Energy Policy 148 (2021) 111997

Contents lists available at ScienceDirect

Energy Policy

journal homepage: http://www.elsevier.com/locate/enpol

Electricity market design for low-carbon and flexible systems: Room for improvement in Chile

Francisco D. Muñoz[a,d,*], Carlos Suazo-Martínez[b], Eduardo Pereira[b], Rodrigo Moreno[c,d,e]

[a] Facultad de Ingeniería y Ciencias, Universidad Adolfo Ibáñez, Santiago, Chile
[b] SPEC Energy Consulting, Santiago, Chile
[c] Department of Electrical Engineering, University of Chile, Santiago, Chile
[d] Instituto Sistemas Complejos de Ingeniería, Santiago, Chile
[e] Imperial College, London, UK

ARTICLE INFO

Keywords:
Market design
Electricity
Flexibility
Decarbonization

ABSTRACT

Chile was the first country that privatized all generation, transmission, and distribution services, and introduced competition in the generation segment. Nearly four decades after its creation, many features of the original electricity market design remain unchanged. In this paper, we provide a brief history of the Chilean electricity market and explain its main limitations going forward. Some of these include the use of a cost-based mechanism for spot transactions based on a merit-order curve, low temporal granularity of spot prices, missing forward markets to settle deviations from day-ahead commitments, inefficient pricing of greenhouse gas emissions due to administrative rules, and a capacity mechanism that does not reflect a clear resource adequacy target. Many of these limitations are also present in other electricity markets in Latin America that, when privatized, mirrored many features of the electricity market design in Chile. Failing to address these limitations will provide distorted incentives for the efficient entry and operation of resources that could impart flexibility to the system, increasing the cost of decarbonizing the power sector.

1. Introduction

In 2019, Chile became the first country in Latin America to announce its commitment to become carbon neutral by 2050. Achieving this goal will involve large transformations of the mining, transportation, agricultural, construction and infrastructure, and energy sectors in the country over the next three decades.

One of the industrial sectors that has already initiated a transition to low-carbon energy sources is the electric power system. From 2008 to 2019, the installed capacity of wind, solar, and small hydro projects increased from nearly 120 MW to more than 5000 MW, with many more renewable projects in line for construction in the next years (CNE, 2019a). Currently, nearly 50% of the 24 GW of installed capacity in the Chilean electric power system is carbon free, including large hydro units and carbon-neutral biomass generation. Factors that underpin such large growth of investments in renewable energy generation in the country include the availability of high-quality renewable resources (Watts and Jara, 2011; Jimenez-Estevez et al., 2015), massive cost reductions of wind and solar projects (Vimmerstedt et al., 2019), a period of high electricity prices until 2014 (CNE, 2019a), a liquid market for Power Purchase Agreements (PPAs) (Moreno et al., 2010; Reus et al., 2018), and strong social opposition to the development of large coal and hydropower plants (Bronfman et al., 2012).[1]

The ongoing decarbonization of power systems is creating challenges in electricity markets. For instance, the variable and unpredictable nature of generation from the fastest-growing renewable energy technologies—wind and solar—requires the availability of other flexible resources to balance unexpected changes in generation supply and reductions of synchronous inertia (Denholm and Hand, 2011; CDEC-SIC, 2014; Inzunza et al., 2016). The volatility of wind and solar resources creates a need for increasing the temporal granularity of price signals to ensure that spot prices reflect the changing physical conditions of the

---

* Corresponding author. Facultad de Ingeniería y Ciencias, Universidad Adolfo Ibáñez, Santiago, Chile.
E-mail address: fdmunoz@uai.cl (F.D. Muñoz).

[1] While country has a binding renewable target with tradable Renewable Energy Certificates, Munoz et al. (2017) argue that the effect of this policy on investments decisions is minimal because, every year, the market has delivered a much larger share of generation from renewables than the annual requirement specified in the policy.

https://doi.org/10.1016/j.enpol.2020.111997
Received 31 May 2020; Received in revised form 17 October 2020; Accepted 19 October 2020

system (IRENA, 2019). Consideration of renewable energy units in resource-adequacy mechanisms has been problematic because the lack of a uniform framework to assess their contribution to the system (Munoz and Mills, 2015; Bothwell et al., 2017). High shares of wind and solar generation can increase the frequency of periods with zero or negative spot prices, which affects revenue streams for generators that expect to recover investment costs from the energy market (Ela et al., 2014). Additionally, it has been difficult to implement first-best carbon-pricing mechanisms, with carbon prices that reflect current estimates of the social cost of carbon emissions (Jenkins, 2014).

Worldwide, regulators are addressing these challenges using different approaches. In 2016, the Federal Energy Regulatory Commission (FERC) in the US approved Order 825 that requires Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to settle energy and ancillary service markets at the same time interval of dispatch decisions (i.e., every 5 min) (FERC, 2016). This change ensures that real-time prices reflect the changing physical conditions of the system—including periods of scarcity of energy or ancillary services—and that market participants have the right incentives to respond to dispatch signals. The same year that FERC Order 825 was approved, both the California and the Midcontinent ISOs introduced new ramping products in the reserves market to ensure sufficient upward and downward ramping capability due to demand and renewable forecast errors with increasing shares of generation from wind and solar resources (Wang and Hobbs, 2014, 2015). In 2014 the Electric Reliability Council of Texas (ERCOT)—the market with the fastest-growing wind capacity in the US—introduced Operating Reserve Demand Curves (ORDCs) to ensure that the incremental value of reserves is accurately reflected in the price of electricity and reserves (Hogan and Pope, 2017). The PJM market recently proposed introducing ORDCs such as the ones used in ERCOT, because reserve products are not being valued appropriately in the current market (PJM, 2019). In addition, there is a recent FERC order that requires RTOs and ISOs “ … *to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets*’’ (FERC, 2019). States are also employing a variety of policy instruments that incentivize increasing shares of generation from renewables and low-carbon resources, including production tax credits, renewable requirements, and carbon cap-and-trade mechanisms (Wiser et al., 2007; Perez et al., 2016; Borenstein et al., 2019).

Electricity markets in Europe are also going through a process of reform. In 2019, the EU Parliament adopted a package of new market design proposals that aim at the efficient decarbonization of the electric systems of member countries, improving market design features from the latest reform in 2009 known as the *Third Energy Package*. According to a report for the European Commission “ … *the rules of the Third Energy Package appear to be insufficient to cope with such current levels of R (enewable) E(nergy) S(upply). Different rules appear needed to ensure in particular the development of short term markets and the emergence of prices that reflect actually scarcity. Rules to ensure closer cooperation of grid operators are also insufficient as they stand*’’ (EC, 2016). The new package includes measures that will facilitate cross-border trade, restrictions on the participation of carbon-emitting generators in capacity mechanisms, and the introduction scarcity-pricing mechanisms. Countries in Europe also employ carbon cap-and-trade mechanisms, carbon taxes, and other policies to promote investments in renewable energy technologies (Grubb and Neuhoff, 2006; Kitzing et al., 2012).

With the exception of some elements of the Colombian system, electricity markets in Latin America are not as sophisticated as the ones used in the North America, Europe, and Oceania (Rudnick and Velasquez, 2018; Munoz et al., 2018) and have lagged behind the last wave of reforms in developed countries. The simplicity of these market designs has been justified for a number of reasons, including the high implementation and ongoing costs of operating and maintaining sophisticated market platforms, the lack of competitive forces coupled with the absence of market monitoring departments that could prevent or mitigate the exercise of market power, and the lack of independent regulatory institutions (Wolak, 2003; Estache and Wren-Lewis, 2009). However, there is an increasing number of developing countries that have adopted decarbonization targets or carbon-pricing mechanisms for the next decades. Furthermore, renewable energy and storage technologies have become competitive alternatives to conventional forms of generation, even in regions without renewable energy policies or carbon-pricing mechanisms. Failing to adapt electricity market designs to these new technologies and societal goals will likely distort electricity prices, lead to inefficient entry and exit of generation and other technologies such as energy storage, prevent innovation, and limit the participation of demand-side resources and the electrification of other energy vectors such as heat and transport. These limitations will also make it much more expensive to achieve carbon emissions reductions than if these markets adopted some of the elements of the recent reforms in the US or Europe.

In this paper, we address some of the main limitations of the current electricity market design in Chile going forward, considering the ongoing transition of the system to low- and zero-carbon energy sources. Although there are multiple aspects of the market that could be improved, we focus on five features that require modifications in the near term to ensure efficient price signals and investment incentives under increasing shares of generation from renewables and the potential entry of energy storage devices. These include: 1) price distortions caused by the use of a merit-order curve to settle spot transactions, 2) the importance of increasing the granularity of spot prices, 3) the need for multi-settlement markets to settle deviations from committed schedules and hedge risks, 4) the long-term effects of the administrative rules present in the current carbon-pricing mechanism, and 5) an overview of the main limitations of the current capacity mechanism. Many of these limitations distort investment incentives for the efficient entry of technologies that could impart flexibility to the system, including energy storage devices. Limitations 4) and 5) have a direct impact on incentives for the entry of more low- or zero-carbon generation capacity and for the exit of conventional generation units.

Additionally, we also discuss other modifications to the electricity market design in Chile that could improve price signals but that—from our perspective—have a lower priority than the first five measures mentioned before. Here we discuss the potential benefits of introducing reserve products to hedge against steep ramping events and sloped Operating Reserve Demand Curves to enhance short-term price signals under scarcity conditions. We also discuss the potential benefits that could result from introducing demand participation in the wholesale market, which could reduce reserve requirements both in the short and long term. Finally, we include a qualitative discussion about the potential benefits and costs that would result from a transition from the current cost-based electricity market design to a bid-based pool.

We structure the rest of the paper as follows. In Section 2 we provide a brief history of the Chilean electricity market, describe the current electric power system, and outline the country’s future goals with regards to decarbonization and renewable energy targets. In Section 3 we provide a thorough description of the main limitations of the current electricity market design and their implications for the efficient remuneration of technologies that provide flexibility. In Section 4 we discuss more challenges and potential solutions going forward, in the context of systems with high shares of generation from renewables. Some of these include the introduction of scarcity pricing mechanisms and ramp products, allowing for demand participation in the wholesale market, and a potential transition from a cost-to a bid-based market design. Finally, in Section 5 we provide some policy recommendations and conclude.

2. The chilean electricity market

Chile pioneered the deregulation of the electricity sector with the 1982 Electricity Act (Rudnick, 1994; Raineri, 2006), nearly 100 years after the inauguration of the first lighting system in Santiago's city center in 1883. This Act, which laid the foundations of the current electricity market in Chile, separated the electricity sector into private generation, transmission and distribution segments. The generation sector began operating as a competitive market, whereas the transmission and distribution sectors were deemed natural monopolies. Since 2004 the law prohibits transmission firms from participating, directly or indirectly, in generation or distribution business. However, both generation and distribution firms are allowed to have some participation in the transmission business.

In the competitive generation sector, the 1982 Electricity Act established that all loads must be contracted at all times with generators, which must settle their differences between physical and financial positions (i.e., contract for differences) in a spot market. The latter includes nodal prices determined in a cost-based economic dispatch managed by a private, non-for-profit, system operator. Importantly, the contract prices associated with regulated consumers were determined by the regulator in a process run every 6 months. This regulated process projected future marginal costs (i.e., spot prices), equalizing the regulated price in the next 6 months to the mean value of the forecast. Contract prices for large consumers, though, are determined through bilateral negotiations. On top of the revenues from the energy market, generation firms also receive capacity payments determined by the regulator. These payments were implemented with the goal of mitigating the potential missing-money problems originated by cost-of-shortage parameters that are too low to support investments and due to the volatility of spot prices that result from a cost-based market affected by the long-term variability of hydro resources.

Although many of the core elements of the original market design remain unchanged, there are various changes that have been undertaken in response to different issues faced during the nearly four decades since its implementation. Fig. 1 shows the key changes since 1982 in the regulatory framework, focusing on the generation sector. Fig. 1 shows that, in 2004–2005, two important changes were carried out. The first one implements a market-based mechanism to procure electricity for retail customers. The mechanism is based on a long-term competitive auction that is used to select enough Power Purchasing Agreements (PPAs) between generation and distribution companies to meet forecasted demand, where the latter act as retailers for regulated consumers (Moreno et al., 2010). The second one allowed small renewable generators (below 9 MW of capacity) to avoid transmission charges, being the first move in Chile towards supporting low-carbon technologies.

Later on, in 2008, Chile implemented its first target for renewables, a binding 10% goal by 2024. This was accompanied by the implementation of a system of tradable renewable energy certificates (RECs) with a penalty on firms that do not fulfill the target using either their own assets or through ownership of RECs. This mechanism of tradable RECs allows firms with more renewable generation than what is required by the target to get additional revenues from the sales of RECs. In 2012–2013, an even larger boost for renewables was enacted, which augmented the renewables target to 20% and implemented a net-billing system for distributed generation (Munoz et al., 2017). Remarkably, it was only in 2015–2016 that the system operator became a fully independent organization, just as system operators in the US. In the same year, a new Act changed the mechanism to auction long-term PPAs, correcting design flaws present in the previous mechanisms that resulted in a lack of competition and high contract prices (e.g., several long-term contracts, up to 15 years of duration, ended up with prices equal to 100–140 \$/MWh).[2]

In addition to the energy market and capacity mechanism, generators can also participate in a new market for ancillary services opened on Jan 1st, 2020. Some of the new services include fast frequency control as well as primary, secondary and tertiary reserves. These services are cleared in a competitive pay-as-bid auction on a daily basis and they are co-optimized with energy. It is worth noting that, to our best knowledge, this is the only electricity market in the world that combines a cost-based mechanism for energy and a pay-as-bid auction for the procurement of ancillary services, without a binding day-ahead market. We will examine the impact of the lack of a forward market later on in the paper.

To date, the Chilean electricity market features an installed capacity of 24 GW and a maximum demand of nearly 11 GW. The generation mix has recently shown an important increase in renewable generation, mainly from wind and solar resources. As we show in Table 1, wind and solar capacity represent, respectively, nearly 7% and 11% of the country's total installed capacity. Investments in thermal generation have also increased significantly since 2000, with natural gas becoming less attractive after Argentina constrained exports to Chile in 2004.

Going forward, policy makers have centered their agenda on promoting decarbonization (Moreno et al., 2017). To achieve this goal, the regulator imposed a $\$5/tCO_2$ carbon tax along with a plan to decommission coal power plants.[3] This, however, might not suffice as decarbonization necessitates complementary measures to promote system flexibility (Moreno et al., 2017b). Next, we discuss the main limitations of the current market design to promote flexibility and propose various regulatory changes to stimulate a cost-effective transition towards a low-carbon electricity market.

3. Main limitations of the current electricity market design

In this section, we describe some of the main limitations of the current electricity market design in Chile and discuss potential solutions. From our perspective, fixing this set of limitations should be a priority for the regulator because they can lead to inefficient remuneration and entry (or exit) of resources that could impart flexibility and contribute to achieve decarbonization goals.

3.1. Pricing spot transactions based on a merit-order curve

Spot transactions in the Chilean market are priced using a merit-order curve instead of the Lagrange multipliers obtained from the supply and demand balance constraints at every bus in the system. The merit-order curve is a resource that is often used in classrooms to explain how electricity should be priced, following general microeconomic theory. The rule of thumb is that, in a simple system without transmission constraints, the spot price is equal to the marginal cost of the most expensive unit running in the system that is needed to serve demand. Nevertheless, the theory of spot pricing states that efficient prices are determined by the intersection of supply and demand at every location, in every period, and for every service provided in the system (Schweppe et al., 2013).

Consider a simple system with only two generators and four consecutive periods t of demand D_t, of 1 h each, where $D_1 = D_2 = 1000$ MW and $D_3 = D_4 = 2000$ MW. Generator A is a low-cost but inflexible resource, with a marginal cost of 30 \$/MWh and a ramping limit of 600 MW/h. Generator B is flexible—it has no ramping limit—but it is much more expensive, with a marginal cost of 70 \$/MWh. For the sake of simplicity, we ignore maximum generation limits.

Table 2 shows the dispatch program that, under a perfect forecast, minimizes the cost of supplying demands D_1, D_2, D_3, and D_4, considering the costs and characteristics of the available generation units. Note that generator B is only operated during period 3, where generator A is only capable of supplying 1600 MW due to its ramping limit and dispatch level of 1000 MW in period 2.

Table 3 shows spot prices per period computed using the merit-order curve and an economic dispatch model that optimizes resources for all

---

[2] All currency in US dollars.

[3] As explained in (Diaz et al., 2020), the current implementation of the carbon tax presents a number of problems that will need to be amended.

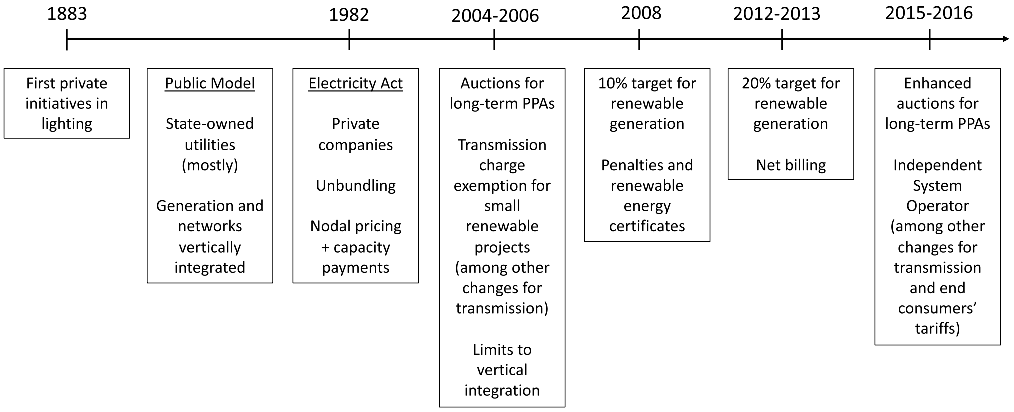

Fig. 1. Timeline of main regulatory changes, mainly focused on generation.

Table 1
Total net installed capacity by technology and max demand per year.

Tech/Year	2000	2005	2010	2015	2018	2019
Biomass-Biogas	25	119	174	493	501	502
Coal	1602	1602	2128	4136	4626	4974
Cogeneration	0	0	0	18	18	18
Diesel-Fuel Oil	321	572	2667	2848	2974	3149
Gas-LNG	2008	3447	3833	3837	4403	4443
Wind	0	0	170	906	1524	1614
Solar	0	0	0	575	2317	2632
Hydro	4327	5044	5314	6397	6618	6656
Total capacity	8282	10,784	14,286	19,210	22,981	23,987
Max Demand	5669	7330	8382	9867	10,626	10,793

Table 2
Demand per period and optimal dispatch levels.

	Time periods			
Unit	1	2	3	4
Generator A [MW]	1000	1000	1600	2000
Generator B [MW]	0	0	400	0
Demand [MW]	1000	1000	2000	2000

Table 3
Spot prices in $/MWh derived from a merit-order curve and from the dispatch optimization model.

	Time periods			
Pricing mechanism	1	2	3	4
Merit-order curve [$/MWh]	30	30	70	30
Economic dispatch model [$/MWh]	30	−10	70	30

four periods simultaneously. Spot prices derived from the merit-order curve are ex-post prices that ignore intertemporal constraints and that only consider the most expensive unit operating in every period. In contrast, spot prices from the economic dispatch model are a byproduct of the optimization of generation units used to meet demand, i.e. they are the Lagrange multipliers of the supply and demand balance constraints that support the optimal dispatch instructions.

Note that spot prices computed using both methods coincide in all periods, except for period 2. In periods 1 and 4 the price of electricity is equal to the marginal cost of the most expensive generation unit running in the system, unit A, with a marginal cost equal to 30 $/MWh. The same occurs in period 3, where the spot price is equal to the marginal cost of unit B, 70 $/MWh. However, the price that balances the supply and demand constraint in period 2 according to the economic dispatch model is −10 $/MWh and not 30 $/MWh. The discrepancy between the prices that result from the merit-order curve and from the economic dispatch model occurs because the latter computes prices that reflect the incremental cost of supplying an additional unit of demand in every period and location, following the theory of spot pricing laid out by Schweppe et al. (2013). If in period 2 we increase demand from 1000 MW to 1001 MW, the most efficient alternative to supply the additional unit of demand would be with generator A, which would impose an additional cost of $30 in period 2. Nevertheless, such dispatch configuration would also allow generator A to ramp up to 1601 MW and reduce the output of generator B to 399 MW in period 3. Therefore, the net effect of an increase of 1 MW of demand in period 2 in the operating cost of the system is $30+$30-$70 = −$10.

In this example, the set of prices derived from a merit-order curve overcompensate the inflexible unit, generator A, and distort incentives for other resources that could, potentially, provide flexibility. For instance, for a small storage unit, the value of arbitraging 1 MWh of energy between periods 2 and 3 under the set of prices derived from the merit-order curve is $40. However, under the set of efficient prices derived from the economic dispatch model, the same storage unit would see that the value of arbitraging 1 MWh of energy between those same two periods is $80, which is double of what the storage unit would receive if prices were computed using a merit-order curve. Incentives for demand response are also distorted under the set of prices computed from the merit-order curve. This is because any action that would increase demand by 1 MW in period 2 should be paid $10 instead of being charged $30.

While here we use an example of how the use of the merit-order curve can distort economic signals with respect to the efficient prices that result from the economic dispatch model in the presence of intertemporal constraints (i.e., ramping limits), there are other features in electricity markets that could also lead to price distortions. For instance, computing efficient nodal prices in meshed and congested transmission systems using a merit-order curve is extremely difficult because such pricing mechanism ignores the effects of Kirchhoff's Voltage Law on power flows. Going forward, we recommend the use of dispatch software that can simultaneously find dispatch schedules and prices that reflect all of the most relevant physical constraints of the system, including intertemporal limits of generators, transmission constraints, and transmission losses. Better pricing would ensure efficient remuneration of resources that provide flexibility and would incentivize entry and exit of the right type of technologies—including both conventional and innovative smart grid technologies such as energy storage and demand response—at the right locations in the network.

3.2. *Low temporal granularity of spot prices*

Building on the previous point, a second main limitation of the current electricity market design in Chile is that spot transactions are settled on an hourly basis. While this level of granularity of spot prices might have been sufficient for a system based mainly on thermal and flexible hydro generation, such time resolution is insufficient for systems with increasing levels of generation from volatile and unpredictable renewable energy resources. Coarse price signals hide the economic effects of sudden demand and supply changes, as well as their impact on inflexibilities present in the system (e.g., ramping limits). In the short term, an electricity market with low price resolution provides distorted incentives for self-dispatched units and demand resources to provide flexibility when the system is in need for this service. This simplification also results in inefficient remuneration of technologies that could provide flexibility, such as energy storage units. In the long term, distorted price signals lead to an inefficient portfolio of generation and energy storage technologies.

Fig. 2 shows a price projection for a summer weekday in the Chilean electric power system in year 2023. The blue curve shows hourly spot prices, as computed today, whereas the red curve shows the spot prices that would be used if settlements occurred every 5 min. Notice that hourly spot prices from this projection present, mostly, two different regimes: low prices during the day, when solar power is abundant, and high prices at night, when solar power is not available. The minimum and maximum hourly prices are 34.5 $/MWh and 56.3 $/MWh, respectively. Nevertheless, when we compute prices every 5-min intervals for the same system we observe more volatility than when they are computed hour by hour. The minimum and maximum 5-min spot prices are 7.4 $/MWh and 56.3 $/MWh.

One alternative to measure the economic implications of using hourly instead of 5-min prices is to quantify the marginal value of a technology that could provide flexibility to the system. We consider a hypothetical lossless energy storage unit of 1 MW with 1 h of storage capability, which, given its size, would act as a price-taking unit. If prices were computed every hour, the storage unit would be capable of making $5.5 from the arbitrage of energy between low and high price periods over this representative day. However, if prices were computed every 5 min, the same unit would be capable of making a profit of $6.6. Consequently, prices computed with low resolution distort the economic value of a technology that could provide flexibility to the system.

The need to increase the time resolution of real-time prices is not unique to the Chilean electricity market. In the US, for example, most Independent System Operators have already adopted 5-min settlement processes in real-time markets, in response to the increasing penetration of volatile generation from renewables and the emergence of demand response programs that can provide flexibility to the grid. The transition towards more granular real-time prices has also been driven by FERC Order 825, which requires system operators to settle real-time energy and operating reserve transactions at the same time interval the transactions are scheduled (FERC, 2016).

Increasing the time granularity of prices is also important for assigning the costs of variability in an efficient manner. With the rising penetration of generation from renewable resources there have been concerns about a) the cost of variability for power systems due to increased cycling and ramping of units and b) how those costs should be allocated among market participants (Milligan et al., 2011; Hirth et al., 2015). Mays (2017) develops a benchmark model that can be used to determine a fair allocation of the incremental costs imposed by the introduction of variable resources. The proposed approach is based on the Shapley value from cooperative game theory, following a cost-causation principle. The author finds that if spot prices are computed correctly (i.e., they are computed using dispatch software and not a merit-order curve, with adequate time resolution), then electricity prices convey most of the incremental costs of variability. In other words, with efficient wholesale prices "… *market participants are unlikely to create a socialized cost due to variability*" (Mays, 2017). This result highlights the importance of efficient pricing of electricity in the short run, which avoids the need to introduce administrative pricing rules to allocate the cost of variability when prices are not derived from first economic principles.

3.3. Use of single-settlement systems

Currently, the electricity market in Chile is based on a single-settlement system, just like the rest of the electricity markets in South America.[4] This means that all spot transactions are settled using real-time prices, which are computed ex post operations. While the SO computes day-ahead prices, these only provide reference price trajectories for self-committed units and are not used to settle transactions.

In contrast, most deregulated markets in the US and Europe employ multi-settlement mechanisms that allow resources to adjust their schedules and financial positions as new information becomes available. In the US, the most common design includes a day-ahead market that clears prior to the real-time one, as we show in Fig. 3. In general, participation in the day-ahead market is voluntary. The DA market clears based on forecasts of demand, wind, and solar conditions as well as reliability requirements for the next day, resulting in a day-ahead price P^{DA} and a day-ahead committed quantity for each generator i q_i^{DA}. The DA market plays a critical role in electricity markets since it provides an economic signal for slow generation units that require many hours to be ready for production during the next day. It is also a hedging market because it allows agents to reduce their exposure to uncertain real-time prices.

The real-time (RT) market is settled based on realizations of demand, wind, and solar conditions as well as on the realizations of component failures, such as the loss of a transmission line or a large generator. The RT market results in a price P^{RT} and a physical obligation for each generation unit q_i^{RT}. Note that if reserves are co-optimized with energy, reserve and energy prices capture the opportunity cost of participating in one market and not in the other one.

The net revenue for a unit i that participates both in the DA and RT markets is $P^{DA} \cdot q_i^{DA} + P^{RT} \cdot (q_i^{RT} - q_i^{DA})$. Here we want to make three observations:

- If the quantity committed in the DA is equal to the delivered quantity in RT, i.e. $q_i^{DA} = q_i^{RT}$, then the net revenue for a unit is i is simply $P^{DA} \cdot q_i^{DA}$. Consequently, a unit that does not deviate from its committed schedule in the DA market is no affected by any potential difference between the RT price P^{RT} and the DA price P^{DA}.
- If the quantity committed in the DA is lower that the delivered quantity in RT, i.e. $q_i^{DA} < q_i^{RT}$, then the unit i is paid P^{DA} for the first q_i^{DA} units of power and receives P^{RT} for the additional $q_i^{RT} - q_i^{DA}$ units sold in RT.
- In turn, if the quantity committed in the DA is higher that the delivered quantity in RT, i.e. $q_i^{DA} > q_i^{RT}$, then the unit i gets a payment P^{DA} for q_i^{DA} units of power from the day ahead, but it must purchase $q_i^{DA} - q_i^{RT}$ units of power at the RT price P^{RT}.

Consequently, a DA market provides a transparent mechanism to assign the costs of deviations from DA schedules. We will now use a simple example with real data to illustrate the disadvantage of settling all transactions using a cost-based RT price.

Fig. 4 shows cost-based RT and reference DA prices for the first week in January 2019 at a large reference bus of the electric power system in Chile. Reference DA prices are computed by the SO using cost-based estimates of generation costs and forecasts of demand, wind, and solar generation for the next day. However, as we mentioned it before, they are not used to settle transactions. We observe deviations of up to 120 $/MWh between DA and RT prices, which indicates that there might be important opportunities for arbitrage between a hypothetical new DA

---

[4] See for example Mastropietro et al. (2020).

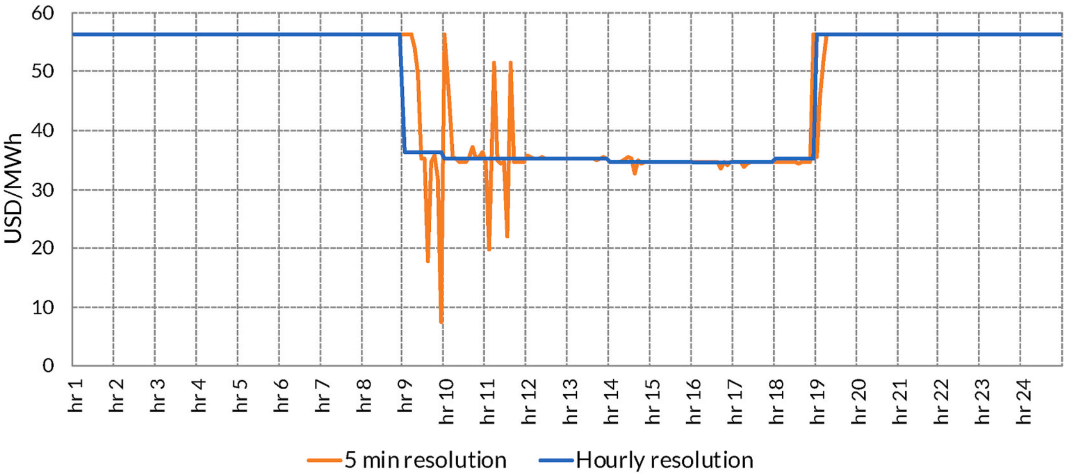

Fig. 2. Energy price forecast based on 1-hr and 5-min settlements.

Fig. 3. Illustration of a two-settlement system, with day-ahead and real-time markets.

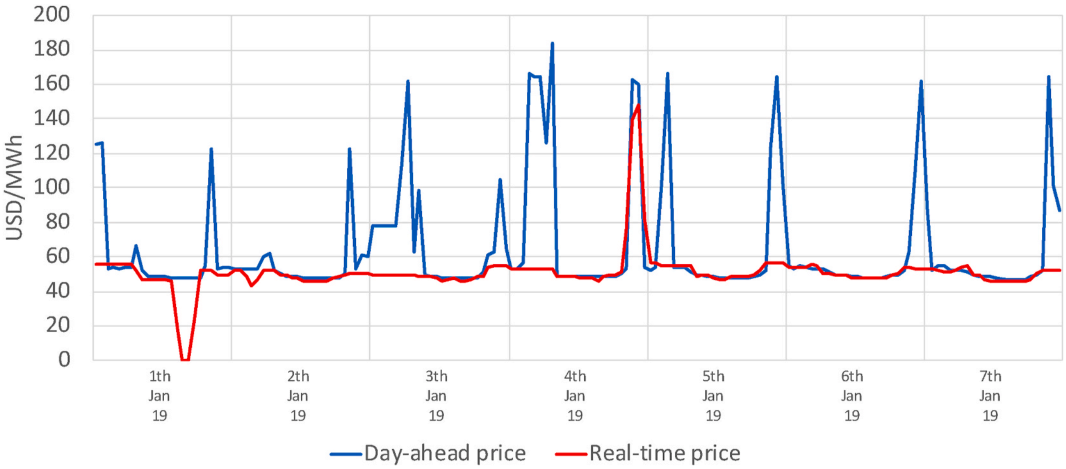

Fig. 4. Hourly cost-based DA and RT prices for the first in January 2019 at a reference bus in Chile (Crucero).

market and the existing cost-based RT market. Notice that, in general, RT prices are much more volatile than DA ones in two-settlements systems. However, in Chile, we observe that reference DA prices can be much more volatile than RT prices. This is because reference DA prices are computed considering security constraints that are not necessarily reflected in RT prices which, as we described in the previous sections, are determined ex post operations based on a merit-order curve.

The lack of a DA market can have multiple implications, here we illustrate just one of the possible disadvantages of only relying on a single-settlement mechanism based on RT prices. Consider the operation of two self-dispatched energy storage units of 10 MW of nominal capacity, with 1 and 4 h of storage capacity, with 93% round trip losses. These batteries are small enough for the size of the system, such that their operation would not change the hourly prices we show in Fig. 4. We consider two scenarios for operations. In the first scenario all transactions are settled at the RT, with DA prices only used as a reference signal. We assume that the storage units schedule their operations based on posted DA prices.[5] However, after operations, these units realize that the true energy price that was used for settling transactions was the RT price and not the DA one. This first scenario emulates operations in the current electricity market in Chile. In the second scenario, we assume that both energy storage units first participate in a hypothetical DA market, where transactions are settled at DA prices. Deviations from DA schedules are settled at the RT price. Table 4 shows net revenues for the two storage units under both scenarios, using the same series of DA and RT prices from Fig. 4.

Table 4 shows net revenues for both storage units under both scenarios. In scenario 1 the DA price is only used as a reference signal. Both energy storage units optimize their charge and discharge decisions based on DA prices, but end up receiving revenues that are 42% and 25% lower than what they would expect because all transactions are settled using ex-post RT prices. In contrast, in scenario 2 energy storage units take financial positions based on the DA price, but end up making dispatch decisions based on RT prices. Financial positions made in the DA market

---

[5] Note that this is only a worst-case scenario where firms only take positions based on DA prices. In reality, firms could learn over time about the type of deviations that occur between DA and RT prices and would take positions based on their risk preferences and their private views about price spreads between DA and RT markets.

Table 4

Net revenues for both energy storage units when all transactions are settled at the RT price (scenario 1) and when units can transact power both in the DA and RT markets (scenario 2). All values in million US dollars.

	Revenues scenario 1			Revenues scenario 2		
	DA	RT	DA-RT	DA	RT	Total
Unit type	[$m]	[$m]		[$m]	[$m]	[$m]
1-hr storage	1.292	0.748	−42%	1.292	0.641	1.933
4-hr storage	3.121	2.335	−25%	3.121	1.425	4.546

are cleared at the DA price and deviations from those positions are settled based on the RT price. Note that, in this case, the RT market provides additional revenues for both storage units.

Nevertheless, this analysis is only a marginal one because we assume that both DA and RT prices remain unchanged with the entry of these storage units. Also, we assume that DA prices will be computed using cost-based estimates with a centralized forecast used by the SO. In practice, most DA markets rely on bids from all market participants, which have incentives to arbitrage price differences away between DA and RT prices. In fact, electricity markets in the US now allow for financial or virtual participants that do not hold physical assets to participate in the DA market. The introduction of virtual bids a) provides options for agents with physical assets to hedge their positions, b) adds liquidity into both forward and RT markets, c) increases price convergence between forward and RT markets, and d) helps to mitigate market power due to structural factors (Woo et al., 2015; Li et al., 2015; Hogan, 2016).

Unlike restructured electricity markets in the US, electricity markets in Europe operate mostly based on bilateral transactions among buyers and sellers with more instances of forward trading prior operations, including intraday markets. Sequential trading allows market participants adjust their positions as new information becomes available, including features such as minimum generation limits (Wilson, 2002). Multiple forward markets also provide a broad menu of insurance options for market participants that are not risk neutral, which is a requirement for markets to operate efficiently under uncertainty (Mas-Colell et al., 1995). In theory, a sequence of forward markets can replicate the menu of financial securities that is needed to complete the market and achieve an efficient outcome (i.e., Arrow-Debreu securities) (Kreps, 1987; Duffie and Huang, 1985).

Here we do not state that introducing markets with more than two settlements or allowing agents to make virtual transactions in the electricity market in Chile should be the first priority. However, we want to highlight the importance of initially introducing one DA market in order to give agents options to hedge short-term risks and as a transparent mechanism to settle the costs of deviations from DA schedules, giving agents the right incentives to improve the quality of their forecasts. As highlighted in IRENA (2017), multi-settlement systems become important elements of electricity market designs for the efficient integration of variable and unpredictable generation from renewable resources. Consequently, regulators should be aware that adding one DA market is only a first step to improve the electricity market design in Chile and in other countries in Latin America. There is evidence that intraday markets could further improve economic efficiency by letting firms adjust their positions as new information (e.g., wind forecasts) becomes available between DA and RT markets (Karanfil and Li, 2017; Herrero et al., 2018).

Finally, the initial implementation of a DA market may only feature bids for quantities rather than sophisticated energy offer curves based on multiple price-quantity pairs, such as the ones used in bid-based markets. In principle, a cost-based DA market could potentially impose some limitations if cost-based estimates do not account for opportunity costs (Munoz et al., 2018). However, this type of DA market has the advantage that it is compatible with cost-based electricity market designs and is already being used in Mexico (Irastroza and Peñuelas, 2020). Although we do believe that moving from a cost-to a bid-based market is one of the key reforms to promote flexibility going forward, we argue that this transition is part of a less urgent set of modifications to the electricity market in Chile.

3.4. Inefficient pricing of carbon emissions

In 2017, Chile was the first country in South America to apply a tax on carbon emissions in the electric power sector with a tax rate of 5 $/tCO2. Unfortunately, the policy includes two indications that limit its efficiency as an instrument to reduce carbon emissions. The first indication is a pass-through restriction, which establishes that the dispatch and pricing of electricity in real time has to be done without consideration of the carbon tax. The second indication is a side-payment rule that helps units that face the carbon tax cover their short-term economic losses. According to this side-payment rule, the fraction of the carbon charge (i.e., carbon tax times emissions) that cannot be covered with the spot price must be prorated among all units in the system, in proportion to the demand they must supply based on existing long-term contracts or PPAs.

Consider the following example where we show the application of the current carbon pricing scheme used in Chile in 1 h. There are three generation units, A, B, and C, with marginal costs $MC_A = 10$, $MC_B = 30$, and $MC_C = 40$, all in $/MWh. The three units have capacities of 100 MW and carbon emissions factors $E_A = 0$, $E_B = 1$, and $E_C = 0.5$, all in tCO_2/MWh. Demand is perfectly inelastic and equal to 220 MW. We denote dispatch levels and profits q_i and π_i, respectively, for each generation unit $i \in \{A,B,C\}$. For simplicity, we apply the side-payment rule over injections q_i and ignore existing contractual obligations. This is equivalent to assume that the contracted volumes are equal to the equilibrium dispatch levels.

For a standard carbon tax we define the profit function of each firm i as follows:

$$\pi_i = (P - MC_i)\cdot q_i - T\cdot E_i\cdot q_i$$

For the current carbon tax used in Chile we define the profit function of each firm as follows:

$$\pi_i = \begin{cases} (P - MC_i)\cdot q_i - T\cdot E_i\cdot q_i - SP_i^- & \text{if } P \geq MC_i + T\cdot E_i \\ (P - MC_i)\cdot q_i - T\cdot E_i\cdot q_i + SP_i^+ - SP_i^- & \text{if } P < MC_i + T\cdot E_i \end{cases}$$

P denotes the spot price of electricity and T is the carbon tax. We refer to $T\cdot E_i\cdot q_i$ as the initial carbon charge faced by a generation unit. In a scenario without a carbon tax, the profit function of a firm is simply $\pi_i = (P - MC_i)\cdot q_i$. Under the current carbon tax used in Chile, generation units that cannot cover their short-run costs, including the carbon tax, are entitled a side payment $SP_i^+ \geq 0$. These side payments are funded by all firms in the system through side charges $SP_i^- \geq 0$, in proportion to their injections.[6]

Table 5 shows dispatch levels, short-term profits, spot prices, and carbon emissions in the system under three scenarios: no carbon tax, a standard carbon tax of 40 $/tCO_2$, and a carbon tax of 40 $/tCO_2$ under the current carbon policy used in Chile.

In the first scenario there is no carbon tax, units A and B are dispatched up to their nominal capacity (100 MW) and only 20 MW of unit C are needed to supply the 220 MW of demand. The spot price is equal to the marginal cost of unit C, 40 $/MWh, and carbon emissions are 110 tCO_2. All units make profits greater than or equal to zero in the short-term.

Consider now the second scenario, where we introduce a carbon tax of 40 $/tCO_2$ in the same system. Now the optimal dispatch changes and

---

[6] For more details about these administrative rules please refer to Diaz et al. (2020).

Table 5
Dispatch levels, short-term profits, spot prices, and carbon emissions under a system without a carbon tax, with a carbon tax, and under the current carbon policy used in Chile, denoted C.P.Ch.

Carbon policy	q_A [MW]	q_B [MW]	q_C [MW]	π_A [\$]	π_B [\$]	π_C [\$]	Spot price [\$/MWh]	Emissions [tCO_2]
No tax	100	100	20	3000	1000	0	40	110
Carbon tax	100	20	100	6000	0	1000	70	70
C.P.Ch.	100	100	20	1456	−1456	−309	40	110

units A and C—the ones with the lowest emissions factors—are used up to their nominal capacities, only 20 MW of unit B are needed to meet demand. This change in the dispatch order results in an emissions reduction of 40 tCO_2 compared to the previous scenario without a carbon tax. In addition, the spot price increases to 70 \$/MWh, reflecting the marginal cost of unit B plus the social cost of a marginal increase in carbon emissions, assuming that the carbon tax of 40 $\$/tCO_2$ reflects the true social cost of carbon. As we illustrate in Fig. 5 a), units A and C earn quasi-rents (green areas) as a result of the introduction of the carbon tax in the system. These quasi-rents incentivize further investments in these two technologies in the long term, which could lead to the displacement of technology B from the system and to further emissions reductions than what it is achieved in the short-term.

In the third scenario we implement the current carbon policy used in Chile, assuming the same tax rate employed before, 40 $\$/tCO_2$. As we show in Table 5, because of the pass-through restriction of the carbon policy, dispatch decisions remain equal to the first scenario, 110 tCO_2. Consequently, the current carbon policy used in Chile does not lead to carbon emissions reductions in the short term, regardless of the tax level. Furthermore, the pass-through restriction also prevents the spot price from reflecting the social cost of carbon. Therefore, the spot price is 40 \$/MWh, equal to the spot price in the scenario without a carbon tax.

A direct implication of the application of the pass-through restriction is that some of the units that face the carbon charge can be forced to operate at a loss in the short term. The blue-shaded areas in Fig. 5 b) show the fraction of the initial carbon charge faced by units B and C that cannot be recovered from the spot price. These losses are equal to \$3600. The side-payment rule establishes that theses losses must be prorated among all units, in proportion to the demand they must supply based on existing long-term contracts or PPAs.[7] Under perfect information we assumed that the contracted volumes are equal to the optimal dispatch levels displayed in Table 5, meaning that units A and B must bear 45.5% of the \$3600 in losses and unit C only 9% of them. As a result of the pass-through restriction and the side-payment rule, units B and C are forced to operate at a net loss in the short term. Furthermore, unit A, which has a carbon emission factor equal to zero, must bear part of the carbon charge faced by units B and C, leading to a reduction of profits from \$3000 (scenario with no carbon tax and spot price equal to 40 \$/MWh) to \$1456.

Naturally, the current carbon pricing policy used in Chile distorts long-term investment signals. In Diaz et al. (2020), the authors developed an equilibrium model to assess the long-term effects of the current carbon policy used in Chile and compared its performance to the first-best alternative, a carbon tax, assuming endogenous investments and perfect competition. Unsurprisingly, they find that for a hypothetical tax rate of 30 $\$/tCO_2$, imposing a pass-through restriction and a side-payment rule to redistribute losses results in nearly 150% more carbon emissions than what a standard carbon tax would yield for the same tax rate, but without any of those two restrictions. They also find that both carbon policies increase average electricity prices as the tax rate increases and that, for high tax rates, the current carbon policy used in Chile yields a higher average electricity price than a standard carbon tax that is accounted for in the dispatch and pricing of electricity in real time. This occurs because, under the Chilean carbon pricing scheme, distorted dispatch decisions and spot prices in the short term lead to inefficient entry of generation in the long term, which is reflected as higher average electricity than under the carbon tax. Interestingly, the authors in Diaz et al. (2020) also show that their results are sensitive to the case study and that, under a different set of assumptions, it is possible that the current carbon pricing mechanism used in Chile could result in an increase in carbon emissions with increasing tax rates, which contradicts the main purpose of the policy.

3.5. *Limitations of the current capacity mechanism*

Currently, Chile employs a capacity mechanism based on capacity payments that remunerates generation units based on an administrative estimate of the capital cost of a peaking generator. The aggregate revenues that are distributed as capacity payments depend on a) the peak demand level, b) a function that provides the desired level of installed reserves, and c) an administrative estimate of the capital cost of a reference peaking generation technology.

Each generation unit receives a capacity payment that is proportional to its nominal capacity derated by an availability factor. This availability factor is less than or equal to one and reflects historical information that includes forced outage rates, maintenance, fuel availability for thermal units, water availability and storage capability of hydroelectric power plants, and hourly generation factors for wind and solar generation.

While the procedure to compute capacity payments has the advantage of being transparent and quite simple, we identified the following limitations of the current capacity mechanism going forward:

- *No clear reliability target:* Although the current regulation makes reference to indices such as the Loss of Load Probability (LOLP), there is no explicit reliability target to aim for. The function that describes the desired reserve margin is decreasing on the installed reserve margin, with a 10% floor.[8] This means that the capacity payment per MW of firm capacity (i.e. nominal capacity adjusted by an availability factor) is always strictly greater than zero, regardless of how large the reserve margin of the system is. Additionally, the Value of Lost Load employed to assess the social cost of short- and long-term outages does not seem to have clear relationship with the willingness to pay for firm capacity implied by the current mechanism of capacity payments.
- *No clear product definition:* This limitation is directly related to the previous one, mainly because the lack of a clear reliability target makes it difficult to define a capacity product that makes sense from an economic point of view. Fixing this issue will ensure that all

---

[7] We want to highlight that the current side-payment rule applies over annual and not hourly losses, with the exception of losses that result from constraints such as minimum running limits, which are active over large fraction of the hours when coal plants operate. Nevertheless, the initial design applied the side-payment rule over hourly losses.

[8] The function is known as the Theoretical Reserve Margin or MRT (in spanish). If r is the installed reserve margin expressed as a fraction of the peak demand level, then $MRT(r) = 0.15 - r/5$ if $r \leq 0.25$ and $MRT(r) = 0.1$ if $r > 0.25$.

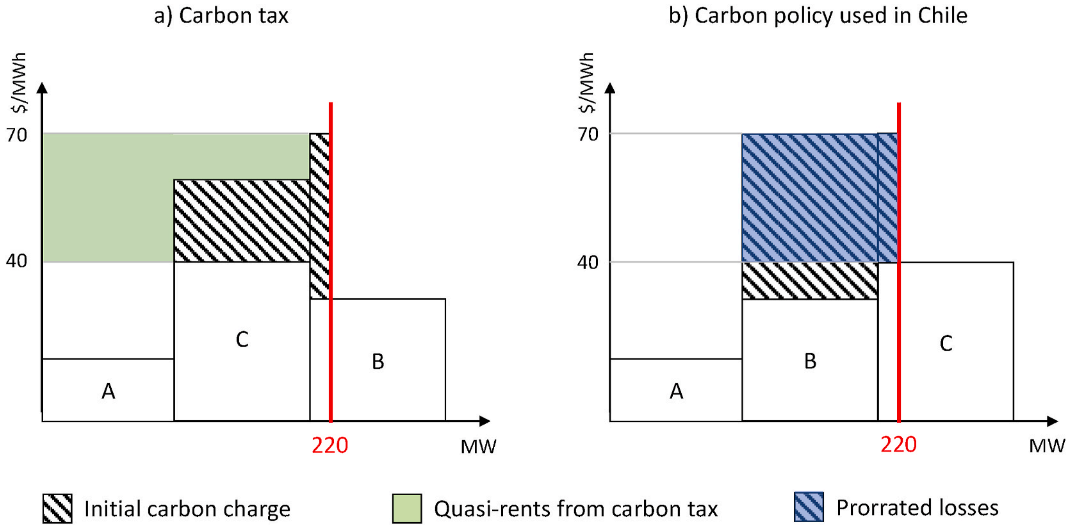

Fig. 5. Application of a carbon tax and the carbon policy used in Chile to a simple system with three generation technologies. Note that the initial carbon charge $T \cdot E_i \cdot q_i$ does not account for side payments SP_i^+ or side charges SP_i^-.

technologies are remunerated based on the same criterion, guaranteeing that all MWs of firm capacity provide the same contribution towards a resource-adequacy target.

- *Resource eligibility:* Under the current design, only generation units are entitled to receive capacity payments; the mechanism does not consider firm capacity contributions from demand resources or pure merchant storage units. This is a clear limitation since it has been demonstrated that both demand resources and storage technologies can contribute to meet resource adequacy targets (Sioshansi et al., 2013). For instance, for the year 2015/2016, more than 14,000 MW of emergency demand response were committed in PJM's forward capacity market, which represented nearly 8% of all capacity supply for the same period (Ott, 2017). Additionally, FERC Order 841 now requires all grid operators in the US to allow participation of storage units in energy, ancillary services, and capacity markets on a nondiscriminatory basis (FERC, 2019).
- *Definition of hours to determine capacity credits:* The peak demand used to determine aggregate capacity payments is computed as the average demand over the 52 h with the highest demand levels over a year. These 52 h are then used as a proxy to determine the hours with the highest LOLP of the system. While this heuristic was a good approximation to find the periods with the highest LOLP for power systems with a large share of generation from thermal units, it is not necessarily a good rule for systems with increasing shares of generation from hydro, wind, or solar resources. Munoz and Mills (2015), for instance, show that with increasing shares of variable and unpredictable generation from solar generation, the periods with the highest LOLP show more coincidence with peak net-demand hours (i.e., demand minus wind and solar generation) than with the peak demand hours. Different definitions of hours to measure firm capacity can lead to inefficient investments signal, which is finally reflected as higher system costs than under a definition of firm capacity that considers the incremental contribution of each resource towards a resource-adequacy target (Bothwell et al., 2017).
- *Upper bound on capacity credits for renewables:* Under the current regulation, wind and solar resources receive a capacity credit that is proportional to the minimum between the minimum annual capacity factor from the previous five years and the capacity factor of the unit during the 52 h of peak load demand. Besides the limitations of using the 52 h of peak demand hours to measure the capacity credit of renewables mentioned in the previous point, this rule imposes a ceiling on the fraction of the nominal capacity of wind and solar units that is eligible for a capacity payment. For instance, a hypothetical hybrid solar + storage unit of 100 MW with 8 h of storage could have nearly perfect coincidence with the hours of highest LOLP of the system, thereby contributing to the definition of resource adequacy used in most electricity markets. However, if its minimum annual capacity factor from the previous five years is only 30%, then at most 30 MW of the unit would be eligible to receive a capacity payment.

Some of these limitations could be addressed with incremental improvements to the current capacity mechanism. For instance, the demand curve for firm capacity could be developed following some economic principle, such as aiming for a clear resource-adequacy target. In PJM, the Variable Resource Requirement (VRR) Curve is anchored at a point known as the Net Cost of New Entry (NCNE), which reflects the difference between the capital cost of building new capacity of a reference technology minus the expected revenues that such unit could receive from energy and ancillary services. The NCNE is the maximum willingness to pay for an incremental unit of firm capacity, up the total level that is needed to meet PJM's resource-adequacy target (maximum outage of 1 day in 10 years, translated into a 0.1 Loss of Load Expectation (LOLE)). Reserves above the ones needed to fulfill the target are valued below the NCNE with a downward-sloping curve, up to a point where the willingness to pay for additional reserves is equal to zero.

Fig. 6 illustrates the differences between the demand for firm capacity in PJM for the 2021/2022 base residual auction, known as the VRR curve, and our own estimate of the willingness to pay for firm capacity in Chile.[9] Note that the VRR curve of the 2021/2022 base residual auction in PJM (gray curve in Fig. 6) shows a clear target of installed reserve margin, 16% approximately. The willingness to pay for installed reserve margins above that level decreases very rapidly and becomes zero for levels higher than 25%. In contrast, the demand curve for firm capacity under the current regulation in Chile (blue curve in Fig. 6) decreases very slowly as we increase the level of the installed reserve margin, showing no clear reliability target. Removing the floor of 10% used in the function to determine the desired reserve margin (orange

---

[9] We determined the demand curve for firm capacity in Chile assuming that the cost of new entry is 242 $\$/MW - day$. This assumption is based on the capital cost of a new 70 MW diesel turbine and the related transmission interconnection costs for the unit used in a recent study by the National Energy Commission (CNE, 2019b). We also assumed that the peak demand of the system is 10.000 MW, which is close to the peak demand for electricity in the main interconnected system in Chile in 2018.

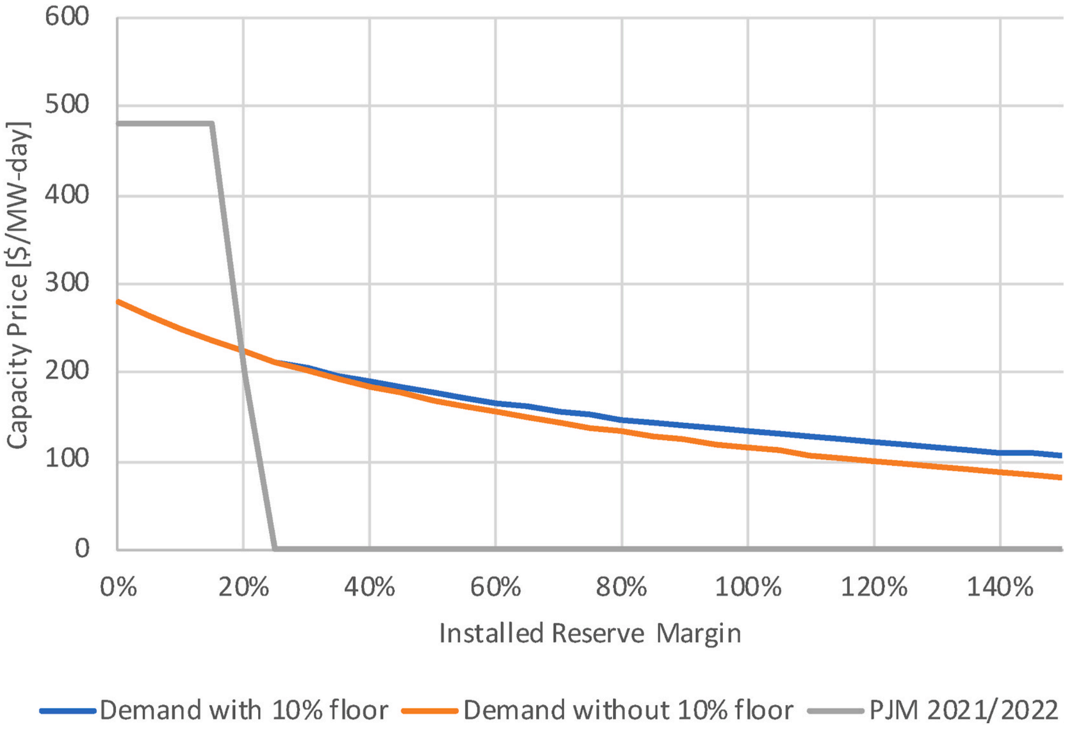

Fig. 6. Demand curves for firm capacity in Chile and the 2021/2022 base residual auction in PJM. Installed Reserve Margin calculated based on firm capacity.

curve) only results in a marginal change in the shape of the demand function.

This rather flat demand curve for firm capacity provides steady and predictable revenue streams for generators, an attractive feature of the capacity mechanism for investors that are highly risk averse (Höschle et al., 2018). However, the shape of the curve can distort investment incentives for the efficient entry and exit of generation units. For instance, such demand curve for firm capacity could be one of the factors that explain recent investments in additional diesel units (REI, 2019). The profitability of these investments came as a surprise, considering that the installed reserve margin of the system in 2018 was already nearly 65% (CNE, 2019b).[10] High capacity payments could also distort long-run contract prices if firms internalize such payments in bilateral negotiations or public auctions for PPAs. Therefore, we consider that defining a clear resource-adequacy target and developing a demand curve that reflects such target should be a first priority for an efficient electricity market design in Chile.

We also recommend improving estimates of capacity credits for renewables using a reliability-based approach such as the ones described in Madaeni et al. (2012), Munoz and Mills (2015), and Bothwell et al. (2017). Other improvements include allowing for demand-side resources and storage technologies to participate in the capacity mechanism. These changes will ensure that all resources have incentives to contribute to the system's resource-adequacy target.

Switching to a market-based capacity auction could also improve upon the efficiency of the current capacity mechanism. In a capacity auction, the capacity price is determined endogenously by the intersection of a supply curve that—in a competitive environment—reflects the net incremental cost of providing an additional unit of firm capacity and a demand curve that approximates the consumers' willingness to pay for the product. An illustrative example of the power of market-based mechanisms for price discovery is the 2014 capacity auction in the UK. The auction cleared at a price that was only 40% of the net cost of new entry in the system estimated by National Grid. The net cost of new entry was based on an administrative estimate of the cost of a combined-cycle gas turbine. In spite of a market-clearing price that was much lower than the administrative estimate by National Grid, two combined-cycle gas units supplied more than 50% of the capacity cleared in the auction (Newbery, 2016).

Lastly, it is also important to keep in mind the limitations of capacity mechanisms, particularly under the ongoing transformation of power systems worldwide. For instance, capacity mechanisms tend to suppress energy prices, which reduces incentives for market participants to react to those prices by either increasing generation levels or decreasing consumption. Forward capacity markets can increase economic efficiency in risky settings, acting as a hedging instrument (Höschle et al., 2018). However, it is not clear if such benefits still exist when there are liquid markets of other financial instruments to hedge risk, such as PPAs (De Maere d'Aertrycke et al., 2017). Mays et al. (2019) show that current capacity mechanisms favour technologies with low fixed costs and high fuel costs (e.g., diesel units), making it difficult to support investments in low-carbon technologies with high capital costs and near-zero operating costs. Governance issues are also a concern if market participants can have an influence on design features of capacity mechanisms or estimates of peak demand levels in forward auctions (Yoo and Blumsack, 2018). Furthermore, integrating demand resources or energy efficiency measures into capacity auctions is difficult because it requires defining some baseline from where to measure "demand reductions'', which creates odds incentives for demand resources (Bushnell et al., 2009). Also, even though we refer to some features of capacity market in PJM as potential improvements to the capacity mechanism in Chile, some of those features have been subject of strong criticism (Hogan, 2019). In fact, a recent study from the US Government Accountability Office concludes that FERC does not have enough data to evaluate the performance of capacity markets in the US (USGAO, 2017).

For all of these limitations, we recommend regulators to see capacity mechanisms as a complementary measure, but not as the only tool, to

---

[10] Note that the installed reserve margin is computed following the rules to estimate firm capacity described previously. This means that, for instance, the installed reserve margin already accounts for derating capacity factors of renewable resources and the risk of low availability of hydro resources for generating electricity.

incentivize investments and achieve resource adequacy targets, particularly under the current transition to a low-carbon power system. Ensuring liquidity in markets for forward contracts, as well as enhancing short-term price signals through scarcity-pricing mechanisms such as Operating Reserve Demand Curves, are other measures that should not be overlooked and that could avoid an excessive reliance on capacity mechanisms to attract investments and to remunerate attributes such as flexibility in an efficient manner (De Maere d'Aertrycke et al., 2017; Hogan, 2013; Mays et al., 2019).

4. Further room for improvement

We now include a second set of limitations that should be addressed after the ones listed in the previous section. Here we discuss measures that include the implementation of markets for attributes such as ramping capability, improving administrative mechanisms for scarcity pricing, allowing for demand participation in wholesale markets, and an eventual transition from a cost-to a bid-based market. From our perspective, implementing elements of this second set of proposals before the ones listed in the previous section will not necessarily improve price signals or investment incentives. For example, there is no guarantee that a transition to a bid-based market will improve market efficiency if agents are expected to include their own private expectations of the impact of physical constraints that are not accounted for in the current dispatch and pricing mechanism because of design features (e.g., hourly time resolution, pricing based on a merit-order curve, no day-ahead market, etc.). Therefore, our recommendation is to first address the limitations listed in the previous section and to consider this second set of proposals afterwards.

4.1. Remuneration of flexibility under uncertainty: ramping products

As we discussed in Sections 3.1 and 3.2, pricing spot transactions based on optimization software that considers most of the physical characteristics of the system—including intertemporal constraints (e.g., ramping limits)—ensures that flexibility is accurately remunerated under variable conditions. However, under uncertainty, such prices might not reflect the true value of flexible resources to the system.

From a theoretical perspective, stochastic dispatch and unit commitment models provide the optimal solution to the problem of making dispatch and commitment decisions under uncertainty. Unlike deterministic dispatch and commitment models, stochastic models choose the optimal levels and location of reserves endogenously, based on the possibility of forecast errors of demand, wind, and solar conditions (Papavasiliou et al., 2011; Papavasiliou and Oren, 2013). Unfortunately, in practice, stochastic dispatch and commitment models lack stakeholder acceptance and still require significant computational improvements in order to be used at scale. For this reason, most system operators deal with uncertainty through a combination of deterministic dispatch and commitment software and a variety of exogenous requirements for reserve products and services that typically include synchronized and non-synchronized reserves as well as frequency regulation.

Ramping products are an example of requirements that have been developed specifically in response to the increasing penetration of variable and unpredictable generation from renewables. Since 2016 the California ISO and the Midcontinent ISO in the US employ ramp products to ensure that resources that are capable of providing ramp products are pre-positioned to accommodate the variability and uncertainty of demand, wind, and solar conditions. Ramp products also provide an additional source of remuneration for resources that can offer this service, thus incentivizing resource flexibility in the short term and strengthening investment signals in the long term.

We believe that the introduction of a ramp product could enhance price signals in the electricity market in Chile, particularly when considering the more frequent occurrence of steep ramp events due to the increasing shares of generation from solar and wind resources. According to Wang and Hobbs (2014) and Wang and Hobbs (2015) the introduction of flexiramp products increase market efficiency with respect to the alternative of using standard deterministic dispatch and unit commitment models with static reserves. However, the authors of these studies also highlight that the performance of these products is sensitive to the choice of parameters. Therefore, the implementation of ramping products would first require a thorough assessment of the effects of the introduction of these products, paying attention to the potential requirements for different hours of the day, seasons, and locations in the network.

4.2. Scarcity pricing through operating reserve demand curves (ORDCs)

If used appropriately, the introduction of reserve requirements in deterministic dispatch and commitment models can capture a large fraction of the efficiency improvements that result from employing stochastic models. However, the price signals that result from deterministic models do not necessarily reflect the true incremental value of reserve products for the system. For instance, in a deterministic dispatch or commitment model, a static reserve requirement of 300 MW translates into a vertical demand curve where every additional MW of the product has zero value for the system. This is obviously an artifact of the modeling assumptions, because, in practice, every additional MW of reserves available in the system reduces the likelihood of load curtailment under contingency events (e.g., failure of a generator, loss of a major transmission line, or the reduction of a large share of wind or solar generation in a short time frame). Since the value that society puts on electricity consumption, i.e., the Value of Lost Load (VOLL), is strictly greater than zero, the incremental value of reserves that could reduce the probability of a loss event, i.e., the Loss of Load Probability (LOLP), also has to be greater than zero when reserves are not abundant.

One alternative to address this limitation of static reserve products in deterministic models is to introduce sloped Operating Reserve Demand Curves (ORDCs). A sloped ORDC is an administrative estimate of the incremental value of reserves for the system derived from first economic principles, considering both the VOLL and the LOLP for different levels of reserves. Sloped ORDCs such as the ones described in Hogan (2013) are currently employed in ERCOT (Hogan and Pope, 2017) and Mexico (SE, 2016) in North America, they are also under consideration in the PJM market (PJM, 2019) and in Belgium (Papavasiliou and Smeers, 2017). In particular, PJM justifies the introduction of sloped ORDCs because "… *(c)urrent reserve market clearing prices (are) zero in about 60 percent of all hours for Synchronized Reserve and in about 98 percent of all hours for Non-Synchronized Reserve. (Consequently, these prices) do not reflect the operational value of resource flexibility*" (PJM, 2019).

Sloped ORDCs have two additional advantages. First, the introduction of sloped ORDCs in bid-based markets allows system operators to increase prices during scarcity events without the need to rely on high bids from generation firms (Cramton, 2017). This is also an advantage for cost-based markets where prices are determined by the marginal cost of the most expensive generation unit operating in the system. Second, sloped ORDCs can also enhance price signals when system operators engage in out-of-market actions that affect the LOLP of the system (Hogan, 2013).

From our perspective, we see a window of opportunity to introduce sloped ORDCs in the emerging markets for reserves in Chile. With the increasing share of generation from wind and solar resources, periods where electricity prices are zero are becoming much more frequent. Consequently, scarcity pricing mechanisms, such as the introduction of sloped ORDCs, will have a growing impact on investment incentives and will provide the right price signals to harness flexibility from energy storage devices and demand-side resources in electricity markets.

4.3. Allowing for demand participation in wholesale markets

Currently, demand-side resources are not allowed to participate directly in wholesale transactions in Chile, only generation firms can buy and sell power in the spot market. While large customers have the option to be exposed to spot prices through PPAs with partial or total indexation to real-time prices—using generation firms as intermediaries—they face several barriers to participate in the markets for energy and ancillary services and in the current capacity mechanism. This is a costly limitation considering the large potential benefits of increasing levels of demand participation in electricity markets, including response from various distributed energy resources (DER) such as distributed energy storage, distributed generation, and flexible demand from electrified transport and heat/cooling sectors (Moreno et al., 2017b).

A recent study by The Brattle Group finds that an effective integration of demand-side flexibility into electricity markets in the US could yield savings of $15 billion per year by 2030 (Hledik et al., 2019). Nearly 57% of these savings would come from avoided generation capacity investment for periods of peak demand or in transmission-constrained locations. In Europe, Faruqui et al. (2010) estimate that improving demand participation in electricity markets and increasing the adoption of dynamic tariffs could save more than €50 billion in a 20 year period.

These large benefits have been the main driver for the creation of new market platforms that allow system operators to harness the flexibility of demand-side resources. In 2011, FERC issued Order 745, which required that demand response “*… must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP).*” (FERC, 2011). Today, all of the major electricity markets in the US have mechanisms in place that allow demand resources to participate in some or all of the markets coordinated by system operators, including day-ahead, real-time, ancillary services, and capacity markets (Flores-Espino et al., 2016).

However, demand participation in wholesale markets requires a bid-based market design, at least for the demand side of the market. Considering that Chile relies on a one-sided cost-based market design for the dispatch and pricing of electricity in real time, allowing for demand participation in energy, ancillary services, and in the capacity mechanism would require the adoption of some form of bidding mechanism.

4.4. Transitioning to a bid-based market

The potential transition from a cost-to a bid-based electricity market design in Chile has been on ongoing debate since the early 2000s. In fact, the topic has received lots of attention from the research community. For example, Villar and Rudnick (2003), Barquin et al. (2003), and Arellano (2005) all employed equilibrium models that aimed at predicting how generation firms could exercise market power if the Chilean electricity market were to switch to a bid-based mechanism. These studies concluded that the high concentration of ownership in the generation market would have allowed large incumbent firms to exercise market power, particularly the ones that owned large hydro units. Results from these studies, combined with the lack of experience monitoring electricity markets and the precedent of the electricity crisis in California in 2000–2001, were probably enough reasons for the regulator to disregard the option to switch to a bid-based market.

However, many aspects of the electricity market in Chile have changed since the early 2000s. While the concentration of ownership in the generation market is still high based on standard concentration measures, it has decreased substantially with the entry of new generation firms, most of which own solar and wind generation assets. In fact, the installed generation capacity has more than tripled from 2000 to 2019. Additionally, most industrial demand and all retail consumers buy electricity through forward contracts or PPAs that are not indexed to spot prices. This is an important new feature of the electricity market in Chile because there is ample evidence that forward contracts are very effective instruments to reduce the incentives of generation firms to exercise market power in the short term (Wolak, 2000; Bushnell et al., 2008).

A retrospective analysis of the California crisis also provides insights about the market design and regulatory flaws that should be avoided when implementing bid-based electricity markets. As pointed out by Bushnell (2004), the distinctive feature of the California market right before the crisis was the lack of forward contracts between electricity retailers and generators. Other elements that exacerbated the crisis include the concentration of ownership, a flawed market design that did not reflect the physical constraints of the system, and a lack of demand participation. Yet, these last three features have been present in other markets that have not experienced issues with the exercise of unilateral market power, at least, not to the extent it manifested itself in California during the crisis.

Measures to monitor and mitigate market power have also improved substantially since the California crisis. For example, all electricity markets in the US have market monitoring departments that continuously monitor unexpected changes in bidding conduct with respect to historical patterns. They also mitigate the potential exercise of market power using cost-based estimates of generation costs at times or locations where market competitiveness tests are not met. In other words, they still rely on a cost-based market when they estimate that market forces are unlikely to guarantee competitive outcomes.

The cost-based markets that are currently used in Chile and in many other countries in Latin America have some virtues. They are relatively simple to implement and are very effective at preventing the type of strategic behavior that regulators are most sensitive to: strategic bidding in spot markets. Cost-based markets seem appropriate for very small systems without an active market for forward contracts or for countries with weak institutions that do not have the resources (e.g., human capital) needed to run sophisticated market monitoring groups such as the ones used in the US. El Salvador is probably the only example in the world of an electricity market that started as a cost-based market, that then switched to a bid-based market, and that ultimately transitioned back to a cost-based market because of the costly exercise of unilateral market power by the few firms in the market. In the US, cost-based markets also served as an intermediate step in the transition from the previous regulatory structure to competitive bid-based markets (Hogan, 2019).

Nevertheless, cost-based markets have important limitations. In cost-based systems it is very difficult to determine prices that reflect all the opportunity costs of generators and not just the directly attributable marginal cost from fuel expenses. These opportunity costs can arise from intertemporal limits on generation (e.g., maximum number of starts in a time window or energy-storage constraints that link consecutive periods of operation), inflexible fuel contracts (e.g., take-or-pay clauses), as well as from renewable or environmental policies that are difficult to audit by the system operator and that become relevant in a transition to a low-carbon system. Furthermore, cost-based markets do, effectively, prevent one form of strategic behavior. Yet, in a cost-based market generators can still exercise market power through other strategic decisions (e.g., investments, fuel contracts, reporting of technical parameters, etc.) Munoz et al. (2018); Fernández et al. (2020).

Given these conditions, we hypothesize that Chile could transition to a bid-based electricity market without the risk of running into a crisis such as the one in California in 2000–2001. As mentioned earlier, the extensive use of forward contracts between consumers and generators substantially reduces the incentives for generation firms to exercise unilateral market power in short-term markets. Also, the current cost-based system can still be used as a backstop anytime the market is deemed non-competitive, just as in electricity markets in the US.

Computer simulations with models of imperfect competition could be used to explore the validity of our hypothesis (Bushnell et al., 2008; Helman and Hobbs, 2010). Such models would provide information about the conditions in which generators would have incentives to exercise market power, considering transmission constraints, different levels of demand and hydro conditions, and, most importantly, existing forward contracts. Ignoring this last feature, forward contracts, could lead to a large overestimation of the inefficiencies that would result as a consequence of strategic behavior in spot markets (Bushnell et al., 2008).

We also recommend the market monitor to conduct a thorough analysis on the potential application and effectiveness of impact tests employed in most markets in the US if applied in Chile. For example, a direct application of pivotal tests in Chile would disregard the extensive use of forward contracts in the country, which could lead to over-mitigation of bids. Monitoring bidding behavior of firms that own large hydro units would also require tools that differ from the ones used in electricity markets in the US. It is because of these conditions that, in a hypothetical transition to a bid-based system, we would recommend monitoring the market using a combination of simple tools, such as pivotal tests, and computer simulations.

5. Conclusions and policy implications

Decarbonization targets and large reductions in the cost of renewable energy technologies are driving a deep transformation of electric power systems. While the foundational theory to design efficient electricity markets is, in general, well understood, the characteristics of low-carbon resources raise questions about the ability of current market designs to attract efficient investments and to incentivize flexibility to accommodate the intermittency and unpredictability of wind and solar resources. Regulators in the US and in Europe are already addressing some of these challenges with a series of reforms aimed at improving price formation, scarcity pricing, resource adequacy, and carbon-pricing mechanisms. However, electricity markets in Latin America are lagging behind this transformation of electricity and environmental market designs. Failing to address these new challenges will result in distorted price signals for resources that could impart flexibility, leading to inefficient entry and exit of generation resources and increasing the cost of achieving decarbonization targets in the next decades.

In this paper, we focus on five main features of the electricity market design in Chile that should be improved in order the incentivize efficient entry of low-carbon and flexible resources. Our first two recommendations—computing prices using optimization software and increasing the temporal granularity of spot prices—point at reconciling the spot market with the physics of the system. This is a first step to ensure that resources that provide flexibility are adequately remunerated for their services in the spot market (e.g., energy storage). Our third recommendation is the introduction of a day-ahead market to settle deviations. This two-settlement system—common in electricity markets in the US—would allow all market participants to hedge their positions in real time based on the available forecasts for the next day. However, with increasing shares of generation from renewables it might also be worth considering additional settlements, such as intraday markets. We also recommend correcting the administrative restrictions on the current carbon pricing mechanism since it has been demonstrated that such restrictions lead to inefficient entry and exit of generation resources (Diaz et al., 2020). Our last main recommendation is to improve the capacity mechanism, ensuring that the demand curve for firm capacity reflects a preference for a resource-adequacy target based on the value of lost load used in the system. Improving the capacity mechanism will also require that all resources are treated equally, computing their firm capacity contribution based on some reliability metric.

We also list further possibilities for improvements that should be considered after addressing our first five recommendations. These include the introduction of specialized reserve products for ramp capability and a sloped operating reserve demand curves to enhance price formation during periods of scarcity, allowing for participation of demand resources in wholesale products, and a potential transition to a bid-based market design. While we believe that the transition to a bid-market would enhance price formation, we recognize that there are many other features that could be improved without the need to abandon the current cost-based design.

Due to space limitations, we decided to leave other issues related to the current electricity market design and regulation in Chile out of our discussion. Some of these include mechanisms for the recovery of fixed operating costs of generation units (O'Neill et al., 2005; Herrero et al., 2015), the design of markets for ancillary services (Muñoz and Harrison, 2020), the treatment of inflexible fuel contracts in the dispatch and pricing of electricity, the potential for the exercise of market power through fuel imports (Fernández et al., 2020), the effect of policy uncertainty on investment decisions (Bergen and Muñoz, 2018), the impact of model simplifications upon planning decisions for new technologies such as energy storage (Pereira-Bonvallet et al., 2021; Díaz et al., 2019), and the design of auctions for long-term contracts for retail customers (Reus et al., 2018). We also highlight the need to reform the existing mechanisms to regulate the distribution and retail sectors. A modern regulation could give firms incentives to increase the reliability of distribution networks and enable the participation of distributed and demand-side resources in wholesale markets (Moreno et al., 2020). These are all issues that should be addressed in future studies.

Finally, we want to highlight that while some of our suggested improvements are rather specific to the Chilean electricity market (e.g., correcting the design of the current carbon tax), there are many other countries in Latin America and Asia that have electricity markets designs that could also benefit from what we discuss in this paper. For instance, the Brazilian government recently proposed a power sector reform that includes a transition to more granular spot prices, proposing a change from weekly to hourly prices. According to the proposal, such measure will allow spot prices to better reflect the actual system's conditions under increasing shares of generation from variable renewable energy sources (Batlle et al., 2018; Rodilla et al., 2018).

CRediT authorship contribution statement

Francisco D. Muñoz: Conceptualization, Methodology, Supervision, Writing - original draft, Writing - review & editing, Project administration, Funding acquisition. **Carlos Suazo-Martínez:** Conceptualization, Writing - review & editing. **Eduardo Pereira:** Software, Formal analysis, Data curation, Visualization. **Rodrigo Moreno:** Conceptualization, Writing - review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

This research was supported by CONICYT FONDECYT #1190228, FONDECYT #1181928, ANID/PIA/ACT192094, ANID/FONDAP/15110019 (SERC-CHILE), ANID-Basal Project FB0008, and the Complex Engineering Systems Institute (ANID PIA/APOYO AFB180003). We thank Pablo Serra, Serguey Maximov, and two anonymous referees for useful comments that helped us improve previous versions of this paper.

References

Arellano, M.S., 2005. Reformando el sector eléctrico chileno: Diga No a la liberalización del mercado spot. Estud. Publicos (99), 63–96.

Barquin, J., Centeno, E., Lopez-Nicolas, A., Quinteros, R., 2003. Forecasting the Chilean short-term electricity market behavior under a new proposed regulation. In: 2003 IEEE Bologna Power Tech Conference Proceedings, vol. 4. IEEE, p. 7.

Batlle, C., Pires, M., Rodilla, P., Tomé, J., 2018. Brazil considers reform of the electricity sector. Oxf. Energy Forum 21–24.

Bergen, M., Muñoz, F.D., 2018. Quantifying the effects of uncertain climate and environmental policies on investments and carbon emissions: a case study of Chile. Energy Econ. 75, 261–273.

Borenstein, S., Bushnell, J., Wolak, F.A., Zaragoza-Watkins, M., 2019. Expecting the unexpected: emissions uncertainty and environmental market design. Am. Econ. Rev. 109 (11), 3953–3977.

Bothwell, C., Hobbs, B.F., et al., 2017. Crediting wind and solar renewables in electricity capacity markets: the effects of alternative definitions upon market efficiency. Energy J. 38 (KAPSARC Special Issue).

Bronfman, N.C., Jiménez, R.B., Arévalo, P.C., Cifuentes, L.A., 2012. Understanding social acceptance of electricity generation sources. Energy Pol. 46, 246–252.

Bushnell, J., 2004. California's electricity crisis: a market apart? Energy Pol. 32 (9), 1045–1052.

Bushnell, J., Hobbs, B.F., Wolak, F.A., 2009. When it comes to demand response, is FERC its own worst enemy? Electr. J. 22 (8), 9–18.

Bushnell, J.B., Mansur, E.T., Saravia, C., 2008. Vertical arrangements, market structure, and competition: an analysis of restructured US electricity markets. Am. Econ. Rev. 98 (1), 237–266.

CDEC-SIC, 2014. Estudio de operación de la zona norte del SIC en el periodo 2014-2017. URL. https://sic.coordinador.cl/wp-content/uploads/2014/06/Informe-DO-04-Operacion-Zona-Norte-con-ERNC-2014-20171.pdf.

CNE, 2019a. Anuario Estadístico de Energía. Comisión Nacional de Energía. URL. https://www.cne.cl/wp-content/uploads/2019/04/Anuario-CNE-2018.pdf.

CNE, 2019b. Fijación de Precios de Nudo de Corto plazo. Comisión nacional de Energía. URL. https://www.cne.cl/en/tarificacion/electrica/precio-nudo-corto-plazo/.

Cramton, P., 2017. Electricity market design. Oxf. Rev. Econ. Pol. 33 (4), 589–612.

De Maere d'Aertrycke, G., Ehrenmann, A., Smeers, Y., 2017. Investment with incomplete markets for risk: the need for long-term contracts. Energy Pol. 105, 571–583.

Denholm, P., Hand, M., 2011. Grid flexibility and storage required to achieve very high penetration of variable renewable electricity. Energy Pol. 39 (3), 1817–1830.

Díaz, Gabriel, Inzunza, Andrés, Moreno, Rodrigo, 2019. The importance of time resolution, operational flexibility and risk aversion in quantifying the value of energy storage in long-term energy planning studies. Renew. Sustain. Energy Rev. 112, 797–812.

Diaz, G., Muñoz, F.D., Moreno, R., 2020. Equilibrium analysis of a tax on carbon emissions with pass-through restrictions and side-payment rules. Energy J. 41 (2), 65–94.

Duffie, D., Huang, C.-F., 1985. Implementing Arrow-Debreu equilibria by continuous trading of few long-lived securities. Econometrica 53 (6), 1337–1356.

EC, 2016. Evaluation Report Covering the Evaluation of the EU's Regulatory Framework for Electricity Market Design and Consumer Protection in the Fields of Electricity and Gas. Part 1/2. SWD(2016) 412 final. European Commission. URL. https://ec.europa.eu/energy/sites/ener/files/documents/2_en_autre_document_travail_service_part1_v2_1.pdf.

Ela, E., Milligan, M., Bloom, A., Botterud, A., Townsend, A., Levin, T, 2014. Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation. Technical Report NREL/TP-5D00–61765 National Renewable Energy Lab. NREL, Golden, CO (United States).

Estache, A., Wren-Lewis, L., 2009. Toward a theory of regulation for developing countries: following Jean-Jacques Laffont's lead. J. Econ. Lit. 47 (3), 729–770.

Faruqui, A., Harris, D., Hledik, R., 2010. Unlocking the €53 billion savings from smart meters in the EU: how increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment. Energy Pol. 38 (10), 6222–6231.

FERC, 2011. Docket No. RM10-17-000; Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets. Federal Energy Regulatory Commission. URL. https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf.

FERC, 2016. Docket No. RM15-24-000; Order No. 825, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators. Federal Energy Regulatory Commission. URL. https://www.ferc.gov/whats-new/comm-meet/2016/061616/E-2.pdf.

FERC, 2019. Docket Nos. RM16-23-001; AD16-20-001; Order No. 841-A, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. Federal Energy Regulatory Commission. URL. https://www.ferc.gov/whats-new/comm-meet/2019/051619/E-1.pdf.

Fernández, M., Muñoz, F.D., Moreno, R., 2020. Analysis of imperfect competition in natural gas supply contracts for electric power generation: a closed-loop approach. Energy Econ. 87, 104717.

Flores-Espino, F., Tian, T., Chernyakhovskiy, I., Chernyakhovskiy, I., Miller, M., 2016. Competitive Electricity Market Regulation in the united states: A Primer. Tech. Rep. National Renewable Energy Lab.(NREL), Golden, CO (United States).

Grubb, M., Neuhoff, K., 2006. Allocation and competitiveness in the EU emissions trading scheme: policy overview. Clim. Pol. 6 (1), 7–30.

Helman, U., Hobbs, B.F., 2010. Large-scale market power modeling: analysis of the US eastern interconnection and regulatory applications. IEEE Trans. Power Syst. 25 (3), 1434–1448.

Herrero, I., Rodilla, P., Batlle, C., 2015. Electricity market-clearing prices and investment incentives: the role of pricing rules. Energy Econ. 47, 42–51.

Herrero, I., Rodilla, P., Batlle, C., 2018. Enhancing intraday price signals in US ISO markets for a better integration of variable energy resources. Energy J. 39 (3), 141–165.

Hirth, L., Ueckerdt, F., Edenhofer, O., 2015. Integration costs revisited–an economic framework for wind and solar variability. Renew. Energy 74, 925–939.

Hledik, R., Faruqui, A., Lee, T., Higham, J., 2019. The National Potential for Load Flexibility: Value and Market Potential through 2030. The Brattle Group.

Hogan, W., 2019. Strengths and Weaknesses of the PJM Market Model. Handbook on the Economics of Electricity.

Hogan, W.W., 2013. Electricity scarcity pricing through operating reserves. Economics of Energy & Environmental Policy 2 (2), 65–86.

Hogan, W.W., 2016. Virtual bidding and electricity market design. Electr. J. 29 (5), 33–47.

Hogan, W.W., Pope, S., 2017. Priorities for the Evolution of an Enery-Only Market Design in ERCOT. FTI Consulting. URL. https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.

Höschle, H., Le Cadre, H., Smeers, Y., Papavasiliou, A., Belmans, R., 2018. An admm-based method for computing risk-averse equilibrium in capacity markets. IEEE Trans. Power Syst. 33 (5), 4819–4830.

Inzunza, A., Moreno, R., Bernales, A., Rudnick, H., 2016. CVaR constrained planning of renewable generation with consideration of system inertial response, reserve services and demand participation. Energy Econ. 59, 104–117.

Irastroza, V., Peñuelas, J.A., 2020. Mexican Electricity Wholesale Market Report 2019, NERA Economic Consulting. URL. https://www.nera.com/content/dam/nera/publications/2020/PUB_Mexican-Electricity-Wholesale-Market-Report_013120.pdf.

IRENA, 2017. Adapting Market Design to High Shares of Variable Renewable Energy. International Renewable Energy Agency, Abu Dhabi.

IRENA, 2019. Innovation Landscape Brief: Increasing Time Granularity in Electricity Markets. International Renewable Energy Agency, Abu Dhabi.

Jenkins, J.D., 2014. Political economy constraints on carbon pricing policies: what are the implications for economic efficiency, environmental efficacy, and climate policy design? Energy Pol. 69, 467–477.

Jimenez-Estevez, G., Palma-Behnke, R., Latorre, R.R., Moran, L., 2015. Heat and dust: the solar energy challenge in Chile. IEEE Power Energy Mag. 13 (2), 71–77.

Karanfil, F., Li, Y., 2017. The role of continuous intraday electricity markets: the integration of large-share wind power generation in Denmark. Energy J. 38 (2), 107–130.

Kitzing, L., Mitchell, C., Morthorst, P.E., 2012. Renewable energy policies in Europe: converging or diverging? Energy Pol. 51, 192–201.

Kreps, D.M., 1987. Three essays on capital markets. La Revista Espanola de Economia 4, 111–145.

Li, R., Svoboda, A.J., Oren, S.S., 2015. Efficiency impact of convergence bidding in the California electricity market. J. Regul. Econ. 48 (3), 245–284.

Madaeni, S.H., Sioshansi, R., Denholm, P., 2012. Estimating the capacity value of concentrating solar power plants: a case study of the southwestern United States. IEEE Trans. Power Syst. 27 (2), 1116–1124.

Mas-Colell, A., Whinston, M.D., Green, J.R., et al., 1995. Microeconomic Theory, vol. 1. Oxford university press, New York.

Mastropietro, P., Rodilla, P., Rangel, L.E., Batlle, C., 2020. Reforming the colombian electricity market for an efficient integration of renewables: a proposal. Energy Pol. 139, 111346.

Mays, J., 2017. Cost allocation and net load variability. IEEE Trans. Power Syst. 33 (2), 2030–2039.

Mays, J., Morton, D.P., O'Neill, R.P., 2019. Asymmetric risk and fuel neutrality in electricity capacity markets. Nature Energy 4 (11), 948–956.

Milligan, M., Ela, E., Hodge, B.-M., Kirby, B., Lew, D., Clark, C., DeCesaro, J., Lynn, K., 2011. Integration of variable generation, cost-causation, and integration costs. Electr. J. 24 (9), 51–63.

Moreno, R., Barroso, L.A., Rudnick, H., Mocarquer, S., Bezerra, B., 2010. Auction approaches of long-term contracts to ensure generation investment in electricity markets: lessons from the Brazilian and Chilean experiences. Energy Pol. 38 (10), 5758–5769.

Moreno, Rodrigo, Bezerra, Bernardo, Rudnick, Hugh, Suazo-Martinez, Carlos, Carvalho, Martha, Navarro, Alejandro, Silva, Carlos, Strbac, Goran, 2020. Distribution Network Rate Making in Latin America: An Evolving Landscape. IEEE Power and Energy Magazine 18 (3), 33–48. https://doi.org/10.1109/MPE.2020.2972667. In press.

Moreno, R., Ferreira, R., Barroso, L., Rudnick, H., Pereira, E., 2017. Facilitating the integration of renewables in Latin America: the role of hydropower generation and other energy storage technologies. IEEE Power Energy Mag. 15 (5), 68–80.

Moreno, R., Street, A., Arroyo, J.M., Mancarella, P., 2017b. Planning low-carbon electricity systems under uncertainty considering operational flexibility and smart grid technologies. Phil. Trans. Math. Phys. Eng. Sci. 375 (2100), 20160305.

Munoz, F.D., Mills, A.D., 2015. Endogenous assessment of the capacity value of solar PV in generation investment planning studies. IEEE Transactions on Sustainable Energy 6 (4), 1574–1585.

Munoz, F.D., Pumarino, B.J., Salas, I.A., 2017. Aiming low and achieving it: a long-term analysis of a renewable policy in Chile. Energy Econ. 65, 304–314.

Munoz, F.D., Wogrin, S., Oren, S.S., Hobbs, B.F., 2018. Economic inefficiencies of cost-based electricity market designs. Energy J. 39 (3).

Muñoz, F.D., Harrison, R, 2020. Análisis y Propuestas de Mejora para el Mercado de SSCC de CSF y CTF, Informe Final. Coordinador Eléctrico Nacional. https://www.coordinador.cl/wp-content/uploads/2020/10/Informe-Final-Mejoras-SSCC-Harrison-y-Mu%C3%B1oz.pdf.

Newbery, D., 2016. Missing money and missing markets: reliability, capacity auctions and interconnectors. Energy Pol. 94, 401–410.

O'Neill, R.P., Sotkiewicz, P.M., Hobbs, B.F., Rothkopf, M.H., Stewart Jr., W.R., 2005. Efficient market-clearing prices in markets with nonconvexities. Eur. J. Oper. Res. 164 (1), 269–285.

Ott, A.L., 2017. Case study: demand-response and alternative technologies in electricity markets. In: Renewable Energy Integration. Elsevier, pp. 261–270.

Papavasiliou, A., Oren, S.S., 2013. Multiarea stochastic unit commitment for high wind penetration in a transmission constrained network. Oper. Res. 61 (3), 578–592.

Papavasiliou, A., Oren, S.S., O'Neill, R.P., 2011. Reserve requirements for wind power integration: a scenario-based stochastic programming framework. IEEE Trans. Power Syst. 26 (4), 2197–2206.

Papavasiliou, A., Smeers, Y., 2017. Remuneration of flexibility using operating reserve demand curves: a case study of Belgium. Energy J. 38 (6), 105–136.

Pereira-Bonvallet, E., Moreno, R., Muñoz, F.D., 2021. Estimating the value of electricity storage in Chile through planning models with stylized operation: how wrong can it Be? Current Sustainable/Renewable Energy Reports. https://doi.org/10.1007/s40518-020-00158-0.

Perez, A.P., Sauma, E.E., Munoz, F.D., Hobbs, B.F., 2016. The economic effects of interregional trading of renewable energy certificates in the US WECC. Energy J. 37 (4).

PJM, 2019. Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket Nos. ER19-1486-000, EL19-58-000. URL. https://pjm.com/directory/etariff/FercDockets/4036/20190329-el19-58-000.pdf.

Raineri, R., 2006. Chile: where it all started. Electricity market reform: an international perspective 77–108.

REI, 2019. Este año se instalarán 512 MW en centrales diésel, el mayor registro desde 2009. Revista Electricidad. URL. https://bit.ly/2GsVGVS.

Reus, L., Munoz, F.D., Moreno, R., 2018. Retail consumers and risk in centralized energy auctions for indexed long-term contracts in Chile. Energy Pol. 114, 566–577.

Rodilla, P., Mastropietro, P., Gómez, T., Agurto, R., Skerk, C., Batlle, C., 2018. Developing the design of the Chilean power market to allow for efficient deployment of renewables. Oxf. Energy Forum 19–21.

Rudnick, H., 1994. Chile: pioneer in deregulation of the electric power sector. IEEE Power Eng. Rev. 14 (6) (Institute of Electrical and Electronics Engineers);(United States).

Rudnick, H., Velasquez, C., 2018. Taking Stock of Wholesale Power Markets in Developing Countries: A Literature Review. The World Bank.

Schweppe, F.C., Caramanis, M.C., Tabors, R.D., Bohn, R.E., 2013. Spot Pricing of Electricity. Springer Science & Business Media.

SE, 2016. Manual de Mercado de Energía de Corto plazo, secretaría de Energía, diario oficial de la Federación. URL. http://www.diputados.gob.mx/LeyesBiblio/regla/n463.pdf.

Sioshansi, R., Madaeni, S.H., Denholm, P., 2013. A dynamic programming approach to estimate the capacity value of energy storage. IEEE Trans. Power Syst. 29 (1), 395–403.

USGAO, 2017. Electricity markets: four regions use capacity markets to help ensure adequate resources, but FERC has not fully assessed their performance. URL. https://www.gao.gov/assets/690/688811.pdf.

Villar, J., Rudnick, H., 2003. Hydrothermal market simulator using game theory: assessment of market power. IEEE Trans. Power Syst. 18 (1), 91–98.

Vimmerstedt, L.J., Akar, S., Augustine, C.R., Beiter, P.C., Cole, W.J., Feldman, D.J., Kurup, P., Lantz, E.J., Margolis, R.M., Stehly, T.J., et al., 2019. 2019 Annual Technology Baseline. Tech. Rep. National Renewable Energy Lab.(NREL), Golden, CO (United States).

Wang, B., Hobbs, B.F., 2014. A flexible ramping product: can it help real-time dispatch markets approach the stochastic dispatch ideal? Elec. Power Syst. Res. 109, 128–140.

Wang, B., Hobbs, B.F., 2015. Real-time markets for flexiramp: a stochastic unit commitment-based analysis. IEEE Trans. Power Syst. 31 (2), 846–860.

Watts, D., Jara, D., 2011. Statistical analysis of wind energy in Chile. Renew. Energy 36 (5), 1603–1613.

Wilson, R., 2002. Architecture of power markets. Econometrica 70 (4), 1299–1340.

Wiser, R., Bolinger, M., Barbose, G., 2007. Using the federal production tax credit to build a durable market for wind power in the United States. Electr. J. 20 (9), 77–88.

Wolak, F.A., 2000. An empirical analysis of the impact of hedge contracts on bidding behavior in a competitive electricity market. Int. Econ. J. 14 (2), 1–39.

Wolak, F.A., 2003. Designing Competitive Wholesale Electricity Markets for Latin American Countries.

Woo, C.K., Zarnikau, J., Cutter, E., Ho, S., Leung, H., 2015. Virtual bidding, wind generation and California's day-ahead electricity forward premium. Electr. J. 28 (1), 29–48.

Yoo, K., Blumsack, S., 2018. Can capacity markets be designed by democracy? J. Regul. Econ. 53 (2), 127–151.