



# SHARING POWER AMONG THE PACIFIC STATES

*"This system [the Pacific Intertie] is proof of the power of cooperation and unity. You have proved that if we turn away from division, if we just ignore dissension and distrust, there is no limit to our achievements."*

- LYNDON JOHNSON, 1964



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## GRIDWORKS

# SHARING POWER AMONG THE PACIFIC STATES

CREATING GREATER BENEFITS FOR WEST COAST CONSUMERS AS THE RESOURCE MIX ON THE WESTERN GRID EVOLVES AND INCORPORATES A HIGHER PERCENTAGE OF INTERMITTENT RENEWABLE RESOURCES

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## INTRODUCTION

“Resource Adequacy” is a term that has come into more common usage in recent years in the electricity industry, but the concept that it represents is probably nearly as old as the industry itself. Simply put, resource adequacy seeks to determine if sufficient resources exist in a system (either broadly or in a specific local area) to ensure that there is enough capacity available to meet the peak demand of consumers under adverse conditions. In recent times, with the rapid spread of renewable resources in the West, the concept of resource adequacy has expanded to include still-evolving measures to determine if the system has sufficient flexibility to meet load under rapidly changing conditions of resource availability, such as the setting of the sun in a heavily solar-reliant area. Some experts have suggested that as renewables become a larger and larger fraction of the resource mix, *flexibility* will become an even more important concern than the traditional problem of maintaining sufficient capacity to meet peak demand.

So why do we care about a rather arcane subject like Resource Adequacy (RA)? Fundamentally, RA lies at the intersection of two of the most important considerations for electric system planning — reliability and cost. Build or buy too many resources and the system will be highly reliable but expensive for consumers. Build or buy too little and rates may be marginally lower, but reliability will be weakened and periodic shortages — leading to blackouts or very high prices in the market — will become a real threat. Striking this balance has been a key consideration for Investor-Owned Utility (IOU) regulators and Publicly-Owned Utility (POU) governing bodies for decades. And, given that uncertainty about future conditions is a constant in this industry, costly mistakes can be made even when the best planning tools have been utilized. Increased reliance on markets only exacerbates the uncertainty, even as it shifts some of the risk of error from consumers to private investors. In addition, the increased emphasis on carbon reduction and air quality

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improvements has added a third key dimension — the environment — to the tradeoffs inherent in assessing RA, complicating the analysis even further.

This paper is intended to assist key stakeholders in the Pacific Coast states in understanding how RA policies for electric utilities in the area are structured today, and how those policies might be modified in the future to create greater benefits for consumers in all of the involved states, as the resource mix on the Western grid evolves and incorporates a higher percentage of intermittent renewable resources. It begins with an introduction to the basic concepts and terminology of RA, and then summarizes the different approaches employed in the Pacific Northwest and in California today. The paper then discusses some of the benefits that could be captured via a more uniform approach to RA planning and implementation throughout the region. Simply put, the sharing of resources across a broader geographic footprint reduces the risk of error and reduces cost. The paper concludes with suggestions for initiating a process to develop a set of mutually-agreeable policies that will benefit all of the involved states, in an effort to capture the benefits of increased coordination and cooperation.

## BACKGROUND AND DEFINITIONS

“Resource Adequacy” is the term used to describe the ability of an electrical system to supply the aggregate electrical demand and energy requirements of customers at all times, except under the most extreme conditions. RA takes into account the physical characteristics of the transmission system, such as transmission line ratings and scheduled and reasonably-anticipated unscheduled outages of system elements (generators, transmission lines, transformers, etc.). It is a *planning* concept that is typically assessed from as little as a season to many years in advance, to ensure that the peak demand and energy needs of a system will be met.

Resource Adequacy constitutes one component of what we refer to as system reliability, and it is typically the province of the generation side of an integrated utility and its regulators. The other component is called “Security,” which refers to the ability of the electrical system to withstand sudden disturbances, or contingencies, such as electric short circuits or unanticipated loss of system elements (outages). The security component is normally the province of the transmission system operator. Security is a *real time operational* concept that considers voltage,

frequency and system stability, among other attributes. The North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) have promulgated mandatory reliability standards designed to prevent cascading outages on the interconnected transmission grid. These reliability standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability overlap. But there are other levels of performance where security can be maintained without ensuring adequacy. In those situations shedding of firm load may be permitted to maintain grid security, even if adequacy for certain end users must be sacrificed in the process.

These mandatory reliability standards require that each Balancing Authority (BA), of which there are no less than 38 in the West, maintain adequate operating reserves in order to assure system Security (maps of the current BAs in California appear on Figures 3 and 4, below). The WECC’s minimum operating reserve requirement for each BA is equal





**TABLE 1 | PLANNING CRITERIA USED BY UTILITIES ARE WIDELY VARIED**

	PEAK DEMAND IN 2021 (MW)	PLANNING CRITERION	PRM	PEAK SEASON
Puget Sound Energy	7,000 MW	LOLP: 5%*	16% (2023 - 2024)	Winter
Avista	Summer: 1,700 MW; Winter: 1,900 MW	LOLP: 5%*	22% (14% + operating reserves)	Both
PacifiCorp	10,876 MW	LOLE: 2.4 hrs/ year	13%	Summer
Arizona Public Service	9,071 MW	One Event in 10 Years	15%	Summer
Tuscon Electric Power	2,696 MW	PRM	15%	Summer
Public Service Co. of New Mexico	2,100 MW	LOLE: 2.4 hrs/ year	Greater of 13% or 250 MW	Summer
El Paso Electric	2,000 MW	PRM	15%	Summer
Cleco	3,000 MW	LOLE = 1-day-in-10 yrs.	14.8%	Summer
Kansas City Power & Light	483 MW	Share of SPP**	12%**	Summer
Oklahoma Gas & Electric	5,500 MW	Share of SPP**	12%**	Summer
South Carolina Electric & Gas	5,400 MW	24 to 2.4 days/10 yrs	14-20%	Both
Tampa Electric	4,200 MW	PRM	20%	Both
Interstate Power & Light	3,300 MW	PRM	7.3%	Summer
Florida Power and Light	24,000 MW	PRM	20%	Both
California ISO	52,000 MW	LOLE: 0.6 hours/year	15-17%	Summer

\* PSE and Avista use NWPCC criterion of 5% probability of shortfall occurring any time in a given year

\*\* SPP uses 1-day-in-10 years or 12% PRM system-wide

Source: Energy+Environmental Economics

to 3% of system load plus 3% of system generation, with at least half of that amount met through spinning reserves, that is, unloaded capacity on generating units that are already operating and synchronized with the system. The other 3% can come from non-spinning reserves, resources that are not currently operating but can be started up and synchronized to the grid within 10 minutes. But BAs must also plan for the most severe single contingency (MSSC) on their individual systems, and for some BAs this MSSC can exceed the 6% and create a higher requirement. Partly for this reason, most utilities in the Northwest (as well as the Balancing Authority of Northern California (BANC) and the Turlock Irrigation District (TID) in California) have joined the Northwest Power Pool, which offers an operating reserve sharing agreement under which the various participating BAs will support each other in providing operating reserves for the first hour following a contingency. This type of operating reserve sharing is one means for utilities to reduce costs by cooperating with neighboring entities to maintain reliability. A similar arrangement, the Southwest Reserve Sharing Group, includes a number of smaller utilities in the Desert Southwest.

Aside from Security, there is no single mandatory planning standard for utilities in the WECC for Resource Adequacy. Historically utilities employed deterministic Load and Resource Balance calculations, with the goal of achieving a sufficient Planning Reserve Margin (PRM) above forecasted coincident peak demand to cover forecast error and unit outages. While each BA must still be prepared to meet

its MSSC, larger and more complex systems have generally concluded that a computationally-intensive probabilistic modeling analysis is needed to more accurately assess adequacy. Measures such as Loss of Load Probability (LOLP), Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) have been developed to assess the adequacy of a particular system, employing differing modeling techniques. These metrics are often used to choose a PRM that is sufficient to achieve the desired probabilistic level of Resource Adequacy, such as “one day in ten years”. While the modeling aspect of these studies strives to be as accurate as possible, the ultimate selection of a PRM is necessarily a judgmental exercise that considers the trade-off between greater reliability and lower customer cost.

## RESOURCE ADEQUACY IN THE PACIFIC NORTHWEST

In the Pacific Northwest (NW), the Northwest Power and Conservation Council (NPCC) has developed a regional Resource Adequacy standard of 5% LOLP five years in advance<sup>1</sup>. However this standard applies to the region as a whole and not to any specific utility individually. For the Investor-Owned Utilities (IOUs) in the region, the state commissions assess RA as part of each company's

1 [www.nwcouncil.org/media/30058/2011\\_14.pdf](http://www.nwcouncil.org/media/30058/2011_14.pdf)

## FIGURE 1 | PACIFIC INTERTIE FACTS

**PURPOSE:** Connect Columbia River hydroelectric to California

### CALIFORNIA-OREGON INTERTIE (COI)

**BORN** | 1964, Expanded 1993

**CONFIGURATION** | 500 kV AC (3)

**CAPACITY** | 4,800 MW (N-S) / 3,675 MW (S-N)

**OPERATOR** | BPA (Oregon), CAISO (California)

**WECC PATH** | 66

### PACIFIC DC INTERTIE (PDCI)

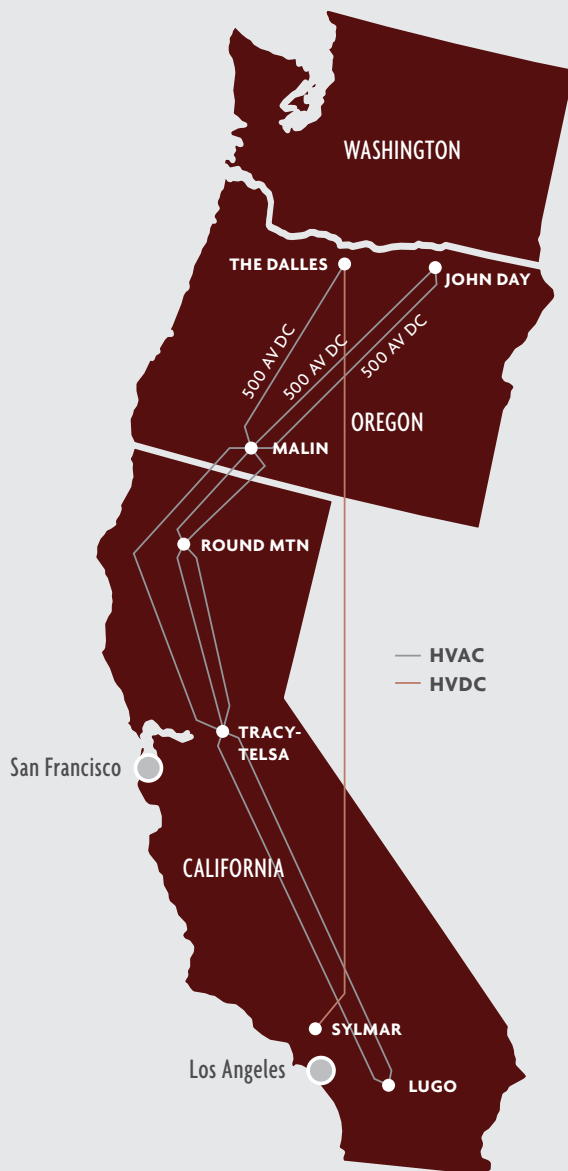
**BORN** | 1970, Subsequent expansion

**CONFIGURATION** | 500 kV DC (1)

**CAPACITY** | 3,100 MW

**OPERATOR** | BPA (Oregon), Southern California municipalities (California)

**WECC PATH** | 65



Integrated Resource Planning (IRP) process. For example, in its 2015 IRP, Puget Sound Energy proposed to use a 1% LOLP standard rather than the 5% established by the NPCC. The Washington commission rejected this change in its May 9, 2016 acknowledgement letter for the IRP, and maintained its use of the NPCC standard (Docket UE-141170). In its final 2017 IRP, filed in Docket UE-160918, Puget Sound Energy has moved to the 5% LOLP metric.

Other NW utilities have presented a variety of reliability studies in their various IRPs as support for their proposed RA standard. PacifiCorp's April 4, 2017 IRP filing proposed to continue that company's use of a 13% target PRM. In contrast, Portland General Electric's 2016 IRP proposed to increase the 12% PRM adopted in its 2013 IRP to 17% for 2021, based on achieving a one-day-in-ten-years LOLP. The Oregon Commission's Order 17-386 in Docket LC 66, dated October 9, 2017, did not specifically address the change in PRM but did find that PGE had a resource need in 2021. In its final 2017 IRP, Avista chose a 14% reserve margin for winter and a 7% reserve margin for summer, in addition to its requirements for operating reserves and regulation. Avista did not conduct its own regional or balancing area RA assessment, choosing instead to rely on the work of the NPCC, with modifications based on the fact that its generating units are rather large relative to its load, which may indicate the need for a higher PRM.

One of the complexities that the Washington and Oregon commissions have noted is that some of the individual company IRPs rely on a certain amount of off-system market purchases (sometimes called Front Office Transactions or FOTs) as part of the resources needed to achieve their RA target and meet peak demand. Since the NW system as a whole has been in a surplus condition for some time, this has been a reasonable and cost-effective strategy, as market purchases have been available at relatively low cost to meet individual utility peak needs. However, the NPCC's 7th Northwest Power Plan, released on February 10, 2016, noted that the overall regional system is moving from an energy-constrained situation to one of capacity-constraint, particularly in the winter, as the system's resource mix changes. Historically, NW utilities have relied on a certain amount of imports from California (CA) over the Pacific Intertie to meet their winter peaks, as the CA system is summer peaking. The continued future availability of such imports is another planning uncertainty, but the current generation surplus in CA is likely sufficient to meet NW needs, assuming adequate transmission is available. One difficulty is that RA analysis typically does not include the complex modeling of transmission constraints that is conducted in transmission planning studies.

It is clear that in an interconnected system with a diverse climate, individual utilities do not need to "go it alone" and build 100% of the capacity resources required to meet their individual peak demands. Diversity across the system is a tremendous benefit, which enables individual utilities to rely on each other by purchasing wholesale supplies that are



surplus to the needs of other entities. Indeed, this has been the traditional pattern since the Pacific Intertie was first constructed. But the challenge is to determine how much temporary or seasonal surplus is available for any given utility to use to meet its need, when and where that need exists. The benefits of a developing a more holistic analysis of demand and resource availability across a wider footprint seem obvious in this context.

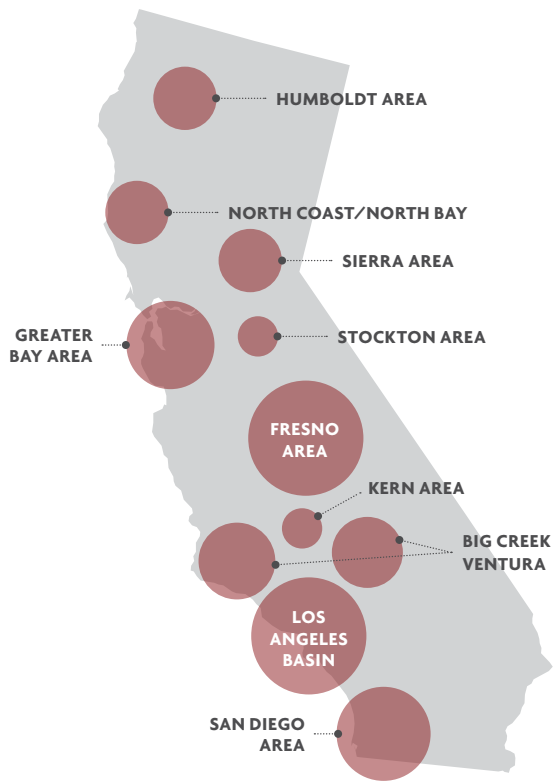
## RESOURCE ADEQUACY IN CALIFORNIA

In the wake of the 2000-2001 electricity crisis, the California legislature enacted Public Utilities Code Section 380, which requires the California Public Utilities Commission (CPUC), in consultation with the California Independent System Operator (CAISO), to establish Resource Adequacy requirements for all load-serving entities (including utilities, direct access providers and community choice aggregators) in the CAISO footprint. The CPUC's RA program requires each jurisdictional Load-Serving Entity (LSE) to contract for physical generating capacity adequate to meet its load requirements, including peak demand and planning and operating reserves. That generating capacity must also be deliverable to locations, and at times, as may be necessary to maintain electric service system reliability and local area reliability. Thus, in addition to obtaining sufficient *energy*

to serve its customers, each LSE must also contract for adequate generation *capacity* to assure that the system can operate reliably under all but the most extreme conditions. CPUC-jurisdictional LSEs, including the IOUs, begin this process "capacity short," since the 1998 industry restructuring resulted in the divestiture of most of the IOUs' generation plants to independent third-party ownership. Public power entities that have joined the CAISO — many of which are fully resourced — set their own RA requirements, or are subject to the "default" provisions of the CAISO tariff if they fail to do so.

From its fairly simple beginning, with a CPUC-established minimum PRM of 15% over monthly peak demand, the RA program has evolved into a relatively complex set of requirements. The "currency" of the CA RA system is an "RA tag." Each in-state generator qualified to provide RA capacity is listed on a public master file maintained by the CAISO, which indicates the MWs of "net qualifying capacity" ("NQC," the technical term for RA tags) that each generator is able to sell. The CPUC allocates to each LSE an annual quantity of RA tags that it is required to "show" in its periodic compliance filings, and there are financial penalties for failure to procure sufficient RA. RA tags are sold in bilateral markets, and can be purchased as "RA-only," or bundled with the energy produced by the plant. When a generator sells RA, it undertakes a "must-offer" obligation under the CAISO tariff, requiring it to schedule or bid the





**FIGURE 2**  
2018 LOCAL CAPACITY REQUIREMENTS

LOCAL AREA NAME	EXISTING CAPACITY NEEDED
Humboldt	169
North Coast / North Bay	634
Sierra	1826
Stockton	398
Greater Bay Area	5160
Fresno	2081
Kern	453
LA Basin	7525
Big Creek/Ventura	2321
San Diego/Imperial Valley	3833
<b>Total</b>	<b>24400</b>

associated capacity into the CAISO day-ahead market. This then ensures that the CAISO will have sufficient supply available to meet demand.

Most purchasers buy a combination of RA bundled with the associated energy (often in the form of tolling agreements) and RA-only tags to fulfill their requirements — there is no restriction on portfolio composition in this respect. RA can also be associated with firm energy imports into CA from outside the ISO, but in order to count imports for RA purposes the LSE must also obtain an allocation of firm import capability on the transmission path that will be used to bring the energy into CA. The CAISO conducts an annual process to allocate this import capability among all LSEs serving load in the CAISO balancing authority area. However, this import allocation process is only an accounting exercise for purposes of the resource adequacy program — it does not create firm transmission rights for particular transactions in the traditional sense.

As the program has evolved, there are now three different RA categories that each LSE is required to procure and show in its compliance filings. The most basic type is “System RA.” Each LSE must purchase and show to the CAISO and its applicable regulatory authority (CPUC, or local governing body for POU), that it has procured a *monthly* quantity of RA tags equal to the total load of its customers at the time of the system’s monthly peak demand (known as “coincident peak demand”) plus the applicable PRM. (The reserve margin is intended to provide operating reserves for the system as a whole, as well as backup generation in

the event of load forecasting error or an outage of one or more power plants or transmission lines.) System RA can come from any generator included on the CAISO’s NQC list, or from firm out-of-state imports (but only if that LSE has obtained an allocation of import capability on the appropriate transmission intertie). LSEs are required to show that they have procured at least 90% of the required 115% of peak load for the upcoming summer months by the end of October of the prior year. In addition, prior to each month of the current year, the LSE must demonstrate that is has procured the full 115% of its coincident peak demand for that upcoming month. At the same time, each generator is required to tell CAISO to whom it has sold RA for the upcoming period, and the CAISO matches those sales with the reported purchases to ensure no double counting. The generator’s obligation is then to make the contracted RA capacity available to the CAISO’s day-ahead market through either an economic bid or a self-schedule.

The second category of required RA procurement is called “Local RA.” Each year the CAISO calculates and the CPUC confirms a certain quantity of capacity that is electrically required to be available within certain identified load pockets that are subject to transmission system constraints. These requirements currently apply year-round and do not vary by season. There are ten such load pockets within the California — seven on the Pacific Gas and Electric Company (PG&E) system, two on the Southern California Edison (SCE) system, and one that comprises essentially the entire San Diego Gas & Electric Company (SDG&E) system. These load pockets are illustrated in Figure 2, above.



A minimum MW requirement is determined for each load pocket and then allocated among all LSEs serving load in that utility service territory on a percentage of summer coincident peak load basis (load-ratio share). Each LSE must then include in its end-of October compliance filing a showing that it has obtained the required quantity of RA tags from generators located within the identified load pockets for the following year. 100% of the Local RA requirement must be procured and shown in the year-ahead October filing (although updates and changes can be made in the month-ahead filing). All Local RA also counts toward the System RA requirement, so these purchases are not in addition to the System RA procurement obligation, but rather a subset. Importantly, the obligation to procure Local RA is not dependent on the location of the specific loads served by the LSE — all LSEs must procure their load-ratio share of Local RA for the utility service area, although not necessarily distributed proportionately in each local load pocket.

The concept of Local RA may seem foreign to those used to working with vertically integrated utilities in the absence of significant retail competition, but in reality there are similar requirements enforced internally by many utilities, who may treat certain units as “must-run” for reliability purposes. These units are typically committed, perhaps at minimum load, and kept online to provide service in the event that a transmission contingency requires the system operator to quickly call on local generation that might otherwise be uneconomic. The CA IOUs had a number of such units prior to industry restructuring, but with the opening of the market to limited retail competition, the obligation was quantified and assigned proportionally to all LSEs. The methods employed for quantifying such Local RA needs are not necessarily the same for the NW IOUs as they are in CA, however.

The third and most recently-established category of required RA procurement is called “Flexible”, or simply “Flex RA.” This category is currently under review by the CPUC and CAISO and may be modified on a prospective basis for future years. Designed to address the so-called Duck Curve, the Flex RA product has all the attributes of System RA, but in addition must offer economic bids and be available for economic dispatch by CAISO (no self-scheduling). A generator’s Effective Flexible Capacity (EFC) is determined by CAISO based on its ability to ramp up and sustain a level of output over a four-hour period (again CAISO maintains a public master list). Thus, a plant’s EFC may be different (usually less than) its NQC, but the Flex RA requirement is also considerably smaller than the System RA requirement. The total Flex RA requirement is determined by the CPUC and CAISO and then allocated to the individual CPUC-jurisdictional LSEs and POUs for procurement. Each LSE must include in its late October compliance filing a showing that it has procured 90% of the required amount of Flex RA for the upcoming year, with 100% then shown in the month ahead.

Notably, the CAISO allocates the Flex RA obligation among the various regulatory jurisdictions based on their relative shares of the maximum ramping requirement within the CAISO BA. The CPUC, however, allocates its total requirement among its LSEs based on their load-ratio shares. As of today, the Flex RA requirement is stated on a seasonal basis, although this could change for the future. Flex RA procurement is not subject to any locational requirements, although imports of Flex RA from outside the CAISO BA can be difficult if not impossible to arrange, as the resource must be available for five-minute dispatch by the CAISO in order to qualify. Imports can meet this requirement only via dynamic scheduling, and only about 400 MW of Pacific Intertie capacity is available for use in this manner. Again, this Flex RA requirement is a subset of the System RA requirement, not an addition to it.

In their recent IRPs, some of the NW utilities have begun to present similar studies of the need for flexible capacity on their individual systems. Indeed, the Oregon commission, in its Order 12-013 (pp.16-18), adopted an IRP guideline that requires each such filing to address the supply and demand for flexible capacity. As the proportion of intermittent generation on the grid continues to increase, it is likely that Flex RA will become a more prominent issue for utilities throughout the West. As noted, the CAISO and CPUC are reassessing their approaches to Flex RA. BPA, Powerex and the Public Generating Pool have all submitted comments to the CAISO stakeholder process that suggested fairly significant changes to the CA approach that would facilitate the participation of NW resources<sup>2</sup>. The CAISO’s examination of this issue continues in its “FRACMOO-2” stakeholder process, and recent CAISO proposals indicate a desire to allow the participation of NW resources to the extent that transmission arrangements allow.

A key part of the California RA paradigm is that the authority of what are termed Local Regulatory Authorities (the CPUC, or local governing bodies for POUs) is acknowledged, and on certain issues differences in procurement rules are acceptable. This is particularly true with respect to system RA requirements-- there is no single planning reserve obligation in the CAISO BA (the CPUC has adopted a 15% PRM for its jurisdictional entities). This successful application of procurement level flexibility may provide some insight into how RA policy might be applied across a multi-state footprint.

The regulatory paradigm for RA in CA is complex and time-consuming for LSEs to navigate. The process begins with the submission of the LSE’s load forecast, which is provided to the California Energy Commission (CEC) in April of each year for the next calendar year, subject to minor revisions in August. The CEC accumulates all of the load forecasts, makes adjustments as necessary, and provides the final “official” forecasts back to the LSEs, usually by early

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2 <http://www.caiso.com/Documents/BPAComments-FlexibleResourceAdequacy-CriteriaMustOfferObligationPhase2SupplementalIssuePaper.pdf>; and <http://www.caiso.com/Documents/PowerexComments-FlexibleResourceAdequacyCriteriaMustOfferObligationPhase2-SupplementalIssuePaper.pdf>

July. The CPUC uses the official load forecasts to allocate System, Local and Flex RA obligations to its jurisdictional LSEs, also typically in July, following an end-of-June Commission decision that determines the total Local and Flexible needs for the coming year.

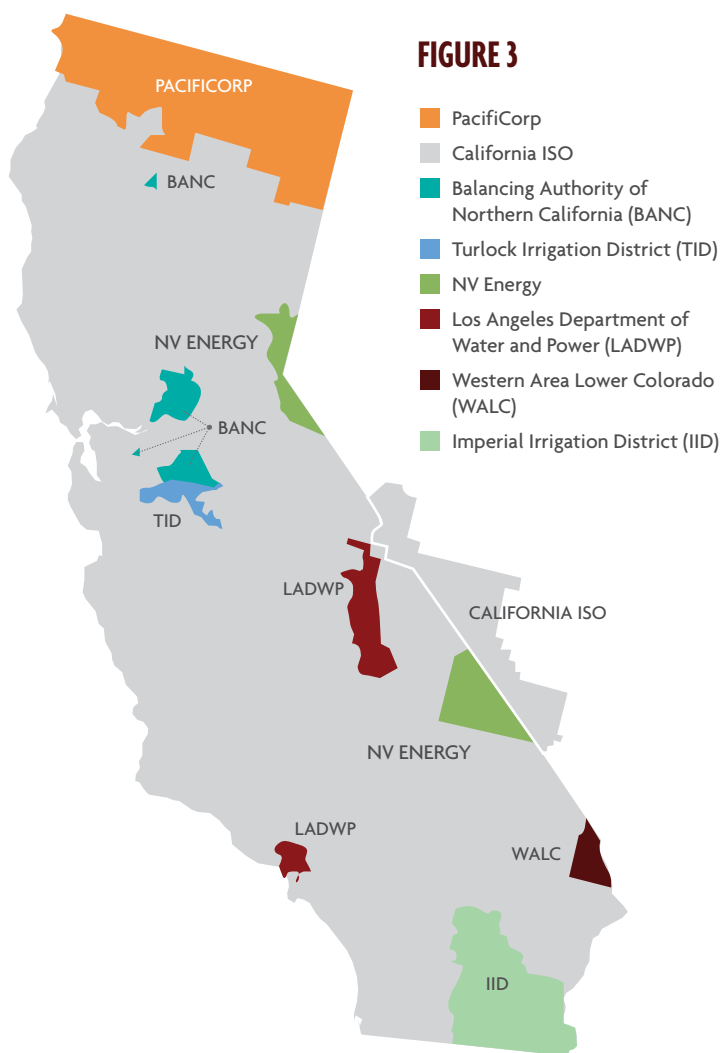
LSEs must submit their year-ahead compliance showings by the end of October, and then follow up with monthly showings about 45 days in advance of the beginning of each month. There is also an update to the load forecasts early in the calendar year to reflect migration of loads from one LSE to another. Local and Flex RA obligations may be reallocated among LSEs based on this update, with the revised obligations going into effect for the month of July. The CPUC staff publishes an annual RA program guide to assist LSEs in complying with these requirements<sup>3</sup>.

## COULD A MORE UNIFORM APPROACH TO RESOURCE ADEQUACY CREATE BENEFITS?

During 2016, considerable work was undertaken around the West to investigate the potential for PacifiCorp (PAC) to join CAISO as a Participating Transmission Owner (PTO). The CAISO issued several issue papers suggesting how its RA program might be expanded to encompass the PAC footprint, and parties filed extensive comments on those papers. The CAISO proposal anticipated that System, Local and Flexible RA requirements would be applied to the PAC system in much the same way that they have operated within CA. While some progress was made, it also became apparent fairly quickly that the approaches to RA in CA and the Pacific NW differ significantly. In particular, the complex interactions between BPA and the IOUs in the NW presented challenges that were not easily resolved.

While the most immediately obvious distinction in the approaches to RA would appear to be PAC's use of a 13% PRM in contrast to the CPUC's 15% PRM, that numerical difference is really only the tip of the iceberg. For example, PAC's RA planning assumes that short-term purchases from liquid trading hubs such as Mid-C will meet a portion of its peak reliability needs. In contrast, the CA program only allows firm imports to count for RA if they are arranged in advance of the start of the RA month and hold an allocation of firm import capability. Shorter-term imports of energy or capacity do not count, and cannot be relied upon to meet RA obligations. While this rule was adopted in CA to assure that sufficient supplies would be available to the CAISO system when needed, it is not a good fit with traditional practices in the NW, where surplus energy has typically been readily available from trading hubs to which many LSEs have easy access. At the same time, recent analyses for the Pacific NW have begun to question whether this surplus situation will continue into the future. The availability of energy and capacity from CA to meet NW winter peaks is often a factor in those assessments, but can be difficult for NW entities to determine with certainty.

Historically the CA IOUs entered into seasonal exchange agreements with BPA or other NW entities that took advantage of the summer-winter diversity of peak demands in the two regions. These types of arrangements appear to have dwindled since the creation of the CAISO. In the early years of the CA industry restructuring, longer-term contracts were discouraged and the IOUs were required to purchase all of the supply to serve their bundled service customers from the now-defunct California Power Exchange (PX). NW entities could offer power into the PX market on a day-ahead basis, but there was little ability to engage in longer-term arrangements. After the electricity crisis of 2000-01 longer-term contracts were once again encouraged in CA, but the focus tended to be on development of new generation within CA, and not on out-of-state purchases. Shorter-term transactions have continued, and some monthly or seasonal contracts have qualified to provide



<sup>3</sup> <http://www.cpuc.ca.gov/General.aspx?id=6311>

System RA, but the traditional summer-winter capacity exchanges do not appear to have re-emerged in any substantial way.

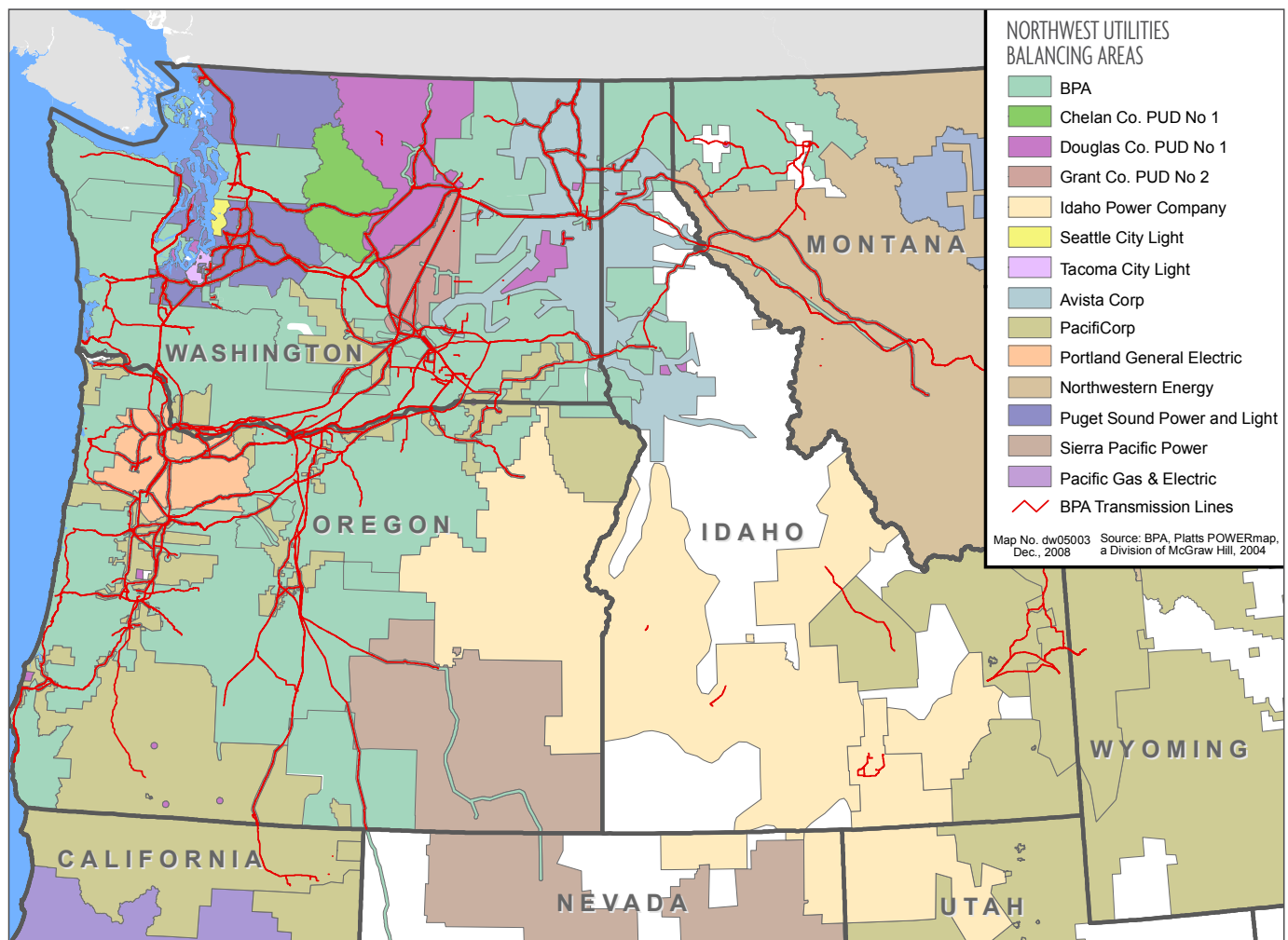
Part of the challenge of re-capturing the benefits of NW-SW diversity is that the CA IOUs are facing the prospect of reduced customer load as energy efficiency, rooftop solar PV, Direct Access and now Community Choice Aggregation (CCA) have all combined to erode IOU sales. With the increasing fragmentation of the retail service obligation, and declining IOU load shares, there may be reluctance to enter into significant longer-term commitments to what would otherwise appear to be mutually-beneficial seasonal exchanges, although any LSE could potentially do so, assuming that there are adequate products within the CAISO market design to accommodate them. The CAISO itself, which may be in the best position to see the big picture, cannot directly participate in market transactions except in extreme and unusual circumstances.

With the advent and growth of the Duck Curve in CA, and the periodic need to curtail wind resources in the NW, there may be an additional opportunity for beneficial daily

exchanges between the regions. In the low-demand spring shoulder period, excess solar generation in CA can lead to an over-supply situation at mid-day and a steep upward system ramp in the evening as the sun sets. While surplus hydro conditions in the NW may complicate the situation, there should be opportunities to “bank” mid-day CA solar generation behind NW dams and draw down that supply in the evening when upward ramp is needed, given appropriate commercial arrangements. But the commonly-traded 6x16 firm energy blocks that dominate the interstate markets today are not a good fit for this growing issue. At the same time, the scheduling protocols for the CAISO market can make it difficult for parties to structure the types of transactions that could meet this emerging need.

BPA addressed these topics in a May 12, 2017 presentation to a Joint CEC/CPUC workshop, pointing out that the California-Oregon Intertie (COI) can provide only 400 MW of dynamic transfers on a 5-minute basis, but potentially the entire 4800 MW of capacity for 15-minute transactions. However, the flexibility of the hydro system decreases as real-time approaches, since most flow commitments occur

**FIGURE 4**





by, at the latest, the day-ahead timeframe. Forecasted CA system needs can be accommodated in this context much more easily than those that arise close to real time (which limits the effectiveness of the Energy Imbalance Market (EIM) in addressing this issue, since it is only a real-time market). BPA suggested that the current 6x16 block product could potentially transition into a more flexible shaped product under the right conditions, in order to reflect the changing circumstances on the grid. There are, however, numerous challenging issues that would need to be resolved in order for this to occur.

The current CA RA framework was not designed with these challenges and opportunities in mind, and any attempt to extend that framework more broadly to the NW is likely to prove sub-optimal, if not fail entirely. At the same time, it would appear that there are significant opportunities for mutually beneficial transactions that are not being captured under the current system. System planners in both regions would benefit from greater knowledge of the amount of power likely to be available (or, even better, committed) from the other to meet their respective peak season needs. This does not seem to be happening in any systematic way today. In addition, while RA policy may not be the best forum for addressing daily interchange transactions, CA's Flex RA rules could potentially be modified to make it easier for NW imports to help meet CAISO daily load swings.

Clearly these issues would benefit from greater discussion among key players in both regions. While it is beyond the scope of this paper to attempt to prescribe any single "silver bullet" solution, it seems clear that RA in both regions could be strengthened and costs reduced through closer coordination. An expanded planning area, whether as part of an expanded ISO or simply via better coordination, would appear to be beneficial for both regions.

## SUGGESTIONS FOR FURTHER ACTION

It is clear that opportunities exist for additional mutually-beneficial system planning activities and marketplace transactions between the NW and CA – both for meeting peak demands in the two regions (conventional System RA) and for mitigating the emerging challenges with renewable integration and daily net load swings (which may implicate Flex RA policies). The question at hand is how best to move forward toward finding practical solutions. The efforts that took place in 2016, which were mostly framed in terms of how to adapt the current CA RA rules to encompass PAC, may have started in the wrong place. Rather than trying to apply CA's rules to the NW, or the reverse, it may be beneficial to start afresh and design a new solution that better meets the needs of both areas.

One path forward that might prove fruitful would be to convene a working group of regulators/staff, utilities and other stakeholders from the NW and CA, including BPA and other key public power entities, to discuss and promote better understanding of how planning and market operations take place in the two regions today, with an eye toward finding improvements and efficiencies. The CAISO and CPUC should certainly be part of these conversations, but the starting point should not be how the CAISO and CPUC handle RA today, but rather a "blank slate" exploration of current problems and potential opportunities for creative solutions. A better system can only be devised with a fuller understanding of the possibilities and constraints faced by each region.

One interesting idea for advancing regional coordination has been offered as a "straw proposal" by Arne Olson of the consulting firm Energy and Environmental Economics, Inc. (E3). Olson suggests the development of a voluntary

**TABLE 2 | SIGNIFICANT POTENTIAL SAVINGS FROM REGIONAL RESOURCE ADEQUACY**

	NORTHWEST		SOUTHWEST	
	BPA+ Area	NWPP (US)	AZ-NM-NV	WestConnect
Individual Utility Peak + 15% PRM	33,574	46,398	35,459	57,270
Regional Peak + 15% PRM	32,833	42,896	34,474	54,597
Reduction (MW)	741	3,502	985	2,673
<b>Savings (\$MM/year)</b>	<b>\$89</b>	<b>\$420</b>	<b>\$118</b>	<b>\$321</b>
Regional Peak + 12%	31,977	41,777	33,575	53,173
Reduction (MW)	1,597	4,621	1,884	4,097
<b>Savings (\$MM/Year)</b>	<b>\$192</b>	<b>\$555</b>	<b>\$226</b>	<b>\$492</b>

- Calculated as the difference btw. regional coincident and non-coincident peaks, averaged over 2006-2012
- Assumes capacity cost of \$120/kW-yr.
- Assumes no transmission constraints within the regions
- Ignores the fact that some savings already being achieved through bilateral contracts

Source: Energy+Environmental Economics

*planning* reserve sharing agreement among utilities in the West (not necessarily limited to the Pacific Coast states), similar to the voluntary *operating* reserve sharing conducted by the Northwest Power Pool and the Southwest Reserve Sharing Group today. This new entity, which would be governed by participating entities and regulators from the affected states, would first conduct a study to determine, based on LOLP or other metrics, what planning reserve margin for the entire area covered by the participating utilities would provide sufficient reliability for the region. Given load and resource diversity, this regional PRM would almost certainly be smaller than the sum of the individual PRMs for the participating entities. Just as the Energy Imbalance Market (EIM) has resulted in tens of millions of dollars of *energy* cost savings for the participating entities, a regional planning reserve sharing system could produce significant capacity cost savings, potentially as much as \$1 billion per year under Olson's initial rough analysis.

Under the straw proposal, the obligation to secure the required level of planning reserves would be allocated

among the participating entities based on their respective contributions to the annual or seasonal coincident peak of the entire group. This would create a forward capacity procurement *obligation* for the participants, but not a centralized capacity *market*, as transactions to meet the obligation would be conducted bilaterally, as is the case throughout the West today. Individual entities would build or procure resources to meet their obligations, potentially using an "RA tag" counting system similar to that employed in CA today. The participants would need to agree on resource counting rules, and provisions would have to be made to take into account transmission constraints, but all of this would be undertaken via a voluntary agreement among the participants, with no transfer of control of transmission assets or other elements typically associated with a regional RTO or ISO. As with the EIM, this approach would help to build trust among participants and demonstrate the potential success of efforts to cooperate regionally.

Whether the result is to pursue Olson's proposal, a larger



regional RTO, or some other approach that has not yet surfaced, there appear to be a few key principles that would need to be reflected in a new model. As revealed in the 2016 PAC/CAISO discussions, the preservation of state authority over resource planning and procurement is an essential principle. Continuing steady progress toward a low carbon electricity system is certainly another, as expressed in the three-state MOU signed by California, Oregon and Washington in March 2017. States may also wish to ensure the opportunity for new technologies to find their place in the resource mix. And traditional concerns about reliability and cost will certainly remain central.

A working group could begin by developing a set of such shared principles, and then proceed to carefully examine the existing planning and operational practices in each area to acquire a common understanding of the facts on the ground. From there, a framework could be constructed that would fulfill the principles, while facilitating the achievement of mutually beneficial opportunities not fully captured under current practices. An RA framework for the future will most likely continue to recognize the

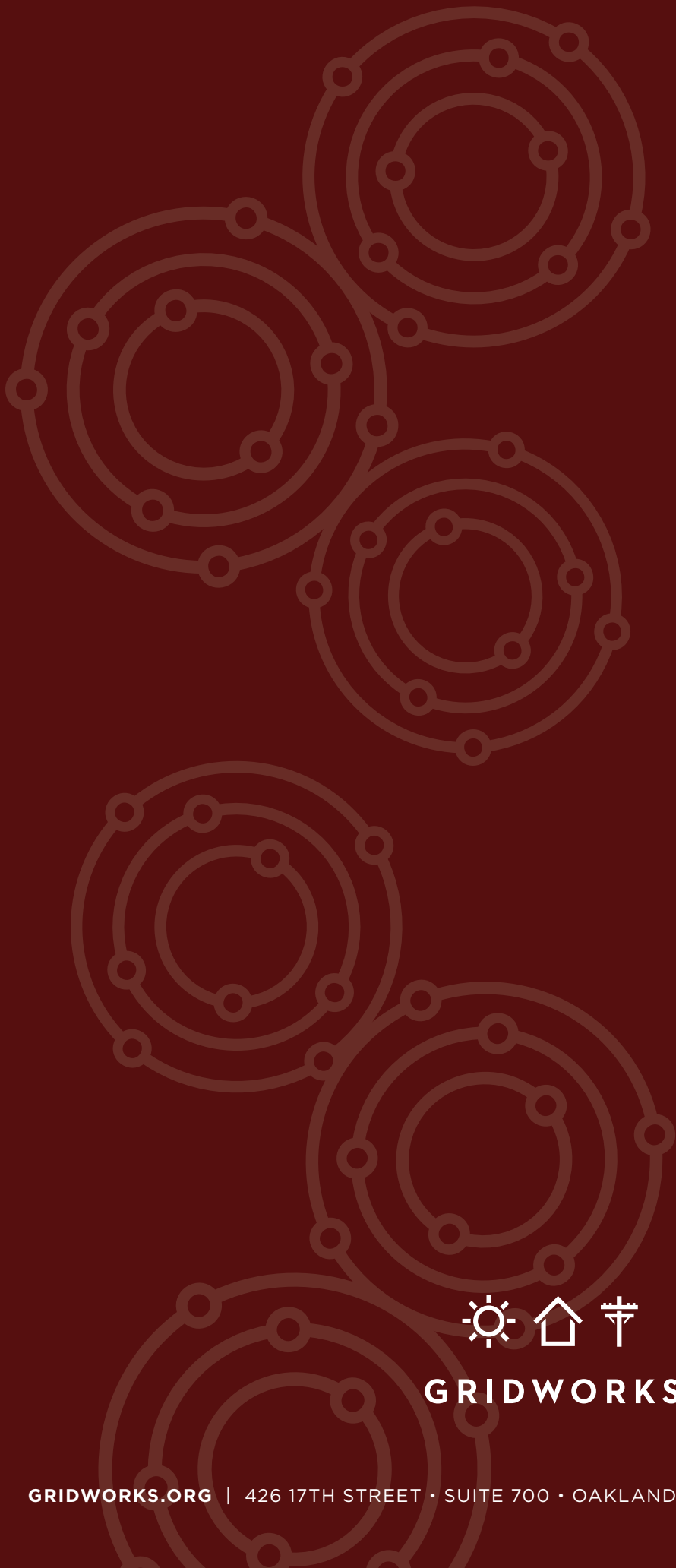
need for overall System and Local reliability, but Flexibility to accommodate increased penetration of intermittent renewables will likely take on an even larger, if not primary, role.

The intent of this paper is to help initiate a process, such as that described above, in order to develop a set of mutually-agreeable policies that will benefit all of the involved states. Success will require time, effort and compromise, but the value that can be achieved is substantial enough to more than justify that investment.

On Sept, 17, 1964, President Lyndon Johnson addressed the Intertie Victory Breakfast in Portland, which took place the day after he had proclaimed the ratification of the Columbia River Treaty in a border ceremony with Canadian Prime Minister Lester Pearson. Johnson's remarks at the Intertie Victory Breakfast are as relevant today as they were in 1964:

*This system is proof of the power of cooperation and unity. You have proved that if we turn away from division, if we just ignore dissension and distrust, there is no limit to our achievements.*





**GRIDWORKS**