Review of Management's Buy-Through Pricing Proposal

for
Salt River Project Agricultural Improvement and Power District – Board of Directors

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Christensen Associates Energy Consulting, LLC
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EXECUTIVE SUMMARY

SRP's management team has developed a proposed Buy-Through Program that meets all the design criteria identified by the Board regarding the costing, pricing, and statutory requirements for a successful program. Most importantly, the program structure promotes full cost recovery from participants while offering them the opportunity to seek and acquire efficiently priced generation services.

The cost underpinnings of the buy-through design are sound.

- Embedded costs of delivery services are properly classified by cost-causative factor and appear to be allocated according to conventional principles.
- Generation services, where provided by SRP (imbalance and resupply) are based on sensible representations of marginal cost/wholesale market energy price.
- Ancillary services are acceptable in embedded cost form given the lack of reserves markets in the region.

Management's design offers pricing that recovers cost fully and is efficient.

- The design is consistent with the Board's general principles of gradualism, price efficiency, and revenue recovery.
- The design is consistent with sound utility practice and general economic theory:
  - Delivery services are priced based on embedded costs based on established costing methods. In particular, fixed cost recovery does not appear to take place via volumetric (kWh) pricing.
  - Generation services are based on market prices.
- Prices reflect their underlying cost drivers, by subfunction.

Lastly, the program's structure responds fully to the obligations of the legislation.

Management's approach to the key issues of buy-through pricing is largely sound, although we raise questions as to pricing methodology and eligibility/departure requirements.

- **Resource adequacy.** SRP's program provisions limiting scale, requiring detailed GSP vetting, tiered pricing of imbalances and resupply premium pricing all indicate that the program has multiple structures to support SRP being able to deliver generation to all its customers.
- **POLR consideration.** SRP plans to use public price indexes that allow the utility to match revenues from POLR customers to the cost to serve them.
- **Imbalance service charges.** SRP has chosen to settle imbalances with customers (rather than the GSP), using a tiered structure based on the utility's expectation that this will avoid or limit strategic scheduling based on forecasts of market prices relative to contract prices.
  - There might be opposition to the tiered pricing approach, but it appears to provide SRP with a necessary incentive to customers to minimize imbalances. The power to remove someone from the rate for persistent excessive imbalances is reasonable but arguably not sufficient.
  - The Tier 2 markup might be set at a level that makes SRP indifferent between customer imbalance increases and reductions. Observation of behavior early in the program may provide guidance here.
- **GSP Default.** SRP's use of the Palo Verde day-ahead price indexes plus a price premium appears to give customers using resupply service a strong incentive to recontract with a new GSP. The resupply price also gives customers the incentive to give SRP three-years' notice before returning to retail service.
  - There might be opposition to SRP charging a premium for resupply service. However, SRP is entitled to earn a premium in return for offering the service.
  - SRP's preference for Palo Verde appears defensible from both theoretical and operational perspectives.
- **Return to Standard Offerings.** SRP offers a clear path to return. The issue associated with return is the length of advance notice. Three years' notice is based on capacity availability concerns and planning experience. However, this may be conservative, and a policy of allowing a shorter time period in the event of availability may help to improve the attractiveness of the program.
- **Bypass.** The Buy-Through Charge is well documented and the calculations of administrative, reserve capacity and ETAC charges appear sound and defensible. As the program ages, reductions in administrative and ETAC charges should be expected.
- **Responsibilities of Contracting Parties.** SRP's program documents set out parties' responsibilities clearly. Aggregation is not currently feasible but can be considered in the future.
  - Ancillary services will be managed by SRP for sound reasons of lack of market sources. As markets develop, this could change without hurting the program.

Management's design appears to conform to industry practice based on a short list of examples.

- Examples from California and Nevada indicate that there is precedent for SRP's approach to limiting cost shifting.
  - California devised the Power Cost Indifference Adjustment (PCIA) to ensure that the out-of-market costs of energy resources would continue to be billed

to customers who secured power elsewhere. Their methodology does not need to be applied at SRP partly due to the relatively small scale of SRP's cost recovery and partly due to their more comprehensive view of generation value.

    - Nevada developed an impact-fee approach to valuation. Again, it has value as precedent for recovering out-of-market costs, but its methodology appears to be more complex than SRP needs, involving production cost simulations to estimate these costs.
    - FPPAM: it is difficult to find analogies but SRP's approach appears to be consistent with what other utilities do regarding fuel and purchased power costs.
    - ETAC: SRP's approach is simpler than the California and Nevada methodologies. SRP's approach has the advantages of transparency and likely ready acceptance. The possible disadvantage is that the approach does not attempt to evaluate the market value (and hence out-of-market cost) of the whole generation portfolio.

- Several aspects of the SRP design make use of similar design components at Arizona Public Service in its AG-X rate. However, SRP has adopted a different approach in some cases, partly due to differences in underlying rate design and pricing, and partly based on different perceptions about pricing incentives.
    - Both utilities include a reserve capacity charge to ensure that the lost customer loads continue to pay their share of reserve capacity costs, as the host utility is providing that reserve capacity.
    - Both utilities undertake imbalance settlement, but APS settles with the GSPs while SRP has decided to settle with the customers, based on the understanding that customer strategic behavior to minimize their costs can be influenced and reduced by a tiered pricing scheme.

Summary:

SRP management's proposed Buy-Through Program appears to meet the Board's requirements for a successful design: participating customers can contract with GSPs for service without introducing cost shifts to other customers, paying embedded costs for delivery services and market-based prices for generation services from their GSPs and from SRP through imbalance settlement and resupply pricing in the event of contract default. Customers may return to SRP under clear terms. Furthermore, the program appears capable of being scaled up and of responding to changes in wholesale markets, including with respect to alternatives to the provision of ancillary services.

1. INTRODUCTION

The management team of Salt River Project (SRP) has developed a Buy-Through Program that is intended to offer participating customers the opportunity to acquire electric energy from third-party generation service providers (GSPs). This pricing initiative responds to, and intends to fulfill, the requirements of new Arizona legislation with the express purpose of introducing buy-through at agricultural improvement districts in the state. The legislation is A.R.S. § 30-810, and it requires SRP to offer such a program to customers by January 1, 2024. SRP is entitled to specify conditions of service and limitations on eligibility such as minimum customer size and maximum participation. SRP is also required to offer buy-through service in such a way as to maintain system reliability and avoid shifting costs to other nonparticipating customers of the utility.

The Board of Directors of SRP (the Board) engaged Christensen Associates Energy Consulting (CA Energy Consulting) to review management's Buy-Through Program proposal with regard to its ability to meet several criteria. These criteria are:

- Consistency with the Board's retail electricity pricing principles,
- Consistency with sound utility practice and general economic theory,
- Success in reflecting cost causation, and
- Ability to meet the requirements of the legislation.

The Board would also like the review to compare the design with other rates intended to accomplish similar objectives of customer choice using efficient pricing and achieving revenue recovery.[1]

This report presents the results of our review. The next section summarizes management's proposed design. Our review of the design begins in Section 3, which examines the program's connections to its underlying costs. Embedded costs support the services that SRP will continue to provide buy-through customers. Marginal generation costs, in the form of wholesale market prices, provide the basis for retail prices that customers will pay for generation services that the GSPs do not provide. These come in the form of 1) imbalance charges, which occur as a result of the ongoing mismatch between GSP deliveries and customer consumption, and 2) resupply charges which apply in the event of GSP contract termination.[2]

Section 4 contains our review of the main program provisions. These include core aspects of pricing and structural provisions that set the terms of service. Section 5 reviews the program's approach to managing several issues that can arise in offering buy-through service. Section 6 compares SRP's design with other programs having some features similar to those of the Buy-Through Program. The closing section presents our findings.

[1] Salt River Project Board of Directors, *Request for Proposal No. V100405NCP*, Section 2.1.

[2] This occurs when no contract is in force (e.g., in the event of GSP default) or when customer participation is cancelled with less than three-years' notice. See SRP, *Program Requirements* document, Section V.

2. SUMMARY OF MANAGEMENT'S BUY-THROUGH PROPOSAL

SRP management sets out its Buy-Through Program proposal in three documents: a *Program Design* that serves as a draft tariff, *Program Requirements* providing operational guidance to prospective participants, and a *Program Overview*.[3] This last document contains a high-level description of the program, including what SRP expects to accomplish through their program design. Collectively these documents provide a description of a customer's, GSP's, and SRP's rights and obligations under the program. These documents also specify the retail charges that the participating customer will pay and how the program will operate on a day-to-day basis.

2.1 Program Plan and the Parties' Obligations

Program Eligibility and Limitations

The Buy-Through Program will be available for large general service customers in good standing with SRP that are currently being served on the E-65 and E-67 rates. The program's minimum qualifying load is 5 MW of annual peak demand and customers are required to have an average monthly load factor of at least 60%.[4] The proposed program participation cap is 200 MW of demand. Participating customers are required to give SRP a three-year notice to return to standard service under SRP's retail rates.

Customer Obligations

Customers participating in the program are responsible for finding a GSP to serve their participating loads. The GSP will deliver energy to SRP on the customer's behalf and all charges from the GSP for this energy will be billed to SRP on a monthly basis and passed directly on to the customer. The GSP is required to meet legal and regulatory requirements to be a wholesale energy supplier to SRP and must meet credit requirements.[5] The GSP is required to make an effort to match the customer's scheduled loads in each hour. Mismatches will result in imbalance energy charges and, in the event of excessive energy imbalance occurring two or more times per year, a termination of the contract.[6] SRP is not responsible for helping a customer find a GSP or a replacement GSP in the event of default by the current provider.

Management's plan for the initial program implementation on January 1, 2024, is to have a program enrollment period during which half of the program cap of 200 MW will be reserved for larger customers with demand exceeding 25 MW and the remaining half will be reserved for

[3] Formal titles: 1) Salt River Project Agricultural Improvement and Power District, *Buy-Through Program*, draft of 6/1/23; 2) SRP, *Program Requirements*, draft proposal 6/13/23; 3) Salt River Project Agricultural Improvement and Power District, *Proposal for SRP's Buy-Through Program*, Effective January 1, 2024, June 1, 2023.

[4] Terms such as annual peak demand are defined in the *Program Design* document. Annual Peak Demand is the maximum 30-minute integrated kW demand for the customer over the 12-month period preceding the customer's enrollment in the program or any recalculation periods.

[5] Specifically, the GSP must be a member of the WSPP and provide firm capacity and energy sales or exchange service under WSPP Service Schedule C.

[6] Excessive energy imbalance is further discussed in Section 2.4.

customers with demand between 5 and 25 MW.[7] Buy-through customers will have an obligation to fully participate in the program for loads up to 50 MW. Customers with demands that exceed the 50 MW per customer cap and customers that receive some energy under another SRP program, such as a renewable energy program, will be subject to partial-load participation. Management's proposal defines relevant terminology for partial participation in the Buy-Through Program and explains how partial program participation will be determined and how the program will operate for these customers.[8]

Customers will be given a pro-rated share of the available program loads if there is considerable interest in the program. (That is, they will only be able to partially participate in the program). After the initial enrollment period, additional customers will be considered for the program on a first-come, first-served basis. Once the program is fully subscribed, additional customers will be placed on a waiting list.

GSP Obligations

The GSP is required to meet the customer's full scheduled loads of a fully participating customer. For a partially participating customer, the GSP must supply a share of the customer's scheduled loads according to their "participation factor". The participation factor is determined at the time of enrollment and is based on the ratio of the customer's participating demand, as determined by SRP staff, to the customer's annual peak demand. For example, a customer that has eligible loads that exceed the per-customer cap of 50 MW will have a participation factor equal to 50 MW divided by their annual peak demand. For a customer that receives a set amount (e.g., 20 MW) of energy from another SRP program, SRP will subtract this amount from the customer's eligible demand to determine their participation factor. (For example, 60 MW of demand less 20 MW is 40 MW, and the participation factor would be 40 MW/60 MW = 67%). SRP will adjust the customer participation factor if the customer's annual peak demands change over the course of their participation in the Buy-Through Program.

SRP Obligations

SRP's first obligation is to offer the program in a timely manner, as required by the statute. Additionally, SRP is required to operate the program, including qualifying customers and GSPs. Implicitly, SRP must treat customers fairly under the general commitment of obligation to serve, including providing fair terms of admission, rules of participation, and discontinuance. SRP also is required to support metering and billing necessary to facilitate actual buy-through transactions.

Additional Contractual Obligations

Customers and GSPs have additional obligations in the Buy-Through Program.[9] Customers are obligated to find a single GSP to cover their loads. A GSP may serve multiple buy-through customers but must have a separate contract with SRP for each customer. GSP contract terms

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[7] The initial program implementation is described in the *Program Requirements* document. SRP does not commit to maintaining this apportionment of the program for small and large customers over the course of the program.

[8] The *Program Requirements* document explains partial participation, including the Appendix, which provides examples of how a customer's percentage participation will be determined. Relevant terms are defined in the *Program Design* document.

[9] These are described in the *Program Requirements* document.

must be at least one year. SRP will enter into a service contract with customers for each of the participating service accounts. SRP will execute a separate service contract with the GSPs. These contracts must be in place at least 30 days prior to the commencement of customer service under the Buy-Through Program.

A customer must continually maintain contracts with a GSP during their participation in the program, but there may be a 60-day grace period between contracts, during which the customer will receive resupply energy from SRP. The GSP must bill SRP for the energy they deliver through the program on a monthly basis. GSPs serving multiple customers must provide SRP with a separate bill for each customer. As might be expected, GSPs must securely handle sensitive customer billing information.

SRP also reserves additional rights to ensure that the Buy-Through Program maintains the intended design through the course of the program's life.[10] SRP may cancel a customer's participation in the program if they cease to satisfy the requirements for the program, including situations in which there are excessive energy imbalances between the customer's scheduled loads and the GSP's supplied energy.[11] If a customer's participation in the Buy-Through Program is cancelled, they must wait one year to be eligible for the program again. SRP has the discretion to determine if there are any limitations on the program due to equipment availability and can require customers to upgrade metering equipment as needed. Finally, SRP is not responsible for any losses to the customer due to the default of their GSP or to the GSP as a result of the customer leaving the Buy-Through Program.

2.2 Buy-Through Base Rate Charges

A Buy-Through Program participant will bypass the generation and fuel adjustor charges from their retail rate but will continue to pay charges for monthly service, delivery, ancillary services, and system benefits.[12] Customers with partial buy-through participation will bypass the generation and fuel and purchased power adjustment mechanism (FPPAM) charges on their participating metered energy and participating billing demand and continue to pay on the non-participating portion.[13]

Participating customers must also pay an additional buy-through charge on their participating monthly demand, currently set at $4.15/kW.[14] This charge has three components designed to recover 1) the administrative costs of designing, implementing, and operating the Buy-Through Program, 2) the cost of including Buy-Through Program loads in SRP's Planning Reserve Margin

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[10] These rights are described in the *Program Requirements* document.

[11] For example, if a customer's demand or load factor drop below the program minimum requirements, they would cease to satisfy to program qualifications.

[12] The *Program Overview* document explains which retail tariff charges are bypassed and which retail tariff charges the customer must continue paying.

[13] These terms are defined in the *Program Design* document. The participating billing demand is the customer's maximum monthly demand during the on-peak period, as defined in their retail tariff, multiplied by their program participation factor. The participating metered energy is the total metered energy multiplied by the customer participation factor.

[14] The Buy-Through Charge is set forth in the *Program Design* document.

(PRM) via a reserve capacity charge component,[15] and 3) an Early Technology Adoption Charge (ETAC) component. This last component covers the cost of SRP's legacy renewable generation assets that were procured between 2009 and 2012 on behalf of all customers to satisfy renewable generation portfolio requirements.[16]

2.3 FPPAM Balances

While participating customers will be excused payment of fuel and purchased power charges on participating loads, they will still be liable to pay or receive their share of accumulated FPPAM balances. SRP tends to go through cycles of over- or under-collection of FPPAM charges relative to their actual cost of fuel and purchased power costs. (The current status is under-collection.) To prevent cost shifting of under-collected FPPAM balances onto non-participating customers (or excessive crediting to non-participating customers in the event of FPPAM over-collection) SRP will charge (or credit, as appropriate) the buy-through customer based on their share of these balances through the FPPAM Settlement Adjustment (FSA).[17]

This FPPAM settlement will be performed only when FPPAM balances exceed +/- $20 million. A participating customer's FPPAM balances may be handled as a lump sum upon joining the Buy-Through Program or as equal installments over a 36-month period. Customers will be charged (or credited) a pro-rata share of the existing FPPAM balance corresponding to their entry date into the Buy-Through Program. The customer's share of total energy usage during the accumulation period associated with the balance is multiplied by the excess balance amount (i.e., the total balance minus $20 million). In the event that a customer's participation in the Buy-Through Program is canceled, SRP will reconcile with the customer any remaining FSA balances at the date of program departure.

2.4 Energy Imbalance Charges

In each hour, a customer's consumption, adjusted for losses, will not necessarily equal their GSP's injection of generation supply, creating hourly imbalances. SRP will settle the cash implications of such imbalances with the customer. Management's plan proposes that buy-through customers be charged or credited for energy imbalances according to a two-tiered system.[18] Imbalances that are within +/- 15% or +/- 2 MW (whichever is greater) of scheduled loads are considered Tier 1 imbalances, while imbalances beyond that threshold are deemed Tier 2.

Tier 1 imbalances are charged or credited at the applicable CAISO Load Aggregation Point (LAP) price. For example, an instance of Tier 1 oversupply by the GSP to the customer results in a

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[15] This document also describes how SRP has based this portion of the Buy-Through Charge on capacity-related costs related to their generation and FPPAM rates from their 2019 Cost-Allocation Study.

[16] These early renewable investments involved costs that are currently considered to be above-market compared to the current costs of renewable power generation projects. SRP argues that the ETAC charge is essential to prevent the Buy-Through Program from shifting these costs onto SRP's other customers.

[17] The settlement process is explained in the *Program Overview* document and the calculation of the pro-rata settlement share is detailed in the *Program Design* document.

[18] Imbalance charges are detailed in the *Program Design* document.

credit by SRP to the customer of the load difference priced at the LAP price. (This credit reflects the anticipated change in SRP's revenue from either a reduction in cost of purchased power or increased revenue from the sale of the oversupply at the same market price. SRP is financially whole following the imbalance payment.)

Tier 2 imbalances are charged or credited according to the CAISO LAP price with a 25% premium or discount applied in SRP's favor, with the stated purpose of deterring large imbalances.[19] For example, an instance of Tier 2 oversupply (when the LAP price is positive) results in a credit to the customer at 75% of the LAP price. SRP's costs decline, or its revenues increase, by the full LAP price applied to the settlement amount.[20]

For a case of Tier 2 under-supply, the customer pays a premium price to SRP on the difference between energy used by the customer and delivered by the GSP, i.e., the entire difference, not merely the excess over the 15% threshold, is priced as Tier 2. In the case of sustained under-supply at times of high LAP prices, the customer would quickly find itself facing bill increases above the levels expected by their contract with the GSP.

Imbalance charges must be settled by the monthly bill's due date based on preliminary values, but SRP will perform a reconciliation using actual figures in subsequent months.[21] SRP also makes provision for customers who maintain "excessive imbalances," which are defined as occurring when at least 20% of the hours in a monthly billing period have Tier 2 imbalances. SRP will notify customers and GSPs of any months with excessive imbalances and SRP has the right to terminate the GSP's service contract and cancel a customer's participation in the program for at least two months of excessive imbalances during a rolling 12-month period. SRP may also make a GSP ineligible to participate in the program due to excessive imbalances.

2.5 Resupply Energy

SRP must provide participating customers with resupply energy in the event of default of the customer's GSP. Resupply energy pricing applies during periods in which there is no contract in effect between a customer and a GSP, or if a customer leaves the Buy-Through Program with less than three-years' notice.[22] During resupply energy periods, SRP charges customers using retail price based on the time-of-use (TOU) prices of the Palo Verde Peak or Off-Peak Intercontinental Exchange (ICE) day-ahead indexes (or any such replacement index if these become unavailable). SRP will apply a premium to the index prices that is the greater of $10/MWh or 10% of the index price.

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[19] This premium means that over-supply will be credited at 75% of the LAP price while under-supply will be charged at 125% of the LAP price, in situations where the LAP price is not negative. For negative LAP prices, the premium will move in the opposite direction, i.e., convert into a discount. That is, over-supply will be charged at 125% of the LAP price and under-supply will be credited at 75% of the LAP price.

[20] SRP provides an example of the calculation that includes loss adjustment and rounding to the nearest MW to provide an exact representation of the settlement process. See their *SRP Buy-Through Program Overview* presentation at the July 18, 2023 stakeholders' meeting, available on their website: https://www.srpnet.com/price-plans/business-electric/large-general-service/buy-through#3, p. 9.

[21] This process is explained in the *Program Requirements* document. The *Program Overview* document describes the deterrent purpose of the Tier 2 pricing rule.

[22] Resupply energy is explained in the *Program Overview* and *Program Requirements* documents.

Resupply energy differs from imbalance energy in that it is expected to be used intermittently and for short duration, until the customer acquires a new GSP or returns to service with SRP. The TOU price structure can be quite volatile, based on historical Palo Verde prices, suggesting that customers will usually have a strong inducement to seek a new GSP contract.

2.6 Program Operation

Management sets out a process for day-to-day scheduling and delivery of energy as well as the process of billing.[23] The customer will provide the GSP with forecasts of their hourly loads. From these forecasts, the GSP determines their delivery obligation by multiplying the forecasted loads by the customer's participation factor and by adjusting for line losses.[24] The GSP is required to deliver energy to the delivery point (an SRP-approved 230 kV receiving station) and is responsible for all costs and regulatory obligations (e.g., CAISO requirements) before the energy reaches the delivery point. The GSP will provide SRP with the scheduled hourly loads (rounded to whole MW) for the month at least seven business days before the beginning of the billing month.

SRP will act as the scheduling coordinator, tagging the forecasted energy deliveries in accordance with the WECC Preschedule Calendar and entering the forecasts in the trade capture system.[25] The GSP, supplied by information from the customer, can update the forecasted loads as late as the (trading) day before scheduled deliveries. The GSP must provide physical path information, including all information about the path upstream of the delivery point, by this date as well. SRP also has the option, in emergency situations, to interrupt planned buy-through energy deliveries. If SRP must cut the GSP's energy due to system issues, they will not charge the customer for resulting energy imbalances.

The process for monthly billing and reconciliation is as follows: SRP will issue a bill to the buy-through customer by the second business day of the following month; GSPs have until the 10th day of the month to validate or modify tagged hourly delivered loads for the previous month; reconciliations will be made on future bills if necessary.

3. ANALYSIS OF SUPPORTING COSTS

3.1 Embedded Costs (Cost Allocation Study)

CA Energy Consulting reviewed the base tariffs of customers eligible for the Buy-Through Program, along with the Cost Allocation Study (CAS) that supports their prices, primarily for the purpose of evaluating the degree to which program participants will continue to pay their cost to serve. Failure to do so would result in cost shifting to other customers.

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[23] The *Program Requirements* document provides a useful description of how energy scheduling, delivery, and billing will work in the program.

[24] The projected line loss multiplier is 1.0343.

[25] Additional details and requirements related to scheduling, not enumerated here, are described in the document.

Customers currently taking service under rates E-65 (Standard Price Plan for Substation Large General Service) and E-67 (Standard Price Plan for Large Extra High Load Factor Substation Large General Service) are eligible to apply for service under the Buy-Through Program. Both of these rate designs are characterized by functionally unbundled rate components. That is, each function of electric service is accorded a separate line or lines in the bill rather than being bundled into single conventional customer, energy, and demand charges. The rates have monthly facilities charges, per kW charges, and per kWh charges with disaggregation as follow:

Monthly Service Charge

- Billing and Customer Service
- Meter

Per kW Charge

- Transmission
- Ancillary Services (E-67 only)
- Generation (waived for Buy-Through Program participants)

Per kWh Charge

- Transmission (E-65 only)
- Ancillary Services (E-65 only)
- System Benefits
- Generation (waived for Buy-Through Program participants)
- Fuel and Purchased Power (waived for Buy-Through Program participants)

Provided that all generation-related costs are restricted to the generation and fuel line items, and that no other costs are incorporated into these line items, cost shifting will not readily occur.[26] Based on the line items above, and upon SRP's intention to provide transmission and ancillary services to buy-through customers, and upon the continuation of a system benefits charge applicable to total customer consumption, it appears that cost shifting is unlikely to be a problem, pending the analysis of embedded costs below.

SRP provided a recent CAS to facilitate review of the utility's cost allocation practices.[27] The study performs the familiar tasks of functionalizing, classifying, and allocating the revenue requirements of the utility to the various rate classes. The study that we reviewed combined large customers now served under rates E-65 and E-67 into a single class, denoted E-65. The study's schedules depict the utility's costs for the various functions and subfunctions (e.g., meters) and permits the reviewer to follow functional costs through to full allocation by class.

SRP also provided a rate design workbook that demonstrates how tariff prices are derived from the costs allocated by subfunction in the CAS. The workbook demonstrates that costs incurred by subfunction are included in the individual prices of that subfunction. Specifically, generation prices are based on generation-related revenue requirements and the appropriate billing

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[26] Riders that recover costs that are excluded from the cost of service and base rates can also produce cost shifting. SRP has a number of riders applicable to E-65 and E-67 customers. None appear to present cost shifting potential in this case.

[27] Salt River Project, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the May 2019 Billing Cycle*, December 20, 2018.

quantities. The unbundled nature of the rate permits clear understanding of the absence of potential for cross subsidy based on tariff prices and the costs that they represent.

One obscure point worth mentioning is that SRP removed its Environmental Programs Cost Adjustment Factor (EPCAF) line item from the CAS and deposited some of those costs into the generation and fuel components of the bill.[28] As a result, the Buy-Through Charge applicable to participating customers includes a non-bypassable charge that permits continued recovery of these costs despite the elimination of the generation and fuel-related charges from the bill.

Another non-bypassable cost included in the Buy-Through Charge, the reserve capacity charge component, is designed to recover portions of the generation retail charge that are related to capacity-related costs for resource adequacy. SRP will continue to include buy-through customers in their capacity reserve margin to ensure resource adequacy on their system. Since these costs are not unbundled from the generation costs that SRP will avoid as a result of the Buy-Through Program, they seek to recover these costs via the Buy-Through Demand Charge. One alternative for future rate cases would be for SRP to unbundle their capacity-related charges from other generation charges for E-65 and E-67 customers for more transparency with respect to the Buy-Through Program design.

The use and level of a reserve capacity charge component has been an issue of some interest in a recent regulatory proceeding that includes their Arizona Power Company's AG-X tariff, the counterpart to SRP's planned Buy-Through Program. Testimony included review by one witness of whether the supporting utility should necessarily provide capacity or whether the GSP could be the provider. Another witness supported the utility's resource adequacy charge and recommended a level equal to 15% of the generation demand charge. This level is close to SRP's planning reserve margin of 16%, which results in a reserve capacity ratio of about 14% (reserves relative to generation including reserves).

In our view, the reserve capacity charge component is readily justifiable, both in principle and as an SRP charge (exclusively for now). The current absence of markets for reserves suggests that a financial cost-based charge offered by the supporting utility is simple, readily monitored by a regulator, and thus not injurious to any approximation to a competitive market that might emerge. Additionally, the capacity reserve level appears justified by SRP's operational rules and supported by the presence of a comparable measure at a neighboring utility.

In summary, it is possible to infer that the components of the rates that buy-through customers will continue to pay will recover costs associated with these functional components. In contrast, the bypassed retail generation and fuel rates include a mixture of costs that SRP will avoid as a result of the Buy-Through Program and costs that buy-through customers will continue to impose, which motivates the buy-through rate design.

3.2 Marginal Costs (Marginal Cost Study)

SRP provided CA Energy Consulting with a study of its marginal costs so that we could review it for information about the pricing of any aspects of the program that might use marginal cost, including imbalance and resupply pricing. The time pattern of the marginal costs of generation services appear to influence the seasonal and time pattern of pricing, as the tariff sheets

[28] Other costs were deposited in the fixed monthly charges and system benefits charge.

demonstrate. However, marginal costs do not appear to play a role in other aspects of the existing underlying rates. SRP's approach raised no issue since it appears in line with utility practice of setting relative energy prices with reference to relative marginal generation costs.

Nor do internal marginal costs figure in the pricing of imbalance and resupply services. These are based on market prices in some form: the CAISO Load Aggregation Point (LAP) prices for imbalance services and Palo Verde peak and off-peak price ICE day-ahead indexes in the case of resupply. In both cases SRP is engaged in applying prices to relatively short-notice purchases and sales in the regional wholesale market to balance customer needs with GSP energy provision. Market-based prices help SRP match its revenue recovery with the incremental/decremental costs of the customers' consumption.

SRP takes the position that market-based pricing is an appropriate approach to take in pricing these services. It is difficult to think how imbalance services could be priced in any other way. However, critics might suggest that resupply services could or should be priced on an embedded cost basis, placing buy-through customers on the same pricing basis as full-requirements SRP customers. SRP management believes that this argument is not correct because buy-through customers are not contractually similar to other customers. Buy-through customers have acquired access to capacity through their chosen GSP. The termination of that service does not grant the customer immediate access to SRP's generation capacity. While SRP continues to charge buy-through customers for reserve capacity, it is not charging for base, firm power-supporting capacity. That is the responsibility of the GSP. This implies that generation services ought to continue to be provided on the basis of market prices. CA Energy Consulting concurs with this argument.

SRP also believes that the use of the two different sets of prices is required by differences in the services required and in the nature of these prices. In the case of imbalance services, service provision is intended to occur on an ongoing basis in (normally) small increments or decrements relative to scheduled amounts. From an operational perspective, imbalance pricing benefits from local prices reflecting current market conditions and available on an hourly basis, if possible. The LAP prices fit that need.

For resupply services, on the other hand, SRP must step in with supply on a whole-load, likely multiple-day basis to cover a GSP default or some similar contractual breakdown. Although not hourly in frequency, the current Palo Verde indexes for peak and off-peak pricing periods offer a day-ahead benchmark for customer planning, a vital tool in risk management.

SRP also found that the Palo Verde prices were systematically higher on average than the LAP prices.[29] The Palo Verde price indexes, which reflect the price of WSPP Schedule C firm power, better reflect capacity costs compared to the real-time CAISO LAP prices. Firm power is more relevant to SRP's obligation to provide resource adequacy for customers during resupply. Moreover, the Palo Verde prices, in addition to the attributes mentioned above, suggest that they might prove to be a useful risk hedge for SRP and its non-participating customers. This point is especially relevant if SRP is confronted with systematically higher prices while trying to acquire

[29] See the Appendix for more information about the differences between the Palo Verde ICE day-ahead peak price index and the Palo Verde real-time hourly LAP prices. The Palo Verde ICE day-ahead prices are not shaped to hourly settlements and are fixed across the on-peak period (hours ending 7 to 22). This results in the day-ahead prices being higher during most of these hours. However, they may be lower than the real-time prices during one or more hours in which the system loads peak and reserves are low.

resupply power at short notice, for potentially long periods, and covering large volumes of energy for the affected customer(s).

In the next section, the report reviews from an economic theory perspective pricing issues that arose in our review of SRP's buy-through pricing approaches. From an operational perspective, though, the program's imbalance and resupply pricing plans appear sensible.

3.3 Ancillary Services

Ancillary services are provided by generation facilities and are vital for the reliable delivery of electricity services to consumers. Ancillary services include energy services, referred to as imbalance services, and non-energy services including operating reserve and non-reserve categories. Operating reserves constitute the share of operating capacity held as reserve supply, available on short notice in response to changes in total system demand.

SRP's retail charges for non-energy ancillary services are based on the average financial costs of selected generation facilities which provide such services, and are strongly driven by total system loads. Within the proposed Buy-Through Program, SRP's approach regarding ancillary services is to charge average cost-based ancillary service prices, as posted in the relevant retail tariff, on the total loads of participating customers, including load served by GSPs.

Because the costs of ancillary services are a function of system loads, and system loads are unlikely to be greatly affected by the availability of buy-through pricing, SRP costs of non-energy ancillary services will remain virtually unchanged regardless of whether energy is provided by SRP's internal generation portfolio, or the resources employed by GSPs to serve buy-through transactions.

From this perspective, it appears that SRP's approach to pricing and cost recovery of ancillary services from participating customers achieves the objectives of full cost recovery and comparable pricing with customers on the underlying rates. Note that this is true even though the pricing of ancillary services differs across these rates (per kW pricing for E-65 and per kWh pricing for E-67).

4. THE PROPOSED RATE'S ABILITY TO ACHIEVE DESIGN OBJECTIVES

The Board's seeks a review of the proposed Buy-Through Program with respect to several criteria for successful design:

- Consistency with the Board's general principles,
- Consistency with sound utility practice and general economic theory,
- Ability to reflect underlying cost drivers, and
- Compliance with the enabling legislation: A.R.S. § 30-810.

4.1 Consistency with Board Principles

The Board's general principles for successful rate design, as presented in the Request for Proposal, require:

- ***Gradualism:*** avoidance of large customer bill impacts arising from changes in retail prices or in rate designs.
- ***Relationship of prices to underlying costs:*** basing the prices of each rate on the underlying cost to serve such customers, with the consequence that other rate classes and water rates are not encumbered with the electricity costs of new rate design.
- ***Customer choice:*** striving to offer diverse customers rate options that meet their needs, including, in this case, the option to seek generation services from third parties.
- ***Equity:*** treating customers with similar cost to serve with similar pricing and billing, such that rates are perceived as being fair to all.
- ***Revenue Sufficiency:*** ensuring that the revenue requirement associated with a class of customers is recovered fully via rates, thereby minimizing the likelihood of cost shifting.

Management's proposed Buy-Through Program appears to satisfy the Board's criteria. With respect to the relationship of prices to underlying costs, the previous section of the report documents that SRP's unbundled rates E-65 and E-67 have charges that correspond to each of the subfunctions of SRP's electric services and that cost recovery of each subfunction is achieved with each of the corresponding prices. In addition, SRP's Buy-Through Charge fully collects the administrative costs of the program, assuming that the program is fully subscribed. Additionally, this charge makes provision for capacity-related charges that the participating customers would bypass, and recovers each customer's responsibility for early technology adoption of renewable generation facilities (ETAC costs).

The new rate option enhances customer choice by definition: customers hitherto required to take power from SRP by virtue of their location within its service territory will now have an opportunity to "shop" for generation services, a choice that has been available in some other U.S. jurisdictions for several years. The increase in customer choice is restricted to large customers on the two underlying rates and by the fact that not all those who apply for choice may be granted it. At present, this is not a material limitation, as SRP is opening customer choice to those customers most likely to be able to manage the extra contractual and risk management burden of energy management and choice of provider. Earlier offerings of customer choice in other jurisdictions made use of the same strategy of offering choice first to larger customers.

Management's plan also satisfies equity considerations in the sense that non-participating customers who continue to receive generation services under E-65 and E-67 pay the same charges as before and as are paid by participating customers for all services except for generation. This satisfies the traditional objective of like customers paying like amounts.

Lastly, the plan provides for revenue sufficiency with respect to participating customers. They pay SRP fully for non-generation services, reimburse their GSPs through SRP for generation services, and resolve imbalance issues in a manner that does not burden SRP with financial obligations. The program's costs and non-bypassable costs are fully incorporated in the Buy-Through Charge. Additionally, in the event of default, it appears that neither current customers of SRP nor SRP itself are exposed to increased costs, due to the provisions of resupply pricing.

4.2 Consistency with Sound Utility Practice and Economic Theory

Management's plan is consistent with sound utility practice, not simply from the costing and pricing principles espoused above by the Board, but also by virtue of the program's operational practices in developing the program and prospectively offering service under its provisions. The program documents specify the terms of customer entry and departure. The program reserves space for both smaller (25 MW or less) customers and larger, and specifies how customers with loads in excess of 50 MW will have their partial program participation determined. However, it does not specify fully how the *initial* customer selection will occur should the program be over-subscribed.[30]

Management has also detailed operational aspects of scheduling, price provision, and billing sufficiently to enable participating customers and GSPs to understand the mechanics of scheduling loads, delivering, and paying for them. Customers schedule loads for the coming month a week before the start of the month. SRP's and the GSP's responsibilities are clearly defined. The billing implications of imbalances are clearly explained as well. However, pricing aspects of the design of imbalance service charges deserve further review, which occurs in the issues section below.

The Buy-Through Program plan also makes provision for both customer departure prior to contract completion and the departure of a GSP. These provisions also raise issues:

- Customers must provide three years' notice of departure from the program. Is this duration necessary?[31]
- Default by a GSP results in a customer relying on SRP for resupply energy until they can find a new GSP. If they fail to find one, they face a wait of three years to rejoin SRP's retail service, unless SRP waives this requirement due to their conclusion that resources are adequate to provide firm service. Is the pricing plan appropriate for this situation or should it be modified?

The next section discusses these issues.

Management has also engaged prospective participants in briefings soliciting their response to the program design. Presumably, material concerns will receive management review in time for the January 1, 2024 start date should any changes be desirable.

With respect to economic theory, management's program aligns well with economic theory and the general principles of rate design. Of the main functions of a utility, delivery services are usually viewed as natural monopolies while generation services, including both production and the retail provision of energy, are viewed as workably competitive. Traditional vertically integrated utilities under regulatory supervision are still regarded as a viable means of providing electricity, but deregulation of generation services is now common.

Management's design is similar to rate designs found in deregulated markets in that delivery services are still to be provided by the regulated utility (SRP) while generation services are to be provided under competitive conditions. The proposed structure departs somewhat from the

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[30] SRP management has stated that they would prorate the participation factors for all customers.

[31] SRP has stated that they intend to add language to their program documents stating that they will attempt to acquire the necessary capacity in less time, if possible.

market model found in organized transmission jurisdictions elsewhere in the U.S. in that SRP will retain provision of ancillary services, and transmission services will continue to be billed under the regulated utility's authority. Consistent with this arrangement, SRP will act as the scheduling coordinator; the market model typically designates an RTO or ISO to carry out these functions.

The proposed structure reflects current conditions in Arizona, which is to be expected in that the state is not yet fully operating under an RTO/ISO framework. The proposed structure appears appropriate at present and can be readily modified to suit future developments in wholesale markets.

It bears repeating that we concur with management's position that the pricing of imbalance and resupply services comports with economic theory in that SRP is providing services incremental to or temporarily supplanting generation services provided by the customer's chosen source of both firm energy and capacity. Market prices – separate from the utility's embedded cost-based prices designed to recover the costs of supporting full-service customers – are the appropriate metric for pricing.

4.3 Reflection of Cost Drivers

Management's proposal relies on the same representation in retail prices of cost drivers as the underlying tariff for all but generation services. Since SRP's CAS and rate design for these tariffs closely tie subfunctional costs to prices of those services, and the prices largely use the appropriate representation of the cost driver (e.g., demand charge for recovery of demand-related costs) the proposed design begins with solid grounding in appropriate pricing of costs.[32]

The remaining prices, for generation with respect to imbalances or resupply, largely reflect SRP's costs of buying or selling power at short notice, subject to the discussion of the issues below. From this perspective, the proposed Buy-Through Program effectively reflects cost drivers in its prices.

4.4 Compliance with Legislation

Management's proposal fully complies with the terms of A.R.S. § 30-810. Specifically, SRP intends to provide a Buy-Through Program in a timely manner that clearly specifies the terms and conditions of service for program participants, both customers and GSPs, including minimum customer load and maximum program participation. The design has readily discernible implications for cost recovery and is unlikely to generate cost shifting to SRP's other customers or the utility as a whole. Furthermore, there appears to be no threat to system reliability in the short run due to imbalance issues or in the long run due to customers shifting back to SRP. The design deters customers from no-notice changes in status, charges customers for reserve

[32] Reviewers of the E-65 and E-67 tariffs will note differences in price configurations and relative emphasis on demand-based revenue collection. The very high load factors of E-67 customers cause differences in price perception between the rates. The need for E-67 customers to control peak demand appears less since consumption fluctuates relatively little over time. In contrast, E-65 customers arguably perceive a more forceful influence on restraining peak demand, focused on hours when they near their peak demand level.

capacity as if they were still with the utility and has provisions for GSP default that induce customers to seek out a new GSP promptly.

5. POTENTIAL ISSUES ASSOCIATED WITH THE PROPOSED RATE DESIGN

5.1 GSP Resource Adequacy

Management's plan to ensure GSP resource adequacy has several components: controls on GSP eligibility, a limit on the scale of customer participation, rules for scheduling and related operational reliability, and a price incentive to minimize imbalances. Limitations on GSP eligibility are appropriate: legal and regulatory requirements to sell wholesale energy to SRP for any purpose, ability to deliver subject to the firm capacity and energy requirements of WSPP Schedule C, and an ability to meet SRP's counterparty credit criteria. In brief, a GSP must meet standard business requirements for participation in wholesale markets and making associated sales to retail customers.[33]

The program design also specifies scheduling requirements for customers and GSPs to ensure that the GSP can acquire power requested formally by the customer and can arrange for delivery to SRP. The Program Requirements document sets out in some detail the scheduling requirements for these parties, and these requirements indicate that SRP schedulers will be involved in an ongoing basis in ensuring compliance.

The design recognizes the inevitable presence of imbalances in the course of daily operations and the management proposal relies on a price premium relative to LAP prices to induce customers and GSPs to follow schedules and to avoid the accumulation of systematic imbalances. The size of the premium is the subject of discussion below. However, for purposes of this section, the proposed design seeks to use the premium structure as a price-based inducement for closely matching demand and supply on an hourly basis.

Even in the case of default, when the GSP is clearly not providing adequate resources, the program plan makes it likely that SRP will be able to obtain resources necessary to provide resupply energy for the customer.[34] Additionally, the premium of the Palo Verde ICE day-ahead price index over the real-time CAISO LAP prices reflects SRP's need to obtain firm power and signals that valuation to customers. Furthermore, the presence of the reserve capacity provision in the Buy-Through Charge is designed to reflect SRP's commitment to secure the resources to ensure available capacity, while assuming that energy is likely to be secured in the wholesale market as a result of that capacity. We comment further about Palo Verde price patterns below.

Taken together, these measures minimize the likelihood that GSP resource adequacy will be an issue in the short and long run.

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[33] See the *Program Overview*, p. 5.

[34] SRP notes that any liquidated damages arising from the default will be paid to the customer, since SRP will have recovered its supply costs via the resupply price mechanism.

5.2 Provider of Last Resort Considerations

SRP will need to act as a provider of last resort (POLR) in the event of GSP default. Management's plan not only strives to minimize concerns about GSP resource adequacy and viability, but the proposed design also provides for resupply pricing as a POLR pricing structure. Reliance on a publicly available price index at a nearby location characterized by a large volume of transactions offers a reliable basis for contracting at short notice. Such pricing should satisfy several criteria, including freedom from controversy, price transparency, and ready availability. The price premium and potential variability of prices will provide a strong inducement to customers to keep the period of resupply price exposure short.

5.3 Imbalance Service Charges

Imbalance services constitute a settlement procedure to reconcile actual vs. forecast quantity differences. Such mechanisms are common features of commercial trade and are particularly applicable to energy and financial markets. Well known examples in energy markets include:

- The dual settlements procedures of unbundled electricity markets organized under ISOs/RTOs settle actual vs. day-ahead load differences according to real-time energy prices.
- Two-part tariff options common to retail electricity markets settle differences between actual and projected loads according to short-run marginal cost-based prices.
- Contracts for differences (CfDs) applicable to commodity markets settle actual vs. forecast price differences on defined contract quantities.
- Fuel adjustment charge mechanisms common to retail electricity services settle actual vs. projected fuel price and sales quantity differences.

In short, provisions to settle actual vs. projected differences are integral to workably competitive markets. Accordingly, the inclusion of imbalance charges in SRP's Buy-Through Program appears to be on solid ground. In addition, the settlement mechanism of SRP's proposed Buy-Through Program gets much right.

Quantity Differences are measured in hourly frequency. It is important to meter differences in high frequency. First, the hourly loads of participating customers will generally have higher variation than system level loads and vary substantially among participants. Thus, hourly variation is important in order to accurately capture the cost responsibility of individual loads to cost levels of SRP and, to a lesser extent, regional markets. Second, long time intervals can conceal short-term differences between actual and forecasted values: netting balances across time will cause under-representation of SRP's costs of providing imbalance services.

Net monthly charges reflect actual vs. scheduled differences, including charges for quantity supply shortfalls (actual < scheduled) and credits for quantity supply surpluses (actual > scheduled). Settlement costs are likely to be much higher during times of high system loads. Hence, with settlements in hourly frequency, participating customers have incentives to realize quantity supply surpluses but not excessive surpluses, reflected in net bill credits.

Actual vs. scheduled quantity differences, settled at marginal costs, are also measured in hourly frequency. SRP's proposed approach to determining imbalance charges will settle quantity differences at marginal costs, measured as the real-time dispatch (RTD) load aggregation point (LAP) prices for the Salt River balancing authority.

One difference with respect to SRP's imbalance pricing plan compared to other buy-through programs in Arizona is that settlement is to occur between the customer and SRP rather than between SRP and the GSP. SRP selected this approach because their research indicated that GSPs tend to deliver scheduled amounts with precision regarding timing, location, and amount, barring transmission constraints outside SRP's service territory. On the other hand, the natural variability in customer loads is complicated by some customers' ability to strategically over- or under-schedule to reduce their costs.

The basis for such behavior is that the (presumably) fixed price of their scheduled generation charges from their GSP may exceed or be less than the imbalance price that SRP uses. Customers rapidly acquire the ability to forecast LAP prices, having access to weather and market price data for their region. If low LAP prices are expected, the customer can reduce their bill by under-scheduling and purchasing the load shortfall from SRP. If widely practiced, strategic behavior leads to systematic and increasing swings in imbalance totals. A price premium/discount for excessive imbalances always in SRP's favor will provide an incentive to mitigate the size of such imbalances and encourage truthful revelation of scheduling plans.

Viewed in this light, the price incentive applicable to extreme imbalances, backed by the power to discontinue service in cases of persistent imbalance, appears to be wholly appropriate. We support the proposed imbalance settlement and pricing system, including the use of premium and discount pricing to deter strategic customer behavior.

One might question management's plan to impose the 25% premium/discount level in SRP's favor for large imbalances. From the perspective of economic theory, the percentage ideally would be set high enough to make SRP indifferent between whether a customer exceeded the Tier 1/Tier 2 boundary or not. We anticipate that experience during the first year or two of the program will help to determine whether the premium/discount percentage should be altered in the future. Since the size of the percentage may act as a deterrent not only to strategic behavior but to participation on the basis of heightened bill risk, we suggest that SRP investigate this question in the future. Not yet acquired knowledge of customer preferences and the cost and frequency of imbalance ought not to delay program roll-out.

5.4 Default by the Customer's GSP

Management's plan for cases of GSP default (or customer early departure from the program) involves provision of resupply energy using pricing based on Palo Verde ICE day-ahead price index values. This plan is sensible, since it sets the energy price for short-notice transactions based on a publicly available market value, providing a clear signal to customers, and holding non-participating customers harmless, assuming that SRP's power acquisition costs are close to those of the index values. This approach is similar to POLR pricing in other jurisdictions, being based usually on wholesale market valuation of generation services.

Management's plan permits SRP to charge a resupply customer based on a wholesale price location at which the utility can obtain power, minimizing risk to the utility. The price premium helps to ensure cost coverage. In contrast, a customer might compare the pattern and level of SRP's resupply prices, as derived from Palo Verde ICE day-ahead indexes, with the pattern and level of hourly EIM prices and wonder whether SRP's pricing is fair. (See the Appendix for discussion of historical price patterns.)

With regard to average level, SRP management maintains that the revealed difference in level reflects the difference in power firmness and regional power availability. As noted previously, SRP can provide ongoing imbalance services with low-volume trades in the imbalance market. In contrast, obtaining firm power for resupply requires access to the relatively high-volume Palo Verde ICE day-ahead index prices and market. Operationally, then, the difference in level between these two markets ought to be reflected in the pricing of resupply services.

With regard to pattern, a customer might express concern that their usage pattern is priced at TOU period average prices, while the EIM reveals that they consume power that in a manner is relatively inexpensive compared with the average within each TOU period. The difficulty for SRP is that it is difficult to translate their perceived lower cost to serve based on hourly prices into actual lower cost purchases, since the utility must purchase at the index prices. The potential for inequity across customers exists: equal pricing but unequal costs. A scheme of price "shaping" might improve equity across customers, provided that the price premium could cover total resupply energy costs.

This equity improvement would be purchased at the cost of price complexity in that SRP would need to acquire CAISO hourly shaping factors, which are available daily, and price each resupply customer's load on this basis. While feasible, developing such a system, often for a single resupply customer, seems not to be cost effective since, regardless of shaping, SRP must acquire power at the index prices. Additionally, price shaping in the presence of price volatility, creates the possibility that a customer would find that a single hour at a time of high EIM prices is priced at, say, $1,000/MWh. If their actual load in that hour was high, their risk exposure would be magnified by price shaping. In brief: the customer would be on day-ahead real-time pricing without hedging capability. The TOU pricing scheme offers a partial hedge against price spikes in the EIM by avoiding shaping based on EIM price pattern.

One might also be concerned about the proposed markup: the larger of 10% of the index price or $10/MWh. Since the firm prices of the Palo Verde ICE Day-ahead price indexes are consistently higher on average than the CAISO LAP real-time prices, the need for a markup might appear questionable. Arguably, though, this premium simply represents the premium that a utility is entitled to charge for procurement of retail energy at relatively short notice. This is not a service that ought to be offered for free. Supporting this perspective is the use by other jurisdictions of price premium values. Notably, Arizona Public Service's buy-through resupply price includes a premium of $10/MWh.

In summary, the resupply price should provide for cost recovery by SRP, minimize the likelihood of cost shifting to other customers, and encourage customers using resupply pricing to plan for and obtain longer-term generation supply, either through a new GSP or through a return to their original SRP rate design. Experience with this component of the design during the first few years of the program will provide a basis for subsequent review.

5.5 Return to Company Standard Rate Offerings

Closely related to the issue of resupply price is that of management of customers who use resupply pricing. This pricing can apply due to a customer's GSP defaulting and to the customer departing the Buy-Through Program at shorter notice than the required three years, either by choice or due to violation of the program rules. Such pricing is intended to apply for a limited period of time, to allow the customer to find a new GSP or to return to their standard SRP rate.

5.5.1 Length of Advance Notice of Cancellation

The main issue additional to the pricing issues described above is associated with the duration of notice for departing the Buy-Through Program that the customer must offer in order to avoid these prices. The duration reflects SRP's perception of the time that it requires to secure capacity for the customer who has been outside the SRP system.

One issue with this position is whether a customer who has departed the system truly ceases to figure in SRP's capacity calculations and, therefore, whether SRP would need to acquire capacity were the customer to return. SRP's stated timeline for developing new capacity is three years.[35] Inquiry about this timeline yielded management views that SRP would no longer have access to the capacity included in the canceled GSP contract. While it might appear that such capacity would instantly become available, SRP cannot presume that it would be able to acquire the newly available MW. Currently tight markets lead the utility to expect that capacity might be available, but only at a high price or not at all. A cancellation just before the summer peak season would be particularly difficult for SRP to manage.

If this is the case, SRP would be right to be cautious. As the rule stands now, the three-year notice rule is mandatory. SRP could modify the rule to state that advance notice could be from one to three years, depending upon SRP's ability to secure capacity to serve the returning customer. This flexibility might improve the attractiveness of the Buy-Through Program by reducing a potentially significant barrier to participation. A customer who joins the program expecting to save money on generation services costs but has a contract that includes flexible pricing to some degree might be more willing to participate, or more willing to sign a flexibly priced contract in the first place if the door to returning were open with shorter notice.

Alternatively, SRP could offer shorter notice in return for interruptible service for all or a portion of the customer's load. The viability of such a strategy might depend on the likely availability of even non-firm power. If the summer peak season is characterized by chronically low capacity reserves, such an arrangement might not be feasible, as the customer would have to expect extended outages.

It should be noted that the APS Buy-Through rate requires just one year's advance notice of departure. However, that utility's perspective on capacity inclusion in planning may well be different from that of SRP, so it is not certain how comparable the advance notice settings are.

5.5.2 FPPAM Settlement Adjustment of Returning Customers

As we describe in Section 6, the proposed FSA is consistent with the treatment of directly served customers in other jurisdictions. While management's proposal is appropriate for the current circumstances (i.e., the beginning of the buy-through program, at a time with significant FPPAM balances), management may eventually need to consider symmetrical treatment for customers returning to SRP for full requirements service. That is, a customer returning to SRP will not have

[35] Reported in a conversation with SRP management.

been responsible for the FPPAM balance at that time and thus should not be responsible for paying / receiving credit for it. A possible method for treating returning customers in a consistent manner as departing customers would be to calculate the customer's load share of the current FPPAM balance (as management proposes for departing customers) and establish the resulting amount as a balance against which ongoing FPPAM charges are assessed.

For example, if a customer rejoins SRP when there is a +$50 million FPPAM balance, the customer would be assigned their load share of that balance (using the customer's historical loads) and the resulting amount would be established as a credit against which the ongoing FPPAM charges would be applied. Under this method, the customer would be assessed the FPPAM charges immediately upon returning to SRP, but they would only affect their total bill amount after the customer's share of the upon-return FPPAM balance is exhausted. The same methodology can be applied to an FPPAM overcollection scenario, which would prevent the rejoining customer from benefiting immediately from the FPPAM balances accrued during their absence from the system.

5.6 Cost Avoidance and Bypass

As previously discussed, the Buy-Through (Demand) Charge is designed to recover administrative costs associated with the Buy-Through Program as well as some of the costs embedded in the generation and FPPAM prices that might improperly be bypassed under the Buy-Through design. The costs retained in the new rate design's Buy-Through Charge include reserve capacity and ETAC price components, which represent the participating customer's ongoing obligation to pay. This approach seems reasonable, although one potential issue relates to the ETAC component.

SRP assesses the customer's obligation at the start of buy-through service and converts that to a lump sum obligation for immediate settlement or liquidation over the following 36 months. A customer who returns before the 36 months have elapsed receives a similar settlement undoing the remaining months' obligations. This approach appears neutral to the outcome of a customer who remains on the underlying rates.

The issue has to do with timing as the program evolves. ETAC obligations change over time, as the generation facilities age out and depreciate fully. SRP has not yet formally indicated its approach to how the valuation might change, but considers that revision during each rate application would be practical.[36] This should not delay program implementation, but SRP might want to set out plans for revaluation early in the program.

A related issue is the updating of the administrative component of the Buy-Through Charge. This is created to recover program set-up and ongoing administrative costs. Presumably the set-up cost recovery, which is spread over the program's first five years, would be terminated following that interval, assuming full subscription. (Ongoing costs would, presumably, be revised over time to ensure that the charge fully recovers these costs.)

Some might note that utilities frequently distribute the set-up costs of a program across all customers to avoid deterring participation. An example is the introduction of time-of-use options, where the incremental metering, billing, and administrative costs could have reduced

[36] From conversation with management.

participation to near zero. The justification for the policy of system-wide allocation was that all customers would benefit from the reduction in system costs by the shifting of participants' loads into off-peak periods. The argument for use of this approach here is weaker than usual since departing customers are not likely to confer significant benefits on non-participating customers left behind.

One might also question whether participation is deterred by the existence of large under-recovered FPPAM balances. A customer who selects the Buy-Through Program will likely accelerate payment of their share of these balances into either the first bill or the first 36 months of service. This risk appears to be overstated, though, other than the possibility that some degree of cash liquidity would be necessary for the advance in payment timing. The overall payment level to be made by the customer would be unlikely to change. Accordingly, this possible change in payment timing does not appear to be a barrier to participation.

More generally, the Buy-Through Charge, aside from the administrative component, consists of non-bypassable costs that the customer would pay regardless of participation. The size of the charge might appear to be a deterrent, but clear description of its role would ensure that the customer's perception of additional cost is confined to the cost of program administration: $0.51 per kW-month.

Another cost avoidance issue is whether it is appropriate to use embedded or marginal cost as the basis for avoidance of generation costs. SRP is planning to use embedded costs (i.e., the customer does not pay for generation services under their current tariff). Theoretically, the customer (and their GSP) could claim that the customer departing from standard service should pay their full standard tariff and then be provided with an avoided cost-based discount, where the costs avoided are estimated based on SRP's marginal generation costs. Furthermore, this discount on full service would cause SRP revenue to decline at exactly the same rate as its costs, assuming its avoided cost is equal to the market price. This approach would arguably avoid swings in participation resulting from swings in marginal cost.

However, the question of the valuation of avoided costs is likely to be problematic for two reasons related to price: the challenge of developing an agreed method of estimating avoided cost of generation and the problem of variation over time in the forecasted wholesale price proxy for marginal/avoided cost. Customers applying at different times would receive different credits based on the most recent year-ahead forecast of load-weighted marginal cost. An indication of the practical challenge can be seen below in Section 6 in the review of the problems California and Nevada faced in evaluating avoided cost.

Another challenge with the avoided cost approach is the need for a fixed contract quantity as the basis for valuation. The computational and administrative aspects of this challenge are a good reason for using SRP's embedded cost-based approach: the customer simply is not charged for generation services avoided.

In SRP's case, an additional problem exists: a wholesale price of sufficient granularity and firmness might not be available. The same issues that affect the selection of resupply pricing apply here. Errors in forecasting would produce varying shortfalls and surpluses in cost that would shift to the standard tariff customers of the utility. In summary, the use of avoided cost valuation might avoid swings in participation but would present administrative costs and the possibility of variable cost impacts on remaining customers. Because SRP's embedded generation costs are properly unbundled and are likely to be close to avoided cost on average in the long run, the proposed use of embedded cost appears to be a good starting point for rate design. The simplicity and stability of the pricing plan appears to be advantageous, although it may influence likelihood in participation over time.

A more extensive revision in rate design in the future might also be helpful to stabilize participation. Currently, generation and FPPAM charges recover costs that include fixed costs. Were those to be separated from variable costs, and fixed cost recovery included in the charges to be retained, then the charges to be bypassed could be converted to marginal costs. Essentially, this revision would convert rates E-65 and E-67 into delivery and GSP components, with SRP's GSP service being available to customers who can choose other GSPs. The costs bypassed would then correspond to the utility's marginal costs and non-participating customers would not be at risk of cost shifting.

5.7 Responsibilities of Contracting Parties

SRP's program documents clearly delineate the responsibilities of participating customers, the GSPs, and SRP itself. The eligibility of the GSPs and the nature of their contracting and report activities are defined, including operational interactions with customers and with SRP with regard to scheduling and delivery of power, and in facilitating billing, without formal restrictions being placed on the nature of their contracts with customers. The sole requirement restricting their actions appears to be that account aggregation is out of bounds, at least for project initiation.

Similarly, customers' responsibilities are well defined, with one key component, imbalance settlement with SRP standing out. It appears that SRP has thought through the incentives properties of scheduling and set up a settlement protocol that deters customers from strategic scheduling.

SRP has structured the program to meet its objectives without placing obstacles in participants' and GSPs' paths for contracting and operation of the process of purchasing generation. For the most part, the utility has created a program that facilitates competitive provision of generation services. One remaining issue is the provision of ancillary services, which SRP plans to offer exclusively. In recent testimony at APS, questions arose regarding separate acquisition of ancillary services, but the absence of wholesale markets for these services at present tilts the balance in favor of SRP's approach, at least for the present. This issue can be revisited if market conditions change in the future.

6. COMPARISON WITH OTHER DESIGNS

This section contrasts SRP's Buy-Through Program design with limited retail choice offerings in other jurisdictions including direct access programs in Arizona, California, and Nevada. We also discuss some relevant green tariff power purchase programs in the U.S. These comparisons show that Management's Buy-Through Program design has reasonable program requirements, including the eligible customers and the cap on the size of the program. These comparisons also suggest alternative ways to handle some of the issues with the Buy-Through Program charges raised above.

6.1 Limited Retail Choice in Other Jurisdictions

The National Renewable Energy Laboratory (NREL) summarizes U.S. jurisdictions with full and partial retail energy choice as of 2017 in its report "Charting the Emergence of Corporate Procurement of Utility Scale PV."[37] Retail choice programs enable customers to acquire generation from alternative sources to their utility while continuing to pay for energy distribution costs. While 13 states (e.g., Texas, New York) and Washington D.C. have full retail choice available to all customers, eight states in jurisdictions that have not transitioned to fully de-regulated markets offer limited retail choice, which NREL calls "partial retail choice". The partial retail choice states summarized in the NREL report are California, Georgia, Michigan, Montana, Nevada, Oregon, Virginia, and Washington. Because these states do not have fully deregulated markets, these retail choice offerings are generally limited to certain customers and are subject to enrollment caps. We discuss the California and Nevada Direct Access programs in the following sections.

Eligible Customers

While California and Michigan allow any customer to participate in their retail choice programs, most states limit retail choice programs to large, nonresidential customers.[38] The minimum demand for these large customer-only programs ranges from 900 kW to 5 MW, which puts SRP's 5 MW requirement squarely within the requirements for these programs. Virginia allows two or more customers to aggregate their loads to meet the minimum requirement. Washington determines a customer's retail choice eligibility on a case-by-case basis. Georgia allows only new customers to apply for retail choice at service initiation, prohibiting existing retail service customers from leaving retail service.

Program Limitations and Requirements

Most partial retail choice programs involve program caps to control the impact of the program to the grid. In some cases, these caps are specified as a share of total system loads, such as 10% in Michigan or 12% in California. The large utilities in Oregon have fixed caps of 175 MW (PacifiCorp) and 300 MW (Portland General Electric). This suggests that SRP's Buy-Through Program cap is reasonable.

In states that have renewable portfolio standards, departing customers may be required to meet these standards with their purchased energy, similar to the requirements that utilities must meet in the state. This is the case with Nevada's retail choice program.

Exit Fees

In California, Nevada, and Washington, customers that are departing from a utility's retail service pay an exit fee to the utility to cover the costs of investments made to serve the departing

[37] NREL Technical report: NREL/TP-6A20-69080, September 2017. This report discussed options that corporate customers have for acquiring solar power, including both physical and financial power purchase agreements (PPAs), utility partnerships (including green tariffs and bilateral contracts with utilities), retail choice, and becoming a wholesale power provider.

[38] See Table 3 of the NREL report for details about these programs.

customer's load.[39] We discuss the California and Nevada fees in more detail in the following sections. Virginia does not require an exit fee but requires that customers give utilities five years' notice before exiting retail service.

Program Charges and Retail Rate Bypass

Retail choice programs require that customers continue paying utilities for transmission and delivery-related costs but bypass the generation-related charges. Customers are usually charged for program administration costs and additional fees may be added to account for system planning.

6.2 California Direct Access and Community Choice Aggregation

California requires customers that leave a utility to be served by another provider (i.e., via direct access or to be served by a community choice aggregator) should not shift costs to customers remaining with the utility. That is, departing customers continue to be responsible for costs the utility incurred to serve them. In practice, this requirement is implemented through the Power Cost Indifference Adjustment (PCIA).

Theory of the PCIA

The objective of the PCIA is to recover the difference between the market value and the cost of the energy resources that were contracted on the departing customer's behalf.

The PCIA is described in more detail in the CPUC's most recent annual report on the calculations of the market price benchmarks (MPBs) for the PCIA. [40]

> "The PCIA, or an IOU's Indifference Amount, is equivalent to an IOU's total PCIA eligible portfolio costs less the portfolio's market value in a given year. Market value is defined in D.19-10-001 as "the estimated financial value, measured in dollars, that is attributed to an IOU portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year." D.19-10-001 defines MPBs as "estimates of the value per unit (not total portfolio value) associated with three principal sources of value in IOU portfolios (energy, resource adequacy, and renewable energy)." MPBs are multiplied by the relevant portfolio volume as part of the overall calculation of market value. The forecasted adders are mechanisms that aim to reduce uncertainty of the indifference amount, and the true up adders are mechanisms that aim to align realized market revenues with forecasted values."

The PCIA is calculated for different customer exit years (the "vintage") to account for the fact that the composition of energy resources changes over time. The PCIA will tend to go down over time, eventually reaching zero when enough time has passed that the relevant resources are retired, and contracts have expired.

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[39] Fees associated with leaving retail service can be a combination of upfront exit fees, ongoing adjustment fees, and other surcharges to prevent cost-shifting.

[40] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/calculation-of-the-market-price-benchmarks-20220930.pdf.

CCAs have some objections to the PCIA, including non-transparency of the calculations; lack of incentives for utilities to reduce costs; the added rate volatility; and questions about its effectiveness in preventing cost shifts.[41]

Components of the PCIA

Energy Index

The Energy Index represents the market value of the contracted power in $/MWh. It is calculated using Platts-ICE Forward-Curve Electricity Market Data. It was formerly called the "Brown Power Index".

Resource Adequacy (RA) Adder

The RA adder is the value of each unit of capacity in the PCIA-eligible portfolio used to satisfy RA obligations, expressed in $/kW-month. It has three sub-components: system, local, and flexible. It is calculated from RA-only market transactions data.

Renewable Portfolio Standard (RPS) Adder

The RPS adder reflects the value (in $/MWh) of energy that helps meet RPS obligations. It is developed from market transactions data.

Comparison of the PCIA and Management's Proposal

The PCIA is intended to address many of the same issues as management's proposal but uses different methods.

- *More comprehensive view of generation value.* The PCIA compares the market value to the cost of the entire applicable generation portfolio, whereas management's Early Technology Adoption Charge (ETAC) proposal is limited to renewable sources built prior to 2013. The implicit assumption of management's proposal is that the generation that served departing customers was either purchased at market prices or has a value that approximates that of the market. The advantage of this assumption is that it simplifies the calculations, which may improve transparency and stakeholder acceptance.
- *Vintaging of the generation assets.* The PCIA has different values according to the year in which the customer left the system. (The PCIA for a given vintage also changes over time.) At this time, vintaging isn't necessary for SRP, as it is calculating the ETAC for the first year of the program. In addition, calculating the ETAC for only older renewable assets may limit (or perhaps eliminate) the need for vintaging going forward. However, SRP may want to revisit this issue if additional resources become uneconomic in the future.
- *The FPPAM Settlement Adjustment (FSA).* While the PCIA does not include shares of the fuel adjustment clause, the principle behind the PCIA supports management's proposal to charge the FSA to departing customers. The Public Utility Code sections cited by the CPUC (366.1 and 366.2) specifically reference

[41] https://californiachoiceenergyauthority.com/pcia-fee/.

recovering the departing customer's "fair share" of purchase power costs. We therefore view California as providing support for management's FSA proposal.

- *Basis for the renewable energy value.* SRP management is proposing to base the renewable value of the ETAC-eligible resources on its Solar Choice Plus Program premium, which is currently $0.005 per kWh. In contrast, California bases its renewable value on RPS-related market transactions.

6.3 MGM Departure from Nevada Power

In 2015, MGM Resorts International (MGM) filed an application with the Public Utilities Commission of Nevada to exit NV Energy's system and instead purchase energy, capacity, and/or ancillary services from a third-party provider. The departure occurred in October 2016, with MGM paying an initial exit fee (called an "impact fee" in the proceeding) of $86.9 million. MGM continued to pay impact fees of varying amounts for the following six years, at which time MGM's departure was found to no longer burden remaining customers.

The December 3, 2015 Order approving MGM's application[42] noted that MGM would "pay its load ratio share of unrecovered adjusted balances in Nevada Power's deferred accounts, as reasonably determined by the Commission." (Order page 7, paragraph 18.) This establishes a principle that is consistent with SRP management's FPPAM Settlement Adjustment proposal, which charges departing customers their share (based on their usage divided by system sales) if FPPAM balances, provided the FPPAM balance is outside a $20 million dead-band.

In addition to the impact fee, MGM was required to pay a set of non-bypassable charges. One of these charges is the Renewable Base Tariff Energy Rate (R-BTER) charge, which represents "the embedded costs associated with the long term, above-market-price (or out-of-the-money), must-take renewable energy resource contracts that affect the BTER." (Order page 66, paragraph 189.) This is consistent with SRP management's proposed ETAC, which is intended to recover costs associated with above-market renewable energy sources constructed prior to 2013.

As was the case with California's PCIA, Nevada took a more comprehensive approach than SRP is proposing to evaluate the generation costs that could be shifted to non-participants. For example, NV Energy was directed to perform production cost simulations using PROMOD for various scenarios, the results of which determined the BTER costs that needed to be recovered from MGM to prevent a cost shift. The more comprehensive approach has the potential to better identify potential cost shifts but requires assumptions and is complex to implement. These features may reduce stakeholder acceptance.

Following the MGM proceeding, NV Energy expressed dissatisfaction with the impact-fee methodology's ability to prevent cost shifts as more customers left their system in the same manner as MGM. The Staff-directed modeling used to calculate the impact fees assumed that load growth would eventually employ the generation resources formerly used to serve the departing customer. However, as more customers have left NV Energy's system, the load growth

[42] https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-5/7908.pdf.

forecasts have not come to pass. This has caused NV Energy to propose increasing the six-year exit fee period to 18 years.[43]

6.4 Arizona Public Service's AG-X Rate

Arizona Public Service Company (APS), the other major utility in the Phoenix metropolitan area, has a long-standing buy-through program that is set out in its rate rider AG-X. APS proposed revisions to its AG-X rate rider in a 2022 rate case.[44] We compare the current terms of the AG-X rate rider to SRP's Buy-Through Program and discuss APS' proposed revisions from the 2022 rate case.[45]

Eligible Customers

The AG-X rate rider is available to customers served on the E-34, E-35, E32-L, or E-32 TOU L retail rates who have an aggregated peak load of 10 MW.[46] While this minimum peak load requirement is higher than the 5 MW minimum in SRP's Buy-Through Program, APS has requested to lower this requirement to 5 MW in its 2022 rate case. APS allows customers participating in the program to have load growth of up to 10% and does not limit its program to high load factor customers. APS also has a more expansive set of non-residential customers who are eligible for the AG-X rate rider. The eligible rates include customers that are metered at transmission, primary, or secondary including self-contained meters and instrument-rated meters. The fact that APS allows for account aggregation makes lower voltage service compatible with the minimum size requirements.

Program Limitations and Requirements

The AG-X rate rider is limited to 200 MW of demand and half of the program is reserved for the largest, high load factor customers, those with demands of at least 20 MW and a load factor of at least 70%. APS uses a lottery system to admit customers to the program when demand for the program exceeds the program cap. The terms and conditions for participating customers and GSPs are similar to SRP's Buy-Through Program requirements described above.

While APS does have a minimum demand requirement for participating customers, it does not specify a cap for customer participation size like SRP's 50 MW cap. As such, there are no provisions for partial customer participation as in SRP's Buy-Through Program.

[43] https://thenevadaindependent.com/article/nv-energy-calls-for-higher-exit-fees-on-growing-list-of-departing-companies.
[44] See Arizona Corporation Commission Docket No. E-01345A-22-0144.
[45] For current AG-X terms, see APS' Rate Rider AG-X, Generation Service, Alternative Generation, effective December 1, 2021, https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Business/Rate-Riders/agxAlternativeGenerationGeneralServiceExperimental.ashx?la=en.
[46] Aggregated load refers to the total load of the customer's separately metered accounts, which may include metered accounts served on the E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S retail rates if these are on the same premise as the eligible rate schedule accounts. Aggregated customers must have the same corporate name, ownership, and identity but can be operating under multiple trade names. In is 2022 rate case, APS proposed allowing E-32 M and E-32 TOU M customers to be eligible for the AG-X program.

Buy-Through Charges and Retail Rate Bypass

Customers on rate rider AG-X do not pay retail generation tariffs, power supply adjustment charges, environmental improvement surcharges, and associated taxes. The AG-X rate rider specifies a separate administrative fee for the program bases on monthly energy use of $0.00171 per kWh, and a monthly reserve capacity demand charge of $5.248 per kW.[47] The AG-X rate rider does not charge customers for any portion of APS' investments to meet its obligations for environmental improvement projects.

In its 2022 rate case, APS proposed to modify the AG-X program, providing customers with two enrollment options. Customers may find a GSP that will provide resource adequacy for their loads, including a 15% reserve margin. This option requires that GSPs can prove that the energy being sourced is a more reliable and not otherwise committed to resource adequacy or balancing, according to APS' own standards for its resource adequacy. Customers that choose this option will avoid the reserve capacity charge on the AG-X rate rider but must give three year's notice to return to retail service. Customers that elect to have APS provide resource adequacy will have less scrutiny of their power sourcing but will continue to pay the reserve capacity charge and must give one year's notice to return to retail service. It is worth noting that APS proposed changing this reserve capacity charge to be equal to the unbundled demand generation charge from the E-34 tariff, which would be more than double the previous rate. Essentially these customers would only bypass the generation energy charges and the PSA charge.

In contrast, SRP's buy-through design provides customers with resource adequacy, charges them a more modest reserve capacity fee of $2.87 per kW, and requires three year's notice to return to retail service.

Imbalance Charges

APS has a process for settlement of imbalances similar to the process laid out in SRP's Buy-Through Program with imbalance charges that are based on APS's OATT Schedule 4 imbalance charges (i.e., the relevant LAP price). APS also has a two-tiered system for imbalance charges, with the same threshold between tiers 1 and 2 of +/- 15% or 2 MW. The premium for tier 2 imbalances is a set amount of $3/MWh rather than a +/- 25% premium. APS defines excess imbalances as months with more than 20% of the hours having at least a 20% imbalance, a slightly more lenient definition of excess imbalance compared to SRP's Buy-Through Program. Similarly, customers with two or more months of excess imbalance may be terminated from the program.

Resupply Energy

Customers that are between GSPs or that give less than one year's notice to leave the AG-X program are charged for energy according to the resupply price, which is the same index used as SRP (i.e., the Palo Verde Peak or Off-Peak ICE Day-Ahead Power prices). APS also adds a $10/MWh fee to the index price, similar to SRP. APS specifies that the resupply price cannot be less than $0 and reserves the right to charge the customer based on the applicable retail rate.

[47] In its 2022 rate case, APS proposed lowering the administrative fee to $0.00164 per kWh and changing the capacity reserve charge to be the unbundled generation demand charge associated with the E-34 rate schedule, which is proposed to be set at $12.429 per kW.

Fuel Charge Settlement

APS does not have any provision for the settlement of power supply adjustment charges or other charges such as SRP's ETAC fee that customers will bypass on the AG-X rate rider.

6.5 Green Power Purchase Programs

Green power purchase programs enable customers to procure renewable energy outside of their utility's standard offerings in order to acquire the associated renewable energy certificates (RECs) to satisfy corporate sustainability goals. Green power purchase programs are good comparisons to SRP's Buy-Through Program because many are offered in similarly regulated jurisdictions. We find that many of these programs have eligibility requirements and program limitations that are comparable to SRP's program design. Moreover, some programs provide examples of alternatives to SRP's design for handling issues of rate bypass and program charges.

The Clean Energy Buyers Association (CEBA) produces a periodic summary of green tariffs in the U.S.[48] According to CEBA, "Green tariffs are voluntary utility programs that allow eligible customers to buy both the energy and associated renewable energy certificates (RECs) from a large-scale renewable energy project through an independent tariff or as a rider on a customer's current electricity bill."[49] CEBA categorizes green tariff programs into sleeved PPA models in which customers can enter into physical PPAs with renewable generators, subscription programs in which customers can subscribe to large renewable energy generation projects that are owned by the utility or for which the utility has a PPA, and market-based rate programs which enable wholesale market participation opportunities for customers or groups of customers. Sleeved PPA models are the relevant comparison, and we discuss the program designs that are presented in the CEBA reports.

Sleeved PPA programs are available through Alliant Energy (Wisconsin), Dominion Energy (Virginia), Duke Energy Carolinas, East Kentucky Power Cooperative, Idaho Power, Indiana Michigan Power, Kentucky Power, Kentucky Utilities Company (Kentucky and Virginia), Louisville Gas and Electric Company/Kentucky Utilities Company, Madison Gas & Electric (Wisconsin), Public Service Company of New Mexico, NV Energy, Portland General Electric (Oregon), Rocky Mountain Power (Utah), Tennessee Valley Authority, WE Energies (Wisconsin), and Black Hills Energy (Wyoming).[50] We discuss some of the relevant program elements, but do not provide a comprehensive summary of all of these programs.

Eligible Customers

Most utilities limit green power purchase programs to nonresidential customers, and in most cases the programs are limited to large customers on specific retail tariffs or on specific meter sizes.[51] The minimum demand for these programs ranges from 1 MW to 10 MW, consistent with

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[48] CEBA, "U.S. Electricity Markets: Utility Green Tariff Update," December 2020, and CEBA, "U.S. Utility Green Tariff Report," January 2023. Both reports are available at https://cebuyers.org/programs/education-engagement/green-tariffs/.

[49] CEBA, "U.S. Utility Green Tariff Report," January 2023, pg. 5.

[50] This is based on the sleeved PPA programs summarized in the 2020 and 2023 CEBA reports.

[51] See the CEBA 2020 and 2023 reports for the specific customer classes and rate schedules that are eligible for each utility.

SRP's 5 MW requirement. Unlike SRP, most of these programs allow customers to aggregate multiple service accounts to meet the minimum requirements, often across the utility's system. Black Hills Energy's program is designed for new customer loads that are expected to be 13 MW or greater and is not open to existing customers.[52] Most utilities do not have load factor requirements for customers, but Public Service Company of New Mexico is an exception with their 75% minimum load factor requirement.

Some programs allow customers to subscribe to capacity that exceeds their historical peak demands.[53] Black Hills Energy, on the other hand, only allows up to 85% of billing capacity in order to include a planning reserve margin. Many of the utilities also allow net metering customers to join the program.

Program Limitations and Requirements

Most of these programs have subscription caps ranging from just 50 MW for Madison Gas and Electric's existing customers (no limit for new customers) to 4,000 MW for Duke Energy in North Carolina. More commonly the cap is around 150-300 MW, consistent with SRP's Buy-Through Program cap. Other utilities such as the Tennessee Valley Authority do not have enrollment caps, but enrollment may be subject to the regulator's approval in these cases. Utilities such as Duke Energy Carolinas have sub-divided the program cap to reserve a portion of the program for specific customer groups such as local governments and higher education institutions.

Several of the utilities require that the renewable generation facility is located in their service territory or the same state. Kentucky Utilities Company specifies that the generator must be located in one of the states in the same region including Kentucky, Indiana, Tennessee, Ohio, West Virginia, Virginia, Missouri, or Illinois. Other utilities require that the generator be located within the RTO territory (e.g., PJM's territory).

It is also common for these programs to require a minimum commitment by the customer which can range from as little as one year for Indiana Michigan Power to 15 or more years but is more commonly around five years. This is usually related to whether the utility commissions new renewable projects on the customer's behalf rather than just contracting with an existing renewable generator. In these cases, there can also be project size limitations such as 2-500 MW projects within the Tennessee Valley Authority. Idaho Power also works with customers to develop new renewable generation facilities with the construction cost borne by the customer, while Rocky Mountain Power assumes ownership of facilities that are built by developers. Other utilities such as Indiana and Michigan Power work with customers to find renewable generation sources and to execute a PPA for this energy supply. Duke Energy Carolinas allows customers to find their own renewable generators.

Program Charges and Retail Rate Bypass

Most green tariff (sleeve PPA) programs have a similar rate structure which involves the customers continuing to pay their retail tariffs, the additional cost of the acquired renewable energy, and a modest administrative fee (usually between several hundred and several thousand dollars per month). In exchange, customers are given a credit for the renewable energy they

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[52] Public Service Company of New Mexico also limits its green tariff program to new customers.

[53] For example, Duke Energy Carolinas has allowed customers to purchase up to 125% of their capacity needs and Idaho Power allows up to 110%. This provision is less relevant to buy-through programs.

consume. This approach assures that customers in green tariff programs are paying all of their system costs and are not cross subsidized by other customers. The nature of the energy credit varies widely across these programs:

- Duke Energy Carolinas credits customers for the renewable energy delivered by the GSP to the system based on the marginal hourly avoided cost to Duke. These marginal avoided costs include expected production costs as well as capacity costs for hours in which there are generation constraints.
- East Kentucky Power Cooperative credits participants based on the total avoided cost (i.e., the base fuel, the fuel adjustment clause, and the variable environmental surcharge)/MWh and a capacity credit, when applicable. The credit is the lesser of the total credit or the PJM Locational Marginal Price.
- Portland General Electric gives participants a credit for the energy and capacity value of the renewable power produced. The utility also charges customers a risk adjustment factor if customers do not commit to the program for the full PPA term.
- Alliant Energy allows customers to bypass fuel cost surcharges on renewable energy consumed and gives customers renewable energy credits based on the MISO energy market prices.
- Dominion Energy provides credits based on PJM settlement amounts.
- Public Service Company of New Mexico gives participants excess energy credits based on the Palo Verde ICE day-ahead price index during hours with energy production that exceeds customer demand.
- WE Energies gives customers a monthly energy generation credit equal to the renewable generation project's settled MISO market energy credit value (applied to the lesser of energy generation or actual consumption) and a monthly capacity credit equal to 1/12 of the resource's annual amount capacity credit from MISO.
- Madison Gas and Electric participants bypass fuel costs and renewable resource rates (instead participants pay a project-specific renewable resource rate) but do not get credits for renewable energy production.
- Black Hills bypass the Power Cost Adjustment and DSM surcharges but are assessed an additional microgrid management fee based on billing capacity of the facility as well as facility-specific energy costs.
- Idaho Power has a negotiated price that the customers pay for renewable generation project output and the customer gets credited this price for energy production in excess of their demand.
- Kentucky Utilities Company gives participants renewable energy credits that are negotiated with the customers in addition to the negotiated project charges.

Rocky Mountain Power is an exception to this general structure of paying full retail rates and getting renewables credits. The utility has a completely separate tariff for customers in this program that includes customer and delivery charges and demand charges based on the project contract capacity. Customers are not credited for renewable energy production in excess of the customer's demand.

7. FINDINGS

SRP's management team has developed a proposed Buy-Through Program that meets all the design criteria identified by the Board regarding the costing, pricing, and statutory requirements for a successful program. Most importantly, the program structure promotes full cost recovery from participants while offering them the opportunity to seek and acquire efficiently priced generation services.

The cost underpinnings of the buy-through design are sound.

- Embedded costs of delivery services are properly classified by cost-causative factor and appear to be allocated according to conventional principles.
- Generation services, where provided by SRP (imbalance and resupply) are based on sensible representations of marginal cost/wholesale market energy price.
- Ancillary services are acceptable in embedded cost form given the lack of reserves markets in the region.

Management's design offers pricing that recovers cost fully and is efficient.

- The design is consistent with the Board's general principles of gradualism, price efficiency, and revenue recovery.
- The design is consistent with sound utility practice and general economic theory:
    - Delivery services are priced based on embedded costs based on established costing methods. In particular, fixed cost recovery does not appear to take place via volumetric (kWh) pricing.
    - Generation services are based on market prices.
- Prices reflect their underlying cost drivers, by subfunction.

Lastly, the program's structure responds fully to the obligations of the legislation.

Management's approach to the key issues of buy-through pricing is largely sound, although we raise questions as to pricing methodology and eligibility/departure requirements.

- **Resource adequacy.** SRP's program provisions limiting scale, requiring detailed GSP vetting, tiered pricing of imbalances and resupply premium pricing all indicate that the program has multiple structures to support SRP being able to deliver generation to all its customers.
- **POLR consideration.** SRP plans to use public price indexes that allow the utility to match revenues from POLR customers to the cost to serve them.
- **Imbalance service charges.** SRP has chosen to settle imbalances with customers (rather than the GSP), using a tiered structure based on the utility's expectation that this will avoid or limit strategic scheduling based on forecasts of market prices relative to contract prices.
    - There might be opposition to the tiered pricing approach, but it appears to provide SRP with a necessary incentive to customers to minimize imbalances. The power to remove someone from the rate for persistent excessive imbalances is reasonable but arguably not sufficient.

- The Tier 2 markup might be set at a level that makes SRP indifferent between customer imbalance increases and reductions. Observation of behavior early in the program may provide guidance here.

- **GSP Default.** SRP's use of the Palo Verde day-ahead price indexes plus a price premium appears to give customers using resupply service a strong incentive to recontract with a new GSP. The resupply price also gives customers the incentive to give SRP three-years' notice before returning to retail service.
  - There might be opposition to SRP charging a premium for resupply service. However, SRP is entitled to earn a premium in return for offering the service.
  - SRP's preference for Palo Verde appears defensible from both theoretical and operational perspectives.
- **Return to Standard Offerings.** SRP offers a clear path to return. The issue associated with return is the length of advance notice. Three years' notice is based on capacity availability concerns and planning experience. However, this may be conservative, and a policy of allowing a shorter time period in the event of availability may help to improve the attractiveness of the program.
- **Bypass.** The Buy-Through Charge is well documented and the calculations of administrative, reserve capacity and ETAC charges appear sound and defensible. As the program ages, reductions in administrative and ETAC charges should be expected.
- **Responsibilities of Contracting Parties.** SRP's program documents set out parties' responsibilities clearly. Aggregation is not currently feasible but can be considered in the future.
  - Ancillary services will be managed by SRP for sound reasons of lack of market sources. As markets develop, this could change without hurting the program.

Management's design appears to conform to industry practice based on a short list of examples.

- Examples from California and Nevada indicate that there is precedent for SRP's approach to limiting cost shifting.
  - California devised the Power Cost Indifference Adjustment (PCIA) to ensure that the out-of-market costs of energy resources would continue to be billed to customers who secured power elsewhere. Their methodology does not need to be applied at SRP partly due to the relatively small scale of SRP's cost recovery and partly due to their more comprehensive view of generation value.
  - Nevada developed an impact-fee approach to valuation. Again, it has value as precedent for recovering out-of-market costs, but its methodology appears to be more complex than SRP needs, involving production cost simulations to estimate these costs.
  - FPPAM: it is difficult to find analogies but SRP's approach appears to be consistent with what other utilities do regarding fuel and purchased power costs.
  - ETAC: SRP's approach is simpler than the California and Nevada methodologies. SRP's approach has the advantages of transparency and likely ready acceptance. The possible disadvantage is that the approach does not

attempt to evaluate the market value (and hence out-of-market cost) of the whole generation portfolio.

- Several aspects of the SRP design make use of similar design components at Arizona Public Service in its AG-X rate. However, SRP has adopted a different approach in some cases, partly due to differences in underlying rate design and pricing, and partly based on different perceptions about pricing incentives.
  - Both utilities include a reserve capacity charge to ensure that the lost customer loads continue to pay their share of reserve capacity costs, as the host utility is providing that reserve capacity.
  - Both utilities undertake imbalance settlement, but APS settles with the GSPs while SRP has decided to settle with the customers, based on the understanding that customer strategic behavior to minimize their costs can be influenced and reduced by a tiered pricing scheme.

Summary:

SRP management's proposed Buy-Through Program appears to meet the Board's requirements for a successful design: participating customers can contract with GSPs for service without introducing cost shifts to other customers, paying embedded costs for delivery services and market-based prices for generation services from their GSPs and from SRP through imbalance settlement and resupply pricing in the event of contract default. Customers may return to SRP under clear terms. Furthermore, the program appears capable of being scaled up and of responding to changes in wholesale markets, including with respect to alternatives to the provision of ancillary services.

APPENDIX: COMPARISON OF HISTORICAL ICE DAY-AHEAD PEAK PRICES AND CAISO REAL-TIME PEAK PRICES, PALO VERDE NODE

This appendix examines the Palo Verde ICE day-ahead peak weighted average prices (available through the Energy Information Administration) compared to the CAISO real-time energy imbalance market (EIM) hourly LAP prices for the Palo Verde node (PALO_VRDE_5_N101) provided by SRP Management, for the period from 2020 through 2022. The ICE peak period hours are those ending 7 through 22 (i.e., 6:00 am to 10:00 pm) Monday through Saturday.

ICE Day-Ahead Price Premium over Real-Time Market

We compared the Palo Verde ICE peak day-ahead prices to the EIM prices to assess SRP management's belief that the former index reflects the value of firm power (and to some extent capacity constraints) which are not accounted for to the same extent in the EIM prices. The table below summarizes the average hourly prices during ICE peak hours compared to the EIM prices for the Palo Verde (PV) node during the same hours, by year. There is over a 50% premium in the ICE peak prices compared to the EIM prices during this time, which may be due in part to historically high prices and large price volatility during this time.

Table 1
Annual Average Palo Verde Peak Period Prices

Peak Price Comparison	2020	2021	2022
EIM Annual Avg Price	$ 26.87	$ 40.33	$ 63.96
PV ICE Annual Avg Price	$ 44.95	$ 59.62	$ 98.23
PV ICE % Premium	67%	48%	54%

SRP management conducted a similar analysis for all hours (including the Palo Verde ICE off-peak period prices). Their calculations yielded a smaller price premium in each year, which one might expect when including off-peak hours. Nonetheless, this analysis shows that the WSPP Schedule C firm power that is traded on the ICE is reflected in the persistent price premium over the real-time EIM prices.

Table 2
Annual Average Palo Verde All-Hours Prices

All Hours Comparison	2020	2021	2022
EIM Annual Avg Price	$ 24.59	$ 36.80	$ 62.03
PV ICE Annual Avg Price	$ 37.84	$ 51.77	$ 88.57
PV ICE % Premium	54%	41%	43%

Hourly Variation in the ICE Day-Ahead Prices and the Real-Time Market

Next, we examine the hourly differences between the ICE Day-ahead and EIM prices. Figure 1 below shows the average prices across peak days in 2020-2022 in each ICE peak period hour. The Palo Verde ICE day-ahead peak prices (blue) are higher on average than the EIM prices at the Palo Verde node (red) during each hour except for the hour ending 19. This reflects the fact that the ICE day-ahead prices are not shaped and are identical over 16 hours. The figure also shows that there is a considerable price premium during hours ending 7-16 for ICE day-ahead prices relative to EIM prices.

One might question whether variations in resupply customer load might lead to pricing inaccuracy (over- or under-charging of customers) under TOU pricing relative to an hourly pricing scheme. SRP's buy-through customers are expected to have relatively high load factors but loads with differing patterns within TOU periods might have identical bills under the proposed TOU pricing scheme but different bills under an hourly shaped pricing arrangement. CAISO provides hourly shaping factors from the real-time market that would permit creation of shaped hourly Palo Verde prices.

If the Palo Verde ICE peak period were shortened to reflect a time period closer to SRP's own TOU peak period hours, then the problem might be less significant. However, SRP cannot control the TOU period length of the Palo Verde ICE prices.

Figure 1
Average Hourly Palo Verde Peak Period Prices

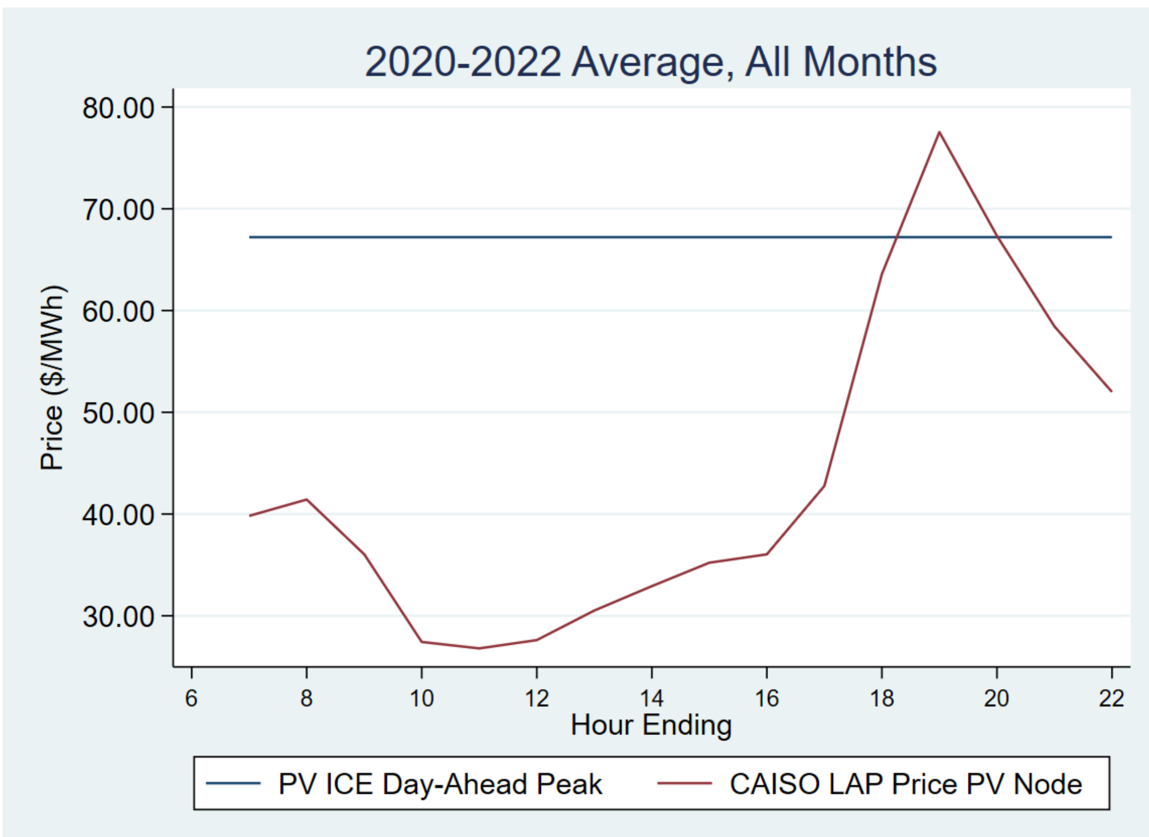
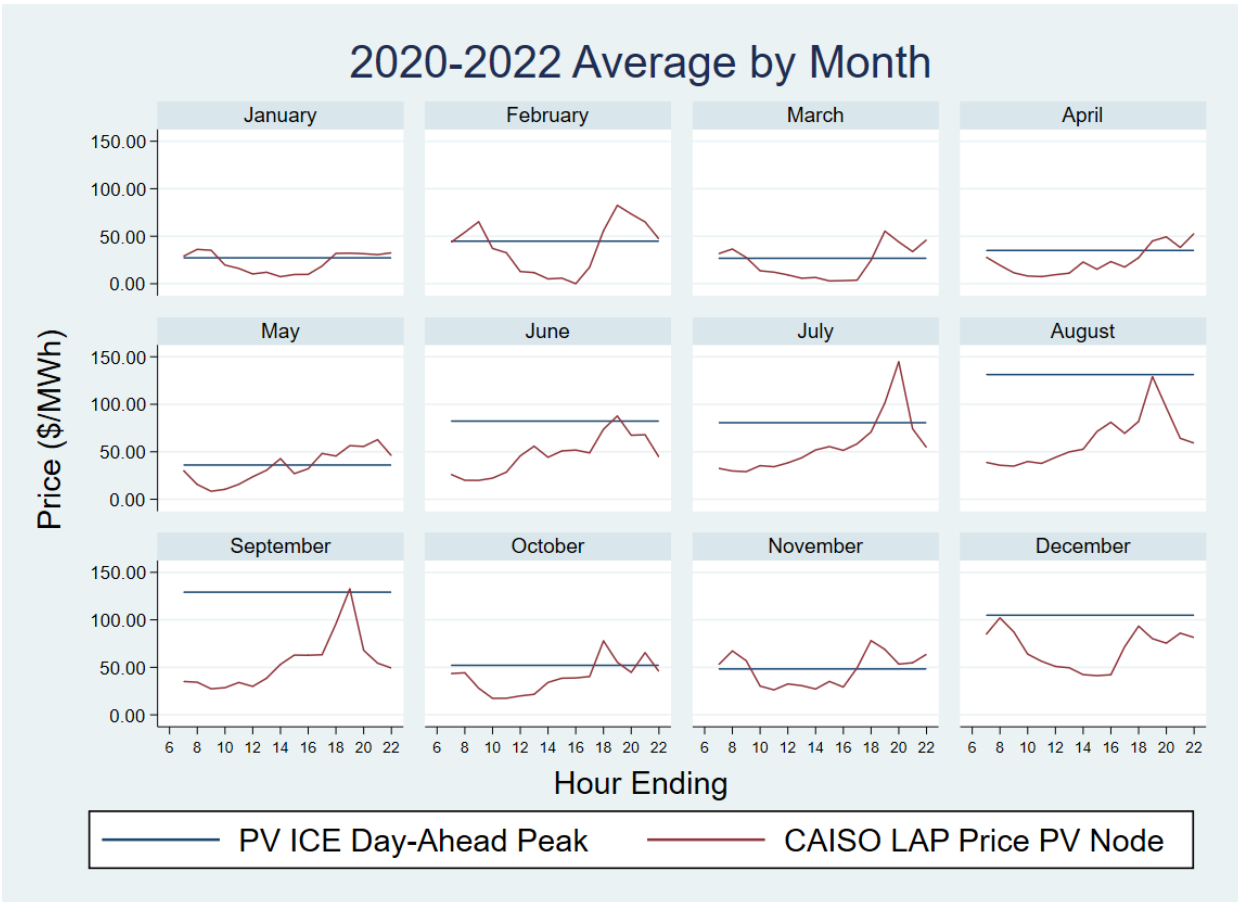


Figure 2 provides a comparison by month of the year. The winter months have a slightly different pattern of price premium hours in both the morning and evening hours compared to the summer months which have a large evening spike in hourly prices.

Figure 2
Average Hourly Palo Verde Peak Period Prices, by Month



Resupply Energy Price Premium Analysis

Figure 3 shows the average prices across peak days in 2020-2022 in each ICE peak period hour. In addition to the average of the ICE day-ahead (blue) and the EIM prices (green), there is a line representing SRP's resupply price (red) over the same period. The price premium indicates, that for these data, the resupply price is higher than the EIM price, even during the peak hour ending 19.

The figure should be interpreted with caution. SRP intends to provide resupply energy at the resupply price and to purchase the required energy and capacity at Palo Verde day-ahead price (the resupply price excluding the premium). Such pricing has low risk to the utility and its standard tariff customers but high variability across days and months, representing risk to the resupply customer while subject to these prices. Additionally, resupply customers with different load profiles might pay the same for resupply energy but have different costs to serve were hourly pricing available. In SRP's case, at least for the present, such pricing is not available with reliability. While CAISO day-ahead hourly prices are available in some months (typically not peak summer months) it would be difficult to characterize such power as firm in the sense that the Palo Verde ICE day-ahead power is.

Figure 3
Average Hourly Palo Verde Peak Period Prices
and SRP Resupply Price

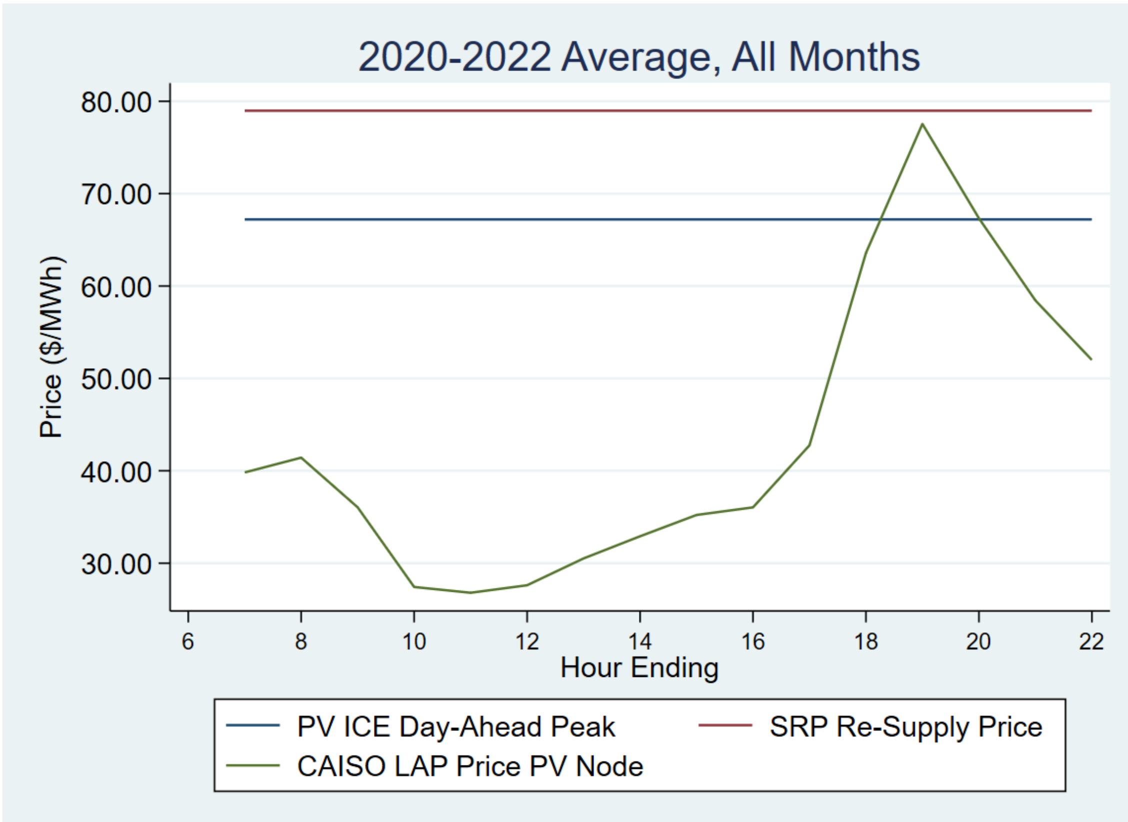


Figure 4 shows a similar comparison by month of the year. Each month is depicted using the same vertical scale, indicating seasonality of pricing for the historical period. The level of the resupply price varies with the season, rising in summer and falling in other months.

Figure 4
Average Hourly Palo Verde Peak Period Prices
and SRP Resupply Price, by Month