission-related requirements might be imposed on market participants. SPP has indicated that, at a Market Operator level, it does not plan to implement any particular requirements. However, it is possible that such requirements could be implemented by individual Transmission Service Providers (TSP). WPTF has raised concerns with the possibility of different requirements at the TSP-level and will continue to advocate that, if transmission requirements are imposed, the general guidelines should be outlined by the Market Operator. This will ensure requirements are reasonably consistent and not unduly restrictive.

One way the market design seeks to retain the value of transmission rights is to provide day-ahead congestion rents to network and long-term firm point-to-point transmission service reservation (TSR) holders. A number of details on congestion rent allocation will be further considered in Phase 1 including: the treatment of conditional-firm TSRs and determining whether congestion rent zones should be defined to enable a more granular approach to congestion rent allocation process.

Markets+ will require a common RA program across the market footprint. Specifically, participation in the Western Resource Adequacy Program (WRAP) and there will be a must-offer quantity into Markets+ which is in line with WRAP obligations. The WRAP program includes non-binding and binding participation options up until the winter 2027/2028. Some entities, such as the Bonneville Power Administration (BPA), are electing later dates to join the binding portion of WRAP. We anticipate Phase 1 will discuss whether non-binding participation in WRAP will be sufficient to enable full participation in Markets+ or if binding participation is required. Phase 1 will also discuss "interoperability" with WRAP and how WRAP participants can continue to meet their "hold-back" requirements for WRAP members within and outside of Markets+.

There are many more details of the market design outlined in the Final Service Offering. And we anticipate significant ongoing discussions around a variety of topics in Markets+, including Greenhouse Gas (GHG) pricing and accounting during Phase 1. More comprehensive stakeholder meetings are expected to resume in late Q1 or early Q2 2023, after SPP has completed efforts to secure Phase 1 funding commitments. In the meantime, certain groups, including a Seams Working Group may be stood up in order to begin work on seams issues with CAISO and SPP's RTO in the east. Participation in, and monitoring of, this next stage of the Markets+ development efforts will be a key focus for the WPTF Wider West Committee in 2023.

CARBON AND CLEAN ENERGY COMMITTEE

Clare Breidenich

Clare Breidenich coordinates WPTF's Carbon and Clean Energy Committee. *In this role, Clare has been actively involved in the development of California's cap and trade program since its inception and has particular expertise on issues related to the treatment of electricity imports under the program and the interactions of the carbon market and the markets operated by the CAISO. Clare also represents WPTF on matters related to carbon and clean energy policies in other western states.*

Prior to joining WPTF, Clare worked on international climate issues at the Environmental Protection Agency, the US Department of State and the United Nations Framework Convention on Climate Change Secretariat. Clare has extensive knowledge of the technical and policy options for greenhouse gas mitigation, including market mechanisms, and methodologies and protocols for estimation, reporting and verification of greenhouse gas emissions and reductions. She has served on the Washington Governor's Climate Action Team, the Washington Carbon and Electricity Markets Workgroup and on a National Academy of Sciences' Committee on monitoring of greenhouse gas emissions. Clare is a graduate of the University of Michigan and has a Master of Public Affairs and a Master of Science in Environmental Science from Indiana University School of Public and Environmental Affairs.

Electricity Sector Confusion and Legal Challenges as Washington's Cap and Trade Program Goes into Effect

Well, here we are in Mid-January, and from the perspective of the power sector at least, the Washington cap and trade program (known as the Climate Commitment Act or CCA) is off to a less-than-auspicious start. As reported previously, the Washington Department of Ecology will conduct the first auction on February 28, 2023 – a full two months after electricity imports into the state began incurring carbon obligations. Without the benefit of the price discovery provided by the auction, electricity sellers are flying blind when it comes to including anticipated compliance costs in their offer prices. Will allowance prices be at the low end of the auction price floor ($22.20) or closer to the allowance price ceiling ($81.47)? Most observers lean toward the high-end, but at this point, it's really just a wild-assed guess…

The price uncertainty is clearly impacting the Mid-C trading hub. While it is impossible to ascertain a clear carbon price signal due in part to high natural gas prices and the weird January weather in the West (which may be obscuring a carbon price jump), volumes and transaction numbers are thin. A look at the bilateral and broker market, where the WSPP Wheel-through product is trading, yields an even more confusing picture. (Now that seven companies, including BPA, have signed on to the Wheel-Through product on the WSPP website, and more are expected, ICE has confirmed that it intends to post the product on its platform in the coming weeks.) The price of that product compared to the standard Schedule C at Mid-C has been all-over the place, even trading at a small premium to the standard product at one point. Since the Wheel-through product should be expected to trade at a lower price than the standard product, because sellers will include anticipated carbon costs in their offer prices for the standard product, these strange pricing dynamics probably reflect general confusion in the market.

Much of the market confusion can probably be attributed to the fact that market participants do not have a clear and common understanding of which electricity transactions result in a carbon obligation under the CCA, and which entity bears the carbon obligation for a given import transaction. Unlike the California's cap and trade program where the state's border generally aligns with the border of the balancing authority areas (BAAs), Washington is served by several multistate BAAs, and most of the electricity that is imported into the state is via the transmission system of three

of them (BPA, PacifiCorp and Avista). The determination of whether electricity has been sunk in the state, where it entered, and which entity is the importer is thus more complicated than it is in California. To further complicate matters, because BPA has not elected to comply with the program for at least 2023, the compliance obligation for its imports to the state roll downstream. In an attempt to inject some clarity into the mix, WPTF is working with members and other organizations to develop a comprehensive guidebook on the electricity import rules, with the hope that if industry can develop a common view, that the regulator (the Department of Ecology) could be convinced to formally adopt it as guidance.

Turning back to the February auction, another industry concern is the liquidity of the allowance market. In the auction notice, Ecology indicated that it intends to make approximately 10% of the annual allowance budget (i.e. the program cap for the year) available at the first auction. This suggests that a total of 40% will be auctioned over the coming year. But the sector that is likely to be the biggest driver of demand for allowances – transportation – is estimated to comprise 46% of covered emissions. This, plus the fact that none of the allowances that have been allocated to natural gas and electric utilities, and able or required to be consigned to auction, have actually been distributed to those entities raises serious questions about the auction supply relative to demand, and whether independent power producers, marketers and other importers that don't receive a free allocation will be able to get their hands on allowances.

Opposition to Ecology's allowance allocation is behind one of the two legal challenges related to the Washington cap and trade program that dropped this month. Invenergy owns and operates Grays Harbor Energy Center. This power plant has the unique and unfortunate distinction of being the only gas generator subject to Washington's cap and trade program that will not receive a free allocation of allowances. The other gas resources will receive a free allocation by virtue of being owned by one of the state's electric utilities. Ecology followed in California's footsteps in generally not providing free allocation of allowances to independent power producers or marketers and other importers. However, California also required the investor-owned-utilities to consign allowances to auction, required utilities to fully price carbon in the energy offers of their gas resources, worked with independent power producers and marketers to attempt to renegotiate contracts with utilities that did not provide for pass through of carbon costs and, in the case where those negotiations failed, provided a time-limited free allocation to generators and marketers that were unable to pass through compliance costs in these 'legacy contracts'. The Department of Ecology did none of these things. As a result, Invenergy has sued the Department of Ecology. While I am not a lawyer, Invenergy does seem to have a strong case.

The other legal challenge with potentially more far-reaching implications is a FERC protest brought by the Utah Department of Public Utilities (UDPU) in response to the CAISO's filing of its EIM Tariff Amendment. The CAISO filed the amendment in November to be able to include carbon compliance costs of Washington's participating gas resources in default energy bids. UDPU intervened "because it represents the public interest in ensuring safe, adequate, and reliable service and reasonable rates for PacifiCorp's Utah customers." Although the protest was filed with FERC, the heart of UDPU's objection appears to be that the carbon compliance obligation imposed by the cap and trade program on PacifiCorp's Washington resources will alter EIM costs and benefits to PacifiCorp's Utah customers served by Rocky Mountain Power. UDPU charges

that "the proposed changes allow one state's unconstitutional program to unduly affect FERC jurisdictional wholesale markets. The proposed tariff amendments violate the Supremacy Clause by allowing one state's policies to materially affect the clearing of a wholesale electricity market, which the Federal Power Act leaves to FERC. The proposed amendments also effectively impose an unlawful border tax on imported electricity and exempt one state's own residents from significant portions of that tax. Additionally, the proposed CAISO tariff also fails to fully integrate all of the compliance paths Washington's law allows, which could also significantly affect the wholesale market."

Ironically, the output of PacifiCorp's Chehalis facility is primarily allocated to Oregon load under PacifiCorp's multi-state cost allocation, not Utah. As a Washington resource, all the emissions of the facility will have a compliance obligation under the CCA. However, PacifiCorp is only expected to receive free allowances for the portion of Chehalis's output designated to serve Washington load. PacifiCorp will undoubtedly face higher costs, but without adjustment to cost allocation formula (negotiations of which have been ongoing for several years), these costs would likely hit Oregon consumers, not Utah.

Whether or not FERC determines that UDPU's charges are valid, this protest may be an opening salvo in a broader effort of the less climate-friendly states to challenge the increasingly aggressive climate policies of other Western states. The opportunity didn't really present itself under California's program, because PacifiCorp doesn't operate gas generation in the state. And many of the early voices that threatened to challenge the California program may have concluded that they were not harmed enough to justify a lawsuit. Time will tell.