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Financing the Energy Transition in a Low-Cost Intermittent Renewable Energy Environment[1]

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1.1 Introduction

Until recently, transitioning from a fossil fuel-dominated electricity supply industry to an intermittent-renewables-dominated low-carbon electricity supply industry has required significant above-market financial support for investments in wind and solar generation resources because the levelized cost of energy (LCOE) from these resources was greater than the average market price at which the electricity they produced could be sold. Declines in the cost of both wind and solar generation capacity over the past decade has significantly closed the gap between the LCOE for these resources and the LCOE of natural gas and coal-fired generation.

Figure 1.1 plots the annual global quantity-weighted average LCOE for grid scale wind and solar photovoltaic generation units that began operation during each year from 2010 to 2020 (IRENA 2021). Figure 1.1 also plots the annual quantity-weighted average LCOE for residential and commercial solar photovoltaic generation units that began operation during the year (IRENA 2021). This graph demonstrates that in 2020, the LCOE of grid scale wind and solar was one-third to one-quarter of the LCOE of distributed solar energy.

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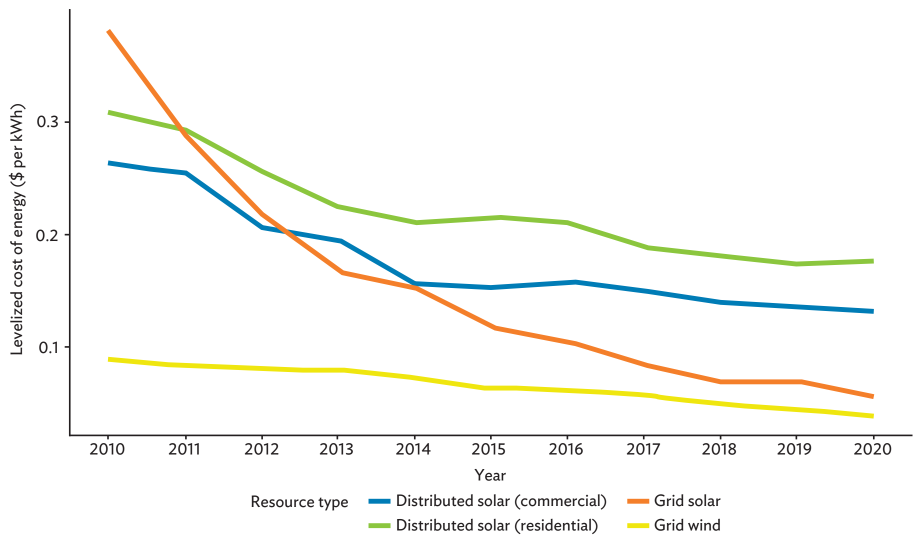
[1] This chapter is an updated version of chapter 4 that originally appeared in Glachant, Joskow, and M. G. Pollitt, eds. (2021).

Figure 1.1: Levelized Cost of Energy from Grid Scale Wind and Solar and Distributed Solar Generation, 2010–2020



kWh = kilowatt-hour.

Source: IRENA (2021).

The United States Energy Information Administration (EIA) estimates that the LCOE for a new combined cycle natural gas generation unit entering service in 2023 is $33.21 per megawatt-hour (MWh) versus $30.44/MWh and $30.63/MWh for grid scale wind and solar resources (EIA 2021, Table A1a). These LCOE differences signal a new regime for investments in wind and solar resources. However, because of the intermittency of wind and solar resources, there is still the need for a significant amount of dispatchable generation capacity to supply energy when the wind is not blowing, or the sun is not shining. This low-cost intermittent renewable energy regime and the desire of policy makers to significantly increase the share of their jurisdiction's energy consumption produced by intermittent renewables argues for a paradigm shift in electricity market design.

The purpose of this chapter is to explain why this paradigm shift is necessary and outline a short-term electricity market design, long-term resource adequacy mechanism, and renewables support mechanism for this low-cost intermittent renewable energy regime. A multi-settlement locational marginal pricing (LMP) market design with the co-optimized procurement of ancillary services rewards quick response dispatchable resources and appropriately prices the intermittency of wind and solar resources. This market design easily accommodates the additional reliability constraints on system operation required by a larger share of intermittent renewables into the energy and ancillary services markets. Finally, this short-term market design prices electricity across both space and time to provide financial incentives to locate storage and load flexibility investments where they can provide the greatest benefits to system reliability. Energy efficiency investments that reduce electricity consumption at high-priced locations in the transmission network provide greater wholesale energy cost savings and grid reliability benefits than the same investment at low-priced locations.

A fixed-price forward contract for energy approach to long-term resource adequacy is the most important change necessary to support large renewable energy shares under a low-cost intermittent renewable energy regime. A significant amount of dispatchable generation capacity will still be required to produce energy when the underlying renewable resources are unavailable. However, these generation resources will start up and shut down more frequently and operate at increasingly smaller annual capacity factors as the share of intermittent renewables increases. Consequently, the long-term resource adequacy mechanism must encourage cross-hedging between intermittent renewables and dispatchable generation units. The intermittent renewable resource owners must have an economic incentive to purchase price spike insurance from dispatchable thermal resources for the times when these renewables are unlikely to produce energy. As explained in section 1.5, these price spike insurance payments provide a revenue stream to dispatchable resources that contributes to their financial viability even though they have significantly lower annual capacity factors in a region with a large share of intermittent renewable generation.

The ultimate success of this approach to long-term resource adequacy requires phasing out a common approach to financing investments in intermittent renewables—paid-as-delivered power purchase agreements. These long-term contracts pay the intermittent renewable generation unit owner according to a fixed price schedule for all energy produced by the generation unit, regardless of when this energy is produced. These contracts provide an implicit subsidy to intermittent renewable resources because similar contract terms are not offered to dispatchable generation units. Moreover, paid-as-delivered contracts dull the financial incentive for intermittent renewable resource owners to pair their investments with storage capacity to manage the uncertainty in energy production from their units. As explained in section 1.4, requiring all resources to sell standardized fixed-price and fixed-quantity forward contracts provides strong incentives for market mechanisms to find the least-cost solution to meeting a given renewable energy target.

To provide the least-cost amount of above-market revenues to intermittent renewables resources to meet a given renewable energy share goal, a renewables portfolio standard mechanism is necessary. This mechanism prices the renewable attribute separate from the energy the intermittent renewable resource produces. This renewables support mechanism and a multi-settlement LMP market design with 5-minute settlement in the real-time market provide strong incentives for investments in the storage facilities necessary to achieve renewable energy shares in excess of 50%.

The remainder of the chapter proceeds as follows. Section 1.2 discusses the essential features of the short-term market design to support the least-cost deployment of large share intermittent renewables. Section 1.3 discusses the necessity of a long-term resource adequacy mechanism for all wholesale electricity markets with a finite offer cap on the short-term market and why the traditional capacity-based approach to long-term resource adequacy is poorly suited to regions with significant intermittent renewable energy goals. Section 1.4 introduces our proposed standardized fixed-price forward contract approach to long-term resource adequacy and explains why it is a more efficient solution to the long-term resource adequacy challenge for an intermittent renewable energy dominated electricity supply industry. Section 1.5 explains why a renewable energy certificate market is necessary to achieve renewable energy shares above 50%. This section also explains why paid-as-delivered forward contracts for intermittent renewable energy do not support achieving a large share of renewable energy at least cost to electricity consumers. This section proposes financial products that allow intermittent renewable resource owners to transition from paid-as-delivered forward contracts to fixed-price and fixed-quantity forward contracts. Section 1.6 concludes and proposes directions for future research.

1.2 Short-Term Market Design

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 operates in real time. In the early stages of wholesale market designs in the United States (US), all the regions attempted to operate wholesale markets that used simplified transmission network models. These single zone or multiple zone markets assume infinite transmission capacity between locations in the transmission grid or only recognize transmission constraints across large geographic regions. These simplifications of the transmission network configuration and other relevant operating constraints 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.

Zonal markets set a single market-clearing price for a half hour or an hour for an entire country or large geographic region, even though there are 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 the wholesale energy market. For example, if a generation unit is paid its offer price for electricity when it is constrained-on and the owner knows the unit will be constrained-on, a profit-maximizing owner will submit an offer price significantly higher than the average variable cost of the unit and be paid that price for the incremental energy, which ultimately raises the total cost of electricity supplied to final consumers.

A similar set of circumstances arises for a constrained-off generation unit. These units are typically paid the difference between the market-clearing price and the unit's offer price for not supplying electricity that the unit would have produced 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, which raises the total cost of electricity supplied to final consumers.

This problem occurred so frequently in the early US zonal markets that it acquired the name "the DEC game," because it involves a supplier selling energy in the day-ahead market that it knows is highly likely to be infeasible to inject into 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 earns the difference between these two prices times the amount of decremental energy purchased for producing little or no energy in real time. Wolak, Bushnell, and Hobbs

(2008) discuss this problem and its market efficiency consequences in the context of the initial zonal 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. The DEC game 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 reconciliation payment mechanism.

1.2.1 Locational Marginal Pricing (LMP)

As described in the previous subsection, 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 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, LMP markets can allow multiple settlements without creating opportunities for suppliers to degrade the efficiency of the short-term market by taking advantage of the constrained-on and constrained-off process 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 generation unit 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 virtually all zonal markets is the centralized commitment of generation units to provide energy and ancillary services. The zonal markets throughout Europe do not typically require generation units to submit energy offer curves into the day-ahead market and instead allow individual producers to make 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 differences between producers in their assessment of the likely market price.

Self-commitment energy 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 day-ahead 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. Suppliers know that capacity sold in an earlier market cannot compete with suppliers in subsequent markets, which limits competition in the markets that clear later in the sequence.

A centralized LMP market that co-optimizes the procurement of energy and operating reserves ensures 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 price of energy at a generation unit's location is $40/MWh, the unit's offer price for energy is $30/MWh, the unit's offer price for the only operating reserve the unit can supply is $0/MWh, and the market-clearing price of that reserve is $5/MWh, then the unit will be accepted to supply energy rather than that operating reserve. This outcome occurs because the opportunity cost of supplying energy, $10/MWh = $40/MWh – $30/MWh, is less than the price paid for that operating reserve. At this price of energy, the unit will be accepted to supply the operating reserve only if its price is greater than or equal to 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 least-cost choice between supplying energy or an ancillary service from each generation unit in the market. This is possible for a supplier to do within its portfolio of generation units, but it is unlikely to be the case across all suppliers in the market. Consequently, there are likely to be many instances when a resource is taken to supply an operating reserve at a dollar per megawatt-hour price that turns out to be less than the 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 with that same generation capacity.

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 as-offered costs objective function due to 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 market-clearing mechanism and reflected in the resulting locational marginal prices. This property of LMP markets is particularly relevant to the cost-effective integration of a significant amount of intermittent renewable generation capacity because additional reliability constraints may need to be formulated and incorporated into an LMP market mechanism to account for the fact that this energy can quickly disappear and reappear.

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 the East of PJM (the original PJM Interconnection footprint), before and after these regions were integrated into a single LMP market that accounts for the configuration of the transmission network throughout the entire expanded PJM region. Average daily energy flows from the Midwest to the East of PJM almost tripled immediately following the integration of the two regions into a single 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.

1.2.2 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 generation unit-specific offer curves for each hour of the following day for energy and operating reserves, as well as the 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 sets 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 of these costs enter the objective function used to compute hourly generation schedules and LMPs 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 start-up, minimum load and energy operating costs to provide these products throughout the day, they are provided with a make-whole payment to recover the remaining costs. 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 a price of $82/MWh, the unit's make-whole payment would be $5,000 – $4,200 = $800. Total make-whole payments are recovered from all loads through a dollar per megawatt-hour charge. For example, 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 $0.20/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 their day-ahead sales and purchase obligations.

In all US wholesale markets, real-time LMPs are determined from the real-time offer curves of all available generation units and dispatchable loads by minimizing the as-offered cost to meet real-time demands (rather than bid-in demands) 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. Wolak (2021b) discusses mechanics of a two-settlement (day-ahead and real-time) market and why it provides strong incentives for generation unit owners and loads to schedule accurately in the day-ahead market and limit the magnitude of their real-time deviations from these day-ahead schedules.

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 is very similar to the standard market design currently in Europe and other industrialized countries. Wolak (2011) finds that for the same amount of hourly system-wide thermal generation, the total hourly British thermal units of fossil fuel energy consumed to produce that electricity is 2.5% lower, the total hourly variable cost of production for fossil fuels units is 2.1% lower, and the total number of hourly starts is 0.17% higher after the implementation of nodal pricing. This 2.1% 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 (2022) study the transition from a Europeanstyle 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 1 December 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, yielding annual cost savings of $323 million.

1.2.3 Multi-Settlement LMP Market with Significant Intermittent Renewables

A multi-settlement LMP market design is 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 zonal market designs that do not model transmission and other operating constraints are likely to be greater the larger the share of intermittent renewable resources. Bjørndal et al. (2018) shows that in a region with significant wind resources even embedding a nodal market design within a larger zonal market design outperforms a full zonal market design. The authors also demonstrate that a nodal design for the entire region yields even greater savings relative to a zonal design. 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. Wolak (2021b) provides several examples that demonstrate that despite paying the same price for all energy at the same location in the day-ahead and real-time markets, a multi-settlement market pays a higher average price for the energy ultimately produced in real time to the dispatchable generation unit relative to the intermittent wind or solar generation unit. This is because intermittent resources typically sell more than their day-ahead schedule when real-time prices are lower than average and sell less than their day-ahead schedule when real-time prices are higher than average. In contrast, dispatchable resources can produce more than their day-ahead schedules when real-time prices are higher than average and produce less than their day-ahead schedules when real-time prices are lower than average.

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 US wholesale markets set real-time prices and dispatch levels every 5 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 a decrease 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 are needed to maintain system balance within the hour. More frequent settlement of the real-time market rewards dispatchable resources for the quick response and flexibility that they provide, particularly if the share of intermittent renewable generation increases significantly.

1.2.4 A Cost-Based Multi-Settlement LMP Market

The transition to formal market mechanisms in a number of Asian countries has been slow. These regions frequently face significant challenges because of limited transmission capacity between and within their member countries. Consequently, any attempt to operate an offer-based market for most of these countries is likely to run into severe local and system-wide market power problems. In addition, the almost complete absence of hourly meters in these regions limits the opportunities for active demand-side participation, which makes implementing an offer-based wholesale market even more challenging.

Building on the experience of the Latin American countries discussed in Wolak (2014), a viable market design for these regions is a cost-based short-term market that uses LMP. This market design is straightforward to implement because it simply involves solving for the optimal dispatch of generation units in the region based on the market operator's estimate of each unit's variable cost, including start-up and minimum load costs, subject to the operating constraints implied by the actual regional transmission network and other reliability constraints.[2]

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[2] Galetovic, Muñoz, and Wolak (2015) describe the Chilean cost-based market, which has been in operation since the 1980s.

All generation unit owners submit the technical characteristics of their generation units to the market operator, including the heat rate curve, the amount of fuel required to start up the unit and operate at the unit's minimum safe operating level, the unit's ramp rate, and minimum uptime and downtime. The system operator would then determine the start-up cost and variable cost of operating for each generation unit using a publicly available price index for the unit's fossil fuel. For example, for a coal-fired generation unit, the market operator could use a globally traded price for coal and a benchmark delivery cost to the generation unit to determine the fuel cost of the unit. This would be multiplied by the unit's heat rate to compute its variable fuel cost. An estimate of the variable operating and maintenance cost for the unit could be added to this variable fuel cost to arrive at the total variable cost of the unit.

The variable cost computed by the market operator along with the configuration of the transmission network would be used to set day-ahead schedules and prices for each location in a multi-settlement version of this market design. In real time, the dispatch and LMP process would be completed using the actual system demand and actual configuration of the transmission network with these same generation unit-level variable cost figures.

It is important to emphasize that this short-term market is only for settling imbalances relative to long-term contracts for energy. Joskow (1997) argues that the majority of the economic benefits from electricity industry restructuring are likely to come from more efficient investment decisions in new generation capacity. The combination of a cost-based multi-settlement LMP market and fixed-price forward contract mandates on electricity retailers as discussed in section 1.4 is a low-cost and low-regulatory burden approach to realizing significant increases in new generation capacity. This market design can be implemented in any Asian country with limited regulatory burden and provide strong incentives for least-cost operation of existing generation resources and least-cost investment in new generation resources to serve load growth and unit retirements.

This market design also has the advantage that it can easily transition to an offer-based market once the transmission network in the region is expanded, hourly meters are deployed, and the regulator is able to design an effective local market power mitigation mechanism. Graf et. al (2021) summarize the structure and performance of the local market power mitigation mechanisms in place in US markets. If a cost-based LMP market is in already place, the generation unit owners' costs as computed by the market operator can easily be replaced by the offer prices of these 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. PJM Interconnection in the eastern

US followed this strategy during the early stages of its development. It operated as a cost-based market before transitioning to an offer-based market.

1.3 The Reliability Externality and Long-Term Resource Adequacy

Why do wholesale electricity markets require a regulatory mandate to ensure long-term resource adequacy? Electricity is essential to modern life, but so are many other goods and services. Consumers want cars, but there is no regulatory mandate that ensures enough automobile assembly plants to produce these cars. They want point-to-point air travel, but there is no regulatory mandate to ensure enough airplanes to accomplish this. Many goods are produced using high fixed cost, lowmarginal cost technologies similar to electricity supply. Nevertheless, these firms recover their production costs, including a return on the capital invested, by selling their output at a market-determined price.

What is different about electricity that requires a long-term resource adequacy mechanism? The regulatory history of the electricity supply industry and the legacy technology for metering electricity consumption results in what Wolak (2013) calls a *reliability externality*.

1.3.1 The Reliability Externality

Different from the case of wholesale electricity, the markets for automobiles and air travel do not have a regulatory limit on the level of the short-term price. Airlines adjust the prices for seats on a flight over time in an attempt to ensure that the number of customers traveling on that flight equals the number of seats flying. This ability to use price to allocate the available seats is also what allows the airline to recover its total production costs and can result in as many different prices paid for the same flight as there are customers on the flight.

Using the short-term price to manage the real-time supply and demand balance in a wholesale electricity market is limited by a finite upper bound on a supplier's offer price and/or a price cap set by the regulator that limits the maximum market-clearing price. Although offer caps and price caps can limit 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 and not the cause of the *reliability externality*.

This externality exists because offer caps limit the cost to electricity retailers of failing to hedge their expected purchases from the short-term market. Specifically, if a retailer or large consumer knows the price cap on the short-term market 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 the offer cap is more than the amount suppliers are willing to offer at this offer cap.

This outcome implies that the system operator must be forced to either abandon the market mechanism or curtail firm load until the available supply offered at or below the offer cap equals this level of demand, as occurred several times in California between January 2001 and April 2001, and most recently on 14 and 15 August 2020. A similar, but far more extreme set of circumstances arose from 14 to 18 February 2021 in Texas, and this required significant demand curtailments from 15 to 18 February.[3]

Because random curtailments of supply to different distribution grids served by the transmission network—also known as rolling blackouts—are used to make demand equal to the available supply at under these system conditions, this mechanism creates a *reliability externality* because no retailer bears the full cost of failing to procure adequate energy to meet their demand in advance of delivery. A retailer that has purchased sufficient supply in the forward market to meet its real-time demand is equally likely to be randomly curtailed as any other retailer of the same size that has not procured adequate energy in the forward market. The technology to curtail specific customers when there is a system-wide shortfall of energy does not currently exist in any electricity delivery network.

For this reason, all retailers have an incentive to under procure their expected energy needs in the forward market. However, when short-term prices rise, retailers that have not hedged the wholesale energy necessary to serve the demand of their fixed-price retail customers are likely to go bankrupt. If these retailers attempt to pass these short-term wholesale prices on to their retail customers, many will be likely to be unable to pay their electricity bills. As discussed in section 4.4.2 of Wolak (2022), both outcomes occurred in Texas following the events of 14 to 18 February 2021.

The lower the offer cap, the greater is the likelihood that a retailer will delay its electricity purchases to the short-term market. Delaying more purchases to the short-term market increases the likelihood of

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3 https://www.ercot.com/files/docs/2021/02/24/2.2_REVISED_ERCOT_Presentation.pdf

insufficient supply in the short-term market at or below the offer cap. Because retailers do not bear the full cost of failing to procure sufficient energy in the forward market, there is a missing market for long-term contracts for energy with 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. Therefore, a regulator-mandated long-term resource adequacy mechanism is necessary to replace this missing market.

Regulatory intervention is necessary to internalize the resulting *reliability externality* unless the regulator is willing to eliminate the offer cap and commit to allowing the short-term price to clear the real-time market under all possible system conditions. There are no short-term wholesale electricity markets in the world that make such a commitment. All of them have either explicit or implicit caps on the offer prices suppliers can submit to the short-term market. ERCOT had a $9,000/MWh offer cap, which was highest in the US in February of 2021. Australia's National Electricity Market currently has a A$15,500 MWh offer cap.

As the experience of 14 to 18 February 2021 in Texas demonstrated, an extremely high offer cap on the short-term market does not eliminate the *reliability externality*. It just shrinks the size of the set of system conditions when random curtailments are required to balance real-time supply and demand.

1.3.2 Conventional Solution to Reliability Externality with Intermittent Renewables

Currently, the most popular approach to addressing the *reliability externality* is a capacity procurement mechanism that assigns a firm capacity value to each generation unit based on the amount of energy it can provide under stressed system conditions. Retailers are then required to demonstrate that they have purchased sufficient firm capacity to meet their monthly or annual demand peaks. Having sufficient firm capacity typically means that the retailer has purchased firm capacity equal to between 1.10 and 1.20 times its annual demand peak. The exact multiple of peak demand chosen by a region depends on the mix of generation resources and the reliability requirements of the system operator.

Under the current long-term resource adequacy mechanism in California, firm-level capacity procurement obligations are assigned to retailers by the California Public Utilities Commission to ensure that monthly and annual system demand peaks can be met. Electricity retailers are free to negotiate bilateral capacity contracts with individual generation unit owners to purchase firm capacity to meet these obligations. The eastern US wholesale electricity markets in the PJM Interconnection, independent system operator (ISO) of New England, New York ISO, and Midcontinental ISO markets all have a centralized market for firm capacity. These involve periodic capacity auctions run by the wholesale market operator where all retailers purchase their capacity requirements at a market-clearing price. ERCOT does not currently have formal long-term resource adequacy mechanism besides its \$9,000/MWh offer cap and an ancillary services scarcity pricing mechanism.

All capacity-based approaches to long-term resource adequacy rely on the credibility of the firm capacity measure assigned to each generation unit. This is a relatively straightforward process for dispatchable thermal units. The nameplate capacity of the generation unit times its annual availability factor (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. As discussed below, if all retailers have met their firm capacity requirements in a sizable 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 example helps to illustrate the logic behind this claim. Suppose that the peak demand for the market is 1,000 MW, the market is composed of equal size generation units, and each unit has a 90% annual availability factor, meaning that it is available to produce electricity any hour of the year with 0.90 probability. Suppose that the event that one generation unit 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 nameplate capacity of 100 MW, each has a firm capacity of 90 MW (= 0.90 x 100 MW). If there are 13 generation units, then with 0.96 probability peak demand will be met.[4] Thus, 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 electricity supply industries, but it does illustrate the important point that smaller markets require

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4 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.

firm capacity equal to a larger multiple of peak demand to achieve the desired level of reliability of supply.

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 nameplate 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, 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 an independent 10% probability 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 peak system demand 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 importantly, the availability of 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 than a 0.9 availability factor for meeting system demand, almost regardless of the amount intermittent renewable capacity that is 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 of 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 Niño and La Niña weather events as discussed in McRae and Wolak (2016).

Incorporating wind or solar generation units into a firm capacity mechanism is even more challenging, 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. There can be substantial differences across and within days in the output of wind and solar generation units. 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 when 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 or wind generation resources for a given geographic area is typically extremely high. There is even a high degree of correlation across locations in the output of wind and solar resources. Wolak (2016) demonstrates the extremely high degree of contemporaneous correlation between the energy produced each hour of the year by solar and wind facilities in California. Again, information on marginal distribution of wind or solar energy availability at a location is much more readily available than the joint distribution of 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 a wind or solar resource that is equivalent to the firm capacity of a dispatchable thermal generation resource is extremely difficult, if not impossible.

The high degree of contemporaneous correlation across locations in hourly capacity factors requires a methodology for computing firm capacity that accounts for the joint distribution of hourly capacity factors across locations throughout the year. Not only does this methodology need to account for the contemporaneous correlation in capacity factors across locations, but also the high degree of correlation of capacity factors over time for the same location and other locations. California currently uses an effective load carrying capacity (ELCC) methodology for computing the firm capacity values of wind and solar generation units. The ELCC methodology was introduced by Garver (1966), and it measures the additional load that the system can supply from a specified increase in the megawatts of that generation technology with no net change in reliability. The loss of load probability, which is the probability that system demand will exceed the available supply, is the measure of reliability used in the ELCC calculation. Consistent with the results of Wolak (2016), the ELCC values for solar generation resources in California have declined significantly as the amount of solar generation capacity in the state has increased.

For example, a recent study prepared for California's three investor-owned utilities (Carden, Dombrowsky, and Winkler 2020), Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric, recommended ELCC values for 1 MW of fixed-mount solar photovoltaic capacity for 2022 of approximately 5% of the nameplate capacity. Their estimates for 2026 are less than half that amount, and those for 2030 are less than one-fourth that amount. These declines in the ELCC values are due to the forecast increase in the amount of solar generation capacity in California.

An additional problem with computing the firm capacity of solar or wind generation resource using the ELCC methodology is that the same megawatt investment in wind or solar capacity 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 based on their location in the transmission network. This would likely be a very politically contentious process because of the many assumptions that go into computing the ELCC of a 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 ELCC values could sell the same product to the potential detriment of overall system reliability.

Wolak (2022) evaluates the performance of California's capacity-based long-term resource adequacy mechanism based on the experience of 14 to 18 August 2020. Except for May for wind and July for solar, the monthly values of firm capacity computed using the ELCC methodology are slightly below the average capacity factors for the month. However, it is important to bear in mind that the firm capacity of a generation unit is supposed to measure what the facility can reliably produce under extreme system conditions, not what it produces on average. Consequently, a monthly average capacity factor less than the firm capacity value assigned to wind or solar generation resources provides further evidence against the viability of a capacity-based long-term resource adequacy mechanism with a large share of intermittent renewables. This outcome implies there are many hours in the month when the intermittent wind or solar resource is producing less than its firm capacity. Given the unpredictable intermittent nature of these resources, there is a non-zero probability this outcome will occur during a time with stressed system conditions, similar to those that occurred in August 2020 in California and February 2021 in Texas.

These facts, and the fact that what are predicted to be the major sources of renewable electricity in the future have been estimated to have a little firm capacity value in a high intermittent renewable energy future, imply that it would be prudent for Asian countries with ambitious renewable energy goals to consider alternatives to a capacity-based long-term resource mechanism if they intend to meet these goals in a least-cost manner.

1.4 Standardized Fixed-Price Forward Contract Approach to Long-Term Resource Adequacy

The primary reliability challenge in regions with significant intermittent renewable energy goals is not adequate generation capacity to serve demand peaks but adequate energy available to serve realized demand during all hours of the year. As the examples of California in August 2020 and Texas in February 2021 demonstrate, supply shortfalls do not necessarily occur during system demand peaks, but during net demand peaks.

Because of the substantial contemporaneous correlation in hourly output across locations and across renewable energy technologies, ensuring sufficient supply to meet demand throughout the year will require taking full advantage of the mix of available generation resources. Intermittent renewable resources must reinsure the energy they sell in the forward market with dispatchable generation resources and storage devices. The long-term resource adequacy mechanism must also recognize the increasing weather dependence of electricity demand with more customers heating and cooling their homes with electricity.

The Standardized Fixed Price Forward Contract (SFPFC) mechanism introduced in Wolak (2021a) results in the realized system demand each hour of the compliance period being covered by a fixed-price forward contract. The SFPFC approach to long-term resource adequacy recognizes that a supplier with the ability to serve demand at a reasonable price must also have the incentive to do so if it has the ability to exercise unilateral market power in the short-term energy market. As Wolak (2000) demonstrates, an expected profit-maximizing supplier with the ability to exercise unilateral market power that has a fixed-price forward contract obligation would like to minimize the cost of supplying the quantity of energy sold in the forward contract.

The SFPFC long-term resource adequacy mechanism takes advantage of this incentive by requiring retailers to hold hourly fixed-price forward contract obligations for energy that sum to the hourly value of system demand. This mechanism also implies that all expected profit-maximizing suppliers would like to minimize the cost of meeting their hourly fixed-price forward contract obligations, the sum of which equals the hourly system demand for all hours of the year.

To understand the logic behind the SFPFC mechanism, consider the example of a supplier that owns 150 MWh of generation capacity that has sold 100 MWh in a fixed-forward contract at a price of \$25/MWh for a certain hour of the day. This supplier has two options for fulfilling this forward contract: (i) produce the 100 MWh energy from its own units at their marginal cost of \$20/MWh or (ii) buy this energy from the short-term market at the prevailing market-clearing price. The supplier will receive \$2,500 from the buyer of the contract for the 100 MWh sold, regardless of how it is supplied. This means that the supplier maximizes the profits it earns from this fixed-price forward contract sale by minimizing the cost of supplying the 100 MWh of energy.

To ensure that the least-cost "make versus buy" decision for the 100 MWh is made, the supplier should offer 100 MWh in the short-term market at its marginal cost of \$20/MWh. This offer price for 100 MWh ensures that if it is cheaper to produce the energy from its generation units—the market price is at or above \$20/MWh—the supplier's offer to produce the energy will be accepted in the short-term market. If it is cheaper to purchase the energy from the short-term market—the market price is below \$20/MWh—the supplier's offer will not be accepted, and the supplier will purchase the 100 MWh from the short-term market at a price below \$20/MWh.

This example demonstrates that the SFPFC approach to long-term resource adequacy makes it expected profit-maximizing for each seller to minimize the cost of supplying the quantity of energy sold in this forward contract each hour of the delivery period. By the logic of the above example, each supplier will find it in its unilateral interest to submit an offer price into the short-term market equal to its marginal cost for its hourly SFPFC quantity of energy, in order to make the efficient make-versus-buy decision for fulfilling this obligation.

The incentives for supplier offer behavior in a short-term wholesale electricity market created by a fixed-price forward contract obligation are analyzed in Wolak (2000). McRae and Wolak (2014) provide empirical support for these incentives for the four largest suppliers in the New Zealand electricity market. Under the SFPFC mechanism, each supplier knows that the sum of the values of the hourly SFPFC obligations across all suppliers is equal the system demand. This means that each supplier of SFPFCs knows that its competitors have substantial fixed-price forward contract obligations for that hour. This implies that all suppliers know that they have limited opportunities to raise the price they receive for short-term market sales beyond their hourly SFPFC quantity.

As discussed below, a supplier's fixed-price forward quantity for an hour under the SFPFC mechanism increases with the value of hourly system demand. Therefore, the supplier that owns 150 MWh of capacity in the above example has a strong incentive to submit an offer price close to its marginal cost for the capacity of its generation unit to ensure that its hourly production is higher than the realized value of its SFPFC energy for that hour. Therefore, the SFPFC mechanism not only ensures that system demand is met every hour of the year, but it also provides strong incentives for this to occur at the lowest possible short-term price. Wolak (2022) provide a number of examples that illustrate the details of the SFPFC mechanism and why it ensures that system demand will be met at least cost with a high probability.

1.4.1 Mechanics of the Standardized Forward Contract Procurement Process

The SFPFCs would be purchased through auctions several years in advance of delivery in order 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.

The wholesale market operator would run the SFPFC auctions with oversight by the regulator. One advantage of the design of the SFPFC products is that a simple auction mechanism can be used to purchase each annual product. 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. With 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.

The wholesale market operator would also run a clearinghouse to manage the counterparty risk associated with these contracts. All US wholesale market operators currently do this for all participants in their energy and ancillary services markets. In several US markets, the market operator also provides counterparty risk management services for long-term financial transmission rights, which is not significantly different from performing this function for SFPFCs. Both buyers and sellers would be required to post collateral with the wholesale market operator to ensure that each market participant finds it unilaterally profit-maximizing to meet its financial commitments for the SFPFC energy that it has purchased or sold.

SFPFC auctions would be run on an annual basis for deliveries starting 2, 3, and 4 years in the future. In steady state, auctions for incremental amounts of each annual contract would also be needed so that the aggregate share of demand covered by each annual SFPFC could increase over time. The eventual 100% coverage of demand occurs through a final true-up auction that takes place after the realized values for hourly demand for the delivery period are known. The mechanics of the true-up auctions are described in Wolak (2022).

1.4.2 Incentives for Behavior by Intermittent Renewable and Controllable Resources

Under the SFPFC approach to long-term resource adequacy, all suppliers know that all energy consumed every hour of the year is covered by SFPFC energy purchased at a fixed price. This creates a strong incentive for suppliers to find the least-cost mix of intermittent and controllable resources to serve these hourly demands. To the extent that there is concern that the generation resources available or likely to be available in the future to meet demand are insufficient, features of the existing capacity-based resource adequacy mechanism can be retained until system operators have sufficient confidence in this mechanism leading to a reliable supply of energy. The firm capacity values from the existing capacity-based long-term resource adequacy approach can be used to limit the amount of SFPFC energy a supplier can sell.

The firm capacity value multiplied by number of hours in the year would be the maximum amount of SFPFC energy that a unit owner could sell in any given year. Therefore, a controllable thermal generation unit owner could sell significantly more SFPFC energy than it expects to produce annually, and an intermittent renewable resource owner could sell significantly less SFPFC energy than it expects to produce annually. This upper bound on the amount of SFPFC energy any generation unit could sell enforces an incentive for cross-hedging between controllable generation units and intermittent renewable resources. This mechanism uses the firm capacity construct to limit forward market sales of energy by individual resource owners to ensure that it is physically feasible to serve demand during all hours of the year.

Cross-hedging between a controllable resource and an intermittent resource implies that in most years, the controllable resource owner would be producing energy in a small number of hours of the year 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 resource owners would typically produce more than their SFPFC obligation in energy and sell any energy produced beyond this quantity at the short-term price. In years with low renewable output near their SFPRC obligations, 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 largely be shielded from these high short-term prices because of their SFPFC holdings.

1.4.3 Empirical Evidence on the Performance of the Standardized Forward Contract Mechanism

Although the SFPFC mechanism in the form described above does not exist in any currently operating electricity supply industry, the long-term resource adequacy mechanisms in Chile and Peru create the same set of incentives for supplier behavior as the SFPFC mechanism by assigning system-wide short-term price and quantity risk during all hours of the year to suppliers. Both Chile and Peru operate a supplier-only, cost-based short-term wholesale electricity market. The system operator employs regulated variable cost estimates for each generation unit and an opportunity cost of water for hydroelectric generation units to dispatch all generation units to meet locational demands throughout each country. All consumers or their retailers are required to purchase full requirements contracts from suppliers to meet their retail load obligations. Suppliers financially settle imbalances between the amount of energy they produce and the amount of energy their customers consume under these full requirements contracts. Suppliers that produce more energy than their customers consume receive payments from the suppliers that produce less energy than their customers consume.[5]

To see the equivalence of the incentives created for supplier behavior under the market designs in Chile and Peru and the SFPFC mechanism, let QR_i equal the consumption of customers served by the supplier i and PR_i the quantity-weighted average price paid for full requirements

5 See section 3.2 of Wolak (2021c) for more details on this settlement mechanism.

contracts by customers served by supplier i. Let system demand equal QD, which is also equal to $\sum_{i=1}^{N} QR_i$, the sum of the consumption of all customers served by the N suppliers. The short-term price is PS, amount of energy sold in the short-term market is QS and cost of producing this energy is C(QS). The variable profit of supplier i is equal to

$$\begin{aligned}\pi_i &= PS \times QS - C(QS) - (PS - PR_i) \times QR_i \\ &= PS \times (QS - QR_i) + PR_i \times QR_i - C(QS), \end{aligned} \qquad (1)$$

which is identical to the case of supplier having fixed-price forward contract equal to QC and at price of PC by setting QR_i equal to QC and PR_i equal to PC. Moreover, because QD = $\sum_{i=1}^{N} QR_i$, all short-term price and quantity risk is borne jointly by the N suppliers that have sold full requirements contracts to electricity retailers and large loads.

The long-term resource adequacy mechanisms in Chile and Peru have delivered a reliable supply of electricity for at least the past 15 years in each country in the face of significant hydroelectric energy supply uncertainty and an increasing share of the energy consumed coming from intermittent wind and solar generation units. This outcome has been achieved through a cost-based short-term market in two countries with typical growth rates in annual electricity demand that are three to four times that in regions in the US with formal wholesale electricity markets. Consequently, the experience of Chile and Peru provides a strong argument in favor of the SFPFC mechanism for Asian countries with significant intermittent renewable energy goals.

1.5 Mechanisms That Support Large Renewable Energy Shares

This section describes two mechanisms that support large renewable energy shares at least cost to electricity consumers. The first mechanism is a renewable energy certificate market for a region to meet its renewable energy goals. This is followed by a 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.

1.5.1 Renewable Energy Certificate Market

A renewable energy certificate (REC) market is a significantly lower-cost approach to achieving a given renewable energy goal than other available mechanisms because it creates a competitive market for the renewable energy attribute. Under this mechanism, the relevant regulatory authority would set up a registry of qualified renewable energy resources (RERs) for the region. The set of generation resources that are qualified to sell RECs would be established and overseen by this regulatory authority. Once a resource is qualified to sell RECs, its energy production would be compiled in the registry established by the regulatory authority and each of these resources would be issued a quantity of RECs equal to the megawatt-hours of energy the resource produced during the compliance period.

Assuming an annual compliance period for the renewables mandate, retailers would be required to purchase the required percentage of their annual consumption of energy in RECs. For example, if the renewables mandate was 30% for 2024, free consumers and distributors would have to surrender RECs produced during 2024 equal to 30% of their annual consumption in 2024. A retailer with an annual consumption of 20,000 MWh would be required to surrender 6,000 RECs or pay a $1/MWh penalty set by the regulatory authority for any shortfall relative to this magnitude. For instance, if the retailer only held 5,900 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 a 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. This resource owner could also purchase these 100 RECs from qualified renewable generation unit owners with surplus RECs.

Unused RECs from the previous compliance year could be used in the following compliance year, but not in any subsequent year. For example, an 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 carry over 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 a jurisdiction establishes a legal commitment to renewable energy targets into the distant future, there is no reason to establish a REC market. Moreover, a longer regulatory commitment would increase the likelihood that a forward market for RECs would develop to support investments in RERs 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 the region's renewable energy goals. For example, centralized auctions for RECs could be run at similar time horizons to delivery compared to the SFPFC auctions. A guaranteed 4-year future revenue stream from future REC sales would provide the above-market revenues to the quantity of RERs necessary to achieve the long-term RER goal.

It is important to emphasize that without a legally mandated commitment by the relevant jurisdiction to meet a specific renewable energy target, such as 20% of electricity consumption from these resources by 2030, establishing a RPS is unnecessary. Intermittent renewable resources are free to compete with conventional generation resources in the long-term resource adequacy mechanism selling SFPFCs.

Procurement processes for specific renewable technologies should be avoided. Procurement mechanisms that specify shares of renewable energy for specific technologies 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. As noted in Wolak (2021c), an RPS creates a competitive market for the renewable attribute that all qualified sources of renewable energy can compete to provide. Different from a regulatory mandate that requires, say, 40% of renewable energy to come from wind and 60% to come from solar, an RPS provides strong incentives for suppliers to find the least-cost mix of renewable resources to achieve a given renewable energy goal. Technology-specific feed-in tariffs that specify a fixed price schedule paid for energy from each renewable technology not only fail to find the least-cost mix of renewable energy technologies but may not even find the least-cost mix renewable generation units for the same technology. That is because as long as a feed-in tariff provides a revenue stream greater than the cost of the renewable energy, the project developer has an economic incentive to build the project, whether or not it is the cheapest source of the energy from that renewable generation technology.

1.5.2 Transitioning Renewables to Standardized Forward Contracts

As the share of intermittent RERs 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 renewable resource owner a fixed price for all megawatt-hours regardless of when this energy is produced provides an implicit subsidy to the RER owner in a multi-settlement LMP market. The period-level variable profit of the RER unit owner under a paid-as-delivered PPA is (PC − C) QC, because the short-term market output of the resource QS is equal to the forward contract quantity QC for all periods under the terms of a paid-as-delivered contract that pays the RER owner PC for every megawatt-hour produced regardless of when 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 its 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 must eventually be eliminated for all RERs, because a paid-as-delivered contract leaves the buyer of this energy with a volatile net demand position that must be purchased from the short-term energy market. Every hour the buyer of this renewable contract must purchase or sell the difference between its real-time demand and the output of the renewable resource. Moreover, the hours when short-term prices are high (because of little renewable energy production) the net demand of the retailer is likely to be positive and large, and the hours when short-term prices are low the net demand of the retailer is likely to be negative and large in absolute value.

Under the proposed multi-settlement LMP market without these PPA contracts, RERs that schedule energy in the day-ahead market must be responsible for the cost or revenues associated with any deviation between their day-ahead schedule and real-time output level. 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. Because of the high degree of contemporaneous correlation between wind and solar generation resources documented in Wolak (2014), selling in the real-time market only implies selling low output relative to capacity at a high price and high output relative to capacity at a low 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 hourly payment stream of max(0,(P(spot,h)-P(strike))) times the number of megawatt-hours sold during the term of this "cap contract." P(spot,h) is the spot price during hour h, P(strike) is the negotiated strike price of the cap 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 megawatt-hour 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.

Under a fixed-price and fixed-quantity forward contract, the renewable resource owner's variable profit is $\pi = PS(QS - QC) + PC^{*}QC$, where both PS and QS are random variables not known to the resource owner until after the hour. The variable cost of producing QS is assumed to be zero. The expected value E(.) of the resource owner's variable profit is:

$$E(\pi) = Cov(PS,QS) + E(PS)E(QS) - E(PS)QC + PC^{*}QC \qquad (2)$$

As noted earlier, Cov(PS,QS), the covariance between the PS and QS, is likely to be negative. Under the paid-as-delivered forward contract the resource owner's variable profit is $\pi = PC^{*}QC$, because QS = QC each hour. Consequently, transitioning from paid-as-delivered contracts to fixed-price and fixed-quantity forward contracts implies a significant increase in variable profit risk for intermittent renewable resource owners.

Cross-hedging between dispatchable resources and intermittent renewable resources selling fixed-price forward contracts 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 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 government has set a legally binding target for energy production.

1.5.3 Cost-Based LMP Market and Renewables Integration

The strength of a cost-based LMP market design for RER integration is that all 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 SFPFC energy.

Shifting renewable resource owners to fixed-price and fixed-quantity forward contracts 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 provides is a crucial step in increasing the amount of intermittent renewable energy produced while maintaining a 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 into 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 with an associated 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.

1.6 Concluding Comments

Achieving the large shares of intermittent renewable energy necessary to reduce substantially the carbon content of a region's electricity supply is likely to be significantly less costly because of the recent reduction in the LCOE of wind and solar resources. However, ensuring that this transition occurs in a least-cost manner requires efficient pricing in the short-term energy market and a long-term resource adequacy mechanism designed for an industry with a large share of intermittent renewables. Zonal pricing markets that do not account for all relevant operating constraints on dispatchable and intermittent renewable generation units in day-ahead and real-time markets unnecessarily increase the cost of making this energy transition.

The major system reliability challenge with a significant amount intermittent renewable resources changes from having sufficient generation capacity to meet annual system demand peaks to the ability to meet the hourly net demands (system demand less intermittent renewable output) for energy throughout the year. Particularly in an electricity supply industry with a summer annual peak demand and significant installed solar generation capacity, meeting daily system demand peaks is relatively straightforward because demand peaks occur when there is significant solar energy production. The new focus on meeting net demand peaks implies a system-wide focus on energy adequacy where intermittent renewable resources have a financial incentive to hedge their short-term and production quantity risk with dispatchable generation resources to cover these net demand peaks.

A multi-settlement LMP market design efficiently prices the system-wide and local reliability benefits provided by dispatchable resources relative to intermittent renewable resources. By co-optimizing the procurement of energy and ancillary services, this market design ensures that the demand for energy and ancillary services at all locations in the transmission network are met at least cost. The standardized energy contracting approach to long-term resource adequacy described in this chapter addresses the primary long-term resource adequacy challenge in regions with significant intermittent renewables. It provides strong incentives for intermittent resources to cross-hedge their quantity and price risk associated with selling these standardized long-term contracts with dispatchable resources to provide the revenue necessary to keep enough of this generation capacity available to meet hourly net demands throughout the year. The experience of Chile and Peru over the past 15 years, each of which has a market design that creates the same set of incentives for supplier behavior as the SFPFC mechanism, provides encouraging empirical evidence in favor of its adoption in regions with significant intermittent renewable energy goals.

Finally, if a region has a legal mandate to achieve a prespecified renewable energy goal by a given date, such as 60% of energy consumed by 2040, then a renewable energy certificate market is the least-cost approach to achieving this goal. If a region does not have a mandated renewable energy goal, then such a market is no longer necessary. The recent declines in the LCOE of wind and solar resources currently make them a lower LCOE solution than natural gas and coal generation units in many regions.

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