Energy Strategy Reviews 39 (2022) 100798

Contents lists available at ScienceDirect

Energy Strategy Reviews

journal homepage: www.elsevier.com/locate/esr

Chile's electricity markets: Four decades on from their original design[☆,☆☆]

Pablo Serra

Departamento de Economía, Universidad de Chile, Chile

ARTICLE INFO

JEL classification:
N7
Q4
L1
L9

Keywords:
Energy markets
Market design
Competition
Contracts

ABSTRACT

It has been almost 40 years since Chile reformed its electricity sector. In 1982, the Electricity Act created an energy market for generators and large customers to negotiate supply contracts. It also established a centralized dispatch of power plants in ascending order of generation cost, independent of their owners' supply contracts. This setup results in power exchanges between generators, which are valued using the system's marginal costs. This paper: (i) describes the market design; (ii) shows its evolution to date; (iii) describes the triggers for change; (iv) draws policy lessons and (iv) provides a preliminary assessment of the reform.

1. Introduction

In 1982, Chile carried out the world's first comprehensive reform of the electricity sector, aiming to make electricity generation competitive [1].[1] To this end, the Electricity Act issued that year distinguishes three activities: generation, transmission, and distribution, though initially, it not prohibited vertical integration. Its centerpieces are the design of an energy market for generators and large customers to negotiate electricity supply contracts and an exchange market for generators to trade their instant energy imbalances [4]. This paper: (i) outlines the initial design; (ii) shows its evolution to date; (iii) describes the triggers for change; (iv) draws some policy lessons and (iv) provides some preliminary evaluation on the original market design and its subsequent adjustments.

The Act obliges all electricity companies located in the same area to interconnect and coordinate to maintain service security and minimize system operating costs. To this end, they had to create coordinating bodies (Economic Load Dispatch Centers, ELDCs), later replaced by an independent coordinator. Over time, two interconnected systems emerged: The Central Interconnected System (CIS) in 1982 and the Big North Interconnected System (BNIS) in 1993, which, in turn, interconnected in 2017. The analysis focuses mainly on the CIS, which has accounted for around 75% of the country's power generation (Table 1).

Small customers, initially those with a maximum demand of less than 2 MW, have to purchase electricity from distribution firms at a regulated tariff with two components: the electricity price at which distribution firms buy energy from generators and a distribution service charge.[2] The regulatory agency sets the distribution charge and its indexation formula every four years so that a hypothetical efficient company achieves a predetermined real rate of return on its assets. Thus, the Act introduced a novel regulatory approach that incentivizes efficiency by, in principle, setting tariffs without considering the utilities' actual costs.

The restructuring of the electricity sector was the second component of the reform. In 1982, Chilectra and Endesa (the two large state-owned companies) generated 13.4% and 64.1% of the country's total, respectively, while self-producers accounted for 22.4% [5]. The government unbundled Chilectra and Endesa into seven generation companies (one in the Big North Zone and six in the Central Zone) and eight distribution companies, privatizing most of them between 1983 and 1989. Endesa retained its transmission assets, the backbone of the CIS's transmission

; ARC, Antitrust Resolution Commission; AS, Ancillary services; BNIS, Big North Interconnected System; CIS, Central Interconnected System; ELDC, Economic Load Dispatch Center; LCOE, Levelized cost of energy; NEC, National Energy Commission; NCRE, Non-conventional renewable enery; PV, Photovoltaic; RE, Renewable Energy.

☆ I thank Giovanni Villa and Carlos Matamala for their valuable research assistance and two anonymous reviewers for their insightful comments and suggestions.☆☆ This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

E-mail address: pserra@fen.uchile.cl.

[1] [2,3] provide insightful analyses of the design of energy markets.

[2] Later, a charge was added to the tariff to finance the system Coordinator and the Expert Panel described in Section 4.

https://doi.org/10.1016/j.esr.2021.100798
Received 16 September 2021; Received in revised form 26 November 2021; Accepted 12 December 2021
Available online 23 December 2021

network.

A partial reversal followed the initial restructuring. In the late 1980s, Endesa purchased three of its spun-offs. As a result, in 1990, three companies accounted for 97.2% of total generation in the CIS, with Endesa alone supplying 52.1% (Table 1). Moreover, Enersis, the holding owner of two distribution companies (Chilectra and Río Maipo) that jointly served about 45% of CIS customers, initiated in the late 1980s a buyout of Endesa shares that culminated in 1995 when it reached 25.3% of Endesa's capital stock becoming its controller.

This industrial organization, compounded by regulatory weakness stemming from a poor institutional framework and lax access rules to grids, negatively impacted the sector. Endesa had a competitive edge over its competitors as it could delay the negotiation of access charges to its transmission assets. Although generators could access transmission networks before agreeing on a tariff with the owner, this constituted an additional risk when signing supply contracts. Also, the Enersis distribution affiliates could allocate to Endesa the supply of their regulated customers at the regulated price,[3] especially in the low-demand time blocks with lower spot prices.

These conditions led to high litigation, both within the ELDCs and before the antitrust commission (see Ref. [11]),[4] and to a higher rate of return for Endesa than for its competitors.[5] This reality constituted an entry barrier. By 1995, no large generating firms had entered the CIS despite the rapid demand expansion, and the three largest generators accounted for 95.1% of the total generation (Table 1). Also, very few non-regulated customers of distribution companies that could contract directly with generators had done so [12].

Tackling these regulatory deficiencies was not straightforward. The Act included details usually left to the regulators to determine and granted firms the right to appeal regulatory decisions in court. This approach was probably appropriate for Chile in the 1980s, as investors needed reassurance that they would not be subject to regulatory takings [13]. However, this legal regime prevented the updating of regulation as its shortcomings became known.

Generation firms concerned about both a lowering of entry barriers and the ability of Congress to legislate on the details of regulation successfully lobbied lawmakers against amending the Act. The close ties that controllers of incumbent firms had with the opposition parties rendered it cumbersome to modify the legislation against their wishes as the government did not control the Senate.[6]

Also, regulators could hardly cope with the political and social influence that electricity firms had acquired due to their sheer economic weight. Nor did they have all the necessary skills to deal with the companies [1]. Moreover, companies could fill legal recourses to derail or delay regulatory decisions and lawsuits against regulators in an attempt to influence them. It was not until 1998 that the government, spurred on by an antitrust ruling, enacted Decree 327 with a watered-down version of a 1992 draft of supplementary regulations [11].

Substantive regulatory upholding, however, had to wait until the 1998–99 electricity sector crisis, the worst since 1982. The 1998 drought drastically reduced hydroelectric generation, forcing the government to ration supply, as the market design prevented rapid market response. This crisis provided the impetus for regulatory reform, further facilitated by the sale of the Enersis conglomerate in 1997 to foreign investors, which reduced its political clout.

In 2004 and 2005, Congress amended the Act to lower entry barriers to generation. In the following years, however, market concentration remained high, and energy prices reached record levels.[7] The growing environmental restrictions and citizen opposition, which led to increasing difficulties in constructing conventional power plants, explain these outcomes. The government response in the mid-2010s was to deepen earlier pro-competition modifications to the Act and promote non-conventional renewable energy (NCRE), i.e., renewable energy (RE) except for hydropower plants with a capacity of more than 20 MW,

In later years, the sharp drop in RE levelized costs led to a rapid

Table 1
Public service generation in Chile:[a] 1980–2020.

Year	Total Generation GWh	Share of Systems (%)			Central Interconnected System					
		CIS	BNIS[b]	Other[c]	Technology[d] %			Largest firms[e] %		
					H	T	R	E	G	C
1980	8,887	95.1	3.4	1,5	78	22	0	69.1	27.4	0.0
1985	11,042	95.4	3.0	1,6	91	9	0	82.2	13.8	0.0
1990	13,916	98.0	1.0	1.0	60	40	0	52.1	31.1	14.1
1995	25,040	81.9	17.6	0.8	86	14	0	59.7	19.2	16.2
2000	39,142	75.6	23.8	0.6	63	37	0	50.5	22.1	19.0
2005	50,788	74.7	24.9	0.4	70	30	0	50.0	18.0	26.9
2010	57,882	73.4	25.9	0.7	67	32	1	44.5	27.8	21.3
2015	72,188	73.3	26.0	0.7	45	50	5	33.2	21.5	23.4
2017	74,647	73.5	25.8	0.7	40	51	9	33.0	19.1	22.4
2020[f]	78,240	–	–	0.7	27	57	16			

[a] Public service generation accounted for 75.6% of the country's total in 1980, 78.5% in 1985, 75.7% in 1990, and 89.6% in 1995.
[b] System formed in 1993.
[c] Includes two vertically integrted systems in the south of the country.
[d] H: Hydroelectricity, T: Thermoelectricity, and R: Solar + Wind.
[e] Firms: E: Endesa, G: Gener (previously Chilectra), and C: Colbún.
[f] Data for the national system.
Source: Author's compilation from Refs. [5–8]; and [9].

[3] Between May 1986 and September 1996, Chilectra purchased energy from generators at the nodal price that, on average, was 11.5% higher than the spot price [10].

[4] The Ministry of Economy settled one ELDC dispute from 1984 to 1990, two in 1991 and 1994, 3 in 1995 and 1996, 8 in 1997, and 11 in 1998 [11].

[5] From 1989 to 1997, the average returns on equity were 12.9% for Endesa, 9.3% for Gener, and 3.7% for Colbún [10].

[6] The binominal electoral system, with each constituency electing two senators, and the existence of appointed senators, legacies of the Pinochet regime (1973–1990), gave the opposition a working majority in the Senate.

[7] A far-reaching revision of the Act debated by Congress in 2000 proved too controversial and complex to be enacted (see Ref. [1]).

expansion of these technologies. As a result, the marginal costs fell sharply, as did the bid prices in the auctions called to supply regulated customers. In addition, the number of bidders in these tenders soared, with almost all of them being entrants backing their submissions with RE projects, signs of a well-functioning market.

The organization of the rest of the paper is as follows. Section 2 describes the original design of the energy market, while section 3 highlights the regulatory deficiencies that emerged in the 1990s. Section 4 then presents the first round of regulatory changes in the 2000s. Next, Section 5 describes the increasing difficulties in building conventional power plants and the second phase of Act amendments. Then, Section 6 focuses on NCRE expansion, and section 7 draws some policy lessons from the Chilean experience. The paper ends with conclusions.

2. The energy markets design and initial adjustments: 1982–1990

The primary objective of the reform was to create a competitive wholesale energy market in which generation companies and large customers could freely enter into bilateral supply contracts. To this end, the government first issued the 1982 Electricity Act. The Act was the brainchild of the National Energy Commission (NEC), created in 1978 to propose sectoral policies and regulations and calculate regulated tariffs.[8] Previously these tasks had been in the hands of the largest state-owned electric company (Endesa) and the Tariff Commission, respectively. The latter included representatives of the President of the Republic, the electric companies, and the consumers.

The Act lays down a design that considers the two key features of electricity: it is not economically storable, and transmission lines must transport it to consumer sites. Accordingly, it obliges electricity companies located in the same area to interconnect and coordinate to maintain service security. To this end, they had to create the ELDCs. Secondly, although it initially left tariffs and grid expansion unregulated, it granted generators access to the transmission grid subject to capacity availability even before agreeing on tolls with their owners.

The legislation also mandates the minimization of the systems' operational costs. Accordingly, ELDCs dispatch plants in ascending order of operating costs, regardless of existing supply contracts, until generation matches demand. This situation results in energy transfers between generators, metered on an hourly basis. Thus, in each hour, a generator's energy transfer to the system equals its plants' injections, following the ELDC's instructions, less its energy withdraws to supply its customers.

The Act provides using the system's marginal costs to value these transfers, which ELDCs compute assuming a price-inelastic instantaneous demand and a capacity adapted to peak demand. Thus, the system's marginal cost at the peak hour also includes the cost of capacity expansion.[9] In this context, marginal cost pricing – known as peak-load pricing – consists of two prices. One is the marginal cost of operation – called the hourly marginal cost of energy (HMCE). The other is the marginal cost of capacity –named the peak power price, which only applies in the peak hour.[10]

In each hour, ELDCs approximate the HMCEs with the operating cost of the last plant dispatched, which they calculate from (i) fuel prices and yields reported by plant owners and (ii) the stored water option price. Given how the HMCEs are determined, in the absence of inflexibilities, merit-order dispatch would be consistent with the decisions that generators would freely make in a competitive environment. A plant would choose not to generate in those hours when its operating cost is higher than the HCME and vice versa. In this sense, the HMCEs are market-clearing prices. Accordingly, in the remainder of this paper, I will follow the customary usage of calling spot market the energy exchanges between generators and spot prices the HMCEs.

A generator's peak power transfer equals the difference between the power it can reliably inject into the system during the annual peak hour and the energy it withdraws from the system to supply customers during this hour. Due to the seasonality in consumption and production, the measurement of the peak hour is on an annual basis. The NEC calculates the peak power price –the marginal cost of capacity– as the annuity that pays the cheapest possible capacity addition at the peak hour, scaled by the system's power reserve margin.

The energy that a plant can reliably inject into the system during the peak hour, known as preliminary sufficiency power (PSP), is calculated based on its actual availability over the last five years. The PSP of all plants is scaled down so that their sum matches the expected peak demand for the year. Thus, in theory, the definitions of sufficiency power and peak power price ensure that the investments in generation capacity can supply the peak demand plus the reserve margin.

The Act also mandated the NEC to calculate every six months the price to be paid for energy purchases made by distribution firms to supply their regulated customers. The so-called nodal price had two components: the nodal power price, equal to the peak power price, and the nodal energy price, which corresponded to the average of the expected spot prices for at least the following 24 months. The purpose of this forward-looking formula was to stabilize regulated prices.

The NEC calculated the expected spot prices using a dynamic optimization model that minimizes the sum over the planning horizon of the system's discounted expected costs of investment, operation, and rationing. Model inputs included: water reservoir levels, demand forecasts, fuel price projections, existing and under construction facilities, rainfall over the past 40 years that the modeling assumed to be equiprobable, and the outage cost. The latter was the average price that consumers would be willing to pay for each unit of failed energy. In those months when generation was insufficient to meet the price-inelastic demand projection, the rationing cost equaled the failed energy times the outage cost. The expected spot prices were equal to the outage cost in those periods with projected energy shortages.

During the 1990s, the government introduced minor regulatory changes. In 1985 it issued Decree 6 requiring generators to have the means, owned or contracted, to fulfill their energy supply contracts, an exigence transferred to peak hour in 1998 (Decree 327), the sole regulatory intervention in an otherwise fully decentralized market. In 1990, Law 18922 introduced criteria for calculating transmission tolls and a mandatory binding arbitration process if the parties failed to reach an agreement. In addition, it provided that new transmission facilities were to be financed for by the generators requesting the additional capacity, who could either build them or negotiate terms with the transmission companies.

The same year the Ministry of Finance enacted Law 18959, authorizing the NEC to issue Rationing Decrees on occurrence or anticipation of energy shortages. The issuance of a decree (i) allows modifying the mandatory merit order dispatch of power plants to preserve stored water and (ii) obliges generators to compensate regulated consumers for failed energy. The compensation equals the difference between the outage cost and the nodal price multiplied by the hypothetical energy deficit that would have occurred with the worst drought in the last 40 years. The Act limited the compensation for symmetry with the expected spot price calculation method but left unspecified how to treat the difference between the actual and hypothetical energy shortfall.

[8] The NEC is also responsible for setting technical standards for electricity companies. In turn, the Superintendence of Electricity and Fuels enforces compliance with regulations, supervises the system coordinator, resolves user complaints, and determines the generators' compensation for failed energy.

[9] See Ref. [14].

[10] In practice, the system operator uses, say, the 25 peak hours. Otherwise, all consumers would try to skip the peak demand. For simplicity, I will refer to the peak demand hour.

3. The regulatory deficiencies impact on the energy market: 1991–2001

In the 1990s, regulatory deficiencies, such as laxity in network access, lack of price signals in electricity rationing scenarios, and weak institutions, became visible. The NEC professional ranks, consisting mainly of electrical engineers, lacked the legal, economic, accounting, and financial specialists necessary for efficient regulation [1]. Also, public sector salaries allowed hiring inexperienced professionals, and many of the most qualified after gaining experience migrated to higher-paying electrical companies. Thus, the NEC's initial skills did not match the electric companies, as attested by profit rates of around 20% for distribution companies in the 1990s [10], a situation that also hindered the passing of the necessary legal reforms.

The ELDCs' governance was precarious. Representatives of the generation and transmission companies selected its board of directors. Internal resolutions required the unanimity of the directors or had to await the decision of the Minister of Economy, who had 120 days to resolve. Constant conflicts among ELDC members left controversial decisions to Ministers, who, reluctant to assume political risks, delayed decisions on disputes involving large money transfers [16].

Five un-paid members made up the Antitrust Resolution Commission (ARC): A Supreme Court Justice, appointed by her peers, who presided over the Commission; two heads of public administration services (one appointed by the Ministers of Economy and the other by the Minister of Finance) and two deans of universities selected by lottery, one from an Economics School and the other from a Law School. The commissioners often lacked experience in antitrust litigation, given the selection rules, and devoted little time to the Commission, resulting in lengthy proceedings.

The ARC did not prevent the sector's vertical integration. In 1991, the National Economic Prosecutor requested the ARC to order Enersis and its subsidiaries to refrain from increasing their shareholding in Endesa beyond the 12.5% reached the previous year. In June 1992, the ARC, with the two government representatives voting against, dismissed the request on the grounds that (i) the defendants had no legal control of Endesa; (ii) the Act provided adequate safeguards to consumers; and (iii) the prosecution had not proved abuse by the defendants (Resolution 372).

The prosecution filed before the Supreme Court a complaint against the ARC for this ruling. The Court dismissed it but ordered the competition authorities to monitor the defendants and restore market transparency. In 1994, the Prosecutor, invoking the Supreme Court sentence, requested the ARC to vertically disintegrate the Enersis conglomerate claiming that it constituted a risk to competition.

In 1997, the ARC denied the demand arguing that the risk of anticompetitive behavior was hypothetical (Resolution 488). But, it ruled that Endesa should transfer its transmission assets to a subsidiary with a single business line and open to third-party shareholders, which led Endesa to sell its transmission assets in 2000. Furthermore, the ARC recommended the authorities some regulatory measures, which, in turn, the Ministers of Energy and Mining had proposed in briefs filed in the case.

In 1998, the Ministry of Mining issued Decree 327, with regulations complementing the Act, that contained recommendations from Resolution 488.[11] These include: (i) requiring distribution companies to publicly auction the supply of regulated consumers under objective and non-discriminatory conditions with a ceiling price set by the NEC; (ii) refining the criteria for setting transmission fees and (iii) providing guidelines for computing distribution tolls for non-regulated users, including binding arbitration in case of disagreement. It also gave legal validity to decisions taken by the majority of the ELDCs' boards of directors and reduced to 60 days the deadline for the Minister of Economy to rule on ELDCs' discrepancies.

The electricity crisis of 1998–99 exposed once again the weaknesses of the sector's governance while revealing regulatory loopholes. In 1998, the CIS, with an average hydroelectric generation of 77% in the previous five years [9], suffered a severe drought. Moreover, three natural gas combined cycle plants broke down for varying lengths of time. These problems caused blackouts between November 1998 and April 1999. A more resolute intervention by the authorities could have avoided them as the failed energy –450 GWh– represented about 0.2% of the annual CIS consumption [17].

The government, permeable to the hydroelectric companies' lobbies, delayed the rationing decree that would have allowed for the adoption of water conservation measures. An overestimation of the volume of water provided by the melting of snow accumulated in the mountain ranges would also have influenced the postponement. In addition, the government's tardiness in filling some regulatory gaps in the law led to a temporary collapse of the pricing signals [17].

Generators with power deficits claimed that, under the Act, they did not have to compensate regulated customers for the unsupplied energy because the year had been drier than the driest in the previous 40 years, a position upheld by regulators. Thus, generators had no incentives to install emergency turbines or negotiate consumption reductions with their regulated customers.

Moreover, the ELDC's directors, unable to agree on the spot price under rationing, referred the dispute to the Minister of Economy, who, after taking the maximum 120-day period to resolve, ruled that the spot price should be the outage cost given that a rationing decree was in force [16]. But he left the responsibility for determining the amount of failed energy to the ELDC Board, where a new disagreement arose that further postponed the solution. Thus, energy transfers between generators remained unpaid throughout this lengthy process.

The crisis prompted lawmakers to provide in the Act that the spot price equals the outage cost under rationing and to obligate generators to compensate regulated customers for the unsupplied energy in all circumstances. This change led generators to skip auctions called to supply regulated customers in the early 2000s. They argued that compensation risks were not worth it, given the auctions' price caps.

4. The first round of pro-competition amendments: 2000–2009

In the 2000s, lawmakers enacted successive amendments to the Act to reduce entry barriers in the energy market. Changes aimed at improving regulation of access to networks, facilitating the participation of new entrants in the auctions called to supply regulated customers, and strengthening the sector's institutions.

The vagueness of the guidelines introduced by Decree 327 to determine transmission tolls led to exhausting arbitration processes with unpredictable results [18]. Moreover, arbitration did not guarantee efficient pricing, as its outcome depended on its sophistication, likely less than a regulatory process [1]. The leading transmission company, in turn, complained that the guidelines, based on the flow of energy in the direction of demand centers, left backup lines unpaid (see Ref. [1]). Thus, it had slowed down its expansion after its divestiture from Enersis, leaving the regulator hands-tied as transmission companies had no obligation to expand capacity.

The 2004 legal reform addressed this problem by transforming transmission into public service (Law 19940). First, it obliges the NEC to prepare annual transmission expansion plans and the ELDCs to auction the plans' projects based on the yearly payments requested for their construction and operation. Second, it limits the participation of generators and distributors in transmission companies to 8% individually and 40% jointly. Third, it established guidelines for allocating the transmission costs among users and entrusted ELDCs with the calculations.

[11] The ARC recommendations were considered mandatory in that the authorities should address the issues they raised, but not necessarily in the proposed manner [11].

Also, the amendment provides that consumers with a maximum power demand between 0.5 MW and 5 MW connected to a distribution grid could buy electricity at regulated prices or contract with generators or power brokers. Likewise, it stipulates that the non-regulated users would pay the regulated distribution charge for accessing the grid. Moreover, it introduces payment for ancillary services (AS), requiring the ELDCs to define, manage, and value the AS rendered.

As mentioned earlier, in the early 2000s, most of the auctions called by the distribution companies to supply regulated customers did not attract bidders. In 2001, Resolution 88 of the Minister of Economy provided a temporary solution to this problem. It ordered generators to deliver at spot prices the consumption of non-regulated customers not covered by contracts, which implied considering such consumption in the spot market exchange of imbalances.

The definitive solution came with the 2005 Act amendment, which obliges distribution companies to call - individually or collectively - international auctions to supply their regulated customers. To make it easier for entrants to finance and build their projects, auctioneers had to award contracts lasting up to 15 years at least three years in advance. The amendment keeps the energy price as the bidding variable and the peak power payment. It also provides the setting of award prices in US dollars and their adjustment according to a weighted average of 5 price indices that determine generation costs, with weights chosen by bidders. In addition, it raised price ceilings considerably, increasing reliance on market forces in what was supposed to be a more competitive environment.

Successful bidders must guarantee that the contracted energy will be available at the award price, regardless of spot prices. Thus, in each hour, an awardee that generates less energy than needed to serve its contracts must buy it on the spot market or sell it surplus otherwise. Thus, the auction rules require bidders to back up their bids with, among other things, installed or planned plants, but without establishing a direct relationship between generation capacity and contracted demand.

The authorities likewise enacted a series of legal changes to strengthen the sector's institutions. The 1998–1999 crisis had raised concerns about the incumbents' lobbying and the lengthy time taken by the Minister to resolve disputes within ELDCs [1]. To address these concerns, legislators in the 2004 amendment to the Act created the Expert Panel and made it responsible for resolving ELDC's internal conflicts and those related to regulatory decisions.

The Panel, comprised of seven professionals chosen by the Tribunal for the Defense of Free Competition, resolves disputes within legal timeframes. Its decisions are unappealable, but the parties may file remedies for protection against Panel members before the appellate courts for arbitrary or illegal actions. As of 2016, electric firms had filed six, which the courts dismissed on the grounds that the appellants' constitutional rights and guarantees had not been affected.[12] Nevertheless, the possibility of these remedies has some effect on the Panel's resolution.

The 2005 Act reform marginally improved the governance of ELDCs by incorporating a representative of large customers to their Board of Directors. Also, successive legal changes strengthened the NEC. The number of employees grew from 30 in 1982 to 56 in 2006 (Decree-Law 2224, Ministry of Mining, 1978). Since the 2000s, the NEC has recruited lawyers and economists, complementing its initial staff of engineers.

In 2009, lawmakers created the Ministry of Energy (Law 20402), which took the NEC's responsibilities of developing and coordinating plans, policies, and regulations. In addition, the Ministry became responsible for conducting a five-year prospective study of the electricity sector, known as the energy planning process.

The government also strengthened the antitrust institutions. In 2003, Law 19.911 replaced the Antitrust Resolution Commission with the Tribunal for the Defense of Free Competition, composed of five judges selected based on their antitrust experience. The law provides for the dedication of competition judges and commensurate remuneration. It also doubled the maximum pecuniary penalty. Subsequent legal changes have continued enhancing the competencies and capacities of the Tribunal.

5. Increasing environmental requirements and the enactment of further pro-competition amendments

By 2010, despite pro-competition reforms introduced in the 2000s, no large generators had entered the CIS (Table 1), and the spot price had reached record levels (Fig. 1). These negative results primarily derived from the increasing difficulty in building conventional power plants due to tightening environmental regulations and opposition from civil society organizations.

Strong opposition from environmental and "indigenist" groups halted the construction of new hydropower plants with reservoirs from 1998 onwards. The last one (Ralco) started construction that year and became operational in 2004. In the following years, gas-fired power plants absorbed the growth in demand fed with natural gas (NG) brought from Argentina in pipelines that came on stream from 1997 onwards.

In 2005, Argentina began restricting and taxing NG exports due to domestic deficits. In Chile, this development raised the NG price from US $ 83.69 per million m^3 in 2004 to US$ 403.84 in 2008 and decreased consumption from 5,140 million m^3 to 1,117 in the same period.[13] This situation severely affected Chile's electricity systems, as 13% of CIS generation was gas-fired and 63% of BNIS generation in 2005 [19]. Generators coped with the NG shortage by (i) modifying gas turbines so that they could also burn oil and (ii) installing oil-fired plants.

In the following years, the construction of coal plants covered the demand growth due to their lower levelized cost of energy (LCOE). But, increasing public opposition and stricter environmental requirements halted the construction of coal-fired plants in the 2010s. In the CIS, the last coal-fired plant became operational in 2015, and 2019 in the BNIS.[14]

The entry of oil-fired power plants, which faced less environmental scrutiny due to their smaller size, ensured supply. Between 2005 and 2015, their capacity in the CIS quadrupled, increasing their share from 9% to 21% [19]. Although their operating costs strongly depend on the oil price, they have always been higher than those of other thermoelectric technologies, as shown by Table 3. These events led to the spot price increases between 2007 and 2013 exposed in Fig. 1. In a context of high concentration in baseload generation capacity, the spot price rise impacted contract award prices in the auctions called to supply regulated consumers. Thus, despite changes to the auction rules, those held between 2006 and 2014 attracted few bids, and bid prices were high, as shown in Fig. 2.

The authorities reacted by amending the law again. Law 20805, enacted in 2015, modified the rules of the auctions to supply regulated consumers. The changes included (i) handing over to the NEC the responsibility for the auction design and management, (ii) withholding ceiling prices until the bids' opening, (iii) extending the minimum period between contract awarding and supply start to five years and to 20 years the maximum duration of contracts and (iv) instructing auctioneers to select the combination of bids that covers the energy tendered at the lowest cost, but considering security and diversification objectives.

The NEC implemented the diversification objective by auctioning

[12] https://www.panelexpertos.cl/wp-content/uploads/2018/12/Informe-de-Actividades-2016.pdf.

[13] https://www.cne.cl/estadisticas/hidrocarburo/.

[14] In Mejillones, thermoelectric plants faced less citizen opposition as they provide many local jobs, and the geographical conditions allow for a wider dispersion of polluting gases than in other locations.

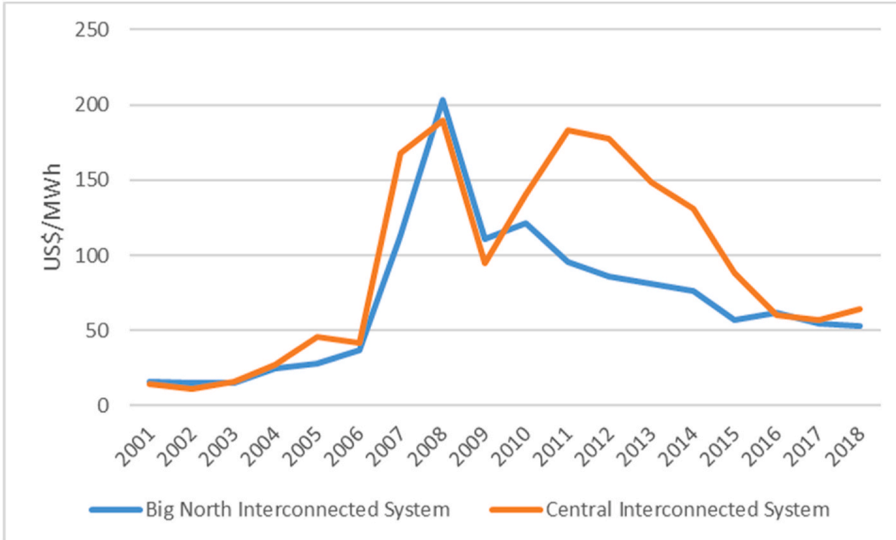

Fig. 1. Annual average hourly spot prices.
Source: Author's compilation from the Coordinator. https://www.coordinador.cl/operacion/graficos/operacion-real/costo-marginal-real/, 2020).

supply contracts restricted to time blocks adapted to the generation profile of NCRE technologies. Previously, supply contracts were for annual energy blocks that distribution companies freely withdrew throughout the year based on the consumption of their regulated customers. Thus, highly variable spot prices represented a risk for variable RE generators, as they could be unable to generate when their customers consume energy, and the spot price could be lower when they inject energy into the system.

Moreover, an article added to the Act establishes that the auction rules might contain clauses entitling awardees that backed their submissions with new projects to request, upon payment of a fee, their postponement or early termination of the contract if the projects are delayed or become unfeasible for reasons beyond their control. Finally, the amended Act allows the auction rules to incorporate a price review mechanism for significant and unexpected legal, regulatory or fiscal changes.

Transmission regulation was further amended in 2016 to provide for transmission systems to be financed exclusively by final consumers in proportion to their energy consumptions, except for dedicated transmission systems (Law 20936). The latter, consisting of facilities arranged primarily for supplying unregulated clients or connecting power plants to transmission systems, must be financed by their users.

This legal change also provides the auctioning of AS required for the system operation. Only when (i) market conditions are uncompetitive or (ii) the auction called to provide AS is declared void, the Coordinator –that replaced the ELDCs– may oblige the electric companies to supply AS, in which case it must assess and procure their remuneration. Consumers finance the AS needing new infrastructure, while generators bear the cost of providing the technical resources in proportion to their energy sales.[15] Finally, the amendment defines the energy storage activity, stating that the Coordinator will govern its operation.

The same law created the National Electric Coordinator (Coordinator), which replaced the ELDCs. A five-member Council elected by a special committee directs the Coordinator. The head of the NEC, a counselor of the Superior Council of the Public Administration, a member of the Expert Panel, and a judge of the Competition Tribunal compose the selection committee. The amendment also added to the Coordinator the responsibility to monitor competition in the energy market and report to the National Economic Prosecutor any clue of non-competitive behavior.

Finally, the government strengthened the NEC, whose number of employees reached 108 in 2018. Moreover, the professionals' salaries increased considerably over time, fluctuating in 2018 between 4 and 8 million Chilean pesos per month (approximately 6 and 12 thousand US$, respectively).[16]

As of the mid-2010 decade, the energy market conditions started to change dramatically. In the CIS, the spot price fell from US$ 183/MWh in 2011 to US$ 88/MWh in 2015 and US$ 64/MWh in 2018 (Fig. 1). In the auctions called to supply regulated consumers, the average award energy price fell from US$ 129/MWh to US$ 33/MWh in the same period (Fig. 2).

The second round of Act amendments undoubtedly lowered entry barriers in generation by reducing risk to entrant firms, especially with variable RE technologies. However, they hardly explain by themselves these price drops. In the next section, I argue that the sharp fall in the costs of RE technologies was the leading cause.

6. The expansion of renewable energies

From 2014 onwards, the commissioning of photovoltaic and wind farms skyrocketed, as Figs. 3 and 4 illustrate. This section explores the reasons for this upsurge.

Chile implemented several policies to promote NCRE. The 2004 Act amendment exempted NCRE plants with a capacity of less than 9 MW from paying transmission tolls, a benefit that extended proportionally to plants with a capacity between 9 and 20 MW. Since 2008, generators were obliged to source at least 10% of their annual sales from NCRE plants, either their own or third parties. The penalty for each MWh of NCRE shortfall is 0.4 UTM (≈25 US$).

In 2013, lawmakers raised the NCRE requirement to 20% and directed the Ministry of Energy to hold, if necessary, up to two public auctions per year to ensure compliance with the overall target, which will be 20% in 2025, when the transitional articles lowering the NCRE requirement for existing contracts expire (Law 20698). As mentioned above, since 2015, the auction rules for contracts to supply regulated customers include energy time blocks tailored to the production profiles of NCRE.

[15] Technical resources are facilities' attributes that may contribute to the system's safe, high-quality, and economic operation.

[16] https://www.cne.cl/transparencia/.

Table 2
Stages of reform.

Enactment of the Electricity Act and initial adjustments: 1982–1990	DFL-1[a] (Electricity Act), 1982, (i) obliges all companies in the same area to interconnect and coordinate to maintain service security and minimize system operating costs, for which they have to create Economic Load Dispatch Centers (ELDCs), (ii) sets a mechanism for generators to nettle their energy and power (energy measured at peak demand hours) imbalances valued using marginal costs and (iii) provides for the regulation of the price of electricity for small customers. Formation of the CIS (1982). The electricity companies, Endesa and Chilectra, are split into various firms and then privatized (mostly between 1983 and 1989). Endesa retains the transmission assets and is later allowed to buy some of its generation spin-offs. Decree 6[a], 1985, states that generators must have the means to supply their contracts. Law 18922[a], 1990, sets criteria to negotiate transmission tolls between parties and binding arbitration in case of disagreement. Law 18959[b], 1990, provides that generators must compensate regulated customers with the outage cost for the failed energy if the drought is not too severe.
Regulatory flaws impact on the energy market, and end of the construction of large hydropower plants: 1991–2000	Enersis, the owner of the largest distribution firms in the CIS, takes control of Endesa (1989–1995). Formation of the BNIS (1993). High litigation between companies, higher profitability for integrated companies, and no entrance of large firms characterize the market (1991–2000). Decree 327[a], 1998, (i) mandates distributors to auction the contracts to supply regulated consumers publicly, (ii) gives legal validity to the decisions taken by a majority of the ELDCs' boards, (iii) sets a 60-day deadline for the Minister of Economy to rule on ELDCs' disagreements and (iv) establishes criteria for negotiating unregulated customers' access to the distribution networks. Approval of the last hydroelectric plant with a reservoir (1998). Severe drought and poor sector governance lead to energy rationing (1998–1999). Law 19613[c], 1999, provides that (i) generators must compensate regulated customers for failed power in all circumstances and (ii) equates the spot price to the outage cost in case of rationing. Endesa sells its transmission assets (2000).
The first round of pro-competition amendments, increasing environmental restrictions, and high electricity prices: 2001–2010	Law 19940[c], 2004, (i) regulates transmission tolls and mandates the regulatory agency to draw up annual transmission expansion plans whose projects the ELDCs must auction, (ii) restricts transmission firms from integrating with other activities, (iii) establishes that consumers with a peak power between 0.5 and 5 MW can opt between free or regulated status, and (iv) creates an Expert Panel to resolve disputes within ELDCs and between companies and the regulator. Law 20014[c], 2005, mandates distribution companies to call - individually or collectively - international auctions to supply their regulated customers through contracts of up to 15 years of duration awarded at least three years in advance. Law 20257[c], 2008, obliges generators to source at least 10% of their annual sales from NCRE plants. Increasing environmental demands, compounded with public citizen opposition, gradually stop the construction of thermoelectric power plants, except for oil-fired power plants that face less scrutiny due to their smaller size (1988–2010). No new large generators enter the market, and energy prices skyrocket. Law 20402[a], 2009, creates the Ministry of Energy.
Enactment of further pro-competition amendments and expansion of RE: 2011–2020	The decade starts with high electricity prices. Law 20698[d], 2013, raises the renewable obligation to 20% and mandates the Ministry of Energy to auction NCRE contracts if necessary to meet the country target. The world levelized cost of energy of PV plants halves between 2010 and 2014, and that of wind generation falls by 72% over the same period, a trend that continues (2010–2020).M ost new plants installed are wind and PV farms (2014–2020). Law 20805[d], 2015, modifies the rules of auctions to supply regulated consumers to lower entry barriers, especially for NCRE generators. It includes the tender of hourly energy blocks. In the auctions to contract supply for regulated consumers, the number of independent bidders increases from two in 2013 to 59 in 2017, while the average award energy price falls from US$ 129/MWh to US$ 33. Law 20936[d], 2016, (i) establishes the payment of public transmission by end-consumers, (ii) replaces ELDCs with an independent Coordinator. The two electric systems interconnect (2018).

[a] Ministry of Mining.
[b] Ministry of Finance.
[c] Ministry of Economy.
[d] Ministry of Energy.

Other factors favoring the recent expansion of NCRE were: the willingness of free customers for paying more for certified renewable energy [20], the exemption of generators from paying transmission fees since 2016, which benefits RE plants usually located far from consumption centers and the reinforcement of the transmission system linking the north with the main demand centers, which allowed evacuating RE that was spilling over.[17]

[17] Transmission congestion caused the spillage of about 6% of the NCRE generation in 2018. After the inauguration of the Cardones-Polpaico line in June 2019, spillage fell to less than 1% [21].

Table 3
Operation costs informed by owners of plants (US$/kWh).

	Coal			Gas			Oil		
	2010	2015	2020	2010	2015	2020	2010	2015	2020
Maximum	44.7	43.8	62.1	153.4	128.4	172.2	360.3	396.5	267.0
Minimum	31.4	28.0	26.7	56.0	10.2	31.2	125.6	83.5	70.3
Median	40.7	33.8	31.5	96.1	84.5	60.3	209.5	162.7	143.3

Source: Author's compilation from CNE, Fijación de precios de nudo de corto plazo, Informe Técnicos Definitivos, 2010 and 2015 for the CIS, and 2020 for the National System, https://www.cne.cl/wp-content/uploads/2015/07/ITD_OCT_2010_SIC.rar, https://www.cne.cl/wp-content/uploads/2015/08/ITD-SIC-OCT15.pdf. https://www.cne.cl/wp-content/uploads/2020/08/ITD-PNCP-Jul20-Rectificado.pdf

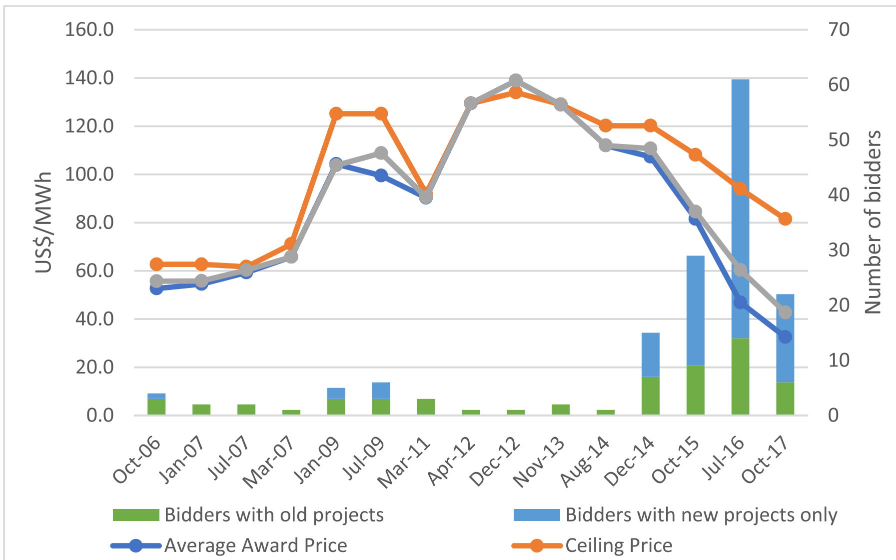

Fig. 2. Energy auctions to supply regulated customers: Average bid prices, average award prices, and ceiling prices. The date corresponds to the submission deadline.
Source: Compiled by author from https://www.licitacioneselectricas.cl

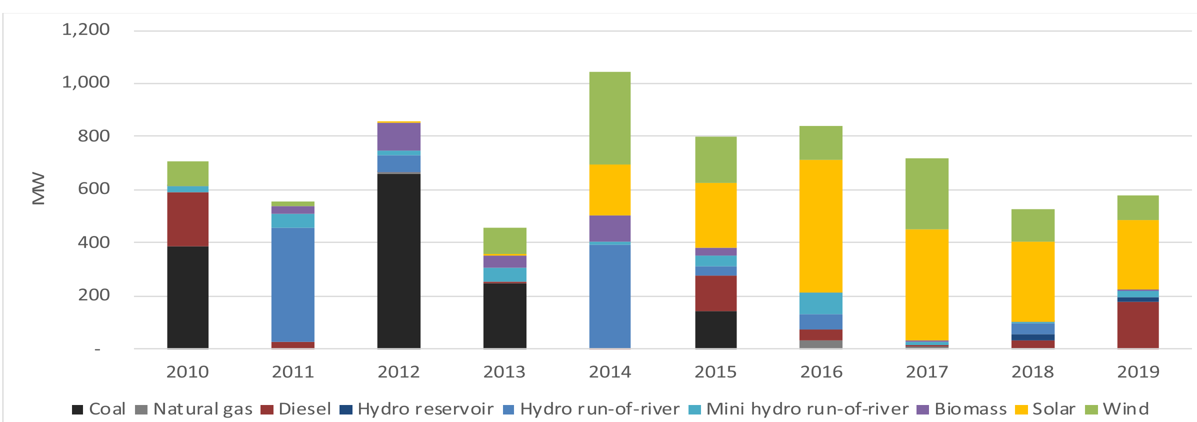

Fig. 3. New generation capacity, CIS.
Source: Author's compilation based on NEC (http://energiaabierta.cl/blockchain/), 2020.

The above policies and developments, however, seem insufficient to explain the rapid NCRE expansion. First, NCRE generation always has exceeded the target. In 2020 NCRE accounted for 23.4% of total generation,[18] surpassing the 20% target set for 2025. This situation will not change in the coming years. As of December 31, 2020, 80.7% of the generation capacity under construction were NCRE plants, 14.2% hydroelectric plants with a maximum capacity of more than 20 MW, and the remaining 5.1% oil-fired plants, which rarely generate [23].

The tendering of energy time blocks tailored to the production profiles of NCRE generators in the auctions called to supply regulated customers also had limited benefit. First, competition among RE producers reduced prices in these time blocks. In the 2014–2016 auctions, the award prices were significantly lower in the daytime blocks intended for PV farms. Moreover, bids with lower prices in these time blocks may

[18] That year, NCRE generation reached 16,794 GWh, representing 23.4% of energy sales, which amounted to 71,782 GWh (http://datos.energiaabierta.cl/dataviews/92666/cumplimento-de-ley-ernc-20257/).

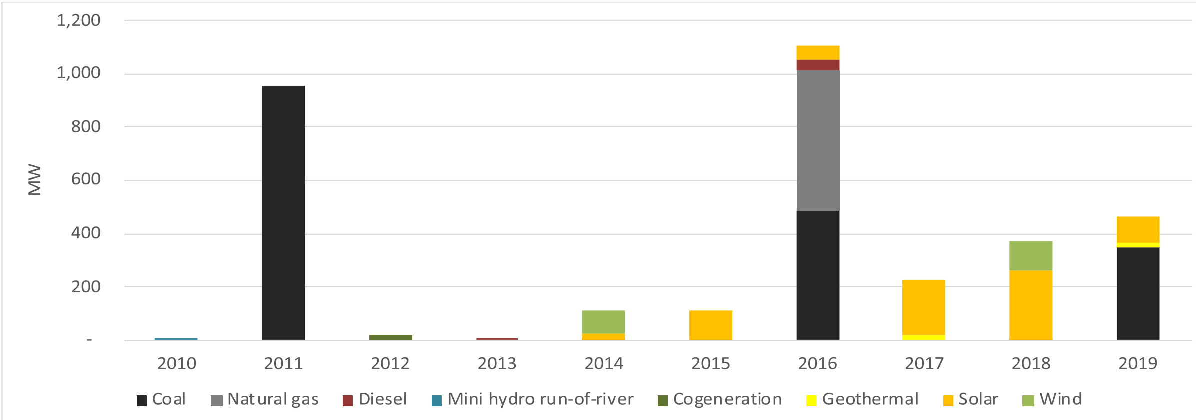

Fig. 4. New generation capacity, BNIS.
Source: Author's compilation based on NEC (http://energiaabierta.cl/blockchain/), 2020.

not win contracts, as was the case in the 2017 auction (https://www.licitacioneselectricas.cl/). The reason is that contract award algorithms seek to cover all demand and the auction rules allow bidders to link bids submitted to different time blocks, conditioning them (for example) on being awarded all or none.

Data points to the sharp drop in RE generation cost as the primary driver of the drastic fall of prices since 2014. The world's weighted average LCOE of commercial-sized PV plants halved between 2010 and 2014, and that of wind generation fell by 72% over the same period [24]. In 2014, the world's most competitive PV projects provided electricity for just US$ 80/MWh, and the best wind projects consistently generated electricity for US$ 50/MWh. By 2017, the LCOE of the most efficient PV and wind projects had fallen to US$ 30/MWh [25].

In the auctions convened to supply regulated customers, the average bid prices of firms that supported their submissions exclusively with PV or wind projects fell by approximately two-thirds between 2014 and 2017, reaching levels similar to the lowest in the world, as Fig. 5 shows. In the November 2013 auction, one wind project and two solar projects backed submissions, raising to 22 and 20, respectively, in the July 2016 auction (Fig. 2).

The above is evidence that electricity market design was appropriate and that regulatory changes intended to level the playing field for all companies worked. Despite this conclusion, it follows that the Chilean electricity sector would have experienced extremely high energy prices in the second half of the 2010s if the costs of RE had not fallen as sharply as they did, given the almost impossibility of installing conventional baseload plants.

The rapid expansion of renewable energy presents new market design challenges. The way of calculating the spot prices ignores intertemporal plant inflexibilities, such as ramp times and plant technical minimums, which affect dispatch (see Ref. [26]). This approach was reasonable in 1982 when demand fluctuated little throughout the day in the BNIS (about 90% came from large mining operations), and hydroelectric generation share in the CIS fluctuated around 80% (Table 1). However, it has become less realistic with the sharp drop in hydroelectric generation share and, more recently, the massive commissioning of PV and wind farms.

A second challenge will be the calculation of the plants' sufficiency power. The current method measures plants' availability at peak hours. This approach does not take into account that variable RE is not dispatchable. Intuitively, it seems that the measurement of the plants' sufficiency power should consider the hour of highest net demand (demand less the contribution of non-dispatchable energies), but proving this is beyond the scope of this paper. It is also unlikely that foisting the AS costs on consumers, either directly or indirectly, will lead to the efficient working of markets.

7. Lessons learned

Chile's experience shows that a decentralized energy market can work well. Investment has been sufficient to support the economy's growing demand for energy, and occasional energy shortages were mainly due to regulatory defects. The profitability of generating companies was not excessive for a developing economy, even when regulatory deficiencies were at their worst between 1989 and 1997 (see footnote 5).[19] On the other hand, it illustrates the unlikelihood of implementing the perfect market design from the outset, especially if there is no previous experience elsewhere on which to build.

Policymakers design markets based on economic theory, but often without complete information. In particular, they set market rules without knowing how economic agents will interact with them. Although game theory, behavioral theory, and experimental economics can help anticipate how markets will work [3], only the operation of the market reveals some of its design flaws, as the Chilean experience shows. Consequently, a first lesson is that the initial market design is likely to need adjustments to correct initial defects or to respond to new information or technological advances.

Chile's Act incorporated aspects usually left to the regulator's discretion, an approach chosen to reassure investors that the regulatory agency would not change the rules on a whim.[20] Therefore, minor regulatory changes required congressional approval, which was hard to obtain when the economically and socially powerful electricity companies opposed them. A less concentrated sector would probably have had less lobbying power. Thus, regulatory rigidity may be necessary to attract investors in certain circumstances, but it should be a reason to avoid unnecessary hindrances to reform the law when needed.

The governance of the system coordinator is highly relevant as its decisions often have significant economic consequences for electricity companies. The Act drafters' decision to let companies select the ELDC made it difficult for the boards to resolve the internal disputes leading to temporary market dysfunctions, such as the energy shortages in 1998–99. This understanding led legislators to create an independent specialized Panel to resolve ELDC disputes and later substitute the ELDCs with an independent Coordinator.

Another lesson is that a well-functioning energy market requires

[19] Other factors explaining this result include the price ceilings on small customers purchases and the government's pro-competitive use of Colbún, a hydropower plant commissioned in 1986 and privatized in 1997.

[20] [27] praise this choice arguing that in the 80s Latin American governments had to weigh the advantages of flexible regulation against the possibility of regulatory opportunism. In this case, however, this is debatable since local investors with close ties to the regime acquired power companies.

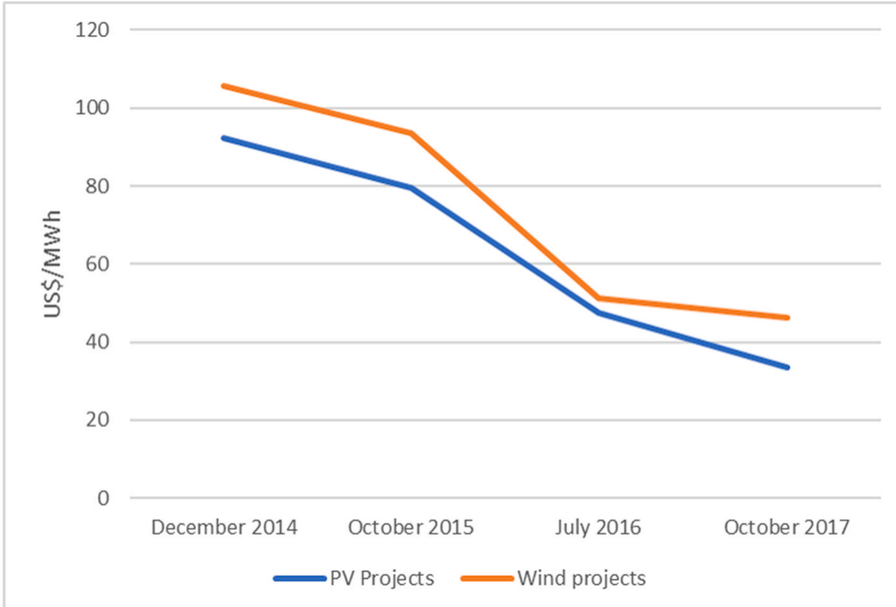

Fig. 5. Average bid price by firms backing their submissions with new projects.
Source: Author's calculation based on NEC's database. https://www.cne.cl/nuestros-servicios/licitaciones-y-suministros/

ensuring the expansion of transmission facilities to meet users' needs and non-discriminatory and cost-reflective access to grids. The Act drafters expected symmetrical bargaining power in transmission toll negotiations as they involved large companies and generators could always build their lines. However, their trust ignored that transmission installations are essential facilities due to their significant scale economies. Thus, transmission lack of regulation led to lengthy and costly litigation, especially when service provision required system expansion. Hence, after trying more decentralized solutions, Chile opted to treat transmission as a public service.

Less visible design flaws often remain unresolved for many years, such as capacity payments in Chile. In theory, given the criteria for calculating the peak power price and the plants' sufficiency power, investors should install baseload and reserve plants until the sufficiency power of the system equals the system's peak demand increased by the reserve margin. However, once the NEC sets the peak power price, investors have incentives to install cheap and inefficient reserve plants, as the diversity of unit operational costs among oil plants in Table 3 shows. This situation leads to over-investment in low-yield oil plants and high spot prices if dispatched.[21]

Comparing Chilean experience with other countries that reformed their electricity sector provides additional lessons. The second country to introduce an energy market was the UK. The British Electricity Act (BEA) issued in 1989 forced generators and consumers in England and Wales to trade energy in the spot market. The BEA also created a coordinating body to schedule generation to meet demand in real-time at the lowest aggregate cost. To this end, the system coordinator constructed an energy supply for each half-hour from the quantities and prices offered by generators for their different generation units. The spot price corresponded to the offer price of the last unit dispatched. Likewise, the BEA provided payments for the capacity made available to the system, although its formula differed from the Chilean one [28].

As for the British market restructuring, the unbundling of the public generation company led to the creation of one transmission company and three generators, all privatized in 1990 except for the generator formed with the nuclear plants privatized in 1996. In 1989–1990 the two privatized generators produced 48.0% and 29.7% of electricity, respectively. The transmission company, initially collectively owned by the distribution firms, took over the coordination of the system. Distribution firms were granted monopoly franchises overall customers with peak loads less than 1 MW [28].

UK regulators soon realized that they had underestimated the generators' market power, leading to successive regulatory changes. First, the authorities forced the two largest generators to divest 15% of their capacity in two years in 1994. In1994–1995, their respective market shares were 33.9% and 25.9%. The regulators also capped the pool prices, quite at odds with the deregulatory principles of reform. The scarce effects of these measures led the authorities to modify the energy market architecture in 2001. The New Electricity Trading Arrangements (NETA) removed the obligation to trade on the spot market and replaced the centralized dispatch with a supply-demand balancing mechanism.

Thus, the UK addressed the problems in the energy market faster than Chile. Two complementary hypotheses can be advanced to explain this difference: the above-described legal and political difficulty to modify regulations and a better initial market design in Chile. An indication in support of the latter is that British regulation, in Wilson's [2] terminology, shifted from an integrated market with energy traded on the spot market to a disintegrated market in which parties negotiate bilateral contracts and the spot market is used to settle last-stage energy imbalances, as Chile established from the outset.

In principle, disintegrated markets should be more competitive to the extent that parties agree on the contract terms with enough time from the start of supply as supply is more price-elastic in the medium term than in the short run. In Chile, large customers such as mining companies confronted the generators' market power by contracting energy through auctions called with anticipation. In contrast, a centralized spot market, with highly inelastic demand, daily auctions, and complete information on the offers of each participant, created the ideal conditions for the tacit collusion of generators [29].

Integrated markets where parties enter into financial contracts to hedge against price volatility tend to behave similarly to disintegrated ones. Generators that contracted their generation have no incentive to increase the spot price, as they have to pay the difference between the spot price and the contract price. Empirical evidence, although scarce, supports this conjecture. Wolak [30] hypothesizes that high initial levels

[21] Oil-fired plants accounted for 21% of installed capacity and just 2% of generation in 2015 [19].

of contract hedging in the Australian market were the cause of low electricity prices during its first months of operation. In the UK, generators and customers could enter into financial contracts. Initially, contracts for differences with generators covered the needs of distribution companies. Prices increased when these contracts expired without being renewed.

British and Chilean law established the merit-order dispatch of plants, one based on offer prices and the other on marginal costs. Both approaches should lead to similar outcomes only in competitive spot markets. The UK experience suggests that if Chile had used offer prices instead of marginal costs for dispatching plants and determining spot prices, it would have increased the market power of Endesa, despite the spot market only serves to offset energy imbalances between generators (see Ref. [12]). Thus, a final lesson is that a combination of a disintegrated market with marginal cost-based dispatch works better than an integrated market unless the parties enter into financial contracts in addition to trading energy in the spot market.

8. Conclusions

Chile was the first country to create an energy market in 1982, and its core has remained unchanged since then. It consists of (i) of a market in which generators and large customers, including distributors on behalf of their regulated customers, trade supply contracts, (ii) a centralized dispatch of power plants in ascending order of cost, regardless of their owners' supply contracts and (iii) and an exchange market in which generators cancel out their energy and power (energy measured at the peak demand hour) imbalances, which are valued using peak-load pricing. Legal changes affected aspects lateral to the energy market design, such as generators' access to grids and the governance of the system coordinator, aspects that nevertheless showed their relevance for the functioning of energy markets.

In 2004 and 2005, legislators introduced pro-competition measures. These included regulation of transmission and distribution networks, strengthening sector institutions, and modifying auction rules to facilitate the participation of new bidders in supplying regulated customers. Despite these changes, no new generators entered the market, and energy prices soared. The primary cause was the halt in the construction of conventional power plants, hydroelectric and thermal, due to the increasing environmental restrictions and citizen opposition.

Since the mid-2010s, investment in renewables increased rapidly. Policies to promote NCRE may have contributed to this, but the primary cause was the sharp fall in the costs of these technologies. In the auctions called to supply regulated customers, the number of bidders soared, and bid prices fell abruptly. In particular, bidders who backed their proposals with NCRE plants offered prices similar to the lowest in the rest of the world.

The above is an indication that, following regulatory changes, the market design is working well. Many companies are competing vigorously, and energy prices tend to reflect the long-term costs of new baseload technologies, i.e., PV and wind farms. In the future, however, the increasing penetration of variable renewables will force changes in market design related to spot price calculation and the development of an efficient ancillary services market.

Credit author statement

Author: Pablo Serra: Conceptualization, Formal analysis, Investigation, Writing, Visualization (Tables 1–3). Research assistants: Carlos Matamala: Visualization (Figs. 1 and 3, 4), Giovanni Villa: (Figs. 2 and 5).

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.

References

[1] M. Pollit, Electricity reform in Chile lessons for developing countries, Compet. Regul. Netw. Ind. 5 (3–4) (2004) 221–263, https://doi.org/10.1177/178359170400500301.

[2] R. Wilson, The architecture of power markets, Econometrica 70 (4) (2002) 1299–1340, https://doi.org/10.1111/1468-0262.00334.

[3] A. Roth, Marketplaces, markets, and market design, Am. Econ. Rev. 108 (7) (2018) 1609–1658, https://doi.org/10.1257/aer.108.7.1609.

[4] S. Bernstein, Competition, marginal cost tariffs and spot pricing in the Chilean electric power sector, Energy Pol. 16 (4) (1988) 369–377, https://doi.org/10.1016/0301-4215(88)90183-8.

[5] Endesa, Producción y Consumo de Energía en Chile, 1986. ISSN 0711-353X, http://www.memoriachilena.gob.cl/602/w3-article-80929.html.

[6] CNE. Balance Nacional de Energía 1977-1996 Chile, Comisión Nacional de Energía, Santiago, 1997, pp. 1–206.

[7] CNE. Estadísticas Sector Energía Chile 1990-2004, Comisión Nacional de Energía,, Santiago, 2005.

[8] CNE, Generación Bruta, 2021. https://www.cne.cl/wp-content/uploads/2021/09/Generación_BrutaAnuario.xlsx.

[9] CDEC-SIC, Estadísticas de Operaciones, 1990-1999, 2000. https://sic.coordinador.cl/wp-content/uploads/2014/01/anuario2000.pdf.

[10] R. Fischer, P. Serra, Efectos de la privatización de Servicios públicos en Chile Serie de Estudios Económicos y Sociales CSC-07-009, Inter-American Development Bank, Washington D.C., 2007, pp. 1–148. https://publications.iadb.org/publications/spanish/document/Efectos-de-la-privatizaci%C3%B3n-de-servicios-p%C3%BAblicos-en-Chile.pdf. (Accessed 15 December 2021).

[11] C.F. Basañes, E. Saavedra, R. Soto, Post Privatization Renegotiation and Disputes in Chile IFM-116, Inter-American Development Bank, Washington D.C., 1999. https://publications.iadb.org/publications/english/document/Post-Privatization-Renegotiation-and-Disputes-in-Chile.pdf. (Accessed 15 December 2021).

[12] P. Joskow, Comments on Fischer and Serra, Economia 1 (1) (2000) 199–209, https://doi.org/10.1353/eco.2000.0003.

[13] R. Fischer, P. Serra, Regulating the Electricity Sector in Latin America, Economia 1 (1) (2000) 155–198, https://doi.org/10.1353/eco.2000.0003.

[14] M. Boiteux, Peak-load Pricing, J. Bus. 33 (2) (1960) 157–179. https://www.jstor.org/stable/2351015.

[16] R. Fischer, A. Galetovic, A. Regulatory Governance and Chile's 1998-1999 Electricity Shortage, J. Pol. Reform 6 (2) (2002), https://doi.org/10.1080/1384128032000145323.

[17] C.A. Díaz, A. Galetovic, R. Soto, Anatomía de una crisis eléctrica, Revista de Análisis Económico 16 (1) (2001) 1–49. https://www.rae-ear.org/index.php/rae/article/view/1.

[18] H. Rudnick, M. Soto, R. Palma, Use of system Approaches for transmission open access pricing, Int. J. Electr. Power Energy Syst. 21 (2) (1999) 125–135, https://doi.org/10.1016/S0142-0615(98)00054-4.

[19] CNE, Anuario Estadístico de Energía 2005-2015, 2016. https://www.cne.cl/wp-content/uploads/2016/07/AnuarioCNE2015_vFinal-Castellano.pdf.

[20] Revista Electricidad, Grandes compañías apuestan por contratos de energía 100% ERNC por mayor oferta, 2017. https://www.revistaei.cl/2017/10/26/grandes-companias-apuestan-contratos-energia-100-ernc-mayor-oferta/.

[21] Valgesta, Energía, Boletín Informativo, January 2020, 2020. https://www.valgesta.com/bole/2020/1.Enero-2020.pdf.

[23] CNE. Sector Energético, Enero 2021, Comisión Nacional de Energía, 2021. https://www.cne.cl/wp-content/uploads/2021/01/%20RMensual%20_v202101.pdf.

[24] IRENA, Renewable Power Generation Costs in 2014, International Renewable Energy Agency, Abu Dhabi, 2015. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/IRENA_RE_Power_Costs_2014_report.pdf.

[25] IRENA, Renewable Power Generation Costs in 2018, International Renewable Energy Agency, Abu Dhabi, 2019. https://www.irena.org/publications/2019/May/Renewable-power-generation-costs-in-2018.

[26] F.D. Muñoz, C. Suazo-Martínez, E. Pereira, R. Moreno, Electricity market design for low-carbon and flexible systems: room for improvement in Chile, Energy Pol. 148 (PB) (2021), https://doi.org/10.1016/j.enpol.2020.111997.

[27] P. Spiller, L. Viana-Martorell, How should it Be done? Electricity regulation in Argentina, Brazil, Uruguay and Chile, in: R.G. Gilbert, E.P. Kahn (Eds.), International Comparisons of Electricity Regulation, Cambridge University Press, Cambridge, 1996, pp. 82–125.

[28] J. Kwoka, Transforming Power, Lessons from British Electricity Restructuring, Regulation 20 (3) (1997) 47–54. https://www.cato.org/sites/cato.org/files/serials/files/regulation/1997/7/reg20n3e.html.

[29] A. Sweeting, Market Power in the England and Wales Wholesale Electricity Market 1995-2000, Econ. J. 117 (520) (2007) 654–685, https://doi.org/10.1111/j.1468-0297.2007.02045.x.

[30] F.A. Wolak, An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market, Int. Econ. J. 14 (2000) 1–39, https://doi.org/10.1080/10168730000000017.