



A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

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Oxford Energy Forum 104 (February 2016) looked at the transformation under way in the electricity sector, driven by technological developments and policies on decarbonization. It focused mainly on OECD (Organisation for Economic Co-operation and Development) countries, and on Europe in particular, where there are major challenges, ranging from the practical issues associated with the integration of the new intermittent renewable sources to the wider policy question of whether there is a fundamental conflict between two objectives – decarbonization and liberalization – to which these countries are committed. This issue of the *Forum* explores related issues, but on a wider canvas – countries across the world, with a diverse range of approaches, many outside the OECD.

Unsurprisingly, with this wide perspective, the picture is one of considerable variety. Liberalization and decarbonization are secondary issues, at best, for many of the countries examined in this issue. Other goals often have priority – such as the need to incentivize new capacity to modernize the system or meet growing demand (for example in Russia and India). Many of the systems discussed



here are considerably more centralized than is typically the case in Europe; competition is often limited to generation, and consumers are normally regarded as a captive market. So some of the challenges Europe is facing are of limited interest to decision-makers in these countries.

At the same time, there is a surprising degree of commonality across the world; many countries face very similar problems, and while there has been a range of different responses, a number of broad themes emerge. For instance:

- Renewables are growing rapidly in all parts of the world. Even where there is no overriding climate-change policy motivation (e.g. South Africa and India), the falling cost of renewable sources has increased their attractiveness – with the result that the problems associated with integrating these new sources are being faced across the world.
- Electricity markets are in general becoming more complex. While some countries or regions still operate energy-based markets (e.g. the Electric Reliability Council of Texas and Australia's National Energy Market), the general trend is to develop other products (such as ancillary services, flexibility, reliability, capacity, and green certificates), which are accounting for an increasing proportion of total system costs.
- These new products are often developed via special mechanisms. Increasingly, the emphasis is on contracts and auctions rather than bilateral markets or exchange trading,

and in many ways this is changing the dynamic of the sector and reinforcing central decision-making.

- This in turn tends to undermine the scope for effective consumer response (which *OEF* issue 104 identified as a key element of the new approach). Many decisions are being made via the new centralized mechanisms in which it is impractical for most consumers to participate. The result is normally that the costs determined centrally are passed through to consumers administratively rather than through responsive price mechanisms. It is notable how much the articles in this issue focus on wholesale markets and mechanisms rather than on consumer markets.
- Although most economists (and many of the authors in this issue) favour carbon pricing as an effective route to decarbonization, this tool is little used in practice – even in China, where there is a national cap-and-trade system, initial prices have been low and have had little direct impact.

Despite the variety of routes being taken by the different countries examined, one message comes out of a number of the articles: that they can learn from each other's experiences, and in particular that there is an opportunity for developing countries to 'leapfrog' advanced economies by developing new market structures which integrate low-cost renewables and decentralized sources more effectively.

Three articles look at differing approaches to liberalization and

decarbonisation within North America. *Walter Graf and colleagues* consider the case of Ontario, which has proved very successful on at least one measure, having achieved a system 90% based on low-emission sources, with coal and gas now playing only a minor role. But there have also been challenges – for instance, rising consumer costs at a time of falling wholesale power prices – and some have suggested a return to centralized planning. Instead, the authors propose market reform with an expanded role for wholesale markets, flexibility and ancillary services, and capacity payments. They also put forward ideas for pricing 'environmental attributes' and promoting distributed resources, leading to a vision of a five-component market. *Fereidoon Sioshansi* looks at California's nonconventional forms of liberalization and experience with decarbonization. Again, this has proved very successful in some respects – California is the leading US state on solar energy by a wide margin, and is home to a growing number of 'community choice aggregators' providing a sort of alternative route to liberalization. But like other jurisdictions, it has also faced problems – such as in determining fair retail tariffs which allocate costs equitably between, for example, solar and non-solar customers. *Audun Botterud* looks at the market operated by the Electric Reliability Council of Texas (ERCOT). Like many other markets, it has been experiencing a high level of growth of renewables; unlike many others, however, ERCOT remains faithful to its energy-only market and to the promotion of retail competition. The market is likely to face future challenges as the penetration of wind power continues to grow, but Botterud predicts that it will still be able to cope, with some evolutionary improvements – for instance an intraday market with more decentralized balancing. *Steven*



Corneli takes a wider look at the options for integrating new renewable resources in the US system as a whole. He makes a case for what he calls 'configuration markets'. The markets would proceed via periodic auctions under which existing and proposed resources (including transmission) would submit bids consisting of the revenues they would need to continue operating or to commit to development and operation. The configuration model would use these bids in its optimization process to identify a least-cost configuration of the system as a whole.

A number of articles look at the issues faced in Latin American systems, many of which are largely dependent on hydro power. *Pablo Rodilla and colleagues* look at the Chilean market, which, like many others, has been experiencing a rapid penetration of renewables. Chile is in many ways a special case: it is an OECD country in South America, with a distinctive geography, and has been a pioneer in electricity liberalization (which started there in 1982). Its market is based on long-term contracts and captive consumer demand, to which has now been added a requirement to incorporate renewable energy sources. The authors argue that market reforms will be needed to integrate these new sources efficiently, in particular to incentivize flexibility, expand ancillary markets, and co-optimize energy and reserves. *Carlos Batlle and colleagues* look at the market in Brazil, which has been struggling for some years to find the best ways to attract investment to match the rapid growth in demand – in a hydro-based system which faces occasional but extended droughts. Brazil's market, like others in South America, is based on long-term contracts, which may move out of line with market realities, especially in drought years, creating significant risks for market participants. The authors describe a more responsive market that

offers more granular wholesale prices, a capacity product, and clean energy certificates. *Iván Mario Giraldo and David Robinson* examine Colombia's electricity system, which presents many points of comparison with Brazil's, including the risk of El Niño-related droughts. Colombia has a reliability market based on firm energy, but the authors argue that it does not take sufficient account of the complementary effect of different sources on overall system reliability, and discourages investment in nonconventional renewable energies, like wind and solar. They propose changes which would recognize the full value of nonconventional sources and reward the ability of energy resources both to cope with extended shortages and to provide short-term flexibility. *Michael Hochberg and Rahmatallah Poudineh* look at experience with auctions in the electricity systems of Brazil and Mexico. They link the interest in auctions with the wish to promote renewable sources (which can be difficult to remunerate in conventional markets) and consider the trade-offs involved in auction design. They conclude that there is no one-size-fits-all approach and that auction design must be subject to continuous review to respond to new circumstances.

Eurasia is also home to a variety of approaches. *Ksenia Letova and colleagues* look at the market in Russia. Because of the vast size of the country, it is split into separate pricing zones, each of which has a different underlying generation structure. A key concern in Russia has been to encourage investment in new capacity, mainly with a view to modernizing the system. But in some ways, the capacity market has overshot – demand in 2015 was 30 per cent lower than the forecast in 2007, which underlay the projected need for new capacity. Other strains are caused by the effect of the different pricing zones in limiting competition

and the need to integrate inflexible generation like nuclear and combined heat and power. So while Russia does not yet face a high penetration of new renewables, it is experiencing some similar issues in relation to market operation. In China, *David Robinson and colleagues* look at a more specific issue – how coal-fired generation might be phased out over time. This is, of course, an issue of considerable significance for the global climate, and the authors consider a range of measures designed, among other things, to provide long-term credible signals, price carbon more effectively, address concerns over local air pollution, and discourage investment in new unabated coal plants. *Yu Nagatomi* looks at liberalization and decarbonization in Japan, where the position is complicated by the uncertainty about the future role of nuclear power following the Fukushima incident. Japan has been following a process of gradual market liberalization for the past two decades, and there is a new post-Fukushima emphasis on the promotion of renewable sources via feed-in tariffs. This has led to concerns about overinvestment, equity, and costs, and the author argues that there is a risk of introducing too many ill-coordinated market interventions.

Jorge Blazquez and Rolando Fuentes look at developments in Gulf Cooperation Council countries. They point out that liberalization in the region has seen rather mixed progress; however, as in many other parts of the world, renewables are seeing rapid growth. The authors suggest that a more concerted approach to these issues could deliver a triple benefit: greater efficiency, higher potential for oil exports, and faster energy decarbonization. *Anupama Sen* looks at the challenges involved in integrating decarbonization and market reform in India, where the rapid development of renewables is encouraged as much by



economics as by climate change. She argues that there has been an emphasis on quantity over quality of capacity – perhaps understandable in view of the rapid growth in demand in India, the financial problems of the state electricity companies, and the generally low level of reliability of public electricity supply. She argues for a more integrated approach which would bring together India’s objectives for decarbonization and electricity market reform.

In other parts of the world, *Bruce Mountain* considers Australia’s National Electricity Market. He notes recent increases in electricity prices, concern about power stability, and the dubious effectiveness of retail markets, concluding that instead of waiting for top-down centralized solutions, Australia should embrace decentralization and markets that value flexibility and adaptability. Finally, *Anton Eberhard and Catrina Godinho* look at experience in South Africa. That country is something of an outlier in sub-Saharan Africa, accounting for fully half of the generation there and having achieved much higher levels of access to power than elsewhere in the region. Despite these successes, the central role of its dominant utility, Eskom, is coming into question for a variety of reasons, including the considerable success of recent renewables auctions and financial strains within Eskom itself. Although renewables growth has been driven by economic rather than environmental considerations, these factors have prompted renewed consideration of the options for power market reform to meet the new challenges. The authors suggest that countries in the region might be able to draw on the experience of developed economies and ‘leapfrog’ some of the challenges they have faced in integrating renewable resources.

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90 PER CENT DECARBONIZATION IN 10 YEARS: ELECTRICITY MARKET DESIGN LESSONS FROM ONTARIO

Walter Graf, Kathleen Spees, Judy Chang, and Johannes Pfeifenberger

Ontario had great success decarbonizing its electricity sector, increasing the share of energy produced from non-emitting resources to 90 per cent in 10 years (2004–2014). It has also faced challenges because the policy-driven decarbonization has outpaced the evolution of its wholesale power market design. Today, the Ontario Independent Electricity System Operator (IESO) is modernizing its market design for energy, capacity, and flexibility through the Market Renewal program. This effort needs to advance further to fully position Ontario for a clean energy future and implement a robust suite of market-based, technology-neutral products that can be provided competitively by all resource types. To maximize efficiency, competition, and innovation in a decarbonized system, the vision for Ontario’s comprehensive market design could be expanded to include resource-neutral clean-energy products that allow market-based valuation of clean-energy attributes and evolving distribution system services to coordinate demand response and distributed energy resources. This is also a model for the many other markets around the world that are pursuing decarbonization.

Decarbonization achievements and the resulting challenges

In 2004, Ontario began a significant effort to decarbonize its electricity sector and reduce greenhouse gas emissions from coal-fired generators, which met a quarter of the province’s energy needs at the time. By 2014 the

province retired its last coal-fired generating plant. This rapid decarbonization was accomplished through a combination of accelerated coal retirements and resource-specific procurements of cleaner energy resources. Non-emitting generation resources – refurbished nuclear, biomass, wind, and solar – and natural gas replaced most of the coal-fired generation. This substantially decarbonized the Ontario system, from 49 terawatt-hours (TWh) of coal and gas generation in 2003 to 5.9 TWh in 2017.

This ambitious achievement was accompanied by new challenges in the electricity markets. The most obvious problem from a public perspective has been a significant increase in the cost of electricity to end users. Ontario consumers pay for the commodity cost (cost excluding delivery) of electricity in two parts: energy, based on the average Ontario-wide market price for electricity, and a ‘global adjustment’ (GA) that covers investment costs for new resources, maintenance of existing resources, and conservation and demand management programs, and includes coal retirement costs that are still being paid for. While the energy component has decreased by nearly 70 per cent – from Can\$0.052 per kilowatt-hour (kWh) to \$0.017/kWh – between 2008 and 2016 as a result of decarbonization and low gas prices, the GA has increased more than 15-fold over the same time period (from \$0.006/kWh to \$0.097/kWh). (IESO, “[Global Adjustment](#)”.) As a result, the total commodity cost of electricity has increased from \$0.058/kWh to \$0.113/kWh, or almost 100 per cent. While some increase associated with decarbonization is unavoidable in most regions, a significant portion of the cost increase in Ontario likely has been associated with inefficiencies in wholesale market design and long-term procurement.



Like many decarbonizing markets, Ontario experienced a reduction of wholesale power prices, as shown in the figure below, with many low-, zero-, and negative-price hours driven by negative price offers from inflexible resources and resources with feed-in tariffs. As a result of the changing resource mix, Ontario now commonly experiences surplus generation events and system flexibility challenges that historically were handled by fossil-fuel plants. Curtailment of renewable and other generation is common, with over 3,300 gigawatt-hours (GWh) of wind and solar generation curtailed and 960 GWh of nuclear manoeuvres and shutdowns during periods of surplus baseload generation in 2017, representing 26 per cent of renewable and 1 per cent of nuclear generation output, with additional hydro curtailments and spilling beyond these figures. (IESO, “[2017 Electricity Data](#),” 2018.)

Many of these emerging issues relate to the fact that the current wholesale market was designed before decarbonization, when it handled a very different supply mix. The limitations of the existing market design were

recognized by the Market Design Committee that originally developed the system. It was intended as a temporary solution that would transition to a system with locationally-varying pricing over 18 months, but it has remained in place for one and a half decades.

Various patches and temporary improvements have been layered onto the original design, but these are insufficient to address today’s challenges. The inefficiencies of the existing design have been documented and analysed by the IESO, the market monitor, and independent observers. The changing supply mix and increasing flexibility needs have amplified these challenges. The introduction of new technologies, such as distributed generation and storage, add operational complexities that will also require significant modifications to the overall market design.

Current efforts to redesign Ontario’s electricity market

The Ontario IESO has introduced an ambitious Market Renewal program at the wholesale level to help address the market’s growing efficiency, reliability, and cost challenges. While the specific implementation details of this program

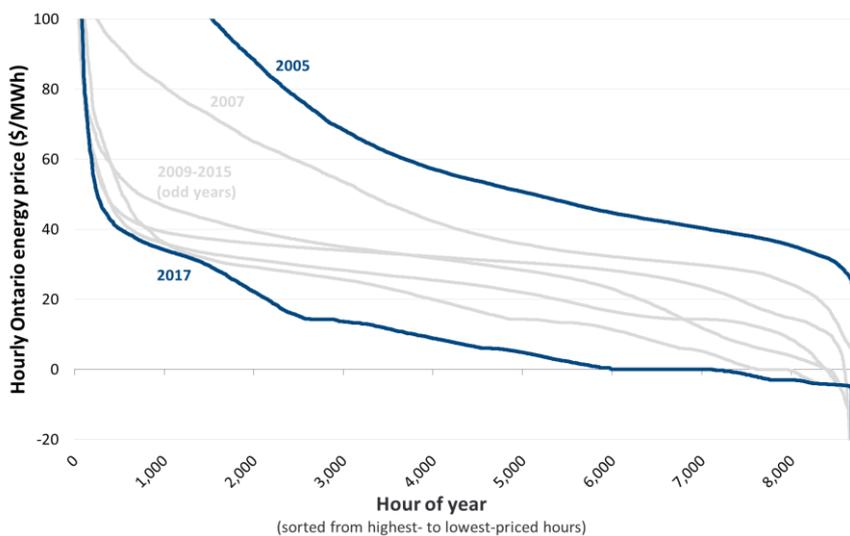
are still under development, the general features are organized into three workstreams:

- **Energy:** Move to a market with a single schedule for operations and financial settlement, including locational marginal pricing for suppliers, improved generation commitment and dispatch in real time, and a financially binding day-ahead market.
- **Operability:** Increase system flexibility to reduce the cost associated with surplus-generation conditions, variable renewable generation uncertainties, and the need to curtail resources.
- **Capacity:** Improve procurement of resources to meet the province’s resource adequacy needs through an incremental capacity auction that stimulates competition from all qualified supply resources in a technology-neutral manner.

These reforms will increase the extent to which Ontario relies on transparent market-based mechanisms to provide electricity to all consumers. ([See here](#)). The primary benefits of the Market Renewal program are:

- savings on fuel, emissions, and operations and maintenance costs
- reduced curtailment/spilling of nonemitting resources
- increased export revenues and reduced import costs
- investment cost savings
- reduced gaming opportunities, administrative complexity, and unwarranted transfer payments

Ontario wholesale power prices, 2005–2017



Source: Based on data from IESO (2018), Hourly Ontario Energy Price, 2002-2017, available at: <http://www.ieso.ca/en/power-data/data-directory>



- enhanced competition and innovation
- alignment with provincial policy goals.

In previous work, we estimated the benefits of each of the three Market Renewal workstreams. The projected value of benefits between 2021 and 2030 is approximately \$510 million from energy market reforms, \$580 million from operability reforms, and \$2.5 billion from capacity auction reforms. Benefits are expected to continue beyond 2030 and grow over time as more existing contracts expire. These benefits compare to \$200 million in estimated IESO implementation costs.

Overall, we estimated the 10-year present value of Market Reform benefits at approximately \$3.4 billion (net of implementation costs), with a baseline benefit-to-cost ratio of 18-to-1. Considering the uncertainties about the nature of reforms and the magnitude of benefits from each workstream, these net benefits over 10 years could range from \$2.2 billion to \$5.2 billion, with a benefit-to-cost ratio ranging from 12-to-1 to 27-to-1. In other words, the benefits from Market Renewal are expected to greatly outweigh the implementation costs, even considering the significant uncertainty range.

We also expect Market Renewal to produce additional benefits that have not yet been quantified. For example, the above estimates do not include the benefits of better integration of diverse and emerging resources, reduced opportunities for gaming and administrative burden, for both the IESO and market participants, or the longer-term savings from enabling innovation through a more open, competitive marketplace.

The future of the market

Ontario’s aggressive decarbonization and increasing reliance on variable and intermittent resources have forced it to

face head-on issues that are just becoming salient in other markets. Worldwide, the electricity industry is undergoing a fundamental shift in resource mix, policy drivers, technology costs, and customer preferences. Wholesale markets are also adjusting to these new realities – but not always quickly enough to match the pace of change. Policymakers and industry participants are similarly impacted as these shifts will require fundamentally different policy approaches and business models. To some, uncertainty about the future appears so troubling that they suggest a return to the regulated planning approaches of the past.

We see a different future with an expanding role for wholesale markets, harnessing competition and innovation to supply a wider array of electricity services from a broad pool of conventional and emerging technologies. The volume and value of these grid services will change over time, as will the revenue sources available to individual market participants. These shifts in grid values will likely include changes to wholesale energy, flexibility and ancillary services, and capacity markets, corresponding to the three workstreams of Ontario’s Market Renewal described above:

- **Energy markets:** Baseload energy prices are low and will continue to bottom out in many hours as markets continue to decarbonize, but this need not result in a complete collapse of the energy markets, as some fear. Instead, the emerging influence of scarcity pricing, storage, and demand response will produce much higher prices during shortage events, thus improving incentives for fast-responding and peaking resources.

Energy markets also have to change to more accurately place higher value on peak pricing hours (including adding compensation for commitment and minimum generation costs incurred in other hours).

- **Flexibility and ancillary services:** This important market component will continue to expand as a more material revenue source in both volume and price, as well as playing a key role by supporting energy prices during scarcity and peaking events.
- **Capacity markets:** Prices for capacity may decline through transition periods as new clean energy resources enter and contribute to oversupply conditions; but over time, capacity prices are likely to increase to the higher levels needed to attract and retain adequate supply. Compared to today’s markets, a decarbonized grid will likely require a much greater share of price-responsive demand and storage for supplying capacity needs. We expect that Ontario will need to attract a much more significant share of these resources than other markets in order to stay decarbonized.

Two additional wholesale market components, not yet addressed by Ontario’s Market Renewal effort, likely will become increasingly important to maintain or expand the province’s clean energy grid:

- **Environmental attributes and carbon markets:** To maintain or expand the current level of decarbonization, value streams for low-carbon



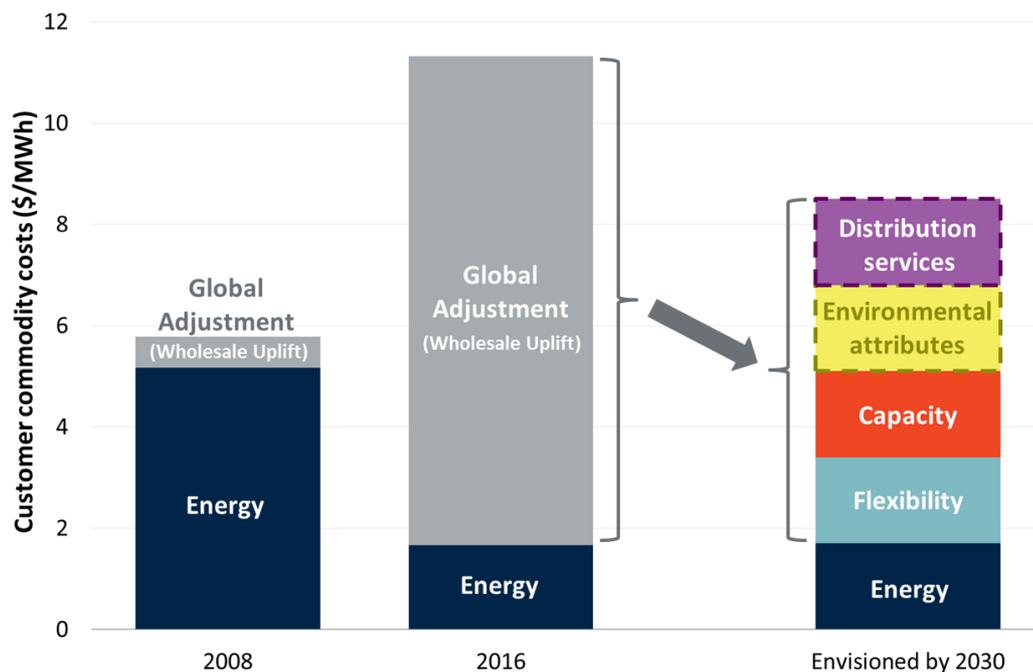
electricity will need to become a much larger share of the total electricity market and may require the introduction of an entirely new set of competitive products and markets. Ontario already has a cap-and-trade market for carbon emissions, but prices have been relatively low. Given that electricity is already relatively well decarbonized, it is likely that other sectors will be able to reduce carbon emissions more and at lower cost. This may result in some recarbonization in the electricity sector if cap-and-trade is the only mechanism. If the policy goal is to sustain or increase current levels of decarbonization, a higher carbon price may need to be adopted in the electricity sector, or a separate market for clean electricity attributes may need to be introduced.

However, the design of a clean attribute market in Ontario will need to significantly improve over traditional fixed feed-in-tariffs or bundled energy and attribute procurements of the past, to eliminate the incentives for negative energy price offers and better align with carbon abatement value. An example of such a clean attribute market was developed in recent work by the Brattle Group on a dynamic clean attribute product proposed for New England. ([See here](#)).

- Distribution system services:** Technological change has finally advanced to the stage where a broader suite of revenue-generating customer-level and distribution-system products and services is within reach. In

Ontario, distributed resources are being developed more quickly than in many markets, partly driven by the incentives to avoid GA charges. As these distributed resources expand, unlocking innovative business models and solutions will require coordination of wholesale market and customer-side policies. We expect that customer experience and demand for associated products and services will drive disruptive innovation, just as it has in other network industries. Some of the most critical enabling policies are allowing aggregations of distributed resources to participate directly in wholesale markets, and putting customers in control of allowing third-party providers near-real-time access to their meter data.

Evolution of Ontario wholesale electricity market components



Note: Future market components are illustrative and are not intended to represent specific price forecasts. Dotted boxes in third bar represent market components not addressed by current Market Renewal program.
 Source: Costs for 2008 and 2016 are from IESO (2017), Price Overview: Global Adjustment, available at: www.ieso.ca/power-data/price-overview/global-adjustment.



These wholesale market reforms can help to align system costs with incentives for consumers and producers alike. Just as consumers pay for energy and GA market components today, costs for the five market components described above will be passed to consumers, but these costs can be allocated in a way that more closely reflects incremental system costs, instead of socializing many costs as the GA does today. While Ontario's GA has grown unsustainably in recent years, a competitive market-based vision for the future would unbundle market components to improve incentives and lower costs, while ensuring that decarbonization achievements are maintained or expanded.

Conclusion

While the market design evolution discussed here will likely pose many challenges for market operators, policymakers, and industry players, it also introduces new opportunities for value creation. Complementing the existing energy market with additional wholesale market components for flexibility, capacity, environmental attributes, and customer and distribution system services will help to send clearer signals of value to consumers and producers. Ultimately, the power of a market-oriented approach is the ability to define system needs and refine market rules so that they are positioned to attract more innovative, cost-effective, and competitive solutions for meeting those needs and enhancing customer value.

CALIFORNIA'S DECARBONIZATION EXPERIENCE

Fereidoon Sioshansi

Setting a decarbonization target

In 2006, California passed Assembly Bill 32 (AB32), the California Global Warming Solutions Act of 2006. The law requires sharp reductions in statewide greenhouse gas (GHG) emissions, setting the stage for a transition to a sustainable, low-carbon future. It is the first, and thus far the only, comprehensive mandatory programme of its kind in the US.

AB32 requires California to reduce its GHG emissions to 1990 levels by 2020 – a reduction of approximately 15 per cent from projected emissions under a 'business as usual' scenario. It calls for additional reductions by 2030 and 2040, culminating in an 80 per cent reduction below 1990 levels by 2050 – despite continued growth in the state's population and economy.

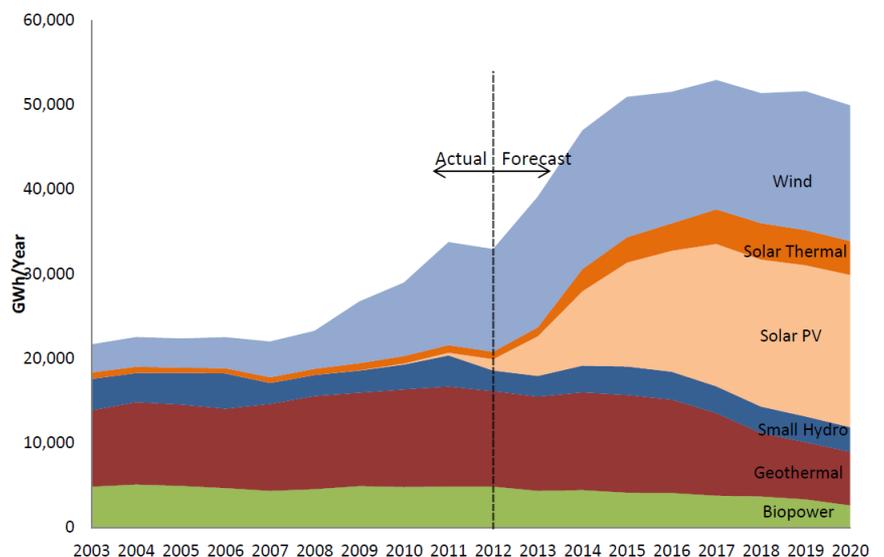
The California Air Resources Board

(CARB) is the state agency responsible for achieving the targets set out in AB32 by adopting 'regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions,' through a wide range of measures including 'improving energy efficiency, expanding the use of renewable energy resources, cleaner transportation, and reducing waste.' CARB's strategy to achieve this is laid out in the Scoping Plan, which was first released in December 2008 and updated in May 2014 ([See here](#)) updates are planned every five years.

Initially, a disproportional share of GHG emission reductions are expected to come from the electricity sector, since decarbonizing this sector is relatively easy and not too expensive. Under the state's Renewables Portfolio Standard, the state's target is 50 per cent new renewables by 2030 – and there have been proposals to raise this target even higher.

This means that by 2030, California's electricity generation mix will have 50 per cent new renewables in addition to the renewable resources that were already in place – including hydro,

California's renewable generation mix, actual and forecasted, 2003–2020



Source: Fong Wan, PG&E; Powering California Forward.



geothermal, biomass, solar, and wind – before the passage of AB32. The balance of the generation mix is expected to come from natural-gas-fired plants, which are relatively low carbon and will continue to be needed, mostly to provide flexibility and balancing services.

AB32 authorizes the collection of a fee from GHG emitters. In 2010, CARB began collecting this fee annually from major emitters, including oil refineries, electric power plants (including those exporting power to California from out of state), cement plants, other industrial sources, and potentially some commercial sources as well. There are approximately 250 fee payers that emit 330 million metric tons of GHG emissions per year. Funds from this fee are used to cover the annual expenses of CARB and other state agencies that help implement AB32.

Recent initiatives

In January 2017, CARB issued a plan to achieve what it called groundbreaking 2030 climate goals, including expansion of existing programmes, continuation of the cap-and-trade scheme, and additional efforts to cut GHG emissions at oil refineries and other major emitters. These efforts are expected to reduce GHG emissions to 40 per cent below 1990 levels by 2030 – the most ambitious target in North America.

California's economy is the sixth biggest in the world, but it is 20th in terms of GHG emissions. Clearly, state officials do not expect state efforts to single-handedly address global climate change. Rather, it is expected that other states, the US federal government, and other countries will follow California's lead once they are convinced that a robust, prosperous economy need not be carbon-intensive. Thus far it has been a hard sell. Few other states have followed, and even

fewer have joined California's cap-and-trade scheme (the Canadian provinces of Quebec and Ontario have expressed interest in linking their climate efforts to it).

At the time of the release of the latest update in January 2017, CARB Chair Mary Nichols said, 'Climate change is impacting California now, and we need to continue to take bold and effective action to address it head on to protect and improve the quality of life in California,' adding,

The plan will help us meet both our climate and our clean air goals in the coming decades and provide billions of dollars in investments to cut greenhouse gases, smog and toxic pollution in disadvantaged communities throughout the state. It is also designed to continue to drive creative innovation, generating good new jobs in the growing clean technology sector.

Among other things, the 2017 updated plan extends the existing cap-and-trade programme through 2030 and includes a new approach to reduce GHGs from refineries by 20 per cent and other measures already underway to ensure that California's natural and working lands increasingly sequester carbon.

The analysis done by CARB led to the conclusion that the state's existing cap-and-trade scheme is the lowest-cost, most efficient policy approach and provides certainty that the state will meet the 2030 goals even if other measures fall short. To date, a total of \$3.4 billion in cap-and-trade funds have been appropriated for the California Climate Investments programme.

This author is not aware of any studies to date that provide a comprehensive assessment of how much GHG emission reductions have been

achieved by the various programmes highlighted in the preceding text, and at what cost. However, a number of studies have provided partial answers to the question or shed light on the effectiveness and/or cost of some programmes. For example, meeting the state's rather ambitious Renewable Portfolio Standard has so far been achieved with relatively little impact on retail rates.

As the state moves towards greater use of renewables, however, the costs of compliance in the electric power sector can be expected to increase – for example, due to the need for more storage, more cycling of flexible natural-gas-fired plants, and more efforts to integrate additional variable renewables into the grid.

The evidence on some of the other measures, including the state's stringent building codes and appliance energy-efficiency programmes, suggest that, for the most part, these measures save more than the costs they impose.

Further research seems prudent to determine which programmes are the most effective and least costly and how the cost-benefit picture is likely to change over time as the required efforts are ratcheted up to meet the 2030, 2040, and 2050 goals. The state's cap-and-trade scheme is expected to be increasingly fine-tuned and ready to take a more central role over time.

Disconnect between decarbonization and market liberalization

Unlike some markets in Europe and elsewhere, where decarbonization goals are directly or indirectly linked to market liberalization efforts, in California's case the two are, for the most part, divorced. This may be mostly explained by the electricity crisis of 2000–2001, when California's nascent 'restructured' market collapsed, ending the liberalization



experiment and retail choice (*The California Electricity Crisis*, James Sweeney, Stanford University Press, 2002).

Decarbonization of the entire economy, not just the electricity sector, remains among the state’s most ambitious targets. How this target is expected to be reached, however, is far from certain, especially once the initial relatively low-hanging fruit has been picked in reaching the 2020 and 2030 targets. Achieving 80 per cent reduction from the 1990 level will be much more of a challenge.

In the short to medium term, a number of parallel programmes are active, each with its own incentives, funding mechanism, and/or regulatory mandate. Together, these programmes deliver the bulk of GHG reductions in the state. They include the following (not necessarily in order of importance):

- Building codes and energy-efficiency standards, including a zero-net-energy building code for new residential buildings starting in 2020 and for commercial buildings by 2030, under the purview of the California Energy Commission;
- Appliance energy-efficiency standards, also under the purview of the California Energy Commission;
- The Renewables Portfolio Standard, requiring 50 per cent new renewables by 2030 and proposed to increase by 2045;
- Several measures designed to increase the numbers of electric vehicles on California roads to 5 million by 2030;
- 1 million solar roofs;

- A generous net-energy-metering scheme, which currently gives credit at the full retail price for every kilowatt-hour fed into the grid;
- Promotion of low-carbon vehicle fuels;
- Integrated land conservation and development strategies;
- A proposal to phase out the sale of new internal combustion engines by 2040.

With these programmes, California leads the states in adoption of solar energy, both utility-scale and distributed, by a wide margin.

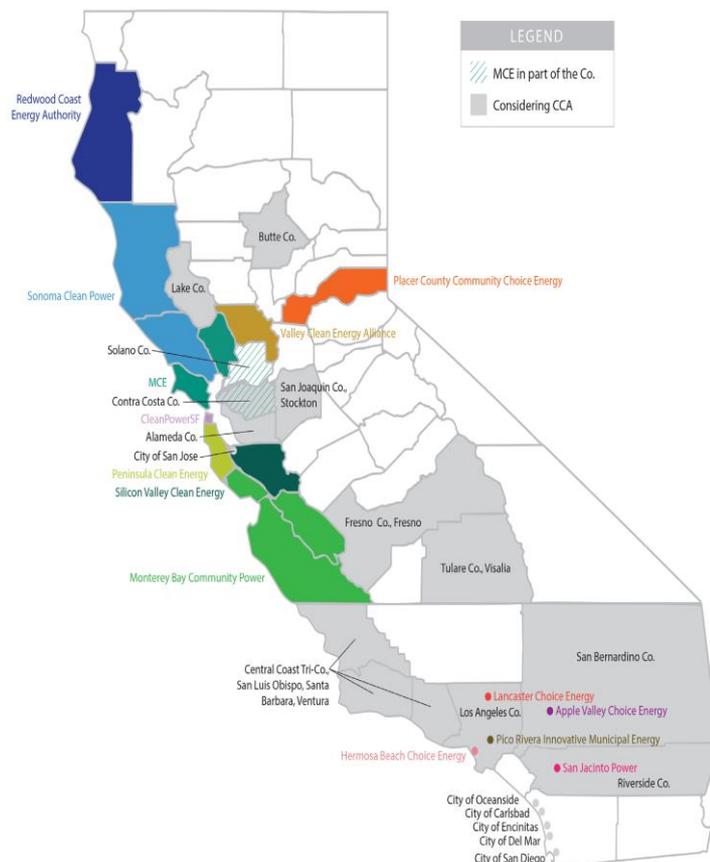
In addition to these efforts, California is home to a growing number of community choice aggregators (CCAs), where communities of customers can switch en masse to an alternative retailer under state law. As of the end

of 2017, just under 2 million customers had switched to CCAs, many of which offer higher levels of renewable generation in their electricity mix. According to the California Community Choice Association, this has already resulted in reductions of GHG emissions by 940,000 metric tons.

The rapid proliferation of CCAs, not linked to or driven by the decarbonization effort, is nevertheless having a significant impact due to the predominance of renewable sources in their energy mix. The cost of energy from the CCAs tends to be competitive with the incumbent utilities since abundant supplies of renewable generation are currently available at relative low prices.

Another important trend is the growing interest from commercial and industrial customers in buying 100 per cent renewable energy as part of corporate

Existing and proposed Community Choice Aggregators in California



Source: California Community Choice Association (<https://cal-cca.org>).



sustainability efforts. Many companies – including Apple, Google, Facebook, and Tesla – are taking an early lead in buying 100 per cent renewable energy.

Together, these programmes are delivering results, and the benefits generally exceed the costs. In other cases, the cost–benefit metric may not be as convincing. For example, the state’s net-energy-metering regulation is widely believed to be overly generous to customers who invest in rooftop solar panels. And because residential customer bills are almost totally volumetric, solar customers tend to shift costs to nonsolar customers. The regulators are increasingly aware of these cross-subsidy issues and are expected to address the matter as early as 2019.

The need to design retail tariffs to be more cost-reflective, fair, and equitable in view of the rapid rise of ‘prosumers’ is among the thorny issues facing the CPUC. And with the expected fall of the cost of storage, both utility-scale and distributed, many prosumers may become ‘prosumagers’ by investing in distributed storage (*Innovation and Disruption at the Grid’s Edge*, F. Sioshansi [ed.], 2017).

Another issue of rising concern is the increasing penetration of variable renewable generation in the electricity generation mix. This has given rise to the so-called California “duck curve” – reflecting the reduction in ‘net’ load (total load minus renewable energy) during mid-day hours when the most solar energy is available. This challenges to deal with the curve is intensifying.

It may be impossible to predict the cost of the consequences, intended and unintended, of the measures described above – including the effect of a more pronounced ‘California duck’ or the impact of rising numbers of EVs on the distribution network. The CPUC is

increasingly engaged in integrated distribution resource planning to develop a more comprehensive picture of the future costs of maintaining the distribution network and who is going to pay for it (for further discussion, see *Future of Utilities, Utilities of the Future*, F. Sioshansi [ed.], 2016).

While it is fair to say that the decarbonization of California’s energy sector is mostly divorced from market liberalization, many of the regulatory initiatives have arguably resulted in new and more powerful forms of competition than one might expect from classic market liberalization initiatives.

In this context, it could be argued that by encouraging consumers to generate their own electricity (through net energy metering), California has introduced a potent form of competition with the traditional utility-generated power. In this sense, rooftop solar installers are competing with electricity provided by the grid and distributed through the network. While this may not qualify as conventional retail market liberalization or competition, it is competition in the generation of electricity and this has important consequences.

Likewise, the growth of CCAs has given rise to intense competition between the traditional utilities and the new suppliers whose most potent marketing ploy is to promise 100 per cent renewable energy. This has also accelerated the decarbonization effort through yet another form of market competition.

Conclusions

With passage of the 2006 Global Warming Solutions Act, California set an ambitious target not just to decarbonize its electricity sector but to move its entire economy towards a low-carbon future. The target is expected to be achieved mostly, but not entirely, through a myriad of command-and-control measures and mandatory

requirements rather than a market-driven approach. This is particularly true in the early years; in later years the state’s cap-and-trade scheme is expected to play a more central role. Moreover, the decarbonization effort is mostly, if not entirely, divorced from a traditional market liberalization approach, which in the case of California came to an abrupt and unpleasant end following the state’s electricity crisis of 2000–2001. However, with the incentive for self-generation and promotion of CCAs, California has unleashed fierce competition with traditional utility companies.

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MANAGING RENEWABLES IN AN ENERGY-ONLY MARKET – THE CASE OF THE ELECTRIC RELIABILITY COUNCIL OF TEXAS

Audun Botterud

This article reviews opportunities and challenges that arise from the increasing role of renewable energy, focusing on the experiences of the electricity market in the US state of Texas, which is operated by the Electric Reliability Council of Texas (ERCOT). The ERCOT market is interesting for several reasons. First, it has seen a large expansion of wind power in recent years. Second, it is the only US electricity market that operates as an energy-only market – that is, without reliance on explicit capacity mechanisms to ensure resource adequacy in the long run. Third, ERCOT’s transmission system, which covers most of Texas, is largely disconnected from the rest of the US power grid and therefore operates largely as an independent system.

The article briefly reviews the history of the ERCOT electricity market, including recent changes in the generation



portfolio. It then highlights selected features of ERCOT’s market design and discuss measures that have been taken to address the challenges of incorporating more renewables in the power grid. Finally, it identifies lessons learned that are relevant to other electricity markets going through a similar shift towards cleaner and more renewable sources of electricity, and points out areas for future improvement in ERCOT.

The ERCOT electricity market

The ERCOT electricity market was restructured in 1999, when investor-owned utilities were unbundled and customer retail choice was introduced. As the independent system operator, ERCOT’s main responsibilities are to (1) maintain system reliability in operations and planning, (2) conduct wholesale market settlements, (3) provide retail switching for customer choice, and (4) ensure open access to transmission. The demand and supply resources in the ERCOT power system have gone through substantial changes since restructuring began. Load has grown steadily, by almost 30 per cent from 2002 to 2017. In contrast to many

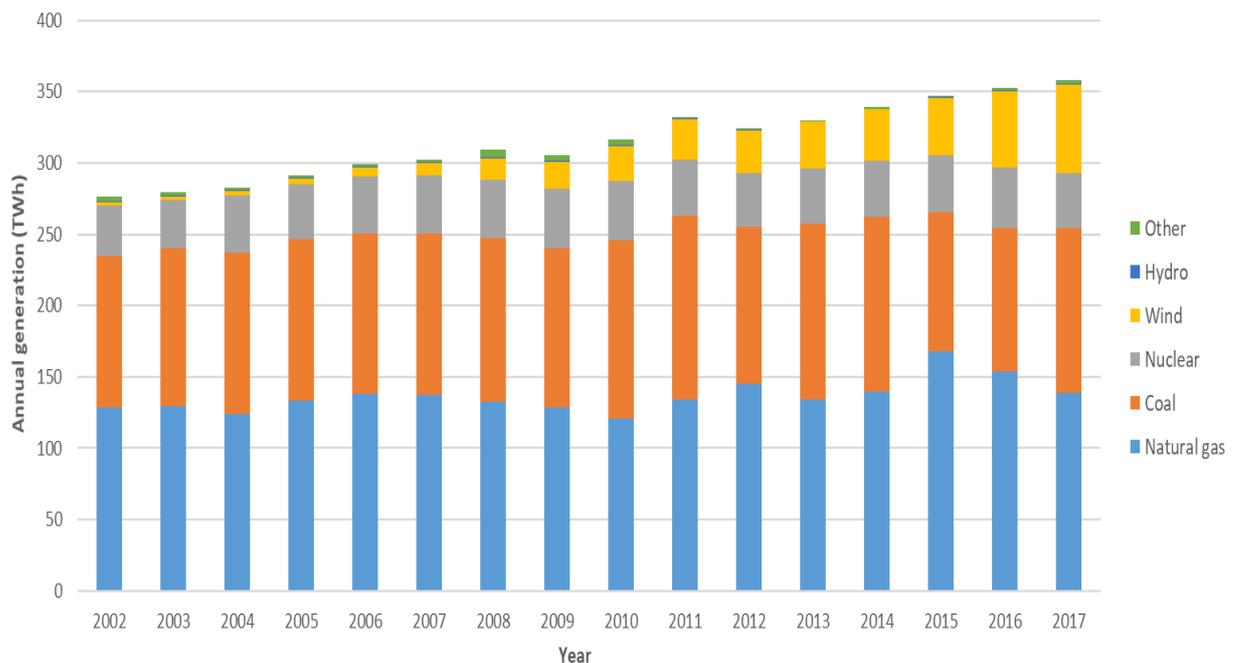
other regions of the United States, load growth continued even after the economic downturn triggered by the financial crisis in 2008. In fact, peak load has grown by almost 10,000 megawatts since 2008.

Natural gas has been the largest part of the generation resource mix in ERCOT in most years since 2002, typically meeting more than 40 per cent of the annual load. Coal-fired generation has been reduced from around 40 per cent in the early 2000s to about 30 per cent in recent years. Renewable generation has seen the largest growth. Wind power’s contribution has grown from less than 1 per cent of load in 2002 to more than 17 per cent in 2017. The large expansion of wind power in Texas has been driven by good wind resource conditions, particularly in the northwestern part of the state. Declining technology costs and renewable energy incentives have also helped spur investment. In particular, federal production tax credits, which are set to expire after 2019, have been an important factor improving the profitability of wind power investments. When it comes to other renewable

resources, several utility-scale solar projects have also been installed recently, whereas hydropower only makes a marginal contribution.

Overall, investments in new generation capacity have kept up with the growing demand and corresponding reserve margin needs, although there have been periods where a capacity shortage has been predicted. The average price for electricity in ERCOT has largely followed the cost of natural gas, which is not surprising given the fuel’s dominant role as a marginal generation resource in the system. Recent studies have shown that the large reduction in electricity prices in the last 10 years is largely due to lower natural gas prices. In contrast, wind power has had only a limited impact on average prices so far. Negative prices, which are frequently attributed to an oversupply of subsidized renewables combined with constraints in the rest of the system, occur relatively infrequently in ERCOT.

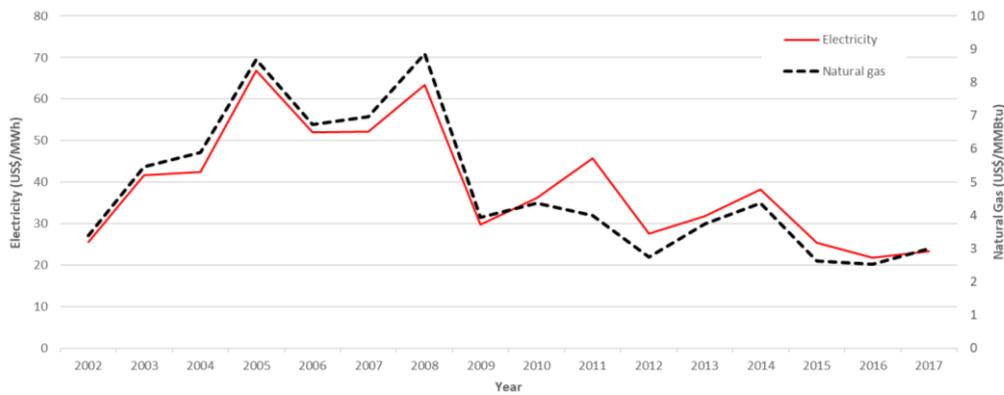
Annual electricity generation by fuel source in the ERCOT market, 2002–2017



Source: ERCOT



Average annual wholesale electricity (ERCOT North Hub) and natural gas (Henry Hub) market prices, 2002–2017



Source: ABB Velocity Suite and US Energy Information Administration

General electricity market design features

The ERCOT market is built on many of the same principles as other US electricity markets operated by independent system operators (ISOs). The focus is on short-term operation of the power system, where ERCOT, as the ISO, provides centralized coordination and control of the system’s resources. Generation scheduling is done in the day-ahead market, whereas balancing of supply and demand takes place in the real-time market with dispatch intervals of 5 minutes. ERCOT uses locational marginal prices to manage transmission congestion, which is reflected in the resulting nodal market clearing prices. In contrast to several other US markets, ERCOT does not conduct a centralized unit commitment as part of the market clearing, which is rather based on an economic dispatch algorithm.

Commitment decisions are primarily left to the individual market participants in response to market signals. However, ERCOT still has a centralized ‘reliability unit commitment’ process between the day-ahead and real-time markets, where additional generating units may be committed by the ISO in case of concerns about system reliability.

A distinctive feature of the ERCOT electricity market is the high degree of competition in the retail market. In fact, this was one of the main goals when the ERCOT market was restructured in

1999. Today, ERCOT administers retail switching for 7 million meters (75 per cent of the total load). Customers can choose between more than 50 retail companies and 300 different contract plans, which are being increasingly customized to meet individual customers’ needs as well as to reflect system conditions (e.g. through time-of-use or real-time pricing). The retail market is very active, with the highest switching rate in the United States – about 1 million customers switch their supplier in an average year. Moreover, there have been substantial reductions in retail prices for energy in recent years, in line with the prices in the wholesale market.

ERCOT also regularly conducts studies to assess the long-term resource adequacy of the system. It has been using a target planning reserve margin of 13.75 per cent based on the common reliability standard of 1 day of lost load in 10 years. However, it is in the process of switching to a planning reserve target based more on economic assessments and the trade-off between cost and reliability. ERCOT’s planning studies provide guidance to the system, but decisions about expansion in new generation capacity are still left to market participants, who receive investment incentives through the prices in the energy and reserves markets.

Since there is no explicit capacity mechanism or payment, pricing of

energy and reserves during scarcity conditions is critical for the recovery of capital costs for generation assets. ERCOT has taken several measures to improve scarcity pricing. For instance, the price cap in the energy market has gradually increased to \$9,000 per megawatt-hour. Moreover, a demand curve for operating reserves was introduced in 2014, designed to reflect the marginal economic value of reserves to system reliability. In turn, this influences the pricing of energy and reserves in the real-time market. More recently, ERCOT also adjusted the way prices are calculated to account for commitment decisions made outside the regular market clearing (i.e. the reliability unit commitments). However, the price impacts of both the operating reserve demand curve and the reliability adjustments have been limited so far, and the frequency of price spikes is rather low. This is due partly to a surplus of capacity, but possibly also to specific implementation details in scheduling, dispatch, and market clearing. Of course, investment decisions are primarily driven by expectations of future profits, which may be different from recent historical prices, and the ERCOT system has seen sufficient new capacity expansion to meet the target planning reserve margins so far.

Although investment decisions are primarily driven by market forces, one backstop mechanism that ERCOT still



has is the authority to prevent generators from retiring when this may threaten system reliability. So-called reliability must-run agreements, one of which was entered into in ERCOT as recently as 2016, ensure profitability for a critical generation resource outside of the regular market mechanisms for a specified period of time.

Renewables-related measures

ERCOT is continually working to improve its procedures for planning, market, and system operations in light of the changing resource mix. A few important measures that have been taken to enable a large-scale and cost-efficient integration of renewable resources are highlighted below.

In 2005 the Texas Legislature introduced the concept of Competitive Renewable Energy Zones to increase the state's use of renewable energy and alleviate grid congestion. As part of this initiative, ERCOT assisted the Public Utility Commission in defining five geographical zones for renewable energy in western and northern Texas and corresponding transmission expansion needs to transmit the power to the major population centres, which are primarily in the eastern part of the state. At the same time, cost allocation rules were defined and transmission providers were also selected to expand the transmission system. By 2014 more than 3,500 miles of new transmission lines were built at a cost of about \$7 billion. The Competitive Renewable Energy Zones initiative has played a major role in facilitating the large-scale expansion of wind power in Texas in the last decade, by providing transmission access and thereby reducing the need for wind power curtailment.

When it comes to short-term market and system operations, one important tool for integration of renewable energy is forecasting. ERCOT has been using

wind power forecasting to guide their operational decisions for a long time, and more recently introduced solar power forecasts as well. Forecasting helps improve scheduling and dispatch and thereby maintain system reliability in a cost-effective manner. ERCOT has also adjusted their ancillary services in response to the increase in renewables in the power grid. Minimum operating reserve and frequency regulation requirements are updated annually based on historical variability and forecasting errors for load, wind power, and now also solar power. Combined with the operating reserve demand curve, the time-varying reserve requirements improve operational efficiency as well as price formation in the electricity market.

Last year ERCOT introduced a separate reliability risk desk in their control room to address the impacts of renewable energy on system operations. The reliability risk desk improves situational awareness by monitoring updated forecasting information, including a probabilistic ramp forecast for wind power. Moreover, the desk can initiate the procurement of additional ancillary services and resource commitments if shortfall situations emerge, and ensure that wind and solar producers follow dispatch instructions during surplus conditions.

Lessons for other regions and market design improvements

The ERCOT system has seen a rapid shift towards more wind power in the last decade. The integration of renewables is to some extent eased by the presence of flexible natural gas resources in Texas. However, ERCOT has also demonstrated a striking ability to efficiently plan and operate the system based on effective transmission planning and primarily market-based operational mechanisms. There are several important lessons to be learned

for other regions going through the same transformation, including the large-scale build-out of transmission for wind power resources located far from load centres and the active use of renewable energy forecasting in market and system operations.

The ERCOT electricity market is also characterized by a high level of consumer engagement through active retail competition, which is an important foundation for a well-functioning electricity market, as it needs both supply and demand to respond to market signals. Furthermore, operational and investment incentives are provided through scarcity pricing and high price caps in energy and reserve markets.

Through its experience in the last decade, ERCOT has demonstrated that an energy-only market can work with substantial shares of renewable energy. The system is currently seeing tightening reserve margins due to generation retirements and loads that continue to increase. It will be an important test of the ERCOT market design to see if prices provide adequate scarcity signals for sufficient response from existing and new supply and demand resources to maintain reliability under these conditions.

While the ERCOT market has evolved with the changes in its generation resource mix, further improvements will be needed as the amount of renewables continues to grow. ERCOT expects wind power capacity to grow by almost 50 per cent and solar capacity to triple in the next five years. Important refinements to market design to address the higher penetration levels of renewable energy include full co-optimization in the real-time market of energy and ancillary services, directly accounting for the operating reserve demand curve in the system dispatch. The locational marginal prices should reflect losses in addition to congestion.



Moreover, it is important to minimize dependence on out-of-market reliability unit commitment in the short term for the energy-only market to provide correct price signals. This could be done by introducing intra-day markets enabling a more decentralized balancing of deviations in the system by market participants. In the long run, the use of reliability must-run contracts should also be minimized to avoid interference with market-based investment incentives. Finally, enabling liquid long-term forward markets that reflect the expected spot prices is important for hedging and investment decisions, particularly in an energy-only market like ERCOT.

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EFFICIENT MARKETS FOR HIGH LEVELS OF VARIABLE RENEWABLE ENERGY

Steven Corneli

How and why today's power markets are failing

After several centuries of exponentially increasing fossil fuel use, it has become clear that the global economy is rapidly approaching the limit of the atmosphere's ability to benignly store carbon dioxide. Power sector decarbonization appears to be necessary, though not sufficient, for staying within this limit. As a result, technology markets and policymakers alike are accelerating the commercialization and deployment of wind and solar energy, while seeking complementary technologies to fully decarbonize a still-growing global economy's energy use. Current electricity markets did not evolve around such technologies and are poorly suited to support their rapid and efficient deployment.

The minimal marginal costs and limited ability to continually balance output with

energy consumption of variable energy resources (VERs), such as wind and solar, are widely seen as the biggest challenges to current electricity market designs, and may indeed be fatal to these designs. Yet VERs pose a more profound challenge for electricity markets. Dispatchable fossil, hydro, and nuclear resources typically offer choices between smaller technologies with high per-megawatt-hour (MWh) operating costs, greater flexibility, and low total fixed costs, and larger-scale technologies with low per-MWh operating costs, limited flexibility, and high total fixed costs. These cost and performance characteristics made it relatively easy for both central planners and markets to select the least-cost combination of traditional plants capable of meeting the fundamental requirement for reliability, which is to continually and exactly balance aggregate power injections into the grid with aggregate consumption.

Typically, this has meant adding large, inflexible 'baseload' resources up to the first inflection of the load duration curve, 'intermediate' plants up to the next inflection, and small, highly flexible 'peakers' above that. Adding enough transmission to connect them all to load and to adequate reserves, while managing contingencies, ensured an efficient, low-cost, secure, and reliable system.

High levels of wind and solar deployment – likely essential for rapid decarbonization – make achieving even a moderately optimal system configuration much more challenging. With highly variable power availability, systems with a large share of VERs cannot readily balance instantaneous generation with load. However, they can do so significantly better with a diverse set of wind and solar resources selected to have a combined production shape that more closely matches that of aggregate load over

time. The remaining balancing must be achieved by varying load to match generation, or by other controllable resources that do not emit carbon, such as battery storage, hydro power, or (potentially) advanced nuclear and biofuel technologies.

This means the optimal configuration of a carbon-free power system will be much more complicated than it was for historic systems of fully dispatchable generators. Identifying and tapping an efficient amount of complementary solar, wind, and hydro resources will depend not only on adequate transmission to high-quality, renewable resources located in other regions and even other countries, but also on how much flexible load, storage, and other complementary flexibility resources can be developed in local load centres. Too much or too little of any of these elements, or the right amount in the wrong location, can lead to much higher-cost systems, curtailment of VERs, and a continued need for controllable but carbon-emitting fossil resources.

These problems are both more complex and much larger in scope than in the days of costless atmospheric carbon disposal and highly dispatchable fossil fuel power technologies. This is especially the case where high-quality solar, wind, and hydro resources are located thousands of miles away from each other and from large load centres, as is the case in Europe, North America, Africa, and other major economic regions. It is unrealistic to think that power prices in today's subregional, and typically subnational, dispatch-cost-based markets can drive the optimal configuration of these larger markets, especially as power market prices fall due to a growing share of resources with minimal marginal costs and high levels of out-of-market compensation.

But absent some new, cheap, safe, ubiquitously available, and highly



dispatchable power technologies, the co-optimization of a portfolio of local flexible load with a continentally scoped portfolio of VERs and other clean-energy technologies is exactly what a decarbonizing global power sector needs. How should such a co-optimizing, competitive system be designed and implemented?

First, we must be explicit about its goals. For electricity markets to work during rapid decarbonization, they need to provide both efficient operation of the grid and its connected resources, and efficient development of new resources. Such markets must offer efficient prices and incentives, for both short-run operation and long-run investment decisions and project development. Further, these prices and incentives need to be sufficient to drive the efficient configuration of the system – that is, a low-cost and highly effective mix of resource types, quantities, and locations, regardless of whether those resources are owned by regulated utilities or by competitive providers. It should also be dynamically efficient and support continuous innovation, deployment, and integration of zero-carbon and complementary technologies, using market-based incentives rather than central planning, command-and-control regulation, or political popularity contests. And it should also inform the development and support the effective implementation of wise clean energy and climate policies. Since time is short, it should be easy to implement incrementally, without major revisions to laws, regulations, and market software.

After a brief overview of the current US wholesale market, this article will propose one potential way to achieve these goals.

US power market basics

The US has seven distinct centrally operated spot power markets that all use similar security-constrained economic dispatch (SCED) programs as the basic platform for both system operation and market price formation. SCED runs on a digital simulator of all the key transmission elements, connected generators and load, both in a day-ahead market (DAM) based on forecasts, projections, and bilateral schedules and again in a real-time market (RTM) based on actual operating conditions. The essential feature is that system operating constraints are built directly into the dispatch and price formation of both the DAM and the RTM; as a result, congestion and constraints are priced efficiently and there is no post-market redispatch of commercial schedules by the system operator.

The SCED takes the as-bid marginal costs of generation at each generator node and the load at each load node and determines the least-cost dispatch to meet load without violating thermal and stability constraints – hourly in the DAM and every five minutes in the RTM. If constraints between injection and withdrawal nodes require a more expensive local dispatch, in either the DAM or the RTM, that dispatch is built into the market-clearing dispatch and the prices produced by it. These locational marginal prices (LMPs) are based on marginal generation costs, both for system energy and for losses and local constraint resolution at each node.

The DAM takes place 24 hours before real time, which gives plants and load time to start up, procure fuel, and confirm forecasts. Resources and load that clear in the DAM take on the financial obligation and right to sell or buy, respectively, the amount they cleared in the DAM market, at the DAM price, in the RTM the next day. The

DAM market is voluntary for most resources, though participation requirements vary by region.

The RTM repeats the dispatch process in real time, using actual load, transmission topology, and generator availability, to get the operating dispatch exactly right and avoid after-market redispatch costs. Resources that perform according to their DAM bid settle in the RTM at those prices and pay, or are paid, for deviations from their DAM schedules at the RTM prices. It is also possible to enter ‘virtual’ or financial-only bids in the DAM to sell (or buy) specified amounts of power at the DAM price and buy (or sell) it back in RTM at the real-time price. This allows hedging of the forward DAM positions and supports convergence between prices in the two markets. Operating reserves are typically co-optimized with the DAM and RTM, to preserve efficient participation incentives and energy price formation for both energy and reserves. Some US markets also have additional reliability-enhancing commitment updates between the DAM and RTM markets to accommodate and incent better forecasts of VERs. This aspect of US markets, along with enhanced participation pathways for storage and flexible load, are two areas of ongoing market evolution.

The final major element of these markets is transparent, efficient pricing for transmission congestion. If a constraint causes the DAM LMP to separate across several nodes, the congestion cost is precisely the difference between the LMPs at the two nodes. Because of the security-constrained dispatch, it is not possible to sell or ship more power from the injection node to the withdrawal node, regardless of any physical transmission rights. Instead, these markets provide a tradable financial transmission right, which is the right to receive the



difference between the LMPs at the two nodes. Holding financial transmission rights allows load-serving entities and market participants to hedge their exposure to transmission congestion, while also ensuring that such congestion reflects the most efficient, secure, and reliable operation of the grid and the most efficient short-run marginal cost-based prices, including the cost of getting the dispatch right in the market, without costly redispatch, for both producers and consumers.

While this system may appear heavily centralized, its deep liquidity, efficient prices, and ample opportunities for hedging actually support robust bilateral markets, both for schedules to meet load, as dispatched by the SCED process, and for purely financial supply and hedging transactions around the SCED-based prices. For example, in PJM (a US regional transmission organization and market operator), only 27.5% of load was met purely through the RTM/DAM market settlement process. Yet, despite these markets' elegance and efficiency when dispatching 20th century technologies, for the reasons discussed above they do not seem to be working well with those of the 21st century.

Proposal for market evolution to efficiently incorporate clean energy resources

The first step in addressing this problem is to be clear-eyed in evaluating how well current market designs can meet the goals articulated at the end of the first section. Current US spot market designs unambiguously achieve only efficient short-run operation, and only through competition to be committed and dispatched.

This is insufficient to achieve the optimal configuration of wind, solar, flexible load and transmission, and it is likely to prove inadequate to support investment in even the wind, solar, and

flexible resources needed for a zero-carbon grid. Instead, today's market designs beg for ever-growing out-of-market incentives and subsidies for politically favoured (and hence jurisdictionally localized) resources, which work actively against an efficient configuration. Given this weak showing, we need to design a new market system that will achieve, Rubik's-cube-like, all of the criteria simultaneously.

First, the problem of efficient configuration needs to be addressed directly. Current US nodal markets operate on the platform of a set of digital models of the transmission system, its connected load, and each connected power plant. These models are designed to identify the sequential patterns of power plant dispatch that will meet varying load at the lowest economic cost, while preserving system security – hence the name security-constrained economic dispatch (SCED). In early power pools, SCED was calculated based on engineering data on the marginal cost and start-up requirements of the connected power plants. The SCED modelling platform grew into a nodal marketplace simply by substituting competitive bids to generate for the marginal cost assumptions in the dispatch model, along with some modifications to support price formation and financial settlement.

A parallel transformation of models to market platforms can provide a market-based solution to the configuration problem. Analysts are now using sophisticated grid expansion models, coupled with granular data on wind and solar resources, to determine how to efficiently incorporate high levels of solar, wind, storage, and transmission into the grid. These models typically use engineering assumptions and forecasts of fuel prices, heat rates, locational solar and wind resources, transmission costs, and storage or

flexible load costs. Replacing these cost estimates with actual bids should allow such models, as they evolve, to themselves become the platform on which a longer-term investment market runs. I call this new market the 'configuration market', and envision its key functional elements this way:

The configuration market would be conducted periodically – say, once every three years – by the regional transmission operator (RTO) that is already responsible for running the SCED operating market and, in the US, for developing regional transmission plans in cooperation with the regulators of states within the RTO footprint. All existing and proposed resources (including transmission) would submit bids into the configuration market consisting of the revenues they would need to receive to continue operating or, for proposed resources, commit to development and operation. The configuration model would use these bids in its optimization process to identify a least-cost configuration of the system.

Proposed and existing resources that are included within this least-cost configuration will be deemed to have cleared in the configuration market. Cleared operating and transmission resources would then be eligible for fixed cost recovery, under a variety of modes. Competitive resources would receive competitive fixed cost recovery, typically through medium- to longer-term power purchase agreements. These agreements could be structured to pay as-bid fixed costs net of operating market revenues, that is as contracts for differences relative to those revenues. Regulated resources would be compensated through state or federal tariffs, with the as-bid costs that clear in the configuration market revealing the costs that are eligible for regulatory recovery. Clearing in the configuration market would be



considered by both federal and participating state regulators as a necessary condition for regulatory approval for recovery in cost-regulated rates.

Operating resources – generation equipment, storage, and flexible load – that clear in the configuration market would also be obligated to participate in a short-term operating market, as could resources that do not clear in the configuration market. In the US, this operating market would be an SCED-based market much like today's, enhanced to support more VERs and much more flexible load, including storage. These latter resources would participate actively through aggregators, corporate buyers, competitive retailers, and community-based deployments, as well as passively through decentralized price-responsive load technologies. Sufficient penetration of these technologies would replace administrative adequacy requirements with efficient, decentralized, market-based reliability levels, and at least help provide more efficient spot market prices, while also helping integrate substantial amounts of VERs.

Both competitive and regulated asset cost recovery would be subject to a set of contractual performance requirements, for each resource type, that are known at the time of the configuration market bids. Failure to meet those requirements would result in reductions in payments under the power purchase agreements or tariffs. This would ensure strong incentives for following dispatch signals and otherwise achieving efficient operations, even if operating market prices become very low and the incentives they provide for efficient operation become correspondingly weak.

Several features of the configuration market would support dynamic

efficiency. Tranches of the market could be set aside for emerging technologies to compete for, which would provide those technologies with the benefits of learning-by-doing, scale, and competitive toughening, much as competitive procurement did to help commercialize solar and wind technologies. Timely retirements and roll-over of technologies whose high costs or carbon dioxide emissions make them uneconomic would be driven primarily by their failure to clear in the market as cheaper, cleaner, and more flexible resources enter. Additional retirement incentives could be provided by targeted payments for such plants, such as buy-outs of their interconnection rights and potentially the option value of future configuration market results. Further incentives would result from the market's highly efficient incorporation of carbon prices and clean energy incentives enacted by states or the federal government. The broader goals of supporting and informing more efficient policies would be a natural output of the configuration market approach. A better understanding of the complex impacts of clean energy policies and incentives would help both state and federal governments develop more efficient policies, while avoiding those that lead to excessive costs, high levels of curtailment, and other problems that are already emerging in the US and other regions with Balkanized, jurisdictionally incompatible clean energy and climate policies.

Finally, the configuration market approach would readily meet our incremental adoption criterion. In the US at least, it could evolve sequentially out of the periodic regional transmission planning required by the Federal Energy Regulatory Commission's Order 1000, which is almost tailor-made to utilize the co-optimizing system expansion models that will become the platform for the

configuration market. Once this platform has achieved sufficient maturity, converting it to a bid-based selection system with corresponding benefits and obligations should be relatively simple and achievable through RTO filings, without new legislative authorization, in much the same way as Orders 888 and 889 created and established competitive wholesale markets without explicit legislation. Further, by incorporating today's SCED-based operating markets, rather than replacing them, the configuration market would avoid the cost and conversion problems that arise when creating entirely new operating platforms.

What problems might we be wise to anticipate? It may not be easy to develop existing system optimization models into an accurate and useful market platform. However, to manage this challenge, the power market could take advantage of the growing potential of artificial intelligence, big data, and autonomous optimization applications – as most other sectors of the economy already do.

It might be tougher to get realistic and enforceable bids in the configuration market. These projects will be highly contingent on other events and could be subject to gaming to capture valuable queue space by clearing in the configuration market. To address this problem, the configuration market must look to best practices in a variety of analogous markets, such as spectrum auctions, competitive procurement, forward markets, and interconnection proceedings, and be informed by game-theoretic policy analysis.

Some are concerned about the potential for regulatory capture of the RTO in charge of the configuration market by incumbents or other powerful interests. This risk may be no greater for the configuration market than for the status quo, or any other mix of federal



and state policies. Further, the objectives of the configuration market include not just clean energy deployment, but the broader virtues of economic efficiency, reliability, and universally available service, along with the incorporation of new, more efficient competitive technologies. This means the existing standards of just and reasonable rates without undue discrimination will be powerful public-interest weapons to prevent regulatory capture's inefficient thumb-on-scale decisions, or to correct them if they occur.

Finally, there is the concern that all of this is too cumbersome, too centralized, and too much like government planning to be trusted to produce efficient outcomes or to really be called a market. Yet surely the existing processes of ad-hoc, legislatively mandated subsidies for favoured technologies, almost exclusively within Balkanized state and utility service territory boundaries, is even further from a market or from the thoughtful incentives needed for the rapid decarbonization of the power system. Any level of insight brought about by broad regional system optimization models and tools would be an improvement. And any additional level of competitive cost information and competitive incentives for efficient risk allocation, development, and operation of a more integrated system would be an even greater improvement. Since the incremental growth path of the configuration market would give us these improvements early on, why not at least get started and see how well we can make it work?

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DEVELOPING THE DESIGN OF THE CHILEAN POWER MARKET TO ALLOW FOR EFFICIENT DEPLOYMENT OF RENEWABLES

Pablo Rodilla, Paolo Mastropietro, Tomás Gómez, Renato Agurto, Carlos Skerk, and Carlos Batlle

The Chilean electric power system is undergoing substantial change, marked by a significant increase in the use of renewable energy. These changes were prompted by the declared intention of the government to respond to the following challenges: the diversification of the country's power-generation sources; the phenomenon of climate change; the desire for energy independence and efficiency; and, in a broad sense, the need to ensure sustainability and security of the national energy matrix. However, since the first market reform in 1982, Chile has not undertaken the significant structural reform of market regulation necessary to address these challenges.

This article outlines the changes that the Chilean electricity market requires to facilitate efficient deployment of high penetration of nonconventional renewables, in particular solar and wind. After outlining the Chilean context and some peculiarities of its market design (which are, however, common to many South American power systems), we present an integrated proposal to improve the resilience and efficiency of the Chilean market design to enable high renewable penetration in the short, medium and longer term.

The Chilean context

The Chilean electricity sector is characterized by the linear shape of the country and its complex mountainous topography. The two main power systems, the northern and central power grids, have recently been

connected, creating the National Electric System. Hydropower accounts for 27 per cent of installed capacity; solar photovoltaics and wind resources account for 8 per cent and 6 per cent, respectively; and the rest is shared in roughly equal measure among coal-, natural gas- and fuel oil- fired plants.

Distribution companies act as regulated retailers for captive demand. Most of the economic exchanges are based on long-term contracts between generators and distribution companies or free consumers. The spot market is only open to generators, which use it to settle imbalances between their contract commitments and their actual production. The market is based on audited costs, and no bid is presented by market agents. Even though the system operator provides instructions during the week, and especially the day before real time, these instructions are not binding. The market is cleared ex post – that is, after real-time operation – using the real dispatch to calculate nodal spot prices. Operating reserves are mostly provided by hydropower units, and the original restructuring of the power sector did not consider a real market for ancillary services. The cost of balancing reserves is socialized through demand charges. In addition to a remuneration for energy produced, generators receive a capacity remuneration, through an administratively set capacity price that is included in long-term contracts.

In the last decade, nonconventional renewable energy (NCRE) sources have been promoted through specific amendments to the electricity law. In Chile, the definition of NCRE includes wind, solar, geothermal, biomass, and maritime generation technologies as well as hydraulic technologies that produce less than 20 megawatts. In 2008, Law 20.257 established a 10 per cent NCRE quota by 2024, in the form of a renewable portfolio



standard. This law was complemented in 2013 by Law 20.698, which increased the NCRE quota to 20 per cent by 2025. If the penetration of NCRE does not reach the mandated levels, the Government can implement a call for tenders to cover the deficit. However, in October 2017, NCRE use reached the 20 per cent quota established for 2025; the system operator has projected that by 2030, it will exceed 30 per cent.

The current market design does not seem to be suitable to efficiently integrate these resources; the Government and the generators agreed that an amendment to the current electricity law will be required. To that end, a public regulatory discussion was launched in late 2017 to develop a new Ancillary Services Regulation.

The current ex-post clearing does not make it possible to give a value to flexibility, and thus does not properly reward the agents that provide backup to intermittent renewable generation. As a result, the current market design does not provide adequate signals for further investments capable of providing the flexibility that will be required. Furthermore, from a short-term operational perspective, the current design for the remuneration of ancillary services and the later allocation of these costs does not provide the right incentives for generators to be available in real time.

The next section summarizes the regulatory changes we believe are needed to correct these flaws.

Regulatory proposals

Based on a review of the current design of the Chilean electricity market and a comparison with markets in other countries, regulations can be proposed to help ensure a harmonious integration of renewable technologies.

Binding dispatch

A binding dispatch should be introduced in the day-ahead market, with a price calculated ex ante to remunerate the capacity committed in that dispatch, regardless of later modifications to the unit commitment. The binding dispatch provides market agents with an essential tool to hedge their risk in a context where that risk may increase, since dispatch modifications may become more frequent with high NCRE penetrations. Furthermore, a binding dispatch is necessary for efficiently assigning the cost of successive redispatches (and, ultimately, the cost of ancillary services) to the agents who cause them.

A price should then be calculated for each redispatch or reprogramming of the system carried out in the intraday time horizon, and any difference with respect to the previous programme should be settled at that price. Binding positions, on which imbalances will be calculated, must be updated after each redispatch. Only this series of binding programmes can provide efficient economic signals in the time horizon between the initial dispatch instructions and real-time operations. The potential accuracy of forecasts for renewable power improves as one moves closer to real time operations. At all stages, but especially between the initial dispatch and real time operations, it is important to have incentives for accurate forecasts of output from renewable power stations in order to minimize the cost of alternative resources when those renewable stations are not generating as forecasted.

Fixed operational costs

The significant hydro component of generation has usually been able to provide most of the required response in the very short-term; because of this, the current regulation does not explicitly consider remuneration for the thermal plants' fixed operational costs (such as

for start-up and shutdown). However, these costs are likely to rise in response to the variability of renewable generation; therefore, a sound methodology for their recovery must be established. The recovery of these costs must be guaranteed to the agents incurring them through the introduction of either an uplift on the spot market price or a fair, discriminatory side-payment. Uplifts to the market price or side-payments must be considered in the calculation of the price of the binding dispatch as well as of any successive redispatch.

An efficient market for reserves

As previously mentioned, there is a consensus that the ancillary services market requires substantial reform. In our view, this should include the following:

- Co-optimize energy and reserves, thus clearing the energy and reserve markets at the same time and with the same algorithm. Those markets can be based on audited costs, as they are in the current design. Co-optimization makes it possible to take advantage of the synergies between these two complementary products and to avoid a bid-based reserve market that would not be consistent with the rest of the Chilean market design. Chile does not have any institutional barrier to co-optimization, since the system operator also operates the market.
- Design reserve products which do not present implicit barriers for the participation of some market participants, including NCRE technologies. The procurement of upward and downward reserves should be separated and pushed as close as possible to real time.
- Avoid as much as possible the socialization of reserve costs.



The latter must be assigned to the agents responsible for them. Costs related to balancing energy (reserve activation) can be assigned according to the imbalances registered between the last binding dispatch and the actual injection of each resource. Costs related to balancing capacity can be assigned either through an enhanced methodology for the calculation of the reserve requirement (fulfilling the cost-causality principle) or by using a moving average of imbalances, calculated for each resource, as a proxy of the responsibility for the incurrence of such costs.

Long-term signals

The Chilean system must guarantee that the future power system will be not only adequate (enough installed capacity) but also flexible enough to cope with renewable intermittency and variability. Proposals have been advanced for introducing specific tenders for flexible capacity, to be launched each time the system operator foresees a lack of flexible resources in the medium term. In order to introduce long-term signals for attracting flexible resources, it would be better to encompass such signals in the current capacity payment, rather than segmenting the market with targeted auctions. This can be achieved either by modifying the methodology for the calculation of firm capacity (considering a term that favours flexible resources) or by introducing a new product, a 'flexible capacity payment', with a specific administratively set price, which would be paid only to resources fulfilling a set of requirements.

Conclusions

At the beginning of this century, Chile – like many South American countries –

introduced long-term auctioning mechanisms with the objective of guaranteeing the security of electricity supply. These reforms, which are still in place, did not affect the design of short-term markets for energy and ancillary services. Renewable technologies represent a huge opportunity for the Chilean power sector, but they may significantly alter the current functioning of the electricity market. To make that market more resilient to the expected rapid increase in renewables, it must be reformed to guarantee their efficient integration. First, the new market design must be based on binding dispatches, which fix remuneration and responsibilities of market agents, second, ancillary services must be procured in a market environment, preferably through a co-optimization of energy and reserves. Third, the cost of keeping the system balanced should not be socialized, but rather assigned to agents according to their responsibility for the occurrence of that cost. Finally, the long-term signal conveyed by the capacity payment may need to be modified to attract flexible technologies.

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BRAZIL CONSIDERS REFORM OF THE ELECTRICITY SECTOR

Carlos Battle, Mário Domingos Pires Coelho, Pablo Rodilla and João Tomé Saraiva

When Brazil's electricity market failed to attract enough investments to meet the country's rapid growth in demand, a 2004 law shifted the focus from the short-term market to long-term electricity contracts, as a way to provide investors with hedging tools against the significant volatility of spot prices. Since then, the market design has been based on two obligations: for demand to be 100% covered by long-term contracts, and for the contracts to

be 100% covered by firm energy certificates. These long-term contracts have been assigned through a variety of centralized electricity auctions. The regulator can also hold so-called reserve auctions, which are intended as a last-resource mechanism to increase the reserve margin of the entire system, in case it is deemed insufficient. These auctions have been used in recent years to foster the installation of renewable energy technologies.

This combination of auctions and long term contracts attracted the needed investments in generation; but as time progressed, it has showed increasing signs of stress. The government that took office in June 2016 asserted that a number of factors – including previous intervention in resource allocation and prices, inadequate and overly centralized risk allocation that led to judicial disputes, inadequacy of spot market prices as investment drivers, lack of transparency, and subsidized financing via the Brazilian Development Bank – had created the need for an overhaul of the legal framework to enable Brazil to adapt to a more decentralized power system.

In February 2018, the Brazilian Ministry of Mines and Energy, after several months of public consultation, sent the president a proposed Law for the Modernization and Expansion of the Free Market for Electricity. The law has four aims: (1) increasing the granularity of wholesale-market price formation, (2) introducing a mechanism to allow for the internalization of environmental externalities, (3) designing a new capacity product, and (4) widening the scope of the retail market. It complements another, more ambitious proposal to privatize the state-owned utility, Eletrobras, and grant new concessions for its generation plants to operate in the private sector.

The proposed law has not yet been submitted to Congress. However, on



March 13 this year, the Ministry of Mines and Energy published an ordinance establishing the main principles to guide future rule-making in the electricity sector. The proposed new regulatory framework attempts to enhance market signals to allow more decentralized risk management, with the expectation that this will further engage market agents to improve overall efficiency. Its proponents in the Government have consistently emphasized property rights and contract sanctity, including mechanisms to accommodate legacy obligations.

The main elements of the proposed reform are described below.

Change in the concession rules

In 2012, then-President Dilma Rousseff's Government approved a package of laws (the 'MP 579'), supposedly aimed at reducing electricity prices. At that time, many hydropower plant concessions were expiring. Under this framework, the concessionaires could renew their concessions only if they agreed to be paid on a cost-plus basis, which would cover operational and maintenance costs plus a reasonable profit for electricity sales to the captive market, instead of continuing to function as independent power producers. Companies rejecting this proposal would have to auction off their concessions under the same cost-plus regime. Most expiring hydropower concessions were renewed under this arrangement; though it may not be a coincidence that plants covered by these concessions belonged to Eletrobras, the government utility.

Electricity produced by these power plants was then sold forward to distribution companies to fulfil the needs of the regulated market. Under the MP 579, these companies bore the hydrological risk of the new contracts. A sequence of dry years (2012–2016)

caused a hydro shortfall that resulted in dramatic price increases, creating a huge debt for the distribution companies.

The proposed 2018 law would make it possible to grant new concessions for Eletrobras' plants to the private sector for a period of 30 years (effectively privatising those concessions), allowing owners to trade electricity in the free market, in an attempt to increase liquidity and, as a result, market efficiency.

However, taking into account the particular characteristics of the Brazilian power system, especially the hydro system, the efficacy of this measure appears to be somewhat limited, because the management and planning of the hydro plants (both reservoir-based and run-of-the-river) in Brazil is fully centralized and controlled by the market and system operator (Operador Nacional do Sistema Elétrico, ONS). The proposed solution certainly transfers the volume and price risk from end users to power producers, but it is unlikely to induce more efficient management of the hydro resources.

A highly relevant factor underlying this new regulation is the great pressure that current hydro generators are putting on the Government to move towards bid-based dispatch, and away from central despatch based on ONS interpretation of the opportunity cost of hydro. During the severe drought of 2016, spot prices skyrocketed, and the ONS was accused of withholding hydro generation due to excessive risk aversion. Hydro generators found themselves in a contractually short position and incurred great losses buying energy in the spot market to meet their contractual commitments. Although it was crystal clear at the time of signing the contracts that the responsibility for hydro management resided with the hydro generators, most of the latter have taken legal action

arguing defencelessness in view of the de facto control that ONS has over despatch.

New market structure

The design of the Brazilian wholesale market has been heavily influenced by its heavy reliance on hydro. Because of the significant multiannual hydro reservoirs, the system has not been subject to capacity constraints, so there was no need for intraday price differentiation or ancillary services markets. On the other hand, to ensure security of supply and the promotion of nonconventional renewables, the system has relied on calls for tenders for long-term energy contracts, supported financially by the regulated customers.

A key part of the proposed reform is the full redesign of the wholesale market, broadly aligned with, for example, the market design recently implemented in Mexico, consisting of three complementary markets: an energy market (including ancillary services), a capacity market, and a market for clean certificates. The declared objective is to create market signals to better align individual and societal goals in the power system of the future, which is expected to change significantly due to the deployment of nonconventional renewables as well as greater empowerment of end users. The main elements of the new market structure are described below.

More granular electricity pricing

Electricity spot prices are currently calculated on a weekly basis for three tiers of load – peak, shoulder, and valley – linked to the traditional representation of demand in the stochastic dual-programming model used by the ONS in operational planning. This weekly aggregation has made sense because, due to the hydro regulation capability, the system was mainly energy constrained (as opposed



to traditionally capacity-constrained thermal systems) and there were consequently no significant intraday price differences. However, demand patterns are starting to change, deviating from the current load and price tiers. More importantly, the reduction of the system's storage capacity with less construction of new hydro plants, and the increasing penetration of variable energy resources, are expected to introduce an increasing capacity constraint, leading to more significant hourly price spreads. So hourly prices are a required feature to provide both generation and demand with incentives to efficiently adapt to the future price dynamics.

The proposed law would establish a target (January 2020) for prices to be set hourly, foreseeing that prices should be obtained ideally from an open-source tool that calculates the dispatch that minimizes operational costs each hour. The law formally introduces the possibility of deriving these prices from market bids of prices and quantities, to be implemented no earlier than 2022. This would occur only after one year of a shadow operation of the market and after studies, expected to last through 2020, to develop a bidding arrangement that deals effectively with the complexities of the Brazilian cascaded-hydro system.

New capacity product

As already mentioned, long-term auctions for new generation plants have been the resource adequacy tool used in Brazil since 2004. Separate auctions are organized for new and existing power plants, with different lag periods (between the auction and when the plants should be available) and contract durations. A1 has a one-year lag and targets for existing plants; A3 and A5 have 3- and 5-year lag periods, respectively, and target new power

plants with different construction times. Contracts also differ according to the technology. For example, A3 and A5 offer 30-year forward contracts for hydropower plants and 15- to 25-year option contracts for thermal plants and renewable energy facilities.

A crucial factor in the current framework has been that free customers have not been obliged to procure their electricity through these long-term auctions for new generation, as long as in the medium term they are 100% covered by contracts. This has clearly led to free riding at the expense of regulated end users, who have borne fully the resource adequacy costs.

Under the proposed law, Brazil would move towards a capacity market mechanism involving both regulated and free end-users, although it is still to be determined how the capacity product will be defined. With such a particular and evolving power system mix, very different from the classic thermal systems in which capacity products have been defined to date, this task will certainly be a challenge. The Colombian reliability charge mechanism is a potential starting reference, although it is also currently undergoing a much-needed review. (See the article by Giraldo and Robinson in this Forum.)

Clean energy certificates scheme

Nonconventional renewable sources have been promoted through the reserve auctions, and have been subsidized through discounts in transmission and distribution tariffs. Wind and solar power, for instance, have received a 50 per cent discount, and power plants using biogas from landfills have received a 100 per cent discount. The current regulation also includes a net metering mechanism as a further way to promote distributed generation. As has been well demonstrated in the literature, net metering is an inefficient and

unsustainable way to subsidize such technologies, since it leads to a significant imbalance in cost allocation, given that network costs are not monetized according to end users' actual use. Under the proposed law, this inefficiency would be tackled by redesigning end-user tariffs, adding a capacity charge to the existing volumetric one.

The establishment of a clean energy certificates market is an attempt to rationalize and combine the diverse subsidies that currently exist. As with the capacity product, how the regulation defines 'clean' is still to be determined. The final scope of the mechanism is likely to be broad to reflect the fact that, besides the new wind and solar photovoltaic plants, the current mix also contains large hydro, nuclear, and biomass plants.

Widened scope for the retail market

Currently the unregulated (free) end market is limited to large consumers – those connected to voltages above 500 kilovolts (kV). The proposed legislation would lower this limit by 2026, enabling any end user connected to voltages higher than 2.3 kV to participate in the free market, enlarging the share of that market to more than 40 per cent.

An immediate effect of this policy would be that distribution companies, which entered into long-term Power Purchase Agreements (PPAs) to hedge the price of their captive demand, could be in a long contractual position. They would be allowed to trade these contracts in the new and wider market environment. In principle, it is assumed that any residual loss due to over-contracting will be passed through to consumers as a system-wide charge. If allocated only among captive demand, the natural consequence would be that the end users remaining under the regulated rates would be subsidizing the ones exiting to the free market.



It is not clear, either, which efficiency gains should be expected from the implementation of this measure or why it is supposed that the newly liberated end user will be able to sign better contracts than the ones resulting from the current centralized auctions. However, this relevant discussion, common to the whole South American continent, is beyond the scope of this paper.

Other aspects

The proposed law also opens the possibility of redesigning the current system of transmission and distribution tariffs, possibly moving from the current volumetric design to a more sophisticated format including a fixed charge, as mentioned earlier, as well as increasing time and spatial granularity.

One key flaw in the proposed law must be addressed: distribution companies play the role of regulated retailers for the captive end users, but despite their regulated nature, they are treated as market retailers, as they bear both volume and market price risks. For obvious reasons, it would be much healthier if these entities would merely pass through the wholesale market prices to their captive end users.

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**BALANCING
DECARBONIZATION AND
LIBERALIZATION IN THE
POWER SECTOR:
LESSONS FROM
COLOMBIA**

**Iván Mario Giraldo and
David Robinson**

All electricity models must meet multiple objectives, including efficiency in investment (resource adequacy), operations (merit order dispatch), and consumption (pricing), as well as environmental sustainability. The Colombian wholesale market scores high on most of these measures and

may be an interesting model for other countries to study. However, the country faces important challenges, in particular the integration of nonconventional renewable energy (NCRE), notably wind power, and its increasing reliance on fossil fuels to provide system security during El Niño events.

Since 1995 Colombia has built a wholesale electricity market based on the core principle that the market should allow free entry and promote efficient investment and operating decisions. Technology neutrality is central to this principle; it means that the market design should not subsidize or favour any particular technology. As in other countries, the market was designed before wind and solar photovoltaic energy became economically viable, and we argue that the design is no longer neutral because it does not adequately reflect the value of these renewables.

This article describes the Colombian wholesale electricity market, analyses the effect on it of El Niño climate events, and suggests options for revising the market to better integrate NCRE.

The wholesale electricity market

There are three related sets of transactions in the Colombia wholesale electricity market: spot, medium-term bilateral contracts (of one to two years), and long-term firm energy contracts (20 years). Spot prices are determined by the bid of the most expensive plant required to operate in the merit order. Bilateral contracts offer a hedge for retail suppliers and large unregulated users against spikes in the spot price, especially those due to severe droughts that reduce the water inflow to dams, occurring each three to five years with El Niño events. Imbalances of actual demand and generation compared to these contracts are settled at the spot market. Bilateral contracts account for

84 per cent and spot transactions 16 per cent of the aggregate income of these two types of transaction.

Colombia’s long-term firm market for firm energy is quite unique. With 70 per cent of power capacity consisting of large hydroelectric plants, and limited storage capacity (only 6 per cent of total capacity in reservoirs can save water for more than six months), the main characteristic of the Colombian wholesale power market is an extreme variation of water inflows coinciding with El Niño weather. Under normal conditions, hydro accounts for 85 per cent of total generation, but during El Niño events this share falls to 65 per cent, typically for five to twelve months. Other technologies are required to cover the hydro deficit during El Niño periods.

To ensure resource adequacy to cope with hydro deficits, in 1996 the government introduced a mechanism to remunerate backup capacity, and in 2006 the concept of ‘capacity’ was replaced by ‘firm energy’. This latter concept reflects the fact that a hydro plant’s firm (i.e. constant and reliable) generation during periods of water shortage does not depend on the plant’s capacity, but rather on the energy it can generate with close to 100 per cent probability during these periods from water inflows and reservoirs.

A key change introduced in 2006 for firm energy payments was moving from an administrative mechanism to a market-driven reliability charge, determined through auctions. These auctions occur when projections suggest that there will be inadequate firm energy to cover demand projected four years ahead. Market prices for firm energy are determined by the marginal offer selected through the auction. New power plants compete in a given auction to receive the reliability charge for 20 years in exchange for assuming



obligations to (a) build the plant and begin operating within four years of the auction, (b) guarantee permanent availability of the quantity of firm energy offered and selected in the auction, and (c) deliver the firm energy assigned when the system calls for it, which happens whenever the spot price is above a defined scarcity price (similar to a call option, with the scarcity price as the exercise price). The new plants bid prices and quantities for new firm energy contracts to meet expected demand growth, and are paid the reliability charge defined by the new auction for 20 years. Existing plants are price takers and passive bidders in the reliability auctions – which means that their quantities are taken into account in the auction and the price they receive changes with each new auction.

Two firm energy auctions, in 2008 and in 2011, guaranteed 3,996 megawatts (MW) in new projects under the reliability charge mechanism, with projects coming into operation between 2010 and 2018; this is almost a quarter of the 16,742 MW of capacity at the end of 2017. Natural gas plants (13.5 per cent of total capacity) are the main source of reliability during critical hydro periods, and coal-fired plants have a relatively low share (8.1 per cent), in spite of the abundance of coal in the country. The decline in international coal prices is encouraging the construction of new coal-fired plants. Although Colombian electricity generation has a very low carbon intensity due to the predominance of hydro, the trend is towards greater reliance on fossil fuels.

One special condition for thermal plants to earn a firm energy payment is the obligation to guarantee firm contracts for fuel supply and fuel transport at all times. Given the low dispatch factor of gas-fired plants under normal hydro conditions, obtaining firm fuel supply

contracts requires the existence of a liquid secondary market in which to sell contracted gas when not needed. Because of concerns over the liquidity of such a market, the government approved the construction of a liquefied natural gas (LNG) import terminal. Generators have to contract only for the regasification capacity in support of their firm energy obligations.

Spot prices for energy in a normal year fluctuate at rather low levels, \$25–40 per megawatt hour (MWh), well below the average cost of new capacity. In principle, the difference in total costs is supposed to be recovered from long-term firm energy markets, or through medium-term bilateral contracts with prices at about \$50–60/MWh. As prices in the El Niño years can reach \$80–120/MWh or higher, the government and the energy regulator aim to enforce bilateral contracts and firm energy obligations to ensure that consumers are exposed as little as possible to high spot prices.

The ability of a generator to offer bilateral contracts depends on the firm energy of its plants and the generation costs. Hydro and coal plants compete in the bilateral contract market at around \$50–60/MWh. However, gas and diesel plants do not compete in this market because of the higher variable cost they might incur to generate under tight market conditions. So their incomes rely only on long-term firm energy and short-term markets.

Long-term El Niño intermittency

The system has been stressed with two El Niño events in the last 10 years, in 2009–2010 and 2015–2016. In the first period, the government intervened heavily in the markets, through administrative assignment of natural gas to gas-fired plants that had insufficient gas supply contracts, and the decision to designate coal and gas-fired plants as base load plants (that

run almost continuously). In 2015–2016, electricity spot prices were very high, up to \$650/MWh, reflecting the use of diesel-fired plants at the margin. The system was near to rationing, due to an accident in a large hydroelectric plant that held 25 per cent of the system's water reserves and the refusal of the owners of a large diesel-oil-fired plant to comply with their firm energy obligations. These owners argued that the difference between the spot price and scarcity price was so large that they would have been bankrupt had they met their long-term firm energy obligations throughout the El Niño period.

The system was able to maintain service without blackouts or rationing, but the experience demonstrated the need for reform. Based on that, an international expert panel appointed by the energy regulator (Comisión de Regulación de Energía y Gas or CREG) analysed possible reforms – including changing the method of calculating the scarcity price and its effects on reliability charge auctions; establishing a forward contract market for energy; introducing mandatory day-ahead and intraday markets; and establishing mechanisms to elicit investment in NCRE.

Remarkably, the Colombian energy wholesale market has preserved the basics of its original design – in particular, the principle of technology neutrality and market-based incentives for operations and investments. It has done so while adapting to deal with long-term hydro intermittency related to El Niño, including through reliability auctions and by introducing flexibility through the construction of an LNG terminal that established a link to international LNG spot markets. However, there is a fundamental challenge to the current market design, namely the integration of NCRE.



Integration of nonconventional renewable energy

Recent studies by the government's energy planning agency have identified projects with the potential to produce 10,747 MW in wind and solar, from which 4,068 MW could be developed to meet forecast demand in competition with other new capacity. If built, this increment from NCRE would represent 24 per cent of current capacity. The challenge of integrating this new renewable capacity is both technical and economic.

Since the Colombian system is heavily hydro-based, it can cope quite easily with short-term fluctuations but has trouble with long-term drought. Short-term price fluctuations provide signals for hydro to be scheduled based on opportunity costs and provide short-term flexibility to cope with variations in demand and supply. In principle, this should facilitate the physical integration of renewable energy like wind and solar, which involve relatively short-term intermittency. However, this does not provide a financial basis for investing in NCRE.

Colombia currently relies on fossil fuels, especially for firm energy, whereas many countries aim to fully decarbonize electricity. The Colombian market design does not attract investment in NCRE; the combination of low short-term prices and firm energy auctions does not generate sufficient revenue for these technologies. Since the full (fixed and variable) cost of renewables in many countries is now below the variable costs of fossil fuel plants, it is important to ensure that the market does not discourage entry of more efficient plants.

Investors have asked the government to establish a mechanism to promote investment in NCRE, arguing that without it investment would not be economic and would not occur. In

March 2018, the Ministry of Mines and Energy issued policy guidelines governing long-term contracts for generation projects that help reduce greenhouse gases and mitigate the effects of climate change, by taking advantage of the complementarity between available energy resources. The government's stated objective is to increase the nonconventional share of generation from 2 per cent to 10 per cent in five years (by 2023), to 'guarantee not only a better supply, but an improvement in end users' electricity rates'.

There is very little information about the proposed long-term contracts for NCRE. In 2016, the CREG and its international expert panel discussed four possible contractual alternatives to integrate NCRE into the system ([See here](#)):

1. Contracts with a 'green charge' added to the spot price, with the charge defined through auctions and assigned to projects until the MW goal for NCRE has been reached. In the auction, NCRE generators would offer a quantity in MW and a price in \$/MWh.
2. Pay-as-generated contracts, assigned through a sealed-bid auction. Bidders would specify MW quantity and price in \$/MWh, and contracts would be assigned until the specific MW goal for NCRE has been reached.
3. Energy contracts for NCRE, similar to contracts for difference, also assigned through a sealed bid auction. Bidders would specify MWh per year and price, with the possibility to deviate 10 per cent annually in energy.

4. Pay for contracted energy, with contracts assigned through two-sided auctions with generators and suppliers sending offer and demand curves, with the possibility that conventional plants compete with NCRE.

Since these contracts appear to involve some advantage for NCRE, critics could argue that they upset the technology-neutrality basis of the wholesale market model. But since some NCRE technologies are widely considered to be economically more attractive than fossil fuels in many countries, one wonders whether Colombia's current system is actually penalizing them.

In principle, the current fiscal regime supports investments in NCRE, by exempting equipment from VAT and allowing up to 50 per cent of total investment to be deducted from income taxes over a five-year period. However, to qualify for these benefits, the projects must be profitable, which has not been the case to date.

There are at least four reasons to question whether the current system is technology neutral and may actually discourage investment in NCRE:

1. In many countries wind and solar power are less expensive than conventional generation, at least on a levelized cost of energy basis. Fixed and variable costs of these renewable technologies are often below the variable costs of coal and gas-fired plants. There may be reasons that these renewables are not economic in Colombia, for instance location or backup costs. Nevertheless, the onus should be on the Colombian government to explain why NCRE is not economic in



Colombia, and to demonstrate that the current market system truly is technology neutral.

2. The Colombian system does not tax carbon emissions. In the absence of this or a similar policy, it makes economic sense to include a special payment to technologies that do not emit carbon dioxide.
3. The CREG's method of determining the capacity factor (guaranteed firm energy as a percentage of a plant's output at full capacity) could well understate NCRE's contribution to system reliability, thereby lowering revenue earned in the firm energy auction. Capacity factors define how much firm energy a plant can sell in an auction. Thermal plants (diesel, gas, and coal) have factors of 88–97 per cent; hydro's is 55 per cent with storage and 30 per cent without storage. CREG assumes a capacity factor for wind plants of 14 per cent or less, and even that only for plants with more than 10 years of wind speed data. However, some studies have demonstrated firm energy availability of 25–40 per cent during critical hydro periods.
4. A handicap of the methodology used to calculate firm energy is that it does not take into account the complementarity between different technologies – especially between hydro on the one hand and wind and solar on the other – and its effect on system-wide reliability. Recent studies have shown high correlations between low water inflows and

high wind and solar availability. However, the contribution of each plant is calculated on a stand-alone basis. The same criteria are applied to NCRE as to hydro plants: maximum daily energy that can be generated with a high probability in a continuous way. The valuation of firm energy for NCRE is less than it would be if complementarity were included in the calculation.

Another important consideration is the impact of higher penetration of intermittent renewables on the economics of the other assets in the system. Heavy penetration of wind and solar is likely to drive down wholesale energy prices, requiring higher firm energy prices to attract new firm energy supplies, probably reducing the returns on existing generation assets (and possibly stranding assets).

The challenge, then, is how to introduce the required reforms to a model that is working pretty well, reinforcing the basic principles of true technology neutrality, competition, and efficiency in investment and operations while enabling the integration of NCRE. In addition to other reforms being considered, the markets should in future reflect the economic value of all renewable resources that are carbon-free. That would require at least two measures. One is to pay these resources an extra fee, in effect a zero-carbon subsidy in the absence of a carbon penalty (e.g. a carbon tax). The second measure is to modify the methodology for evaluating capacity factors for NCRE to reflect the complementarities between hydro and wind/solar, providing incentives to use dams as swing resources to optimize the quantity of firm energy available for system reliability.

Because of its heavy reliance on hydro, Colombia should find it relatively easy to cope with short-term intermittency related to NCRE. Countries without significant hydro potential will have more difficulty dealing with deep penetration of wind and solar. For them, the question is whether the Colombian model provides efficient signals to cope with short-term intermittency, while also providing long-term signals for low-carbon investment. The answer could well be yes, on two conditions. First, the model should recognize the full benefit of NCRE resources, including their contribution to sustainable resource adequacy, both as a complement to other resources and as a substitute for polluting fuels. Second, in order to provide backup for the renewables, the long-term energy auction needs to reward energy sources that provide both reliability to cope with extended shortages and flexibility to cope with short-term intermittency.

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ELECTRICITY AUCTIONS IN BRAZIL AND MEXICO: KEY LESSONS

Michael Hochberg and Rahmatallah Poudineh

Auctions for long-term contracts as means of encouraging investment in renewable and non-renewable energy have become increasingly popular around the world. Reasons for this trend include the inefficiency of short-term markets, risk, lack of decentralised forward markets, and the need to introduce market mechanisms in non-liberalised markets. The experiences of Brazil and Mexico in long-term auctions represent an interesting point of comparison. Both countries are global leaders in these auctions, attracting US\$12.4 billion in clean energy investment commitments in 2017 alone, making up more than 70 percent of the



annual total in Latin America and the Caribbean. Brazil was the first country to introduce long-term auctions for electricity procurement (2004) and renewable specific auctions (2007), and therefore has significant experience in the design and implementation of such mechanisms. Holding its first auction in 2015, Mexico is one of the most recent countries to introduce auctions for renewable support. The two nations are also home to Latin America's largest economies and populations, and lead the region in oil production and installed generation capacity.

This article explains the rationale behind electricity procurement through long-term auctions and discusses some of the key trade-offs auction designers face. It then examines the auction process in Brazil and Mexico, identifies potential areas for improvement and makes corresponding recommendations.

Why long-term auctions?

Long-term procurement of electricity is often interpreted as a regulatory intervention in liberalised electricity markets in response to the inefficiency of short-term markets in providing a long-term investment signal for new capacity in general and renewables in particular (in non-liberalised markets, it is a step forward toward exploiting the power of competition). For example, spot market price caps (to support political aims or policy goals) can ruin the economics of a power generation project. Investors and generators may depend on price spikes to recover the fixed costs of their investments. Price caps can thus lead to revenue shortfalls (a phenomenon known as the 'missing money' problem), and skew the investment signals provided by the short-term markets. Even without price caps, investors may be reluctant to depend entirely on the short-term markets for full investment recovery. Increasing penetration of zero marginal

cost intermittent renewable generation amplifies price uncertainty and market volatility, especially at peak demand and for peaking units.

Renewable generation is also disproportionately disadvantaged (compared with conventional generation) given its intermittency, and the inverse relationship between the dispatch of near-zero marginal cost units and wholesale market prices. When weather conditions cause renewable generation units to sit idle or contribute minimally to baseload power supply, wholesale prices are likely to be higher due to the absence of near-zero marginal cost renewables. Clearly, renewable generators will not claim these higher prices if they are not producing power. Conversely, when renewables are producing at or near full capacity, this lowers wholesale prices by replacing more expensive generation on the dispatch curve. For example, this sequence can make peaking plants uncompetitive, and can cause relatively inexpensive generation to serve as the unit on the margin of the dispatch curve. This unit sets the system's marginal price which is claimed by all generators. This situation creates a quandary for renewable generators, which apply downward pressure on the wholesale market prices on which they depend to recover their investment and earn a rate of return.

Accordingly, the short-term markets designed at the early stages of market liberalisation internationally may not be sufficient to guarantee security of supply and encourage an adequate generation mix and decarbonisation objectives. Long-term electricity procurement auctions represent an important complement to short-term markets, and have become increasingly popular as a means of coordinating and ensuring resource adequacy through a competitive, albeit interventionist

mechanism. At least 60 countries have adopted competitive tendering as a procurement method for renewable energy generation. As such, these auctions for the allocation of long-term contracts have become a mainstream mechanism for renewable support as they isolate generators from short-term market volatilities and reduce their capital costs (as the main component of total costs), which should translate into lower power prices for consumers. This is specifically helpful given the absence of decentralised forward markets in most liberalised markets. Forward contracts in liberalised markets rarely go beyond one year. Nonetheless, the centralised long-term contracts can have adverse effects on the operation of short-term markets, which can be minimised through appropriate design.

Trade-offs in auction design

To be efficient and effective, auctions must be designed prudently. Auction design elements, however, interact with one another creating continual trade-offs between reducing the likelihood of unwanted outcomes and achieving optimal auction results. Notable examples of these trade-offs in auction design are described below.

- Severe noncompliance penalties or large bid bonds may increase the probability that winning projects are built; however, they also may reduce the number of participating bidders and increase the risk premium on the cost of capital, leading to less competitive bidding and higher electricity prices.
- Short lead times between auctions and commercial operation dates may not provide sufficient time to meet development deadlines, which can result in mutual blaming and missed milestones. Yet



too much lead time can cause project developers to bid at excessively low prices in order to wait and see how market conditions and technology costs develop before making a final investment decision.

- Technology-specific vs. technology-neutral auctions represent a trade-off between government control of generation mix and cost efficiency. Technology-specific auctions (and multi-technology auctions with limited technology options) provide the most control over generation technology build and can help align generation mix evolution with government objectives, yet they are also likely to be less cost efficient. Technology-neutral auctions maximise cost efficiency but provide minimum levels of government control over deployed technologies. Thus, neutrality toward technology can lead to conflict between installed capacity type, and government environmental policy or industrial strategy.
- Auctioning large volumes through a single tender may lead to rapid development of new capacity, yet could reduce competition and lead to higher prices. As bid prices are largely a function of supply and demand, volume caps may be implemented to ensure that offered volume in a given auction remains below the total volume that the market could absorb. Over capacity is a risk in long-term auctions given the imperfect information of auctioneer and the tendency of the centralised coordinator to over-contract

capacity at the expense of consumers. Volume caps set below the total estimated market volume can therefore lead to bid price reductions due to limited supply and fiercer competition, yet may yield less capacity buildout.

- Grid connection models which expose project developers to the full cost of connection, known as ‘deep cost’ allocation, can disadvantage renewable developers when competing with conventional resources. As site selection for renewables is already reduced by the availability of resources, grid interconnection locations can be much more limited than those for conventional generation. However, from a social welfare perspective, a ‘shallow cost’ allocation model, in which the transmission system operator assumes all or most interconnection costs, reduces the exposure of renewables to their full economic costs, including integration and grid interconnection. If renewables avoid full cost exposure through inefficient siting, welfare is not maximized, as renewable investment would occur where it is uneconomic.

Auction design elements also interact with the larger market and policy frameworks in which auctions exist. For example, if project developers are required to submit bids according to their short run marginal cost of generation, does the wholesale market have sufficient mechanisms for capacity or ancillary services to cover fixed costs for generators? Alternatively, if generators bid according to their long run marginal

costs or levelized cost of energy, does it lead to foreclosure of short-term markets? The above considerations are just some of the features which must be considered when designing and evaluating auctions.

High level assessment and key lessons from Brazil’s auctions

Since 2004, Brazil has held at least 74 auctions resulting in more than 8.7 million gigawatt-hours (GWh) of electric generation and US\$488 billion in investment. Under the auctions, renewable electricity prices have decreased considerably compared to the precursor program with feed-in tariffs of \$150 per megawatt-hour (MWh) for wind, \$96/MWh for small hydro, and \$70/MWh for biomass. Average auction prices for these three technologies decreased from 2004 to 2017 to \$53/MWh, \$65/MWh, and \$69/MWh, respectively. Solar PV and large hydro have been deployed through auctions as well.

Accordingly, Brazil’s auctions have been largely successful in increasing security of supply by attracting new generation capacity, encouraging a more diversified generation mix, and promoting competition and efficiency in generation to achieve cost reduction. Moving forward, issues to consider include introducing a formal capacity product and market, and auction frequency concerns.

Capacity product

While the forward contracts and firm energy certificates (FECs) Brazil currently utilizes may somewhat resemble capacity market features, energy is the only official product in Brazil’s long-term auctions. The specific energy products are forward contracts which cover the distribution companies’ load forecasts. These contracts help reduce risk for generators, and increase security of supply. The FECs support the monitoring and



maintenance of the nation's supply–demand balance; as each participant is in charge of its own load, FECs, and contracts, the certificates are essentially a decentralized mechanism to secure supply.

The introduction of a proper capacity market may help encourage investment in capacity and reduce the likelihood of supply shocks (however, careful examination is required to explore the impacts of such a market on the existing energy product market). In fact, there is discussion within the Brazil's market operator (Câmara de Comercialização de Energia Elétrica, or CCEE) of creating a separate capacity market. To this end, a proposal was sent to the Brazilian Congress with the objective of creating a capacity market by 2021. The initiative could unbundle capacity and energy, and possibly introduce renewable certificates. The capacity market would potentially include centralised auctions five years ahead of project delivery, with costs shared by all customers, and the mechanism would operate under the management of the CCEE.

Auction frequency

Tenders should only be held when a market is able to absorb the auctioned generation, and is prepared to facilitate project development. Recession in Brazil has recently led to weaker demand growth and an excess of power supply. Accordingly Brazil held a de-contracting auction in 2017 to cancel projects (mostly solar PV and wind) that it had awarded in reserve energy auctions in 2014 and 2015. Beyond the recession, it is likely that delays related to project finance, permitting and other administrative issues were responsible for significant project delays, which led to a backlog of projects. Combined with economic downturn, this provided the government with the pretext to cancel auctions, clear the pipeline, and start afresh.

While this de-contracting mechanism was innovative and resolved the issue in the short-term, it may have created a degree of moral hazard, as project developers were able to avoid full penalties and may assume the same mechanism will be available if a similar situation arises in the future. Further, the mechanism required significant time and effort to develop on the part of the Brazilian government, the exact opportunity cost of which is unknowable. However, if Brazil had not contracted too much capacity, the time and effort could have been better spent. Lastly, cancelling projects across the board from multiple auctions can negatively impact investor confidence, which may raise the cost of capital and bid prices.

This issue illustrates the challenges of centralised coordination mechanisms in responding to market conditions. Due to macroeconomic conditions in Brazil, typical annual electricity demand growth of approximately 4 percent dropped to 0.9 percent in 2016 and was forecast at 2 percent for 2017. When determining auction dates and volumes, governments must consider worst case demand scenarios, and develop precautionary measures, or a means to cope with excess capacity if demand unexpectedly drops due to external factors. For example, policymakers can start with minimum demand and correct this estimation in subsequent re-configuration auctions. Governments should also ensure that a certain number of projects from the most recent auction are making tangible progress toward development before holding a follow up auction.

High level assessment and key lessons from Mexico's auctions

Since beginning power market liberalization in 2014, Mexico has held three long-term auctions for clean energy, offering three products: energy, capacity and clean energy certificates,

which were created as a means of supporting clean energy targets. Mexico has also held one medium-term auction which functions as a means for generators to reduce exposure to short-term markets by selling uncontracted energy and capacity one year in advance, with contract durations of up to three years.

While it may be premature to make conclusive assessments regarding the country's auctions, Mexico seems to enjoy a last-mover advantage, as many previous international experiences provided insights and a framework on which to base Mexico's auctions. If all contracted projects from Mexico's first three long-term auctions are realized, the country would add at least 7.5 GW of installed solar and wind capacity to the 3.5 GW of wind and solar it currently enjoys. Issues to be considered moving forward include the potential for low project realization rates due to low pricing, and increasing efficiency in its medium term auctions.

Low pricing

Record low prices down to \$20.57/MWh (third auction average) have been celebrated by the national government, yet they are also a cause for concern. Underbidding can lead to underbuilding, as overly aggressive pricing may expose investors to excessively low or even negative returns, which can lead to higher non-completion rates for projects, or cause insolvency at some point in the project lifecycle. Such consequences can negatively impact system planning, the overall investment climate and the market liberalisation process. The purpose of renewable auctions is to create investment incentives for the deployment of renewables. Auctions are not meant to create a market in which firms may purchase options to deploy renewables in the future.

To increase the likelihood of project realization and discourage speculative



bidding, Mexico's bid bond, which may be comparatively low, should be evaluated. In Mexico, the bond includes a fixed fee of about \$99,000 (regardless of the number of bids submitted by the same generator), approximately \$21,000 per MW of capacity offered in the auction in a year, plus \$10/MWh and \$5 for each clean energy certificate offered in the auction in a year. Auction participants are able to reduce this bid bond by up to 50 percent if an interconnection agreement is reached beforehand. Depending on technology, country-specific capital costs and specific offers, Mexico's bid bond may prove low when compared with a fixed percentage of estimated project costs (particularly if no capacity product is offered). For example, Brazil requires investors to submit a bid bond worth 5 percent of total estimated investment costs to be able to win a project in an auction. For the 14 winning solar and wind projects in Mexico's third auction, the average bid bond submitted was 11 percent (nearly 900,000 USD) lower than it would have been under Brazil's methodology. Including the one winning gas project (which won only a capacity contract) increases this difference to 13 percent, more than US\$1.3 million lower than under Brazil's methodology. It should also be noted that the design of the bid bond in Mexico, which is not fixed and is highly sensitive to capacity offers, could be an attempt to encourage lower financial commitments from intermittent renewable generators, which may be less likely to seek winning significant capacity in the auctions.

In addition, Mexico uses a pay-as-bid pricing rule, which encourages bidders to guess the market clearing price, and bid at or just below that price in order to clear in the auction. Employing a uniform pricing rule, in which all bidders receive the market clearing price, is likely to encourage auction participants

to bid closer to their marginal costs, thus reducing the propensity to 'race to the bottom' in terms of extremely low pricing (pay-as-bid vs. uniform pricing is a complex issue, and a full discussion of the merits of each pricing system is beyond the scope of this article).

Efficiency of midterm auctions

The results of Mexico's first midterm auction were released in late February 2018, yet no electricity or capacity contracts were awarded. This was the consequence of significant mismatch between demand bid prices and supply bid prices. The midterm auctions serve as a market hedge for load serving entities which seek to offload uncontracted energy and/or capacity in advance.

Generators thus face a trade-off between locking in contracts through this midterm hedge market or selling directly into the short-term markets. In the midterm auction, demand submitted very low purchase bids, perhaps with the prices of the long-term auctions in mind. However, the two markets offer very different products; long-term auctions allocate the right to build and secure financing, while midterm auctions offer a hedge for existing generators. It seems that demand failed to recognize this distinction. The midterm auctions represent a meaningful opportunity for load serving entities to secure contracts with end users. Auction participants on the demand side should recognize the purpose of each type of auction to avoid submitting unrealistically low bids based on expectations from a different type of auction.

Demand response: a suggestion for both Brazil and Mexico

Ideally, demand-side resources like energy efficiency and demand response should be able to participate in long-term capacity auctions as well as short-term energy and ancillary

service markets. Reducing demand through load shedding, load shifting or energy efficiency can reduce the short-term price of electricity and result in long-term avoided costs of generation, transmission and distribution. As such, consumers who effectively respond to price signals or implement efficiency measures provide value to the overall system by increasing available capacity and reducing system costs. These consumers should be entitled to compensation for the value they provide to the system.

While implementing such a mechanism is not straightforward in long-term auctions, it is already happening in several geographies such as the US and UK. Mexico is already planning to implement demand response services later in 2018 in its capacity market. Brazil can also consider allowing demand-side resources in its long-term auctions given it may implement a capacity market. Brazil and Mexico would also benefit from demand-side resource aggregators, which could participate in the capacity auctions on behalf of consumers. The aggregation service could be provided by new companies or by existing energy service companies.

Conclusion

Long-term auctions are increasingly popular as a means to deal with the imperfections of liberalised markets or improve efficiency in non-liberalised markets. However, auction design requires continuous review and improvement to respond to new challenges and market events. Successful auctions that meet the goals of both policymakers and society are a constant balancing act, which includes weighing the trade-offs between specific design elements. Ultimately, auction design seeks to be consistent with the broader market context, and spread risk efficiently amongst primary auction participants to ensure that the



trade-offs do not too heavily favour or disadvantage a particular class of auction participants (i.e. investors, government, or rate-payers). There are numerous trade-offs along every step of the auction design process that impact the per unit price of electricity resulting from auction, the generation technology deployed and resulting carbon emissions, as well as other critical outcomes such as local content, investor confidence and the likelihood of project completion.

As a tool to address inefficiencies in imperfect power markets, there is no optimal one-size-fits-all centralised auction design. Each country implementing auctions must consider the broader market design, policies and context as well as the myriad of trade-offs at each step of the design process, from determining what type of auction to hold to deciding lead times and penalties. There is no single solution to these or other design decisions, as no two market contexts are identical, and auctions come about in different geographies in their own way and time.

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THE ELECTRICITY MARKET IN RUSSIA

Ksenia Letova, Rui Yao, Mikhail Davidson, and Janusz Bialek

The Russian Federation is the world’s largest country. Its Unified Power System consists of seven interconnected power systems (IPSS) covering nine time zones. Network infrastructure is comparatively well developed in the densely populated Centre IPS, while the East and Siberian IPSs are less developed. The East IPS has a very weak connection to the neighbouring Siberian IPS, so the East IPS usually operates separately.

Russia’s installed capacity is the fifth largest in the world (after China, the United States, India, and Japan). The total installed interconnected capacity

in the Unified Power System reached 236 gigawatts (GW) in 2017, with fossil-fuel power plants (natural gas and coal) accounting for about 68 per cent, hydropower for about 20 per cent, and nuclear capacity for about 12 per cent. The wind and solar plants make up a trivial contribution (less than 0.05%) to the capacity mix. In 2017, the total electricity generation was about 1060 terawatt hours.

The Russian power sector has undergone several changes, beginning in the early 1990s after the dissolution of the USSR, when the country underwent a drastic move from centralized economic planning to a market economy. This paper reviews the reform of Russia’s electric power industry, summarizes its achievements and current challenges, and provides some insights into the potential future of the Russian electricity market.

The Russian electricity market

The Russian electricity market is divided into wholesale and retail, as well as regulated (for residential customers) and competitive segments. In the competitive market, both energy and capacity prices are determined by the market, although the capacity market is less exposed to competition and has more limitations.

The main participants are six wholesale generation companies, RusHydro, 14 territorial generation companies, Rosenergoatom, InterRAO, and about 250 local retail supplying companies. Each wholesale generation company has several major fossil-fuel power plants, located in different regions of Russia to prevent regional monopoly. They are the main competitors in the wholesale electricity market. RusHydro, a joint-stock company, owns all major hydropower stations, which are price-takers. The territorial generation companies were formed mainly from combined heat and power stations in

neighbouring regions. Government-owned Rosenergoatom is the only company in Russia operating nuclear power plants: there are 10 such plants in Russia, and they are price-takers. Inter RAO was created in 1997 to operate international assets and international grids under state control. Monopolistic retail companies supply power to the end users; tariffs for their services are based on a formula set by the government.

Due to the vast expanse of Russian territory, the electric power system is split into zones with different pricing rules. Pricing zone 1 is in Europe and the Urals, where gas-fired plants are dominant. Pricing zone 2 is in Siberia, where nearly 50 per cent of the capacity is hydropower and around 40 per cent is coal-fired. There are several non-pricing zones in the rest of Russia. These areas are isolated from Russia’s main grid, or consist of vast territories with sparse populations in which the local grid’s connection to the national grid is weak or absent. In the non-pricing zones, tariffs are still regulated.

Energy market

The electricity market consists of the day-ahead market and the balancing market; in addition, a small portion of the energy is traded through regulated and unregulated bilateral contracts. Since 2011, regulated trades cover only residential consumption in competitive pricing zones, while about 70 per cent of energy is traded on the day-ahead market. The Russian electricity market is based on the full nodal pricing model, similar to that widely used in the USA and other countries. The Alternate-Current Optimal Power Flow algorithm is used to determine prices; it gives very good accuracy in modelling power flows and losses given the extensive and strongly constrained grid infrastructure of the Russian energy system.



Capacity market

The capacity market was created to maintain sufficient generation and to stimulate investment in new generation capacity. It also has regulated and unregulated bilateral contracts, but most transactions are settled through competitive capacity selection (CCS), capacity delivery agreements (CDAs), and reliability must-run (RMR) contracts.

CCS started in 2008. The generators selected by CCS are paid for their capacity by all customers in the region. The competitive auction for the capacity is held annually to contract capacity for the next three years. The system operator calculates the cleared price, and the cleared capacity is traded at that price multiplied by a seasonal factor.

CCS was designed to cover the fixed costs of existing power stations, not to fund construction of new ones. In 2010, CDAs were introduced as a mechanism for guaranteeing investment in the construction of new plants. A CDA is an agreement among generation companies, their customers, and investors. Generation companies are obliged to commission new capacity within a specified timeline, and in return they are guaranteed remuneration for their investments. If companies fail to build power stations within the specified time, they are obliged to pay a penalty for each day of the delay.

Capacity market rules were introduced in 2008–2011, when it was expected that the demand for electricity would increase quickly and much new capacity would be needed. In 2007, it was assumed that power demand would grow by 4.1–5.2 per cent per year. However, by 2015, the actual demand was lower than the forecast by 30 per cent – equivalent to the generation of thermal plants of about 60 GW. This overcapacity put a financial burden both on consumers,

who had to pay for the built but unused capacity, and on producers, who were getting lower revenues. On the one hand, due to the overcapacity, the price set by the CCS mechanism decreased. On the other hand, the number of cheap blocks introduced under CDAs lowered the price of electricity on the day-ahead market (the system operator estimated that about 20 GW of capacity are price-takers).

The RMR contract was introduced to guarantee that generators that are important for system reliability but less economically competitive would still operate. In most cases, the participating generators and the RMR capacity are determined before the CCS, and the price for RMR is determined by the government. In the operation of markets, the participants in RMR and CDA as well as hydro-power plants and nuclear power plants act like price-takers, so that an adequate electricity supply is guaranteed.

Price components

Generally, the price consists of four major components: energy price, capacity price, grid services, and infrastructural and retail surplus. The price for the regulated component is quite high and depends on the voltage level. The regulated part also includes the payments to the system operator, the administrator of the trading system, and the Market Council, but these payments make up a comparatively small share of the overall price. The retail margin is usually fixed at around 5 per cent. The figure below shows the end price breakdown of the Moscow region in December 2016.

Power market reform successes and challenges

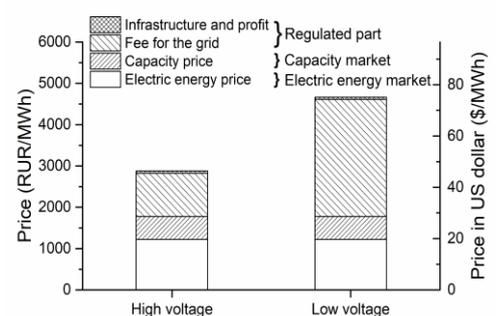
The most successful result of the power market reform was the creation of a competitive wholesale market. Electricity energy prices

reflect the supply–demand fundamentals much better than, for example, gas prices, which remain largely under government control. This was particularly evident in the global financial crisis of 2008, when the power consumption decline put on a brake on energy price growth, despite the fact that fuel costs (especially for gas power stations, which provide half of the energy production) continued to rise.

While the electricity market can be considered competitive, a substantial part of the capacity market (44 per cent and 24 per cent for the first and second pricing zones, respectively) is still represented by nonmarket mechanisms, such as regulated contracts and CDAs. Regulated contracts are used to provide electricity to residential consumers and consumers in the non-pricing zones, while the CDA is not a market but a one-off mechanism designed to minimize the risks of building new power stations and attract investments to prevent capacity deficits.

This, combined with an overestimation of the need for new generation, resulted in serious overinvestment. The cost of capital is generally much higher in Russia than in the West, even after several reductions in the Central Bank’s rate (which at the time of writing is 7.25 per cent). Hence, when the government expected a massive demand for investment (when the economy was growing at a significant rate just before

Price breakdown as of December 2016 in Moscow





the crisis), it could not rely on purely competitive mechanisms for creating new capacity. There were fears that the most likely private investors in generation capacity would be large consumers investing in self-generation and going off-grid. This would reduce demand from the central grid and would transfer the burden of supporting the fixed grid costs to other consumers, with disastrous effects for small-business and residential customers. The need for investment in grid infrastructure and power stations from 2000 to 2010 was estimated at \$74 billion, and a five-year investment plan suggested that another \$72 billion would be needed by 2012. As a result of the reforms, most of these funds were raised; a substantial part of the investment programme was covered by private capital.

There are still many factors that limit competition and distort market signals. First, the four largest generators have a more than 70 per cent market share, and the controlling stakes in all of them belong to the government. The capacity of the largest private generation company, Eurosibenergo, is about 1/7 of the total capacity of these four companies.

Second, the existence of separate pricing zones limits competition. For example, coal power stations in Siberia might compete with European gas stations, but under the current pricing mechanism, their competition cannot

be reflected in prices, because these zones are priced separately.

Third, in generation dispatch, the highest priority is given to nuclear power, second to hydropower, and third to combined heat and power (CHP) stations during the winter heating season as practically all Russian cities use district heating. The priority of nuclear and hydropower stations is justified by their lower costs, but priority dispatch of CHP stations limits competition among generators. With a total capacity of around 100 GW, CHPs account for nearly 40 per cent of the total Unified Power System capacity while providing most of the must-run generation. Due to lower industrial demand, the heat supply has decreased by roughly half during the last 30 years. The lower load factor of the boilers leads to less efficient operation, and the plants become less competitive. Moreover, although the CHP plants are more efficient, the number of small municipal boilers has increased by more than 20 per cent since 2000. Sometimes, despite the availability of underused CHPs, local operators still use the more expensive boilers, whose heat supply costs might be more than three times the cost of the CHP.

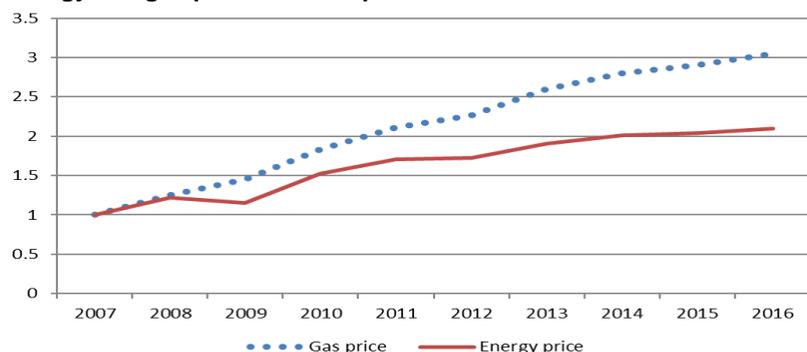
In July 2017, the Law on the [Supply of Heat](#), in Russian, was amended to consolidate and simplify regulation of the heat supply. The amendments stipulate that in each heat supply system, the price of heat supply is set based on comparison of boiler

efficiencies. This approach will create incentives to utilize more efficient heat sources, such as CHP, and that will increase their competitiveness in the electricity market. Also, in the medium and long term, such a scheme can help reduce the number of the must-run units.

Fourth, the reserve level of the overall system remains high. Consumers must pay for the underutilised power stations and excess reserves. In 2016, the average load factor of the Russian power plants was just 50 per cent. Regulators have been trying to develop a mechanism that would create stimulus for the RMR generators to shut down. Starting in 2015, the government restricted the conditions for qualification of RMR (Governmental decree No 820.2014, On the Change and Cancellation of Some Actions of Russian Federation Government in Wholesale Markets of Electric Energy and Capacity, [\(See here - in Russian\)](#). This step was welcomed by market participants as it is expected to lead to a significant reduction of the number of RMR.

Russia has failed to create a competitive environment in the retail market. One of the reasons is that, at the low-voltage level, the share of the grid component in the final price is about 60–70 per cent, and another 10–15 per cent is capacity (which is not very competitive, as discussed above). Hence the proportion of the competitive energy price in the final electricity price is very low. Consequently, local electricity supply companies are monopolists in their regions. Independent retailers are usually just resellers, buying energy from the regional monopolies. Thus, customers do not have the option of choosing a supplier and must buy electricity at prices that are sometimes artificially high.

Energy and gas prices as multiples of their 2007 levels.





Discussion and conclusions

Despite undoubted successes in the liberalization of the Russian power market, there is still much to be done, especially with regard to the capacity market. While most of the units covered by CDAs have been built and the deadlines for the contract payments are approaching, the government prolonged the programme to raise funds for further power system modernization. In January 2018, the government announced a new investment programme which will presumably affect 76 GW of the acting thermal power capacity and will last till 2030 ([Fundamental Principles for the Competitive Selection of Reconstruction Projects of Thermal Power Plants in Wholesale Markets of Electric Energy and Capacity](#), in Russian). While it is expected that the new system will also be based on CDA-type contracts, the main principles of the programme are the subject of a deep and detailed discussion among electricity regulators, consumers, and producers. There are risks that a new mechanism might repeat past mistakes and CDA holders will be chosen behind closed doors, leading to inefficient decisions.

At the same time, keeping in mind that there are a number of large market players, there are hopes that the new CDA programme will not grant preferences to any of them but rather be based on a bidding process with transparent and clear rules. The competition would help to eliminate inefficiencies. If competition is utilised, the CDA mechanism would mean no price rise for customers (as they will continue paying the same fixed ‘modernization’ rate as before), while the capacity will get the needed gradual upgrading and customers will not suffer from unexpected power station shutdowns and price fluctuations.

It remains to be seen whether the new mechanism will take into account the new market realities and be able to lay a foundation for the economically efficient renewal of energy capacity in the Russian power system.

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PHASING OUT COAL IN CHINA: INSIGHTS FROM INTERNATIONAL EXPERIENCES

David Robinson, LI Xin, and XU Qinhua

There is a growing consensus among scientists and policymakers that achieving the central aims of the Paris Agreement – keeping the global temperature increase this century well below 2 degrees Celsius above pre-industrial levels and trying to limit it to 1.5 degrees Celsius – requires an early capping and then a rapid decline in unabated coal-fired generation. The term “unabated” refers here to electricity produced in coal-fired power stations that do not have carbon capture and storage (CCS) or other technology to abate carbon dioxide (CO₂) emissions. Achieving the central aims of the Paris Agreement will require closing many coal-fired power stations, substantially reducing CO₂ emissions in those that remain, and building no new unabated coal-fired stations. This consensus has driven policy and financial decisions in many countries, with over 30 countries already having committed to phasing out coal altogether.

Nowhere is this issue of phasing out coal-fired power more important than in China, whose power sector relies heavily on coal and accounts for 13.7 per cent of the world’s energy-related CO₂ emissions. At the end of 2016, coal represented 57 per cent of the total generating capacity and 65 per cent of the generation in China. Concern is growing over the

environmental impact of China’s coal-fired plants, but China also faces significant strategic, financial, operational and political-economy costs associated with phasing out coal. The challenge for China is to stop building new unabated coal-fired power stations, while managing the transition away from coal.

This article draws on international experience to suggest eight ideas for China to consider in order to make it easier to accelerate the phasing-out of coal-fired generation. They focus primarily on addressing concerns arising within the power sector itself. It does not discuss estimates of stranded assets, or ways to smooth the political-economy-related frictions of phasing out coal; these topics are addressed in other studies.

(For relevant publications, see [A](#), and [B](#) - in Chinese).

Provide credible long-term policy signals to investors

Governments we have studied send clear policy signals regarding their long-term intentions for coal, usually through one or more of the following:

- legislation with a timetable for phasing out coal or steeply reducing emissions
- standards that require CCS or similar abatement equipment
- the requirement for new plants to be ‘carbon capture ready’
- a credible, long-term CO₂ emission price floor which rises over time
- refusal to provide public finance for unabated coal-fired power
- disclosure to financial markets of information on the risk of stranded assets.



A number of countries have announced plans to phase out coal altogether. At COP 23 (the 23rd annual Conference of the Parties to the 1992 United Nations Framework Convention on Climate Change [UNFCCC]), Canada and the UK announced the formation of a new global alliance committed to this goal. Another 32 countries/regions and 24 businesses and other organizations have outlined similar plans.

China has made many important commitments to address climate change. These include peaking greenhouse gas emissions by around 2030, increasing nonfossil fuel sources to 20 per cent by 2030, and reducing carbon intensity to 60–65 per cent below 2005 levels by 2030. In addition, China has substantially increased the role of renewable energy and taken steps to reduce coal consumption, including bans on new coal plants (except combined heat and power plants) in the three economic pillar regions: Beijing-Tianjin-Hebei, the Yangtze River Delta, and the Pearl River Delta. China has also included ambitious CO₂ emission performance targets in its Thirteenth Five-Year Plan. However, we are aware of no explicit official government policy on the role of coal-fired power in the longer term, or on reducing emissions from coal-fired stations by closing assets or retrofitting them with CCS or other abatement equipment. A policy statement on these matters would provide guidance to investors and inform better decision making.

If China is to reduce coal use significantly, it needs a policy for phasing out coal in all sectors, not just in the power sector. Focusing solely on the power sector will give incentives for industry to use coal rather than less carbon-intensive fuels.

It is also important to be clear about policies related to curbing emissions from existing plants. Retrofitting of CCS

or carbon capture and utilization (CCU) equipment has had little support in the US and the European Union, in large part because most plants are old and often inefficient. However, because more of China's plants are new and efficient, there is greater potential economic benefit from CCS retrofitting and from seeking new commercial ways to utilize the captured CO₂, for instance through mineralization (www.carboncapturejournal.com/news/making-money-from-mineralisation-of-co2/3251.aspx).

Address concerns about local air pollution throughout the country

Although climate change is a powerful reason to phase out coal-fired generation, international experience confirms that local air pollution and related health concerns have triggered regulations and public support for the displacement of coal by lower-carbon alternatives.

This is, of course, also true in China. Air pollution was a major issue first in the more industrialized regions, then in the rest of the country. For instance, public concerns over health explain the closure of coal plants in Beijing. However, the problem is now a national one. Some studies have concluded that the use of coal for power and heat in winter has a serious impact on people's life expectancy in northern China. Air pollution in western China has also become increasingly severe since the air pollution reduction campaign in the eastern coastal regions has led to a spatial transfer of air pollution within the country. The evidence of the impact on health in these other regions of China reinforces the case for phasing out coal throughout the country.

Accelerate power market reform

Competitive electricity market mechanisms can improve efficiency and help reduce the cost of phasing out coal. Many power systems in countries

that have phased out coal make use of competitive market mechanisms, for instance to support least-cost dispatch, retail competition, regional trading, integration of renewables, resource adequacy, and flexibility.

The challenges of climate change and local pollution in China and elsewhere offer a good opportunity to accelerate power sector reform that encourages the phase out of coal-fired plants. China began its electricity reform at the beginning of this century, but the system is still rigid in ways that discourage competition from renewable energy, demand response, and other sources of cleaner energy. This rigidity promotes the use of coal and is inconsistent with the objective of efficient decarbonization. In March 2015, the State Council published *Document 9*, setting out the main principles for power system reform. Key ideas include separating tariffs for transmission and distribution based on the principle of earning 'cost plus reasonable profit', and separating retail from network activities. These are important reforms, because they would support greater competition in both the retail and wholesale generation markets. In particular, least-cost dispatch and pricing based on short-term marginal costs would help to increase penetration of renewables whose marginal costs are near zero, thereby reducing the role of coal.

Additional reforms are now being discussed in China. For example, the Thirteenth Five Year Plan on Electricity System Development calls for spot market power trading to start on a trial basis by 2018 and be fully operative in 2020, after reforming transmission and distribution tariffs. China is also implementing new market-driven policies (e.g. renewable-energy green power certificates and a voluntary trading system) to reduce the cost of integrating renewable energy and



increasing its market uptake. The full implementation of these and other market-based reforms, including carbon emission trading, would further reduce reliance on coal.

Establish carbon emission allowance prices and trading

Pricing CO₂ emissions is an efficient way to internalize environmental externalities – requiring generators to treat these emissions as costs. China introduced a national cap-and-trade system for carbon in December 2017, building on over 10 years of experience with the Clean Development Mechanism and China’s seven pilot carbon markets. Only electricity and heat supply are covered in the initial stage of the national system, and initial carbon prices are low. On the other hand, the system includes over 1,700 power and heat generating companies and covers 3,500 million tonnes of CO₂ equivalent per year, which is over 38 per cent of China’s energy-related emissions and almost 11 per cent of global energy-related carbon emissions. (For more details, see www.carbonbrief.org/qa-how-will-chinas-new-carbon-trading-scheme-work.)

Four key lessons can be learned from international experience on this issue:

1. Credible, long-term carbon price signals are important to encourage investment and innovation in low-carbon technologies. This could be achieved through the introduction of a longer-term, forward-looking, rising carbon price floor for emission allowances. As used in the UK, the price floor acts as a tax. That floor should reflect the social cost of carbon emissions – the monetized damage caused by the emissions – or the level that is

considered necessary to meet decarbonisation targets. An alternative to a rising price floor is a central banking system that adjusts the supply of emission allowances to ensure that prices remain within upper and lower limits. The key is credibility, which the Chinese government is well placed to provide.

2. China may want to consider basing the lower price limit for emission allowances on the concentration of greenhouse gases in the atmosphere, so as to provide a sharper price signal if needed. Since this idea makes sense only at a global level and has consequences for industrial competitiveness, China might consider proposing it during future UNFCCC negotiations, perhaps conditioned on countries responsible for a certain percentage of global emissions adopting it. China is, of course, a developing country and should not be expected to lead global negotiations. However, with the United States withdrawing from the Paris Agreement, this is an opportunity for China to collaborate with other nations, for instance India, European Union countries and Canada, to provide leadership. We would advise not ruling out the possibility of introducing carbon price border adjustments on imports from countries that do not apply emission prices or equivalent restrictions.
3. The funds raised through auctioning of allowances or through environmental taxation could be recycled

within the economy, either to reduce the impact of higher energy costs on vulnerable consumers or to support investment in decarbonization and other green technologies. Among other merits, this could reduce opposition to pricing or taxing carbon emissions. It has been successfully implemented in various jurisdictions, including the Canadian province of British Columbia.

4. As mentioned in Section 1 of the paper, focusing on one particular industry (electricity) may encourage the use of fossil fuels in other sectors. For example, the Regional Greenhouse Gas Initiative cap-and-trade programme in New York led to a 10 per cent emission reduction in the power sector between 2012 and 2015. However, the overall emission level increased by 4 per cent during the same period due to emission increases in heating and transportation. An emission trading system with a broader scope is more likely to achieve greater emission reductions.

Rethink the ownership structure and governance of the electricity sector

The most relevant international experiences on the closure of coal-fired power are those of privately owned companies operating in markets where networks are separately owned from generation and retail activities, and where generation and retail are subject to competition. Governments determine the laws and regulations, but companies for the most part make investment decisions based on the economic merits of the investment, and are free to change their business model



and company structure. There are exceptions to this general principle, for instance where closure of plants would lead to problems of supply security.

In China, the ownership structure may distort decisions. For instance, public ownership of coal-fired plants may make it even more difficult than it would be for private companies to shut those plants due to the consequences for local communities. It may also encourage the building of new coal-fired plants when they are not needed, since the consequences of stranded assets are farther down the road and may be ignored by government. The recent integration of coal mining and coal power generation companies in China (e.g. the integration of Shenhua Corporation and Guodian Corporation) could help or hinder the closure of coal plants. On the one hand, integration could help the newly formed companies to close inefficient units. However, with more guaranteed supplies of coal, new and more efficient coal-fired plants could be an option. Further integration would also increase consolidation and decrease competition in the industry, while Document 9 encourages competition. In this respect, we support the original structural reform ideas identified in Document 9 and other measures to lower the barriers to entry by private investors, encourage competition in generation and distribution of the electricity value chain, strengthen governance and regulation, and improve power system planning.

Consider compensation to owners of coal-fired plants

International practice in liberalized electricity markets normally involves giving the owners of existing plants many years notice of any regulatory changes that will require additional investment to meet new emission standards. Owners are given the option either to make the investments or to opt

out. If an owner chooses to opt out, the plant is typically given a transition period and a controlled operating regime before it shuts down.

Furthermore, normal practice is not to subsidize the investment required to meet new standards. This approach has good incentive properties and is especially suitable for systems with relatively old and inefficient plants. It does not require the payment of compensation.

However, governments sometimes agree to compensation for early closure, or phasing out, of coal-fired power stations. The case for compensation is greatest when plants are relatively new and owners can claim that government decisions could amount to confiscation – the taking of private property for public use without compensation. However, there is a more general “political” case for compensation, namely to win the support of electric utility management, shareholders, employees and local communities that would otherwise fight closure and thereby slow the process of decarbonisation. A similar argument was used in the US and Europe in the 1990’s to justify paying competition transition charges (CTCs) to utilities in return for the latter accepting and supporting liberalisation of the power sector, on the understanding that liberalisation would lower the value of their assets. The logic then was that, in the absence of CTCs, utilities and all those who had a vested interest in them could and would slow the process of liberalisation.

In the case of government-mandated early closure or phasing out of coal-fired stations, compensation could take many forms.

- Direct compensation to the owners. In Alberta (Canada), for instance, the provincial government decided to pay the owners of coal-fired power stations over Cdn\$1 billion in

compensation for early closure of their plants, as part of the government’s climate change agenda. ([See here](#)).

- Indirect compensation via taxation. Governments can mitigate losses by providing tax benefits to early closers, for instance through allowing accelerated depreciation.
- Securitisation. Governments could move the plants to the public balance sheet, close them and then refinance the liability, in parallel with other forms of compensation to the owners.
- Payment to remain open. Governments or regulators may pay the plant to remain open, on the condition that it not generate, or that it generate in a very restrictive operating mode. This limits the impact on local employment and, where the plants continue to be available to generate in emergencies, can even contribute to supply security.
- Support conversion or mitigation retrofits. An additional form of compensation is for government to provide financial support for retrofitting of CCS or CCU on relatively new and efficient plants, or to convert the coal plant to a less polluting alternative.

Taking into account the ownership issue discussed above, the Chinese Government is well placed to negotiate these and other forms of compensation. International best practice is that compensation is a step in the direction of closure, not an interim stage before the plants begin to operate again at full capacity.



Discourage investment in new unabated coal-fired plants

Closure of existing plants, especially when they are relatively new as in China, is much more difficult than discouraging investment in new plants. When plants close prematurely, investors do not recover sunk investment costs. This is likely to lead to strong opposition from investors, employees, and the local community. In contrast, the decision not to proceed with an investment usually incurs very limited losses. Currently, China relies on administrative measures to discourage investments in new coal plants. Given the ownership structure and existing electricity market conditions, these measures can be effective and efficient.

The last couple of years have seen over 100 gigawatts of coal plants shelved or postponed. However, the main reason for this appears to be concern about temporary excess production capacity rather than the risk of stranded assets associated with future environmental regulations. Government can help investors make informed decisions – and avoid unexpected stranded assets – by providing clear long-term signals on the role of coal in the future power mix.

Explore opportunities for an eco-friendly transition, especially on the Belt and Road

Governments and companies are finding ways to exploit the opportunities associated with the transition away from unabated coal. That transition corresponds to a fundamental transformation of the energy sector, involving decarbonization and decentralization of the sector as well as electrification of key end markets, such as transport, buildings, and some industry. The transformation broadly benefits society and offers an opportunity to promote new lower-carbon technologies and business

models that are sustainable and have global markets.

What does this mean for China? Domestically, a phase-out of coal would result in a cleaner environment, lower costs, the creation of new sustainable businesses, and improved social welfare and health. It would do so by encouraging more efficient use of existing resources, regional coordination of investment and operations, the integration of renewable power, reduced pollution, and lower system costs and prices. It would encourage investment in low-carbon energies and new business models that enable consumers to participate effectively through self-generation, demand response, and storage. And it would support the electrification of final energy markets, such as transportation and heating, lowering China's reliance on imported fossil fuels.

These reforms could also support China's international goals, both political and economic. For instance, as it has successfully done with solar panels and wind turbines, China has the potential to exploit global commercial opportunities related to other low-carbon technologies, from smart appliances to electric vehicles and CCU technologies. Furthermore, China is planning to make a major contribution through its Belt and Road Initiative (BRI). The largest infrastructure initiative ever undertaken, the BRI has been compared to the Marshall Plan, under which the US government provided funding to help rebuild Europe after World War II, but its scale and funding (in real terms) are larger. Under the BRI, funding will be provided for roads, railways, and ports, as well as energy infrastructure including pipelines, transmission lines, conventional power stations and renewable-energy projects.

The BRI is highly significant for the affected countries, and offers China the

potential to be as influential, in the region covered by the BRI, as the United States became in Europe – provided the BRI is well received, especially by recipient countries and financial institutions. Along with that influence comes tremendous opportunity and responsibility. The Chinese Government's Guidance on Promoting Green Belt and Road was issued jointly by the National Development and Reform Commission, the Ministry of Foreign Affairs, the Ministry of Commerce, and the Ministry of Environmental Protection. Among other things, it calls on BRI participants to do the following:

- Formulate environmental protection standards and codes for infrastructure construction.
- Increase environment protection services and support for major infrastructure construction projects along the route.
- Popularize energy conservation and environmental protection standards and practices in such sectors as green transport, green buildings and green energy.
- Prioritize infrastructure and capability-building projects for energy conservation, emission reduction, and eco-environmental protection.
- Enhance green guidance for corporate behaviour and encourage businesses to adopt voluntary measures.
- Make use of the unique advantages of policy-based financial institutions in guiding and channelling the funds of various parties to jointly support the development of the green BRI.



For more details, see David Sandalow and Qinhua Xu, [Belt and Road Initiative Green Development Conference Reports](#), November 2017.

China could, and we think should, contribute to achieving these aims by promoting decarbonization and green energy solutions through the BRI. However, plans exist to financially support fossil fuel projects through BRI, partly in response to the requests of the participating countries. Investment in new coal-fired power stations is bound to be controversial. Though China argues that the investment will involve advanced coal technology that has carbon emission intensity close to natural gas and will have lower carbon emissions than any plant that would otherwise be built, new coal-fired power stations will nevertheless increase absolute levels of CO₂ emissions for decades to come. If China encourages new carbon-intensive investments through BRI while other countries and international organizations (like the World Bank, the OECD, and private banks) move away from such investments, this will raise concerns not only about environmental consequences but also about the investors' risk of stranded assets. The financial risk for investors will also grow with a recipient country's level of indebtedness since a project may be initiated but not completed due to lack of available funds at an acceptable cost.

As other countries are doing, China should encourage a public discussion of how best to exploit the opportunities to build a low-carbon economy in China and abroad, especially through the green BRI. As renewable and other very low-carbon technologies move into the market and become economically competitive, the nature of the climate policy debate is changing. The challenge now is how to make the domestic and international economy

work better – smarter, cheaper, and cleaner – and reap all the climate benefits on the way.

LIBERALIZATION AND DECARBONIZATION UNDER THE ELECTRICITY SYSTEM REFORM IN JAPAN

Yu Nagatomi

The Great East Japan Earthquake of 2011 drastically changed the situation of Japan's power industry. It revealed bottlenecks and inflexibilities in the existing market structure, forcing the government to embark on restructuring its power industry. The government also began a comprehensive examination of its energy and environment policy, by revising the Strategic Energy Plan which had been approved by the Cabinet in 2010. The core priorities of the Revised Strategic Energy Plan are energy security, economic efficiency, environmental protection, and safety, the so called 3Es+S.

The government has set a greenhouse gas (GHG) reduction target of 26 per cent from fiscal year 2013 to fiscal year 2030, a power generation mix target for 2030 with shares for nuclear and renewables of 20–22 per cent each, and an energy security target of around 25 per cent self-sufficiency. The Revised Strategic Energy Plan also introduced the concept of energy industry system reform. In accordance with the Energy Plan, the government has already begun the full liberalization of the electric power and gas industries.

A review of the lessons learned by other developed countries clearly indicates that Japan should expect to face many challenges in the effort to achieve the dual targets of decarbonization and liberalization of the electric utilities. This paper describes

the challenges to Japan's simultaneous achievement of both its energy security and climate change policy targets under a liberalized and competitive energy market. The Japanese case may show how a complicated policy could distort the market and prevent stakeholders from promoting low-carbon energy development.

Energy industry system reform

Prior to the current reform, the government of Japan had been gradually accepting new entrants to encourage more competition in the energy industry. Japan's support for liberalization and deregulation of the electric power sector began in 1995 when the government allowed new entrants to supply power for wholesale services. The retail of power for ultra-high-voltage consumers was liberalized in 2000, and the wholesale power market, the Japan Electric Power Exchange, was established in 2005. Following a series of gradual deregulations, the Cabinet approved the basic policy for a comprehensive energy system reform in 2013. The electricity system reform had three steps: (1) to establish the Organization for Cross-Regional Coordination of Transmission Operators and a new regulatory body in 2015, (2) the full liberalization of the electricity retail business in 2016, and (3) the legal unbundling, by 2020, of the transmission and distribution functions of the 10 incumbent utilities into 10 integrated transmission and distribution network companies, which will be the operators and owners of the network, much like European transmission system operators.

The natural gas market reform is following similar steps. One of the biggest issues for the energy system reform is how a liberalized energy market can simultaneously achieve the 3Es+S targets, including decarbonization.



Decarbonization policies in the power sector

Nuclear, renewables, and energy efficiency were the three main pillars of the decarbonization policy in the power sector in Japan. The previous (2010) Strategic Energy Plan aimed at the construction of at least 14 new nuclear power plants by 2030; but the Fukushima Daiichi nuclear plant incident of 2011 led to fundamental changes in Japan's nuclear policy. The decarbonization target is based on the premises of the power generation mix target, which means that the share for nuclear at 20–22 per cent is essential even in the liberalized market.

The restart of the nuclear power plants and the restoration of the public's trust in nuclear power are first-order priorities for the electric utilities. Nuclear also has many other challenges, including legal risks and the need for additional investments to comply with the new safety standard. On top of that, the uncertainty of the power market will be increasing due to the high penetration of renewables and further market competition. If the nuclear restart and operation fall short of the targeted level, the government will face additional challenges to achievement of the 3Es targets, including the GHG emission target. Considering the importance of nuclear in the 3Es target, uncertainty about the future of nuclear causes uncertainty about Japan's decarbonization policies.

To promote greater use of renewables by the incumbent utilities, the Ministry of Economy, Trade, and Industry introduced the Renewable Portfolio Standard regulations in 2003. Unfortunately, the numerical target was not sufficiently high to encourage stakeholders to make large-scale investments in renewables. The government, led by the Democratic Party of Japan at the time of the earthquake, decided after the nuclear

accident to introduce a feed-in tariff (FIT) as part of its new policy for renewables. The government has given priority to the promotion of renewables ever since. As European countries have experienced, the subsidy for FIT sometimes invites excess investments, and the increased surcharges augment the cost burden on consumers. As in other countries, FIT substantially enhanced the capacity increase of renewables in Japan, and as of March 2017, the total amount of approved capacity was more than 105 gigawatts (GW) (roughly 180 terawatt-hours), equivalent to almost two-thirds of peak demand (156 GW in 2016) in the daytime summer heat.

Such a huge amount of approved capacity revealed the limits imposed on the energy system and the energy market. For instance, the approved capacity of photovoltaic in the Kyushu area exceeds the physical limit of the current network capacity of Kyushu Electric Power Company. Kyushu Electric announced in 2014 its intention to curtail the supply of renewable power when it exceeds the company's capacity to absorb it. Following the example of the European countries, the government of Japan amended its FIT Act and introduced auctions for some renewables to promote a more cost-effective approach. To achieve the dual target of decarbonization and liberalization, it is important for Japan to increase and diversify its low-carbon energy resources, including nuclear.

Liberalization and decarbonization – is cost the first priority?

The government has decided to promote the liberalization of its energy system. Liberalization should invite more competition which in turn should reduce costs. Many power generation companies in Japan are considering new coal power plant construction projects in a bid to survive market liberalization. The Ministry of

Environment in Japan expressed deep concern about the sudden 'dash for coal'. Key questions include the following: How should the government address the externalities of low-carbon energy in the liberalized market? How can the government encourage the development of low-carbon energy? Who are the market players that prefer and could increase the amount of low-carbon energy?

Opinion surveys in Japan indicate that household consumers are more interested in the cost of energy than its sources. Therefore, there are few retailers providing a green-energy or low-carbon electricity menu to that sector. In contrast, from the viewpoint of fulfilling environment, social, and governance targets, large energy consumers such as manufacturing companies and global companies are planning to utilize more low-carbon energy. The government still expects that liberalization will encourage power retailers to provide a variety of options in the form of diversified services to customers. Thus, the Ministry of Economy, Trade, and Industry is considering an array of policy instruments to support markets in which power generators and retailers would be able to address different consumers' needs in line with the 3Es targets. Measures considered include a FIT system, a trading market for non-fossil-fuel energy, a green energy certification scheme, a capacity market, and a baseload power market. Liberalization and deregulation of the market often do not achieve all preset targets by themselves.

Policies improving access to low-carbon energy

Because renewables are low-carbon energy sources, they are expected to play a key role in energy security and GHG emissions mitigation. The FIT scheme redistributes renewables equally to all retailers and therefore is



not necessarily useful in meeting a particular retailer's needs. To access more low-carbon electricity, a retailer must purchase it directly from the power generators or from the green certification scheme. Otherwise, it needs to have its own low-carbon energy sources. The green certification scheme aims to encourage retailers which find it difficult to have their own green power generation facilities to purchase a green value (i.e. a green certificate) in addition to the value of the electricity generated by green energies. They can purchase green power by combining a green value certified by Japan Quality Assurance Organization (JQA) with their purchased electricity. The total volume of green-certified renewables is not sufficient at the moment to satisfy retailers' or consumers' demand.

Until recently, the subsidy under the FIT scheme was so attractive to power generators that most of them preferred to sell their power under that scheme. In other words, the scheme removed the trading opportunities from those who wanted to buy renewables and thereby distorted the market function. In addition, the FIT scheme obliges the transmission/distribution companies to buy power from renewable resources and deliver it to consumers through the wholesale market. Lessons in Germany confirm that a massive introduction of renewables in the wholesale market would eventually distort the market, typically by lowering prices considerably. The high penetration of renewables supported by FIT creates a risk of price stagnation in the wholesale market.

Nuclear is another important option for a competitive and low-carbon power source in Japan. The big electric utilities are struggling to restart their existing nuclear power plants, due to public opposition, and it would be even more difficult for new entrants to

construct their own nuclear power plants. Even when utilities successfully restart their nuclear plants, court injunctions may suspend their operation. The stagnation and downward pressure of the wholesale market price, caused by FIT, generates additional uncertainties regarding the profitability of operating a nuclear power plant. Under the current tough market competition and until Japan expresses a clear vision for the future of nuclear energy, the utilities are likely to delay further investment decisions. Despite the power generation mix target's expectation of a 20–22 per cent share for nuclear in the future power generation mix, the future of nuclear power generation in Japan remains uncertain.

Hence, the government has begun to consider additional policy measures to promote low-carbon energy. For instance, a trading market for non-fossil-fuel energy is expected to enable retailers to buy power, whether the source is nuclear or renewable, and incorporate it in their low-carbon power menu. The base load power market will enable retailers to acquire power from nuclear, while the capacity market will give power generators an additional cash flow on a kilowatt basis, much like markets in the UK and PJM work to compensate for possible lowering of wholesale electricity prices. These measures are expected to improve the profitability of conventional power plants, including nuclear. Finally, the government has already determined what will be the regulated share of non-fossil-fuel power for retailers in the fiscal year 2030, in order to stimulate the low-carbon energy market.

Demand for low-carbon energy

Many global companies are interested in procuring low-carbon energy to achieve their environmental goals. Apple, IKEA, Ricoh, and other prominent companies have already set

targets for renewables use. They want to gain access to low-carbon power, especially renewables, at a reasonable price in Japan. The market for non-fossil-fuel energy combined with the current FIT is expected to increase the availability of low-carbon energy. However, those global companies, as well as non-profit organizations like RE100 and CDP (formerly the Carbon Disclosure Project) are concerned about the transparency of traceability of power sources in the market. They are asking the government to intervene to ensure the availability of a sufficient amount of renewables. As mentioned above, most household consumers of electricity in Japan are primarily concerned about the cost; they may want low-carbon energy if it is provided at a competitive price. The government and market players need to reduce the cost of electricity and give consumers access to more low-carbon energy through the market.

Carbon pricing as an economic incentive

In addition to the market scheme, economic incentives are expected to give a signal to consumers to promote low-carbon energy in the liberalized market. In Japan, there is increasing attention being given to the use of carbon pricing and carbon credits to address the externalities of carbon emissions. One existing initiative is the government's J-Credit Scheme, under which small and medium sized enterprises can earn credits by reducing their carbon emissions and then sell those credits to major companies, which use them to achieve their carbon-reduction targets.

To promote further decarbonization, the Ministry of Environment is considering more powerful policy measures such as a carbon tax and a carbon emission trading scheme following the Paris Agreement. The Ministry argues that these pricing measures can contribute economically to the expansion of low-carbon energy in a liberalized market.



However, careful discussions are needed of whether and why these measures are needed to support low-carbon energy. Deregulation often results in reregulation or invites too many other regulations. Policymakers must consider comprehensive and workable policy measures to achieve the primary target. A wrong signal created by a complicated policy can easily lead the market in the wrong direction.

Conclusion

Low-carbon energy use is expected to expand under the 3Es policy goal established in Japan’s new Strategic Energy Plan. To increase low-carbon energy in the liberalized market, the government is considering policy measures to address environmental problems as externalities by appropriate use of market mechanisms. But there is a risk that complicated ad-hoc interventions may distort the market and actually discourage the use of low-carbon energy. Japan has already decided to liberalize its energy industry, while committing to a GHG emissions reduction target under the Paris Agreement. It will continue to struggle to address the liberalization and decarbonization agendas simultaneously and to manage the trade-offs between them. Japan should continue to learn from the experiences of other countries in pursuing these goals and to share the lessons of its own experiences.

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**ELECTRICITY
 LIBERALIZATION,
 RENEWABLES POLICY,
 AND THE MISSING
 MACROECONOMIC
 ELEMENT**

**Jorge Blazquez and
 Rolando Fuentes**

The member states of the Gulf Cooperation Council (GCC) – Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates – are aiming to transform their electric power sector. They plan a dual agenda: liberalization (through privatization and the introduction of competition, as a means to boost economic efficiency), and decarbonization (with ambitious goals for incorporation of renewable energy sources).

International experience described elsewhere in this issue shows, however, that these two goals can be difficult to reconcile. In ‘The renewable energy policy paradox’ (Jorge Blazquez et al., *Renewable and Sustainable Energy Review*, vol. 82, part 1, February 2018, 1–5), we considered the extent to which concurrent policies of liberalization and renewables promotion can be compatible. That article postulated that promoting renewables in liberalized power markets may create a paradox, in that successful market penetration by renewables could fall victim to its own success. We argued that wholesale prices do not provide adequate signals for operations when renewable penetration is significant. This means that after deployment of renewable energy reaches a certain threshold, it will necessarily be more costly and less scalable. An Oxford Institute of Energy Studies publication (*Electricity Liberalization in the UK – the End is Nigh*, Malcolm Keay, 2012) also argued that – given that liberalization policies aim to improve economic efficiencies

and decarbonization sets mandatory goals for deployment of renewables or emissions reduction – policymakers would need to select just one of these goals, and it is unlikely to be liberalization.

However, these arguments may be too narrow to persuade the resource-rich, oil-producing countries of the GCC to abandon their dual agenda. Because their policies keep domestic fuel prices below international levels, the region’s power generation is based almost entirely on hydrocarbons – and as a result, per capita carbon emissions are among the highest in the world (see ‘The cost of domestic energy prices to Saudi Arabia’, Yousef Alyousef and Paul Sevens, *Energy Policy*, 39, 2011, 6900–6905; *GCC Energy System Overview*, David Wogan et al., King Abdullah Petroleum Studies and Research Center, 2017). While there are plans to deploy significant renewable capacity in the near future, the contribution of renewable technologies to the current capacity mix is almost negligible.

These conditions should make it possible to obtain a triple dividend from this agenda – economic efficiency and decarbonization now and diversification from oil and gas in the future – because both of these policies would reduce domestic consumption of oil. The macroeconomic benefits obtained from reallocating oil away from electricity generation would largely outweigh potential inefficiencies that may arise from pursuing conflicting objectives in the power sector.

To elaborate this argument further, we first present empirical data on the relationship between decarbonization and liberalization in the GCC, taking Saudi Arabia as an example. We then take two steps back and discuss the macroeconomic impact of avoiding using oil for local consumption. We conclude with a forward-looking view of the power sector.



Liberalization and renewables

GCC countries are trying to liberalize their power sector in a context where utilities receive fuels at a low price to ensure low generation costs. This policy allows utilities to maintain low prices for the domestic and industrial sectors, as a way to both redistribute the wealth from oil and gas exports and foster industrial competitiveness. In compensation, some governments are willing to pay for their electricity at higher rates to help utilities meet their revenue requirements.

The impetus toward liberalization comes at a time when GCC countries are also aiming to increase the market share of renewables as part of an effort to curb carbon emissions. For example, in early 2017, Saudi Arabia announced a National Renewable Energy Plan that targets the installation of 9.5 gigawatts of renewable energy capacity by 2023. So far, most of the effort in this direction has been via auctions that have produced remarkably low bids. In October 2017, the Kingdom held an auction to build and operate its first solar project, consisting of 300 megawatts. The winner, Acwa Power International, bid at US\$ cents 2.3417/kilowatt-hour (8.781 halalas/kilowatt-hour), one of the lowest solar bids recorded worldwide.

Electric power sector liberalization is usually characterized by the introduction of competition, the privatization of state-owned assets, and the establishment of independent regulators. Structural changes can include the removal of subsidies, the unbundling of vertically integrated utilities, guarantees of non-discriminatory access to transmission and distribution networks, and the establishment of wholesale and retail markets.

The restructuring of the electricity sector in the GCC has seen mixed

progress so far. For example, while in Oman and Qatar the state-run power industry is already unbundled, in Bahrain the government has privatized its generation plants but still oversees operations in the sector. Saudi Arabia has established an independent regulatory authority, Electricity & Cogeneration Regulatory Authority (ECRA), which oversees the electricity and water desalination industries in the Kingdom. There are preliminary plans for the unbundling of Saudi Arabia's power market structure, with the presence of independent power producers.

If followed closely, the textbook model of restructuring should be a sound guide for successful reform, as Paul Joskow argued in 'Lessons learned from electricity liberalization' (*Energy Journal*, Special Issue on the Future of Electricity, 2008, pp. 9-42), but carries significant costs if it is implemented incompletely or incorrectly, as explored in *Reforming Power Markets in Developing Countries: What Have We Learned?* (John E. Besant-Jones, Mining and Energy Board Discussion Paper No. 19, World Bank, 2006). The implementation of electricity reform is a cumbersome process, politically and technically constrained, and these restrictions end up affecting market design. It is easy to depart from this model, as policymakers can choose from a large menu of policy instruments (see Rahmatallah Poudineh, Anupama Sen and Bassam Fattouh, *Advancing Renewable Energy in Resource Rich Economies of the MENA*, OIES, 2016, 30).

Having acknowledge this potential difficulty, let us assume the choices made in the implementation process – such as privatization, unbundling, and establishment of an independent regulator – deliver the most efficient outcome, which is when electricity prices are set equal to marginal costs

and fossil fuel prices are liberalized and reflect opportunity costs. If this scenario materializes, GCC countries could potentially gain a triple dividend from these reforms: more efficiency, decarbonization at the national level, and a favourable macroeconomic impact.

According to *Restructuring Saudi Arabia's Power Generation Sector: Model-Based Insights* (Bertrand Rioux, Fernando Oliveira, Axel Pierru, and Nader AlKathiri, King Abdullah Petroleum Studies and Research Center, 2017), restructuring the Kingdom's electricity sector would deliver an annual aggregate economic surplus of more than \$4 billion, since the government's savings in fuel subsidies would exceed the loss in consumer surplus from increases in electricity prices. However, this study also suggested that there is, at least in theory, significant room for price manipulation, particularly at peak demand times.

If only fuel prices were deregulated – meaning that crude oil and refined products would be traded at international market prices and natural gas at the domestic market clearing price – there could be savings of around \$3.8 billion per year, mostly from oil saved (see 'Jointly reforming the prices of industrial fuels and residential electricity in Saudi Arabia', Walid Matar and Murad Anwer, *Energy Policy*, 109, 2017, 747–756).

In a theoretical scenario, there would be not only significant energy and financial savings but also a natural decarbonization in the power sector. Matar and Anwer (cited above) found that when prices are set at the long-run marginal cost of delivering electricity, the generation mix switches from oil towards natural gas and solar photovoltaics. The explanation for this is that the model the authors used to perform their analysis, a multiple



equilibrium model, was instructed to invest and operate additional capacity if it is cheaper than using an existing plant. The cheapest additional technology is solar, and in that way it is possible to achieve the first two dividends now, avoiding the risk of the renewable energy policy paradox, which occurs at later stages of renewable penetration. The assumption of setting prices equal to the long-run marginal cost can be interpreted as the solution provided by a central planner, though, as liberalized market operations are based on short-term marginal cost.

This result is corroborated by other studies. A recent analysis ('Fuel-price reform to achieve climate and energy policy goals in Saudi Arabia: A multiple-scenario analysis', Groissbock and Pickl, *Utilities Policy*, 2018, 1–12) found that if the administered fuel price were 50 per cent of corresponding international wholesale fuel prices, it would result in 30 per cent of total power capacity being fueled by renewables; if it were 60 per cent of the international price, by 2030 approximately 50 per cent of total power capacity would be renewable.

Saudi Arabia has taken steps in this direction, raising the price of 91- and 95-octane gasoline by about 67 per cent and 50 per cent, respectively, in 2016, and again in January 2018 by about 80 per cent and 125 per cent, respectively. The Kingdom also raised electricity prices to final consumers in 2016 (Council of Ministers decree dated 28 December 2015) and again in January 2018 (Council of Ministers decree dated 12 December 2017). These price increases could have far-reaching economic effects. In the long run, they could reduce domestic oil consumption by around 724,000 barrels per day, increase welfare (equivalent to a private consumption increase of \$2.6 billion), and reduce carbon dioxide

emissions by 97 million tons a year, according to *The Value of Saving Oil in Saudi Arabia* (Jorge Blazquez, Lester C. Hunt, Baltasar Manzano, and Axel Pierru, King Abdullah Petroleum Studies and Research Center, 2018).

This increase in energy prices was accompanied by the Citizen's Account Policy, launched in December 2017. This is a financial transfer from the government to less wealthy households to help them to minimize the negative impact on income and private consumption of the increase in electricity prices and the introduction of a value added tax.

Opportunity costs of missing oil exports

When the scope of this analysis is expanded to include the rest of the economy, it becomes clearer how important it is to understand the opportunity cost of using oil to generate electricity. Liberalization and renewables policies can, as a major side effect, make it possible to avoid using oil for electricity generation.

On the one hand, every new megawatt of renewable capacity installed will, in all probability, displace oil-based generation, as renewables have priority, given their negligible costs and despite their inability at times to dispatch power – the very reason they are not compatible with market design. On the other hand, liberalization – aligning prices to reflect the true cost of energy provision – would create a demand response that would result in fuel savings. Oil that is currently sold domestically for electricity production, at administered prices, could instead be exported at much higher international prices.

The GCC countries could, all else being equal, obtain extra fiscal revenue if they can achieve this. For example, if Saudi Arabia can reduce domestic consumption by 1 million barrels per

day, and if it fully recycles the resulting income through public current spending or investment, the upward effect on growth could be between 0.3 and 0.6 per cent per year by 2030 (see *Impacts of Higher Energy Efficiency on Growth and Welfare Across Generations in Saudi Arabia*, Frederic Gonand, King Abdullah Petroleum Studies and Research Center, 2016).

Another King Abdullah Petroleum Studies and Research Center research paper also found that Saudi Arabia's plan to deploy 9.5 gigawatts of renewables would bring about a positive impact on GDP (gross domestic product) and welfare (see 'Oil subsidies and renewable energy in Saudi Arabia: a general equilibrium approach', Jorge Blazquez, Lester C. Hunt, and Baltasar Manzano, *The Energy Journal*, 2017). For example, market penetration by renewables of 20 per cent would increase oil exports by 2.8 per cent, public transfers by 1.7 per cent, GDP by 0.6 per cent, and welfare (equivalent to private consumption increase of 0.5 per cent). In all probability, an anticipated deployment of renewable technologies could affect short-term oil prices, which in turn could reduce fiscal revenues. Releasing more Saudi oil into international markets would eventually have a negative price impact, but *The Value of Saving Oil in Saudi Arabia* (cited above) found that the overall impact on the economy would be positive.

Economy-wide efficiency impacts

Unlike in OECD (Organisation for Economic Co-operation and Development) countries, where economic growth has been accompanied by declining energy consumption, in the GCC energy and GDP are still strongly linked. Reducing the gap between domestic and international prices, therefore, represents an opportunity to improve economy-wide efficiency across



different activities and sectors. The textbook reason for this is that marginal productivity of energy across all activities and sectors would then be identical and equal to its market price. In the GCC countries, given the lower administered domestic prices of oil and natural gas, their marginal productivity could be expected to be lower than the international price.

The current price structure of these countries has favoured the expansion of energy-intensive industries. It may be reasonable to expect a shift in domestic production towards less energy-intensive industries if domestic energy prices converge with international prices. A recent analysis ('Economic development and energy consumption in the GCC: an international sectoral analysis', Nicholas Howarth et al., *Energy Transitions*, 1:6, 2017) argued that analysing energy productivity – or how maximum value can be obtained from energy consumption – can help guide industrial policy and increase the profile of energy efficiency efforts across the GCC.

Conclusion

International experience shows there are conflicting objectives involved in pursuing liberalizing and decarbonization agendas in the power sector. However, given the GCC's initial situation and assuming the liberalization process delivers the conditions for efficient outcomes, these countries could enjoy three dividends: increasing efficiencies and decarbonization at early stages, and a long-term macroeconomic benefit due to higher oil exports and economy-wide efficiencies.

Initial gains are derived from aligning administered input fuel prices to international benchmarks, which is a precondition of the electricity reform textbook model. Subsequently – once

fuel prices are no longer administered, renewable deployment is higher, and electricity prices result from a market discovering process – the initial dividend could diminish, but the opportunity cost of the displaced fuel would still matter, and the important aspect to observe would be the net effect on public finance. These macroeconomic benefits would reduce the cost of sectoral inefficiencies that may arise later from pursuing policies with conflicting objectives in the power sector. Countries that are net fuel importers, of gas for example, should be able to enjoy similar benefits, depending on the relative size of their imports.

The implication for electric power policy is that the GCC countries have the opportunity to design their electricity markets around the incorporation of renewable power right at the outset, and to take account of the peculiarities of fuel markets and their macroeconomic implications, as well as the emergence of new disruptive technologies.

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QUANTITY OVER QUALITY? INTEGRATING DECARBONIZATION INTO INDIA'S ELECTRICITY REFORMS

Anupama Sen

India's electricity sector is of global significance. The world's second most populous nation, its per capita electricity consumption, at just over 1,000 kilowatt hours (kWh), is barely a third of the world average. It ranks third globally in terms of terawatt hours of generation; yet around 240 million Indians lack access to electricity. As one of the world's five fastest growing economies, its electricity demand is predicted to more than triple by 2040, adding an amount roughly equivalent to the current electricity consumption of

Japan, the Middle East, and Africa (International Energy Agency, "India Energy Outlook, World Energy Outlook Special Report", 2015). Installed generation capacity is dominated (58 per cent) by low quality coal from the world's fifth largest proven reserves; consequently, the power sector accounts for around half of India's total emissions. The way in which India responds to decarbonization will therefore have global repercussions.

Electricity reforms in India were adopted following the experiences of OECD (Organisation for Economic Co-operation and Development) countries in the 1980s and 1990s. OECD reforms involved unbundling the electricity sector from a state-owned, vertically integrated monopoly into its functional components – generation, transmission, distribution, and retail supply – and introducing competition into generation and retail supply (e.g. through the establishment of wholesale markets and privatization of utilities). The economic objectives of OECD electricity reforms included higher efficiency, lower prices, and consumer choice (J.H. Williams and R. Ghanadan, "Electricity reform in developing and transition countries: A reappraisal", *Energy*, 31: pp.815-44, 2006.). With the rise to prominence of decarbonization as an overarching goal, it is now widely acknowledged that the energy-only markets propagated under the OECD model – with prices based on system marginal cost – are incompatible with zero marginal cost renewables (see M. Keay, J. Rhys and D. Robinson, "Decarbonization of the electricity industry – is there still a place for markets?", OIES Working Paper EL9, Oxford Institute for Energy Studies, 2013). There is also a consensus that the application of the OECD model in developing countries, including India, to address entirely different problems – lack of investment in infrastructure and



technology, utilities' declining finances, and constraints on growth due to inadequate electricity supply – has in many cases exacerbated these problems.

This article reviews India's experience with electricity market reforms. It argues that the country has made little progress towards its original economic objectives but has separately forged ahead with renewables, based not on an explicit commitment to decarbonization or other climate-related goals but as part of its search for energy security and low-cost electricity. However, in its efforts to adopt renewables, India risks repeating past mistakes in electricity reforms by focusing solely on capacity addition and not ensuring that utilities are incentivized to offtake the electricity, which necessitates consumer tariff reform. Finally, it argues that to be sustainable in the long run, a strategy to increase renewables' share of the generation mix will need to explicitly link that goal to a decarbonization target and disincentivize coal.

Architecture and outcomes of electricity market reforms

Electricity supply in India was dominated for decades by vertically

integrated state electricity boards. Their capture by politicians to provide 'free' electricity to agricultural consumers resulted in financial mismanagement, heavy cross-subsidies between agriculture and industry, and an inverse relationship between the average cost of supply and average tariff (see R. Tongia, "The Political Economy of Indian Power Sector Reforms", in D. Victor and T.C. Heller, T.C. (eds.), *The Political Economy of Power Sector Reform: The Experiences of Five Major Developing Countries*, Cambridge: CUP, 2007). Electricity reforms occurred in three waves. The first, in the early 1990s, introduced independent power producers in generation, with limited success. The second, in the mid-1990s, unbundled the boards and established independent electricity regulatory commissions. The third involved the Electricity Act of 2003 (EA2003), which established the basic architecture needed to transform the sector from a noncompetitive, single-buyer model to a multiple-buyer market.

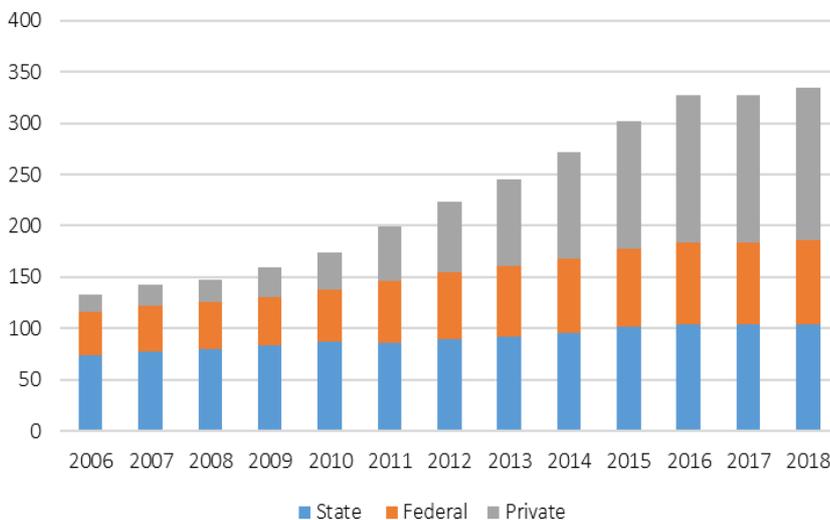
EA2003 had several important features:

- Generation was made a nonlicensed activity. Public or private entities could set up

plants, subject to environmental clearances (with some technological restrictions, e.g. on hydro). Generators could sell to any distribution licensee, and directly to consumers, where permitted by the regulator. The option of captive (own) generation – historically used only by industry – was made easier and extended to groups of residential consumers.

- Transmission was made a regulated function, separate from bulk supply and trading. System operation was to be carried out by a separate company, a federal or state transmission utility. National and regional load dispatch centres were set up to improve scheduling, and transmission entities were prohibited from participating in generation. Nondiscriminatory open access to transmission networks was mandated. Private companies could obtain power transmission licenses.
- Power trading was made a separate activity, to scale up the amount of electricity traded outside of long-term bilateral Power Purchase Agreements (PPAs). Two electricity exchanges were set up, operating with day-ahead and term-ahead products, based on prices arrived at through double-sided auctions.
- Distribution and retail supply remained integrated. Distribution companies were permitted to enter the generation business (and vice versa). Open access to intrastate network

India's installed capacity (gigawatts), 2006–2018



Source: Energy Statistics, 2017



infrastructure was permitted in distribution for consumers over 1 megawatt (MW). Recognizing that this could encourage a flight of paying industrial consumers from state-owned utilities and a loss in revenues used to cross-subsidize agricultural consumers, states were permitted to impose a 'cross-subsidy surcharge' on consumers that opted for open access.

EA2003 laid the groundwork for a transition to market-oriented competition, but its implementation was poor. Three interrelated outcomes demonstrate the extent to which original objectives were met: (1) whether EA2003 removed the investment constraint on capacity, (2) whether it resolved utilities' financial problems, and (3) whether it increased short-term power trading activity within total generation relative to long-term PPAs, reflecting whether open access, a measure intended to enable competition in the market, was effective.

EA2003 more than doubled installed capacity from 2006 to 2018, primarily via the private sector, although over 50 per cent of capacity remains state-owned. However, a substantial amount of this increase occurred in captive installed capacity, indicating that the increase reflected industrial captive (own) generation – made easier by EA2003 – as a way of circumventing problems with utilities' lack of investment in capacity addition on the grid. It has been argued that the state-private dichotomy in electricity sector structure allowed a separation of the problem of electricity supply from the problem of deteriorating finances in state-owned utilities, thus perpetuating the 'electricity-politics nexus' and failing to address the issue of cost-

reflective pricing (see K.L. Joseph, "The politics of power: Electricity reform in India", *Energy Policy*, 38(1), 503–11, 2010).

Electricity reforms also failed to resolve deteriorating utility finances and operational inefficiencies. Aggregate technical and commercial losses have remained over 20 per cent since the 2000s, as have transmission and distribution losses. When EA2003 was passed, average revenue realization from the sale of electricity was 85 per cent of the cost of supply (with the balance meant to be made up by government subsidies); by 2014, this was down to 79 per cent (Central Electricity Authority, "Report on Short Term Power Market in India: 2016-17", Government of India, 2016). An attempt was made to restructure the debt of state utilities in 2015, which involved India's state governments voluntarily appropriating 75 per cent of utilities' debts through bond issuances. Participating states were required to achieve financial turnaround of their utilities within a few years, in return receiving preferential treatment in federal funding. As of 2018, this scheme had yielded mixed results, with some states (Rajasthan, Tamil Nadu, and Uttar Pradesh) reducing utilities' losses, primarily by enforcing bill compliance and closer monitoring of commercial operations. However, the long-term solution requires tariff reform to better reflect costs, and this has not been achieved.

To assess the third outcome, we look at the proportion of short-term (traded) transactions within total electricity generation. These are contracts of less than one year for the following trades: bilateral transactions through interstate trading licensees, electricity traded directly by distribution companies, electricity traded through the two power exchanges, and electricity transacted through a deviation settlement

mechanism to settle differences between scheduled generation and actual draws. The volume of short-term transactions since 2009 (shortly after the power exchanges were established) has stayed relatively static, at roughly 10 per cent of total generation (Central Electricity Authority, "Report on Short Term Power Market in India: 2016-17", Government of India, 2016). Long-term PPAs, a legacy of the single-buyer model, have continued to dominate. A 2017 judgement by the Competition Commission of India highlighted problems with the frequent denial of open-access permissions to third-party users by incumbents, reflecting the poor enforcement of EA2003 (see Competition Commission of India, "[Case No. 39 of 2017](#)", 2017,).

Although a comprehensive assessment is beyond the scope of this article, it can be argued that the architecture laid out by EA2003 does not appear to have met its original objectives. There has also been frequent government intervention – for example, the debt restructuring programme. India also has chronic problems with the reliability of supply. Diesel generator sets, commonly used as a backup option by commercial entities and groups of residential consumers, are estimated to have grown from 80 to 90 gigawatts (GW) between 2014 and 2017 – equivalent to a third of total installed capacity (Business Standard, "Diesel generator sets' capacities witnessing an upward trend in India", 9 June 2017). In rural areas, only six states are reported to provide a 24-hour supply (Parliament (Lok Sabha) Unstarred Question No. 4043, "[Impact of DDUGJY](#)", Government of India).

Renewables adoption as separate from market reforms

India has successfully added substantial renewables capacity, with solar increasing from under 2 GW in 2012 to 17 GW in 2017. In 2017 alone,



India tendered a record 9.3 GW of solar capacity through auctions, achieving record-low tariffs of \$0.04/kWh. Despite this success, there are two main challenges to renewables integration.

First, renewables adoption remains disconnected from the objectives of electricity market reform and is not explicitly linked to decarbonization. Nor is it being driven directly by India's climate commitments.

EA2003 contained recommendations for regulators to set renewable purchase obligations for utilities which could be enforced either by procuring renewable electricity or by purchasing tradable renewable energy certificates on the power exchanges, subject to a floor price. It also recommended fiscal incentives (accelerated depreciation and generation-based payments) to encourage renewables penetration, but set no explicit renewables targets.

India pledged, under the Paris Agreement, to reduce the emissions intensity of gross domestic product (GDP) by 33–35 per cent from 2005 levels by 2030, and to achieve 40 per cent of cumulative electric installed capacity from non-fossil-fuel sources by 2030. Both are achievable with relatively modest addition of renewables. India's emissions intensity of GDP (measured in kilograms of carbon dioxide per 2011 Purchasing Power Parity (PPP) \$ of GDP) is estimated to already have fallen by around 7.5 per cent from 2005 levels and is predicted to reach 41.5 per cent below 2005 levels by 2030 if current trends continue. Non-fossil-fuel sources (including nuclear and hydro) already comprise 30 per cent of installed capacity, requiring only an incremental increase to meet India's commitment.

Instead, renewables adoption in India is being driven by a domestic target to build 175 GW by 2022 (including 100 GW solar and 60 GW wind) – seen as

complementing the goals of energy security and low-cost electricity. India's enthusiasm is reflected in its pivotal role in launching (jointly with France) the International Solar Alliance in 2018, a 62-country group aiming to raise \$1 trillion of investments to create 1 terawatt of global solar capacity by 2030. However, India's domestic target is nonbinding. (The revocable nature of voluntary targets is reflected in the recent paring down of a 2030 target for electrification of vehicles from the entire vehicle fleet to only 30 per cent of it.)

In a second main challenge to renewables integration, the focus on capacity addition is reminiscent of experience in electricity market reform, which failed to address the problem of utilities not purchasing the electricity due to weak incentives, or failing to make timely payments (i.e. power off-taker and credit default risks). Record low solar auction tariffs are predicated on low-cost equipment imports from China, which make up 80 per cent of the Indian market, and it is unclear whether developers have priced in risks of rising supply costs, or costs of integration as solar energy is scaled up. The steep fall in solar tariffs has led some state utilities to hold off on signing PPAs and to demand even lower tariffs (see Kiran Stacey, "Reality Dawns on India's Solar Ambitions",

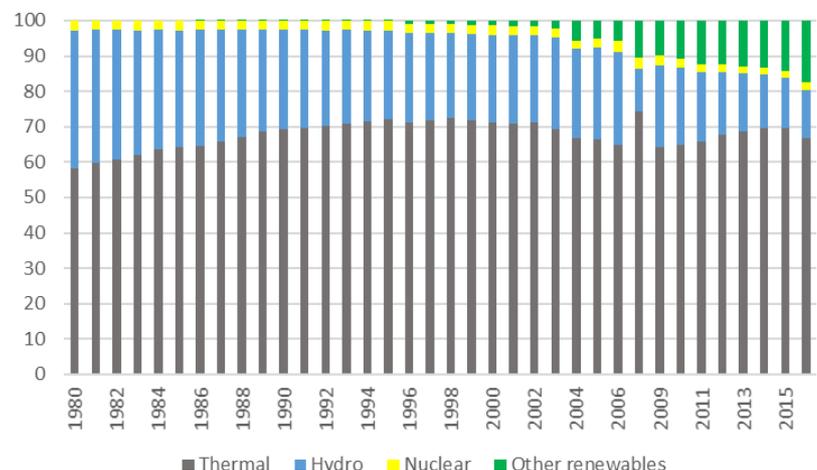
Financial Times, 1 November 2017). Another risk is whether utilities will off-take solar power, due to weak compliance with renewable purchase obligations. This is evident from an oversupply of renewable energy certificates on the power exchanges.

Although solar projects are backed by government guarantees, past experience with state-owned utilities defaulting on payments to independent power producers raises uncertainty about its ability to fulfil them.

The need to explicitly incorporate decarbonization

The implicit assumption appears to be that as renewables capacity is scaled up, it will automatically displace coal in the generation mix. Indian policymakers do not expect to build any new coal capacity (currently around 200 GW), apart from 50 GW already under construction, until at least 2026. However, the possibility remains that solar tariffs will increase and/or contracted solar capacity will not be delivered on schedule. If these situations materialize, given the political pressure to maintain economic momentum, India could return to coal, setting off construction of new (albeit more efficient 'supercritical') coal plants.

Renewables as a percentage of installed capacity, 1980–2015



Source: India Energy Statistics, 2017; EPW Research Foundation)



In the long term, therefore, decarbonization will need to be incorporated as an explicit objective within electricity reforms, and will require measures to actively disincentivize use of coal. While this was thought impossible just a few years ago because of the historical importance of the coal sector, India introduced a tax on coal production in 2014, which was doubled over two years. However, at the very low level of \$6/tonne, it does little for the competitiveness of cleaner substitutes. A recent study estimated that even for gas to compete with coal at current prices, the coal tax would need to be four-and-a-half times higher, equivalent to a 30 per cent increase in coal-fired electricity tariffs (see Anupama Sen, “India’s Gas Market Post-COP21”, OIES Paper NG120, Oxford Institute for Energy Studies, 2017). A much lower amount may be needed to incentivize solar, given the rapid decline in solar costs, but it would need to take account of the fact that current record-low solar tariffs are essentially underwritten by government guarantees rather than based solely on project economics.

Additional market reforms and rural electrification

A planned amendment to EA2003, the Electricity Amendment Bill of 2014, seeks to complete market reforms by permitting open access for small (<1 MW) consumers and separating distribution (‘carriage’) from retail supply (‘content’) in order to encourage retail competition. It also explicitly recognizes renewables integration as an objective, requiring investments in

fossil-fuel plant capacity to be matched by investments in renewables equivalent to 10 per cent of capacity. But it falls short of declaring a target for decarbonizing the electricity sector. Market reforms will continue alongside greater government intervention to meet access and distribution objectives. India is implementing a massive programme of welfare payments based on biometric social security numbers, which could enable regulators to raise consumer tariffs to reflect costs, with the government making direct subsidy payments to eligible poorer consumers.

The size of the unelectrified rural market, estimated in April 2015 at 18,452 villages, presents potential opportunities for off-grid solutions (see data from Government of India, “[Garv Dashboard](#)”, 2018;). However, India’s government has instead backed extending last-mile grid connectivity to as many villages as possible through state funding. Although at the time of writing it claimed that 91 per cent of this target had been achieved, given the definition of rural electrification (10 per cent of households in a village, and some public institutions such as schools), this does not necessarily equate to universal or reliable access. Only 8 per cent of the electrified villages have 100 per cent household connectivity. There are a number of remote villages and hamlets that the grid cannot reach; a government scheme has been proposed for these to be powered with solar panels, with the provision of five LED lamps, a DC fan and a plug point, along with repair and

maintenance for 5 years. A recent analysis found that for both microgrids and the traditional grid, fixed costs of wiring and connectivity are very high for low levels of consumption, implying the need for subsidies or grants from government (R. Tongia, “Microgrids in India: Myths, Misunderstandings and the Need for Proper Accounting”, Brookings India Impact Series, 2018). The scope of the market for off-grid solutions will remain limited as long as the government continues to give preference to grid connectivity.

Conclusion

This article has made three arguments. First, India’s efforts to adopt renewables are driven not by explicit decarbonization targets or binding climate commitments but by the opportunities they present for energy security and low-cost electricity supply. Second, despite early gains, India risks repeating past mistakes by focusing on capacity addition without ensuring that utilities are incentivized to offtake the electricity – which could jeopardize efforts to scale up renewables. And third, to sustain its gains in the long run, India will need to link renewables integration to an explicit decarbonization target within its electricity reform agenda, and to disincentivize coal in the generation mix.

ELECTRICITY MARKET REFORM IN AUSTRALIA

Bruce Mountain

The National Electricity Market (NEM) covering the southern and eastern states of Australia is now almost 20 years old. It was constructed in the mould of similar reforms in Great Britain a decade earlier, and its proponents promised a more productive industry that would better meet customers’ needs and charge them less.

Average number of buy and sell bids for renewable energy certificates

	2012	2013	2014	2015	2016	2017
Buy bids	3,029	6,970	5,517	30,881	33,175	71,541
Sell bids	639	21,646	88,895	1,572,901	2,343,628	3,558,059

Source: Indian Energy Exchange.
 Note: renewable energy certificates began trading in 2011.



But over these 20 years, electricity prices have risen from amongst the lowest globally to amongst the highest. Industry profits have risen, productivity has fallen, investors complain of policy uncertainty, and greenhouse gas emissions are no lower. Electricity users are dissatisfied.

This article presents a history of the NEM, examines the outcomes in networks, production, and retail markets, and suggests a direction for reforms.

History

The NEM was created in the context of broader microeconomic and structural reforms that originated with reformist governments of the 1980s. Those governments reduced trade barriers, privatized banks and insurers, deregulated the currency and labour markets, and implemented reforms in product and service markets. Restructuring the electricity sector, hitherto dominated by state electricity commissions, was an important part of these reforms.

The essence of the reform – vertical separation of production, distribution, and retailing – and the creation of wholesale and then retail markets emulated earlier changes in Great Britain. In Australia, electricity provision is a constitutional responsibility of state and territorial governments, not the

Australian national government. The creation of a single market in electricity across the southern and eastern states was therefore described as a triumph of ‘co-operative federalism’. Privatization was limited to electricity supply in Victoria and South Australia, although production, retail, and some networks in New South Wales have since been privatized.

In wholesale markets, the NEM is a mandatory (for generators typically bigger than 30 megawatts), centrally

settled, regionally priced energy-only market with half-hourly settlement periods and five-minute trading periods. It also has markets for the sale of frequency control ancillary services. Unlike wholesale markets in Britain, the NEM has remained largely unchanged since its introduction and it is now one of the few remaining mandatory, centrally settled, energy-only markets in the world.

In retail markets in Australia, as in Great Britain, the large power user market was quickly opened to competition. Deregulation of small consumer markets in Australia has been slower, with one region still regulated; all states except Victoria were subject to some form of price control until recently.

In networks, periodic price controls have been sent for the last 17 years. But again there are important differences. Whereas in Britain, regulatory asset values at privatization reflected the market capitalization of the newly listed companies, in Australia assets were revalued substantially above depreciated historic cost before they were privatized or ‘corporatized’ (the government-owned networks). The corporatized networks, which make up about half the industry, are regulated as if they were investor financed.

Outcomes and issues

Networks

In networks, regulatory asset values have more than tripled per connection under regulations initially set by state commissions and subsequently the Australian Energy Regulator. About one-third of this increase is associated with pre-privatization/corporatization asset revaluations and two-thirds with capacity expansion, mainly in substations, despite reductions in the average and peak demands over the period of that expansion (and since).

While Australia’s regulators, like Ofgem in Great Britain, failed to predict the

decline in borrowing costs since the global financial crisis, for the government-owned networks the impact was particularly significant. This is because they were allowed to charge consumers as if they were investor-owned, thereby settling allowed financing charges far above the actual cost of government bonds, their principal source of finance. This stimulated expansion of the regulated asset base in order to make the most of the gap between actual financing cost and regulatory allowances. The owning governments took the benefit in sharply higher profits, dividends, and tax receipts.

In addition, the price cap approach has underpinned a normative philosophy of regulation focussed on defining the costs of a ‘benchmark efficient’ monopoly. The benefit of lobbying the regulator as to the characteristics of that benchmark has proved to substantially exceed the cost, justifying a cottage industry of lawyers and regulatory economists. To the detriment of consumers, regulators have willingly turned a blind eye to the monopolies’ actual financing costs and tax payments. As in Great Britain, price cap regulation has turned out very unlike the ‘regulation with a light rein’ that Professor Littlechild (the first electricity regulator) had intended.

Retail

In retail markets, price deregulation is associated with significant increases in retailers’ charges for their service. In Victoria, the market has been fully deregulated since 2009, but the typical small customer seems to be paying more for electricity in Victoria than elsewhere in Australia, and much more than in other countries.

While it is possible in the deregulated markets to find offers that are much lower than the typical offers, the evidence suggests that a minority of customers select these lower offers. As in Great Britain, Australia’s retail



markets are characterized by high search costs. Also as in Great Britain, customer engagement in the market is low.

If markets exist to discover customers' needs and find efficient ways to meet them, customer groups suggest that in retail energy markets this is not happening.

In Australia as in Britain, the extent of the failure of retail markets is contested: the Australian Competition and Consumer Commission and the Victorian government have expressed concern, while other states equivocate, and the Australian Energy Markets Commission defends the market. While it is widely accepted that the market has high search costs, some regulators and policymakers suggest the onus is on consumers to engage. But is disengagement not a rational response to a market with high search costs, and does this not explain why the rents collected by the dominant incumbent retailers have not been competed away?

Production

The production of electricity has for many years been the least contentious part of the NEM. With a few exceptions, annual average wholesale prices have until recently been reasonably stable. Last year prices roughly doubled relative to their long-term averages. While the blame for this is contested, many observers have pointed to a combination of the closure of coal generation in Victoria, South Australia, and New South Wales, very large increases in gas prices after liquefied natural gas exports started, and the exercise of market power in concentrated markets.

The quantity of fossil fuel generation has remained roughly unchanged over the life of the NEM: while several coal-fired plants have closed, most had produced little in the years before their

closure. Since they have closed, the remaining coal-fired plant has made up the lost production, so total emissions have not declined. A widely expected 'dash for gas' fizzled after gas prices rose and emission prices were withdrawn (emission policy is discussed below).

The market has also turned out very differently to how the NEM's proponents had intended. Hedge markets are incomplete: largely illiquid beyond a year ahead and much less sophisticated than hoped. Unsurprisingly, vertical integration has followed wherever possible.

Furthermore, the aspiration that the mandatory market would provide the sole remuneration (subject to hedges) for almost all production has not been fulfilled. Renewable certificate schemes have become increasingly important. Significant distributed and large-scale renewable investment has also occurred in response to state and territorial government auctions and financing provided by an Australian government entity. Most recently the South Australian government underwrote the development of the Hornsdale Power Reserve, a Tesla battery that is now the world's largest grid battery and was built and operational in less than 100 days.

In response to generalized concern about power system stability associated with the growth of intermittent renewable capacity, proposed solutions involving large amounts of pumped hydro, grid scale, and distributed batteries are in various stages of exploration and development, funded by customers, the industry, and government bodies.

Even the Australian government, which is critical of state governments for their intervention in wholesale markets and has long been an advocate of privatization, is promising to develop

pumped hydro generation equivalent to the combined capacity of Dinorwig and Ffestiniog in Great Britain.

Another major feature is the rise of distributed small-scale production. One in five households in the NEM have installed solar photovoltaic (PV) panels on their roofs, and in some regions this is now one in three. More than 6,000 megawatts of rooftop PV capacity exists (about 20% of NEM coincident peak demand), of which around one-third of production is used by the houses on whose roofs the devices sit, with the remainder exported. Factories and farms are now also installing PV at record rates.

Rapid PV uptake was stimulated initially by generous regulated feed-in tariffs, though these were quickly withdrawn. A large increase in retail electricity prices, decline in PV prices, and rise in (unregulated) grid export prices has continued to sustain demand. Although Australia already has the highest per capita uptake of rooftop solar of any major country, every passing month seems to set a new record for rooftop PV installation. High grid export prices have tended to reflect higher wholesale market prices, although the export prices vary widely in different retail offers.

Network tariffs applicable to households in the NEM tend to have large fixed charges, though the fixed charge in retail tariffs is higher still. As a consequence, households with PV tend to pay significantly higher prices per kilowatt-hour imported from the grid, whether measured in the retail offers or the component network tariffs.

Distributed batteries are increasingly popular (20,000 installed in 2017, up from 6,000 in 2016), and it is now evident that the combination of PV, battery, and grid backup is cheaper than grid-only supply for many households. New distributed power



exchanges cater for the trade of production from distributed resources.

Emission policy uncertainty has bedevilled the large-scale production markets. As a major coal-exporting country and with coal making up a larger percentage of electricity production than in almost any other country, there are deeply vested interests in preserving coal-fired production. Furthermore, a bicameral Westminster-model legislature with disproportionate representation from rural constituencies (a vestige of federation at a time when the population was much less urbanized) means that although the popular vote supports emission reduction, Parliament has not managed to hold a steady course in emission reduction policy. Emission prices were introduced and then withdrawn by the subsequent government. Renewable subsidy policy has likewise proved susceptible to the prevailing political winds.

It is very unlikely that the NEM will be able to deliver the scale of investment needed to decarbonize electricity production at a rate consistent with the emission reduction commitments that Australia made as a signatory to the Paris Agreement, without substantial emission prices.

Suggested reforms

Networks

Improving network regulation offers considerable benefit to consumers, particularly smaller consumers, for whom network charges are often the largest single part of their bills. In the case of the government-owned distributors, changes should recognize that independent regulation of government-owned monopolies has proved to be an oxymoron. Nobel Laureate George Stigler warned:

Until the basic logic of political life is developed, reformers will be ill-

equipped to use the state for their reforms and victims of the pervasive use of the state's support of special groups will be helpless to protect themselves. Economists should quickly establish the license to practice on the rational theory of political behaviour.

— Stigler, GJ (1971), 'The theory of economic regulation', *Bell Journal of Economics and Management Science*, 2(1), 3–21.

A government that owns its networks, and is made to balance the political upside of higher dividends with the political downside of higher prices, will ensure the accountability and moderation that existed before the NEM was developed.

Beyond such major institutional changes, regulators should be encouraged to focus more on what regulation is actually delivering rather than what they imagine it should be delivering. The concern that moving from normative to positive philosophies of regulation will diminish incentives to efficiency should be tempered by the evidence of the stark failure of the normative approach.

Consideration should also be given to addressing the dead-weight loss of large amounts of excess infrastructure. Policymakers who revalued assets above depreciated historic cost when they thought network monopolies were secure might consider applying this same logic to justify write-downs now that distributed production has already undermined, and is increasingly undermining, that monopoly.

Retail

The solutions to retail concerns are less obvious. A market characterized by high search costs is consistent with the evidence that most small customers don't engage in the market. The few

remaining regulated retail markets in Australia charge less than most customers in the deregulated markets are paying. High search costs deliver rent for the incumbents and make it harder for new retailers to enter the market.

A convincing solution to this is not yet obvious. Price controls that regulate the rents away might ultimately prove a pyrrhic victory if new entrant retailers disappear, leaving customers, governments, and regulators more beholden to the incumbents.

Furthermore, the rise of distributed production and, more recently, storage make it more important than ever that retailers are incentivized to discover customers' needs. Will regulated retailers be better at this than unregulated ones?

While Australia's authorities have been slow to respond to evidence of unsatisfactory retail market outcomes, in Victoria at least the issue is now receiving much attention.

Production

While the creation of the NEM was hailed as a triumph of co-operative federalism, the benign conditions that existed when it was first implemented – substantial production capacity surpluses, no constraint on emissions, and lack of a realistic option for distributed supply and storage – no longer remain.

Broad market design questions – such as the merits of a day-ahead market or of capacity payments – receive sporadic attention by Australia's policymakers and regulators. Though they have not explicitly commented, the federal and state governments have demonstrated little confidence in the existing wholesale market or the ability of changes to this market to improve matters. By their actions they suggest the question: if co-operative federalism got us to where we are, who needs it?



The 'push' from the failure of the central institutions, combined with the 'pull' of rapidly developing distributed technologies, explain the increasing decentralization and regionalization of the industry and its markets. While some in Australia's energy polity lament the withering of the 'truly national' aspiration, others celebrate technological changes that are presenting customers with an exit from a market that they think no longer works in their interests.

While an increasing number of customers are already better off leaving the grid, or using the grid as a backup to their own supply and storage, others may depend on the grid for the foreseeable future. Distributed production and storage technology is developing rapidly, but keeping the lights on while reducing emissions quickly will require decentralized and often increasingly remote large-scale, centrally co-ordinated renewable production. Networks to facilitate trade and diversify risk will continue to be valuable.

However, since economies of scale in renewable generation and in most forms of storage are much smaller than in fossil-fuel-based generation, the gains from large area co-ordination – even if this could be achieved – are likely to be much smaller. For this reason, and taking into account uncertainty about technology change and the NEM's evident co-ordination failures, waiting for top-down, centralized solutions is misdirecting effort and in many areas akin to flogging a dead horse. It would be better to embrace decentralization and develop institutional arrangements that focus regionally and locally and that value flexibility and adaptability. Let a thousand flowers bloom.

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DECARBONIZATION AND POWER MARKET REFORM IN DEVELOPING COUNTRIES: THE CASE OF SOUTH AFRICA

**Anton Eberhard and
Catrina Godinho**

Much of the debate on decarbonization and power market liberalization in OECD (Organisation for Economic Co-operation and Development) countries has little relevance to developing countries, especially in sub-Saharan Africa, which contributes only 2 per cent of global greenhouse emissions and has no wholesale power markets. However, with breakthroughs in solar and wind energy, plus the proliferation of successful auctions, which are delivering cheap, unsubsidized grid-connected power, and growing experiences with new business models for off-grid solutions, many countries in the global south can avoid carbon-intensive growth. These countries have the opportunity to design and migrate to new power market arrangements which are appropriate to their needs for accelerating investment in power generation, both on and off grid. In this way, countries could leapfrog the challenges experienced in the north, where higher shares of variable renewable sources are disrupting wholesale power markets through occasional negative pricing and where utilities face increasing challenges with stranded thermal and nuclear generation assets.

These developments are especially important in sub-Saharan Africa, where only a third of the population have access to electricity and insufficient supply has been a binding constraint to economic growth in many countries for decades, while financially unsustainable monopolistic state-

owned utilities have struggled to finance and manage system expansion and modernization. Low-cost, low-carbon technology, coupled with private investment and participation and supported by further institutional reforms, can provide new opportunities to meet the region's development challenges.

The South African electricity system

Though South Africa is an outlier in sub-Saharan Africa – the country accounts for half of the installed generation in the region (as well as half of the greenhouse gas emissions), and the access rate is 86 per cent – the country's nascent Renewable Energy Independent Power Producer Procurement Programme presents a striking example of the potential for power market reforms and decarbonization in the global south.

South Africa's electricity sector is highly centralized and carbon intensive, with 95 per cent of its electricity produced by the publicly owned and vertically integrated power utility Eskom, almost exclusively from coal-fired plants. Despite policy commitments to restructuring and liberalization, resistance to market-oriented reforms has been hard to overcome. However, the unexpected outcomes of a series of renewable energy auctions and a looming utility 'death spiral' (series of mutually reinforcing price increases and drops in demand) are casting a new light on the potential of reforms.

Carbon mitigation opens the door for renewable-energy independent power producers

At the 2009 UN Climate Change Conference in Copenhagen, South Africa made a voluntary commitment to cap its carbon emissions. After a slight increase, a result of the construction of two new 4,800-megawatt coal power stations, carbon emissions are expected to plateau and then decline



as older coal generators are retired. These environmental commitments have had a direct impact on national electricity plans and new investments, due to South Africa's unusually dirigiste national electricity planning and investment framework.

Under South African law, the energy minister is required to prepare an Integrated Resource Plan which forecasts electricity demand and identifies an optimal supply mix. The minister may also publish 'determinations' specifying how much power should be publicly procured, from which energy sources, and by when. This allows the government to direct and manage a transition from fossil to renewable resources, bringing together climate and energy policies. Recent electricity plans have incorporated an increasing share of renewable energy, and the energy minister has made determinations totalling 14,750 megawatts, about half of which has already been procured.

In 2011, the Department of Energy began a series of renewable energy auctions which have resulted in US\$19 billion of mostly private investment in 92 projects, predominantly solar photovoltaic and onshore wind energy (the price of which fell around 80 per cent and 50 per cent, respectively, between the first and fourth auctions). Most of these projects have already been built and are connected to the grid.

Renewable-energy independent power producers open the door for reforms

However, Eskom, actors with vested interests in the coal industry, and labour unions representing miners have not remained complacent as they have come to comprehend the significance of these developments.

Over the past two years, Eskom has become reluctant to sign 20-year power

purchase agreements with the 27 independent power producers (IPPs) from the fourth auction. Labour unions and coal transporters have also mobilized to halt the signing of IPPs through the courts and in public demonstrations. Meanwhile, new and old coal industry players are trying to make the most of the supply contracts that they have with Eskom – pushing up prices and lobbying for long-term agreements. This has all sparked a renewed national debate around the utility's dominant market position and the influence of interests active in the minerals and energy industries.

Nevertheless, there is a growing consensus amongst some power sector stakeholders – including parts of government, the ruling party, large electricity consumers, industry organizations, finance institutions, civil society groups, and analysts – that Eskom should be broken up and an independent transmission system and market operator (ITSMO) company formed. This has the obvious advantage of removing Eskom's current conflict of interest, where it is both a generator of power and the single buyer from IPPs, instead creating a transparent and fair process for planning, procuring, contracting, and dispatching power.

With the creation of an ITSMO, the core of the power sector will also be protected – which will allow the country to respond to the challenges and opportunities that will arise with a growing share of cheap, but variable, solar and wind generation. It is here that innovation will be required. Unlike the merchant wholesale markets of the north, the more difficult investment climates of the south require new power investments to be procured competitively on the basis of long-term contracts. The challenge for the ITSMO will be to procure flexible power resources and demand-side responses

to complement and balance the variability of solar and wind.

The alternative, of course, would be new balancing markets – but given the absence of power exchanges in Africa (and many other developing regions) and the more challenging investment climate, it is likely that the bulk of these balancing resources will also be procured through medium- to long-term contracts, or perhaps through direct investments by publicly owned ITSMOs.

Forging a new power future

While it might seem inevitable that solar and wind energy, combined with flexible power sources such as gas engines and demand-side management, will prevail – their combined costs are already lower than Eskom's average cost of supply and will soon approach the marginal cost of the utility's most expensive coal generators – strategic policy and reform management will ultimately determine how smooth the transition will be and how long it will take. Efforts will need to be made to address various constituencies' concerns and to project a convincing and desirable power future for the country.

Firstly, it must be made clear that the financial crisis facing Eskom is structural. Once this is understood, stakeholders will come to appreciate how the unbundling of transmission will allow Eskom to ring-fence its generation business, where most of its financial problems reside. There have been massive cost and time overruns on its new coal power stations, which risk becoming stranded assets as electricity demand stagnates and prices from alternative sources become cheaper. Eskom's coal and staffing costs have also escalated, and regulated tariffs have increased more than threefold in real terms over a decade. Eskom has entered a classic utility death spiral: each year it sells



less electricity, yet its fixed costs have increased, it seeks ever higher tariff increases, more consumers invest in energy efficiency or even defect from the grid, and the utility sells even less electricity. These are structural issues that reforms can address.

Secondly, tough choices will need to be made by Eskom to cut costs, slow its capital expansion programme, close old coal power stations, and restructure its balance sheet, possibly by selling some generation assets. In South Africa, these are ideologically fraught issues. Policymakers will need to show how the energy transition can support social transformation, by replacing archaic apartheid-era coal mining and transport jobs with jobs that have less health risk and offer living wages and real social benefits. In addition, attention needs to be paid to the ownership and social responsibility profiles of the companies that will increasingly take over generation. The energy transition needs to map onto social transformation.

Finally, the tension between forces of centralization and decentralization in the electricity system – which poses real risks in a highly unequal society where cross-subsidization remains a necessity to balance electricity access and services – will have to be dealt with. Reducing the barriers to entry for power producers and off-grid providers will be key; so will the revision of the single-buyer market as municipalities and businesses turn to independent supply.

Structural and market reforms in developing countries

Developing countries will have to revisit the power utility restructuring proposals that were commonly made in the 1990s in order to make the most of developments in technology and to access private-sector finance and innovation. Only a handful of countries in sub-Saharan Africa structurally

unbundled their utilities. Those that did – such as Kenya and Uganda – benefitted from increased investment by IPPs. In those that didn't, monopolistic power utilities pose a real risk to low-carbon sector development where they gain a foothold by building large conventional energy plants. The challenge will thus be to extend reforms to more countries and to capacitate ITSMOs in their management of contracts for new variable renewable energy plus flexible balancing resources, so that throughways to least-cost (and low-carbon) power can be opened. It is likely that ITSMOs in sub-Saharan Africa will mostly remain under public ownership, given the strategic status of the power grid and access to electricity in national development discourse and plans. The challenge of capacitating smart system and market operators that respond with agility to these new markets will not be trivial.

For countries that still need to close the access gap, reforms will need to open a space for off-grid solutions. As solar photovoltaic and battery storage prices plummet, we are seeing an explosion of new business models which are taking solar home systems to the remotest regions. Mobile money linked with mobile telephony and pay-as-you-go contracts are now widespread, particularly in East Africa. These are now viable alternatives to rural grid extension. Traditional utilities will have to decide whether they will enter off-grid and mini-grid markets or will see their grid-connected customer base restricted mainly to urban areas – and even there see customers defect from the grid due to poor service and increasing prices. Easing entry for off-grid providers and for private-sector participation in distribution will have to be incorporated into new market design models, to smooth the transition and bolster access rates.

Conclusion

The decarbonization of power systems in developing regions such as sub-Saharan Africa is being driven not by climate change concerns but mainly by the increasing competitiveness of solar and wind energy. In turn, these developments have reopened debates on market-oriented power sector reforms and power system design, as experiences with renewable energy IPPs from across the developing world point to the need for (and benefits of) reduced barriers to entry, institutional reform, competition, and effective long-term planning and regulation.

In South Africa, where climate-change mitigation commitments have played a role in opening a space for alternative technologies, the increased thrust behind renewable energy is now driven by unsubsidized prices which have dipped below the national utility's average cost of supply and could soon be lower than the marginal cost of operating older coal power stations. The oppositional actions of the monopolistic power utility Eskom, as well as others with a stake in coal mining and generation, are now highlighting the need for structural and market reforms en route to the energy transition.

In South Africa, as may well be the case in other developing countries, further pressures will build to reform these power markets as the share of least-cost variable renewable energy grows and exceeds the installed capacity of legacy thermal plants. Unlike the path to wholesale power markets taken in the north, developing countries in sub-Saharan Africa will need to undertake more basic reforms. The immediacy of the need to unbundle and build capacity in new system and market operators will become increasingly apparent. In hastening such reforms, developing countries will need to ensure that ITSMOs are



designed to manage long-term power contracts and public investments, utilize new procurement mechanisms for flexible and balancing resources, and thereby enable reliable and competitively priced electricity services for all.

As countries embark on reforms that could enable sustainable power sector development, mitigating against the risks of stranded assets, emission limits, and spiralling power costs, building a national consensus around a new locally relevant model will be a necessity.



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