QUARTERLY REPORT

October 2022

Electricity Goes Global

There's no such thing as a "quiet quarter" anymore in our industry. This past month saw the "Heat Wave" event in the first week of September. This has been characterized as a California event, since that's where the real heat was, but it involved resources and prices in the Pacific Northwest and Desert Southwest. Based on what I've seen, we got through this because; 1) CAISO exercised good grid management, 2) the thermal fleet performed very well, 3) hydropower was available during net peak hours, 4) imports of all kinds from the Pacific Northwest came in very big, 5) weather was moderate in the areas around California and 6) state government alerts helped conservation. In other words, everything went well for California. Think that can happen every time there is a "heat event?"

While there has been a great deal happening regarding Western markets – WRAP, EDAM, SPP Markets+, finalization of Washington cap and trade - I'll leave that to the following reports of our committees, which I know you will ravenously read. Suffice it to say things are proceeding apace. But I can't help but wonder – given all our resource challenges – why we are putting so much effort into a "day-ahead" market solution? It has never been accomplished, while an RTO is a proven construct that would help enhance efficient use of the grid and thus resources. Ah, well, I'm told that we must do things differently in the West. C'est la guerre.

Hey, speaking of France, have you noticed how concerned everyone is about the European energy situation? Yes, we know that European markets have been cut off from Russian gas because of the response to the invasion of Ukraine. But the European Union is hamstrung by its lack of regional market structure and adequate pricing which are emerging as a point of concern as they enter what will be a tough winter. Despite efforts to create an integrated continental market, it remains a patchwork of national arrangements. Spain and the Nordic have structures similar to RTOs. Some national markets are composed of monopolies and bilateral arrangements like the one that exist between France/Italy or Germany/Central Europe. Even though many in the region are striving to transition to renewables, there is a strong relationship with natural gas. Given the need for heating this winter and the elimination of Russian gas, prices for the fuel for power plants will be very high. Thus, the desire to protect customers from high prices is being debated with the need to not exacerbate the shortage by imposing low price caps. Let's hope for a mild winter for our friends in Europe – there will be residual effects in the U.S. market.

Let me conclude with a question: Given the seeming rush toward regional market integration, what do you think the name of a Western RTO should be? This is not specific to a CAISO or an SPP outcome and there may be two at some point. A regional market can't be called by the current names (CAISO, SPP) can they? I'll offer my suggestion: "El Dorado" RTO. As some may know, "El Dorado" was applied to a mythical area in Spanish lore that contained of abundant gold. Since then, it has also become synonymous with "the West."

Don't like it? Email me your idea at *smiller@wptf.org*. I'll let you know my favorites in the next Quarterly Report.

Scott Miller

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Save the Date

Check the WPTF website for all the details.

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.

Washington finalizes Cap-and-Trade Program

With a little over two months until the official start of the state's cap-and-trade program, the Washington Department of Ecology (Ecology) finalized the program rules, which resolved some open questions, but created additional ones.

Program targets: As Ecology has previously signaled, the adopted targets (annual program budgets in cap and trade parlance) are very aggressive: 63,288,565 million metric tons of carbon dioxide equivalent (MMtCO2eq) emissions in 2023, declining to 48,997,598 in 2026. By comparison, Ecology's estimate of average emission from covered sectors during the baseline period of 2015-2019 (which many electricity participants suspect is an underestimate) is 68,052,220 MMtCO2eq. These targets will become even tighter because Ecology must carve 5% of each year's allowances off the top to populate the Allowance Price Containment Reserve, and reduce each annual program budget by the quantity of offset credits retired in the previous year. Although unlikely, Ecology has legislative authority to alter the program cap if it determines that the cap-and-trade program is insufficient to drive reductions within covered sectors in line with the states greenhouse gas reduction goals.

First Auction: Despite stakeholder urging, Ecology plans to hold the first auction sometime in February, 2023 – at least a full month after entities begin to incur compliance obligations for direct emissions and embodied emissions in fuels and electricity import transactions. Ecology will be conducting multiple training sessions on auction requirements, including registration, bidding and bid guarantees, as well as the compliance instrument tracking system service. Information on these sessions can be found *here*.

Allowance Distribution: The total quantity of allowances that will be auctioned is not yet known, because Ecology has not yet determined the quantity of allowances that will be freely allocated to Energy-intensive, trade-exposed industry entities (EITEs), natural gas utilities and electric utilities. Transportation fuels, independent power producers and non-utility electricity importers are the only covered sectors that do not receive free allocation of allowances. Using Ecology's baseline emission estimates, sectors receiving free allowances comprise about 52% of emissions covered by the program; this provides a bookend for the quantity of allowances that will be freely allocated. However, because Ecology must use different approaches to determine the quantity that entities in each of these sectors receives – allocations are based on baseline emission intensity for EITEs, proportional baseline emissions for natural gas utilities, and expected cost burden for electric utilities – these numbers cannot be known with precision until Ecology collects the necessary information and performs the calculations. Further, the quantity of allowances consigned to auction by the utilities will not be known until immediately prior to auction. While natural gas utilities must consign 65% of their allocated allowances to auction for the first compliance period, there is no consignment requirement for electric utilities. However, because neither gas nor electric utilities may sell freely allocated allowances in the secondary market, utilities wishing to monetize the value of these allowances must offer them at auction. Regardless of the final quantity of allowances offered at auction, transportation fuels, which makes up around 46% of covered emissions, will be the biggest driver of demand for allowances in the short term.

Electric Transactions: Ecology's final rule further muddies the water around treatment of electricity transactions under the program. While the rules for electricity imported via bilateral transactions were set out in the Climate Commitment Act, the compliance obligation for electricity imported via the Western Energy Imbalance Market (WEIM) were not resolved until the final rule. Unlike California's program, Ecology has determined that the Washington WEIM participating utilities will have responsibility for emissions associated with WEIM imports – not the resource scheduling coordinator. However, it is not yet clear how the quantity of imports assigned to each will be determined. CAISO is close to completing a proceeding that would enable them to provide information to each Washington WEIM utility and to Ecology on each utility's quantity of EIM imports. However, CAISO said it is unable to distinguish transfers to each utility's system that originated from Washington generation, which raises the possibility of double counting of emissions. Ecology must revisit rules for EIM imports by October 2026 and will likely address imports from the prospective day-ahead markets at the same time.

Ecology also threw stakeholders a curveball with the addition of new language that defers the compliance requirement (i.e. the compliance instrument retirement obligation) for electricity exported from Washington and imported to California. WPTF and many other electricity stakeholders have raised concerns about 'pancaking' of carbon costs across the two-state cap and trade programs in the absence of program linkage. WPTF specifically requested Ecology to work with the California Air Resources Board to establish reciprocity provisions within their rules to essentially provide credit to imported electricity for emissions from generation subject to the other program. As Ecology says in the rule's accompanying *explanatory document*, the intent of the new language is to provide time for those discussions to occur. However, because the new language merely defers the compliance obligation until the end of the commitment period, the effect of the provision is unclear. Washington entities that elect NOT to include anticipated Washington carbon costs in their sales to California utilities or into the CAISO day-ahead market risk not being compensated for these costs in the event that Ecology and CARB do not amend their rules to provide reciprocity. Further, even if certainty about the permanence of the provision were possible, it would not help sales by Washington generators into the EIM, or at the Mid-C trading hub, because the generator cannot ensure that that the electricity would sink in California. None-the-less, it is promising that Ecology is taking this concern seriously. Ongoing discussions about greenhouse gas accounting in the EDAM are also giving more credence to concerns about the possibility of pancaked carbon changes.

WSPP Finalizes Wheel-Through Confirmation for Mid-C Trading Hub.

And just in-time for the start of the cap-and-trade program, the Western States Power Pool has approved language for the so-called "Mid-C Wheel-Through" confirmation. This approval enables the Intercontinental Exchange to post the Mid-C Wheel-Through as a new product on the exchange, and allow it to trade in parallel to the existing Schedule C physical product. WSPP will maintain a master list of entities that have elected to trade with the new confirm and ICE will provide functionality at the Mid-C hub for entities to 'turn-on' potential counterparties that have also agreed to the terms of the new product confirm. Anecdotally, I am already hearing reports that traders are already referencing Mid-C wheel-through in their deals. The extent to which the new product will trade, the impacts of the Washington cap and trade program on liquidity at the hub, and ultimately the consequences for the Mid-C index remain to be seen.

Hang on, kids, it's gonna be a bumpy ride. . .

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.

Western Coordination Takes a Step Forward with the Filing of the Western Resource Adequacy Program (WRAP) Tariff; Attention Turns to how WRAP will Operate with Day-Ahead Markets

After years of work, the Western Power Pool (WPP) filed the proposed tariff to operate the Western Resource Adequacy Program (WRAP) with the Federal Energy Regulatory Commission (FERC) on August 31 (in Docket ER22-2762). The program is meant to address resource adequacy challenges in the region, and generally received support from stakeholders, despite some lingering concerns and areas of the program that will require observation. As the region looks to the next phase of regional coordination efforts, assuming that the WRAP is approved and implemented, attention is now turning to how the WRAP's unique provisions, which are necessary because it does not operate in a coordinated wholesale market, can be incorporated and honored by different day-ahead market structures that are currently under development.

If approved by FERC, the tariff would allow the WPP to administer a stand-alone resource adequacy program, which would be voluntary, but include mandatory provisions and penalties for non-compliance for Participants. The tariff's transmittal letter outlines the need to move forward with a regional resource adequacy program, given the "looming resource adequacy shortfall" due to a combination of retirements of conventional generation, increasing use of intermittent renewable resources, and increasingly frequent extreme weather/drought conditions. The Participants were further interested in establishing this type of a program without waiting for completion of western market expansion efforts that are currently underway and have been for quite some time. This program would be a "first-of-its-kind," because it's designed to operate outside of an Independent System Operator (ISO) or Regional Transmission Organization (RTO).

WRAP includes a Forward Showing program, with two binding seasons (Summer and Winter). Participants must demonstrate that their resources and contracts meet their Forward Showing obligations (which include the forecasted load and a planning reserve margin). To determine how resources are counted, they are assigned a Qualified Capacity Contribution (QCC), with different methodologies used to determine the QCC for different resource types. WRAP recently held a webinar which reviewed a variety of data related to the QCC's of wind, solar and large storage hydro (you can find the presentation *here*).[1] Additionally, because the program operates outside of an ISO/RTO, WRAP developed requirements for transmission service to help demonstrate that resources/contracts can be delivered to load. The Forward Showing Transmission Requirements require participants to demonstrate that they have at firm (North

American Reliability Corporation priority 6 or 7) transmission service to deliver at least 75% of its capacity requirements to load. This requirement has been the subject of substantial debate and discussion by WRAP participants and stakeholders. In response to concerns over the impacts of this requirement, WRAP developed several "exceptions" for specified conditions, though concerns remain, especially that these exceptions may be too narrow or may require entities to purchase transmission for longer terms than the duration of the binding seasons of the program. WRAP also includes penalties for entities that cannot meet their Forward Showing Requirement or their Forward Transmission Requirement. As might be expected, the penalties are based on a factor of the cost of New Entry (CONE).

In addition to the Forward Showing program, WRAP includes an Operations Program that allows Participants that are expected to be deficient going into operations horizon to tap into certain capabilities of other Participants. Despite not being within an ISO/RTO, the Operations Program permits WRAP Participants to unlock regional diversity and carry lower Planning Reserve Margins than they would need to if the Operations Program did not exist. There are settlement provisions for the Operational Program, which include penalties for failure to deliver. These holdback requirements also open up another set of issues that must be addressed in the face of a likely outcome: the WRAP Participant footprint being different than day-ahead market footprint(s). This has become known as WRAP "interoperability" and is beginning to be discussed in a variety of forums as WRAP participants, potential day-ahead market operators, and stakeholders seek solutions.

There are, of course, substantial other details of the WRAP contained in the tariff filing and left to be ironed out in future business practices. The program is anticipated to evolve over time, with a governance process that delegates initial consideration of program changes to a Program Review Committee (PRC). Following submission of the tariff to FERC, various stakeholders across the West intervened in the docket and submitted comments. While there were some limited protests, most comments were supportive. WPTF *commented* and, despite lingering concerns with some aspects of the filing, supported its approval by FERC. WPTF argued that the transmission requirements deserve special consideration and, going forward, should be the subject of review by the program's Independent Evaluator. WPTF also asked FERC to consider whether any compliance filings might be necessary to ensure that the Board selection, nomination and voting process (which will be under the WPP Bylaws which were not filed with FERC for approval) are sufficient to meet applicable independence requirements. Many comments also highlighted support for WRAP with a hope for additional regional coordination including development of an ISO/RTO. And some pointed out that, if WRAP expands functions beyond the RA program, the current governance structure will be insufficient as it provides very limited opportunities for non-load serving entities to influence the process.

WRAP is certainly a step forward for Western coordination, but the need for it to function efficiently with day-ahead markets that are under development creates the potential for lost efficiency in those markets. Ultimately, a solution for "interoperability" of WRAP's holdback requirements and day-ahead markets is likely to be found. But how it is implemented and whether it creates challenges down the line remains to be seen. An RTO/ISO, where there are common RA requirements over the same footprint the market is optimized across would certainly reduce the likelihood of leaving efficiencies on the table and tripping over seams and interactions between programs. But, for now, the West will have to deal with the hodgepodge of different programs, operators and footprints that appear to be coming to fruition as we strive to make more regional coordination a reality.

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[1]It is important to understand that the zonal Effective Load Carrying capability (ELCC) values for wind and solar will be distributed to individual resources in the zone based on their performance during Capacity Critical Hours (CCH). Thus, determining an individual wind or solar resource's QCC is not as simple as multiplying the ELCC by the nameplate capacity of the resource. WPP has indicated that CCH data will be posted to allow for resources to better understand their QCC (based on their historical or expected output during CCH hours).

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..

Day-Ahead Market Fundamentals

For more than three years now, the CAISO Committee has been excited for the CAISO to move forward with their Day Ahead Market Enhancements (DAME) initiative, but it's getting to the point where one must wonder whether it's even worth it to keep supporting this initiative. There have been multiple design iterations, and this latest might be one of the worst proposals yet. WPTF has supported the development of a day-ahead hourly imbalance reserve product from day one because it would improve the current integrated forward market (IFM) and residual unit commitment (RUC) processes and reduce RUC biasing. In theory, the imbalance product is a great idea. It is co-optimized with energy and ancillary services within the IFM and will ensure additional flexibility is available in the real-time. This allows the CAISO to better accommodate changing real-time needs to due to renewable and demand unpredictability. Unfortunately, the devil is in the details and the latest proposal is so laden with unnecessary and overcomplicated elements, it causes more issues than it solves.

In an effort to steer the CAISO in a better direction, WPTF worked with the California Energy Storage Alliance (CESA) and the Independent Energy Producers (IEP) trade organizations and sent CEO Elliot Mainzer a letter detailing what changes need to be made in order for our organizations to support the proposal. Below is an excerpt from the letter, and I encourage any organization that feels the same way to reach out to the CAISO as well.

"As we move toward an expanded CAISO footprint it is vital that the CAISO design a market based on market fundamentals. The design details of DAME we disagree with would interfere in the market and stem from a fear that generation and storage facilities could earn revenues that staff considers to be duplicative or excessive. As we explain below, these fears are misplaced. We urge you to ask staff to significantly simplify the design and develop additional market rules later, if needed. Undue concern about limiting revenue opportunities during the initial design will unnecessarily complicate the program and lead to unintended consequences. We believe three changes are greatly needed:

1. **Remove all features of the imbalance reserve product that would claw back revenues from facilities with existing RA contracts.** The imbalance reserve product is a separate and new flexibility product distinct from RA, so it is not a double payment. The imbalance product is designed to compensate resources that can quickly respond to grid needs and provide energy to meet intra-hour renewable and load variability. This product is clearly additional to the current nature of the RA contract since the imbalance product, unlike the

RUC product, is not a reliability product that merely seeks to ensure capacity is available over extended periods of time. Instead, it is a co-optimized flexibility product that reserves resources' energy for imbalance needs. Thus, there is no potential for duplicative payments.

We also note that the DAME initiative formally started in early 2019 and even prior to that the CAISO had already considered the idea of an imbalance reserve product in a previous initiative. Thus, many RA contracts already address flexible or imbalance product payments.

2. **Replace the additional local market power mitigation mechanisms with a bid cap.** Implementing local market power mitigation for the imbalance reserve and reliability capacity product introduces unwarranted complexities and adverse market impacts. The CAISO's own analysis has already shown that the current local market power mitigation process for energy indirectly mitigates for market power in imbalance reserves. It is also unlikely that uncompetitive conditions will exist for the imbalance product or reliability capacity product. Finally, any local market power mitigation design requires the development of a default imbalance or reliability capacity bid for which there is no clear method or economic theory in determining. In the unlikely event uncompetitive conditions do arise, the bid cap and tariff rules against exerting market power will diminish the impacts and exertion of market power – and the CAISO can move forward with a local market power mitigation design at that time.

3. **Eliminate the proposal to cap real-time energy bids of capacity awarded imbalance reserves.** An additional real-time energy bid cap, below the existing real-time energy bid cap, distorts market prices and prevents a subset of resources from being able to fully reflect and recover costs in the market. CAISO staff is concerned that the optimization may award a resource with a higher real-time energy offer the imbalance product compared to another resource with a higher imbalance price, but a lower real-time energy offer. The fear is that lower energy offer resources will not get awarded energy in the day-ahead market and will not bid into the real-time market because the CAISO has removed the real-time must-offer obligation. This is a non-sensical fear and not based on market fundamentals. First the day-ahead price on average is higher than the real-time price so staff's concern is baseless. If a resource's offer is economic in real-time, it is more likely to be picked up for day-ahead energy and thus have a real-time must offer. Second, resources with low-cost energy do not solely bid into the energy market because of a must-offer obligation – they bid in to earn profits. The CAISO should trust energy market prices to provide sufficient incentive for resources to bid imbalance and energy prices optimally.

These unnecessary design components result from the CAISO staff not trusting the market to function efficiently. However, the CAISO and DMM have already developed robust systems to detect and mitigate instances of market power, and no evidence of market power manipulation has emerged since the Electricity Crisis. We ask that you direct CAISO staff to return to market fundamentals and eliminate these unnecessary and distortionary design components."

I will add that when it seems like the CAISO doesn't trust their own markets to function, it makes extending them that much harder. Market design does not have to account for every edge case and possible situation, and instead should prioritize simplicity, transactability, and rational economic incentives and outcomes. As we look toward extending the day-ahead market, these principles will only become more important.

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.

While much of the West has spent the past several months vetting various market integration initiatives, California, which accounts for roughly a third of the region's demand, has been focused on keeping the lights on.

No, I'm not talking about the state's close call with rolling blackouts in early September. Yes, the late summer heat wave and the strain it placed on California's electric grid did garner a lot of media attention. And, yes, Governor Newsom's call for Californians to forgo charging their EVs, coming just days after the state banned sales of gas-powered vehicles, did garner hundreds of *chef's kiss* emojis on Twitter. But, notwithstanding the alarmist headlines and mid-wit punditry surrounding the extreme heat event, most of the real action this summer has taken place behind the scenes, including the negotiations that produced the last-minute legislation to keep Diablo Canyon open through 2030.

In the CPUC context, it would perhaps be more accurate to say the real action has taken place behind the screens—i.e., the computer screens—of the CPUC staffers and poor saps like me who have been working on implementing the Commission's structural reforms to the Resource Adequacy (RA) program and developing a more programmatic approach to procurement that flows out of the Commission's Integrated Resource Planning (IRP) process.

The Fecal Follies

In June of this year, the CPUC issued its *decision* adopting an entirely new "slice-of-day" *framework* for the RA program, with the new framework to be tested in 2024 and fully implemented in 2025. Under the new framework, CPUC-jurisdictional load-serving entities—i.e., PG&E, SCE, SDG&E, and the community aggregators and competitive suppliers serving retail load in the utilities' service territories—will need to demonstrate they have procured sufficient system capacity to meet 24 hourly RA requirements for each month of the compliance year, with the hourly requirements being based on forecast system peak loads in each hour of the "worst day" of the month, plus a planning reserve margin.

The June order left open a host of technical issues and implementation details, with the parties being directed to "work together to arrive at an optimal final proposal" to be presented to the Commission in November. To that end, CPUC staff and stakeholders convened weekly workshops from late July through early October.

The topics covered in the weekly workshops included proposed methodologies for calculating hourly "qualifying capacity" values for various types of RA resources, the process for translating staff reliability studies into a planning reserve margin that can be applied to the slice-of-day framework, and the development of new compliance and validation tools.

At the WPTF Summer Meeting, I was asked to characterize the aforesaid workshop process. "It's been a s--t show," I said. My pithy response was not meant to disparage staff or the party representatives that have participated in the workshops. Everyone put a lot of thought and effort into developing and presenting their proposals. And good progress has been made on at least some key topics.

The problem has been the extremely compressed workshop schedule and, perhaps more importantly, the Commission's failure to appoint someone to marshal the workshop process so that it produces the "optimal final proposal," as called for in the Commission's June order.

What the Commission will get instead is a voluminous report that simply describes the workshop process and the various proposals that were presented. It will thus be up to the Commission to decide most of the new framework's implementation details.

The same thing happened with the central procurement framework for local capacity. As a result, we ended up with a deeply flawed program that has had a near-disastrous roll out. Here's hoping we get lucky this time around.

The Next Big Thing

In its February *decision* adopting its 2021 Preferred System Plan, the CPUC committed itself to developing a "programmatic structure for IRP procurement" that would obviate the need for ad hoc procurement directives to support long-term system reliability while achieving the state's clean energy goals.

It was thus no surprise when the ALJ in the IRP proceeding issued a *ruling* in early September seeking comments on a set of staff *proposals* for a new program under which LSEs would have "an ongoing obligation…to procure resources necessary to meet their share of total system reliability and clean energy needs over the medium to long term." What is surprising, however, is the breadth and scope of the proposed program, which goes far beyond past IRP procurement directives.

Staff posits that the proposed IRP procurement program "should be designed to address the main externalities stemming from operation of an unconstrained energy market," which staff identifies as reliability, environmental, financial, and market power. To address reliability and environmental needs, LSEs could be required to procure not only incremental capacity (MW) from new clean energy resources (and possibly, existing RA resources) but also—or alternatively—specified quantities of clean energy (MWh). If the Commission ultimately goes that route (i.e., imposing firm clean energy procurement requirements on LSEs), it would be a massive expansion of the Commission's regulation and oversight of individual LSE procurement activities.

The Commission hopes the new program can be implemented in 2023, but I think 2024 is far more realistic. In any case, both staff and poor saps like me have a lot of work ahead of us to develop an IRP procurement program that is workable and (hopefully) does not end up creating yet more messes as California transitions to a carbon-free energy future.

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.*

End of Session Surprises Ahead of Election Day

State Senator Brian Dahle finished second in the June primary election, and will now face Governor Gavin Newsom in the November 8 general election. The biggest advantage for an incumbent is name recognition, and the latest poll of likely voters found that 53% said they supported Newsom while 32% backed Dahle.

With Democrats holding a 2-1 voter registration advantage over Republicans, Newsom is expected to cruise to reelection – after which he appears to be angling for the White House – but we will discuss that in our next quarterly update. Of course, we never know what may happen between now and election day.

End of Session Surprises

Governor Newsom enjoyed a lot of success this legislative session. Following his big victories in the record budget signing (see our last Quarterly Update), he added victories in a legislative package that he proposed late in the session as well as a bill to keep PG&E's Diablo Canyon operating for an additional 5 or 10 years.

The Case for Diablo

After a successful full court press by the Governor's Office in the legislature, and literally with only minutes to spare, Senate Bill 846 was amended to keep Diablo Canyon running for at least five more years, with a possible 5 more years after.

The language calls for the Department of Water Resources to issue up to a $1.4 billion loan to PG&E for the extension. The bill also asked the California Energy Commission to present a cost comparison and operations assessment of the Diablo Canyon powerplant by late 2023. It would also establish a three-member Independent Safety Committee for the nuclear power plant.

Senate Bill 846 would also extend the plant until 2030 since the once-through cooling extension for the plant expires on October 31, 2030.

Despite several hurdles, Newsom successfully secured enough votes to offer the funding to PG&E to keep the plant alive. While PG&E must still secure federal funding, and many permits to make this extension a reality, Newsom can "check a box" on success.

The Five Point Climate Plan

With three days to go in the session, Newsom pulled another rabbit out of his hat by securing passage for most of his "5 point climate plan," which he introduced late in the session. Aside from the Diablo Canyon's re-licensing push, Newsom also sought legislation for a California Lithium Valley, carbon neutrality, and a ramp up of the

2030 greenhouse gas emissions reduction target from 40 percent to 55 percent below the 1990 level. He also pushed for setbacks of 3,200 feet between new oil wells and schools, clean electricity targets of 90 percent by 2035 and 95 percent by 2040 to keep the state on track to the previously-established goal of total clean electricity retail sales by 2045, and a regulatory framework for carbon removal and capture, utilization and sequestration.

End of Session Outcomes

On the final day of the legislative session, Newsom scored major victories. As for what kind of "horse trading" or favors were afforded for the votes – those will eventually be revealed.

- *AB 1395* would have codified the state's goal to be carbon neutral by 2045 into law – FAILED.
- *AB 2133* would have ramped up the 2030 greenhouse gas emissions reduction target from 40 percent to 55 percent below the 1990 level -- FAILED.
- *SB 1137* established setbacks of 3,200 feet between new oil wells and schools, homes and parks – APPROVED.
- *SB 1020* set clean electricity targets of 90 percent by 2035 and 95 percent by 2040 to keep the state on track to the previously established goal of total clean electricity retail sales by 2045 – APPROVED.
- *SB 905* and *AB 1279*, will establish a regulatory framework for carbon removal and capture, utilization and sequestration – APPROVED.
- *SB 846* Diablo Canyon re-licensing—APPROVED.
- *SB 126*, a budget trailer bill, which has millions for climate change, including funding for storage and the Lithium Valley – APPROVED.

All of the approved bills were signed. Those that failed may return in the next session. Stay tuned.

More Surprises Pending?

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 the SWRCB allow three AES facilities, the 1,137 MW Alamitos, 1,491 MW Ormond Beach and 226 MW Huntington Beach facilities 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.

To date, 16 power plants totaling nearly 18,000 megawatts (MW) in the CAISO balancing area have been shuttered or repowered with air cooling. While the CEC has recently insisted, as has the Governor's Office, that closing natural gas-fueled OTC units remains a goal of the state, the CPUC in its IRP and ongoing concerns about grid reliability has, for the second time in 3 years, called for those resources to stay online until the transition to a 100% clean grid is further along.

According to the report, the cost of keeping the natural gas-fueled plants online longer could be covered by part of the $3 billion allocated to keep existing fossil fuel power plants running in the newly created Strategic Reliability Plan (AB 205). CDWR and the CEC are to manage this fund and contracting.

The *"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,"* according to the State Advisory Committee on Cooling Water Intake Structures' proposal.

SACCWIS cites the updated state energy reliability analysis that concluded that more intense heat waves, wildfires, droughts, and supply chain constraints, are driving the need for the coastal power plant extensions. It highlights the finding that there could be a 10,000 MW shortage by the summer of 2025.

A decision on the recommendation will come later this year.