Final Report on Thematic Line 2:
Transformation of the Peruvian Wholesale Electricity Market

by

Frank A. Wolak*

Director, Program on Energy and Sustainable Development

Professor, Department of Economics

Stanford University

Stanford, CA 94305-6072

wolak@zia.stanford.edu

June 24, 2021

*I would like to thank Professors Ignacio Pérez-Arriaga, Carlos Batlle, and Peter Cramton for very helpful comments on previous drafts. I would also like to thank Electro Dunas, ENGIE, Kallpa, Distriluz, Electro Ucayali, ENEL, Statkraft, and Termochilca for their comments on previous drafts.

Table of Contents

1. Introduction

Restructuring of the Peruvian electricity supply industry began in 1992 with the Law of Electric Concessions (DL25844 of 1992) and was enhanced 2006 with the Law of Efficient Development of Electricity Generation (Law 28832 of 2006). Since 2006, there have been several modifications to the market design and regulatory process governing the industry, but the major features, a cost-based, locational marginal pricing (LMP) real-time market that relies primarily on full-requirements long-term contracts between generation unit owners and distribution companies and free consumers to serve their customers, remain in place.

Over this period there has been substantial technological change in the electricity generation sector, greater emphasis on reducing the greenhouse gas emissions from electricity production, and significantly more international experience with the design and regulatory oversight of restructured electricity supply industries. Combined cycle gas turbine (CCGT) generation technology has found widespread adoption in regions with significant natural gas resources as the most efficient way to produce electricity from a fossil fuel. The levelized cost of energy (LCOE) from wind and solar photovoltaic generation capacity has also declined considerably over this period. This has significantly lowered the above-market costs to jurisdictions of reducing GHG emissions from their electricity sectors. Over past twenty-five years, many countries and regions of United States have dramatically changed their initial wholesale electricity market designs and regulatory policy goals in response to these changes with differing degrees of success.

The experience of these countries and regions with the initial designs and subsequent reforms of their electricity supply industries has provided several valuable lessons about the most efficient short-term market design, long-term resource adequacy mechanism, and effective regulatory oversight process for a wholesale electricity market. A multi-settlement LMP market design that co-optimizes the procurement of energy and operating reserves in the day-ahead and real-time markets is generally acknowledged to be the preferred short-term market design, particularly for regions with significant intermittent renewable energy goals. In the United States, there is widespread recognition of the need for an automatic local market power mitigation (LMPM) mechanism built into the market software for any *offer-based* wholesale market. This logic argues against Peru transitioning to an offer-based market until an automatic LMPM mechanism and other appropriate regulatory safeguards are in place.

With the increasing reliance of many regions on intermittent renewable resources, the need for active involvement of final consumers in the wholesale market is increasingly urgent and the declining cost of interval meters is making this technologically feasible in an increasing number of jurisdictions. In the United States, there is growing dissatisfaction with capacity-based long-term resource adequacy mechanisms, particularly in regions with ambitious intermittent renewable energy goals. As consequence, several regions have implemented or are currently considering alternative long-term resource adequacy mechanisms. Finally, in the United States and in an increasing number of countries, there is a general acknowledgement among market participants and regulators of the need for a formal market monitoring and ongoing market design process to continuously adapt the wholesale market design and regulatory process to changing market conditions and policy goals.

The purpose of this report is to adapt the lessons from international experience with electricity market design and monitoring over the past twenty years to the Peruvian context and provide recommendations for transforming the country's wholesale market design and regulatory process. A major lesson from more than thirty years of electricity restructuring processes is that there are several general principles that must be respected in the market design process. Nevertheless, many details of an efficient market design depend on initial conditions in the country, industry, and regulatory oversight process. Therefore, it is important to understand these initial conditions to provide recommendations with the greatest likelihood of improving market performance with the minimal economic and institutional implementation costs.

After describing those aspects of the Peruvian wholesale market design that are under consideration for reform at the present time, I first review the essential features of the existing market design and regulatory institutions in Peru. I then identify shortcomings in the existing market design based on lessons from the past twenty years of experience with restructured electricity supply industries. I then provide a comprehensive set of recommendations for transforming the Peruvian electricity supply industry and regulatory oversight process based on international experience, as well as general recommendations for how to sequence the implementation of these recommendations.

2. Scope of Work: Transformation of the Wholesale Market

This section describes the four segments of the Peruvian wholesale electricity market design likely to benefit from the lessons learned from the past 25 years of international electricity industry restructuring processes. Significant changes aimed at improving industry performance have been made to these four segments in both industrialized and developing countries. This experience provides important lessons for modernizing the current market design and regulatory oversight process in Peru.

2.1. Evaluation and adaptation of the short-term market

Peru currently operates a real-time market that dispatches generation units every 15-minutes to serve demands throughout the transmission network during that time interval and sets half-hourly locational marginal prices using regulator-validated operating costs, as opposed to offers and bids submitted by market participants. The current market design in Peru shares a crucial feature with the generally agreed upon preferred market design referred to in Section 1 by pricing all transmission network and other relevant operating constraints as well as the marginal losses associated with different points of injection and withdrawal from the Peruvian grid.

An important consideration in the potential evolution of the short-term electricity market in Peru is whether to shift from a cost-based short-term market to an offer-based short-term market. This topic deserves serious consideration as a larger share of the energy consumed in Peru comes from intermittent renewable generation resources that do not have a direct variable cost of producing energy. This increase in intermittent renewable energy production will likely require investments in storage to transfer this energy from periods when it is produced to periods when it is needed to meet demand. However, as discussed below, there are number of necessary features of the market design and regulatory oversight process not yet in place that are pre-conditions for making this transition. Consequently, I believe it would be imprudent to shift from a cost-based to an offer-based short-term market as part of the current reform process.

The following enhancements to the current cost-based market should be implemented. A day-ahead financially binding cost-based forward market for energy should be combined with the real-time market for energy to clear imbalances relative to day-ahead energy sales and purchases. These two markets should allow generation unit owners (suppliers) and distribution companies and free consumers (demanders) to participate symmetrically. Although symmetric treatment of suppliers and demanders in the short-term market is a significant change in the Peruvian market design, I believe it has the potential to improve overall market efficiency relative to the existing short-term market among only generation unit owners for the reasons described in Section 4.1. A day-ahead and real-time operating reserves market should be co-optimized with the day-ahead and real-time energy markets. The operating reserves market should have a mechanism to set scarcity prices for operating reserves and energy when insufficient operating reserves are offered into the short-term market relative to the levels desired by the system operator.

If the Peruvian government decides to commit to explicit targets for the share or quantity of renewable energy produced in Peru, a renewable energy certificate (REC) market should be introduced as the least cost mechanism for meeting these renewable energy resource (RER) targets. Without an explicit renewable energy target set by the Peruvian government, there is no need to introduce a REC market because in many cases RERs can compete against conventional generation resources for new sources of energy without any additional financial support.

Transmission network operation should remain combined with wholesale market operation. A formal market independent monitoring process for the wholesale market should be established to function within the formal regulatory oversight process and market design process. A well-functioning independent market monitoring process is a necessary pre-condition to begin consideration of the introduction of an offer-based market in Peru. Finally, a formal transmission and generation planning process with a regulatory backstop for transmission and generation investments should be established as part of this regulatory process. This planning process should be primarily used to provide unbiased information to policymakers and market participants about transmission and generation unit adequacy. It is also crucial input to the regulatory process that determines whether to implement a regulatory backstop for transmission or generation investments.

2.2. Reformulation of the Long-Term Generation Adequacy Mechanism

The challenge of having sufficient energy available to meet the demand for electricity in Peru is significantly more complicated than it is for many other markets. First, typically more than 50% of the electricity consumed annually comes from hydroelectricity sources. Second, the annual rate of growth of electricity demand in Peru over the past 10 years has averaged over 5% per year, which is substantially higher than the growth rates in the United States and other industrialized countries, where rates of 1% or less are not unusual. Finally, recent energy policy in Peru has focused on increasing the share of energy from intermittent renewable resources such as wind and solar.

All the above factors argue in favor of an approach to long-term resource adequacy that focuses on ensuring an adequate supply of energy to meet demand during all hours of the year, rather than having sufficient installed generation capacity to meet annual peak demands. As the experiences of California during August of 2020 and Texas during February of 2021 demonstrated, installed generation capacity significantly larger than the annual demand peak does not guarantee that this capacity will be able to produce energy when it is needed, particularly if a significant fraction is intermittent renewable generation capacity. Ensuring adequate energy to meet demand throughout the year is particularly important in a market with a large share of the energy coming from hydroelectric resources, because the amount energy available from these resources can be significantly less during years with low water inflows.

Another important concern in the Peruvian context is the duration of long-term resource adequacy commitments. The current long-term resource adequacy (LT-RA) mechanism primarily involves full-requirements contracts between generation unit owners and load serving entities procured through bilateral negotiation subject to the regulated "tarifa de barra" or busbar price cap or through a competitive bidding process. These full-requirements contracts can be as long as twenty years in duration, which is clearly long enough to provide revenue certainty for a generation unit owner. However, because of their duration, these contracts can also completely insulate consumers from current conditions in the short-term energy market in Peru, although the capacity price component of these power purchase agreements (PPAs) is adjusted over time. As Ruff (2005) notes, because sellers of these full requirements contracts must manage all the variability in the hourly quantity of wholesale energy consumed by the free consumers or distribution utilities they serve, large suppliers with a portfolio of generation unit owners have a cost advantage in supplying these contracts, which is likely to limit competition in the market for full requirements contracts.

A regulator-mandated market for standardized fixed-price forward contracts still requires that suppliers to manage the aggregate quantity risk associated with meeting realized system demand each hour of the year like the current full requirements contracts. Because all suppliers compete to sell the same standardized fixed price forward contract for energy, this should benefit distributors and free consumers with lower prices for wholesale energy in the forward market. Allowing distributors and free consumers to be active participants in the day-ahead and real-time markets for energy should increase the liquidity in the market for these standardized fixed-price forward contracts and the market for bilateral contracts to hedge any remaining price and quantity risk faced by individual generation unit owners, distribution utilities, and free consumers.

The financial sector in the United States and many industrialized countries provides a significant fraction of the financing for new investments and allows efficient risk-sharing between generation unit developers, generation unit owners, load-serving entities, and large consumers. Consequently, an important goal of the reform process in Peru is to make both the short-term market design and long-term resource adequacy mechanism amendable to the participation of financial sector entities.

It is important to emphasize that all wholesale electricity markets in the United States and many other industrialized countries have backstop processes that allow regulators to order the procurement of generation resources to ensure long-term resource adequacy. Designing a regulatory backstop is a delicate process. On the one hand, regulatory invention reduces the credibility of market mechanisms. On the other hand, a wholesale electricity market without a clearly specified regulatory backstop process can descend into chaos when existing market mechanisms fail. Adapting the lessons learned from the experience of these countries in developing backstops that are credible enough to be rarely implemented but comprehensive enough to ensure long-term resource adequacy are applied to the Peruvian context.

2.3. Efficient Incorporation of Generation from Renewable Energy Resources

The Law to Promote Investment in Electricity Generation with Renewable Resources (LRER) was approved in May 2008. This mechanism provided for auctions to purchase energy from qualified renewable energy resources (RER), such as wind, solar, biomass, and small hydroelectric resources. However, in the intervening years, the cost of RER facilities, particularly wind and solar photovoltaic units, has declined considerably. Consequently, many regions around the world have revised or are in the process of revising their policies for support of renewable resources. In addition, regions with significant shares of these resources have also had to change how these resources participate in the short-term energy market. The lessons from these international markets will be adopted to the Peruvian context.

Renewables Portfolio Standards (RPSs) exist in 30 states and the District of Colombia in the United States and apply to 58% of total retail electricity sales.[1] RPSs are generally acknowledged by United States regulators and policymakers to be the least cost approach to achieving given renewable energy goal. These policies have the attractive feature that if above-market support for RERs is unnecessary for these resources to compete with conventional generation resources in the long-term energy procurement process, the price of renewable energy certificates will be zero or close to zero, as has been the case for several states that have achieved renewable energy shares beyond those required by the RPS.

As noted above, unless the Peruvian government adopts specific targets for the share or quantity of energy produced by RERs, there is no need to establish an RPS with a renewable energy certificates market in Peru. Renewable resources can compete with conventional resources to provide a new source of electricity. In addition, if the Peruvian government would like to account for the environmental costs of burning fossil fuels to produce electricity, it could impose a fee on the production of greenhouse gas emissions. This carbon fee would likely reduce the amount of greenhouse gas emissions from the electricity sector and make investments in zero carbon sources of electricity more attractive because they do not require paying the carbon fee.

2.4. Development of New Complementary/Auxiliary Services Market

The challenges of integrating intermittent RERs has significantly increased the importance of operating reserves in maintaining the real-time balance between the supply and demand for electricity at all nodes in the transmission network. A larger share of intermittent RERs in wholesale electricity markets in the United States and many industrialized countries have increased

[1] For a comprehensive analysis of the performance of the United States RPS policies see https://eta-publications.lbl.gov/sites/default/files/rps_status_update-2021_early_release.pdf.

both the number of operating reserves and the quantity demanded of each reserve. Virtually all wholesale electricity markets in the United States have made significant changes to their operating reserves markets and ancillary services procurement processes since they were first implemented.

There is general agreement that the short-term operating reserves market should be co-optimized with both the day-ahead and real-time locational marginal pricing energy market described above. This recommendation will be adapted to my recommendations for changes to the Peruvian market design. Lessons from international experience with determining the products traded, the demand for each product and how the costs of these products are allocated to market participants will be incorporated into my recommendations for the design an ancillary services market in Peru.

An operating reserve demand curve is important feature of most short-term operating reserves markets in the United States that increases the prices of operating reserves when the system operator determines there is a scarcity of operating reserves. As discussed in Section 4.4, a reserve scarcity pricing mechanism is particularly important to have in place for a cost-based energy market to reward resource owners to be available to supply energy during system scarcity conditions.

2.5. Regulatory Oversight of Electricity Supply Industry

Regulation of a restructured electricity supply industry is significantly different from regulation of a vertically-integrated monopoly electricity supply industry. The focus of regulation in former regime was on setting "just and reasonable prices" for electricity. These prices allow the monopoly supplier an opportunity to recover its costs through prudent operation. These prices only recover the firm's costs to protect consumers from the exercise of market power by the monopolist. In the wholesale market regime, regulation attempts to solve the far more complex problem of setting "just and reasonable market rules." These are market rules that cause the expected profit-maximizing actions of market participants to deliver market prices that are "just and reasonable" for consumers and producers.

There are number of necessary features of the regulatory oversight process for the wholesale market regime that increases the likelihood that it achieves "just and reasonable" prices for consumers and producers. First, is public access to data submitted to and produced by the system and market operator. This allows all market participants and interested third parties to gain a deeper understanding of how market outcomes are determined, which should improve market performance and reduce the barriers to new entry into the market. Second, an independent market monitoring process should be established to prepare periodic reports on market performance and identify defects in the market design. Finally, a single entity should perform transmission and generation planning and adequacy studies and a formal regulatory process should be established to make backstop transmission and generation investments when the usual mechanisms are determined by the regulatory process to have failed to provide the investments necessary for reliable system operation.

3. The Peruvian Wholesale Electricity Market Design

This section first summarizes market structure in the Peruvian electricity supply industry. This is followed by a description of the key features of the Peruvian wholesale market design broken down into the four segments presented in the previous section. For each market segment, shortcomings of the existing market design are identified, and recommended changes suggested. Section 4 provides a comprehensive set of recommendations for transitioning the Peruvian market design and regulatory process. Section 5 summarizes and concludes.

3.1. Market Structure and Performance in Peruvian Electricity Supply Industry

Figure 1 presents the generation shares for 2020 by technology for Peru. The two major generation sources in 2020 are hydroelectric and natural gas, with solar and wind generation contributing less than five percent of total generation. Figure 2 presents the generation capacity shares of the major suppliers in Peru. The top three firms, Engie, Kallpa, and ENEL, own 50 percent of the installed capacity in the country, with no other supplier owning more than ten percent of the installed capacity of the country. This concentration of generation ownership reinforces the necessity of a cautious approach to transitioning to an offer-based market in Peru.

Figure 3 shows the evolution of investments in RER capacity from 2009 to through 2019, culminating with roughly 1,000 MWs as of 2019. Figure 4 presents weighted average system marginal cost, the annual average system marginal cost and the weighted average busbar price. This graph illustrates the significant divergence between short-term wholesale market conditions and the average busbar price from 2017 onwards. This divergence signals the possibility for significant wholesale energy cost savings to Peruvian consumers from active participation of distribution utilities and free consumers in the short-term market and greater standardization of the products sold in the long-term energy procurement process.

Figure 5 shows the time series of annual electricity consumption in Peru from 2010 to 2019, separately for free consumers and regulated market consumers. The share of free market consumption now exceeds the share of regulated market consumption. Figure 6 presents annual peak demands from 2010 to 2020. Different from many industrialized countries both annual energy consumption and annual peak demands have both experienced significant growth over the past decade.

3.2. Short Market Design

The Peruvian short-term market is operated by Comite de Operacion Economica del Sistema Interconectado Nacional (hereafter, COES) using estimates of the cost of producing electricity for each thermal generation unit and the opportunity cost of hydroelectric energy. Both operating costs are computed by COES. The thermal cost estimates are computed using the technical characteristics of each generation unit such as input energy necessary to start the unit, input energy necessary to operate the unit at its minimum safe operating level and the unit's heat rate. The price paid by the unit owner for input fuel is based on invoices submitted to COES by the generator. This price information is used to convert the fuel input quantities into these costs. To determine the opportunity cost of water, COES uses information on the cost of producing energy from thermal resources, current water levels behind the major hydroelectric generation units, and an estimate of the distribution of future hydroelectric inflows to solve a stochastic discrete dynamic program to compute the opportunity cost of water.

The thermal generation unit costs—start-up, minimum load, and energy cost--and opportunity costs of water for the hydroelectric resources are used to solve for the generation unit output levels that minimize the total cost of meeting demand at all locations subject to transmission network constraints and other system operating constraints and losses in moving energy from where it is produced to where it is exits the transmission network during the current pricing interval. This process is repeated every 15 minutes and produces generation dispatch levels for that time interval. Locational marginal prices that include the marginal cost of energy, transmission network congestion and marginal losses at more than 100 locations in the Peruvian grid are computed every half hour.

Currently COES operates *non-financially binding* week-ahead and day-ahead scheduling processes. The day-ahead scheduling process includes an offer-based market for secondary frequency regulation reserves. Suppliers submit offers to provide these reserves which are combined with the thermal and hydroelectric generation unit cost estimates in the day-ahead scheduling process. The secondary frequency regulation reserve prices and quantities are determined by minimizing the total cost of meeting the demand for these services and forecast demands for energy for the 24 hours of the following day subject to all transmission network and other system operating constraints. However, only the secondary frequency regulation quantities that emerge from the day-ahead scheduling process are financially binding. COES computes a market-clearing price for each secondary frequency regulation reserve as the increase in the optimized value of the minimum cost function associated with increasing the demand for this operating reserve by one MW. Offer prices for secondary frequency reserve regulation are subject to cap set by Organismo Supervisor de la Inversion en Energia y Mineria (OSINERGMIN), the regulator for the energy and mining sector in Peru.

The generation schedules that emerge from the day-ahead scheduling process are not financially binding, although they are provided to market participants for informational purposes. There are also generation unit owners that have sold secondary frequency regulation reserves under long-term contracts. This supply is subtracted from the market demand in solving for secondary frequency regulation reserves prices and quantities. If one of these generation units is dispatched to supply energy, the unit must supply its contracted quantity of secondary frequency reserve or face a financial penalty.

Like the Chilean market, the short-term energy market is primarily used by generators to trade among themselves imbalances between the loads they serve and the output of their generation units. For example, a generation unit owner that serves 100 MWh of load but only produces 90 MWh from its generation units during the settlement period would have a net negative supply shortfall that it must purchase from generation unit owners that supplied more than their load obligations during the compliance period. These imbalances are settled financially as shown in Figure 7. Let G_{ij} equal the generation of supplier i at location j and CMI_j the locational marginal price at location j. Let L_{ik} equal the load the supplier i is withdrawing at location k and CMR_k the locational marginal price at location k. Depending on their generation output and locational marginal prices at these locations and withdrawals of the energy and prices at these locations, a generation unit owner can receive or pay money to the imbalance settlement process. Supplier i's net payment is $\sum_{k=1}^{K_i} L_{ik} \times CMR_k - \sum_{j=1}^{J_i} G_{ij} \times CMI_j$, where K_i is number of locations where it serves load and J_i is the number of locations where it injects energy. Across all firms, the total amount paid for energy exceeds the total amount paid to generators. This means that IT, what is often called the congestion rents, IT = $\sum_{k=1}^{K} L_k \times CMR_k - \sum_{j=1}^{J} G_j \times CMI_j$, where L_k is the total load at location k and K is the total number of load locations and G_j is total injections at location j and J is the total number of generation locations. IT is a revenue stream to the transmission network owner to offset the cost of the transmission grid.

The retail market is divided into free consumers and regulated consumers. Consumers with a peak demand above 2.5 MW must participate in the free market and those with peak demands between 200 kW and 2.5 MW can choose between the free market and regulated market. Free Consumers can negotiate with suppliers for the prices and terms under which they receive wholesale electricity. Regulated Consumers must be served by their local distribution company (electricity retailer) at negotiated prices subject to a price ceiling set by OSINERGMIN.

In 2006, all free consumers and distribution companies (for their large users) were granted permission to purchase up to 10 percent of their demand directly from the short-term market at their point of withdrawal from the transmission network. The remainder of their demands must be purchased from suppliers in full-requirements contracts arranged through bilateral negotiation subject to the busbar tariff cap or through procurement auctions. Under these contracting mechanisms, all the quantity risk associated serving the remainder of the customer's or retailer's demand is borne by the seller of the full requirements contract. These contracts are typically of an extremely long duration of up to 20 years, depending on the retailer. This can lock in extremely high prices for wholesale electricity consumers for an extremely long time, as shown in Figure 4, even though short-term market prices are significantly lower.

The existing generation unit owner-only short-term energy market in Peru is unlikely to yield the least cost wholesale energy supply for distribution utilities and free consumers. For the remaining 90% of their electricity supply these entities must rely on competition among a limited number of suppliers of energy and capacity PPAs that manage all short-term price and quantity risk for buyer of the PPA. A short-term market that allows distribution utilities and free consumers to be active participants and an associated long-term resource adequacy mechanism based on standardized fixed-price forward contracts for energy purchased by distribution utilities and free consumers should allow these entities to construct a long-term supply of energy from these component parts to compete against the offerings of the small number of large portfolio generation unit owners in Peru.

3.2.1. Recommendations for Improving Short-Term Market Performance

The addition of a financially binding day-ahead market has five potential market efficiency benefits relative to the existing short-term market design in Peru. First, it would allow all nonconvexities in generation and system operation to be modelled in determining financially binding day-ahead schedules for generation units for all 24 hours of the day at once. Dynamic operating constraints such as ramp rates, minimum and maximum safe output levels, fixed costs such as start-up and minimum safe operating level costs, and minimum up-time and minimum down-time constraints for generation units can be modelled and priced in the day-ahead market solution. The generation schedules that emerge from the day-ahead market would minimize daily costs of serving offered-in demand at all locations in the transmission network for all hours of the day.

Second, both day-ahead energy schedules and operating reserves schedules can be determined simultaneously by minimizing the cost of meeting the demands for energy and operating reserves for all 24 hours of the following day. This would address a shortcoming of the existing operating reserves procurement process in Peru that generation units can regret the sale of operating reserves after the unit owner finds out the price of energy in the real-time market during that time interval. For example, suppose that a generation unit owner with a marginal cost of energy of $20/MWh was taken for 10 MWs of secondary frequency reserve at a price of $2/MW in the day-ahead scheduling process. If the real-time price of energy is $25/MWh, that unit owner would prefer to have sold 10 MWhs of energy from this capacity rather than provide 10 MWs of secondary frequency reserve, because it would earn $5/MW = ($25/MWh - $20/MWh) from producing energy rather than $2/MW for providing secondary frequency reserve from this 10 MWs of capacity. With co-optimized procurement of energy and operating reserves in the day-ahead market, a generation unit owner would never have capacity chosen to supply energy in the day-ahead market when suppling an operating reserve from this capacity would earn the generation unit owner a higher variable profit. Conversely, capacity from a generation unit would never be taken for an operating reserve when the variable profit earned from supplying energy from the unit is greater than that earned from the providing an operating reserve from that unit.

Third, as discussed in detail in Section 4.1, a financially binding day-ahead market values the dispatchability and flexibility of generation resources despite paying the same price to all generation resources selling energy at a location in the day-ahead market and the same price to all generation resources buying or selling energy at a location in the real-time market.

Fourth, a financially binding day-ahead market would facilitate the active participation of final demand in the wholesale market, because retailers and large consumers can schedule demand in the day-ahead market that they do not consume in real-time market as way to be compensated for demand reductions when the day-ahead price is significantly less than the real-time price. The existence of a financially binding day-ahead market avoids the problem of setting an administratively set baseline relative to which retailers and large consumers are paid for their demand reductions. As noted by Bushnell, Hobbs and Wolak (2009), demand response programs operated and paid based on administratively set baselines can creates both reliability challenges and revenue shortfalls for system/market operators.

Finally, a financially binding day-ahead market with active participation by distribution utilities and free consumers would allow for the introduction of purely financial participants in the Peruvian electricity market. These participants could improve price convergence between the day-ahead and real-time market and reduce the cost of serving demand throughout Peru in real time as shown in Jha and Wolak (2019) for the case of California. The actions of purely financial participants can also facilitate new entry in electricity generation and retailing as discussed in Wolak (2019). By providing strong financial incentives for day-ahead energy schedules to equal real time generation output, COES could also reduce its demand for operating reserves and still maintain supply and demand balance in real time. The introduction of purely financial participation, what is referred to as virtual or convergence bidding in all United States markets, should only be introduced after a significant period of successful implementation of the two-settlement (day-ahead and real-time) short-term market design.

3.3. Long-Term Resource Adequacy Mechanism in Peru

There are two primary revenue streams aimed at ensuring long-term resource adequacy in Peru: (1) full requirements long-term energy contracts with free consumers and distributors and (2) capacity payments. Full requirements long-term energy contracts between generators and large consumers and distribution companies provide virtually all revenues to the generation sector in Peru. Capacity payments received by generation unit are recovered from the revenues generation unit owners receive from the PPA contracts for energy and capacity that they have signed with free consumers and distribution utilities. The capacity payment mechanism in Peru was initially designed to provide a stable revenue stream to generation unit owners selling energy to regulated consumers according to the regulated busbar price of energy that was adjusted every six months by COES.

The following mechanism is employed to determine the monthly capacity payment to each generation unit. First all generation units in Peru are assigned firm capacity values based on their ability to supply energy under stressed system conditions. For thermal resource owners this magnitude is equal to the annual availability factor of the generation unit times the nameplate capacity of the unit. For run-of-run hydroelectric resources this magnitude is equal to the average hourly amount of annual energy the unit can provide under low water conditions. For reservoir hydroelectric units the average initial storage capacity of the reservoir is added to this number.

Under the current capacity payment mechanism wind and solar generation resources receive a firm capacity value equal to their average production during what COES designates as peak hours.

Given these firm capacity magnitudes, once per month generation units are ordered from lowest cost to highest cost up to peak demand for the month and only the lowest costs units that are needed to meet that monthly peak demand plus a reserve margin are entitled to receive a capacity payment currently equal to $7/kW-month at the reference node. For each supplier, COES performs a monthly balance between the capacity provided versus the amount of capacity sold in PPA contracts. If sum of the locational price times the locational quantity of capacity provided during the month across all locations is greater than the sum of the locational prices of times the locational quantity of capacity sold in PPA contracts across all locations, the generation unit owner receives this difference as a payment. If the opposite is true, the generator must make a payment equal to this difference.

Two other regulatory mechanisms have been implemented to address long-term resource adequacy in Peru. The first is the cold reserve capacity purchase which required the construction of two dual-fuel (natural gas and diesel fuel) thermal generation units to provide operating reserves that can be called upon to provide energy under certain system conditions. Because these units were guaranteed cost recovery through a regulatory contract, they cannot sign long-term energy contracts and do not explicitly participate in the short-term market.

The second new regulatory mechanism allows the Ministry of Mines and Energy to run an auction for new generation capacity when it determines this investment is needed to ensure a reliable supply of energy to Peru. Although this mechanism has not been used, it is anticipated that any capacity built under this mechanism will not be prohibited from selling energy in the short-term market or subsequently selling a long-term contract for energy.

The existing long-term resource adequacy mechanism in Peru has several strengths. Most of these are a result of the suppliers-only short-term market design. Besides the allowed 10% short-term market purchases that distribution utilities and free consumers, the remaining short-term price and quantity risk faced by distribution utilities and free consumers is managed by suppliers through PPAs at prices that appear to be significantly above the average short-term price electricity, as shown in Figure 4. The existing long-term resource adequacy mechanism purchases energy and capacity jointly under a long-term contract, which gives buyer and seller price certainty for a specific quantity of energy for the term of the contract, even though the capacity price component of the PPA can change over time. As demonstrated in Section 4.2.2, the seller of a fixed-price forward contract obligation to supply energy has a strong incentive to provide that energy at the lowest possible cost to the buyer of that energy. This logic implies that the supplier-only structure of the short-term market provides sellers of the PPAs with a strong incentive to minimize the short-term market cost of serving the realized hourly pattern of consumption of the consumers served under the PPAs they have sold.

As we discuss in Section 4.2.1 it is extremely difficult to determine the firm capacity value of a hydroelectric, wind, or solar generation unit that is comparable to the firm capacity value of a thermal generation unit. This problem becomes increasingly difficult as the share of intermittent generation in the region increases. This is a major weakness of a capacity-based long-term resource adequacy mechanism in a region that increasingly reliant on intermittent renewable generation resources. Consumers are pay the same price for 1 MW of firm capacity from a dispatchable thermal resource as they do for 1 MW of firm capacity from a hydroelectric, wind or solar resource, even though the thermal unit is far more likely to produce the amount energy equal to that firm capacity during stressed system conditions than any of the three renewable units because these units rely on the availability of the underlying renewable resource which is not under control of the generation unit owner.

Another weakness of the existing capacity payment mechanism in Peru is that it adjusts the capacity price paid to existing generation resources once each year during the term of the PPA. These capacity price changes have no market efficiency or system reliability consequences for existing generation units. These price changes simply result in income transfers from electricity consumers to generation unit owners in the case of capacity price increases and vice versa for capacity price decreases. Paying an existing generation unit a capacity price based on the cost to construct a new generation unit could cause an existing unit to exit the industry if this payment does allow the existing unit to recover its going forward costs.

If the goal of the capacity payment mechanism is to ensure generation adequacy, the mechanism could function equally well with fixed capacity price for the term of the PPA contract. In fact, this would be a lower risk outcome, because suppliers would not have to factor in their expectations about future changes in capacity prices when they determine the energy price associated with their PPA offers to distribution utilities and free consumers.

Viewed from this perspective, the existing capacity payment mechanism is an uncertain supplemental source of income to new and existing generation unit owners over the term of the PPA. If the capacity payment mechanism was eliminated generation unit owners could simply adjust the energy price offers in their long-term PPAs to recover these costs. If this energy price recovers the generation unit owner's fixed and variable costs (including a return on the capital invested in the project) over the term of the PPA contract, by the logic Section 4.2.2, the unit has a strong financial incentive to supply the energy sold in the PPA contract at lowest possible cost.

Another important goal of the existing long-term resource adequacy mechanism is that it provides sufficient revenues for a long enough duration to finance the new generation capacity necessary to serve demand. It is largely irrelevant whether this revenue stream comes in the form of a payment for energy or energy and capacity. As shown in Section 4.2.2, the advantage of providing this revenue stream as a fixed-price forward contract for energy is that it provides a strong financial incentive for the seller of this contract to provide this energy at least cost.

Capacity payment mechanisms typically pay generation unit owners for their firm capacity but have limited incentives to make these units available to the short-term market, particularly if the supplier owns a portfolio of generation units and can raise the market-clearing price received by the units that operate by withholding one or more of these units from the short-term market. Some markets, such as Colombia, have attempted to address this incentive by building in implicit performance penalties into the capacity payment mechanism by required peak energy rent refunds for short-term prices above an administratively set scarcity price. However, as shown in McRae and Wolak (2019), supplier behavior caused by interactions between an incentive-based capacity payment mechanism and fixed-price forward contracts for energy can reduce energy market efficiency.

The fact that distribution utilities and free consumers cannot participate in the short-term market is likely to increase the price consumers pay for wholesale electricity in these full requirements contracts because owners of the remaining 50 percent of installed capacity shown in Figure 2 that is not owned by the three largest suppliers are less able to compete to supply these full requirements contracts. This particularly limits the opportunities for consumers to benefit from periods when short-term wholesale electricity prices are low as shown in Figure 4. In addition, the experience with the cold reserve capacity procurement process suggests the need for a clearly specified regulatory backstop mechanism to determine if an out of market procurement of generation capacity is necessary for long-term resource adequacy.

Transitioning to a short-term market design with active participation by distribution utilities and free consumers has the potential to increase competition in both the short-term market for energy and long-term market for new generation capacity. But there is clearly an increased risk to electricity consumers involved in making this change because they can end up purchasing significant quantities energy at short-term market prices. Consequently, this change in the short-term market design in Peru must be paired with a long-term resource adequacy mechanism that preserves the strong incentives for least cost supply of energy to the short-term market caused by the supplier-only short-term market. The goal of the redesign of long-term resource adequacy mechanism is to preserve the protections that distribution utilities and free consumers have against short-term price volatility and demand uncertainty under the existing supplier-only short-term market with full requirements contracts, while allowing these entities the flexibility to manage some of this short-term price and demand risk and thereby the reduce their wholesale energy and operating reserves costs.

3.3.1. Recommendations for Improving Long-Term Resource Adequacy Mechanism

Peru's significant hydroelectric energy dependence and desire to increase the amount of intermittent renewable energy implies that energy shortfalls due to low water inflows or low levels solar and wind energy production, rather than capacity shortfalls, are the major long-term resource adequacy challenge facing Peru going forward. As discussed in Section 4.2, a long-term resource adequacy mechanism that focuses on the development of a liquid forward market for energy into the distant future at time horizons to delivery that allow new entrants to compete with existing suppliers to provide this energy and yields revenue streams sufficient to finance new investments in generation capacity is likely to be a superior approach. This approach would focus on the development of a market for a standardized fixed-price forward contracts for energy that can form the foundation for the development of a liquid forward market for energy far enough into the future and for a long enough duration to support investments in new generation capacity. Distribution utilities and free consumers purchasing standardized fixed-price forward contracts far enough in advance of delivery for new entrants to compete to supply this energy and for a long enough duration to ensure these units are built will improve the performance of the long-term resource adequacy mechanism.

A key factor in realizing this performance improvement in the long-term resource adequacy mechanism is allowing free consumers and distributors to be full participants in the short-term energy and ancillary services market. This would allow them to serve as counterparties to the standardized fixed-price forward contracts for energy and allow them to clear imbalances relative to their forward market energy purchases and sales similar to what generation unit owners do in the existing market. This would increase liquidity in the forward market for energy because free consumers and distributors could purchase standardized forward market products from all the suppliers in Figure 2 to hedge their energy needs and meet any real-time imbalances through short-term market purchases or sales, rather than purchasing full requirements contracts from a single supplier that owns multiple generation units.

3.4. Integration of Renewable Energy Resources

Peru's policy for renewables energy resource development has focused on running tenders for energy from wind, solar, biomass and small hydroelectric generation technologies. More than 1,200 MW across more than 60 projects have been awarded in these tenders. Renewable resource owners that win in these auctions sell energy in the short-term market and are then compensated annually for the difference between the revenues then receive from the short-term market and the payment determined from the auction. This incremental payment is recovered from final consumers through a transmission charge.

A major lesson from wholesale electricity markets with a large share of intermittent renewable resources is that the number of system operating constraints increases significantly as share of these resources increases because their energy output can disappear and reappear with little warning. Consequently, it necessary to account for this fact in operating the dispatchable generation units in the system. More dispatchable resources are likely to be necessary to operate at their minimum safe operating level and rapidly ramp up if these intermittent resources stop producing. For example, during many days in California, there are daily ramps of dispatchable resources of more than 8,000 MW in three hours in the evening as the solar resources stop producing energy at the end of the day and a slightly smaller ramp down in the early morning as the solar resources start to produce at the beginning of the daylight hours. Managing these reliability challenges has also significantly increased the demand for operating reserves in California.

3.4.1. Recommendations for Improving Renewable Resource Integration

Running a separate procurement process for each RER technology is likely to be an unnecessarily expensive way to procure a fixed quantity of renewable energy for two reasons. First, by segmenting the market for renewable energy by different technologies, each technology-specific auction is likely to have fewer competitors and therefore consumers are likely to pay higher prices for renewable energy from that technology. Second, running separate auctions virtually guarantees that the least cost mix of technologies necessary to provide a fixed quantity of renewable energy will not be purchased. A single procurement process for the renewable attribute significantly increases the likelihood of obtaining the least cost mix of technologies to provide the desired amount of renewable energy.

A renewable energy certificates (RECs) market is generally acknowledged by United States regulators and policymakers as the least cost approach to obtained a given renewable energy goal. One REC is produced each time a qualified renewable resource produces 1 MWh of energy. For example, any wind, solar, biomass, or small hydroelectric facility that is qualified as an RER can sell RECs. The major advantage of establishing a market for RECs to achieve a specific renewable energy goal is that this creates a competitive market for the renewable attribute that is separate from the energy produced by the RER. Creating two separate products provides strong incentives for RER developers to construct the least cost mix of RER generation units to meet a given renewable energy goal.

The following simple example illustrates this point. Suppose that days are composed of two periods--daytime when solar resources produce and nighttime when wind resources produce. Suppose that the average daytime price is $75/MWh and the average nighttime price is $50/MWh. If the levelized cost of energy (LCOE) of solar units is $100/MWh and the LCOE of wind units is $85/MWh, the market-clearing price of RECs will be at least $25/MWh, the difference between the LCOE of solar and the average daytime price. This is less that the difference between the LCOE of wind units and the average nighttime price. This REC price implies that RER developers will construct solar units rather than the less expensive wind units. This outcome occurs because solar is the cheapest way to provide one unit of the renewable attribute.

If, as result of entry by solar resources, the average daytime price falls to $50/MWh, the price of RECs will increase to $35/MWh, the difference between the LCOE of wind units and the average nighttime price. This REC price implies RER developers will construct wind units because they are now the cheapest way to produce RECs. Consequently, the REC approach to achieving a given RER goal, builds in a strong financial incentive for RER developers to find the cheapest source of the renewable attribute given the market prices of energy. If the LCOE of a new RER unit is less than its market value—the weighted average price at which the energy produced by RER unit can be sold in the short-term market—then the price of a REC should be zero.

A government commitment to a given RER goal that is enforced by significant penalties for non-compliance can stimulate the formation of a forward market for renewable energy certificates. This market can enable a RER owner to sell the RECs that the resource is expected to produce over its lifetime. Forward sales of energy in the long-term resource adequacy process combined with forward sales of RECs should provide the necessary revenue stream for a long enough period of time to finance investments in RER capacity. This logic argues for the Peruvian government establishing renewable energy goals similar to those that exist in many states in the United States if it would like to achieve a renewable energy share greater than the amount that would come RERs competing in the long-term resource adequacy process with conventional generation resources. If the government is unwilling to establish such a renewable energy goal, then there is little reason to establish a REC market. Renewable resources will be built to extent they are able to offer lower prices for fixed-price forward contracts for energy than conventional resources.

A two-settlement LMP market is ideally suited to integrating a significant fraction of intermittent renewable resources into Peru's energy mix. The additional system operating constraints and operating reserves requirements necessary to operate a transmission grid with a large share of intermittent resources can easily be incorporated into both day-ahead and real-time markets. As the share of intermittent resources renewable resources increases these resources must transition to selling standardized fixed-price and fixed-quantity forward contracts for energy sold by the dispatchable generation resources. As discussed in Section 4.3, long-term contracts that pay a fixed price to the intermittent resource owners for all the energy the resource produces regardless of when the resource produces are increasingly problematic for system and market operators as the share of intermittent renewable resources increases. Intermittent renewable units must be transitioned to fixed price and pre-specified quantity contracts sold by conventional generation resources. Under the existing Peruvian short-term market design and long-term resource adequacy mechanism, fixed price, and variable quantity contracts for renewable energy favor investments in RER generation units by suppliers that own a portfolio of generation units and are therefore better able to manage this quantity risk.

3.5. Ancillary Services Market Design

The operating reserves market in Peru is run as part of the day-ahead scheduling process with two products Secondary Frequency Up (SFU) and Secondary Frequency Down (SFD). The SFU quantity is a MW upward range from the unit's day-ahead schedule and the SFD quantity is a MW downward range from the unit's day-ahead schedule. SFU and SFD prices for the generation resources providing these services are determined from solving the day-ahead scheduling problem using on offer prices submitted by generation unit owners for SFU and SFD offers, and the generator costs determined by COES. The market-clearing price that emerges from this day-ahead scheduling process is paid to all generation capacity accepted to supply operating reserves.

Primary frequency response is the provided at the generation unit level with a frequency event at a generation unit triggering an automatic, autonomous governor or under-frequency device response similar to how primary frequency response is provided in all wholesale electricity markets in the United States. Tertiary frequency response is provided by the cold reserve capacity discussed earlier. Voltage support is provided at zero variable cost from generation units as long as there is no opportunity cost of providing this service. Black start is purchased from units capable of providing the service under a long-term contract. Operating reserves costs are currently paid by generation unit owners. This cost allocation scheme has potential to create perverse market efficiency consequences because it creates incentive for generation unit owners to take costly actions to reduce the amount of operating reserves they have to pay for.

3.5.1. Recommendations for Ancillary Services Market

The balancing ancillary services or operating reserves market should be integrated into a financial binding day-ahead energy market. Suppliers should submit offers for all operating reserves their units are qualified to provide and COES should combine these offers with each unit's energy costs to solve for day-ahead energy and operating reserves schedules and prices that are financially binding. This market should trade four products, SFU, SFD, Spinning Reserve and Non-Spinning Reserve. Spinning Reserve is unloaded generation capacity of a unit that synchronized to the grid that can respond to a dispatch instruction in a pre-specified period of time. Non-Spinning Reserve is unloaded generation capacity that is not currently synchronized to the grid but can start up and provide energy with a pre-specified period of time.

Prices for these products should computed in the same way as locational energy prices--as the increase in the optimized value of the objective function from the day-ahead or real-time market associated with supplying one more unit of that operating reserve. Any net energy provided by suppliers of these operating reserves would be paid or pay the real-time price for energy at their location. A reserve scarcity pricing mechanism that employs an operating reserve demand curve should be implemented to ensure that operating reserves and energy prices reflect scarcity conditions when the amount capacity available to provide operating reserves is less than the demand set by COES.

Any long-term contracts for the provision of ancillary services with generation unit owners should be converted to purely financial contracts in the sense that the seller of this contract should have the option to either provide the service from their own unit or purchase the necessary ancillary service from the short-term market. This will ensure that the least cost source of each ancillary service is supplied in real-time and will likely reduce the price at which suppliers are willing to sell long-term contracts for ancillary services.

Ancillary services costs should be assigned based on cost-causation principles to the extent that this is possible. This is typically easier said than done, because determining which market participant caused a given ancillary services cost is an extremely difficult if not impossible task, because ancillary services have two features that define a public good. They are *non-rivalrous* in sense that their supply to any market participant does not decline as more market participants consume them, and *non-excludable* in the sense that any market participant cannot be excluded from consuming them. These features of ancillary services and public goods imply that it is not possible to allocate all or even a significant fraction of the costs of ancillary services using the principle of cost-causation.

For this reason, most markets in the United States allocate these costs to loads based on the principle that final consumers are the least likely to take costly actions to avoid paying these costs. All loads pay a per MWh charge equal to total ancillary services costs for the hour divided by the system demand for that hour. To extent that COES can use cost causation principles to make a credible assignment of some of these costs to specific market participants, the remaining ancillary services costs could be assigned to load as a per MWh charge.

3.6. Regulatory Oversight and Market Monitoring

The Peruvian electricity supply industry does not have a single document that defines the market rules similar what exists in most industrialized countries. For example, all United States markets have a formal set of market rules or tariff governing the behavior of market participants, the functioning of market mechanisms, and the behavior of the system operator. These market rules are developed through an interactive stakeholder process and must ultimately be approved by the wholesale market regulator, the Federal Energy Regulatory Commission (FERC) before they are implemented. Both the initial formulation of the tariff and any changes are developed through a public process that solicits input from stakeholders. Any proposed changes must also be ultimately approved by FERC before they are implemented. The existence of a tariff filed with FERC ensures that all parties know the rules governing the behavior of market participants, the system and market operator, and the regulator. From this legal document, the system operator develops what is a called business practice manual (BPM) which lays the details of all procedures necessary to operate the market in a manner consistent with the tariff. The BPM allows current and prospective market participants to determine precisely how their actions and those of other market participants translate into output levels and net revenue streams.

There is also no formal independent market monitoring process that oversees the performance of the market and identifies market rules that adversely impact market efficiency in Peru. A key lesson from the experience of wholesale electricity markets around the world is that electricity market design is a process of continuous improvement. There is no such thing the perfect market design, only better market designs. What a superior market design is depends on initial conditions in the industry, the technologies available produce electricity, and the capability of the regulatory process in the country. An independent market monitoring process that takes the massive amounts of data produced by the market and distils it into measures that can be tracked over time to assess the health of the market and identify any defects in the market rules is an essential component of this process of continuous improvement.

There also no single entity responsible long-term transmission and generation planning in Peru. Different entities in Peru produce assessments of transmission and generation adequacy although there is no clearly defined process for incorporating these assessments into a regulatory backstop for making necessary transmission and generation investment decisions.

3.6.1. Recommendations for Regulatory Oversight and Market Monitoring

COES should propose a formal tariff for the operation of the wholesale market that should be approved by OSINERGMIN. This tariff should be vetted through a stakeholder process involving all market participants to ensure that all perspectives have been considered. From this legal document business practice manuals should be developed and made available on the COES website. This will allow any potential entrant or otherwise interested party to understand the details of how the market in Peru operates, thereby reducing the barriers to new entry into the market.

There should be an independent market monitor appointed to oversee the market, prepare periodic reports on market performance, and to identify potential defects in the market rules. The independent market monitor is an important participant in any market redesign process, by assessing the impact of a proposed change on market performance. Possible approaches to structuring the independent market monitoring process are discussed in Section 4.5.

Finally, there should be a single entity that assesses transmission network and generation unit adequacy and can implement a regulatory backstop for transmission and generation unit expansions. This planning process should be primarily for informational purposes. Unbiased information on the need for future transmission and generation investments can also reduce the barriers to new entry. This planning process should also inform the backstop process, but the regulatory backstop should be deployed only if existing market mechanisms and formal regulatory processes fail to achieve a reliable supply of energy. A suggested process for implementing the backstop mechanism is discussed in Section 4.5.

4. Recommended Peruvian Wholesale Electricity Market Design

This section proposes a comprehensive market design and regulatory oversight process for the Peruvian wholesale market design that reflects the lessons learned from more than twenty years of international experience with electricity industry restructuring. This market design involves changes to the short-term market design, the long-term resource adequacy mechanism, the renewables procurement process, ancillary services procurement process, and the regulatory oversight process for electricity supply industry.

4.1. Short-Term Market Design

This section proposes a cost-based multi-settlement locational marginal pricing market that co-optimizes the procurement of both energy and operating reserves in the day-ahead and real-time markets. All free consumers and distribution companies are active participants in the day-ahead and real-time markets. Different from current supplier-only real-time market only design, a two-settlement market fosters active demand-side participation in the wholesale market because a free consumer or distribution utility can purchase energy in the day-ahead market that it does not subsequently consume when real-time prices are significantly higher than day-ahead prices. Allowing distribution utilities and free consumers to participate in the day-ahead and real-time markets increases the competitiveness of these markets. A multi-settlement market can also allow purely financial participants in both the day-ahead and real-time markets. Finally, necessary conditions in the market and regulatory process to transition from a cost-based market design to an offer-based market are discussed.

4.1.1. Match Between Market Operation and Transmission Network Operation

An important lesson from electricity market design processes around the world is the extent to which the market mechanism used to dispatch and operate generation units is consistent with how the grid is actually operated. In the early stages of wholesale market design in the US, all the regions attempted to operate wholesale markets that used simplified versions of the transmission network. The single zone or zonal markets assumed infinite transmission capacity between locations in the transmission grid or only recognized transmission constraints across large geographic regions. These simplifications of the transmission network configuration and other relevant operating constraints can create opportunities for market participants to increase their profits by taking advantage of the fact that in real time the actual configuration of the transmission network and other operating constraints must be respected.

These markets set a single market-clearing price for a half-hour or hour for an entire country or large geographic region even though there were generation units with offer prices below the market-clearing price not producing electricity and units with offer prices above the market-clearing price producing electricity. This outcome occurs because of the location of demand and available generation units within the region and the configuration of the transmission network prevents some of these low-offer-price units from producing electricity and requires some of the high-offer-price units to supply electricity. The former units are typically called ‘constrained-off’ units and the latter are called ‘constrained-on’ or ‘must-run’ units.

A market design challenge arises because how generation units are compensated for being constrained-on or constrained-off impacts the offer prices they submit into wholesale energy market. For example, if generation units are paid their offer price for electricity when they are constrained-on and the unit's owner knows that it will be constrained-on, a profit-maximizing unit owner will submit an offer price far more than the variable cost of the unit and be paid that price for the incremental energy it supplies, which raises the total cost of electricity supplied to final consumers.

A similar set of circumstances arises for a constrained-off generation unit, which is usually paid the difference between the market-clearing price and the unit's offer price for not supplying electricity that the unit would have supplied if not for the configuration of the transmission network. This market rule creates an incentive for a profit-maximizing supplier that knows its unit will be constrained-off to submit the lowest possible offer price in order to receive the highest possible payment for being constrained-off and raise the total cost of electricity supplied to final consumers.

This problem occurs so frequently in single zone or zonal markets that it has acquired the name "the DEC game," because it involves a supplier selling energy in the day-ahead market that it knows is very likely to be infeasible to inject to the transmission grid in real-time. The supplier then agrees to buy decremental (DEC) energy at a price below the day-ahead market price and earn the difference between these two prices times the amount of energy sold in the day-ahead market for producing little or no energy in real-time. Bushnell, Hobbs and Wolak (2008) discuss this problem and the market efficiency consequences in the context of the initial zonal-pricing market in California. Graf, Quaglia, and Wolak (2020) document the incentives for generation unit owner offer behavior created by the divergence between the day-ahead zonal market model and full network model used to operate the Italian market in real-time. However, this outcome is not unique to markets in industrialized countries. Wolak (2009) discusses these same issues in the context of the Colombian single-price market with its negative and positive reconciliations payment mechanism.

This discussion illustrates the significant market efficiency and system reliability issues that Peru avoids by operating a locational marginal pricing market design. Accounting for all relevant transmission network and system operating constraints in setting generation unit output levels and locational prices provides the initial conditions for many beneficial enhancements to this basic market design.

The need to match the network model used to operate short-term market to network model used to operate the transmission network, strongly argues against separating market operation from system operation. A several of early markets in the United States established a separate day-ahead market operator for the simplified financial market that set day-ahead schedules that was separate from the system operator for the market in real-time. All regions of the United States now operate locational marginal pricing markets where the operator of the day-ahead and real-time markets and the system operator are the same entity. Because the market design in Peru matches the network model used to operate the short-term market with the network model used to operate the system in real-time, both system operation and day-ahead and real-time market operation should be kept within COES.

4.1.2. Locational Marginal Pricing

As described in the previous section, almost any difference between the market model used to set dispatch levels and market prices and the actual operation of the generation units needed to serve demand creates an opportunity for market participants to take actions that raise their profits at the expense of overall market efficiency. Wholesale electricity markets that use locational marginal pricing (LMP), also referred to as nodal pricing, largely avoid these constrained-on and constrained-off problems, because all transmission constraints and other relevant operating constraints are respected in the process of determining dispatch levels and locational marginal prices. Consequently, different from single-zone or zonal market designs, locational marginal pricing markets can allow multiple settlements without creating the opportunities for suppliers to degrade the efficiency of the short-term market by taking advantage of constrained-on and constrained-off generation units as discussed in the previous section.

All LMP markets in the US co-optimize the procurement of energy and operating reserves. This means that all suppliers submit to the wholesale market operator their generation unit-specific willingness-to-supply schedules for energy and any operating reserve the generation unit can provide. Likewise, large loads and load-serving entities submit their willingness-to-purchase energy schedules. Locational prices for energy and ancillary services and dispatch levels and ancillary services commitments for generation units at each location in the transmission network are determined by minimizing the as-offered costs of meeting the demand for energy and operating reserves at all locations in the transmission network, subject to all transmission network and other relevant operating constraints. No generation unit will be accepted to supply energy or an operating reserve if doing so would violate a transmission or other operating constraint.

An important distinction between an LMP market design and the standard European market design is the centralized commitment of generation units to provide energy and ancillary services. European markets do not typically require generation units to submit energy offer curves into the day-ahead market and instead allow individual producers to make the commitment decisions for their generation units using simplified single-zone or multiple-zone models of the transmission network. A self-commitment market can result in higher cost generation units operating because of the differences among producers in their assessment of the likely market price. Self-commitment markets also do not allow the simultaneous procurement of energy and operating reserves and instead rely on sequential procurement of operating reserves before or after energy schedules have been determined. As Oren (2001) demonstrates, sequential clearing of energy and operating reserves markets increases the opportunities for generation unit owners to exercise unilateral market power in the energy or operating reserves markets, because suppliers know that capacity sold in an earlier market cannot compete with suppliers in a subsequent market.

Another advantage of a centralized LMP market that co-optimizes the procurement of energy and operating reserves ensure that each generation unit is used in the most cost-effective manner based on the energy and operating reserves offers of all generation units, not just those owned by a single market participant. Specifically, the opportunity cost of supplying any operating reserve a unit can provide will be explicitly considered in deciding whether to use the unit for that ancillary service. For example, if the market-clearing price of energy at that generation unit's location is \$40/MWh, the unit's offer price for energy is \$30/MWh, and the unit's offer price for the only operating reserve the unit can supply is \$5/MW, then the unit will not be accepted to supply that operating reserve. It is accepted to supply the operating reserve only if the price of this operating reserve is greater than or equal to \$10/MW because of the \$10/MWh opportunity cost of energy for that unit.

In contrast, self-commitment markets or sequential operating reserves markets such as those that exist in Europe and other industrialized countries must rely on individual market participants to make the efficient choice between supplying energy or ancillary services from each generation unit. This is possible for a supplier to do within its portfolio of generation units, but it unlikely to be the case across suppliers. Consequently, there are likely to many instances when a resource is taken to supply an operating reserve at a $/MW price that turns out to be less than unit's opportunity of providing energy. There are also likely to be instances when a resource is providing energy at price that has smaller opportunity cost of energy than the prevailing price of an operating reserve the unit can provide.

The nodal price at each location is the increase in the minimized value of the 'as-offered costs' objective function because of a one unit increase in the amount of energy withdrawn at that location in the transmission network. In a co-optimized energy and operating reserves locational marginal pricing market, the price of each operating reserve is defined as the increase in the optimized value of the objective function because of a one unit increase in the demand for that operating reserve. In most LMP markets, operating reserves are procured at a coarser level of spatial granularity than energy. For example, energy is typically priced at the nodal level and operating reserves are priced over larger geographic regions. Bohn, Caramanis, and Schweppe (1984) provide an accessible discussion of the properties of the LMP market mechanism.

Another strength of the LMP market design is the fact that other constraints that the system operator considers in operating the transmission network can also be accounted for in setting dispatch levels and locational prices. For example, suppose that reliability studies have shown that a minimum amount of energy must be produced by a group of generation units located in a small region of the grid. This operating constraint can be built into the LMP market mechanism and reflected in the resulting locational prices. This property of LMP markets is particularly relevant to the cost-effective integration of a significant amount of intermittent renewable generation capacity in the transmission network because additional reliability constraints may need to be formulated and incorporated into LMP market to account for the fact that this energy can quickly disappear and re-appear.

An important lesson from the US experience with LMP markets is that explicitly accounting for the configuration of the transmission network in determining dispatch levels both within and across regions can significantly increase the amount of trade that takes place between the regions. Mansur and White (2012) dramatically demonstrate this point by comparing the volume of trade between two regions of the Eastern US, what the authors call the Midwest and East of PJM, before and after these regions were integrated into a single locational marginal pricing market that accounts for the configuration of the transmission network throughout the entire integrated region. Average daily energy flows from the Midwest to East of PJM almost tripled immediately following the integration of the two regions into an LMP market. There was no change in the physical configuration of the transmission network for the two regions. This increase in energy flows was purely the result of incorporating the two regions into a single LMP market that recognizes the configuration of the transmission network for the two regions in dispatching generation units.

4.1.3. Multi-Settlement Markets

Multi-settlement nodal-pricing markets have been adopted by all US jurisdictions with a formal short-term wholesale electricity market. A multi-settlement market has a day-ahead forward market that is run in advance of real-time system operation. Generation unit owners submit unit-level offer curves for each hour of the following day for energy and operating reserves as well as technical characteristics of their generation units, such as ramp rates, minimum and maximum safe operating levels, and other operating characteristics required by the system operator. Large consumers and electricity retailers submit demand curves for energy for each hour of the following day. The system operator set the demands for each operating reserve and then minimizes the as-offered cost to meet the demand for energy and each operating reserve simultaneously for all 24 hours of the following day subject to the anticipated configuration of the transmission network and other relevant operating constraints. This gives rise to LMPs and firm financial commitments to buy and sell energy and each operating reserve each hour of the following day for all generation unit and load locations.

The day-ahead market typically allows generation unit owners to submit their start-up and minimum load cost offers as well as energy offer curves, and both costs enter the objective function used to compute hourly generation schedules and locational marginal prices for all 24 hours of the following day. This logic implies that a generation unit will not be dispatched in the day-ahead market unless the combination of its start-up and no-load costs and energy costs are part of the least cost solution to serving hourly demands for all 24 hours of the following day.

To the extent that generation unit owners do not receive sufficient revenues from energy and operating reserves sales to recover their as-offered costs to provide these products throughout the day, they are provided with a make-whole payment to recover these costs. Total make-whole payments are recovered from all loads through a $/MWh charge. For example, if a generation unit owner with a start-up cost of $5,000 and a variable cost of energy offer of $40/MWh sells 100 MWh at price of $42/MWh, the unit's make-whole payment would be $5,000 - $4,200 = $800. If system demand was 4,000 MWh and this was the only make-whole payment made, then the per unit charge to demand would be $0.50/MWh.

The energy schedules that arise from the day-ahead market do not require a generation unit to supply the amount sold or a load to consume the amount purchased in the day-ahead market. The only requirement is that any shortfall in a day-ahead commitment to supply energy must be purchased from the real-time market at that same location or any production greater than the day-ahead commitment is sold at the real-time price at that same location. For loads, the same logic applies. Additional consumption beyond the load's day-ahead purchase is paid for at the real-time price at that location and the surplus of a day-ahead purchase relative to actual consumption is sold at the real-time price at that location. Both buyers and sellers of energy in the day-ahead market bear the full financial consequences of failing to meet the day-ahead sales and purchases. However, it can often be the case that deviating from day-ahead schedules is profit-maximizing for a generation unit owner, distribution utility, or free consumer, particularly as the share of intermittent renewable resources increases.

In all United States wholesale markets, real-time LMPs are determined from the real-time offer curves from all available generation units and dispatchable loads by minimising the as-offered cost to meet real-time demands (rather than bid-in demand) at all locations considering the current configuration of the transmission network and other relevant operating constraints. This process gives rise to LMPs at all locations in the transmission network and the actual hourly operating levels for all generation units. Real-time imbalances relative to day-ahead schedules are cleared at these real-time prices.

The real-time market is typically solved for multiple periods into the future using the system operator's forecast of demands for a number of periods into future, but only the values for the first dispatch interval are used to set prices and real-time operating levels for generation units. As discussed in Price and Rothleder (2011), the California ISO runs the real-time market every five minutes, for twelve five-minute intervals into future in addition to the current dispatch interval using the system operator's forecast of demands over this time horizon. This yields what the system operator calls advisory output levels and prices for these twelve five-minute intervals and actual dispatch levels and prices for the current 5-minute interval. This dispatch horizon for the real-time market ensures that the current period solution for the real-time market reflects the California ISO's best guess of the pattern of demand in the next twelve 5-minute intervals. This process is repeated every 5-minutes so that in the next 5-minute interval advisory dispatch levels and prices for twelve five-minute intervals and the actual dispatch levels and prices for the current 5-minute interval are computed. The average of the twelve 5-minute prices within hour is the hourly real-time price for all generation and load resources that do not have necessary metering technology to record their 5-minute production or consumption. For resources with this metering technology, their real-time is the quantity-weighted average of the twelve 5-minute prices weighted by the 5-minute production or consumption in that dispatch interval.

To understand how a two-settlement market works, suppose that a generation unit owner sells 50 MWh in the day-ahead market at 60 $/MWh. It receives a guaranteed $3,000 in revenues from this sale. However, if the generation unit owner fails to inject 50 MWh of energy into the grid during the specified delivery hour of the following day, it must purchase the energy it fails to inject at the real-time price at that location. Suppose that the real-time price at that location is 70 $/MWh and the generator only injects 40 MWh of energy during the hour in question. In this case, the unit owner must purchase the 10 MWh shortfall relative to its day-ahead schedule at 70 $/MWh. Consequently, the net revenues the generation unit owner earns from selling 50 MWh in the day-ahead market and only injecting 40 MWh is $2,300, the $3,000 of revenues earned in the day-ahead market less the $700 paid for the 10 MWh real-time deviation from the unit's day-ahead schedule.

If a generation unit produces more output than its day-ahead schedule, then this incremental output is sold in the real-time market. For example, if the unit produced 55 MWh, then the additional 5 MWh beyond the unit owner's day-ahead schedule is sold at the real-time price. By the same logic, a load-serving entity (free consumer or distributor) that buys 100 MWh in the day-ahead market but only withdraws 90 MWh in real-time, sells the 10 MWh not consumed at the real-time price. Alternatively, if the load-serving entity consumes 110 MWh, then the additional 10 MWh not purchased in the day-ahead market must be purchased at the real-time price.

By this same logic, a multi-settlement nodal-pricing market is well-suited to regions that do not have an extensive transmission network because it explicitly accounts for the configuration on the actual transmission network in setting both day-ahead energy schedules and prices and real-time output levels and prices. This market design eliminates much of the need for ad hoc adjustments to generation unit output levels that can increase the total cost of wholesale electricity to final consumers because of differences between the prices and schedules that the market mechanism sets and how the actual electricity network operates.

Wolak (2011) quantifies the magnitude of the economic benefits associated with the transition to a two-settlement nodal pricing market from a two-settlement zonal-pricing market that was very similar to the standard market design currently in Europe and other industrialized countries. Wolak (2011) find total hourly BTUs of fossil fuel energy consumed to produce electricity is 2.5 percent lower, the total hourly variable cost of production for fossil fuels units is 2.1 percent lower, and the total number of hourly starts is 0.17 higher after the implementation of nodal pricing. This 2.1 percent cost reduction implies a roughly $105 million reduction in the total annual variable cost of producing electricity from fossil fuels in California associated with the introduction of nodal pricing. Triolo and Wolak (2020) study the transition from a European-style zonal market design with self-scheduling and self-commitment to a multi-settlement nodal market design in the Electricity Reliability Council of Texas (ERCOT) on December 1, 2010. They find a 3.9% reduction in the total variable cost of fossil-fuel generation for the first year of operation of this market, or an annual cost savings of $323 million.

A multi-settlement LMP market design is also particularly well suited to managing a generation mix with a significant share of intermittent renewable resources. The additional operating constraints necessary for reliable system operation with an increased number of renewable resources can easily be incorporated into the day-ahead and real-time market models. Therefore, the economic benefits from implementing a multi-settlement LMP market relative to market designs that do not model transmission and other operating constraints are likely to be greater the larger is the share of intermittent renewable resources. Consequently, any region with significant renewable energy goals is likely to realize significant economic benefits from implementing a multi-settlement LMP market.

This short-term market design values the dispatchability and flexibility of generation units even though it pays all resources at the same location in the grid the same price in the day-ahead and real-time markets. Suppose that a wind unit sells 50 MWh and a thermal resource sells 40 MWh in the day-ahead market at $30/MWh. If in real time not as much wind energy is produced, the dispatchable thermal unit must make up the difference. Suppose that the wind unit produces only 30 MWh, so that the thermal unit must produce an additional 20 MWh. Because of this wind generation shortfall, the real-time price is now $60/MWh. Under this scenario, the wind unit is paid an average price of $10/MWh = (50 MWh x $30/MWh – 20 MWh x $60/MWh)/30 MWh for the 30 MWh it produces, whereas the dispatchable thermal unit is paid an average price of $40/MWh = (40 MWh x $30/MWh + 20 MWh x $60/MWh)/60 MWh for the 60 MWh it produces.

A similar logic applies to the case that the wind resource produces more than expected and the thermal resource reduces its output because the real-time price is lower than the day-ahead price due to the unexpectedly large amount of wind energy produced. For example, suppose the wind unit sells 30 MWh and the thermal resource sells 60 MWh in the day-ahead market at \$30/MWh. However, in real time there is significantly more wind, so that the wind unit produces 50 MWh at a real-time price of \$10/MWh. Because of this low real-time price, the thermal resource decides to produce 40 MWh and purchases the additional 20 MWh from its day-ahead energy schedule from the real-time market. The average price received by the wind unit is \$22/MWh = (30 MWh x \$30/MWh + 20 MWh x \$10/MWh)/50 MWh and the average price received by the thermal unit is \$40/MWh = (60 MWh x \$30/MWh – 20 MWh x \$10/MWh)/40 MWh. Despite paying the same price to all energy in the day-ahead and real-time markets, a multi-settlement market pays a higher average price to the dispatchable generation unit for the energy it provides during the same hour as the wind unit.

An additional way to reward flexibility in a multi-settlement LMP market is to clear the real-time market as frequently as possible within the hour. For example, all United States wholesale markets clear--set real-time prices and dispatch levels—every five minutes. This means that real-time prices can increase rapidly across 5-minute intervals when net system demand—the difference between system demand and intermittent renewable generation—rapidly increases. This rewards generation units that can quickly increase their output with substantially higher prices for the output they supply within that 5-minute interval. Units that can rapidly reduce their output in response to an increase in net demand during a 5-minute interval can sell back energy scheduled in the day-ahead market at substantially lower prices.

Shorter settlement intervals can also reduce the demand for frequency response operating reserves, because more fast-response units are moving up and down according to 5-minute dispatch instructions within the hour, so that less secondary frequency up and less secondary frequency down is needed to maintain system balance within the hour. COES should consider more frequent settlement of the real-time market, particularly if share of intermittent renewable generation increases significantly.

4.1.4. Multi-settlement Market and Active Demand-Side Participation

The active involvement of final consumers in the wholesale market can reduce the amount of installed generation capacity needed to serve them and the cost of integrating an increasing amount of intermittent renewable generation. A multi-settlement market with a day-ahead forward market and a real-time market facilitates active participation by final demand, particularly a market that clear every five minutes. This mechanism allows loads to purchase energy in the day-ahead market that they can subsequently sell in the real-time market. Without the ability to purchase demand in the day-ahead market that is not consumed in real-time, demand reduction programs require the regulator to set an administrative baseline relative to which demand reductions are measured, which can significantly reduce the system-wide benefits of active demand-side participation, as discussed in Bushnell, Hobbs, and Wolak (2009).

4.1.5. Multi-settlement LMP Market for Peru

A multi-settlement, cost-based LMP market for Peru would involve the following market design changes. First, the current day-ahead scheduling market would now become financially binding in the sense that the prices and quantities for generation unit-level energy and hourly operating reserves sales would be financially binding in the sense described above. Suppliers producing more than their day-ahead schedule are paid the real-time price for this difference. Suppliers producing less than their day-ahead schedule must buy this difference at the real-time price. Suppliers that provide an operating reserve are paid a market-clearing price for the MWs of capacity providing this service.

Units providing SFU and SFD, they would receive the market-clearing $/MW prices for these products and the short-term price for any net energy produced during the hour or pay this price for any net consumption of energy during the hour. Generator offers in the day-ahead market would remain cost-based, but suppliers would make operating reserves offers for each hour of the day. The requirement that suppliers submit offers for operating reserves is a result of the fact that there is no direct $/MW cost of providing an ancillary service, even though there is also the need for generation unit owners to recover the annual costs that they incur from providing these services. Free consumers and electricity retailers would submit demand bids for energy at their location for each hour of the day into the day-ahead market. COES would set the demands for each operating reserve during each hour of the day in the day-ahead market.

COES would then solve for the least cost combination of energy costs from all generation units (including start-up costs, minimum load costs and energy costs) and the operating reserves offers to meet the locational demands submitted by all free consumers and electricity retailers and the operating reserves demands set by COES for all 24 hours of the following day. Because the energy market is cost-based, the free consumers and retailers should be required to submit their demand bids into the day-ahead market as price-takers (single inelastic demand), rather than as downward sloping price-sensitive demand bids. The day-ahead market solution process would give rise to financially binding resource-specific schedules for energy and each operating reserve and locational demands for energy. After COES has sufficient experience with the operation of the two-settlement market it can transition to allowing market participants to submit price sensitive bids in the day-ahead market.

The real-time market would operate in the same manner except that COES would have the option buy additional operating reserves or sell operating reserves purchased in the day-ahead market that it no longer requires along with energy in the real-time market. In this market, COES would solve for the least cost combination of energy and ancillary services to meet the actual demands for energy and operating reserves at all locations in the transmission network. It is important to emphasize that demands in the day-ahead market are bid in by free consumers and distributors, whereas real-time demands are the actual demands at all locations in the transmission network. All differences between day-ahead energy (generation and load) schedules and the real-time output or consumption levels at each location in the transmission network would be settled at the real-time price at that location as described in the previous section.

If there is concern that suppliers could exercise unilateral market power in the operating reserves market, COES could consider reducing the cap on the $/MW offers that suppliers can submit to the operating reserves market. If COES is concerned that lower caps on offers to the operating reserves market could reduce the supply of these services, it could develop an automatic market power mitigation mechanism that significantly limits the offer prices of suppliers deemed to have a substantial ability to exercise unilateral market power in the operating reserves market. Section 4.4 describes the basic features of automatic market power mitigation mechanisms.

This market design could also allow purely financial participants into day-ahead energy market. All United States wholesale markets allow purely financial participants to trade day-ahead/real-time price differences at a virtually all locations in the transmission network. Purely financial participants can submit incremental energy offers and decremental energy bids that are treated the same as generation unit offers and demand bids in the day-ahead market. An accepted purely financial incremental energy sale requires a corresponding purchase in the real-time market. Similarly, a purely financial decremental energy purchase requires a corresponding sale in the real-time market. As discussed in Jha and Wolak (2019), these purely financial offers are called virtual bids or convergence bids because they help to converge day-ahead and real-time prices.

Initially, the bids and offers of purely financial players should be as price-takers (inelastically demanded or supplied) given the fact that both the day-ahead and real-time markets are cost-based. Consequently, the offers of purely financial participants can only increase the demand or supply of energy at a location in the day-ahead market. However, this purely financial position in the day-ahead market must be reversed in the real-time market. As shown in Jha and Wolak (2019), the actions of purely financial traders can reduce the cost of serving demand at all locations in the transmission network during system conditions when there are likely to be many binding transmission and system operating constraints in the real-time market. In addition, the ability of purely financial entities to participate in the short-term energy market can reduce the barriers to entry into the generation and retailing sectors as discussed in Wolak (2019).

4.1.6. Transitioning to Offer-Based Market in Peru

The concentration of generation unit ownership in Peru and the numerous market design changes recommended in this report strongly support a cost-based energy market Peru for the foreseeable future. However, after many of the changes recommended in this report have been implemented and their performance assessed, it may be worth considering a transition to an offer-based market.

There are several initial conditions that must be met before this transition should be considered. First, there should be an independent market monitoring process for the Peruvian market that recommends such a change. Second, there should be a COES-approved set of market rules for that defines excessive levels of the exercise of unilateral market power and the appropriate regulatory response. Third, an effective automatic local market power mitigation mechanism should be designed and ready for implementation for an offer-based energy and operating reserves market. Section 4.4 discusses the basic features of these mechanisms in the United States. Finally, there should be an effective long-term resource adequacy mechanism, such as the one described in Section 4.2, that ensures that all or virtually all demand is covered by fixed-price forward contracts purchased at horizons to delivery that allow new entrants to compete to provide this energy.

4.2. Mechanisms to Ensure Long-Term Resource Adequacy

Why do wholesale electricity markets require a regulatory intervention to ensure long-term resource adequacy? Consumers want to be able to withdraw electricity from the network when they need it, just like other goods and services. But it is unclear why electricity is so fundamentally different from other products that it requires paying suppliers for production capacity to exist. For example, consumers want cars, but they do not pay for automobile assembly plants. They want point-to-point air travel, but they do not pay for airplanes. These industries are high fixed cost, relatively low marginal cost production processes, like electricity supply. Nevertheless, all these firms earn their return on capital invested by selling the good that consumers want at a price above the variable cost of producing it. Clearly cars and air travel are in many ways essential commodities, yet there is no regulatory intervention that ensures that there is sufficient production capacity for these products to meet demand.

So, what is different about electricity that necessitates the need for a long-term resource adequacy mechanism? The answer lies in how short-term markets for these products operate relative to the market for wholesale electricity. This difference is the result of the regulatory history of the electricity supply industry and the technology historically used to meter electricity. The limitation on the level of short-term prices and the way that supply shortfalls are dealt with in wholesale electricity markets creates what Wolak (2013) has been termed a "reliability externality" that requires a regulatory intervention to internalize.

In the market for automobiles, air travel and even bread, there is no explicit prohibition on the short-term price of the good rising to the level necessary to clear the market. Take the example of air travel. Airlines adjust the prices for seats on a flight over time to ensure that the number of customers traveling on that flight equals the number of seats flying. This can result in very different prices for a seat on the same flight, depending on when the customer purchases the seat. A customer that waits too long to purchase a seat faces the risk of an infinite price in the sense that all the seats on the flight are sold out. This ability to use prices to allocate the available seats is also what allows the airline the flexibility to recover its total production costs. Airlines can set low prices to fill flights with low demand and extremely high prices on other flights, or at other times for the same flight, when demand is high.

The ability to use the short-term price to manage the supply and demand balance in the electricity supply industry is limited first by the fact that many wholesale electricity markets have offer caps that limit a supplier's offer price into the wholesale market and the magnitude of the eventual market-clearing price. Cost-based markets are an extreme example of this phenomenon because the offers of all generation units are limited to the regulator-verified costs of producing energy from the unit.

Although offer caps or a cost-based market limits the ability of suppliers to exercise unilateral market power in the short-term energy market, they also reduce the revenues suppliers can receive during scarcity conditions. This is often referred to as the *missing money* problem for generation unit owners. However, this missing money problem is only a symptom of the existence of a reliability externality, it is not the cause.

This externality exists because offer caps or a cost-based market limits the potential downside to electricity retailers and large consumers (able to purchase from the short-term market) delaying their purchases of electricity until real-time operation. Specifically, if a retailer or large consumer knows the maximum possible the short-term market price is $250/MWh, then it is unlikely to be willing to pay more than that for electricity in any earlier forward market. This creates the possibility that real-time system conditions can occur where the amount of electricity demanded at a cost-based price is more than the amount suppliers are willing to offer. This outcome implies that the system operator must be forced to either abandon the market mechanism or curtail load until the available supply offered at or below the offer cap equals the reduced level of demand, as was the case several times during January 2001, March 2001, and August 2020 in California and February 2021 in Texas.

Because random curtailments of demand–also known as rolling blackouts–are used to make demand equal to the available supply during periods of shortage, this mechanism creates an "externality" because no retailer or large consumer bears the full cost of failing to procure adequate amounts of energy in advance of delivery. A retailer that has purchased sufficient supply in the forward market to meet its real-time energy demand is equally likely to be randomly curtailed as the same size retailer that has not procured adequate amounts of energy in the forward market. For this reason, all retailers and large loads have an incentive to under-procure their expected energy needs in the forward market.

Retailers have little incentive to engage in sufficient fixed price forward contracting with generation unit owners to ensure a reliable supply of electricity for all possible realizations of future real-time demand. The option to purchase energy from a short-term market with a low maximum price makes it expected profit-maximizing for retailer not to sign a forward contract that allows the generation unit owner full cost recovery. The retailer would prefer to purchase the necessary energy at prices that are limited by the offer cap.

Because externalities are generally caused by a missing market, another way of characterizing this reliability externality is as a missing market for long-term contracts for energy. In this case, because retailers do not bear the full cost of failing to procure sufficient energy to meet their real-time needs in the future, there is a missing market for long-term contracts for long enough delivery horizons into the future to allow new generation units to be financed and constructed to serve demand under all possible future conditions in the short-term market.

The existing market design in Peru addresses the reliability externality by organizing a suppliers-only short-term market which means that all distribution utilities and free consumers must purchase full requirements contracts from suppliers for their wholesale energy needs. Under this market design, the only entities that are subject to short-term price and quantity risk are other suppliers. Except for the allowed the 10 percent of purchases from the short-term market, there are no customers in Peru that are unhedged as can be the case in a wholesale market where distribution utilities and free consumers are active participants in the short-term market. The PPA agreements with suppliers can provide both price and quantity hedges for the remaining 90 percent of their demand.

This logic implies that if Peru transitions to a short-term market with active participation by distribution utilities and free consumers it must explicitly address the reliability externality, because these purchasers of wholesale electricity have a strong incentive to rely on the cost-based short-term energy market price. Capacity mechanisms are one approach to addressing this reliability externality designed primarily for thermal generation-dominated markets, where the major concern is insufficient generation capacity to meet future demand peaks. In hydroelectric and intermittent renewable-dominated markets the major reliability concern is more likely to be insufficient energy (that is, not enough water, wind, or sunshine) to meet demand, which implies other approaches to addressing the reliability externality may dominate a capacity-based approach for these electricity markets.

As the share of intermittent renewable generation in a wholesale electricity market increases, the magnitude of the reliability externality is also likely to increase. The uncertain availability of wind and solar resources increases the magnitude and duration of potential future energy supply shortfalls that must be managed, which implies many more instances when a cost-based short-term energy market may not yield a sufficient energy supply increase or demand decrease to maintain real-time supply and demand balance.

Two general approaches have been developed to address this reliability externality. The first approach is a regulator-mandated capacity payment mechanism. The second is based on fixed-price and fixed-quantity long-term contracts for energy signed between generation unit owners and load-serving entities at various horizons to delivery.

4.2.1. Capacity-Based Approach to Long-Term Resource Adequacy

Particularly in the US, capacity payment mechanisms appear to be a holdover from the vertically-integrated regulated regime with regional power pools where capacity payments compensated generation units for their capital costs, because the regulated power pool typically only paid unit owners their variable operating costs for the electricity they produced. Therefore, all fixed costs had to be recovered through other mechanisms besides the sale of wholesale electricity.

Capacity payments typically involve a dollar per kilowatt per year ($/kW-year) payment to individual generation units based on some measure of the amount of their capacity that is available to produce electricity during stressed system conditions, what is often referred to as the unit's 'firm capacity'. This value depends, among other things, on the technology of the generating unit. All capacity-based approaches to long-term resource adequacy rely on the credibility of the firm capacity measures assigned to generation units. This is a relatively straightforward process for dispatchable thermal units. The nameplate capacity of the generation unit times its annual availability factor, which equals the fraction of hours of the year a unit is expected to be available to produce electricity, is the typical starting point for estimating the amount of energy the unit can provide under stressed system conditions. If all retailers have met their firm capacity requirements in a sizeable market with only dispatchable thermal generation, there is a very high probability that the demand for energy will met during peak demand periods.

A simple model helps to illustrate the logic behind this claim. Suppose that the peak demand for the market is 1,000 MW and the market is composed of equal size generation units and each unit has a 90% annual availability factor, meaning that it is available produce electricity any hour of the year with a 0.90 probability. Suppose that the event that one generation fails to operate is independent of the event that any other generation unit fails to operate. This independence assumption is reasonable for dispatchable thermal generation units because unavailability is typically due to an event specific to that generation unit. If each generation unit has a capacity of 100 MW, and a firm capacity of 90 MW, if there are 13 generation units, then with probability 0.96 the demand peak will be covered.[2] In this case, a firm capacity requirement of 1.17 times the demand peak would ensure that system demand is met with 0.96 probability. Assuming that each generation unit is one-tenth of the system demand peak is unrealistic for most

[2] The number of generation units available is a binomial random variable with probability p = 0.9 and with number of trials N = the number of generation units. The probability of meeting the demand peak is the probability the available capacity is greater than or equal to the peak demand.

electricity supply industries, but it does illustrate the important point that smaller markets require firm capacity equal to a larger multiple of peak demand to achieve a given level of reliability.

Suppose that each generation unit is now 50 MW and each still has the same availability factor, so the firm capacity of each unit is now 45 MW. In this case, the same firm capacity requirement of 1.17 times the demand peak, or 26 generation units, would ensure system demand is met with 0.988 probability. If each generation unit had a capacity of 20 MW with the same availability factor, each unit would have a firm capacity of 18 MW. This 1.17 times peak demand firm capacity requirement, or 65 generation units, firm capacity requirement would ensure that system demand is met with 0.999 probability. This example illustrates that an electricity supply industry based on dispatchable thermal generation units, where each unit has at 10 percent chance of being unavailable, the system demand peak will be met with a very high probability with a firm capacity requirement of 1.17 times peak demand if all the generation units are small relative to the system demand peak.

Introducing renewables into a capacity-based long-term resource adequacy mechanism considerably complicates the problem of computing the probability of meeting system demand peaks for two major reasons. First, the ability to produce electricity depends on the availability of the underlying renewable resource. A hydroelectric resource requires water behind the turbine, a wind resource requires wind to spin the turbine, and a solar facility requires sunlight to hit the solar panels. Second, and perhaps most important, the availability water, wind, or sunshine to renewable generation resources is highly positively correlated across locations for a given technology within a given geographic region. This fact invalidates the assumption of independence of energy availability across locations that allows a firm capacity mechanism to ensure system demand peaks can be met with a very high probability. For example, if the correlation across locations in the availability of generation units is sufficiently high, then a 0.9 availability factor at one location would imply only a slightly higher probability of than 0.9 for meeting system demand, almost regardless of the number of intermittent renewable generation units installed.

Hydroelectric facilities have been integrated into firm capacity regimes by using percentiles of the distribution of past hydrological conditions for that generation unit to determine its firm capacity value. However, this approach only partially addresses the problem of accounting for the high degree of contemporaneous correlation across locations in water availability in hydroelectric dominated systems. There is typically a significant amount of data available on the marginal distribution water availability at individual hydroelectric generation units. However, the joint distribution of water availability across all hydro locations is likely to be more difficult to obtain. The weather-dependent intermittency in energy availability for hydroelectric resources is typically on an annual frequency. There are low-water years and high-water years depending on global weather patterns such as the El Nino and La Nina weather events as discussed in McRae and Wolak (2016).

Incorporating wind or solar generation units into firm capacity mechanism is even more challenging for several reasons, and increasingly so as the share of energy produced in a region from these resources increases. The intermittency in energy supply is much more frequent than it is for hydroelectric energy. Moreover, if stressed system conditions occur when it is dark, the firm capacity of a solar resource is zero. Similarly, if stressed system conditions occur with the wind is not blowing, a likely outcome on extremely hot days, the firm capacity of a wind resource is zero. The contemporaneous correlation across locations in the output of solar generation resources or wind generation resources for a given geographic area is typically extremely high. As demonstrated by Wolak (2016) for the case of California, there is even a high degree of correlation across locations in the output of wind and solar resources. Again, information on marginal distribution of wind or solar energy availability at a location is much more readily available than the joint distribution wind and solar energy availability for all wind and solar locations in a region. For these reasons, calculating a defensible estimate of the firm capacity of wind or solar resource that is equivalent to the firm capacity of a dispatchable thermal generation resource is extremely difficult, if not impossible.

An additional problem with computing the firm capacity of a solar or wind generation resource when there a significant amount contemporaneous correlation across locations and over time is that a 1 MW investment is likely to be able to serve different increments to system demand depending on the location of the investment, the location of the increment to demand, and the size and location of other renewable resources in the region. This leaves the system operator with two difficult choices for setting the value of firm capacity for solar and wind resources. The first would be to set different values of firm capacity for resources employing the same generation technology based on their location in the transmission network. This would likely be a politically contentious process because of the many assumptions that go into computing the firm capacity value for an intermittent renewable resource. The second approach would set the same firm capacity value for all resources employing the same generation technology. This means that two resources with very different locational firm capacity values could sell the same product to the potential detriment of overall system reliability.

This conundrum occurs because of the high degree of contemporaneous correlation between underlying resource availability for hydro, solar and wind resources as well as the need to deliver all renewable energy produced through transmission network with finite capacity. The wholesale electricity markets in the United States with the largest shares of intermittent renewable resources often find it necessary to curtail output from these resources because of local transmission network constraints, which further complicated the process of computing the firm capacity value of intermittent renewable resources.

Wind and solar generation units in California and other market in the United States have firm capacity values significantly below their nameplate capacities, but substantially higher than the amount of energy these units can produce during stressed system conditions, which suggests that the capacity market construct is poorly suited to an electricity supply industry with significant intermittent renewable generation capacity. Wolak (2021) documents many instances when the firm capacity value of wind and solar resources in California is significantly larger than the amount of energy produced during periods in the day with large net demands. For example, on August 14 and 15 of 2020 rolling blackouts occurred in California in the early evening. Solar generation resources were barely producing even though they were credited with firm capacity values equal to 27 percent of their nameplate capacity. Wind resources were also producing significantly less energy than their firm capacity value of 21 percent of nameplate capacity. This experience underscores the challenges faced by a capacity-based long-term resource adequacy mechanism in a market with a significant fraction of energy produced by intermittent RERs.

A final issue with capacity markets is difficulty in setting the price of capacity through a market mechanism. Early United States capacity markets attempted to use market mechanisms to set the value of the $/kW-year payment to the generation units needed to meet the total demand for capacity. However, these capacity markets have been subject to almost continuous revision because they are extremely susceptible to the exercise of unilateral market power. The nature of the product sold–installed generation capacity–and a publicly disclosed perfectly inelastic demand for the product creates extreme opportunities for suppliers to exercise unilateral market power.

This market power problem leaves open the question of how to set the value of the \$/kW-year price cap on the capacity payment. In all regions of the US with capacity payment mechanisms, there is an administratively set process for determining this price. The value of the maximum capacity payment is based on the regulator's estimate of the annual \$/kW fixed cost of a peaking generation unit. This maximum price is typically backed by the argument that because of the offer cap on the short-term market and other market power mitigation mechanisms this peaking unit could only set an energy price slightly higher than its variable operating costs. Because this generation unit and all other generation units are missing the hours when the market price would rise above their variable operating costs, the annual \$/kW cost of the peaking unit is needed to compensate all generation units for the revenues they do not receive because of the offer cap and market power mitigation mechanisms.

This logic for setting the value of the \$/kW-year capacity payment explicitly assumes that the real-time demand for electricity is completely price inelastic and that suppliers are unable to exercise significant amounts of unilateral market power in the short-term market for energy. Both assumptions are clearly false. An increasing number of jurisdictions around the world are installing hourly meters that allow dynamic pricing plans to be implemented. Wolak (2013) discusses these technologies and the pricing plans they enable. The fact that capacity mechanisms can limit short-term energy price volatility and therefore dulls the incentive for active demand-side participation in the wholesale market provides another argument against their implementation. Galetovic, Muñoz and Wolak (2015) use the example of the Chilean market design to demonstrate the market efficiency improvements from transitioning from a capacity payment-based market to an energy-contracting based market even without active demand-side participation in the short-term market.

4.2.2. Fixed-Price Forward Contracts and Long-Term Resource Adequacy

The fixed-price forward contract solution is the standard approach used to ensure a real-time supply and demand balance in markets for products with high fixed costs of production. The prospect of a high real-time price for the product provides incentives for customers to hedge this real-time price risk through a fixed-price forward contract. A supplier benefits from signing such a contract because it has greater quantity and revenue certainty as result.

The airline industry is a familiar example of this phenomenon. There is a substantial fixed cost associated with operating a flight between a given origin and destination pair. Regardless of how many passengers board the flight, the airplane, pilot and co-pilot, flight attendants and fuel must be paid for. Moreover, there is a finite number of seats on the flight, so passengers wanting to travel face the risk that if they show up at the airport one hour before the flight and attempt to purchase a ticket, they may find that it is sold out or tickets are extremely expensive because of the high real-time demand for seats. Customers hedge this short-term price risk by purchasing their tickets in advance, which is a fixed-price, fixed-quantity (one seat) forward contract for travel on the flight. These forward market purchases allow the airline to better plan the types of aircraft and flight staff it will use to serve each route and how much fuel is needed for each flight.

Similar arguments apply to wholesale electricity markets to the extent that real-time prices can rise to very high levels. For example, in Australia the offer cap on the short-term market is currently 15,000 Australia dollars ($AU) per megawatt-hour, yet annual average wholesale prices are less than 100 $AU/MWh. The potential for short-term prices at or near the price cap provides a very strong incentive for electricity retailers and large customers to purchase their electricity through fixed-price forward contracts, rather than face the risk of these extreme short-term prices. However, even at this level of the offer cap on the short-term market in Australia there have been a small number of half-hour periods when supply shortfalls occur, consistent with the reliability externality argument.

Purchasing fixed-price and fixed-quantity forward contracts far enough in advance of delivery for new entrants to compete to provide this energy ensures that retailers will receive a competitive forward market price for their purchases. These forward market purchases far in advance of delivery also ensure that the seller of the contract has sufficient time to construct the new generation capacity needed to meet the demand secured through the fixed-price forward contracts. Consequently, in the same sense that fixed-price forward contracts for air travel allow an airline to better match airplanes and flight staff to routes, fixed-price forward contracts for electricity allow generation unit owners to choose the least cost mix of capacity to serve the demand that has purchased the fixed-price forward contracts for energy. Because capacity payment mechanisms pay suppliers for the administratively determined amount of firm capacity that is provided by each of their generation units, capacity mechanisms do not provide nearly as of a strong incentive for suppliers to find the least cost mix of capacity to serve demand. This outcome occurs because all MWs of firm capacity are treated the same by the capacity payment mechanism, regardless of their actual contribution of system reliability.

Absent regulatory intervention, the success of fixed-price forward contracts in obtaining sufficient energy to meet future demand is the threat of very high short-term prices which provides the incentive for load-serving entities to sign fixed-price forward contracts for their expected future demand far enough in advance of delivery to allow new entrants to compete with existing generation unit owners in the provision of these forward contracts for energy. However, as the events of February 2021 in Texas demonstrated, unless consumers paying according to the real-time price can reduce their demand to zero when wholesale prices rise to extremely high levels, the ultimate outcome is extremely high electricity bills for consumers and random curtailments of demand. Consequently, consumers should only be exposed to short-term wholesale prices only the amount of demand that they can reduce, even under extreme system conditions. Chapter 7 of Hardman and Wolak (2021) outlines a default retail pricing plan with this property. As the events of February 2021 in Texas also demonstrate, a higher offer cap on the short-term market does not eliminate the reliability externality, it only reduces the frequency that random demand curtailments are necessary.

As noted earlier, the current combination of a supplier-only short-term market and the requirement for distribution utilities and free consumers to purchase PPAs for their wholesale energy needs beyond the 10 percent short-term market purchases is an implicit regulatory mandate for all loads in Peru to be covered by fixed-price forward contracts for their actual demand. Consequently, imposing a regulatory mandate for all distribution utilities and free consumers to purchase standardized fixed-price forward contracts for their energy needs is not a major change from the existing long-term resource adequacy mechanism in Peru.

It is important to emphasize that mandating these contracting levels is unlikely to impose a financial hardship on retailers that lose customers to competing retailers. If a retailer purchased more fixed-price forward contract coverage than it ultimately needs because it lost customers to a competitor, it can sell this obligation in the secondary market. Unless the market demand for energy in the future is unexpectedly low, this retailer is just as likely to make a profit on this sale as it is to make a loss, because one of the retailers that gained customers needs forward contracts to meet its regulatory requirements for coverage of its final demand. Only in the unlikely case that the aggregate amount of forward contracts purchased is greater than the realized final demand for the entire market will there be a potential for stranded forward contracts held by retailers that lose customers. The need to develop a liquid secondary market for fixed-price forward contracts for energy argues in favor a standardization of the contract terms and conditions.

Fixed-price forward contract obligations also significantly limit the incentive of generation unit owners to exercise unilateral market power in the short-term market and provide strong incentives for supplier their forward contract obligations at least cost. To understand this logic, let PC equal the fixed price at which the generation unit owner agrees to sell energy to an electricity retailer in a forward contract and QC equal the agreed upon quantity of energy sold. This contract is negotiated in advance of the date in which the generation unit owner will supply the energy, so the value of PC and QC are predetermined from the perspective of behavior in the short-term wholesale market.

Wolak (2000) demonstrates that the quantity of fixed-price forward contract obligations held by the generation unit owner determines what short-term market price the firm finds ex post profit-maximizing given its marginal cost of producing energy, the supply offers of its competitors and the level of aggregate demand. Incorporating the payment stream a generation unit owner receives from its forward contract obligations, its variable profit function for a given hour of the day is:

$$\pi(PS) = (PS - C)QS - (PS - PC)QC, \qquad (1)$$

where QS is the quantity of energy sold in the short-term market and produced by the generation unit owner, PS is the price of energy sold in the short-term market and C is the supplier's marginal cost of producing electricity, which for simplicity is assumed to be constant. The first term in (1) is the variable profits earned from selling energy in the short-term market and second term is the payment or revenue, depending on the sign (PS - PC)QC, associated with financial settlement of the contract. The buyer of this fixed-price forward contract has an equal revenue or payment obligation. The expression for variable profits in (1) can be re-written to demonstrate the incentives a supplier with a fixed-price forward contract obligation faces:

$$\pi(PS) = (PC - C)QC + (QS - QC)(PS - C). \tag{2}$$

The first term in (2) is the variable profit from the forward contract sales and the second term is the additional profit or loss from selling more or less energy in the short-term market than the generation unit owner's forward contract quantity. Because the forward contract price and quantity are negotiated in advance of the delivery date, the first term, (PC – C)QC, is a fixed profit stream to the generation unit owner before it offers into the short-term market. The second term depends on the price in the short-term market, but in a way that can significantly limit the incentive for the generation unit owner to raise prices in the short-term market.

For example, if the generation unit owner attempts to raise prices by withholding output, it could end up selling less in the short-term market than its forward contract quantity (QC > QS), and if the resulting market-clearing price is greater than the firm's marginal cost (PS > C), the second term in (1) will be negative. Consequently, only in the case that the generation unit owner is confident it will produce more than its forward contract quantity in the short-term market does it have an incentive to withhold output in order to raise short-term prices.

The quantity of forward contract obligations held by a firm's competitors also limits its incentive to exercise unilateral market power in the short-term market. If a producer knows that all its competitors have substantial fixed-price forward contract obligations, then this producer knows these firms will submit offer curves into the short-term market close to their marginal cost curves. Therefore, attempts by this generation unit owner to raise prices in the short-term market by withholding output are likely to be unsuccessful because the aggressiveness of the offers into the short-term market by its competitors with substantial fixed-price forward contract obligations limits the price increase a producer can expect from these actions.

When all generation unit owners have a substantial fraction of their expected energy sales covered by fixed-price forward contracts, then all of them have a common interest in reducing the cost of meeting these fixed-price forward contract obligations. The existing supplier-only short-term market and with long-term resource adequacy ensured through PPAs between these suppliers and distribution utilities and free consumers provides strong incentives for least cost supply of wholesale energy. In fact, the equation (2) has the same form for a generator in the existing-supplier only short-term market that has sold the quantity, QR, of energy to a distribution utility or free consumer at price of PR:

$$\pi(PS) = (PR - C)QR + (QS - QR)(PS - C). \tag{3}$$

A supplier that sells more that QR in the short-term market (QS > QR), would like a higher short-term price, whereas a supplier that sells less than QR in the short-term market (QS < QR) would like a lower short-term price. In general, the supplier would also like to obtain QR at the lowest possible cost either by producing it or purchasing it from the short-term market.

4.2.3. Modifying Long-Term Resource Adequacy Mechanism in Peru

As noted earlier, allowing distribution utilities and free consumers to participate in the day-ahead and real-time markets can significantly increase the extent of competition faced by existing suppliers in both the short-term market and long-term resource adequacy process. However, this change in the short-term market design requires a change in the long-term resource adequacy mechanism. The goal of the proposed long-term resource adequacy mechanism is to retain the attractive features of the existing mechanism, but also increase the opportunities for small suppliers and new entrants to compete in the long-term resource adequacy procurement process and the short-term market in order to close the gap between average PPA prices and average short-term market prices shown in Figure 4.

The most attractive feature of the existing long-term resource adequacy mechanism is that it internalizes the reliability externality described earlier by assigning to electricity suppliers the risk of managing the vast majority (90%) of short-term price and aggregate demand risk. It also focuses on providing the revenue streams necessary to support new investment in generation capacity to serve future demand.

However, the full-requirements contract nature of the existing PPA products limits the ability of both small firms and new entrants to compete in providing these products. The proposed mechanism addresses this short-coming by creating standardized fixed-price forward contracts as the basis for the long-term resource adequacy mechanism. The ability of suppliers to sell these standardized fixed-price forward contracts is tied to the maximum annual amount of energy these resources can produce under stressed system conditions, because energy shortfalls, rather than capacity shortfalls, are increasing likely to be the major reliability challenge faced by Peru going forward as it increases the share energy from intermittent renewable resources.

4.2.4. A SFPFC Approach to Long-Term Resource Adequacy for Peru

This section outlines a Standardized Fixed-Price Forward Contract (SFPFC) approach long-term resource adequacy for Peru that internalizes the reliability externality caused by a cost-based market short-term market. This mechanism utilizes the incentives for supplier behavior created by fixed-price forward contracts described in the previous section to provide strong financial incentives for actual system demand to be met during all hours into the distant future, similar to the existing full requirements approach to long-term resource adequacy. However, it also provides maximum flexibility for free consumers and distribution utilities to find the least cost mix of generation resources to meet this goal and maximizes the opportunities for final consumers to actively participate in the short-term market and allows purely financial participation in both the short-term market and long-term resource adequacy mechanism.

The reliability externality is internalized by requiring all free consumers and distributors to hold standardized long-term fixed-price forward contracts equal to fractions of their realized demand at various horizons to delivery. Joskow (1997) argues that the majority of the economic benefits from the electricity industry restructuring are likely to come from more efficient investment decisions in new generation capacity. The combination of a cost-based short-term market and fixed-price forward contract mandates on electricity retailers is a low-cost and low-regulatory burden approach to realizing more efficient investments in new generation capacity. Because of Peru's dependence on hydroelectric resources and its desire to increase the amount intermittent renewables in its energy mix, a capacity-based approach to long-term resource adequacy is increasingly inappropriate.

Implementing a SFPFC approach to long-term resource adequacy does not mean that firm capacity values for all generation units should not be computed by the COES and made available to the public. As discussed below, these firm values should guide for the long-term resource adequacy energy procurement process rather than a product that must be purchased by all loads, because of the challenges in computing credible firm capacity values for intermittent renewable generation units discussed in Section 4.2.1. Firm capacity values provide useful information about the ability of intermittent renewable generation units to provide a specific quantity of energy during stressed system conditions, but as the analysis Wolak (2021) demonstrate for California in August 2020, these figures do not have the same meaning as firm capacity numbers for a dispatchable thermal generation unit. In markets with a significant share of intermittent renewables, whether demand is met under all possible future system conditions ultimately depends on the strength of the financial incentive that suppliers have to make this happen. The goal of the SFPFC approach is to provide this strong financial incentive, while also taking advantage of the information contained in the firm capacity values computed by the COES.

The requirement that all free consumers and distributors hold their fraction of realized system demand in a SFPFC energy would replace the current requirement that all suppliers must purchase full-requirements contracts net of their 10 percent purchases directly from the short-term energy market. In steady state, free consumers and distributors would be required to hold SFPFCs that cover 100 percent of realized system demand purchased three years in advance, 95 percent of realized system demand purchase four years in advance of delivery, 90 percent of realized system demand five years in advance of delivery, and 85 percent of realized demand six years in advance of delivery. The fractions of system demand and number of years in advance that the SFPFCs must be purchased are parameters that would set by OSINERGMIN to ensure long-term resource adequacy. The SFPFCs would clear against the quantity-weighted average of the hourly real-time locational marginal prices at all load withdrawal nodes in Peru.

The compliance period of the SFPFCs can be calendar years, quarters or even months. Regardless of the compliance period, a SFPFC is for a fixed amount of energy that is cleared against hourly quantities during that compliance period based on *realized hourly system demands* during the compliance period. The predictable seasonality in hydroelectric, solar and wind energy production provides a strong argument for quarterly or even monthly SFPFC contracts. This preserves an important feature of the existing long-term resource adequacy mechanism that all quantity risk is assigned to electricity suppliers. Suppliers can share this risk with other parties under mutually beneficial financial conditions. Active participation of distribution utilities and free consumers in the short-term market and the entry of purely financial participants is designed to allow this to occur.

A shorter compliance period for the SFPFCs would also reduce the uncertainty in the final hourly obligations of sellers and holders of SFPFCs. Preliminary settlement of the contracts during the delivery period could be based on the best estimate by COES of the hourly load shape during the compliance period. This could be the hourly load shape during the same quarter of the previous year. Monthly SFPFCs would likely allow more accurate estimates of the realized hourly load shape during the compliance period than quarterly SFPFCs and quarterly SFPFCs would likely allow more accurate estimates of realized hourly load shape during the compliance period relative to annual SFPFCs. The major complication with shorter compliance periods for the SFPFCs is they requires more frequent procurement auctions. For these reasons, the SFPFC mechanism should be implemented with no longer than quarterly compliance periods.

SFPFC energy would be shaped to the hourly system demand within the compliance period of the contract. Figure 8 contains a sample pattern of system demand for a four-hour delivery horizon. The total demand for the four hours is 1,000 MWh, and the four hourly demands are 100 MWh, 200 MWh, 400 MWh and 300 MWh. Therefore, Firm 1, which sells 300 MWh of SFPFC energy for delivery within these four periods, has the hourly system demand-shaped forward contract obligations of 30 MWh in hour 1, 60 MWh in hour 2, 120 MWh in hour 3 and 90 MWh in hour 4 in Figure 9. The hourly forward contract obligations for Firm 2 that sold 200 MWh SFPFC energy and Firm 3 that sold 500 MWh of SFPFC energy are also shown in Figure 9. These SFPFC obligations are also allocated across the four hours according to the same four hourly shares of total system demand derived from Figure 8 of 10 percent in period 1, 20 percent in period 2, 40 percent in period 3, and 30 percent in period 4. This ensures that the sum of the hourly values of the forward contract obligations for the three suppliers is equal to the hourly value of system demand. Taking the example of hour 3, Firm 1's obligation is 120 MWh, Firm 2's is 80 MWh and Firm 3's is 200 MWh. These three values sum to 400 MWh, which is equal to the value of system demand in hour 3 shown in Figure 8.

The total standardized fixed-price forward contracts obligations are allocated to retailers based on their share of system demand during the compliance period. In the actual market operation, these allocations would be based on the share of monthly energy consumed by the free consumer or distribution company. Suppose that the four retailers in Figure 10 consume 100 MWh, 200 MWh, 300 MWh, and 400 MWh during the four periods. This means that Retailer 1 is allocated 100 MWh of the 1000 MWh SFPFC obligations for the four periods, Retailer 2 is allocated 200 MWh, Retailer 3 is allocated 300 MWh, and Retailer 4 is allocated 400 MWh. The obligations of each retailer are then allocated to the individual hours using the same hourly system demand shares used to allocate the SFPFC energy sales of suppliers to the four hours. This allocation process implies Retailer 1 holds 10 MWh in hour 1, 20 MWh in hours 2, 40 MWh in hour 3 and 30 MWh in hour 4. Repeating this same allocation process for the other three retailers yields the remaining three hourly allocations shown in Figure 10. Similar to the case of the suppliers, the sum of allocations across the four retailers for each hour equals the total hourly system demand. For period 3, Retailer 1's holding is 40 MWh, Retailer 2's is 80 MWh, Retailer 3's is 120 MWh, and Retailer 4's is 160 MWh. The sum of these four magnitudes is equal to 400 MWh, which is the system demand in hour 3.

The SFPFCs would be purchased through centralized auctions several years in advance of delivery to allow new entrants to compete to supply this energy. Because the aggregate hourly values of these SFPFC obligations are allocated to retailers based on their actual share of system demand during the month, this mechanism can easily accommodate retail competition. If one retailer loses load and another gains it during the month, the share of the aggregate hourly value of SFPFCs allocated to the first retailer falls and the share allocated to the second retailer rises.

COES would run these auctions with oversight by the OSINERGMIN. One advantage of this long-term resource adequacy design is that a simple auction mechanism can be used to purchase the SFPFC product for each compliance period. A multi-round auction could be run where suppliers submit the total amount of annual SFPFC energy they would like to sell for a given delivery period at the price for the current round. Each round of the auction the price would decrease until the amount suppliers are willing to sell at that price is less than or equal to the aggregate amount of SFPFC energy demanded. COES would also run a clearinghouse to manage the counterparty risk associated with these contracts. This would not be appreciably different from the clearinghouse necessary to settle the current capacity payment mechanism.

An anonymous centralized market for purchasing these SFPFCs would maximize the competition faced by the large suppliers and level the playing field between them and small suppliers and potential new entrants. SFPFCs would be primary product used by distribution utilities and free consumers to hedge their short-term price and quantity risk at least cost. Under this scheme, large portfolio suppliers would have less of competitive advantage selling long-term resource adequacy products than they do under the existing mechanism.

If the compliance period for each SFPFCs product is a quarter of the year, this implies the steady-state need for up-front compliance auctions and a true-up auction each quarter. The compliance auctions should be run sufficiently far in advance of the delivery period to allow new entrants to compete with existing generation resource owners to supply this energy. For example, a SFPFC auction in run in December of 2021 could by for "energy deliveries" starting in Quarter

1 (Q1) of 2024. At this time auctions for the remaining three quarters of 2024 could be run and as well as auctions for all quarters of 2025, 2026, and 2027. This means each quarter, 16 auctions for quarterly products are being run, although more or fewer quarterly auctions could be run depending on the desired amount of future revenue certainty that COES believes suppliers require. The amount of energy purchased in the Q1-2024 auction would be equal to the COES forecast of the total energy demand for the first quarter of 2024. Recall that this is a single number equal to the total amount of energy that the COES estimates will be consumed in that quarter. The Q2, Q3, and Q4 auctions would purchase the COES forecast of the demand for these quarters. For Q1 to Q4 of 2025, the demands purchased could be slightly less than the COES forecast for these quarters, say 95% of the forecast demand in each quarter. For Q1 to Q4 of 2026, the demands purchased could be equal to 90% of the COES forecast for those quarters. For Q1 to Q4 of 2027, the demand purchased could equal to 85% of the COES forecast for those quarters.

As time progresses, additional auctions could be run for the next 16 quarters 3 years in advance to maintain these same percentages at each future annual delivery horizon. For example, in Q4 of 2022, an additional SFPFC auctions would be run to obtain the 100% of the COES forecast for Q1 to Q4 of 2025, 95% of the COES forecast for 2026, 90% of the COES forecast for 2027, and 85% of the COES forecast for 2028. This process would continue until Q2 of 2024 when the first true-up auction would need to be run based on actual energy production during Q1 2024. Then in each subsequent quarter a true-up auction would need to be run for the previous quarter along with the 16 quarterly compliance auctions 3 years in advance of delivery.

The vast majority of SFPFC contracts will be purchased in advance of delivery. However, because the mechanism requires that the total quantity of SFPFC energy sold during the compliance period must equal the realized demand during that same time period, after each compliance period there needs to be true-up auctions to buy back unused SFPFC energy or purchase additional SFPFC energy. The following example uses the 4-period model in Figures 8 to 12.

A compliance auction would be run far in advance of the compliance period to purchase 1,000 MWh of energy for the four time periods shown in Figure 8. Suppose this auction cleared at a price $60/MWh. Figure 9 shows the quantities sold in the auction for the three suppliers and their hourly SFPFC obligations assuming the pattern of aggregate demand in Figure 8 is realized for the four time periods. Figure 10 shows the hourly SFPFC holdings of the four retailers for the four time periods. The total demand across the four periods for each retailer are shown at the top of Figure 10.

Now suppose that the realized demand for the compliance period turns out to be 10 percent higher in each of the four periods. This implies the need for an ex post true-up auction for 100 MWh. Because demand is 10 percent higher in each of the four periods, as shown in Figure 11, the shares that allocate this additional 100 MWh across four time periods to the four retailers are the same as those used to allocate the original 1000 MWh across the four time periods. The increment allocations to each of the four retailers are shown in Figure 13 and the total realized demands for the four periods for each retailer are shown at the top of the graph. The period-level obligations for the incremental SFPFC energy purchased in the true-up auctions depend on which suppliers sell this energy. If each firm sells ten percent more SFPFC energy in the true-up auction and system demand increases by 10 percent in each of the four periods, the period level allocations of the additional SFPFC energy for each supplier are shown in Figure 12. In this example, we assume that the true-up auction cleared at $70/MWh and the demand-weighted average short-term price for the four periods is $55/MWh.

In addition to the variable profits suppliers would earn from selling the energy they produce from their own generation units in the short-term market, the three suppliers would receive the following difference payments to settle their SFPFC contract positions:

Firm 1 = (\$60 - \$55)300 + (\$70 - \$55)30
Firm 2 = (\$60 - \$55)200 + (\$70 - \$55)20
Firm 3 = (\$60 - \$55)500 + (\$70 - \$55)50.

Besides the variable profits they would earn from purchasing energy from the short-term market and selling to their retail customers at the retail price the four retailers would pay the following difference payments:

Retailer 1 = (\$60 - \$55)1000(110/1100) + (\$70 -\$55)(110/1100)100
Retailer 2 = (\$60 - \$55)1000(220/1100) + (\$70 -\$55)(220/1100)100
Retailer 3 = (\$60 - \$55)1000(330/1100) + (\$70 -\$55)(330/1100)100
Retailer 4 = (\$60 - \$55)1000(440/1100) + (\$70 -\$55)(440/1100)100

Both the original and true-up aggregate SFPFC purchases are allocated to individual retailers based on their actual share of total demand served during the four demand periods. The Appendix presents a number of examples of how true-up auctions would work to ensure that the realized demand of all consumers in Peru, rather than a forecast of demand, is covered by a SFPFC, similar to how all demand in Peru (except for the up to 10% purchased from short-term) is covered by a power purchase agreement under the current supplier-only short-term market with full requirements contracts purchased by free consumers and distribution utilities.

The advance purchase fractions of the final demand in the initial compliance auctions for SFPFC energy are the regulator's security blanket to ensure that system demands can be met for all hours of the year for all possible future system conditions. If the regulator is worried that not enough resources will be available in time to satisfy this requirement, it can increase the share of final demand that it purchases in each annual compliance SFPFC auction. As shown the

Appendix, if too much SFPFC energy is purchased in an annual auction, it can be sold back to generation unit owners in a later auction or the final true-up auction.

The true-up auctions in the SFPFC mechanism function in a very similar manner to the monthly balances of energy and capacity among suppliers discussed in Sections 3.2 and 3.3 under the existing short-term market and long-term resource adequacy mechanism in Peru. The major difference between these balancing mechanisms and the true-up auctions is that the price which these purchases and sales occur is determined through a bid-based auction under the SFPFC true-up mechanism.

Cross hedging between controllable generation units and intermittent renewable resources under the SFPFC mechanism is enforced by tying the amount of SFPFC energy a generation unit owner can sell in each quarter to the value of their firm energy. As is the case under the existing long-term resource adequacy mechanism, COES would assign firm energy values for each generation unit using a mechanism based on the current firm capacity values set by the COES. Because of the seasonality in the supply of hydroelectric energy, solar and wind energy, different firm energy values could be assigned for different quarters of the year. For example, a hydroelectric unit could sell more SFPFC energy during historically wet quarters of the year than during historically dry quarters of the year. A similar approach could be used to set quarterly firm energy values for wind and solar resources, because these resources are also known to exhibit strong seasonal patterns in many regions.[3]

Because the firm capacity of a generation unit is defined as the amount of energy it can produce under stressed system conditions, this limitation on quarterly sales of firm energy implies

[3] California is known to produce almost double the wind and solar energy during the May through July period of the year than in any other 3-month period of the year.

that intermittent wind and solar resources would sell much less SFPFC energy than the total MWhs they expect to produce in that quarter and controllable generation unit owners would sell significantly more SFPFC energy than the total MWhs they expect to produce in that quarter.

In most quarters, a controllable resource owner would be producing energy in a small number of hours of the quarter but earning the difference between the price at which it sold the energy in the SFPFC auction and the hourly short-term market price times the hourly value of its SFPFC energy obligation for all the hours that it does not produce energy. Intermittent renewables owners would typically produce more than their SFPFC obligation in energy and sell the additional energy at the short-term price. During quarters with low renewable output near the unit's SFPRC sale, controllable resource owners would produce close to the hourly value of their SFPFC energy obligation, thus making average short-term prices significantly higher. However, aggregate retail demand would be shielded from these high short-term prices because of their SFPFC holdings.

It important to emphasize that a SFPFC approach to long-term resource adequacy would only make use of the firm capacity values computed by the COES to limit the maximum amount of SFPFC energy a supplier could sell within any quarter. There would be no requirement for free consumers or distributors to purchase a firm capacity product because they would be purchasing SFPFC energy from these generation unit owners. This example illustrates the redundancy of the obligation to purchase firm capacity in a SFPFC approach to long-term resource adequacy.

4.2.5. Advantages of SFPFC Approach to Long-Term Resource Adequacy to Peru

This mechanism has several advantages for Peru relative to a capacity-based approach to long-term resource adequacy. First, there is no regulator-mandated aggregate capacity requirement. Discussion of Section 4.2.1 of points out the challenges in setting comparable firm capacity values for controllable and intermittent renewables in a RER-dominated region.

Therefore, a superior approach to ensuring long-term resource adequacy is to make information on the firm capacity of all generation units available to all market participants and let them decide both the total MWs and the mix of technologies to meet the SFPFC energy obligations that suppliers sell. A supplier can sell less SFPFC energy that the firm energy values of their generation units, if they are concerned that selling more SFPFC energy would expose them to excessive risk given the financial obligations associated with selling SFPFC energy.

There is also no prohibition on generation unit owners or free consumers and distributors engaging in other hedging arrangements outside of this mechanism. Specifically, a free consumer could enter into a bilateral contract for energy with a generation unit owner or distributor to manage the short-term price and quantity risk associated with the difference between their actual hourly load shape and the hourly values of their retail load obligation. The SFPFC mechanism provides a nudge to market participants to develop a liquid market for these bilateral contract arrangements at horizons to delivery similar to the SFPFC products. This mechanism starts with 100 percent coverage of system demand, which retailers can unwind at their own risk.

For the regulated customers, the purchase prices of SFPFCs can be used to set the wholesale price implicit in the regulated retail price over the time horizon that the forward contract clears. This would provide regulated retailers with a strong incentive to reduce their average wholesale energy procurement costs below this price through bilateral hedging arrangements, storage investments, or demand response efforts. For example, if the regulated wholesale price was being set for the following year, it could be computed as the quarterly-load weighted average of the quarterly prices of SFPFC energy for that year. This would eliminate the need for OSINERMIN to compute the busbar price used to set regulated retail prices. Instead, regulated consumers would pay a wholesale price that reflects competition between existing and new suppliers as well as the anticipated actions of free consumers and distribution utilities in short-term market.

There are several reasons why this mechanism should be a more cost-effective approach to long-term resource adequacy for Peru than a capacity-based mechanism. First, the sale of SFPFC energy starting delivery three years in the future provides a revenue stream that will significantly increase investor confidence in recovering the cost of any investment in new generation capacity.

If SFPFC energy is sold for delivery in four years based on a proposed generation unit, OSINERGMIN should require construction of the new unit to begin within a pre-specified number of months after the signing date of the contract or require posting of a substantially larger amount of collateral in the clearinghouse with the market operator. Otherwise, the amount of SFPFC energy that this proposed unit sold would be automatically liquidated in a subsequent SFPFC auction and a financial penalty would be imposed on the developer. Other completion milestones would have to be met at future dates to ensure the unit is able to provide the amount of firm energy that it committed to provide in the SFPFC contract sold. If any of these milestones were not met, the contract would be liquidated.

Another advantage of focusing on the development of a liquid forward market for energy instead of capacity is that an active forward market for energy has other hedging instruments besides so-called "swap contracts" where a generation unit owner and a retailer agree to a fixed price at a location in the transmission network for a fixed quantity of energy. Cap contracts are also very effective instruments for guarding against price spikes in the short-term market and for funding peaking generation capacity. For example, a generation unit owner might sell a retailer a cap contract that says that if the short-term price at a specific location exceeds the cap contract exercise price, the seller of the contract pays the buyer of the contract the difference between the spot price and the cap exercise price times the number of MWh of the cap contract sold. For example, suppose the cap exercise price is \$300/MWh and the market price is \$400/MWh, then the payoff to the buyer from the cap contract is \$100/MWh = \$400/MWh – \$300/MWh times the number of MWh sold. If the spot price is less than \$300/MWh, then the buyer of the cap contract does not receive any payment.

Because the seller of a cap contract is providing insurance against price spikes, it must make payments when the price exceeds the cap exercise price. This price spike insurance obligation requires the buyer to make a fixed up-front payment to the seller to take on this obligation. This up-front payment can then be used by the seller of the cap contract to pay for a peaking generation unit that provides a physical hedge against price spikes at this location. The Australian electricity market has an active financial forward market where these types of cap contracts are traded and used to finance peaking generation capacity to provide the seller of the cap contract with a physical hedge against this price spike insurance obligation.

Cross-hedging between hydroelectric generation resources and thermal resources in Peru is crucial to ensuring a reliable supply of electricity throughout the year. Cross-hedging is likely to become even more important to ensuring long-term resource adequacy as the amount of wind and solar resources increases. A wind or solar resource owner that sells a fixed-price and fixed-quantity forward contract for energy to a retailer will need to reinsure the quantity risk associated with such a contract. The wind or solar resource owner can sign a contract with a thermal resource owner that provides insurance against the short-term price and quantity risk it faces from selling a fixed-price and fixed-quantity contract.

For example, the wind resource owner could purchase a cap contract for the quantity of energy sold in the fixed-price, fixed quantity contract to the retailer at a mutually agreed upon certain strike that provides insurance against having to purchase energy from the short-term market at an extremely high price when the wind or solar resource is not producing energy. The up-front payment to the thermal resource for the price spike insurance would help to finance the fixed costs of a dispatchable thermal resource that operates significantly less frequently because of the large amount of intermittent renewable generation capacity. The wind or solar resource owner would then factor in the cost of this quantity risk insurance into the price it is willing to sell any fixed-price, fixed quantity forward contract for energy. The requirement that resources cannot sell more SFPFC energy than their firm energy value provides a financial incentive for this cross-hedging to occur.

4.3. Mechanisms to Support Renewables Deployment

This section outlines the basic features of a renewable energy certificate mechanism for Peru to meet its renewable energy goals. This is followed by the discussion of the need to integrate intermittent renewable resources into the standardized long-term contract approach to long-term resource adequacy as the share of intermittent renewables increases. Finally, this section discusses how a cost-based market can foster the development of renewable resources.

4.3.1. Renewable Energy Certificates Market

As discussed in Section 3.3, a renewable energy certificate (REC) market is a significantly lower cost approach to achieving a given renewable energy goal because it creates a competitive market for the renewable energy attribute. Under this mechanism OSINERGMIN would set up a registry of qualified renewable resources in Peru.[4] The set of generation resources that are

[4] The Western Electricity Coordinating Council (WECC), the interconnected electricity network that covered most of the western United States and Canada, has a registry of renewable generation resources for the renewables portfolio standards that exist in western states (https://www.wecc.org/WREGIS/Pages/Default.aspx).

qualified to sell RECs that would be established and overseen by OSINERGMIN. Once a resource is qualified to sell RECs, the energy production by these resources would be compiled by the registry established by OSINERGMIN and each of these resources would be issued RECs equal to the MWhs of energy the resource produced during the compliance period.

Assuming an annual compliance period for a renewables mandate, all free consumers and distribution utilities would be required to purchase the mandated percentage of their annual consumption of energy in RECs. For example, if the renewables mandate was 10 percent for 2024, free consumers and distributors would have to surrender RECs produced during 2024 equal to 10 percent of their annual consumption in 2024. For example, a free consumer or distribution utility with an annual consumption of 20,000 MWh, would be required to surrender 2,000 RECs or pay a per $/MWh penalty set by OSINERGMIN for any shortfall relative to this magnitude. For instance, if the retailer only held 1,900 RECs for the 2024 compliance period, it would be liable for a penalty of 100 RECs times this penalty price. The penalty price should be set sufficiently high so that all free consumers and distributors find it expected profit-maximizing to meet their renewable energy requirement.

Renewable resource owners would be allowed to sell RECs that their units have not yet produced, but they would be subject to the financial penalty for any shortfall between the quantity of RECs they have sold for the compliance period and the amount of RECs their units produced during the compliance period. For example, if renewable resource owner sold 1,000 RECs and only produced 900 MWh of energy during the compliance year, the resource owner to be assessed a penalty for the 100 REC shortfall times the per REC penalty.

Unused REC from the previous compliance year could be used in the following compliance year, but not in any subsequent year. For example, a RER unit that produced 100 RECs in 2024 and only sold 90 of these RECs for compliance in 2024 could sell the remaining 10 RECs for the 2025 compliance period. Similarly, if a free consumer or distributor only needed 95 RECs for compliance in 2024, but it held 105 RECs for the 2024 compliance period, the unused 10 RECs could be used for compliance in 2025. This ability to carryover RECs would only be possible for consecutive compliance years, so a REC produced in 2024 could not be used in the 2026 compliance year or subsequent years.

Unless the Peruvian government establishes a legal commitment to renewable energy targets into the distant future, there is no reason to establish a REC market in Peru. For example, if the Peruvian government sets a goal of 15 percent renewable energy by 2030 with the share growing by one percent per year from the current roughly 5 percent level over the ten-year period, then establishing a REC market would likely be the least cost approach to obtaining these renewables goals. Moreover, this regulatory commitment would increase the likelihood that a forward market for RECs would develop to support investments in renewable resources to meet this goal.

A centralized forward market procurement mechanism similar to the SFPFC mechanism for long-term resource adequacy could be implemented to ensure retailers purchase sufficient RECs into the distant future to provide the revenue stream necessary to meet Peru's renewable energy goals. For example, centralized auctions for RECs could be run at similar time horizons to delivery to the SFPFC auctions. A guaranteed four-year future revenue stream from future REC sales would provide the above market revenues to the quantity of RERs necessary to achieve given long-term RER goal.

It is important to emphasize that without legally mandated commitment by the Peruvian government to meet a specific renewable energy target, such as 20 percent of electricity consumption in Peru from these resources by 2030, establishing a RPS is unnecessary. Intermittent renewable resources can compete with conventional generation resources in the long-term resource adequacy mechanism selling SFPFCs. Special procurement processes for intermittent renewable resources or specific technologies should be avoided. They simply reduce the extent of competition suppliers of these products face, which increases costs to consumers, with no accompanying economic or environmental benefit that could not be achieved at lower cost through an RPS.

4.3.2. Incorporating Renewable Resources into Long-Term RA Mechanism

As discussed in Section 4.2, as the share in intermittent renewable resources in Peru increases, it is increasing costly to place the burden of managing their intermittency on buyers of the renewable power purchase agreement (PPA). A contract that pays a RER unit owner a fixed price for all MWhs produced whenever this energy is produced, provides an implicit subsidy to the RER owner in a multi-settlement LMP market. In terms of notation of equation (1) of Section 4.2.3, the period-level variable profit of the RER unit owner is (PC – C)QC, because QS = QC for all periods under the terms of a contract that pays the RER owner PC for every MWh produced whenever it is produced. This PPA completely insulates the RER unit from the short-term market price, which means it has no financial incentive to manage it intermittency. This contract form is not offered to conventional dispatchable resources for precisely this reason. Clearly, a thermal or hydroelectric resource owner would prefer a contract that transfers all of its outage or energy shortfall risk to the buyer of the contract. For this reason, all fixed-price and actual production PPA contracts should be eliminated for all generation resources.

Under the proposed multi-settlement LMP market without these PPAs contracts, RER resources that schedule energy in the day-ahead market be responsible for the cost or revenues associated with any deviation between their day-ahead schedule and real-time output level as discussed in Section 4.1.3. If the RER unit does not schedule any energy in the day-ahead market, then the energy the unit produces would be paid the real-time price.

Facing intermittent renewable resources with the full cost of their intermittency will foster the development of cross-hedging arrangements between intermittent renewable resources and dispatchable resources. For example, a solar resource owner might purchase price spike insurance against high short-term prices during hours of the day when the resource cannot or is unlikely to produce energy. In this case, the solar resource owner would make an up-front payment to the dispatchable resource owner in exchange for the following hourly payment stream of max(0,(P(spot,h)-P(strike))) times the number of MWhs sold during the term of the "cap contract," where P(spot,h) is spot price during hour h and P(strike) is the negotiated strike price of the financial contract and max(x,y) is a function that chooses the maximum of x and y. The solar resource owner would earn (P(spot,h) – P(strike)) per MWh purchased from this cap contract when P(spot,h) > P(strike) and zero otherwise. The dispatchable resource that sold this contract is liable for this payment stream. For this reason, the dispatchable resource has a strong incentive to produce as much output as possible during periods when P(spot,h) is likely to exceed P(strike) to avoid making this payment.

This across-technology hedging accomplishes two goals. First, it provides up-front revenues to dispatchable generation resources to cover their annual fixed costs in a world in which they operate during fewer hours of the year because of the increasing amount intermittent RERs. Second, it ensures that intermittent RERs account for the full cost of their intermittency in the prices they offer for SFPFC energy and RECs. If intermittent renewable resource owners are unable to recover these costs from selling SFPFC energy or energy in the short-term market, these above-market costs must then be recovered from sales of RECs, assuming that the Peruvian government has set a legally binding target for energy production. As noted earlier, for the case that the Peruvian government does not set a legally binding renewables target, the renewable resource owner must recover its costs through sales of SFPFC energy, bilateral hedging arrangements, and short-term market sales.

4.3.3. Cost-Based LMP Market and Renewables Integration

The strength of a cost-based LMP market design for RER integration is that all of the resources in the control area, including intermittent renewable resources, will be dispatched in a least cost manner using the variable costs determined by the market operator. How these resources are compensated for the energy they sold in the SFPFC auctions will not impact how the resource is ultimately used to produce energy. As noted earlier all suppliers have a strong financial incentive to supply their hourly allocation of SFPFC energy at the lowest possible cost, either by producing it or purchasing it from the short-term market.

A cost-based short-term LMP market provides RER owners with a transparent short-term market to purchase energy from when their intermittent renewable units do not produce sufficient energy to meet their hourly SFPFC obligation and sell excess energy beyond this forward market obligation when their units produce more than this quantity of energy. This logic emphasizes the importance of a publicly disclosed process for clearing the day-ahead and real-time cost-based markets. The renewable resource owner can factor in how these imbalances will be settled in making offers to supply SFPFCs for energy.

Shifting renewable resource owners to fixed-price and fixed-quantity forward contract from fixed-price and quantity-produced contracts will also provide financial incentives for renewable resource owners to manage the intermittency of their production through storage investments and financial contracts that support investments in fast-ramping dispatchable generation resources to provide insurance against renewable energy shortfalls. Transitioning forward contracts for renewable energy to require the seller to manage the quantity risk associated with the energy it sells is a crucial step in increasing the amount intermittent renewable energy produced in Peru while maintaining high level of grid reliability.

In all LMP markets operating around the world there is an ongoing process of updating the set of constraints incorporated into the market mechanism to ensure that the match between how the market sets prices and dispatch levels agrees as closely as possible with how the grid is operated. This logic implies that as the share of intermittent renewable resources increases an LMP market can be easily adapted to deal with the new reliability challenges this creates.

For example, California has added several new operating reserves to account for the fact that the large share of solar RERs has created the need to manage a large daily ramp up of dispatchable resources at the end of the daylight hours and a slightly smaller ramp down in the early morning hours. The introduction of these new operating reserves required additional constraints in the day-ahead market-clearing mechanism and adding the offer prices times the offer quantities for these products to the objective function.

A multi-settlement LMP market can efficiently manage the sudden generation unit starts and stops that arise with a significant amount of intermittent renewable generation units and the need to configure combined cycle natural gas units to operate as either individual combustion turbines or as an integrated pair of combustion turbines and a steam turbine. A formal day-ahead market allows these generation units to obtain day-ahead schedules that are consistent with their physical operating constraints. The real-time market can then be used to account for unexpected changes in these day-ahead schedules because of changes in the operating characteristics of generation units such as a forced outage or limitations in the amount of available input fossil fuel, as well as changes in demand between the day-ahead and real-time markets.

4.4. Ancillary Services Market Design

A number of important lessons emerge from international experience with ancillary services market design. The first is the need to co-optimize the procurement of operating reserves with energy in both the day-ahead and real-time markets considering all transmission network and system operation constraints in the market-clearing process. The second is the need for a market power mitigation mechanism for an offer-based market for operating reserves, particularly in a country like Peru with concentrated ownership of generation units capable of providing these services. Third is the necessity of a scarcity pricing mechanism for operating reserves to ensure that when COES is unable to procure sufficient reserves, the market price of operating reserves reflects this scarcity condition.

Performance penalties associated with the failure to provide each ancillary service are also necessary. For spinning and non-spinning reserve, a supplier providing either of these products may not be called upon to provide energy, so it is unclear if the capacity sold could have responded if it had been called upon. For this reason, all markets in the United States have a "no-pay" provision that says the seller of spinning or non-spinning reserve forfeits all revenues from selling this service if it fails to provide energy when called upon up to the last time is successfully responded to a request to provide energy when providing this service. For example, if a unit sold 50 MW of non-spinning reserve and was called upon to provide energy from this capacity and failed to do so, it would forfeit all payments received for providing non-spinning reserve up to the last time it sold non-spinning reserve and then was called upon and sold energy from this reserve capacity.

A final important lesson is that the design ancillary services products should be tailored to the set of products the system operator needs to operate the system, rather than the specific technologies available to provide these products. The idea of defining the products to serve the needs of the system operator is to increase the extent competition across the available technologies to provide these services. Generation unit owners should also have the maximum flexibility to meet any forward market obligation for an ancillary service. Just like the case of the energy market, suppliers that sell a forward contract for an operating reserve should be able to fulfil this obligation with their own generation units or through purchases from the short-term market for this product.

4.4.1. Sequential versus Simultaneous Clearing of Energy and Operating Reserves

The experience of several United States markets with sequential clearing of their operating reserves market strongly argues against this market design. Early in the California wholesale market, the operating reserves market cleared after the day-ahead energy market and before the real-time energy market. This meant that suppliers to the operating reserves market knew which resources had sold energy in the day-ahead market before submitting their offers to the operating reserves market. They knew when they were likely to face little competition for a given operating reserve and submitted higher offer prices. Consequently, annual operating reserves costs were 13%, 5.7% and 6.8% of annual energy costs in during the first three years of the market in 1998, 1999, and 2000. During the three most recent years in California, 2017, 2018, and 2019, with a co-optimized day-ahead energy and operating reserves market and approximately 20% of the energy coming intermittent renewable resources, these costs were 1.6%, 2% and 1.7% of annual energy costs, respectively. This experience emphasizes the importance of a day-ahead energy market co-optimized with the operating reserves market relative to a sequential clearing of the energy and operating reserves markets.

4.4.2. Market Power Mitigation Mechanisms

Because the operating reserves market will operate based on generation unit offers even though the day-ahead and real-time energy markets will operate based on cost-based offers set by COES, there is the potential for the exercise unilateral market power in the operating reserves market. Caps on the price offers that suppliers can submit should be sufficient to address this concern, but it may be necessary to develop a formal mechanism to deal with this issue. Developing a formal market power mitigation mechanism for the operating reserves market would have the additional benefit of providing a foundation for the development of a market power mitigation mechanism for the energy market.

An important lesson from the experience of all offer-based markets for energy in United States is that depending on demand levels, generation unit operating levels, and the transmission network configuration, virtually any supplier can have a substantial ability to influence the price it receives for sales in the short-term energy market. Consequently, before Peru transitions to an offer-based short-term energy market, the OSINERGMIN must design and implement an automatic local market power mitigation mechanism that is built into the market-clearing software. In general, the short-term market regulator must determine when any type of market outcome causes enough harm to some market participants to merit explicit regulatory intervention. Finally, if the market outcomes become too harmful, the regulator must have the ability to temporarily suspend market operations. All of these tasks require a substantial amount of subjective judgment on the part of the regulatory process, which can be extremely challenging for countries and regions with limited regulatory experience.

In all offer-based energy markets, a local market power mitigation (LMPM) mechanism is necessary to limit the offers a generation unit owner submits when it faces insufficient competition to serve a local energy need because of a combination of the configuration of the transmission network, the levels and geographic distribution of demands, and the concentration of ownership of generation units. A LMPM mechanism built into the market software that relies on actual system conditions to determine whether a generation unit has a substantial ability and incentive to exercise unilateral market power is likely to be significantly more effective than the prospective approaches used in Europe and initially in the US. This logic explains why all US markets currently have a LMPM mechanism built into their market software and running automatically during each pricing interval.

A LMPM mechanism is a pre-specified administrative procedure (written into the market rules) that determines: (1) when a producer has local market power worthy of mitigation, (2) what the mitigated producer will be paid, and (3) how the amount the producer is paid will impact the payments received by other market participants. Without a prospective market power mitigation mechanism system conditions are likely to arise in all wholesale markets when almost any generation unit owner can exercise substantial unilateral market power. It is increasingly clear to regulators around the world, particularly those that operate markets with limited amounts of transmission capacity, that these automatic regulatory interventions are necessary to deal with the problem of insufficient competition to serve certain local energy or operating reserves needs. Graf, La Pera, Quaglia, and Wolak (2021) survey the range of market power mitigation mechanisms that currently exist in United States markets.

4.4.3. Scarcity Pricing of Operating Reserves

A power system is operated less reliably with less than the system operator's desired quantity of operating reserves. To reflect this increased risk of failure due to insufficient operating reserves in market prices, several regions in the United States have integrated operating reserve demand curves into their short-term market. Figure 17 provides a sample operating reserve demand curve (ORDC). Q(min) is the minimum amount of contingency reserves necessary for reliable operating of the grid. The marginal willingness to pay to avoid lower levels of operating reserves than this magnitude is assumed equal to the value of lost load, P(VOLL). The downward sloping portion of the curve reflects the fact that the loss of load probability declines with values of the contingency reserve greater than Q(min). The motivation for this mechanism is to reward suppliers for providing reserves during circumstances when there is an increased risk of curtailing load. Hogan (2013) presents a comprehensive discussion of this concept with multiple operating reserves.

4.4.4. Ancillary Services Proposal for Peru

This proposal has a short-term operating reserves market that sells four products: (1) secondary frequency up (SFU), (2) secondary frequency down (SFD), (3) spinning reserve (SPIN), and (4) non-spinning reserve (NSPIN). This market is co-optimized with the day-ahead and real-time energy market and combines the thermal and hydro costs with the capped offers submitted suppliers to provide each operating reserve their units can provide. In the day-ahead market, free consumers and distributors submit locational demand bids for energy for all hours of the following day. Individual operating reserves demands are specified by COES for all hours of the day. COES would also formulate in an ORDC mechanism for these four reserves that would have to be approved by OSINERGMIN.

The solution to day-ahead market yields hourly schedules for energy and each operating reserve and locational marginal prices for energy and prices of each operating reserve equal to the increase in the optimized value of the objective function associated with a 1 MW increase in the demand for that operating reserve. This approach to pricing operating reserves accounts for the opportunity cost of the resource providing energy and all other operating reserves the unit can provide in determining whether to accept the unit's offer to supply a given quantity of operating reserves. For example, if a unit is accepted to provide 50 MW of an operating reserve at a price of $10/MW, this means that providing this operating reserve yields the resource a higher margin than it would earn from providing energy from this 50 MW.

SFU and SFD are paid a $/MW price for the range of capacity accepted to supply this operating reserve. These resources are also paid real-time price of energy or pay the real-time price of energy for their net production or net consumption of energy during the hour they are providing these operating reserves. Spinning and non-spinning reserves are paid a $/MW price for the range of capacity accepted to supply these reserves and if these units are subsequently accepted to supply energy, they are paid the prevailing real-time price for their energy.

Because of their local and uncertain demand, there would not be short term markets for primary frequency control, voltage control and black start. Primary frequency should continue to be provided at individual generation units in response to a local frequency event. Voltage control should be provided without compensation within the range of the power factor of the generation unit because the marginal cost of providing these MVars is zero. However, reactive power that requires reducing the output of the generation unit should be paid the opportunity cost of the reduced energy sales.

The opportunity cost payment to the generation unit owner is (P(spot) – MC)(Q(ideal) – Q(actual)), where P(spot) is real-time price of energy, MC is the marginal cost of producing energy, Q(ideal) is the energy output of the unit without the reactive power requirement, and Q(actual) is the energy output with the reactive power requirement. Black start should be purchased from generation units capable of providing this service under a long-term contract. This procurement can be done through a cost-of-service contract or a competitive procurement process, depending on the extent of competition in this market.

As noted in Section 3.5.1, because operating reserves have two features that define a public good it is not possible to allocate all or even a significant fraction of the costs of ancillary services using the principles of cost-causation. For this reason, most markets in the United States allocate these costs to loads based on the logic that final consumers are the least likely to take actions to avoid paying these costs that also degrade market efficiency. By this logic, any ancillary services costs that cannot be causally assigned to specific market participants should be allocated to final consumers on a per MWh of energy consumed basis.

4.5. Regulatory Oversight of Wholesale Market

Regulatory oversight of the wholesale market regime is perhaps the most challenging aspect of the market design process because it requires putting in place of process of continuously responding to change. The regulatory process in the wholesale market regime focuses on the difficult task of setting market rules that yield, through the profit-maximizing actions of market participants, just and reasonable prices to final consumers. The rules that govern the operation of the generation, transmission, distribution and retailing sectors of the industry all impact the retail prices paid by final consumers.

The restructured electricity supply industries that have ultimately delivered the most benefits to electricity consumers are those with a credible and effective regulatory process. The first step in achieving this outcome is a clearly defined set of market rules understood by all market participants and regulators. These rules are typically developed through a public process run by the market operator where all interested can parties participate. Any market rule that is ultimately implemented must be approved by the relevant regulatory authority.

The second step of regulatory oversight process is to provide what I call "smart sunshine regulation." This means that the regulatory process gathers a comprehensive set of information about market outcomes, analyzes it, and make it available to the public in a manner and form that ensures compliance with all market rules and allows the regulatory process to detect and correct market design flaws in a timely manner. Smart sunshine regulation is the foundation for all of the tasks the regulatory process must undertake in the wholesale market regime.

A clearly defined and credible regulatory process limits the ability of political actors to interfere in how the industry operates. There is ample experience from many international markets that decisions taken by political actors, often in response to real or perceived energy supply risks, do not yield the most beneficial outcomes for consumers or producers. If the market rules clearly lay out how decisions to intervene in the market will be made, this can limit the opportunities for political actors with little expertise in the industry to intervene.

Guarding against arbitrary political intervention is particularly difficult with respect to the question of why and when a regulatory backstop is implemented. The very asymmetric loss function facing politicians associated with over-capacity (higher prices for consumers) versus inadequate capacity (rolling blackouts) in generation or transmission induces a significant bias toward intervention that results in over-capacity. This fact implies that the market rules should establish a backstop transmission and generation investment process that explicitly recognizes this asymmetric loss function facing the political process. This means that the backstop process is likely to be biased in favor of over-capacity in terms of the set of circumstances when it will be implemented, both to avoid the perception that political intervention is necessary and to ensure that it is never actually necessary because implementing the backstop avoided a true political emergency.

4.5.1. Stakeholder Process for the Development of Market Rules

All United States wholesale markets have formal stakeholder processes for the development and implementation of market rules or tariff. This process serves two important roles. First it ensures that all market participants can provide input into the development of the tariff. Second it also increases the likelihood that all market participants have common understanding of these market rules and are willing to obey them because they were involved in their development.

All market rule proposals that arise from the stakeholder process must ultimately be approved by the wholesale market regulator. The regulator ensures that these market rules are consistent with enabling legislation for the regulatory oversight process. Proposed rules that are inconsistent with the law are rejected and the stakeholder process must come up with revised rules that must also ultimately be approved the relevant regulatory authority.

4.5.2. Smart Sunshine Regulation

A minimal requirement of any regulatory process is to provide "smart sunshine" regulation. The fundamental goal of regulation is to cause a firm to take actions desired by the regulator that it would not otherwise do without regulatory oversight. Beyond a clearly defined and publicly available set of market rules, in order provide effective smart sunshine regulation, the regulator must have access to all information needed to operate the market and be able to perform analyses of this data and release the results to the public. At the most basic level, the regulator should be able to replicate market-clearing prices and quantities given the bids submitted by market participants, total demand, and other information about system conditions. This is necessary for the regulator to verify that the market is operated in a manner consistent with what is written in the market rules.

A second aspect of "smart sunshine regulation" is public data release. There are market efficiency benefits to public release of all data submitted to the real-time market and produced by the system operator. With the level of coverage of final demand by SFPFC energy anticipated in the long-term resource adequacy mechanism, the short-term market is primarily an imbalance market operated primarily for reliability reasons where free consumers and distributions utilities and suppliers buy and sell small amounts of energy to manage deviations between their forward market commitments and real-time production and consumption. Because all market participants have a common interest in the reliability of the transmission network, immediate data release serves these reliability needs.

The sunshine regulation value of public data release is increased if the identity of the market participant and the specific generation unit associated with each cost offer, generation schedule, or output level is also made public. Masking the identity of the entity associated with an offer or bid, generation schedule or actual output level, as is done in all US wholesale markets, limits the ability of the regulator to use the threat of adverse public opinion to discipline market participant behavior. In all US markets, the very long lag between the date the data is produced and the date it is released to the public of at least six months, and the fact that the data is released without identifying the specific market participants, eliminates much of the smart sunshine regulation benefit of public data release.

Another potential benefit associated with public data release is that it enables independent third parties to undertake analyses of market performance. Virtually all market performance measures require matching data on unit-level heat rates or input fuel prices obtained from other sources to specific generation units.[5] Strictly speaking, this is impossible to do if the unit name or market participant name is not matched with the generation unit. A long time-lag between the date the data is produced and the date it is released also greatly limits the range of questions that can be addressed with this data and regulatory problems that it can address. Taking the example of the California electricity crisis, by January 1, 2001, the date that masked data from June of 2000 was first made available to the public (because of a six-month data release lag), the exercise of unilateral market power in California had already resulted in more than $5 billion in overpayments to suppliers in the California electricity market as measured by Borenstein, Bushnell, and Wolak (2002), hereafter BBW (2002). Consequently, a long time-lag between the date the data is produced and the date it is released to the public has an enormous potential cost to consumers that should be balanced against the benefits of delaying the data release.

A final issue associated with smart sunshine regulation is ensuring compliance with market rules. The threat of public scrutiny and adverse publicity is the regulator's first line of defense against market rule violations. However, the regulator must make the penalties associated with any market rule violations more than the benefits that the market participant receives from violating that market rule. Otherwise, market participants may find it unilaterally profit-

[5] See Borenstein, Bushnell and Wolak (2002) for an example of a market performance measurements exercise involving the first three years of the California electricity market.

maximizing to violate the market rules. One lesson from the activities of many firms in the California market and other markets in the US is that if the cost of a market rule violation is less than the financial benefit the firm receives from violating the market rule, the firm will violate the market rule and pay the associated penalties as a cost of doing business.

An important role of the regulatory process is to detect and correct market design flaws before circumstances arise that cause them to produce large wealth transfers and significant deadweight losses. Identifying and correcting market design flaws requires a detailed knowledge of the market rules and their impact on market outcomes. This aspect of the regulatory process heavily relies on the availability of the short-term market outcome data and other information collected by the regulator to undertake smart sunshine regulation. Another important role for smart sunshine regulation is to analyze market outcomes to determine which market rules might be enhancing the ability of suppliers to exercise unilateral market power or increasing the likelihood that the attempts of suppliers to coordinate their actions to raise prices will be successful.

There are also important market competitiveness benefits from regulatory oversight of the terms of conditions for new generation units to interconnect to the transmission network and determine whether transmission upgrades should take place and where they should take place. As demonstrated empirically for the Alberta Electricity Market in Wolak (2015), transmission capacity has an additional role as a facilitator of commerce in the wholesale market regime. Expansion of the transmission network typically increases the number of independent wholesale electricity suppliers that can compete to supply electricity at locations in the transmission network served by the upgrade, which increases the elasticity of the residual demand curve faced by all suppliers at those locations. An industry-specific regulator armed with the data and experienced with monitoring market performance is well-suited to develop the expertise necessary to determine the transmission network that maximizes the competitiveness of the wholesale electricity market.

The Independent System Operator (ISO) that operates the real-time market is a new entity requiring regulatory oversight in the wholesale market regime. The system operation function was formerly part of the vertically-integrated utility. Because a wholesale market provides open access to the transmission network under equal terms and conditions to all electricity suppliers and retailers, an independent entity is needed to operate the transmission network to maintain system balance in real-time. The ISO is the monopoly supplier of real-time market and system operation services and for that reason independent regulatory oversight is needed to ensure that it is operating the grid in as close as possible to a least-cost manner to benefit market participants rather than the management and staff of the ISO.

A final issue with respect to regulatory oversight of the transmission network and system operation function is the fact that the ISO has substantial expertise with operating transmission network. Consequently, the regulator may find it beneficial to allow the ISO to play a leading role in process of determining competition expansions to the transmission network.

The final responsibility for the regulator is to deter behavior that is harmful to system reliability and market efficiency that occurs despite public disclosure of data and market participant behavior and penalties for publicly-observed objective market rule violations. This is the most complex aspect of the regulatory process to implement, but it also has the potential to yield the greatest benefit. It involves several inter-related tasks. In an offer-based market, the regulator must design and implement a local market power mitigation mechanism, which is the most frequently invoked example of an intervention into the market to prevent behavior harmful to market efficiency and system reliability. In general, the regulator must determine when any type of market outcome causes enough harm to some market participants to merit explicit regulatory intervention. Finally, if the market outcomes become too harmful, the regulator must have the ability to temporarily suspend market operations. All of these tasks require a substantial amount of subjective judgment on the part of the regulatory process.

4.5.3. Recommended Changes in Regulatory Oversight

The regulatory process in Peru would benefit from a formal process for establishing and changing the market rules. Particularly for the case of the regulatory backstop for ensuring supply adequacy, having a formal mechanism governing this process written into the market rules that is developed through a stakeholder process would help avoid politically driven decisions for transmission and generation expansion investments. A public stakeholder process run by the COES for any market rule change where any market rule ultimately adopted must be approved by OSINERGMIN would increase the transparency of the market.

Establishing an independent market monitoring process that oversees the performance of the market and identifies market design flaws would help increase the credibility of the regulatory process. Establishing a responsibility for one entity such as COES to perform transmission network and generation adequacy studies supervised by OSINERGMIN, with the results of these studies feeding into the process used to determine whether regulatory backstop for new investment should be implemented would help to eliminate government intervention into the electricity supply industry. To extent that the market rules clarify this process and make it as credible as possible, the actions of market participants will solve reliability problems before the regulatory backstop is activated.

4.6. Potential Future Changes in Market Design

There are variety potential market rule changes that are best delayed until there is significant experience with the proposed changes in the market design. Examples include, transitioning to an offer-based market, introducing financial transmission rights, allowing price sensitive purely financial bids and offers.

All of these changes involve significant regulatory risk and should be implemented only with the appropriate regulatory safeguards in place, such an automatic local market power mitigation mechanism in place for energy, an independent market monitoring function, and the ability of COES to suspend offer-based short-term market operation at its discretion. The LMP market is already in place and generation unit owners' costs as computed by the market operator can easily be replaced with offer prices made by producers. Starting from a cost-based market and transitioning to an offer-based market is a low risk approach to introducing an offer-based market. The PJM Interconnection in the Eastern US followed this strategy during the early stages of its development. It ran one year as a cost-based market before transitioning to an offer-based market.

5. Sequencing and Interrelationships Between Recommendations

This section describes the preferred sequence for implementing the recommended changes and the interrelationships between these recommendations. Certain recommendations can be implemented independent of other recommendations, but other recommendations should be implemented as a group or not at all.

The recommendation to establish a locational marginal pricing day-ahead market that co-optimizes the procurement of energy and operating reserves should be implemented first. The entire process of developing the details of the day-ahead market and building and testing the market software up to the date that the market goes live should require no more than two years. During these same two years, the real-time market could be re-designed to set prices and dispatch levels every five-minutes. A major source of the economic and reliability benefits of implementing a day-ahead market is the result of co-optimizing the energy market with the operating reserves market. Consequently, the day-ahead energy market and co-optimized operating reserves market should be implemented as a pair or not at all.

The day-ahead energy market with a co-optimized ancillary services market and a real-time market with five-minute settlement can be implemented within the existing supplier-only short-term market design or within a market design that allow free consumers and distribution utilities to participate in the day-ahead and real-time markets. In the former case, suppliers would submit locational demands to purchase energy in the day-ahead market and positive and negative imbalances relative to the actual consumption of their customers at each location in the transmission network would be settled at the real-time price. In the latter case, free consumers and distribution utilities would submit locational demands in the day-ahead market and they would settle deviations between their actual consumption and their day-ahead schedule at the real-time at that location.

The renewable energy certificates market should only be implemented if the Peruvian government decides to set a series of legally binding targets for certain amounts of renewable energy or shares of renewable energy in the energy mix of Peru. Without such a target there is no need for a renewable energy certificates market. If such a series of renewable energy targets is established by the Peruvian government a renewable energy certificate market could be set up and begin operation one year from the date of implementation. The renewable energy certificate market can operate within the existing supplier only short-term market or a short-term market that allow the participation of free consumers and distribution utilities. In both cases renewable energy obligations should be assigned based on the annual amount of load supplier serves in the former case or the annual amount energy consumed in the latter case.

If the Peruvian government does not implement a set of legally binding renewable energy targets, it might consider establishing a carbon price as a mechanism for stimulate investments in intermittent renewable energy. Several US jurisdictions have carbon prices that increase the cost of producing electricity from input energy sources that produce greenhouse gas emissions, which can stimulate investment in generation technologies that do not produce greenhouse gas emissions.[6] A carbon price could be implemented in Peru in less than one year. This could raise revenue for the government and stimulate investments in intermittent renewable generation capacity.

Changes in the regulatory oversight process in Peru should be implemented as soon as possible. The first step in this process is to establish a formal public stakeholder process run by COES for making market rule changes that must be subsequently approved by OSINERGMIN. The first order of business for this process would be to implement an independent market monitoring process, that is not a part of COES, for monitoring in the performance of the market, anticipating market rule changes, and preparing publicly disclosed annual reports on the performance of the market and COES. The second order of business for the stakeholder process would be to establish a formal regulatory backstop process for ensuring transmission network and generation adequacy to limit the opportunities for government intervention into the operation of the wholesale market unless absolutely necessary.

---

[6] See Borenstein, Bushnell, Wolak and Zaragosa-Watkins (2019) for described of the California carbon pricing mechanism and its impact on the state's electricity supply industry.

The reform of the long-term resource adequacy process should be coupled with allowing free consumers and distribution utilities to participate in the short-term market. As noted earlier the motivation for the re-design of the long-term resource adequacy process is to increase competition in both the long-term resource adequacy market and short-term energy market. However, without the mandate that all load in covered by SFPFC energy, it would be imprudent to allow free consumers and distribution utilities to participate in the short-term energy market. Consequently, the SFPFC mechanism or some other long-term resource adequacy mechanism that has the same properties and allowing free consumers and distribution utilities to participate in the short-term market should be adopted together or not at all.

The SFPFC mechanism is designed to provide free consumers and distribution utilities that maximum flexibility to be active participants in the long-term resource adequacy process and the short-term market, while still ensuring that all short-term price and quantity risk is assigned to suppliers. This mechanism encourages active demand-side participation in the short-term market which should also increase the competitiveness of this market.

Implementing the SFPFC mechanism should take at least three years to implement because of the need to purchase a large share of the SFPFC energy far enough in advance of delivery to allow new entrants to compete to provide this energy. Consequently, once a decision is made to transition to this mechanism, at least three years advance notice is necessary before it become fully implemented.

6. Summary and Final Comments

The existing short-term market design in Peru already has overcome the crucial stumbling block in many of regions to implementing a multi-settlement locational marginal pricing market design that co-optimizes energy and operating reserves procurement. The current real-time market already employs locational marginal pricing. This fact should make it relatively straightforward to transition to the recommended short-term market design.

The existing long-term resource adequacy mechanism in Peru already mandates long-term full requirements energy contracts between suppliers and free consumers and distributors. The proposed Standardized Fixed-Price Forward Contract (SFPFC) approach to long-term resource adequacy builds on this contracting mandate by expanding the set of suppliers that can compete to supply forward contracts by standardizing the product sold. It also provides incentives for suppliers, flexible loads, and renewable intermittent renewable resource owners to provide flexibility to the short-term market in order to reduce the cost of serving real-time demands throughout the transmission network.

The renewable energy certificate proposal should reduce the cost of meeting any legally binding renewable energy goal set by the Peruvian government. If the Peruvian government does not set a legally binding renewable energy goal, then there is no need to establish a renewable energy certificate market. However, the Peruvian government may wish to set a price of carbon to account for the external cost of greenhouse gas emissions from using a fossil fuel to produce electricity, which should also encourage investments in intermittent renewable generation capacity.

The ancillary services market proposal should allow COES to reduce its demand for secondary frequency up and secondary frequency down, as well as reduce the overall cost of operating reserves by introducing two new tertiary frequency reserve products, spinning reserve and non-spinning reserve, and co-optimizing the procurement of all operating reserves with energy. Incorporating operating reserves demand curves into this market ensures that the prices of these products rises when the likelihood of a supply shortfall increases because of a reduced supply of operating reserves.

Finally, there is a significant need to enhance the regulatory oversight process for the electricity supply industry in Peru. Establishing a stakeholder process for developing and changing the market rules subject to the approval of OSINERGMIN and establishing a formal market monitoring process, will reduce the scope for costly political intervention in the electricity supply industry.

In closing, it is important remember that there is no perfect wholesale market design. There are only better wholesale market designs, and what constitutes a better design depends on many factors specific to the region. Although there is general agreement on the key features of a best-practice short-term market design, many details must be adjusted to reflect local conditions. The long-term resource adequacy mechanism should be coordinated with the short-term market design. For this reason, wholesale market design is a process of continuous learning, adaption, and hopefully, improvement. The standardized energy contracting approach to long-term resource adequacy described in this paper is an example of this process. There are many details of this basic mechanism and the details of other recommendations made in this report that should be adapted to reflect local conditions.

7. References

Bohn, Roger E., Michael C. Caramanis and Fred C. Schweppe (1984), 'Optimal Pricing in Electrical Networks over Space and Time', *RAND Journal of Economics*, **15** (5), 360-376.

Borenstein, Severin, James B. Bushnell, and Frank A. Wolak, (2002) 'Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market', *American Economic Review*, **92** (5) 1367-1405.\

Borenstein, Severin, James Bushnell, Frank A. Wolak, and Matthew Zaragoza-Watkins. "Expecting the unexpected: Emissions uncertainty and environmental market design." *American Economic Review* 109, no. 11 (2019): 3953-77.

Bushnell, James B., Erin T. Mansur, and Celeste Saravia (2008), 'Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured US Electricity Markets.', *The American Economic Review*, **98** (1), 237-266.

Bushnell, James B., Benjamin F. Hobbs, and Frank A. Wolak (2009), 'When it comes to demand response, is FERC its own worst enemy?', *The Electricity Journal*, **22** (8), 9-18.

Bushnell, James B., Benjamin F. Hobbs, and Frank A. Wolak (2008), "Final Opinion on 'The DEC Bidding Activity Rule under MRTU'", available at https://www.caiso.com/Documents/MSCFinalOpiniononDECBiddingActivityRuleunderMRTU.pdf.

Graf, Christoph, Federico Quaglia, and Frank A. Wolak (2020) "Simplified Electricity Market Models with Significant Intermittent Renewable Capacity: Evidence from Italy," available at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/GrafQuagliaWolak_SimplifiedElectricityMarketModelsRenewables.pdf

Graf, Christoph, Emilio La Pera, Federico Quaglia, and Frank A. Wolak (2021) "Market Power Mitigation Mechanisms for Wholesale Electricity Markets: Status Quo and Challenges," available http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/MPM_Review_GPQW.pdf

Galetovic, Alexander, Cristián M. Muñoz, and Frank A. Wolak (2015), 'Capacity Payments in a Cost-Based Wholesale Electricity Market: The Case of Chile', *The Electricity Journal*, **28** (10), 80-96.

Hogan, William W. "Electricity scarcity pricing through operating reserves." Economics of Energy & Environmental Policy 2, no. 2 (2013): 65-86.

Jha, Akshaya, and Frank A. Wolak. Can Financial Participants Improve Price Discovery and Efficiency in Multi-Settlement Markets with Trading Costs? No. w25851. National Bureau of Economic Research, 2019.

Joskow, Paul L. (1997), 'Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector', *The Journal of Economic Perspectives*, **11** (3), 119-138.

La Pera, Emilio, Christoph Graf, and Frank A. Wolak (2020) "Market Power Mitigation Mechanisms for Wholesale Electricity Markets: Status quo and Challenges," available at http://web.stanford.edu/group/fwolak/cgi-bin/?q=node/3

Kahn, Matthew E. and Frank A. Wolak (2013), 'Using Information to Improve the Effectiveness of Nonlinear Pricing: Evidence from a Field Experiment', accessed 26 September 2020 at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/kahn_wolak_July_2_2013.pdf.

Mansur, Erin T. and Matthew W. White (2012), 'Market Organization and Efficiency in Electricity Markets', accessed 26 September 2020 at http://www.dartmouth.edu/~mansur/papers/mansur_white_pjmaep.pdf.

McRae, Shaun D., and Frank A. Wolak. "Diagnosing the causes of the recent El Nino event and recommendations for reform." (2016) available at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/diagnosing-el-nino_mcrae_wolak.pdf

McRae, Shaun D. and Robyn Meeks (2016), 'Price Perceptions and Electricity Demand with Nonlinear Prices', accessed 26 September 2020 at http://www.sdmcrae.com/research/.

McRae, Shaun D. and Frank A. Wolak (2019), 'Market Power and Incentive-Based Capacity Payment Mechanisms', accessed 26 September 2020 at http://web.stanford.edu/group/fwolak/cgi-bin/.

Oren, Shmuel. S. (2001), 'Design of ancillary service markets', in *Proceedings of the 34th Annual Hawaii International Conference on System Sciences*, pp. 9-pp, IEEE.

Price, James E., and Mark Rothleder. "Recognition of extended dispatch horizons in California's energy markets." In 2011 *IEEE Power and Energy Society General Meeting*, pp. 1-5. IEEE, 2011.

Ruff, Larry E., (2005), "Assuring Generation Adequacy in Peru: Overview and Some Suggestions," mimeo.

Triolo, Ryan C. and Frank A. Wolak (2021) “Quantifying the Benefits of a Nodal Market Design in the Texas Electricity Market,” available at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/BenefitsOfNodalDesignERCOT.pdf

Wolak, Frank A. (2009), ‘Report on Market Performance and Market Monitoring in the Colombian Electricity Supply Industry’, accessed 26 September 2020 at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/sspd_report_wolak_july_30.pdf.

Wolak, Frank A. (2011b), ‘Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets’, *American Economic Review*, **93** (2), 247-252.

Wolak, Frank A. (2015), ‘Measuring the competitiveness benefits of a transmission investment policy: The case of the Alberta electricity market’, *Energy Policy*, **85**, 426-444.

Wolak, Frank A. (2015), ‘Do Customers Respond to Real-Time Usage Feedback? Evidence from Singapore’, at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/Singapore%20residential_nov_2015.pdf.

Wolak, Frank A. "Level versus Variability Trade-offs in Wind and Solar Generation Investments: The Case of California." *The Energy Journal* 37, Bollino-Madlener Special Issue (2016).

Wolak, Frank A. (2019) "The benefits of purely financial participants for wholesale and retail market performance: lessons for long-term resource adequacy mechanism design." Oxford Review of Economic Policy 35, no. 2: 260-290.

Wolak, Frank A. and Ian Hardman (2021) “The Future of Electricity Retailing and How to Get There,” available at http://www.stanford.edu/~wolak.

Wolak, Frank A. (2021), Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables, available at http://www.stanford.edu/~wolak

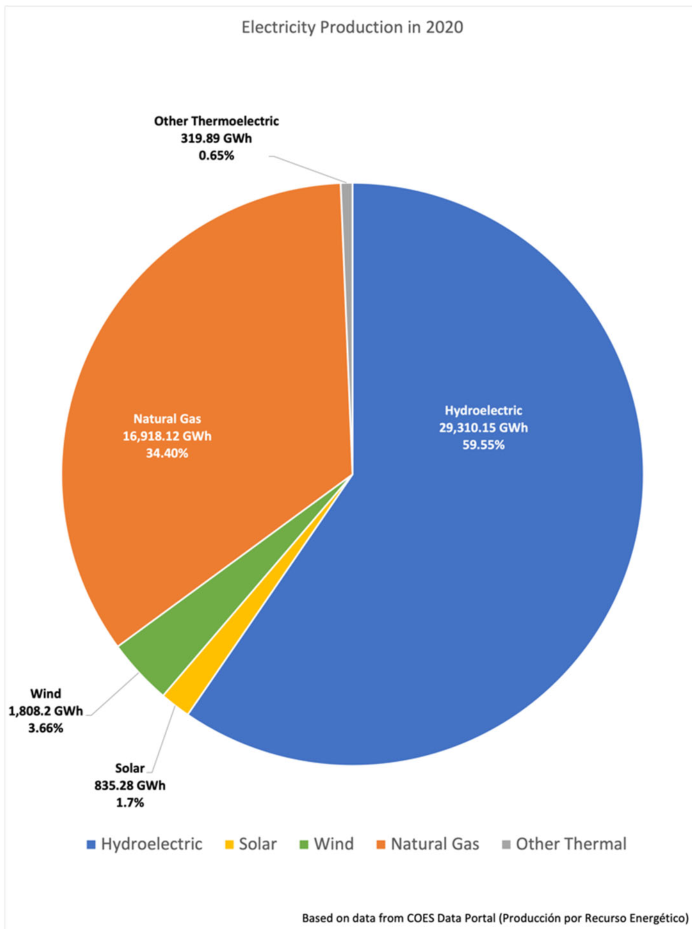


Figure 1: Generation Shares for Peru in 2020

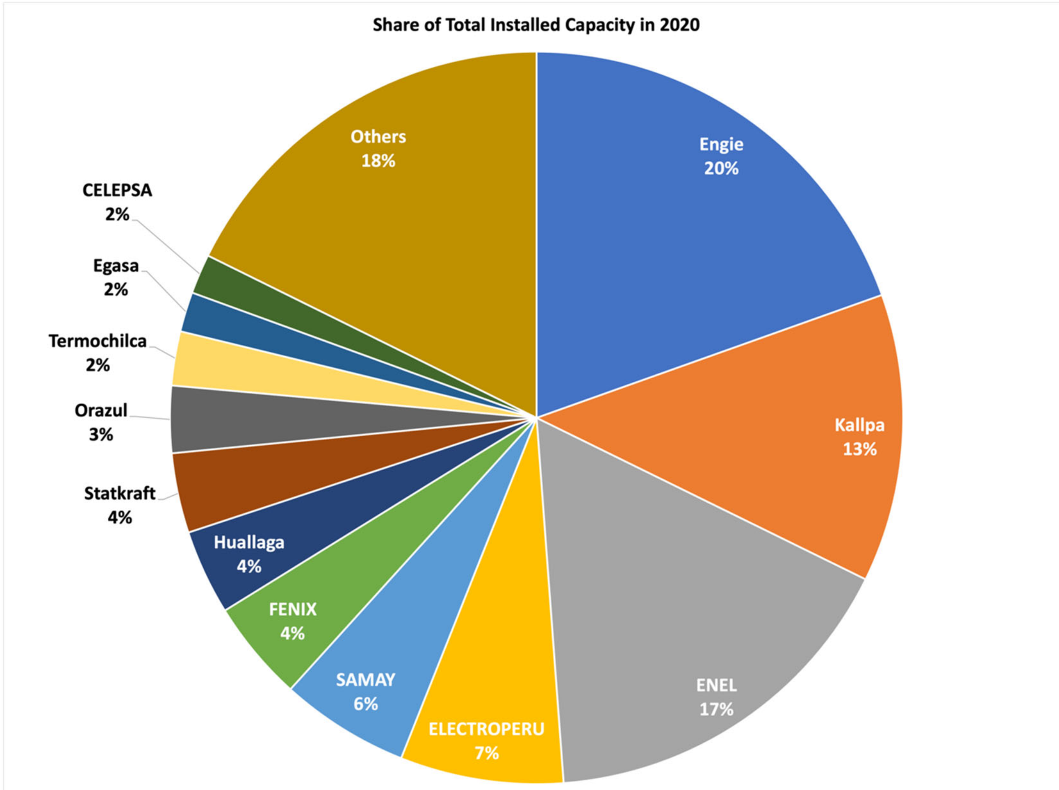


Figure 2: Capacity Shares by Market Participant

Generation Companies	Hydro	Thermal	Solar	Wind	Total Effective Capacity	Share %
Engie	254.47	2185.72	44.54		2484.73	20%
Kallpa	568.08	1047.74			1615.82	13%
ENEL	599.95	1226.96	144.48	132.30	2103.69	17%
ELECTROPERU	898.14	16.56			914.70	7%
SAMAY		723.57			723.57	6%
Fenix		567.19			567.19	4%
Huallaga	476.74				476.74	4%
Statkraft	447.95				447.95	4%
Orazul	375.74				375.74	3%
Termochilca		303.31			303.31	2%
Egasa	177.71	45.54			223.25	2%
CELEPSA	222.49				222.49	2%
Others	1057.77	814.50	96.00	279.91	2248.18	18%
Total Capacity	5079.04	6931.09	285.02	412.21	12707.36	100%

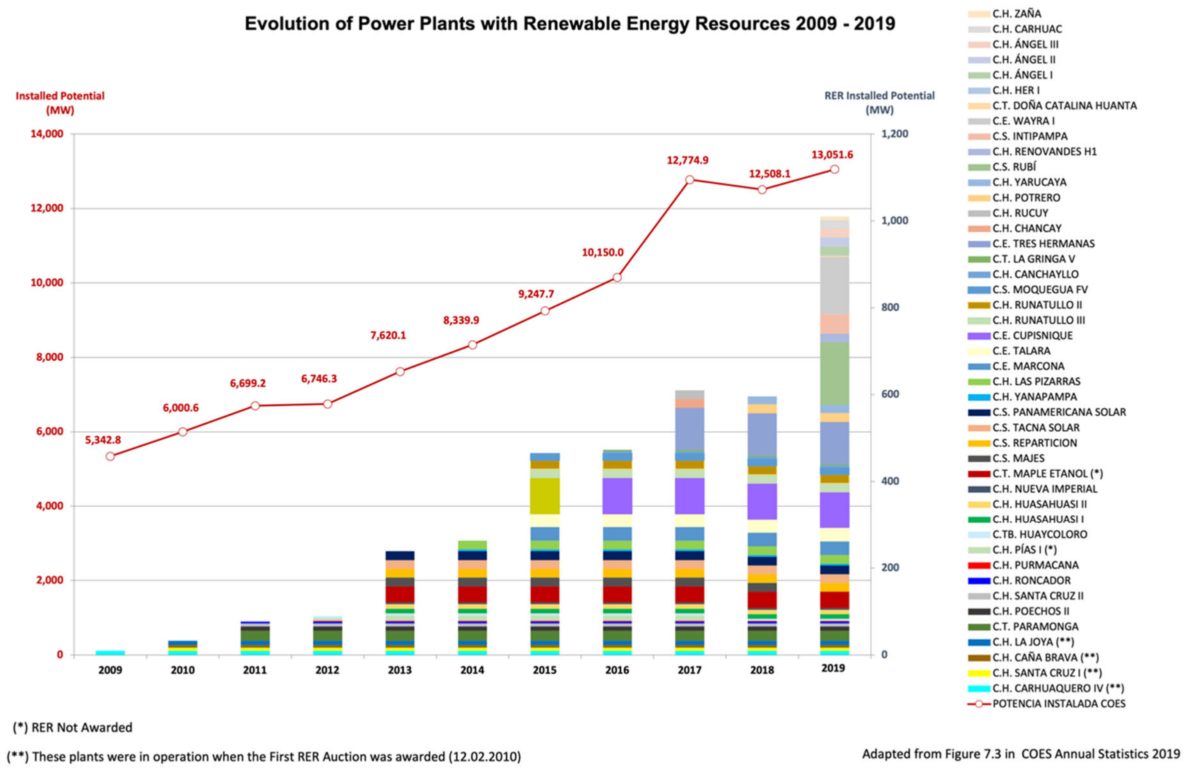


Figure 3: Evolution of Renewable Energy Resource Capacity

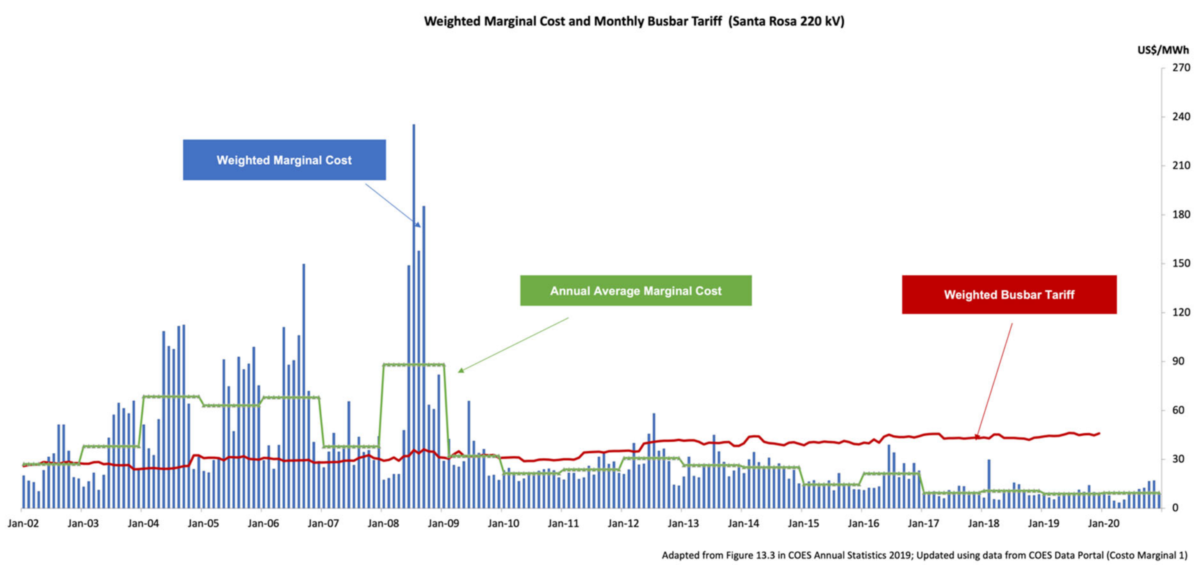


Figure 4: System Marginal Cost, Annual Average System Marginal Cost, Weighted Busbar

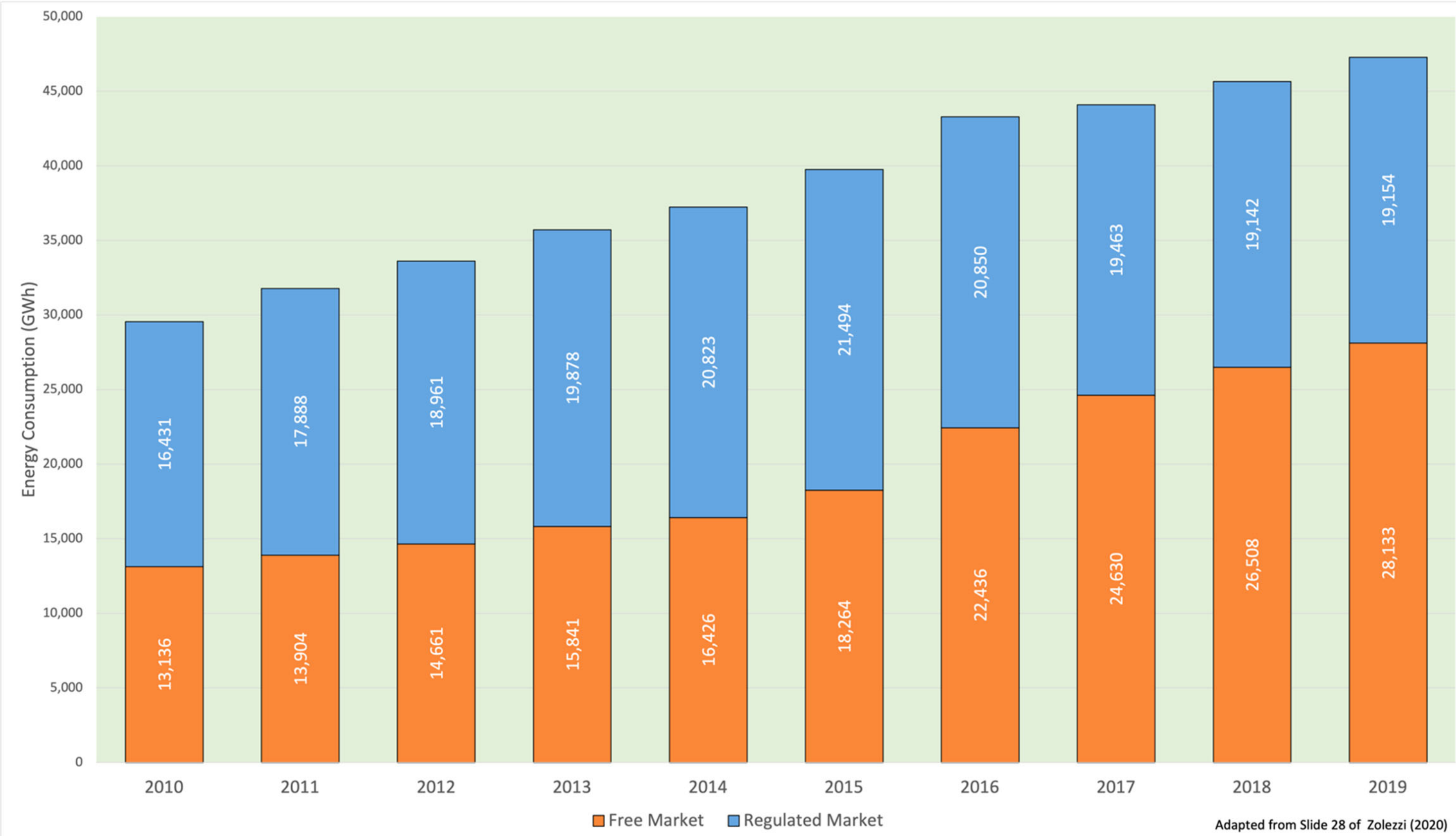
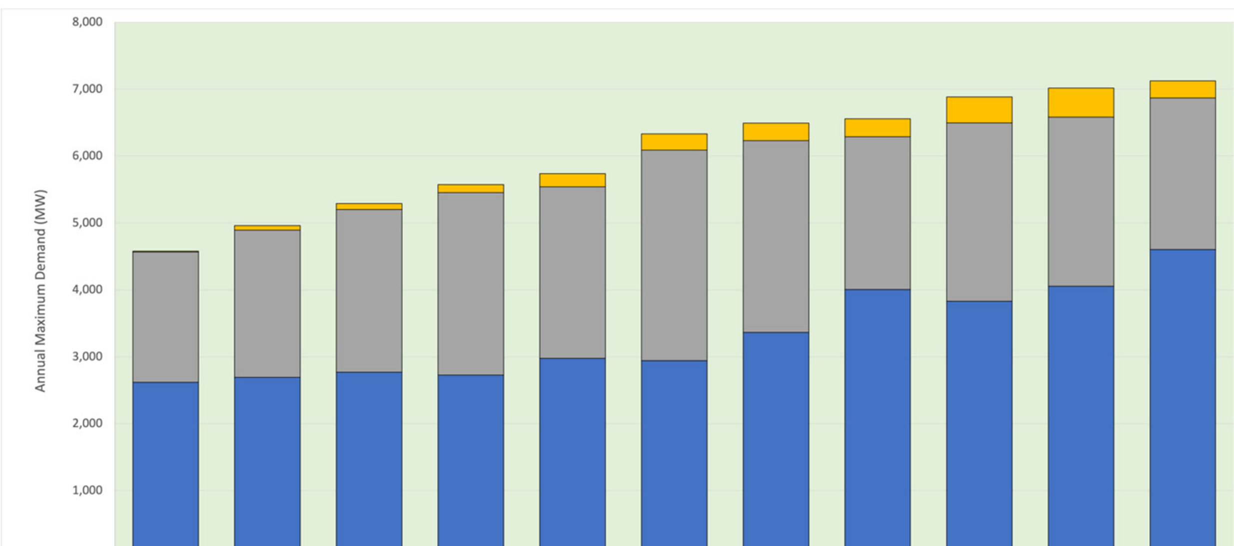


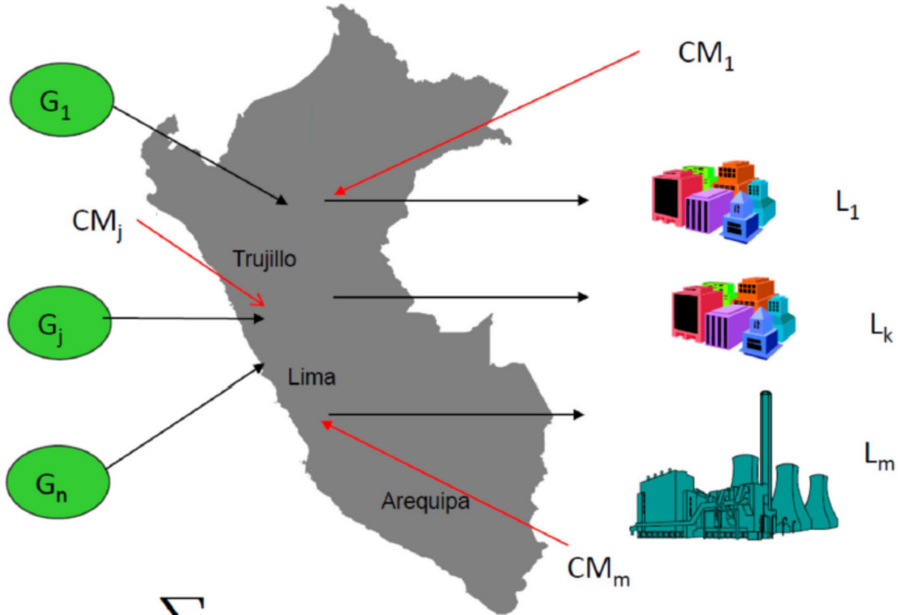
Figure 5: Free versus Regulated Market Energy Consumption



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total	4578.90	4961.30	5291.00	5575.10	5737.30	6331.40	6492.50	6595.60	6884.60	7017.60	7125.30
Renewables	10.70	67.10	89.40	121.10	195.40	240.80	261.40	270.30	387.40	435.10	255.23
Thermal	1948.50	2199.50	2430.70	2727.20	2565.90	3147.40	2867.30	2281.60	2665.30	2528.00	2265.91
Hydro	2619.70	2694.70	2770.90	2726.80	2976.00	2943.20	3363.80	4007.20	3831.90	4054.50	4604.16

Based on data from COES Data Portal (Comparativo Máxima y Energía del COES)

Figure 6: Maximum Annual Demand 2010 to 2020



$$\sum G_j \times CMI_j = \sum L_k \times CMR_k + IT$$

Dollar Imbalances Cleared Based on $\sum G_m \times CMI_m - \sum L_n \times CMR_n$ for Each Supplier

Figure 7: Clearing Imbalances in Short-Term Market

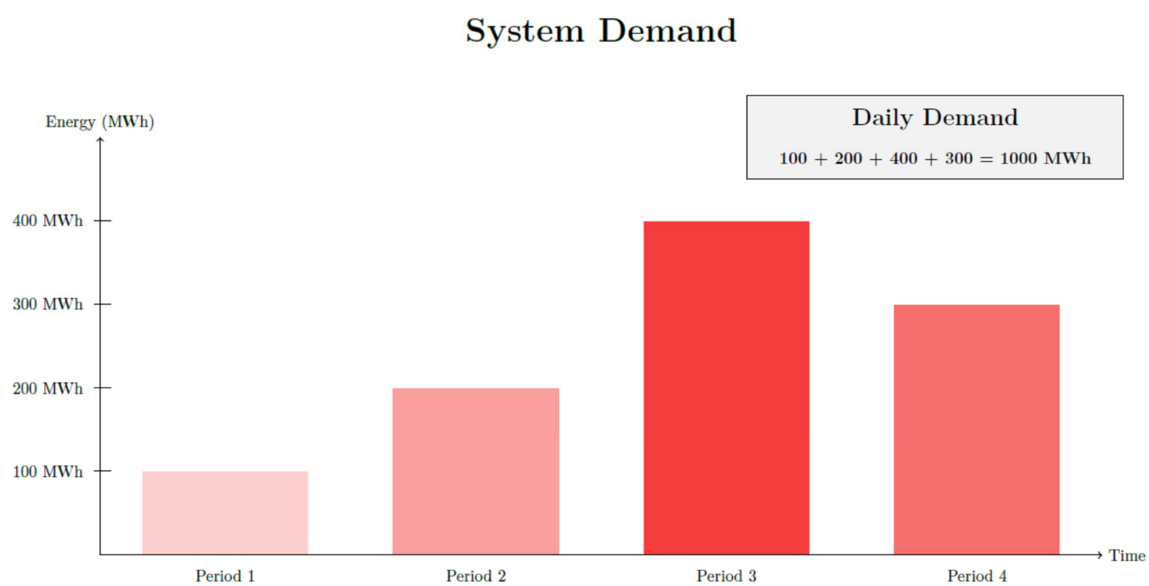


Figure 8: Hourly System Demands

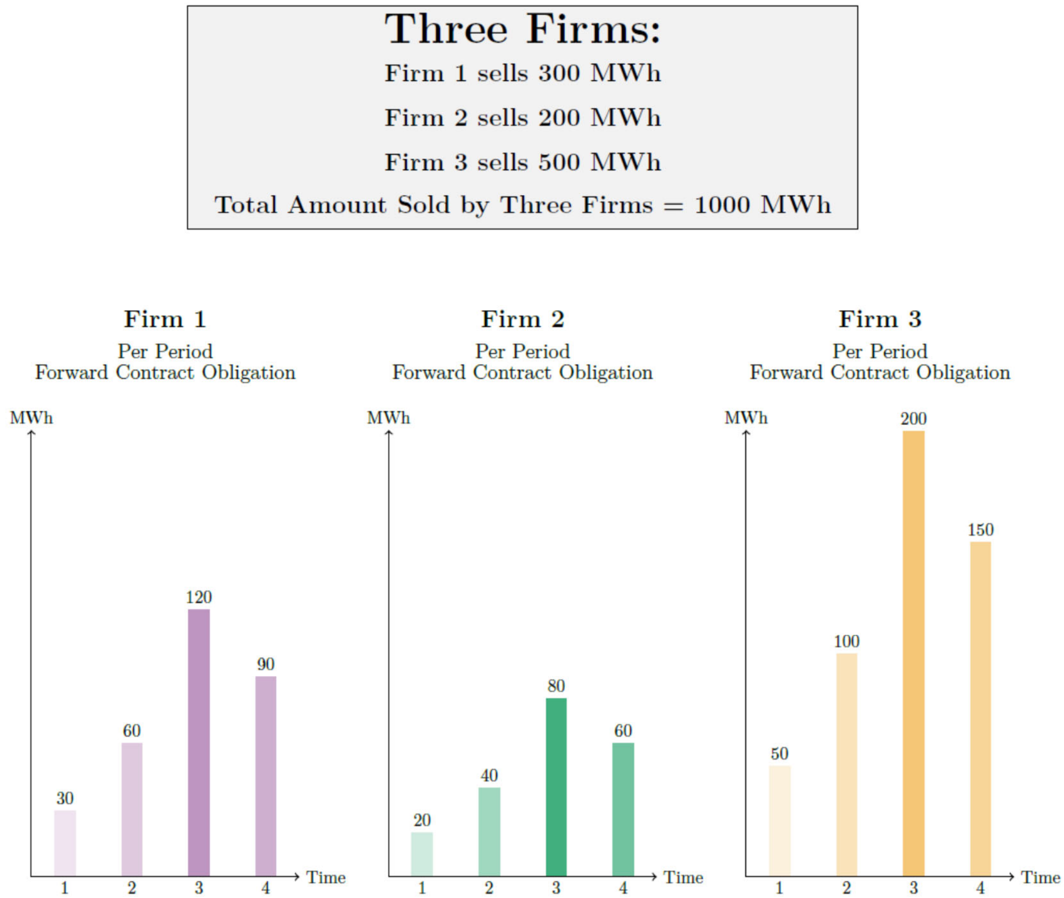


Figure 9: Hourly Forward Contract Quantities for Three Suppliers

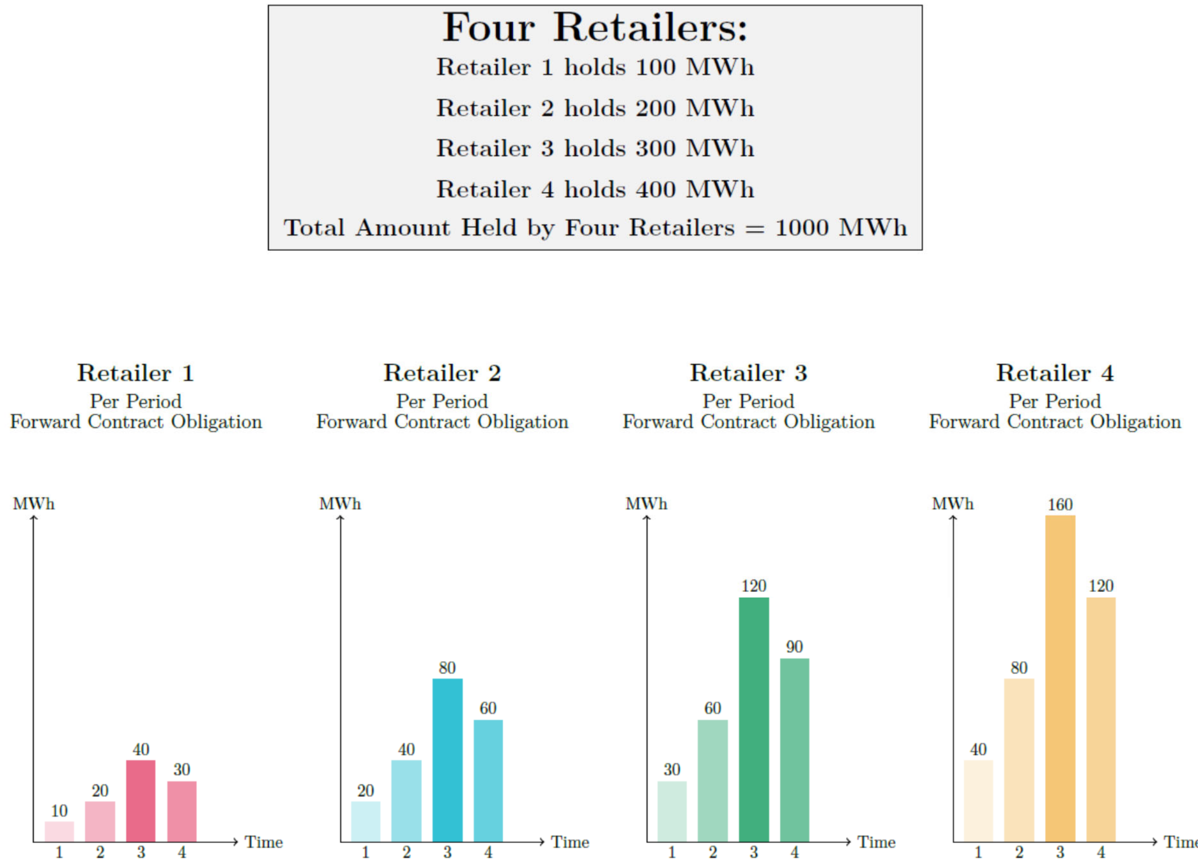


Figure 10: Hourly Forward Contract Quantities for Four Retailers

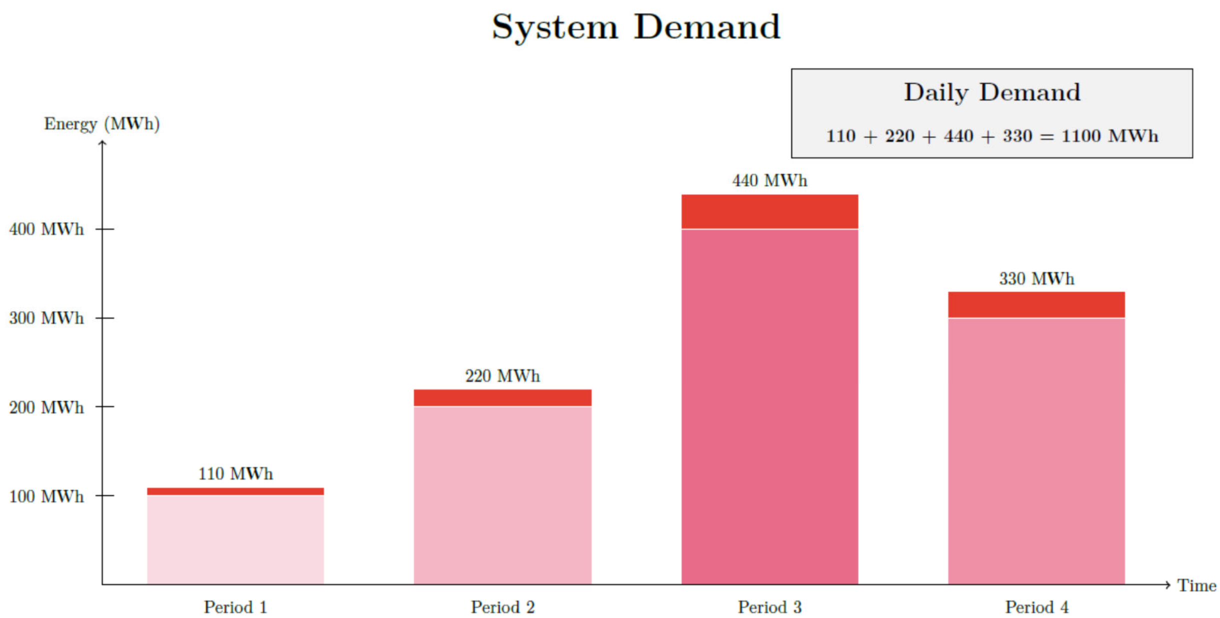


Figure 11: Hourly System Demands (10 Percent Higher)

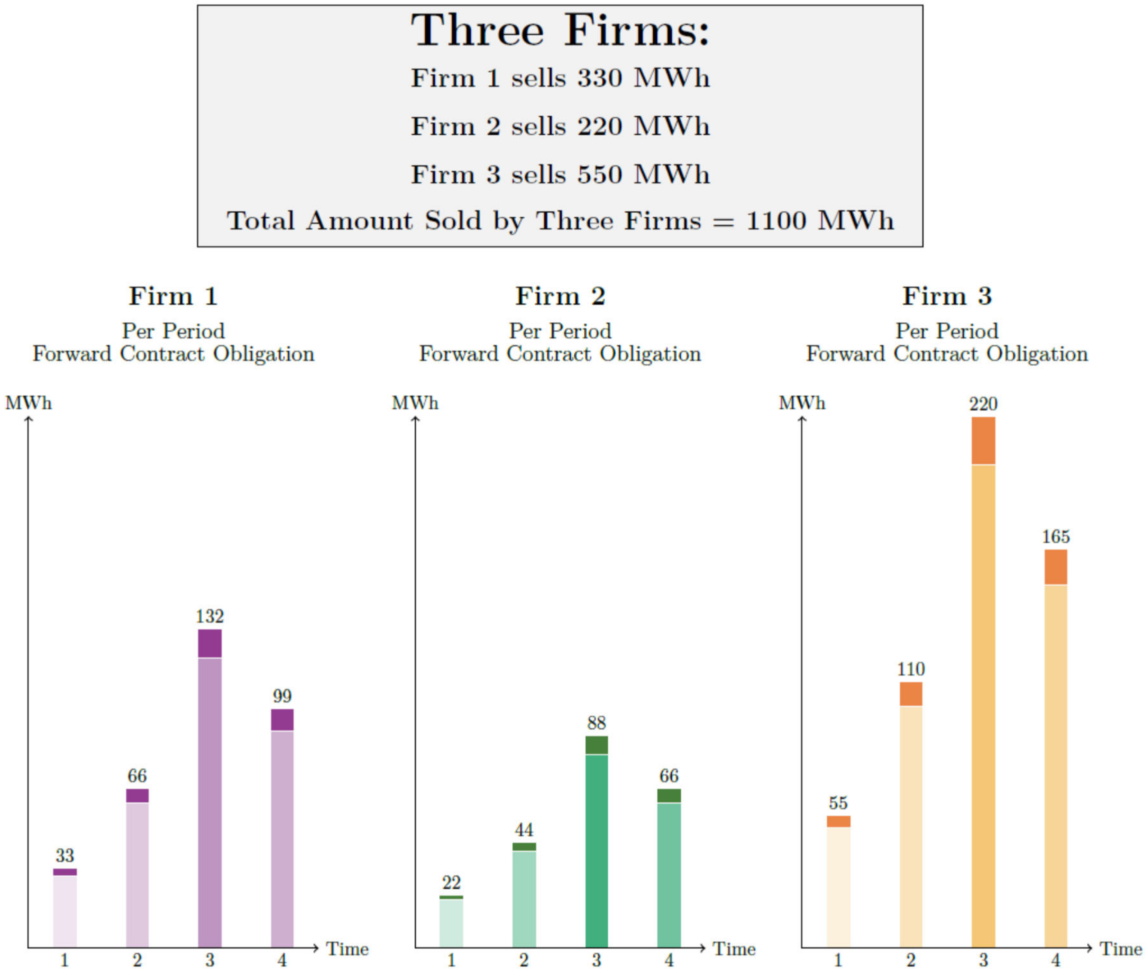


Figure 12: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Higher)

Four Retailers:

Retailer 1 holds 110 MWh

Retailer 2 holds 220 MWh

Retailer 3 holds 330 MWh

Retailer 4 holds 440 MWh

Total Amount Held by Four Retailers = 1100 MWh

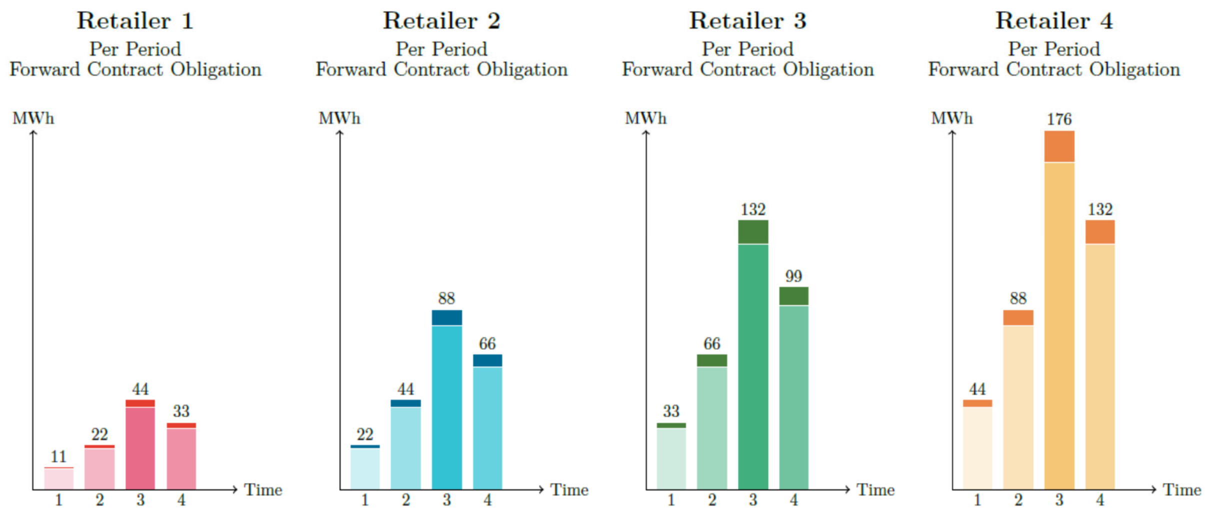


Figure 13: Hourly Forward Contract Quantities for Four Retailers (10 Percent Higher)

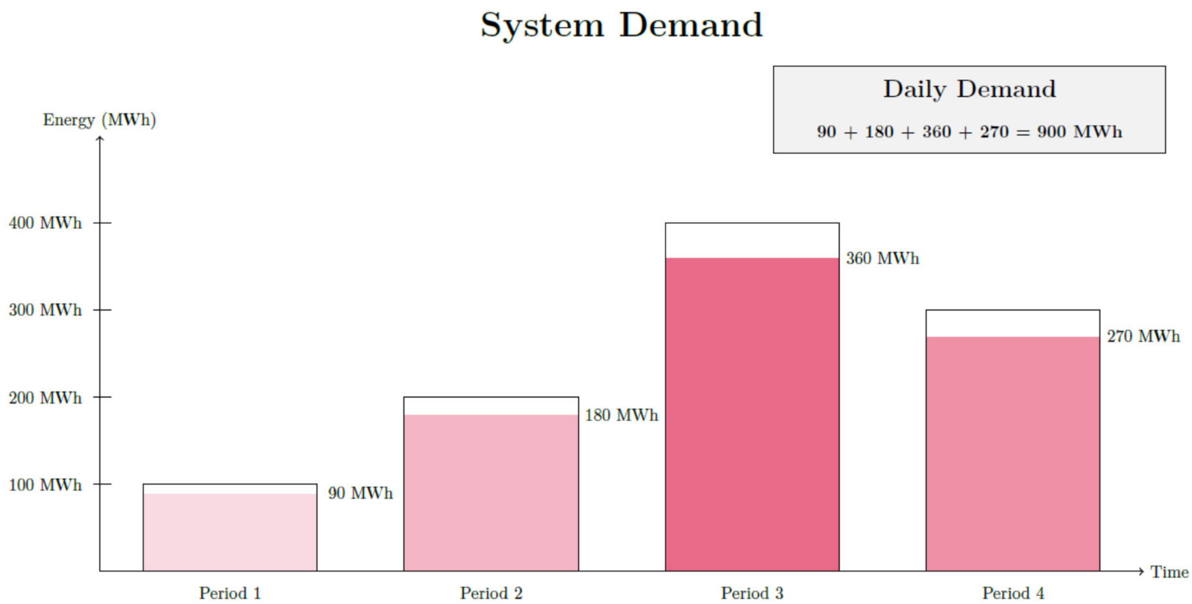


Figure 14: Hourly System Demands (10 Percent Lower)

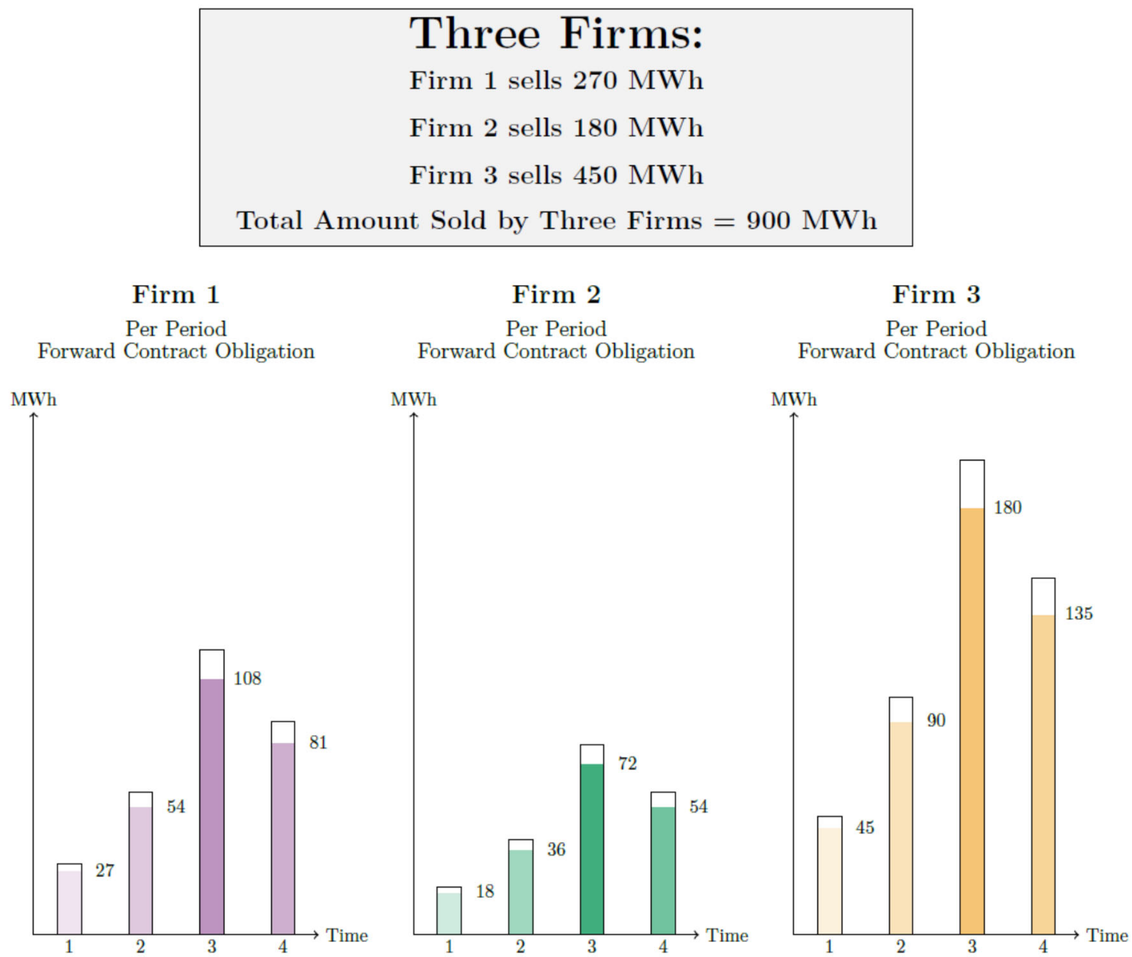


Figure 15: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Lower)

Four Retailers:

Retailer 1 holds 90 MWh

Retailer 2 holds 180 MWh

Retailer 3 holds 270 MWh

Retailer 4 holds 360 MWh

Total Amount Held by Four Retailers = 900 MWh

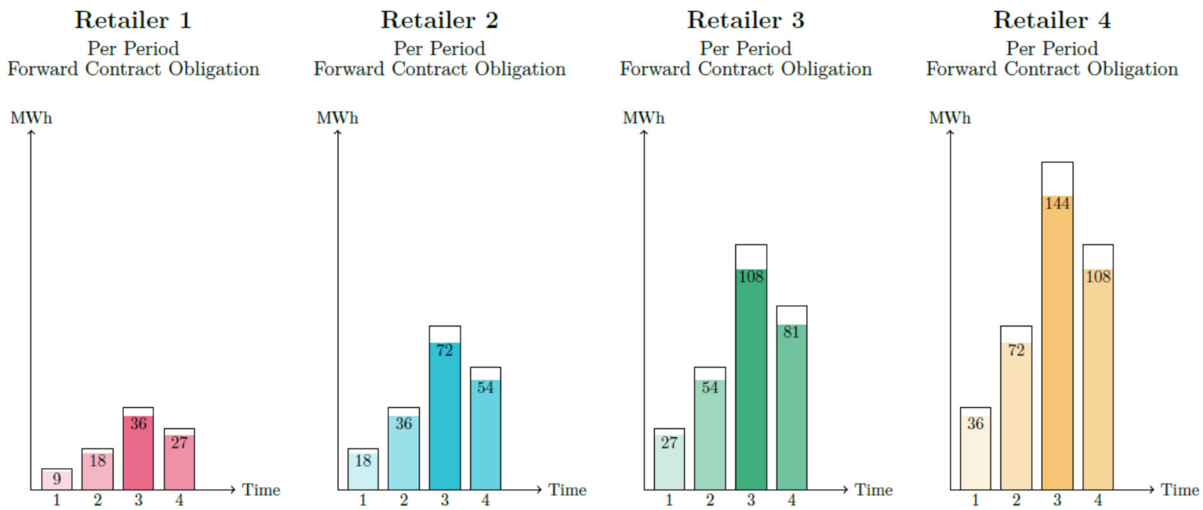


Figure 16: Hourly Forward Contract Quantities for Four Retailers (10 Percent Lower)

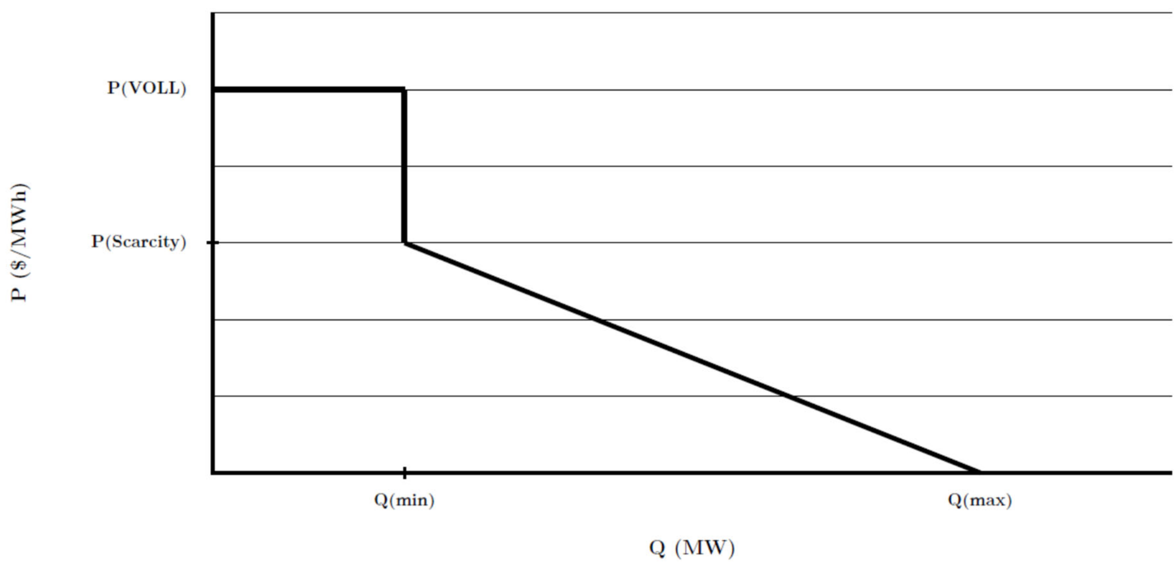


Figure 17: Operating Reserve Demand Curve

8. Appendix: True-Up Auction Mechanics

This appendix presents more examples of how the true-up auction mechanism would function to ensure that 100% final demand is covered by a standardized fixed price forward contract (SFPFC), similar to how all but up to 10% of final demand is currently covered by a power purchase agreement under Peru's supplier-only short-term market design.

Returning to the example of a 10 percent higher demand during the four periods shown in Figure 11, if this 100 MWh total demand increase is instead shared equally between periods 1 and 2, period 1 demand would now be 150 MWh and the period 2 demand would now be 250 MWh. Demand in periods 3 and 4 are unchanged from those in Figure 8. In the final settlement, 150 MWh of the SFPFCs would be allocated to retailers in period 1, 250 MWh percent in period 2, 400 MWh in period 3 and 300 MWh in period 4. Suppose that retailer 1 consumed the entire additional 100 MWh of energy during the compliance period. Retailer 1 would now be assigned 2/11 = (200/1100) of the above period level values of SFPFCs as opposed to the values shown in Figure 11. Retailer 2, 3 and 4 would be assigned 2/11, 3/11 and 4/11, respectively, because their demand totals for the four periods did not change.

Suppose that the entire 100 MWh true-up auction quantity was all sold by Firm 1 at a price of $65/MWh and as result of a different pattern of demands throughout the four periods, the demand-weighted average short-term price is $50/MWh. Now, in addition to the variable profits they would earn from selling energy in the short-term market produced by their generation units the three suppliers would receive the following difference payments to settle their SFPFC contract positions

Firm 1 = ($60 - $50)300 + ($65 - $50)100
Firm 2 = ($60 - $50)200
Firm 3 = ($60 - $50)500.

Besides the variable profits they would earn from purchasing energy from the short-term market to sell to their customers at the retail price, the four retailers would pay for the following difference payments

Retailer 1 = ($60 - $50)(1000)(2/11) + ($65 -$50)100(2/11)
Retailer 2 = ($60 - $50)(1000)(2/11) + ($65 -$50)100(2/11)
Retailer 3 = ($60 - $50)(1000)(3/11) + ($65 -$50)100(3/11)
Retailer 4 = ($60 - $50)(1000)(4/11) + ($65 -$50)100(4/11).

Again, both the original and true-up aggregate SFPFC purchases are allocated to individual retailers based on their actual share of total demand served during the four demand periods.

What price clears the true-up auction depends on the extent of competition among suppliers to provide this additional energy. Clearly, suppliers are extremely unlikely to offer to supply this energy below the demand-weighted average short-term price over the compliance period because its overall profits would decline. However, if there are a substantial number of suppliers willing to sell this additional SFPFC energy, the price is unlikely to be significantly above the demand-weighted average short-term price.

It is important to note that the lower the demand-weighted average short-term price, the larger are the difference payments that suppliers receive. This is another way of demonstrating that all suppliers have an incentive to minimize the cost of meeting their SFPFC obligations by offering to supply this energy at their marginal cost of production in the short-term market.

The true-up auction for excess SFPFC energy operates in an analogous manner. Suppose that demand is 10 percent lower in every period as shown in Figure 14. Suppose each firm buys back 10 percent of its SFPFC quantity in the true-up auction. This yields the period-level SFPFC quantities for each supplier in Figure 15. If all retailers reduce their consumption in each of the four periods by 10 percent their hourly SFPFC allocations and their total demands for the four periods are those shown in Figure 16. Suppose that the demand-weighted average short-term price is \$45/MWh and true-up auction clears at \$40/MWh.

In addition to the variable profits they would earn from selling energy produced by their generation units in the short-term market, the three suppliers would now receive the following difference payments to settle their SFPFC contract positions

Firm 1 = (\$60 - \$45)300 - (\$40 - \$45)30
Firm 2 = (\$60 - \$45)200 - (\$40 - \$45)20
Firm 3 = (\$60 - \$45)500 - (\$40 - \$45)50.

Besides the variable profits they would earn from purchasing energy from the short-term market to sell to at the retail price to their customers, the four retailers would pay the following difference payments

Retailer 1 = (\$60 - \$45)(90/900)1000 - (\$40 -\$45)(90/900)100
Retailer 2 = (\$60 - \$45)(180/900)1000 - (\$40 -\$45)(180/900)100
Retailer 3 = (\$60 - \$45)(270/900)1000 - (\$40 -\$45)(270/900)100
Retailer 4 = (\$60 - \$45)(360/900)1000 - (\$40 -\$45)(360/900)100.

Once again, the price clears the true-up auction depends on the extent of competition among suppliers to purchase the excess energy. Clearly, suppliers are extremely unlikely to bid a price for this energy above the demand-weighted average short-term price over the compliance period. However, if there are a substantial number of suppliers willing to buy this excess SFPFC energy, the auction price is unlikely to be significantly below the demand-weighted average short-term price.

Now suppose that the entire 100 MWh true-up auction quantity was purchased by Firm 1 at a price \$35/MWh and this 100 MWh reduction in demand across the four periods came entirely from period 3 and only from retailer 3. Suppose that as result of a different pattern of demand throughout the day, the realized demand-weighted average short-term price is \$40/MWh. This implies the following realized system load shares for the four periods: 1/9, 2/9, 3/9, and 3/9. The total realized demands for each retailer are now 100, 200, 200, and 400, so portions of both aggregate SFPFC purchases are allocated to retailers using the following shares: 1/9, 2/9, 2/9, and 4/9.

Now, in addition to the variable profits they would earn from selling the energy produced by their generation units in the short-term market, the three suppliers would receive the following difference payments to settle their SFPFC contract positions

Firm 1 = ($60 - $40)300 - ($35 - $40)100
Firm 2 = ($60 - $40)200
Firm 3 = ($60 - $40)500.

Besides the variable profits they would earn from purchasing energy from the short-term market to sell to their retail customers the four retailers would pay for the following difference payments

Retailer 1 = ($60 - $40)(1000)(100/900) - ($35 -$40)100(100/900)
Retailer 2 = ($60 - $40)(1000)(200/900) - ($35 -$40)100(200/900)
Retailer 3 = ($60 - $40)(1000)(200/900) - ($35 -$40)100(200/900)
Retailer 4 = ($60 - $40)(1000)(400/900) - ($35 -$40)100(400/900).

The original and true-up aggregate SFPFC purchases are allocated to individual retailers based on their actual share of total demand served during the four demand periods.

As shown in Figures 13 and 16, each purchase or sale of the same annual SFPFC product is allocated to retailers according to their load shares during the delivery month. If three different size purchases are made for the same annual SFPFC product at different prices, then each retailer is allocated its load share for the month of these three purchases. This ensures a level playing field for retailers with respect to their long-term resource adequacy obligation. All retailers face the same average price for the long-term resource adequacy obligation associated with their realized demand for the month.

The purpose of the true-up auctions is to reward suppliers for ensuring the system demand is met during every hour of the compliance period. If suppliers offer to sell at or above the known quantity-weighted average short-term price in the true-up auction, that cannot lose money from selling additional SFPFC energy in this auction. Similarly, if supplier bid to purchase at or below the known quantity-weighted average short-term price in the true-up auction, they cannot lose money from buying back SFPFC energy in this auction.

The true-up auction creates an incentive for market participant behavior that increases the likelihood that system demand will be met during quarters with a realized demand that exceeds the initial quantity of energy SFPFC sold. Because suppliers know that a true-up auction will be run to purchase the difference between the realized demand for the quarter and the initial quantity of SFPFC energy, they have an incentive to offer energy into the short-term market during high demand periods in the quarter. That is because they face the risk that their allocation of SFPFC energy for the high demand and high-priced hours of the quarter will be higher because system demand is higher for that hour and if they do not offer energy into the short-term market during these periods could end up selling less than their eventual hourly allocation of SFPFC energy in the short-term market.

The example of a 100 MWh higher system demand in Figure 11 illustrates this point. Consider the example of Firm 3 in Figure 12. During the Period 3 its allocation of SFPFC energy goes from 200 MWh to 220 MWh as a result of system demand increasing by 40 MWh in Period 3. If it only sold 205 MWh in the short-term market, it would end up net short relative to its eventual 220 MWh SFPFC allocation for that period, even though it was net long relative to its initial 200 MWh allocation. This example illustrates an important strength of the SFPFC mechanism that is also part of the existing supplier-only short-term market in Peru--the aggregate quantity risk associated with meeting realized demand is assigned to suppliers. However, the major difference between the SFPFC approach and current approach is that free consumers and distribution companies can actively participate in the short-term market and earn revenues from managing this quantity risk.