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The use of wholesale market purchases by Western U.S. electric utilities

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Executive Summary

Vertically-integrated utilities, which dominate the Western U.S., generally have two options for procuring electricity for retail customers[1]: (1) generate it using utility-owned assets or (2) purchase it using bilateral wholesale contracts and real-time spot markets. The balance between these two options is important in many state regulatory contexts, including utility resource adequacy assessments, integrated resource planning (IRP) and resource procurement processes, avoided cost pricing under the federal Public Utilities Regulatory Policies Act, and setting retail rates. Understanding the impacts of increasing reliance on bilateral or organized wholesale market transactions for resource adequacy is of great interest to states. This report provides publicly available data to supplement sparse information published to date on utility procurement trends and the role of bilateral wholesale market transactions in the Western Interconnection.

Specifically, this report evaluates Western U.S. utility (load serving entity, or LSE) decisions regarding owning versus buying resources as well as balancing short- and long-term bilateral wholesale market transactions. Using a mixed-methods approach, we analyze quantitative procurement data, qualitatively assess IRP documents, and conduct structured interviews with investor- and publicly owned utilities (IOUs and POUs, respectively), state public utility commission (PUC) staff, and California community choice aggregators (CCAs). The report also cites trends in wholesale market transactions elsewhere in the U.S.

What do market transactions reveal about utilities' own versus buy decisions?

- LSEs with balancing area obligations—regardless of ownership type (public, cooperative, or IOU)—have procured 30% of their historical resource needs through wholesale market purchases. This similarity across ownership structures suggests that reliability obligations are closely correlated with the operational benefits that asset ownership provides and less so with the IOUs' motive to earn a rate of return on the resources.
- In interviews, several Western LSEs expressed a preference for owning assets from an operational and planning standpoint. Regulatory and utility staff reported that the balance between owned and purchased resources depends in large part on historical procurement practices, and there has been little interest in evaluating this balance.

What is the historical balance of long-term and short-term market purchases (STMP)?

- Use of short-term and non-firm resources by IOUs differs significantly between Western (mostly vertically integrated) and Eastern (little to no vertical integration[2]) region. Western IOUs substantially increased use of short-term and non-firm market transactions from the early 1990s until the peak of electricity sector restructuring in the early 2000s. After the California electricity crisis, the share of STMP decreased from 60% to ~25% by 2008 and remained stable thereafter. In contrast, Eastern IOUs have relied very little on STMP in the last decades and much less on long-term

[1] For the purposes of this paper, we do not consider demand-side or other third-party resources in procurement analyses.
[2] The term "Eastern" is used to refer to regional transmission and independent system operators such as NYISO, ISO-NE and PJM. In these regions, state law limits or prohibits IOU ownership of generation assets, preventing vertical integration.

transactions than Western IOUs. Non-firm transactions represented 40%-60% of total market activity.

How are Western vertically-integrated LSEs using short-term market purchases?

- Western LSEs primarily use STMP to reduce costs by substituting dispatch of owned resources with more cost-effective market transactions on the day-ahead, hour-ahead, and real-time markets.
- Resource adequacy is a secondary reason why LSEs use STMP. LSEs use STMP as a cost-effective strategy in markets that have excess capacity to avoid building plants for which regulatory approval may be challenging or as a "wait and see" strategy until regulatory approval is more likely.

What is the relationship between renewable energy levels and use of market purchases in the West?

- One of the primary sources of variability in STMP has been direct or indirect effects of high penetration of variable renewable energy (VRE) resources. Across the Western Interconnection, higher levels of renewable energy production are associated with lower use of STMP, while the opposite is true, for example, in the ReliabilityFirst region.
- This finding suggests that STMP are being used to balance and integrate renewable energy in Eastern states. However, in the Western U.S., widespread deployment of renewable energy translates to excess energy that reduces the need for STMP.

How are market transactions incorporated into Western utility long-term resource planning?

- A comparison of electric utility resource planning documents over time shows that five times as many LSEs report the use of STMP in older IRPs compared to recent ones. In contrast, the number of LSEs planning to use long-term transactions doubled in recent IRPs compared to older ones.
- The sophistication of wholesale market assessments in more recent Western utility resource plans varies from extensive regional modeling to reliance on third-party price forecasts.
- Two-thirds of LSEs in our sample do not include wholesale market transactions in their IRPs' preferred portfolio of resources, although some LSEs include planned market purchases to cover small capacity deficits *ex-post*. Interestingly, this finding is in contrast to the extended use of actual market transactions as described earlier.

Recommendations and future research needs

The findings from this study suggest a number of avenues for further research including:

- Explicitly identifying the type and use of market transactions—especially STMPs—in regulatory filings and other documents that are used by LSEs, regulators, and other stakeholders.
- Improving electric utility resource planning practices to comprehensively assess the costs and risks of reliance on wholesale market transactions for both economic efficiency and resource adequacy.
- Developing Western regional-level resource adequacy and market assessments that properly account for both owned resources *and* market transactions (e.g., Puget Sound Energy's IRP market assessment could serve as a model for future regional assessments).
- Ensuring that operational constraints, especially for VREs, are adequately considered within the

context of long-term planning activities.

Abstract

Load Serving Entities (LSEs) can procure electricity from their owned generation or purchase it on bilateral or centrally organized markets. Electric utility procurement decisions have important implications for resource adequacy, which is gaining attention especially in the Western U.S. However, there is little or no research on trends of utility procurement practices, and the role that wholesale market transactions can have for resource adequacy and other applications. This paper leverages information from the U.S. Department of Energy's Energy Information Administration, Berkeley Lab's Resource Planning Portal, and structured interviews with regulatory and utility staff. We find that use of market transactions to meet electric energy needs has been increasing across U.S. LSEs. The reasons for this trend include a general stagnation in building owned resources, a preference towards contracting renewable energy resources to meet RPS targets, and the lower relative cost of wholesale market electricity. Among market transactions across different time scales, short-term transactions were prevalent in Western U.S. LSEs until the 2008 recession, and thereafter declined to about a quarter of total purchases. In contrast, long-term market transactions have become more prevalent and resource planning reports project the share of these transactions in the procurement mix may continue to increase. Results suggest resource adequacy obligations may drive preferences for asset ownership more than a profit incentive. We also recommend improving the planning to procurement connection by reflecting in planning assumptions the operational constraints of market transactions. These results provide insights on key issues in electric utility procurement that could improve overall market efficiency, respond to rapidly changing industry conditions, and identify practices that LSEs and regulators should consider incorporating into their long-term transmission and capacity planning processes.

1. Introduction

1.1. Historical background

Starting with the emergence of the U.S. electric power system in the early 20th century, the dominant organizational form in the electricity industry has been that of utilities regulated as natural monopolies. This structure often entailed vertical integration, a form in which utilities have ownership and control of power generation, transmission, and distribution to retail customers within their service territories, as well as responsibility for grid management and balancing[3]. Then, vertical integration did not entail significant market purchases of electricity by utilities from other entities. For this reason, it was typically unnecessary to make decisions about how much generation to own or purchase from other electric utilities through the bilateral-only wholesale market.

The electricity industry's structure began to change in the late 1970s with the U.S. Congress's passage of the Public Utilities Regulatory Policies Act (PURPA). PURPA required that utilities purchase electricity from small non-utility generators of certain types, at their own avoided cost of generation. This policy led to the emergence of independent power producers (IPPs) selling electricity to otherwise vertically-integrated utilities. This segment of the industry was also facilitated by the development of commercially viable natural gas-fired generation by relatively small facilities. Utilities began to take advantage of this new opportunity, and purchases increased substantially during the 1980s. Many jurisdictions adopted competitive procurement guidelines that aimed to make owning and purchasing decisions compete to the benefit of the customer (Tierney and Schatzki, 2009).

Over the course of the next decade, debates centered around the relative merits of utilities self-generating from owned resources versus purchasing power via contracts with IPPs, particularly with respect to the allocation of risk (Brown et al., 1994). Indeed, one aspect of the balance between owned versus purchased resources is risk allocation between utility and consumer: An owned resource that will be added to a utility's rate base will generally remain there until its costs are recovered. Past cost overruns from ratepayer-funded power generation assets are an example of the risks of ownership (Sovacool et al., 2014). Some regulators began to disallow cost recovery by utilities in cases of cost overruns and delays in building baseload generation, especially nuclear plants. Some analysts argued that buying power from IPPs would lower risks for utilities (in part by shifting them to IPPs) and would therefore benefit utilities (Naill and Sharp, 1991). It was argued, however, that purchasing power actually increased risks to utilities: It contributed to erosion of their rate bases of owned generating plants, and also exposed them to being over-committed to purchasing in the event of unexpected shortfalls in customer demand (Perl and Luftig, 1990).

This debate was unsettled and interest in these issues waned with the move, in some regions of the U.S., towards re-structuring of the electricity industry in the 1990s. However, the drive toward restructuring in the U.S. had largely stalled, due in particular to the California electricity crisis in early-2000s. Today, in most of the country, investor-owned utilities that both own generation assets and purchase power on the

[3] Interspersed with vertically-integrated IOUs (and some public power vertically integrated utilities, often larger cities such as Los Angeles, Jacksonville and San Antonio) were, and still are, several thousand publicly- and cooperatively-owned utilities that are distribution-only (also called "full requirements"). These utilities purchase all their electricity wholesale from a neighboring IOU, a public power joint action agency, or a generation and transmission (G&T) cooperative.

wholesale markets continue to exist and operate. Basheda and Schumacher (2008) reported that 32 states were non-restructured, and that 13 of these actively promoted competitive procurement by their regulated utilities and most of the other 19 informally encouraged it. No state specified a minimum requirement for the share of power that its utilities should purchase (as a proportion of their sales or re-sales), and only one state (Georgia) placed an explicit cap on this share. However, Basheda and Schumacher concluded that "[o]n balance, the trend among states is to favor greater reliance on utility-owned generation: 24 states can be characterized as either supporting the status quo or moving in the direction of favoring greater utility ownership of generation."

The balance between own versus buy options is important in many state regulatory contexts, including utility resource adequacy[4] calculations, integrated resource planning (IRP), resource procurement processes, avoided cost pricing under the federal PURPA law, and setting retail rates for electricity customers. Reliance on wholesale market transactions for resource adequacy, and assessments in this area, are of great interest to state officials. More publicly available information is needed. As a recent General Accountability Office report points out, "consistent data on resource adequacy are not available in regions without capacity markets," (US GAO, 2017, p. 24) which includes the Western U.S. Without such data, an electric utility planner, or a state commission exercising oversight, may have difficulty assessing region-wide or multi-state resource adequacy. There is a risk many utilities may be relying on wholesale purchases, resulting in insufficient resources being built. This reports provides publicly-available data to supplement the little research published to date on utility procurement trends and the role of wholesale market transactions in the Western Interconnection.

1.2. Procurement and market transactions

Contemporary vertically-integrated utilities continue to have two general supply-side options[5] for procuring electricity for their customers subject to regulatory, economic, and technical constraints: They can generate power using assets they own, or purchase power in wholesale markets for distribution in their service territories.[6] This is commonly known as the "own versus buy" decision. How utilities choose between these two categories has important consequences for rate levels, reliability, and risk profiles, particularly in cost-recovery regulatory frameworks where public utility commissions (PUCs) approve investment decisions that are then passed on to customers. For example, adding to the rate base assets with higher capital costs but little or no fuel costs (e.g., wind turbines, photovoltaic panels, and geothermal facilities) may eventually increase rates, but also make rates less exposed to the volatility of energy markets. Similarly, a resource that is not easily dispatchable requires a specific set of operational and investment practices to secure resource adequacy and meet prescribed reliability levels, which may also add to rate base with potential increases to the distribution portion of a customer's utility bill. The exposure to market price volatility or supply volatility, respectively, may create risks for the utility and the customer that require specific hedging and management strategies.

Utilities' "buying" option in turn entails choices among transactions over different time frames.

[4] Resource adequacy refers to ensuring that enough resources (e.g. self-generation, demand-side, or purchased electricity) are available in the future to an electric utility to provide reliable electricity to its retail customers. Such future considerations are necessary for a commodity such as electricity, which is not easily stored, but which must be immediately available.

[5] For the purposes of this paper, we do not include demand-side resources in procurement analyses.

[6] These options apply generally to MISO, SPP, WECC, and Southeast utilities that are not operating within an RTO and therefore own generation assets as well as having load serving obligations.

Generally, there are two options: long-term and short-term purchases. There is no standard time period threshold that identifies a transaction as short-term or long-term[7]. However, the Federal Energy Regulatory Commission (FERC) defines short-term transactions as any market transaction delivered in (or with a duration of) one year or less. This definition combines very short-term transactions made in the day- and hour- ahead markets with transactions made weeks- and months-ahead. These two types of short-term transactions may have different motivations and practical uses and we distinguish between them in our interviews with stakeholders.

The main distinction between short- and long-term contracts—in this context—is that long-term contracts (typically called Power Purchase Agreements—or PPAs) can be used by the developer of a project to provide a steady cash flow that finances a substantial portion of the capital costs. Short-term contracts transfer financial risk to the developer and are flexible for the purchaser because prices are locked-in only for a much shorter period of time. Alternatively, locking prices through long-term contracts can be attractive for load serving entities (LSE) and regulators to minimize the volatility of consumer rates and reduce their exposure. Table 1 summarizes possible advantages and disadvantages of short-term market transactions[8]. We characterize these factors as "possible" because their effects may be uncertain, dependent upon particular circumstances, or both.

Table 1. Possible advantages and disadvantages of short-term market transactions as a procurement strategy

Advantages	Disadvantages
The short commitment period of these transactions translates to **flexibility** in investment or other long-term commitment decisions to implement a "wait and see" strategy	Operators do not have full control over the generation unit whose energy is being purchased, which **limits the operational use** of a market purchase
When market conditions are appropriate, these transactions can be used to **reduce LSE's operational costs** by purchasing power rather than dispatching its own units	Short-term market transactions can unduly expose the purchaser to **electricity price risk**
Low risk of stranded assets by using short- and medium-term purchases rather than long-term investment decisions that are rate based	May not meet **resource adequacy requirements**, which means these transactions can only be used to meet energy requirements but not firm capacity needs

LSEs continually assess their current and future resource portfolios in order to address both own vs. buy options and the trade-offs between short- and long-term transactions. One widely used regulatory practice for this ongoing decision-making - in those states that still require it - is IRP, a suite of methods and processes that seeks to assure that future procurement decisions are least-cost, risk-managed, and consider both supply and demand-side resources. LSE planning and procurement decisions can differ for several reasons that include the value of new information, response to unexpected deviations in load forecasts, and actual outcomes of modeling assumptions (Carvallo et al., 2018, 2017). These factors affect LSEs' continual assessments of both own vs. buy and market transactions decisions, and the

[7] There is also an "intermediate-term" time frame used in market transactions. We omit these types of transactions from our analysis, because only ~3% of transactions were made using this time frame in the 2000-2016 analysis period.

[8] We use "transactions" to refer to purchases and sales, "purchases" to refer to procurement transactions, and short-term market purchases (or STMP) to refer to that specific procurement type.

structure and outcomes of IRP are therefore important topics for understanding these decisions.

1.3. Related research

Despite the prevalence of continued regulation and the vertical-integration structure of utilities, the research literature on the economics of electricity planning and procurement continues to be predominantly focused on issues associated with restructuring (Bushnell et al., 2017), in particular the problem of incentives for investments in generation capacity in restructured wholesale markets. There has been relatively little work on the own versus buy problem *per se*, and even less on regulated utilities' choices between short- and long-term purchases on the wholesale market. However, several papers discuss closely-related issues.

Mansur (2007) studied the effects of vertical integration on the exercise of market power in the Pennsylvania, New Jersey, and Maryland (PJM) wholesale spot market. He found that the combination of vertical integration and participation in spot wholesale markets served to mitigate market power relative to a restructured industry configuration. However, the analysis did not include long-term contracts or an evaluation of decisions to invest in new capacity.

Several papers have studied the characteristics and performance of vertically-integrated, wholesale market-participating firms from the perspective of industrial organization. Fabrizio (2012) combined transaction cost economics with a resource-based perspective on firms to study the participation in both centrally organized and bilateral wholesale markets by investor-owned utilities that also self-generate electricity. This paper focused on the relationships among utilities' institutional and regulatory environment, prior experience with contracting, and internal production capabilities, and how these factors affected the extent to which the firms purchased power. It was found that in the event of a demand increase by customers, utilities in regional transmission organizations or independent system operators (ISOs) relied more on purchased power and less on internally-generated power to meet the demand than did non-ISO members. Similarly, utilities with prior contracting experience also relied more on purchased power to meet increased demand. Fabrizio's study did not, however, distinguish between short-term and long-term transactions.

Kury (2015) also studied utilities' participation in wholesale markets, focusing on the effects of "transparency" in these markets, defined as location- and time-specific prices for units of electricity being publicly-available and easily accessible. His sample comprised of utilities serving retail customers using both self-generation and purchasing electricity, and in many cases, selling excess electricity into a wholesale market. He found that transparency increased market participation, but that the effect was greater for investor-owned and larger utilities. The analysis studied these effects over a one-year period, but did not distinguish between short-term (real-time and day-ahead) and longer-term transactions within that time frame.

Finally, Simshauser et al. (2015) apply a transaction cost economics perspective to compare the stability of retail-only, generation-only, and "gentailer" electricity firms, the latter defined by a combination of vertical-integration and participation in both spot markets and forward contracts. They found—using data from the Australian market and a simulation model—that only the gentailer firm was able to sustain investment-grade credit ratings in the long-term. They argued that this provided some explanation of the trend toward re-integration in the Australian electricity industry.

1.4. Overview of paper

Researchers have, with few exceptions, been slow to re-direct their attention to the current state of decision-making in the jurisdictions that avoided both retail and wholesale restructuring, in particular, how utilities address the choice of owning vs. buying in the current environment and the details of their choices in bilateral wholesale markets. Previous work by the authors reviewing Western U.S. electric utility IRP reports revealed significant amounts of medium and longer term electricity purchases in bilateral wholesale electricity markets. The authors also observed substantial differences in the levels of wholesale market transactions across LSEs and potential opportunities for coordination. Perhaps as an indicator of increasing interest, a recent meeting of Western U.S. state electricity officials featured two panels devoted to better understanding wholesale market purchases, including review of whether collective levels of such purchases in the Western Interconnection are appropriate (Mumm and Albi, 2019; Olson, 2019).

Accordingly, this paper describes a study of Western U. S. electric utility decision-making regarding owning vs. buying and balancing short- and long-term market transactions, focused on the following questions:

- What do market transactions reveal about the own versus buy decision?
- What is the historical balance of long-term and short-term market purchases (STMP)?
- How are Western vertically-integrated LSEs using short-term market purchases?
- What is the relationship between renewable energy penetration and market transactions in the West?
- How are market purchases incorporated into Western utility long-term resource planning?

This work was supplemented by an examination of such transactions in the case of newly-emerging community choice aggregators (CCAs) in California. CCAs are entities formed by local governments that procure electricity for residents and businesses as a complement or alternative to utilities. The main reason to include CCAs is specifically that they own no generation assets and purely depend on market transactions to meet their load, providing an interesting comparison to IOUs in the sample. For the utility and the CCA analyses, we leverage information from the U.S. Department of Energy's Energy Information Administration, Berkeley Lab's Resource Planning Portal, and structured interviews with Western regulatory and utility staff.

This analysis is relevant to the industry for several reasons. First, procurement decisions not only affect costs, reliability, resource adequacy and risk profiles, but they are also inextricably connected to the environmental footprint of LSEs. State-level renewable energy standards and related policies are becoming a major factor in procurement decisions in numerous states, and state/local greenhouse gas emissions accounting will require careful tracking of procurement choices, including from wholesale market transactions. Second, understanding the use of market transactions by Western LSEs will help organized wholesale markets such as the Western Systems Power Pool and potential new western market operators update products, schedules, and tariffs to better suit Western LSEs' needs. Third, trends in the use of market transactions inform the reasons, barriers, and benefits for LSEs that are joining or plan to join new organized markets such as CAISO's energy imbalance market[9] (EIM) or the Colorado joint dispatch agreement[10]. Fourth, market transactions could be used to meet resource adequacy requirements at costs that may be lower than other resources, but it is unclear under what conditions this may happen and to what extent it is already being done.

Finally, many Western vertically-integrated LSEs address own vs. buy decisions on an ongoing basis in the context of IRP—a multi-stakeholder regulatory process that seeks to assure that future procurement decisions are least-cost, risk-managed, and consider both supply and demand-side resources. This study provides an overview of how market transactions are treated in a sample of IRPs, and examples of how these planning decisions relate to day-to-day operations. The study is useful to the (1) Western LSEs that are studied and their regulators; (2) other parts of the country that continue to grapple with how to best organize their electric industry; and (3) national policy-makers concerned with the structure, management, and evolution of the nation's electric power system.

The remainder of the report is organized as follows. Section two reports on the methods and sources used in the analysis. Section three delves into the extent of utilities' uses of market transactions; the balance among ownership of generation assets, short-term, and long-term transactions; how renewable energy penetration is affecting this balance; and the treatment of these issues in integrated resource planning and procurement. The report finishes with findings, a discussion of the policy implications of this work, and potential avenues for future research.

2. Methods and sources

We use a mixed-methods approach that combines analysis of quantitative procurement data with qualitative assessments of IRP documents and structured, phone-based interviews with regulatory and utility staff.

2.1. Quantitative data sources

There are two main sources of quantitative data used in this study:

- The *Ventyx Velocity Suite* relational database, which compiles several EIA and FERC forms used by U.S. utilities to report statistical data for their technical, commercial, and financial operations. Most of the database information comes from EIA forms 861, 412, 906, 923 as well as FERC Form 1.
- The Berkeley Lab *Resource Planning Portal*[11], an online platform that contains planning assumptions for 120+ unique IRP plans (documents) filed by approximately 50 LSEs since 2003.

Procurement data are available for all U.S. LSEs during the 1990-2016 period. We select this period to identify possible trends in the use of STMP before and after the wave of power system restructuring from the late 1990s to the time of the recession of 2007/2008. In contrast, the study of planning assumptions and methods is constrained to a sample of Western U.S. utilities. We follow the FERC definition of

[9] See https://www.westerneim.com/pages/default.aspx
[10] See 154 FERC ¶ 61,107, Federal Energy Regulatory Commission (February 18, 2016).
[11] https://resourceplanning.lbl.gov/

short-term transactions, which are transactions with a duration of one year or less.

2.2. Qualitative data sources

There are two main sources of qualitative data used in this study: (1) IRP reports and (2) structured, phone-based interviews. First, we analyze the most recent IRP reports from 11 LSEs across the Western U.S. (see the Technical Appendix for additional details on the plans analyzed). The evaluation of IRP documents focuses on three guiding questions:

- How is the wholesale market assessed in the IRP?
- How are market transactions treated in the analysis of portfolios of supply and demand-side resources?
- What type of wholesale market risk and hedging strategy assessment is performed?

The analysis of the treatment of market transactions in the long-term planning process is relevant in itself, but it is also used to refine the research questions related to actual procurement outcomes.

The second source of qualitative data is a set of interviews with staff from a sample of 14 LSEs and 4 PUCs[12] across the Western U.S.[13] Participating utilities and jurisdictions are shown in Figure 1, and the list of interview questions is included in the Technical Appendix. We interviewed seven investor-owned utilities (IOUs, green in Figure 1), four community choice aggregators (CCAs; highlighted in red), and three publicly-owned utilities (POUs; shaded in blue). The interviews collected information on actual procurement decisions made during the planning, investment, and operational phases—insights that would be difficult or impossible to ascertain from other sources, including regulatory dockets. The interviews with the non-CCAs comprised eight open-ended questions discussed over the phone with staff from the wholesale operations and planning departments. For the CCAs, the interviews focused on a subset of relevant questions. The phone or email interviews were conducted throughout August and September, 2018.

[12] The actual name of the state entity in charge of regulating utilities may be different for a given state, such as the WA Utilities and Transportation Commission (UTC) or the NM Public Regulation Commission (PRC). However, for simplicity we generically refer to these entities as PUC through the document.

[13] It is important to note that the interpretation of interview responses is based on our best assessment of how generalizable a given argument, insight, or issue is. The open-ended nature of the questions leads to answers being elicited as conversation develops, with responses often departing from the original question. These types of responses result in some answers being specific to a particular LSE (or PUC), and other responses being applicable to a broader set of organizations. For example, if staff made a comment about renewable energy penetration within their specific context, we report this finding as potentially applicable to other LSEs that are experiencing similar levels and types of renewable energy adoption, even if not explicitly mentioned.

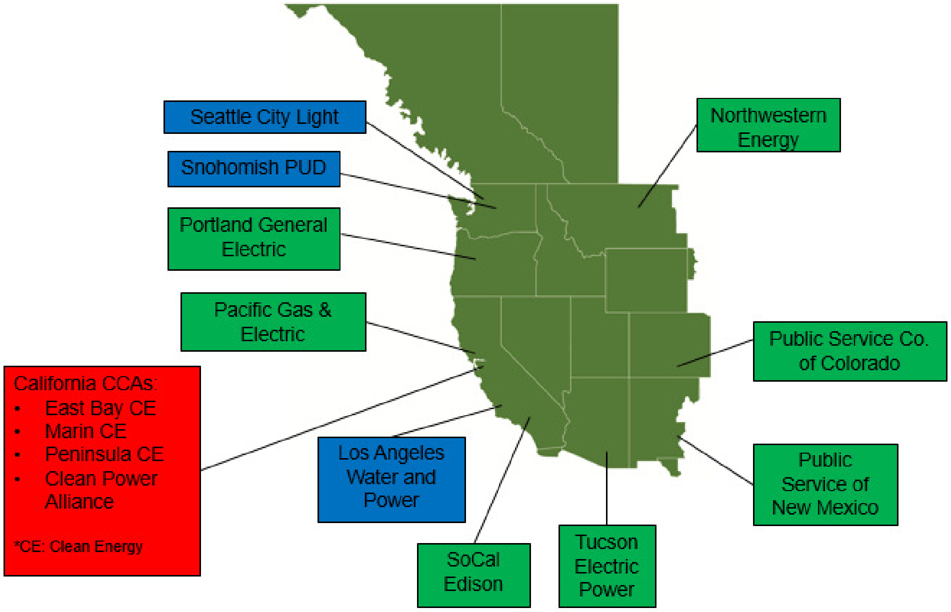

Figure 1. LSEs and jurisdictions interviewed for this study

3. Findings

3.1. Trends in market purchases and the own versus buy decision

LSEs choice regarding owned or purchased resources—in order to meet load obligations—often varies over time. One important driver for this variation may be the range of different regulatory and business incentives that LSEs face, which can be represented by ownership structures—investor-owned, public, or cooperative. The EIA data distinguish among municipalities (Muni), distribution cooperatives (DistCoop), generation and transmission cooperatives (G&TCoops), and investor-owned utilities (IOU) across all non-restructured states[14] in the U.S. G&T cooperatives are owned by distribution cooperatives and provide wholesale power to them, either by generating or by purchasing it. Vertically-integrated IOUs generate power using owned assets and purchase it on wholesale markets, and distribute it to customers within their service territories. Cooperatives and municipalities are not-for-profit entities, while IOUs are regulated, for-profit companies.

Another important driver of the balance between owned and purchased resources may be resource adequacy. In regions with no regional transmission operators (RTO) or independent system operators (ISO), selected load serving entities have the obligation to balance load and resources in real time to maintain reliability of the system. This obligation makes the LSE a "balancing area authority" or BAA. The EIA data reports the BAA for each LSE, which we use to identify LSEs that are providing balancing services from the ones that do not.

[14] We interpret restructured as in limiting vertical integration of generation and distribution assets. States included in this specific analysis include: CA, OR, WA, ID, MT, NV, CO, AZ, NM, UT, WI, GA, KY, MS, KS, FL, LA, TN, MI, IL, VA, IA, IN, MN, MO, ND, WY, AL, AR, NE, NC, SC, OK, and SD. The remaining restructured states are not included, because LSEs in these states do not own generation assets.

The median share of total electricity procured through market purchases for retail customers by these different types of entities and balancing area obligation are shown in vertical bars Figure 2, for all years with available data (1990-2016)[15]. Municipalities and distribution cooperatives that do not have balancing area obligations procure essentially all their electricity needs through market transactions. Trends show that the median share of energy procured through market purchases by G&T cooperatives with no balancing area obligation increased from about 50% in 1990 to close to 75% in recent years, and appears to be stabilizing around that value. It has consistently exceeded the median share for IOUs with no balancing area obligation, which increased from 1990 to 2008 (the onset of recession), and then decreased to early 2000s levels remaining stable at around 40%.

The mix between owned generation and purchases is significantly different for LSEs that have balancing area obligations (top row, Figure 2). G&T cooperatives, municipalities, and distribution companies have decreased the fraction of their procurement coming from market purchases from 40%-50% in the early 1990s to around 25% in recent years. IOUs doubled their market procurement with the advent of deregulation in the late 1990s, but since the mid-2000s have systematically reduced the share of market purchases to a similar level than the other entity types. Overall, all entities that have balancing area obligation show a remarkably consistent share of procurement from market purchases in the last decade.

The fact that BAA entities have similar market purchases preferences suggest that the reliability obligation may be a strong driver for resource ownership. For IOUs, reliability obligations may be potentially stronger than their motive to earn a rate of return on the resources. Indeed, the higher overall relative share of market transactions by G&T Coops compared to IOUs is likely related to basic business model differences. In contrast to IOUs, G&T Coops do not earn a rate-of-return on owned assets. It follows that these cooperatives do not have a profit incentive to own assets as IOUs may have. However, this procurement preference vanishes for BAA. Evidence from our interviews suggests that BAA operators do place a premium on owned resources over purchased resources for reliability purposes, which may explain the lower share of market purchases compared to non-BAA.

[15] We considered calculating the share of load met through these resources. However, it is not possible to identify what portion of self-generation or wholesale purchases is used to serve native load or to be sold in the wholesale market. We also calculated net purchases (wholesale purchases minus wholesale sales) and verified that the trends in Figure 2 are unchanged. Average sample size is 50 G&T cooperatives, 100 IOUs, and 2300 Municipalities and Distribution cooperatives for non-BAA BAA sample size is much smaller (2 G&T cooperatives, 10 IOUs, and 6 municipalities); their results may not be representative.

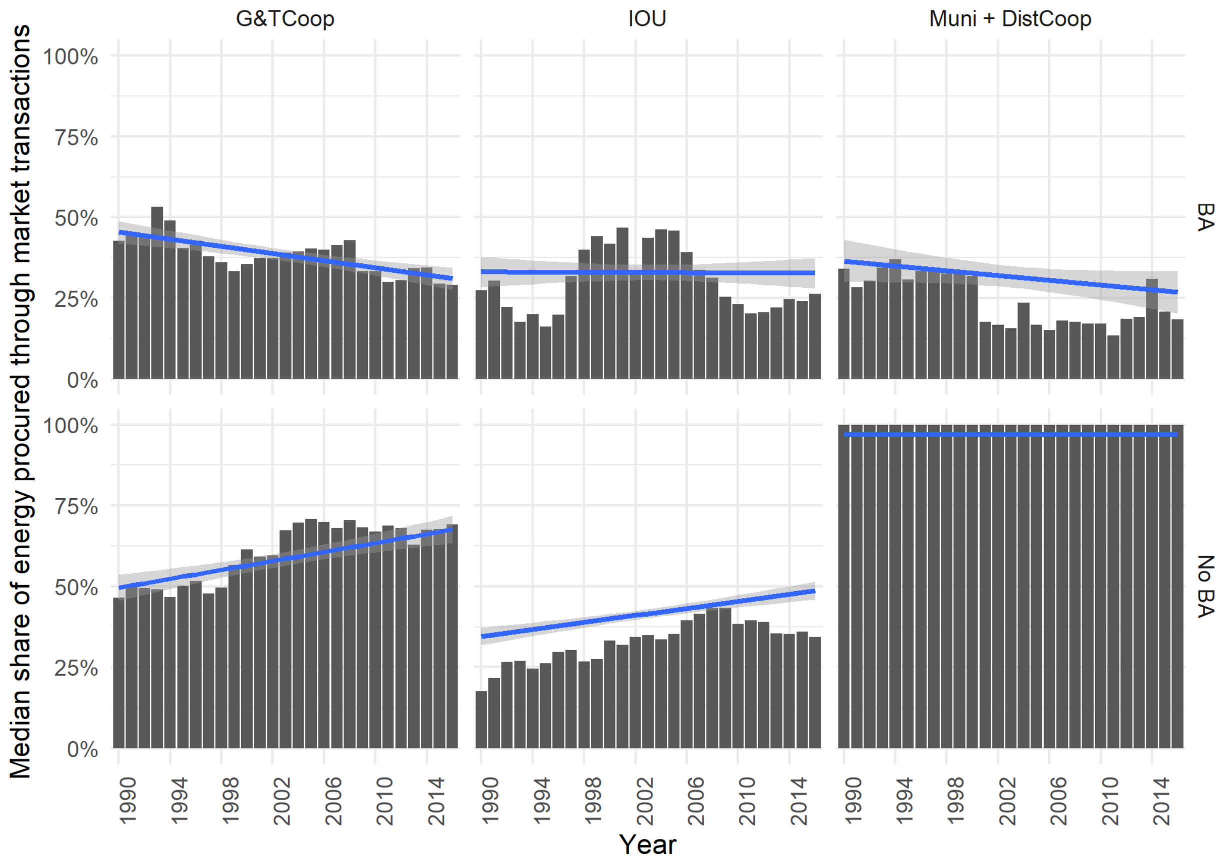

Figure 2. Median share of energy procured through market transactions by entity type and balancing area responsibility

Increasing reliance on market purchases by non-BAA IOUs until 2008 could be due to their joining newly-developed markets organized by RTOs and ISOs. Interviewees point that access to liquid markets with lower transaction costs has enabled a higher volume of transactions for many LSEs across non-restructured states.

Interviews suggest that increased reliance on market purchases in recent years is particularly true for Western U.S. IOUs joining the California ISO energy imbalance market (EIM). This increased reliance may be driven by a growing number of renewable energy PPAs signed to comply with renewable portfolio standard (RPS) targets. Most interview respondents confirmed that meeting RPS targets with contracted resources had been increasing their overall share of market based procurement.

This quantitative analysis of owned and purchased resources informed a discussion of generation asset ownership in our interviews. Regulatory and utility staff reported that the balance between owned and purchased resources depends in large part on historical procurement practices as opposed to strategic (or opportunistic) decision-making processes.

Interviewees generally indicated that there is little interest in revisiting the existing balance of owned and market-based resources. There are several reasons for this lack of interest. First, there is very little actual building of owned resources by LSEs due to stagnant load growth. Second, in many of the states we studied, RPS requirements are driving resource acquisition decisions and LSEs are often unable to claim production and/or investment tax credits for these types of resources. For this reason, many renewable resources are built and operated by IPPs that can claim those benefits. LSEs subject to RPS requirements then sign PPAs with these developers, which generally leads to LSEs having access to more energy than they need. This is one of the main drivers of reduced ownership trends. Third, PPAs reduce or eliminate the price risk for the contracting IOU; regulators interviewed reported being less likely to approve asset building and ownership when a risk-less alternative like a PPA is available.

Finally, retirement of older baseload plants creates an energy gap that these renewable resources fill, which prevents the need to install new owned capacity once these resources are retired. In contrast to these trends for contracting, all PUC staff interviewed acknowledged that regulated LSEs still have a rate-basing incentive to own assets and maintain or increase rates of return. Not surprisingly, one LSE expressed concern that replacing owned assets that are being retired with long-term contracts would erode their rate base. This LSE is proposing to its regulator that a minimum share of that replacement should be fulfilled with owned, renewable resources.

In addition to the rate-basing incentive, several LSEs expressed a preference towards owning assets from an operational and planning standpoint. Wholesale power traders at different LSEs suggested that balancing load using day- and hour-ahead and real-time purchases was more effective and less uncertain when they had full control over the dispatchable resource, which typically occurs with owned assets.

One LSE commented that the option value of owning a resource is not internalized in planning or procurement assessments, but was tangible in their day-to-day operations when compared to contracted resources. Renewable energy adoption is causing higher levels of net load volatility that is balanced with increasing levels of real-time transactions. Most LSEs reported being affected by this increase in net volatility, which suggests that the neglected option value of owned resources is indeed a generalizable concern.

Another LSE reported an example of valuing asset ownership for planning because it provided full certainty of location and transmission access. This certainty not only makes planning easier, but also more robust, as it is less dependent on system topology and transmission allocation decisions that are out of the LSE's control. This consideration may also apply to other LSEs whose bulk power system planning processes are less complex when resource location and quality are known beforehand. Finally, about half the LSEs interviewed reported that ownership of firm capacity has traditionally been a conservative strategy to secure resource adequacy that most regulators tacitly approved. This is consistent with historical procurement practices developed in the 1980s where there was little IPP participation and approved by PUCs in the wake of the California electricity crisis of the early 2000s.[16]

The EIA data disaggregate procurement into owned generation and purchases for energy consumption, but there is no disaggregation for peak demand. Tracking peak demand procurement decisions has important consequences to assess resource adequacy costs and risks. Unfortunately, there is no publicly-available database that records the mix of resources employed by LSEs during their peak load hours or across their highest load hours in a year. For this reason, we asked interviewees about the share of peak demand met with short-term market purchases in 2017. Participants responded that, on average, the share

[16] LSEs that were holding short positions during the California crisis were significantly impacted by price volatility, leading, in some cases, to bankruptcy. Some states responded by demanding that LSEs demonstrate that they owned firm power to meet their peak demand obligations.

of STMP in the peak demand mix is 5 to 10 times higher than for the energy mix[17] (see Table 2). This finding is generally due to the fact that all LSEs reported actively using STMP to improve their economic operation by purchasing in the day-ahead, hour-ahead, and real-time (i.e., spot) markets whenever it was more cost-effective than dispatching their peaking resources. It follows that the likelihood of meeting a larger share of peak demand with STMP on the few high net load hours of the year is much higher than meeting a larger share of energy consumption with those types of purchases.

Table 2. Share of energy and peak demand met with short-term market purchases.

Entity	Share of energy met with STMP	Share of peak demand met with STMP
CCA 1	100%	100%
CCA 2	35%	Over 40%
CCA 3	100%	100%
CCA 4	Confidential	Confidential
IOU 1	12%	17%
IOU 2	0%	5%
IOU 3	Confidential	Confidential
IOU 4	20%-40%	90%
IOU 5	Under 5%	Over 10%
IOU 6	5%	16%
IOU 7	0-50%[1]	20%
POU 1	1%-2%	10%-20%
POU 2	5%	10%-25%
POU 3	1-3%	0%

[1] The actual number is known, but confidential; the IOU provided a broad reference range

The use of STMP to improve economic efficiency is widespread because it improves utilities' operational costs and more importantly because, in many cases, it is promoted by regulatory frameworks that demand LSEs take actions to minimize fuel costs to customers. Utilities are typically required to pass these savings along to their customers. We learned that Colorado was the only state to provide an incentive to its LSEs to maximize these savings by allowing them to keep a share. A potential consequence of this behavior is inefficient investment in owned peak capacity that is available and rate-based, but not used to meet peak demand. When asked about this, most interviewees responded that meeting resource adequacy requirements for reliability purposes had a higher priority than minimizing the costs of underutilized assets borne by rate-payers. However, responses suggest that this equilibrium of balancing transactions and investments in firm resources is not the result of any specific long-term analysis. The practice of substituting peaking generation with STMP when economically and technically feasible raises the question of whether the use of STMP could potentially delay or avoid certain investments. We explore this question in Section 3.4, which features a discussion of planning issues.

[17] Out of 14 responding LSEs, 7 indicated the share of STMP in their mix to serve peak load was significantly higher than the share to serve energy. One LSE declined to provide these values due to sensitivity of the information.

3.2. The balance between short- and long-term transactions

Trends in short- and long-term market purchases

This section examines historical trends for the balance between short- and long-term market purchases in non-restructured and restructured states[18]. For analytical purposes, market transactions are reported to FERC and EIA based on their term and whether they are firm or non-firm contracts. As previously noted, we follow FERC Form 1 definitions for long-, intermediate-, and short-term in our analysis. We include intermediate-term and requirements service transactions in the long-term category to simplify visualization of the data. Finally, we show results split into Western, Eastern+Texas, and remaining states to capture the effect that market restructuring policies—largely implemented in Eastern states and Texas—may have in the purchase balance as suggested during the interviews.

The results are shown in Figure 3. The split between the Western and non-Western regions of the country reveals a stark difference in the use of short-term and non-firm resources by IOUs. Western IOUs significantly increased the share of short-term market transactions from the early 1990s to the peak of restructuring in the early 2000s, before the California energy crisis. This increase in share of STMP was balanced by reductions in long-term transactions, rather than other non-firm transactions. From the early 2000s, the share of STMP decreased from 60% to about 25% by 2008 and remained stable, while long-term purchases share grew to around 50% of total market activity. In contrast, non-Western IOUs have historically relied very little on STMP[19]. In any case, non-Western IOUs rely much less on long-term transactions, which make about 25%-30% of their market activity since restructuring. The high reliance of non-Western IOUs on non-firm transactions may reflect the role that RTOs have played to clear short-term imbalances that use these types of transactions. In contrast to IOUs, cooperatives and municipalities use almost no STMP in their market procurement[20]. This is consistent with views reported in our interviews by POUs, which are managed very conservatively and hence minimize the market exposure produced by short-term transactions.

A detailed explanation of long-term transaction trends is beyond the scope of this paper. However, interviews revealed that retirement of baseload capacity is making it more difficult to firm up long-term market transactions. The difficulty to back long-term commitments may lead to substitution using STMPs. We did ask interviewees about the reasons that may explain trends in STMPs, which we discuss in the following section.

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[18] Restructured is applied to states that limit joint ownership of generation and distribution assets (vertical integration).

[19] This assessment is contingent on whether non-firm transactions—that make up between 40% and 60% of non-Western IOUs market activity—should be classified as short-term transactions.

[20] The extended use of "other" types of market transactions for some entities warrants discussion. In FERC Form 1, "other" is defined as "services which cannot be placed in one of the categories above, such as non-firm services regardless of the length of the contract & service from designated units of less than one year". While STMP could be part of this category, anecdotal evidence from municipal procurement activities suggests that most of the "other" transactions may be non-firm, long-term type contracts with a federal entity such as the Bonneville Power Administration. This interpretation of "other" is consistent with the G&T Coops share of long-term transactions in recent years. It is possible that the classification criteria changed and contracts that were reported as "other" began to fall under the "long-term" category around 2001.

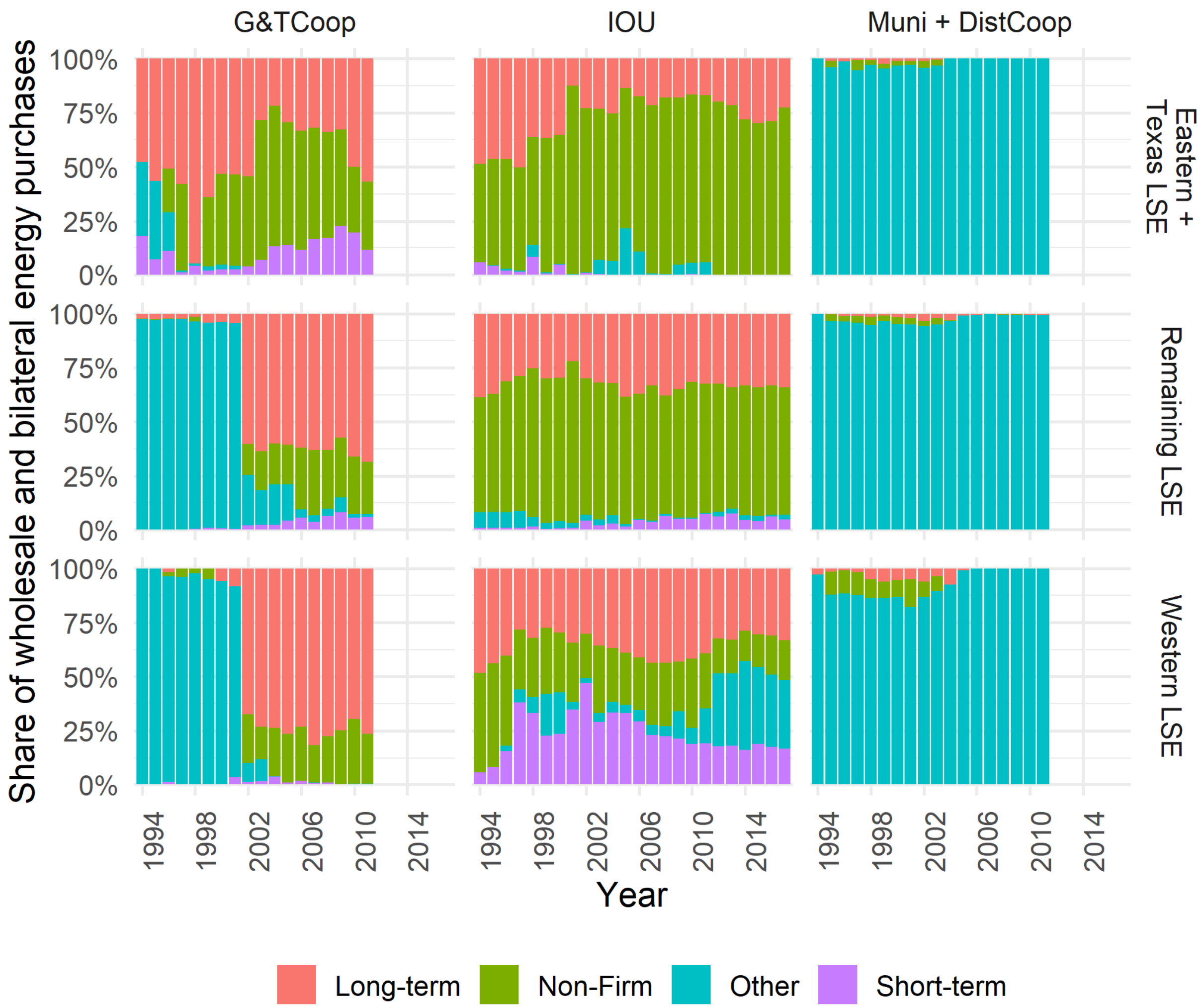

Figure 3. Market purchases split by type and region, based on historical EIA data.

The historical and current use of short-term market purchases

The LSEs that are currently using STMP were asked about the purposes of these transactions (see Figure 4). The main use for short-term purchases is to improve the economic operation by substituting dispatch of own resources with more cost-effective market transactions on the day- and hour-ahead markets, as well as the real-time market wherever possible. In many cases, utilities are mandated to perform this operation, and PUC staff confirmed that there are mechanisms to verify the prudency of these transactions ex-post.

Resource adequacy is the second main application of STMP as a procurement strategy for LSEs that have a capacity deficit. For example, the MT PSC suggested that LSEs under their purview were using a “wait and see” strategy as a response to heightened regulatory uncertainty. Montana repealed restructuring in 2007 and the regulator is still pondering the appropriate levels of asset ownership and contracting. LSEs are using STMP in markets that have excess capacity to avoid building plants that may be challenging to rate base in the future. Fewer than half the LSEs reported using STMP for hedging purposes, although this figure drops to about 20% if CCAs are not included. LSEs with hydropower assets tend to use STMP to optimize the use of their water and hedge against losses. However, most LSEs reported that a significant share of their hedging activities were focused on electricity and natural gas price hedging. They reported using long-term contracts to lock prices for the former, and natural gas forward and option contracts for the latter[21].

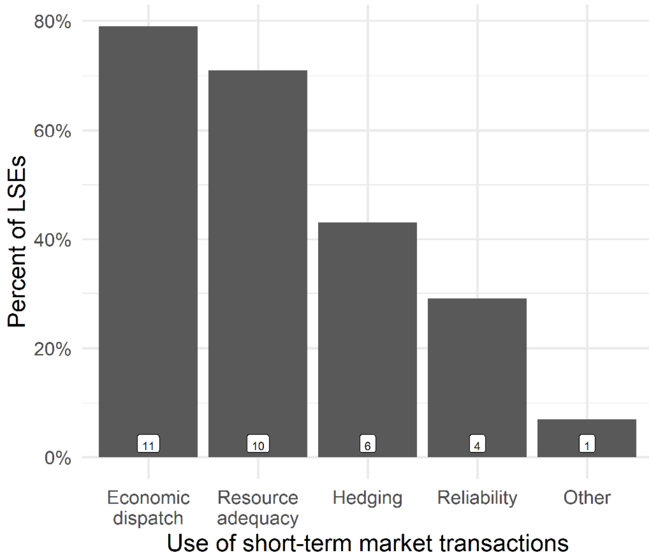

Figure 4. Use of short-term market transactions by LSEs interviewed.

In our interviews, about half the LSEs reported that their use of STMP in the last decade had increased; a third-to-half reported that it decreased; and the remaining reported that it fluctuated, with an uncertain net outcome.

- Increased use of STMP: Several LSEs reported that joining organized markets—such as the EIM—had or is having the effect of increasing market transactions, especially by using ancillary services like ramping in sub-hourly transactions.
- Reduced used of STMP: The main causes for reduction are also related to increase of renewable energy adoption (see subsection 3.3). Interviewees mentioned that the spread reduction between natural gas and coal prices is leading to fewer opportunities for arbitrage, which in turn has limited the need for market transactions to perform this arbitrage function. This decreasing spread is the result of general reductions in natural gas prices and the inclusion of a carbon adder for CA utilities. Finally, in some cases, operational limitations of STMP used for sub-hourly balancing are leading to procurement of owned generation which is displacing market transactions.

High penetration of renewable resources is the main source of variation in STMP use among LSEs, alas with different effects depending on the context. Given its complexity and relevance, the relationship is explored in section 3.3 below.

[21] However, as a reviewer pointed out, currently available long-term contracts are not perfect hedges and require additional financial instruments to curtail risk exposure.

Balancing short- and long-term market transactions

The balance between short- and long-term transactions can have important consequences for risk outcomes. As with owned resources, entering long-term contracts ensures the LSE a stable price at the expense of reducing the flexibility to adapt a portfolio to ongoing market changes or to respond to structural changes in the market. None of the IOUs interviewed followed a methodology to balance long- and short-term transactions either from a cost or a risk perspective.

There are several reasons reported for the lack of balance. First, Western IOU procurement in the past decade has been largely driven by PPAs signed for RPS compliance and not as the outcome of a specific procurement strategy. Second, regulated IOUs can pass contracted costs to customers and effectively share at least part of the risk of long-term liabilities that have been approved by their regulators. Finally, IOUs reported using long-term contracts for planning purposes and short-term purchases for operational purposes. This separation prevents any assessment of their balance. Interviewees were asked if there was any assessment of the impact that short-term procurement decisions had in long-term contracts and investment. Most LSEs interviewed considered this relationship a part of the planning process (see section 3.4). However, three traders confirmed that there is no formalized feedback between the trading floor operations and the long-term planning process. They expressed concern that the modeling of market transactions in IRP did not accurately reflect the challenges of balancing the system on a real-time basis and the resource required for it.

Community choice aggregators

The California CCAs that were interviewed are very concerned about, and are actively managing, the balance between their long- and short-term procurement decisions. The newest CCAs in our sample are procuring almost exclusively on a short-term basis, because they lack appropriate credit ratings and history to sign longer-term contracts. Experienced CCAs are aware of potential changes in the market—including deliberations around the Power Charge Indifference Adjustment[22] mechanism—and place a premium on short-term transactions that give them flexibility to address these changes. CCAs reported being especially concerned about handling departing load and not wanting to be caught with long-term obligations that would be unnecessary if their medium-term load projections were too high. They highlighted IOUs' reliance on rate recovery to transfer the risk of excessive resource contracting to consumers, something CCAs cannot do.

Future STMP use for CCAs should be evaluated separately given their unique condition of not owning generation and nascence. All CCAs were aiming to reduce their current reliance on STMP, largely because of the mandate in SB 350[23] to meet their RPS targets with 65% of long-term contracts by 2021. Even then, all CCAs mentioned expecting to maintain at least 30%-35% of their purchases coming from short-term transactions as a hedge against customer departure.

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[22] This mechanism is designed to compensate IOUs in such a way that their customers' bill will not increase due to a reduced customer base.

[23] Senate Bill 350 established aggressive greenhouse gas reduction goals for the energy and transportation sectors in California.

3.3. Renewable resource and market transactions

As noted above, the penetration of variable renewable energy (VRE) is having an increasing influence on utilities' use of short-term transactions. To explore this topic further, we first examine the empirical relationship between VRE adoption and STMP by comparing historical procurement of both resources by IOUs over a seventeen year period (2000-2016)[24]. We limited the analysis to IOUs, because POUs are generally not subject to RPS requirements and hence are not necessarily procuring higher amounts of VRE due to this policy. However, even among IOUs, the regulatory environment can influence the decisions LSEs make to balance their variable renewable resources. Accordingly, we use information on restructured LSEs operating in the Reliability First Corporation (RFC)[25], which covers thirteen states in the Eastern Interconnection (EI)—as well as the District of Columbia—to compare against Western U.S. LSEs (see map of NERC regions in Appendix 6.4). Results are shown in Figure 5.

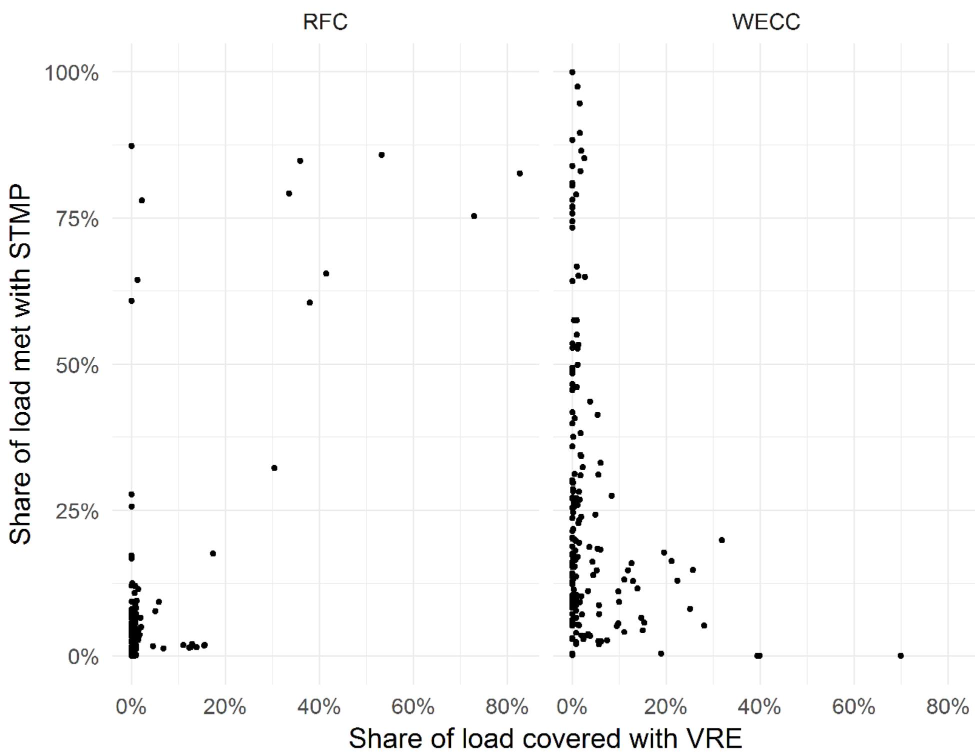

Figure 5. Share of load met with STMP versus share of load met with VRE

As shown in the above figure, at low levels of VRE penetration, STMP use varies much more in the WECC region (from zero to almost one-hundred percent) than in the RFC region (from zero to about twenty-five percent). Higher levels of VRE are also associated with lower use of STMP in the WECC, while the opposite is true in the RFC. This may suggest that STMP is being used to balance and integrate

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24 See Appendix 6.2 for a discussion of the method used to estimate VRE adoption by LSE.

25 The RFC offers a good point of comparison, because its IOUs operate in restructured states and face a different set of incentives compared to WECC IOUs. One of the main differences is that most IOUs in the WECC are vertically-integrated, whereas in the RFC IOUs own little or no generation and rely more extensively on market transactions due to restructuring.

VRE in the RFC[26] and also that in the WECC STMP are being displaced by the energy supplied through VRE resources.

Interviewees indicate a complex relationship between renewable energy adoption and market transactions. There are several effects of VRE resources on market transactions whose direction depends on the local context. The relative balance of these effects may have important consequences for market development in regions that are having or expect to have higher levels of VRE penetration.

First, for some Western LSEs, a higher presence of VRE—particularly wind—is causing more uncertain net load (i.e. load minus VRE capacity) and hence higher forecast error in day- and hour-ahead transactions, which in turn results in an increased need for balancing. In some cases, STMP are being used for this purpose when their costs are less than those of dispatchable peaking capacity (e.g., simple-cycle natural gas-fired combustion turbines). It should be noted that while higher adoption of renewables is leading to increased levels of balancing market transactions, there is a threshold over which LSEs will prefer other balancing methods that are less risky. For example, one Midwestern LSE managing substantial levels of wind generation reported that heightened levels of STMP were reaching their internal thresholds for short-term supply deficits and forcing a need for peaking capacity. In other cases, LSEs that cover energy needs using STMP were reporting less use of them as VRE adoption through mandatory RPS translated into more procured energy from these resources. This increase in available energy reduced the need for market purchases.

Alternatively, higher VRE procurement with near-zero marginal cost, depresses market prices and can make wholesale market purchases relatively cost-effective. We find that LSEs that had access to markets with large solar penetration were increasing mid-day purchases when wholesale market prices were close to $0/MWh (or even negative). The net result of the balance between lower purchases (due to excess energy) and higher purchases (due to lower prices) is unclear.

Another driver for wholesale market transactions is transmission congestion. LSEs that do not belong to an RTO reported that their ability to procure energy through STMP depended on the availability of transmission capacity. Many of the LSEs that we studied are subject to RPS requirements, which are mostly being fulfilled by PPAs. In most cases, these PPAs are based on resources located in remote areas where access to transmission lines is prioritized over non-PPA resources. It follows that higher penetration of VRE has been crowding out STMP by employing increasing portions of available transmission capacity, constraining the ability of physical delivery of short-term market transactions.

Finally, two LSEs whose areas of operation have substantial PV deployment reported that standard market products designed for traditional peak or off-peak hours were becoming less useful with the effect that PV had on net load. The "duck curve"[27] effect is making the shoulder hours (i.e., 4 to 6pm) particularly desirable for LSEs that need to replace substantial blocks of PV energy. However, the duration and timing of existing products has not evolved to capture these new needs. One LSE reported that bilateral transactions were even more problematic for LSEs whose neighbors may have different shoulder hours due to reduced presence of solar PV resources. These various effects are illustrated in Table 3.

[26] It is also possible that VRE is procured through short-term transactions in the RFC, which would mean that as VRE adoption increases so does STMP procurement.

[27] The duck curve or duck chart refers to the shape of a daily net load curve with very high solar penetration, which causes a depression in the middle of the day and a rapid increase in load when the sun sets (CAISO, 2016)

Table 3. Relationship between variable renewable energy and STMP

Effect on STMP	VRE Effect
⬆	Balancing needs due to larger forecast error in hour- and day-ahead purchases
⬇	LSE has excess energy with additional energy from RPS purchases
⬆	Price depression in high penetration hours creates incentives to purchase on the market
⬇	Transmission congestion due to out-of-area renewable imports for RPS reduces space for bilateral transactions
⬇	New net load profiles making standard “block and slice” products less useful

3.4. Planning for market purchases

The role of integrated resource planning in utilities’ forward assessments of their potential needs for market purchases was previously mentioned. In this section, a sample of recent IRP documents from vertically-integrated utilities across the Western U.S. is reviewed to understand how market transactions are considered in the resource planning process. Results are organized around four different topics: (1) regulation; (2) market assessment; (3) treatment of transactions in portfolio analysis; and (4) risk management of market transactions. Since IRPs are publicly-available, we identify specific LSEs in this analysis, in contrast to masked reporting of interviews conducted with individual utility staff.

In addition, the evolution of projected market transactions from preferred portfolios uploaded to LBNL’s Resource Planning Portal is studied. In this case, results are reported for all LSEs that had at least two IRPs—separated for more than five years—uploaded to the Resource Planning Portal.

3.4.1. Planned market purchases

By design, IRPs generally do not identify ownership of the resources in hypothetical portfolios that are quantitatively developed and analyzed in the IRP process; resources are differentiated only by their technology and fuel type. However, some LSEs do report planned long-term contracts (PPAs or tolling agreements) and other market transactions in their IRPs, usually identifying the fuel or resource type. For this analysis, we classify contracted resources codified as “electricity” and “unknown” as short-term purchases, under the assumption that PPAs are signed with specific developers whose resource is well known. Note that IRPs generally do not report expected day- and hour-ahead purchases as part of their preferred portfolios. To make results comparable, the median share of peak demand that was met by market transactions is calculated and reported (Figure 6).

LSEs were found to have substantially increased their projections for the use of long-term transactions in recent IRPs compared to older plans. The expected median share of peak demand met with long-term resources increased from the 0%-10% range to about 15%. Furthermore, projections for long-term purchases in older IRPs were 0% five years ahead, whereas in recent years all LSEs are projecting around 10% of their needs being met with these resources. As reported in the interviews, the most likely reason for this change is the increasing reliance on PPAs to meet RPS targets with renewable energy, some of which has capacity credit. The fact that these contracts remain part of the planned resources through the whole planning horizon may reflect a definitive decision or trend from LSEs to effectively meet RPS targets with contracted resources and a trust in the quality of these resources.

Forecasted short-term purchases behave quite differently, following a pattern of much reduced activity in recent plans. In older plans, LSEs were planning a median share of peak demand met with STMP of about 10%. The share for recent years is actually higher, increasing from 10% to about 20% towards the end of the planning horizon. However, there are considerably fewer LSEs that are planning on using any amount of STMP. For example, there were five times more LSEs reporting the use of STMP in older IRPs compared to recent ones. The number of LSEs reporting reliance on long-term transactions doubled in recent IRPs compared to older ones, which is consistent with our findings for long-term transactions.

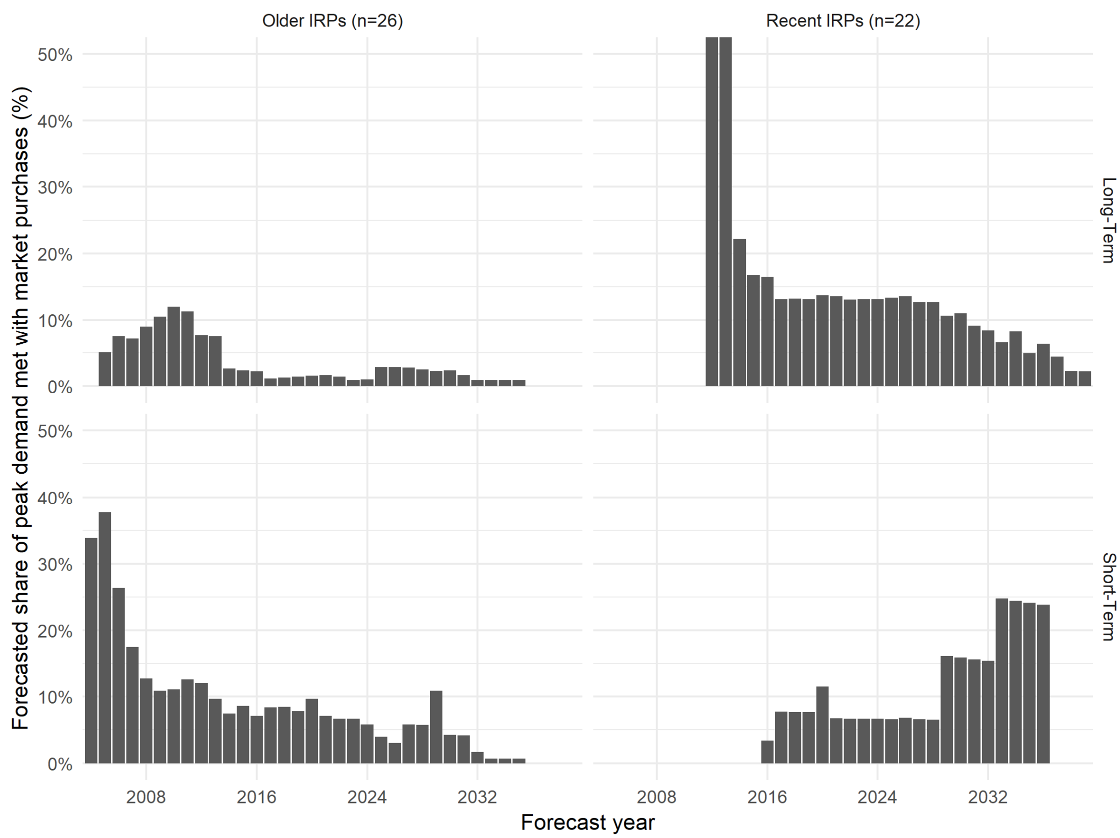

Figure 6. Planned market transactions for older (2003-2007) and recent (2012-2017) IRPs

These results suggest that Western LSEs that file IRPs are expecting to rely more on long-term transactions compared to the past and to substantially reduce the planned use of short-term transactions. These results should be interpreted in the context of the use of STMP reported before. It is very likely that most LSEs will continue to make use of STMP for day- and hour-ahead transactions. However, interviews did reveal that LSEs are expected to reduce their reliance on STMP to meet capacity positions and for hedging, as they are planning to use long-term resources for that. These insights from the interviews are consistent with the quantitative resource balancing reported in recent IRPs.

3.4.2. Treatment of market transactions in IRP

The results reported in the previous section should be interpreted in the context of the planning process and environment, in addition to the valuable information provided by the interviews. It is also important to understand what the processes, restrictions, and conditions are under which LSEs plan for market transactions in their IRPs. We analyzed IRPs for most of the non-CCA LSEs interviewed to understand the treatment of market transactions in the planning process and unearth potential connections to the procurement outcomes of these resources (see Table A.3 in Appendix). Wherever possible, we complement the information from the plans with the responses to question three in the questionnaire. This specific question asks about the connection between short-term purchases and long-term procurement (see Appendix 6.1)

Regulatory elements

A state PUC's IRP regulations typically do not specify how market transactions should be treated when producing and analyzing portfolios.[28] The Oregon PUC has a own versus buy assessment requirement in its planning regulations, and Portland General Electric (PGE) develops a thorough analysis of the benefits and costs of either procurement mode. However, PGE does indicate that the spirit of the IRP is to avoid making ownership decisions within the context of the planning process.

In another example, the Arizona PUC imposes a restriction on its IOUs to prevent them from considering short-term market transactions beyond the first five years of the planning horizon. Even then, Tucson Electric Power restricts identifying STMP as a resource beyond three years into the future, arguing that market conditions are too uncertain beyond that time frame.

Market assessment

All IRPs conduct some sort of market assessment with the basic goal of forecasting wholesale market prices, and in a few cases assessing the resource adequacy (or liquidity) of the real-time market. The sophistication of these assessments in the IRPs studied varies widely. The simplest assessment involved a single LSE using forward wholesale prices from the Intercontinental Exchange escalated by EIA's Annual Energy Outlook wholesale rates. Half the LSEs in our sample base their market assessment on third-party reports, which might include the Northwestern Power and Conservation Council (NWPCC) or the Pacific Northwest Utilities Conference Committee (PNUCC). These LSEs use the information in these reports to create ranges for wholesale price scenario analysis and to gauge how long the region will remain with available excess capacity. About a third of the LSEs—those that rely the most on market transactions—develop regional production cost simulations of the WECC and produce their own wholesale price forecasts.

The LSE in the IRPs for the West examined in the LBNL Resource Planning Portal that relies most on STMP for procurement, Puget Sound Energy (PSE), develops a thorough assessment process that includes tracking NWPCC, PNUCC, and Bonneville Power Administration reports and running a joint capacity expansion and production cost model for WECC. In addition, PSE studies IRPs for other Pacific Northwest IOUs and tracks their expected reliance on market purchases to assess the availability of market transactions in the region. The PSE analysis is the closest to best practice among the sample of

[28] There may be specific regulations in the administrative code that outlines rules and requirements for preparing IRPs, but an in-depth evaluation of these types of documents is beyond the scope of this paper.

LSEs, but it should be noted that it does not consider all possible IPP expansion plans or procurement activities by smaller non-IOU entities. The PSE market assessment could serve as the basis for a thorough, publicly available regional resource adequacy and wholesale market price assessment, possibly conducted by a regional coordinator or other entity.

LSEs study wholesale markets for two primary reasons, which include interest in the:

(1) impact that wholesale market prices may have on their short-term transactions and the potential impact on rates

(2) ability of the market to supply power during peak hours, regardless of the price (i.e., resource adequacy).

In our sample, the majority of LSEs fall into the latter group. This focus on resource adequacy may be explained by the fact that analyses by regional entities (e.g., NWPCC, WECC) are suggesting that some Western regions (e.g., Pacific Northwest) may not have the long-term capacity available to meet customer load.

Treatment of transactions in portfolio mix

Fewer than half of the Western LSEs in our sample treat short-term market transactions as a resource that is equivalent to other technologies in their portfolio analysis. Pacificorp conducts the most thorough characterization of short-term purchases by defining and analyzing three products that differ on duration and timing of day (light, heavy, and super peak load hour products[29]). Pacificorp does indicate that these products are not system balancing transactions.

Two thirds of the LSEs in our sample do not include market transactions in their portfolio, although some of them do to cover small capacity deficits *ex-post*. This is because market transactions are usually treated as being on the margin, which means that they are generally added after the portfolio has been defined. At least two LSEs interviewed commented that their economic models recommend using a higher level of market transactions than what they are willing to actually procure. This explains why some LSEs use exogenous, self-imposed, or regulatory imposed restrictions on the amount of short-term market purchases that they can procure. In some cases, these restrictions affect their planning process, although in practice they are employed in the procurement stage. For example, Snohomish PUD employs a daily limit of 100 MWa and a weekly limit of 200 MWa for its STMP based on a risk tolerance assessment. LSEs, including PSE and Snohomish, also constrain their market transactions based on existing and available transmission capacity.

The varying treatment of market transactions in the resource mix does challenge the idea that IRP—and more generally any power system planning process—can be completely detached from ownership considerations. While this may be closer to true for PPAs, our results have shown that short-term transactions can indeed be a substitute for peaking capacity. This finding would support incorporating STMP as a potential resource for portfolio analysis. Including ownership considerations in planning may also be justified from a risk perspective. We turn then to understand the treatment of risk and uncertainty in market transactions among the LSEs in our sample.

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[29] These are standard definitions employed by Bonneville Power Administration (and possibly others) to characterize their transactions. For example, see https://www.bpa.gov/news/pubs/Pages/Definitions---L.aspx.

Risk and uncertainty treatment as it relates to market transactions

As stated through interviews, market transactions have a distinct risk profile compared to ownership of resources. However, the risk analysis for market transactions is relatively simple and mostly limited to exposure to potential variations in wholesale prices. Wholesale market transactions are not considered in standard stochastic variable analysis (i.e. statistical modeling techniques that consider randomness) in any of the plans studied. In a few cases, LSEs employ a scenario-based analysis to evaluate the impact of wholesale price variation, but these analyses do not generally lead to any significant changes in the preferred portfolio of resources. More generally, the typical risk management discussion around market transactions is qualitative, labeling the market as “risky” and lacking a thorough quantitative analysis of the impacts of more or less reliance on the market in costs and reliability.

In addition to the risk assessment, the planning process does not seem to consider the costs of hedging in the least-cost evaluation employed to produce preferred portfolios. This means that if a certain resource produces a risk level that is mitigated through more expensive hedging products, this cost is not incorporated in the analysis. It follows that the volume and impact of this cost in the preferred resource is unknown.

4. Discussion and conclusion

This paper presents an empirical analysis of procurement practices for Western U.S. electric utilities with an emphasis on wholesale market transactions. We employ a mixed-methods approach combining analysis of quantitative procurement data with qualitative assessments of IRP documents and structured, phone-based interviews with regulatory and utility staff.

Use of market transactions to meet electric energy needs is increasing across U.S. LSEs, whatever the region or whether the LSE is vertically integrated or not, in an RTO/ISO or not. The reasons for this trend include a general stagnation in building owned resources, a preference towards contracting renewable energy resources to meet RPS targets, and the lower relative cost of wholesale market electricity. Among market transactions across different time scales, short-term transactions were prevalent in Western U.S. LSEs until the 2008 recession, and thereafter declined to about a quarter of total purchases. In contrast, long-term market transactions have become more prevalent and resource planning reports project the share of these transactions in the procurement mix may continue to increase.

Interviews revealed that the main purposes of short-term market transactions are to improve economic operation of the power system and to meet resource adequacy requirement. However, neither of these is adequately represented in resource planning processes.

Consequently, new resource planning practices focused on assessing the costs and risks of increased reliance on market transactions for economic efficiency and resource adequacy are suggested. These transactions could be used to meet resource adequacy requirements at costs that may be lower than other owned resources, but it is unclear what the risks of using this procurement strategy are. There is a need to develop regional-level resource adequacy assessments that properly account for market transactions and that can be used in resource planning. Finally, preferred portfolios could be structured differently if the operational cost and benefits of owned versus contracted resources was recognized in the modeling process.

Increased penetration of VRE can decrease or increase the use of STMP depending on LSE characteristics and regulatory environments. Interviews indeed suggest that larger net load forecast error and lower real-time prices due to higher VRE penetration are driving up the use of STMP by some entities.

Conversely, excess energy from RPS compliance, transmission congestion, and changes in net load profiles are decreasing the use of STMP in some cases. Increase in VRE penetration correlates with lower procurement through STMP in the WECC, but higher procurement of STMP in restructured states. This may be explained by differences in how STMP can be used to meet resource adequacy targets and also by the prevalence of day-ahead and balancing markets in restructured states compared to the WECC.

Expected future use of STMP for the IOUs and POUs interviewed depends largely on exogenous issues, rather than internal decisions. Interviewees indicated that technological changes such as widespread battery storage adoption would lead to reduced short-term market transactions, as balancing of net load would be performed using this technology. This presumes that storage would be owned by the LSEs, which was implicit in the answers of at least two interviewees who reported batteries would play an important role in the near future.

Policy changes such as environmental regulation of greenhouse gas emissions would have a dual effect. On the one hand, it may lead to higher prices and reduced opportunities for cost-effective transactions. On the other, it would reduce available firm capacity, which some LSEs may want to purchase in the market. An analysis of projections included in selected IRP reports shows that LSEs are expecting to increase the share of long-term contracts, but reduce the use of short-term market transactions in the near term.

The analysis presented in this paper has several data limitations.

First, the “short-term” includes a range of transactions from real-time (i.e., sub-hourly) to weeks- or months-ahead. The operational, risk, and strategic nature of these transactions is fundamentally different, but the quantitative data used in this analysis does not distinguish between them. Second and related, the share of peak demand met with short-term transactions is not available in the quantitative data and our assessment of the role of STMP in resource adequacy is based on a limited sample of interview responses[30]. Third, it was challenging to trace market transactions back to their source in order to identify which purchases actually came from variable renewable resources. There may be other data sources, such as FERC’s Electric Quarterly Reports, that could be employed to improve the identification of these important resources. Finally, there is a possibility that our interview results are biased, considering the small sample size and the fact that LSEs and PUCs self-selected as respondents.

Notwithstanding these considerations, this study is one of the few empirical assessments detailing levels of and uses of market transactions by U.S. electric utilities—especially short-term purchases.

These transactions may play a relevant role in economic efficiency, resource adequacy, and risk management, but regulatory adjustments are required to planning and market institutions to fulfill these

[30] Furthermore, it was common that LSE personnel would not know how much of their peak demand was met with spot market transactions.

promises. The results of this analysis provide initial insights on key issues in electric utility procurement that could improve overall market efficiency, respond to rapidly changing industry conditions, and identify practices that LSEs, regulators, and other stakeholders should consider incorporating into their long-term capacity and transmission planning processes.

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6. Appendix

6.1. Survey questions

The following is the questionnaire was used to conduct interviews with LSEs and PUCs. CCAs were not asked questions #1, 2, 5, 7 and 8.

Organization Name:

Organization Personnel:

Interview Date:

Interviewer Name:

1. *What is the approximate share of (i) energy consumption (MWh) and (ii) peak load (MW) that was served by short-term market transactions in 2017? How has this share changed in the last 10 years?*

2. *What are the main uses of short-term market transactions for [organization]?*

3. *How do you assess the effect of short-term market transactions on long-term investment or contracting decisions in planning and in procurement?*

4. *What are the top three reasons that explain changes in the amount of short-term market purchases actually procured over the last five/ ten/few years?*

5. *What factors might cause increasing or decreasing reliance on short-term market purchases over the next decade?*

6. *[For LSEs that own assets] This question deals with the owning vs buying decision. How have you balanced the amount of resources owned by utilities versus contracted/purchased resources? Do you see the balance between owned and contracted/purchased resources changing over the next decade? If so, what factors may contribute to this change?*

7. *This question deals with contracted resources only. What are the criteria to produce portfolios with a balance of short- vs. long-term market purchases?*

8. *One of the uses of short-term market transactions is for risk hedging. What is the main risk that*

[your utility] [regulators and consumers] face that are fully (or partially) hedged using these short-term market transactions, if any?

9. *Other notes:*

6.2. Method to estimate VRE procurement

Ventyx Datasets

Ventyx provides multiple datasets that contain data on electricity purchases and generation. However, no single dataset is sufficient for understanding the mix of resources and contracts that comprise an LSE's procurement practice. We use the following three datasets to explore the relationship between renewable load and short term contracts in WECC.

- The *Wholesale Power Purchases and Exchanges* (WPP) dataset contains annual transaction summaries between an LSE and its suppliers. For each purchasing LSE and supplier, it provides the annual volume and charges for purchases under various contracts.
- The *Monthly Generation* dataset (MG) describes plant-level generation by fuel type, but no information on purchasers.
- The *Electric Company Account* (ECA) contains details the amount of energy an LSE's purchased and generated, but nothing about what energy source provided the generation or contract details.

Short term purchases

We begin by standardizing the contract types in the WPP dataset in order to examine the exchanges that best represent wholesale spot markets. We consolidate the contract types, which follow FERC Form 1's contract definitions, into either "short-term" or "long-term" (see Table A.1 below). We find that negative purchases occurred throughout the dataset, but that they had no discernable relationship to contract type. We contacted Ventyx, but were offered no additional explanation. These purchases, however, amounted to less than 5% of the absolute value of all purchases, so they were removed from our analysis. Next, we aggregated each LSE's annual purchases by contract type and divided by total purchases to calculate an annual percentage of short-term purchases.

Table A-1. Mapping of FERC transactions types

LBNL Contract Type	Contract Type	FERC Form 1 Definition
Short-term	Short-term firm	Firm services committed for < 1 year
Long-term	Intermediate-term firm	Firm services committed for 1-5 years
	Long-term firm	Firm services committed for 5+ years, limitations on interruptions
	Designated Intermediate-term	Service committed for 1-5 years and availability and reliability required to match that of designated unit
	Designated long-term	Service committed for 5+ years and availability and reliability required to match that of designated unit
	Requirements Service	Service is on-going. Strict reliability requirements

Renewable energy

For a given LSE, we estimate the amount of procured renewable energy as a share of load served. Since an LSE may generate and purchase the energy it eventually sells to its customers, we needed to estimate both renewable generation and renewable purchases. We begin the estimation of renewable purchases with the WPP dataset, which records the supplier and contract types for an LSE's purchases. The dataset does not detail the type of energy procured, so we estimated the generation mix for each energy-selling LSE and apply it to the purchases.

We derive annual fuel shares for each generator in the United States from Ventyx's *Monthly Generation* dataset (MG). We assign each generator to one of three categories: (1) fossil; (2) variable renewable; or (3) other. We restrict the variable renewable classification to wind and solar and assign additional, baseload-like renewable sources such as biomass and geothermal energy to the other category. For each generating utility, we develop an annual generation profile by aggregating the output of all of its generators by fuel and dividing by total generation. We then take these annual generation fuel profiles and multiply them by the purchases in the WPP data to estimate the amount of each fuel in each purchase. Next, we aggregate all of an LSE's purchases by fuel to arrive at an annual renewable purchase amount for each LSE.

It is important to also consider self-generation. For this component, we use the ECA, which contains annual LSE purchases and self-generation. We apply the same annual generation fuel profile used to estimate renewable purchases to the LSE self-generation in the ECA. We now have renewable self-generation linked to the ECA dataset and renewable purchases linked to the WPP dataset. Next, we merge these two datasets by LSE and year to estimate annual renewable energy procurement. Finally, we divide this amount by total annual load to calculate annual percentage of load served by variable renewables.

It is important to note that there is a loss in sample size during the merging process, because not all LSEs are available in all years within each dataset (see Table A.2). We also lose sample size when we apply filtering criteria. With the ECA-WPP merge, we found that while both had LSE purchase amounts, they often varied. We, therefore, excluded any LSE whose purchases differed more than 10% from each other.

The standardization of contracts resulted in nearly 700 utilities being dropped due to the presence of contract types outside those in Table A.1. We found that almost all of these utilities were cooperatives, which suggests a systematic difference in how these types of LSEs classify their purchases in FERC Form 1.

Table A-2. Sample size after the merging of the data

Dataset	Number of Companies (2000-2016)
Wholesale Purchase Power and Exchanges (WPP)	1,432
Electric Company Account (ECA)	3,730
Monthly Generation Profile (MG)	4,804
Final dataset after processing	177

6.3. IRP documents analyzed

The following table identifies the IRP reports that were analyzed in Section 3.4 of the manuscript.

Table A-3. IRP reports analyzed in this manuscript

Load Serving Entity	States	Interviewed?	Year
Pacificorp	UT, WY, ID, OR, CA, WA	No	2017
PSE	WA	No	2017
PGE	OR	Yes	2016
Snohomish	WA	Yes	2017
Tucson Electric Power	AZ	Yes	2017
PNM	NM	Yes	2017
Northwestern	MT	Yes	2015
LADWP	CA	Yes	2017
NV Energy	NV	No	2016

6.4. Map of NERC regions