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‘Energy Revolution’ and Power Sector Reform

Insights on Challenges in the China Southern Grid Region From a Comparative International Perspective

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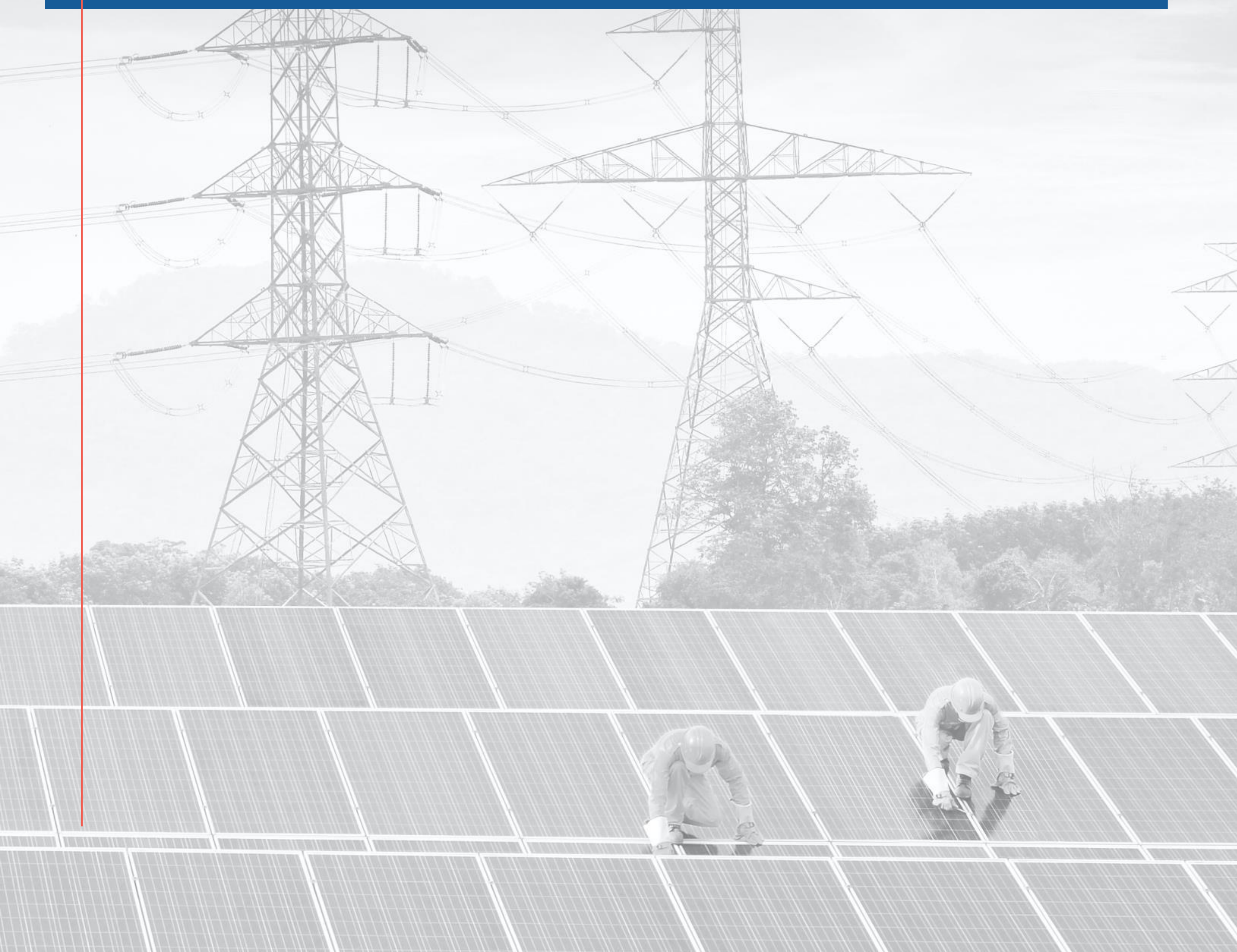

Introduction[1]

Around the world, various countries and regions are grappling with the challenges of reforming and transforming the power sector. Although the context and details are different in each place, there is significant similarity in the guiding objectives. These include — to varying degrees, depending on the place — improving air and water quality, reducing costs, reducing greenhouse gas emissions, supporting new energy technologies and ensuring reliability.

The top level of China’s government has set out an impressive vision of an “ecological civilization” and an “energy revolution,” including ambitious principles for reducing costs, increasing economic efficiency, improving air quality and reducing carbon emissions. Meanwhile, the current round of power sector reform, launched in 2015, is progressing and is helping to support those overarching goals. However, as in the other countries and regions of the globe, the power sector transformation is far from complete, and there is much work to be done to meet the goal of an energy revolution in an efficient and cost-effective manner. The purpose of this paper is to analyze international experience — both successes and failures — and offer comparisons with the situation in China’s Southern Grid region to help provide additional ideas and support useful international discussion. While our focus is on the Southern Grid region, we expect that this paper will be relevant to decision-makers and stakeholders in other parts of China as well, particularly given that the Southern Grid region has often played a leading role and acted as a testing ground for new ideas and as a leading model for other parts of the country.

This paper is written with an eye toward supporting more ambitious scenarios for energy sector transformation out to 2050, but we devote much of our discussion to practical steps for the near and medium term. We discuss perspectives from the discussions in other countries that are grappling with power sector transformation agendas. We also discuss pragmatic steps for the next five years or so for energy policy, market design, planning and associated policies — given the institutional context and current status of reforms in the Southern Grid region. Our analysis takes a wholistic perspective, considering the interrelated challenges of emission reduction, cost reduction and reliability. Accordingly, we take a wide lens and discuss market reform, planning reform, renewable energy integration, flexibility, development of demand side resources, electrification policy, retail pricing and emission pricing — among other measures — which should together ideally form parts of a well-coordinated overall policy package. Of course, this is a very wide set of complex topics, and it is impossible to treat all of them in sufficient detail in a paper of this length. Instead, we aim to provide perspective on how the parts fit together and also to identify some specific issues that are worthy of continued discussion and attention. We aim to follow up on this overarching paper with some briefs articles that further discuss several of the specific policy issues identified here.

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[1] The paper benefited from comments from a group of expert reviewers in China. Christos Kolokathis, Kevin Porter, Frederick Weston and Ryan Wiser also provided helpful comments. Tim Simard managed document review for the English version, and Helen He managed the translation and production of the Chinese language version of this paper.

The main message of our analysis and review of global evidence on these topics is that it will be possible to meet ambitious long-term energy transformation and energy revolution scenarios at reasonable cost and while maintaining reliability. However, there are many practical challenges for the near to medium term. This paper emphasizes electricity market design and regulation because this is a very important part of any power sector transformation effort and because it is a current hot topic in China and the Southern Grid region. (The recent draft Energy Law states that "the state insists on exerting the decisive role of the market in the allocation of resources."[2]) We emphasize, however, that electricity markets are only one element of a comprehensive policy package.

In summary, the main takeaways from this framing paper are as follows:

- International experience suggests that electricity markets alone will not support energy revolution and power sector transformation, although they can be a very important part of the reform package. Electricity markets, planning, regulation, demand side management (DSM), air quality management (AQM), pricing, electrification policy and so on should be tightly coordinated to cost effectively meet overarching goals for energy revolution and power sector reform. These policy areas need to be coordinated and should not be designed in isolation. In particular, we suggest considering the following reforms in parallel to electricity market implementation:
    - Reforming the approach to detailed project planning and approval decisions for which state-owned generation companies and provincial governments are currently responsible. We suggest these companies should be required to estimate and publish net market value and risk metrics as part of individual investment approval processes.
    - Eliminating remaining subsidies to fossil generators (unless the subsidy is a payment to retire).
    - Implementing and enforcing restrictions on new and existing coal, including creating an orderly retirement schedule.
- Market design and administration is a continually evolving process. There have been decades of discussion about market design and market rule revisions in the U.S. and EU regarding electricity market design. Sometimes these debates result in progress, and sometimes there are steps backward. Ideally, electricity market discussions should be guided by a fundamental focus on what electricity markets are supposed to do, that is, support efficient system operations and send signals for rational investment and retirement of various resources. We identify several areas regarding market design that should be worth the attention of policymakers in the Southern Grid region:
    - Implementation of scarcity pricing so that prices better reflect real-time conditions at various places on the grid. This will mean eliminating (or at least loosening)

[2] National Energy Administration (NEA). (2020). Announcement of the National Energy Administration on the public consultation on the "Energy Law of the People's Republic of China" (draft for comment). http://www.nea.gov.cn/2020-04/10/c_138963212.htm

floors and ceilings on bids and on market clearing prices.

- Creating a level playing field in the spot market for *all* resources, including renewable energy, energy storage and distributed energy resources (including demand response). This also means ending any remaining administrative allocation of annual operating hours and thus exposing all thermal generators to the spot market and to markets for longer-term contracts.

- Fleshing out and advancing the excellent work that has been done regarding market regulation in Guangdong. We suggest the next steps could include deciding and publishing crucial details regarding reference prices, market power screens and market monitoring — and clarifying how these relate to dispatch.

- Continuing the effort to establish a financial approach to medium- and long-term (MLT) contracting. The main idea should be that MLTs are financial and not physical. That is, MLT contracts should not affect short-term operational (dispatch) decisions; dispatch should instead be based strictly on economic dispatch principles.

- Establishing an integrated spot market for the whole region. We suggest that the model of a U.S. regional transmission organization (RTO) is a good approach. According to this model, a Southern Grid RTO would include a unified regional set of rules for allocating regional transmission costs, a unified regional transmission planning process, a single regional system operator and a single regional market operator (though these need not necessarily be part of the same organization) overseeing a unified regional market.

1. Coordinating a Power Sector Reform Package

Transitioning to a clean, efficient, reliable energy system will require coordination across diverse economic sectors, policies, regulations, investment planning processes and market mechanisms. This is true in various parts of the world — in the U.S., in Europe and in the China Southern Grid region. Electricity markets can have an important role to play in supporting power sector transformation. Around the world, policymakers have seen a number of important reasons to implement electricity markets. At the most basic level, electricity markets, if designed and implemented well, can help do a number of things, including:

- Reveal the variable (operating) costs associated with individual generation units and with other types of resources (including storage).

- Improve the efficiency and flexibility of system operations (dispatch) and support integration of variable renewable energy.

- Guide retirement of resources that are not needed and promote rational investment in resources that *are* needed.

- Spur competition and innovation, bringing down costs.

In short, well-designed electricity markets can help bring about an energy revolution for the power sector in a way that minimizes costs for consumers. What comprises a well-designed market? There are many details to be considered in market design, but the basic answer is that a well-designed market focuses on ensuring the outcomes in the four bullets above.

There is, however, an important caveat: international experience suggests that these fundamental outcomes can only be achieved if markets are complemented with good planning practices and good regulation and guided by rational power sector policy. It is not easy to coordinate this kind of broad package of market, planning and policy reform. In the U.S., Europe and other places, there continue to be debates about how to transform the power sector, about what basic market model is the best and about the details of market design. This paper focuses on electricity market design and implementation because that is a current topic of particular interest in the Southern Grid region and China as a whole, but it is important to first emphasize a few other aspects of power sector reform that need to be well coordinated with electricity markets. Electricity markets alone are unlikely to spur coal-generation retirements or investments in new clean energy resources that are in line with energy revolution goals. In the U.S. and Europe, these trends may be partially driven by market forces, but there will be a continued need for policy, planning and regulatory measures to drive these transformations.

The U.S. experience strongly suggests that well-functioning planning processes are essential, even in the presence of well-developed electricity markets. These planning processes are needed to ensure that markets are producing outcomes in line with overarching policy goals — and to coordinate across aspects of the power sector that are not fully "marketized," including transmission investment and deployment of demand-side management and other demand-side resources. The development of these processes for electricity planning in the United States has involved identifying:[3]

- How to integrate environmental targets and other public policy goals into the planning process.
- Which organizations are responsible for developing different kinds of plans.
- How local and regional planning should interact.
- When, how and which stakeholders will be able to participate in the planning process.
- How state and federal regulators oversee plans produced by regulated entities.
- How different regulators — for instance electricity and air quality — coordinate within the planning process.
- How plans will affect investment, retirement and approval decisions.

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[3] Regulatory Assistance Project (RAP) & Natural Resources Defense Council (NRDC). (2017). *Power sector planning: US experience and recommendations for China*. https://www.raponline.org/knowledge-center/power-sector-planning-us-experience-and-recommendations-for-china/

What does this mean for Guangdong and the Southern Grid region? Here we offer some observations, based on the history of and current situation in the region. In some ways, Guangdong, the Southern Grid region and China have a context that is very different from the U.S. and other countries. In other respects, there are parallels. In any case, there are useful lessons to be drawn from that international experience.

The five-year plan (FYP) process in China has long played an important role in establishing national industrial and environmental policy and providing high-level guidance for the amount and type of investment and retirement. Meanwhile, central and provincial governments have historically played an active role in forcing retirement of generation capacity. They have also set out resource-specific policies and regulations, including a feed-in tariff (FIT), a renewable energy (RE) quota, an emissions trading scheme (ETS), energy-savings policies and so on. The challenge will be to continue to improve the FYP process and the coordination between that process and the resource-specific policies and regulations. Fortunately, the National Energy Administration's (NEA) 2016 planning policy sets out some very useful integrative principles that serve as an excellent basis for these tasks.[4]

The greatest challenges may be at the next level down in planning and investment decision-making, that is, the more detailed aspects of generation investment identification, evaluation, design, approval and blueprinting. The large SOE (state-owned enterprise) generation companies (central and provincial) have historically played a major role in proposing, designing and moving forward specific utility-scale generation investment decisions, while retirement decisions were often driven by the central government as part of technology upgrade measures. Approval authority in recent years has been with provincial governments, and oversight has been lax for various reasons.[5] This model, in which the major state-owned generation companies drive the next level down of planning and investment decisions, is different than in much of the United States and Europe.

The challenge now, in order to meet goals for an energy revolution, is for the generation companies to stop building coal capacity and instead build new energy resources and focus on *retiring* coal resources at a rapid pace. Because new energy resources will likely need to grow quickly and because demand growth is likely to be slower than in past decades, there may be persistent overall resource overcapacity, depending on the speed of coal capacity retirements.

At the same time, the large generation companies are facing significant disruptions to their business models. They are struggling to adapt to power sector reform and new competitive pressures. One aspect of these competitive pressures is the development of new market mechanisms. The MLT contracting market in recent years has put downward pressure on the

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[4] National Energy Administration (NEA). (2016). Notice of the National Energy Administration on issuing the "Measure for the Administration of Electric Power Planning" Guong Electric Power (No. 139). http://zfxxgk.nea.gov.cn/auto84/201606/t20160606_2258.htm. For discussion, see Dupuy, M., & Xuan, W. (2016). *Excess coal generation capacity and renewables curtailment in China: Getting with the plan*. Regulatory Assistance Project. https://www.raponline.org/blog/excess-coal-generation-capacity-and-renewables-curtailment-in-china-getting-with-the-plan/

[5] Ren, M., Branstetter, L., Kovak, B., Armanious, D., & Yuan, J. (2019). *Why has China overinvested in coal power?* National Bureau of Economic Research. (Working Paper No. 25437). https://www.nber.org/papers/w25437

operating hours of coal generation units, and this is likely to continue with further development of spot markets and other market mechanisms. (However, as we will discuss below, the interactions among the MLT market, the spot market and dispatch are inefficient and can be improved.) Another aspect is that new players and new types of resources are likely to become more important, particularly distributed energy resources (DERs) and the companies that are beginning to exploit new business models in this area.

Despite these disruptive pressures, it may be that policymakers in China and the Southern Grid region see little alternative to keeping the major generation companies in a significant (although somewhat diminished) role with regard to this next level down of planning, investment and retirement decisions, at least for utility-scale generation investments and coal retirement decisions. This is understandable given that existing large generation companies have the staff, scale and technical expertise to do so. The grid companies might play this planning role — in a manner analogous to the way distribution utilities in the U.S. and Europe often play a central role in resource adequacy planning processes — but we recognize that a major thrust of the current round of power sector reform in China[6] has been to reduce and rationalize the scope of the grid companies in power sector decision-making.[7] Alternatively, government agencies at the national and provincial levels could take on direct responsibility for this next level down of planning and acquisition decision-making, but this would be a major challenge to ramp up sufficient technical expertise and staffing.

The government has, however, extremely important roles in higher-level planning and guidance, and there is no alternative to strengthened oversight in this regard to a rational *portfolio* of investment decisions, including distributed and demand-side resources. The key is to ensure that the next level down planning, investment and approval decisions are in line with the FYP, with the energy revolution and with other policy goals. In practice, that means that the FYP forms the basis for resource-specific policies (coal retirements, RE quotas, etc.), but within those constraints, the actual detailed (next level down) portfolio decision-making is left to market participants. One challenge is to ensure that the FYP planning itself is of high quality. The NEA's 2016 policy on planning provides a very useful basis.[8] This will be essential for navigating a world where large generation companies will need to make a lot of these decisions, but other players will make a lot of decisions as well, including regarding DERs.

We suggest revising the manner in which SOE generators are required to demonstrate their decision-making to the State-owned Assets Supervision and Administration Commission (SASAC)

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[6] See Central Committee of the Communist Party & the State Council. (2015). *Reform of the power sector.* Document #9. https://www.ne21.com/news/show-64821.html

[7] The "incremental distribution reform" launched in the wake of Document #9 suggests a possible future somewhat analogous to the U.S. in which distribution utilities (split off from the grid companies and funded by private social capital) are responsible for managing and operating distribution grid service areas. In this case, it is possible that these new distribution utilities could take on planning responsibilities. However, given that the incremental distribution reform effort is still in the early stages in China and only applies in pilot areas that cover a small part of the country, this possibility appears to be quite distant.

[8] NEA, 2016.

and other authorities. We suggest this should include requirements for these companies to estimate and provide an analysis of net market value and risk metrics of planned generation and storage facilities as part of investment approval processes.[9] This analysis would compare the revenues, costs and risks of different investment options, providing justification for both the level and composition of planned investments. With this information, SASAC could ensure that SOE generating companies are making prudent investment decisions. These metrics would be better than some existing metrics that SASAC reportedly uses, such as the annual full-load hours for each generator.[10]

In addition, we suggest spot market prices should provide a new and valuable input into investment approval decisions, generators' portfolio analysis and investment decisions and banks' due diligence analysis. Strict guidelines that condition project approval on meeting criteria for net market value and risk metrics would be very useful. SASAC and the National Development and Reform Commission (NDRC) could set the guidelines and provide oversight in ensuring that the guidelines are met in approval decisions and that the information provided by the SOE generators is accurate and reliable.

It will also be useful to rationalize and refine resource-specific policies while retaining some amount of portfolio flexibility for generation developers. We suggest this should include:

- Refining and rationalizing policies to support new energy (e.g., RE quota, policies for DERs including DSM, and policies for storage investment). Eventually, some of these can sunset when a strong ETS eventually is fully implemented.
- Eliminating remaining subsidies to fossil generators. Well-implemented scarcity pricing as discussed in the next section should be enough to support needed natural gas.
- Implementing and enforcing restrictions on new and existing coal, in line with energy revolution and emission reduction goals. Although the new electricity markets will certainly help identify and retire some uneconomic coal-fire generation units, the market alone will not internalize external costs associated with power plant emissions. In particular, we suggest creating an orderly retirement schedule for coal generation units (e.g., akin to a minimum

[9] Net market value is the present value of energy and ancillary service market benefits over a project's lifetime minus its costs. In the U.S., risk metrics typically incorporate risks associated with market prices, fuel prices and demand forecast uncertainty and are often based on a measure of the variance of a resource's or a portfolio's costs across different input values, using Monte Carlo analysis. Commonly used risk metrics include the 95th percentile of net market value and the ratio of the 95th percentile net market value to expected net market value. For more on net market value concepts and calculations, see Pacific Gas & Electric (PG&E). (2012). *PG&E's description of its RPS bid evaluation, selection process and criteria*. https://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS/2012/Attachment_K_LCBF_12102012.pdf; and Southern California Edison (SCE). (2013). *2013 request for offers: Local capacity requirements*. https://www.sce.com/sites/default/files/inline-files/LCRRFOTransmittalLetter1113_Redline.pdf. For more on risk metrics, see Kahlr, F., Mills, A., Lavin, L., Ryan, N., & Olsen, A. (2016). *The future of electricity resource planning* (Section 3.5). https://emp.lbl.gov/sites/all/files/lbnl-1006269.pdf

[10] Remaining coal generators will need to operate more flexibly to accommodate growing penetrations of VRE on the grid. SASAC's focus on maintaining hours of operation is fundamentally at odds with the idea that each resource on the grid should produce only when it is most efficient to do so. Dupuy, M. (2020). *China's watchdog for state-owned enterprises grapples with coal-fired generation*. Regulatory Assistance Project. https://www.raponline.org/blog/chinas-watchdog-for-state-owned-enterprises-grapples-with-coal-fired-generation/

standard),[11] which could later be replaced by (or merged with) the carbon trading mechanism as that mechanism becomes well developed. We use the term "orderly" to mean that the retirement schedule should consider that a limited number of specific uneconomic units may still need to continue to operate for a short time for system reliability reasons. Such reliability designations should be assigned sparingly and with careful consideration given to cost-effective replacement resources, including demand-side resources.

2. Electricity Market Design and Implementation

Guangdong has made significant strides in establishing the foundations of wholesale and retail electricity markets, as set out in the market regulations issued in August 2018 by the South China Office of the National Energy Administration (hereafter referred to as "the 2018 regulations").[12] These foundations include forward markets for electricity, a retail industry with a significant number of providers and real-time electricity and ancillary services markets that are now in pilot operation. Guangdong is leading China in many aspects of market design.

Guangdong's electricity market is poised to enter a new phase, which will include regular operation of its spot market and the initial development stages of a regional market covering the Southern Grid region. Guangdong's spot market is still intended to be the first step in the creation of this regional market. Despite considerable progress thus far, there are several important questions in Guangdong and the Southern Grid region that need to be clearly resolved. These include:

- Price formation (particularly the implementation of scarcity pricing).
- Development of a level playing field for all resources.
- Oversight and regulation of markets.
- Harmonization of medium- and long-term contracts and spot markets.
- Regional market development.

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[11] An example of a minimum standard is the U.S. Environmental Protection Agency's (EPA's) 2015 New Source Performance Standard, which set a limit of 636 kgCO2/kWh. For more on this rule, see EPA. (2015). *Standards of performance for greenhouse gas emissions from new, modified, and reconstructed stationary sources: Electric utility generating units; Final rule.* https://www.govinfo.gov/content/pkg/FR-2015-10-23/pdf/2015-22837.pdf

[12] South China Energy Regulatory Office (SCERO) of the National Energy Administration (NEA). (2018). Notice of the Southern Energy Regulatory Bureau, Guangdong Provincial Economic and Information Technology Commission, Guangdong Development and Reform Commission on soliciting opinions on the Southern (starting with Guangdong) electricity spot market series rules. http://nfj.nea.gov.cn/adminContent/initViewContent.do?pk=402881e56579be6301658d99ac57001f

a. Improving Spot Market Price Signals With Scarcity Pricing

As in other parts of the world, ensuring grid flexibility will become an important issue in the Southern Grid region as the penetration of variable renewable energy increases. At the heart of any well-designed spot market is the principle of prices that fluctuate throughout the day (and ideally according to location) in response to demand and supply conditions. This concept is known as scarcity pricing. In places and times of system stress, scarce supply or high demand (or a combination of all three), it is natural to expect that prices can rise quite significantly — although these periods of high prices may be quite rare. Scarcity pricing is the way a spot market supports economic outcomes; that is, it motivates economic dispatch. It also motivates investments, including appropriate amounts of flexible resources (such as energy storage, demand response and gas-fired generation capacity), and motivates retirement of unneeded inflexible resources).

Scarcity pricing creates efficient incentives at different timescales:

- Long-run investment and retirement decisions. Scarcity pricing provides price signals that guide investment and retirement decisions for generation, energy storage and demand response resources. Despite the fact that hourly spot market prices can be quite variable, they nevertheless provide valuable and reliable information for long-term planning decisions by incentivizing investments in resources that can be available in the right location and at the right time to meet demand.[13] If expected market revenues are high enough to cover the total fixed and variable costs of a new resource, the market is sending signals for new investment in that resource. If expected market revenues are not high enough to cover the going forward costs of an existing resource (i.e., fixed operation and maintenance costs, taxes and variable costs), the market is sending signals to retire that resource. Revenues are highly sensitive to the rare hours of high prices. Well-designed scarcity pricing will allow all *needed* resources to remain in operation, encourage new needed resources to come into the market and encourage unneeded resources to retire.
- Short-run scheduling and operating decisions. For instance, during times of resource scarcity, energy and ancillary services market prices should be high, providing incentives for resources to be available and able to meet system needs if dispatched. During times of oversupply, market prices will be low, providing incentives for generators to remain offline. The use of price caps and floors can dampen these incentives, leading to inefficient operations.

[13] See Cramton, P. (2017). Electricity market design. *Oxford Review of Economic Policy, 33*(4), 589-612. ftp://www.cramton.umd.edu/papers2015-2019/cramton-electricity-market-design.pdf

All U.S. RTO[14] and European wholesale electricity markets have some form of scarcity pricing.[15] The implementation of scarcity pricing is, however, not perfect and varies from place to place. There is much discussion in the U.S. and Europe about improving scarcity pricing (sometimes referred to as improving price formation), particularly the challenge of forming efficient price signals in the relatively rare hours and locations of system stress.[16] Certain characteristics of the power sector — including lack of real-time retail pricing, which prevents end users from responding to prices, and difficulties of accurately pricing reserves in shortage hours — need to be addressed to promote efficient scarcity pricing. Lack of efficient scarcity pricing can create irrational incentives for investors — sometimes referred to as the missing money problem — and lead to inefficient investment decisions. In some cases, market designers have responded to the missing money problem with poorly designed mechanisms, which have only compounded the problem.[17]

ERCOT (in Texas) and several northern European markets are based on an energy-only model that emphasizes scarcity pricing. In these markets, prices for operating reserves (i.e., energy needed to preserve system security at times of system peak or stress) can rise to very high levels.[18] This happens only occasionally, but it does deliver a very strong price signal to resources, either on the generation side or on the demand side, that are actually available to meet system needs at times of relative scarcity. These markets have had highly variable energy prices. They have also been

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[14] The spot markets under development in several Chinese provinces are roughly analogous to the independent system operator (ISO) and regional transmission organization (RTO) markets that cover about two-thirds of the United States. Because the terms "ISO" and "RTO" are nearly synonymous in the U.S., we will simply refer to RTOs in the text of this paper when describing these U.S. ISO/RTO markets as a category. For more information on ISO/RTO markets, see Hurlbut, D., Zhou, E., Porter, K., & Arent, D. (2015). *'Renewables-friendly' grid development strategies: Experience in the United States, potential lessons for China*. (NREL/TP-6A20-64940). National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy16osti/64940.pdf. (Available in Chinese at https://www.nrel.gov/docs/fy16osti/66729.pdf). See also Federal Energy Regulatory Commission (FERC). (2015). *Energy primer: A handbook of energy market basics.* https://www.ferc.gov/market-oversight/guide/energy-primer.pdf

[15] In Europe, the recently adopted Clean Energy for All Europeans package puts a renewed focus on scarcity pricing and its significance for achieving reliability. According to the Electricity Regulation on the internal market for electricity: "To support this shift to variable and distributed generation, and to ensure that energy market principles are the basis for the Union's electricity markets of the future, a renewed focus on short-term markets and scarcity pricing is essential." The regulation goes on to stipulate that any price caps should be lifted to allow for the formation of scarcity pricing. European Commission. (2019). *Commission Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).* https://eur-lex.europa.eu/eli/reg/2019/943/oj

[16] Hartman, D. (2017). *Refreshing price formation policy in wholesale electricity markets.* R Street. http://www.rstreet.org/wp-content/uploads/2017/08/106.pdf; Chang, J., Geronimo Aydin, M., Broehm, R., Yang, Y., & Sweet, R. (2018). *Shortage pricing in North American wholesale electricity markets*. The Brattle Group. https://www.aeso.ca/assets/Uploads/4.3-Brattle-Paper-Shortage-Pricing.pdf; and European Federation of Energy Trader (EFET). (2016). *The importance of free formation of prices in the European wholesale electricity market: An EFET discussion paper*. https://efet.org/Files/Documents/Electricity%20Market/General%20market%20design%20and%20governance/EFET_Free-formation-of-prices-power-market.pdf

[17] Hogan, M. (2017). Follow the missing money: Ensuring reliability at least cost to consumers in the transition to a low-carbon power system. *Electricity Journal, 30*(1). https://doi.org/10.1016/j.tej.2016.12.006

[18] In the ERCOT case, prices rise up to a cap of U.S. $9,000/MWh. Meanwhile, Belgium has set a dynamic price cap in the balancing market of 13,500 €/MWh. Economie. (2019). *Belgian electricity market: Implementation plan*. https://economie.fgov.be/sites/default/files/Files/Energy/Belgian-electricity-market-Implementation-plan.pdf

successful at supporting needed resources and have maintained reliability.

One major problem with implementing scarcity pricing is the presence of price or offer/bid caps. A number of U.S. RTO markets have had offer caps in place to deal with market manipulation concerns, particularly in the aftermath of the 2001 California crisis in which a number of generators were able to exercise market power, temporarily driving prices to high levels and severely disrupting the markets. Implementation of caps that limit the market clearing price can be an effective way to deal with persistent market power problems. But these caps are also crude and inefficient because price ceilings — and for that matter price floors — dampen *beneficial* scarcity signals. In the U.S., regulators have developed a more sophisticated regime for identifying and mitigating instances of market power. The challenge is to differentiate between beneficial price spikes that reflect scarcity and harmful price spikes that reflect market manipulation. Meanwhile, regulators have gradually loosened price caps, allowing for scarcity pricing signals while guarding against the risk of market manipulation. (For more discussion of market regulation, see Section 2c.)

All U.S. RTOs have some form of reserve scarcity pricing mechanism, although the details vary.[19] Several of these mechanisms use administrative reserve scarcity pricing based on Operating Reserves Demand Curves (ORDCs), which aim to ensure accurate scarcity pricing, particularly at times and locations of system stress. By improving scarcity pricing, ORDCs are intended to improve signals for investment and retirement of system resources. The ORDC is a scarcity price adder, that is, a price adjustment that is administratively added to the energy market price. It is based on operating reserve levels: as operating reserve levels fall, the adder increases, allowing prices to reach thousands of dollars per MWh ($9,000/MWh in ERCOT). If well designed, this approach produces a price signal that varies across time and location and reflects the full cost of meeting the demand for energy and reliability.

Based on Guangdong's spot market rules and trial operation results, we observe that there are significant opportunities to improve the formation of scarcity prices in the spot market. We make the following suggestions or recommendations:

- Design an administrative approach to scarcity pricing, based on an administrative ORDC and careful implementation of reference levels (see Section 2c) as the basis for ensuring rational supplier bids.
- Avoid resource-specific adders in favor of an ORDC-like mechanism that applies to all suppliers. Well-implemented scarcity pricing as discussed in the next section can provide an additional revenue source to any needed natural gas generation in lieu of subsidies.
- In order to support scarcity pricing, eliminate or loosen spot market price floors and ceilings. Similarly, eliminate or loosen ceilings and floors on supplier bids.

[19] Chang et al., 2018.

b. Creating a Level Playing Field for All Resources

In Guangdong, as in other spot market provinces, some thermal generators still receive administratively allocated annual hours of operation under the process known as annual output planning, which dates from before the 2015 launch of the current round of power sector reform. Much progress has been made in Guangdong and other provinces to shift to a market-driven approach. We suggest that it is important to complete this aspect of reform by ending any remaining category of thermal generators still receiving administratively planned allocations of annual operating hours. In addition, we suggest the market design should attempt to create a level playing field for all other resources, anticipating a future in which fossil fuels are no longer the dominant prime movers of Guangdong's electricity system.

Certain generators may be revealed as uneconomic by the market. This is actually an important step forward and one of the main goals of implementing markets. Uneconomic assets should be allowed to retire according to market forces as soon as possible (subject to short-term orderly retirement reliability considerations). The owners of the uneconomic asset may try to argue for some compensation on "stranded assets" grounds. The appropriate official reaction to this argument will vary across countries, according to institutional and historical context, and is beyond the scope of the current paper. However, we emphasize that shielding uneconomic resources from the market and allowing them to continue operation is a very costly (and environmentally harmful) way of resolving the question of who pays for the accounting value of an asset.

In the U.S., the Federal Energy Regulatory Commission (FERC) has, in some cases, required RTOs to establish sets of rules to ensure that specific types of resources, such as energy storage resources, are able to compete in the markets on a level playing field.[20] These new sets of rules (known as participation models) aim to identify and address problems with existing market rules that inefficiently limit participation by various resources. Developing participation models for non-fossil resources could be a valuable next-step exercise for market designers in Guangdong. The main idea is to ensure that market rules allow every market participant to be compensated for the services that they are able to supply to the market. This is not about picking winners but about removing barriers and facilitating open competition to promote system efficiency and lower costs.

This section provides an overview of market design considerations and participation models for variable renewable generation, energy storage and demand response. Large hydroelectric generation should be able to participate in Guangdong's spot market under the existing market design.

[20] FERC has required reviews for demand response (Order 745) and energy storage (Order 841). By the late 2000s, ISO market designs already had five-minute nodal dispatch and other elements that leveled the playing field for solar and wind generation. FERC further leveled the playing field for wind and solar by requiring five-minute settlement and scarcity pricing in 2016 (Order 825). Reservoir hydro had participated in ISO markets since their formation.

Variable Renewable Generation

Variable renewable energy (VRE) includes solar PV, concentrated solar power, onshore and offshore wind and run-of-river hydropower. VRE has very low (near-zero) operating costs. Its generation profile is intermittent (varies over time) and uncertain (is subject to forecast error). Wind and solar generation tend to have much shorter construction lead times and be more modular than traditional central-scale resources.

In China, law and policy requires priority dispatch for VRE. If VRE participates in spot markets, the outcome, at current penetrations of VRE, will (at least in principle) be largely the same as under priority dispatch because VRE has very low operating costs and will almost always clear the market. This is certainly true in U.S. RTOs, where VRE curtailment rates have been very low (see Figure 1).[21]

Several of the core elements needed to enable VRE participation in Guangdong's spot market are already in place, including real-time markets based in locational marginal pricing (LMP), security-constrained unit commitment and dispatch and a two-settlement system of day-ahead and real-time energy markets. The two-settlement system means that deviations between day-ahead VRE forecasts and real-time dispatch can be settled at real-time market prices. Additional enhancements that would improve VRE participation include:

- Well-designed and well-implemented competitive markets for frequency regulation and operating reserves.
- Enhanced wind and solar forecasting capabilities.
- Shift from 15-minute dispatch and settlement to five-minute.
- Creation of financial instruments to allow for hedging locational price risk, such as financial transmission rights.
- Reduced or eliminated offer floor to allow negative prices. In the U.S. and Europe, VRE, thermal and nuclear units will sometimes rationally make negative bids. For VRE, these negative bids may reflect the opportunity costs associated with preferential tax treatment and renewable energy costs. Prohibiting negative bids in these cases would lead to inefficient dispatch outcomes.[22]

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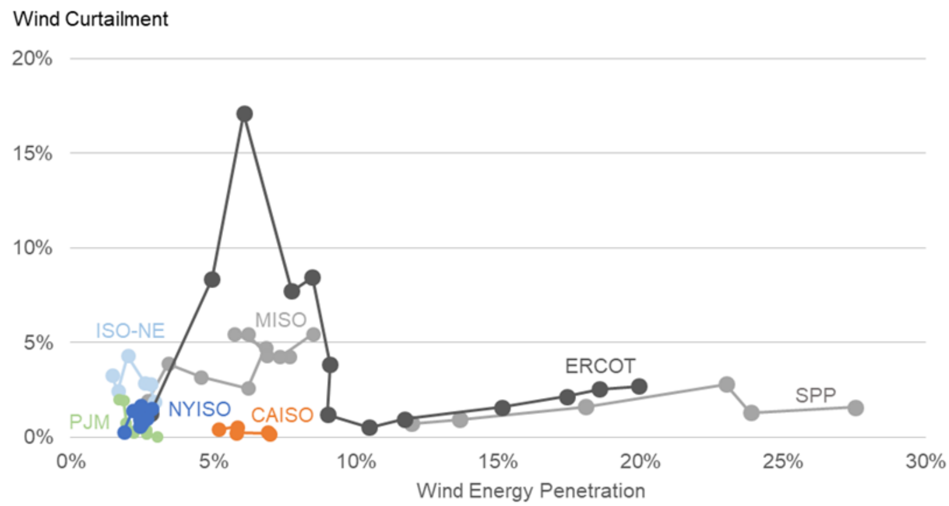
[21] For renewable energy curtailment information for Europe, see Council of European Energy Regulators (CEER). (2018). *Status review of renewable support schemes in Europe for 2016 and 2017*. https://www.ceer.eu/documents/104400/-/-/80ff3127-8328-52c3-4d01-0acbdb2d3bed. In 2016 and 2017, Germany and Lithuania experienced the highest volumes of curtailed renewable energy from the countries reporting RES curtailment data.

[22] Negative prices have become more commonplace in Europe in recent years. For example, on March 17, 2019, prices turned negative in Germany for 20 hours as a result of high wind output, also pushing prices below zero in neighboring countries. Witkop, N. (2019, March 18). Germany sees third weekend of negative prices. *Montel*. https://www.montelnews.com/en/story/germany-sees-third-weekend-of-negative-prices/993002

Figure 1. Wind curtailment in U.S. ISOs as a function of wind penetration



Source: Lawrence Berkeley National Laboratory. Note: High wind curtailment rates in ERCOT were the result of administrative limits on wind operation and transmission constraints.

In the United States, certain aspects of the operational and economic paradigm for VRE are gradually changing as VRE penetration increases. It is increasingly being treated as a resource that can contribute frequency regulation and operating reserve services. Under this new paradigm, the objective is not necessarily to minimize VRE curtailment but to manage VRE resources in an optimal way, which implies having economic amounts of curtailment. For example, wind and solar can effectively be ramped up and down through managing curtailment, providing frequency regulation and ramping services.[23] This shift in thinking in approach is still at an early stage in the U.S. and Europe.

As for Guangdong's medium- and long-term contract markets, VRE participation in Guangdong's would not necessarily require significant changes to contracts or market rules, as long as the contracts are financial (see Section 2d). Under Guangdong's current investment paradigm, generating companies would likely manage most of the risk associated with curtailment and market prices.

Energy Storage

The two main commercial energy storage technologies currently include pumped hydropower and batteries. Both are extremely flexible, with the ability to rapidly start up, shut down and ramp. Both

[23] Loutan, C., Klauer P., Chowdhury S., Hall S., Morjaria, M., Chadliev, V., Milam, N., Milan, C., & Gevorgian, V. (2017). *Demonstration of essential reliability services by a 300-MW solar photovoltaic power plant.* National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy17osti/67799.pdf; and Energy and Environmental Economics (E3). (2018). *Investigating the economic value of flexible solar power plant operation*. https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

have roundtrip efficiency losses that significantly affect their dispatch, and their bidding is driven by opportunity costs. However, the two have different operating constraints and are typically treated differently in U.S. ISO markets.[24]

Energy storage resources are unique in that they act as both a generator, while in discharge mode, and a load, while in charge mode. This means that storage resources must be able to submit bid curves that include both supply (discharge) and demand (charge) bids. In 2018, FERC finalized a rule regarding participation of storage resources in the RTO wholesale electricity markets. The FERC rule required each RTO to develop detailed participation models for storage resources. In its statement, FERC noted that that failure to level the playing field for storage and other resources "can reduce the efficiency of the RTO markets, potentially leading an RTO to dispatch more expensive resources to meet its system needs." The FERC rule requires that each RTO revise its tariffs and market rules to take account of storage-specific characteristics. In particular, the rule specifies 13 "physical and operational characteristics of storage resources," including characteristics related to state of charge, charge time, charge/discharge limits, run time and charge/discharge ramp rate. In short, the RTOs now have to plan their systems and optimize their dispatch around a more realistic picture of the operating capabilities of storage resources.[25]

For Guangdong, facilitating energy storage participation in spot markets likely requires similar participation model rules. In addition, it may require enhancements to dispatch software, to create new resource categories for energy storage and consideration of state of charge rules for batteries and to determine the role of dispatch centers in optimizing battery operation. As in U.S. ISOs, products and market rules for energy storage in Guangdong can develop over time.[26]

Distributed Energy Resources

Distributed energy resources (DERs) include demand response (DR), distribution-level and customer-sited energy storage and distributed generation. U.S. RTOs have been developing participation models to allow these various types of DERs to participate directly (i.e., participate as supply resources, either through aggregators or individually) in the markets. So far, the DERs that have participated directly have been largely DR participating in RTO capacity markets. However, DERs have the potential to play a much larger role in RTO energy and ancillary service (AS) markets. For Guangdong and the Southern Grid region, we suggest developing rules and business models for aggregators to aggregate DERs and manage their participation in the spot markets.

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[24] For instance, the CAISO has separate resource models for battery storage (nongenerator resources) and pumped hydro (pumped storage).

[25] Dupuy, M., & Porter, K. (2018). *Leveling the playing field for storage resources in China's electricity markets: A view from the U.S.* Regulatory Assistance Project. https://www.raponline.org/blog/leveling-the-playing-field-for-storage-resources-in-chinas-electricity-markets-a-view-from-the-u-s/

[26] For an example of evolving products and rules, see Carr, L., Murtaugh, G., & Powers, J. (2020). *Energy storage and distributed energy resources phase 4*. California ISO. http://www.caiso.com/InitiativeDocuments/SecondRevisedStrawProposal-EnergyStorage-DistributedEnergyResourcesPhase4.pdf.

Regarding DR, it can in principle be a plentiful, low-cost and highly flexible resource. DR resources can provide a range of services; in addition to its traditional role of shedding load, it is also capable of operating very flexibly on shorter timescales. FERC requires all U.S. RTOs to allow DR to participate directly in RTO markets, although, in practice, there are a number of barriers to direct participation by DR in RTO markets due to rules that hamper aggregators. To cite just one example, some RTOs require participating resources to be available consistently throughout the year, which hampers DR resources such as those based on management of summer air-conditioning loads. There is ongoing work in the U.S. to remove these inefficient barriers and thus expand direct participation models for DR. At the same time, it is important to emphasize that DR can be an important resource without participating directly in wholesale markets as a supply resource. Time-varying retail prices can help motivate end users to efficiently invest in DR and other forms of DERs — and will be particularly important to cost effectively unlock the flexibility of electrified end uses.

Summary

We recommend that the markets should be designed, from the start, to provide a level playing field for all technologies according to their capabilities. In other words, the markets should not be designed with just the technical capabilities of coal plants in mind. Instead, any resource that is able to provide a service (including energy or any ancillary service) should have the opportunity to participate and be compensated accordingly. This should include distributed energy resources, storage and variable renewable energy.

c. Oversight and Regulation of Spot Markets

Market regulation and monitoring is an important theme in market design and implementation. In the U.S., Europe and other parts of the world, electricity markets are highly regulated. A strong regulation and monitoring regime can help:

- Identify and mitigate episodes in which one or more market participants are able to exercise market power.
- Ensure new markets are producing fair, cost-effective and rational operational results, including least-cost economic dispatch.
- Fine-tune market rules as experience with markets accumulates.
- Address the challenge of integrating variable renewable generation, storage and distributed resources.
- Improve price signals to help rationalize both investment in new resources and the retirement of unneeded and inefficient resources.

Guangdong's spot market rules and associated policy statements from policymakers have rightly focused on these topics. In our view, the existing rules for Guangdong provide an excellent overarching framework by setting out responsibilities for market regulation in Guangdong and eventually the region. Existing policy statements include the following features:

- Recognition of the importance of market monitoring and market power mitigation.
- Some general rules for collection of information on generator operating costs and use of this information for calculation of reference prices.
- Some general rules for establishing screens for market power.
- A role for an independent third-party monitoring organization.
- Requirements for regular reports about the state of the market.

The challenge now is to flesh out and fully implement this policy framework. Strengthening regulation is a particularly important task in Guangdong, the Southern Grid region and China overall, given the high concentration of generation ownership, dominance of a limited number of state-owned enterprises in certain geographic areas and the policy goals for using competitive pressures to reduce costs and reducing emissions.[27] Guangdong appears to be ahead of the rest of the country regarding the market regulatory issues — and accordingly, the Southern Grid region is in place to be a world leader on these topics. In the following, we offer some suggestions based on international experience with market regulation.

Strengthening the Framework for Assessing Generator Operating Costs

Guangdong's 2018 market rules recognize an important place for reference prices, which appear to be analogous to what in the U.S. context are called reference levels.[28] In the U.S., RTOs collect data to make estimates of the operational costs of generation units. The RTOs use these reference levels to judge whether the market is competitive and whether any generators are exercising market power. The estimates are also used to establish the level to which generator offers are mitigated. The basic approach is similar across RTOs and involves calculating the determinants of generator operating cost.

Regulations issued in late 2018 offer some detail on calculation of reference prices and assigns responsibility to the market committee, comprised of market participants, to develop the reference price methodology, subject to government approval.[29] U.S. RTOs publish very detailed documentation regarding reference level calculation methodologies, based on stakeholder discussions.[30] These are regularly updated as part of an ongoing stakeholder process. In the U.S. context, this detailed transparency helps underpin confidence of existing and prospective market

[27] Central Committee of the Communist Party & the State Council, 2015.

[28] SCERO of NEA, 2018.

[29] Power Energy Department. (2018). Letter from the Economic and Information Technology Commission of Guangdong Province on soliciting opinions on Guangdong electric spot market unit generation cost calculation methods and two standard documents (drafts) (No. 214, Annex 1). Department of Industry and Information Technology of Guangdong Province. http://www.gdei.gov.cn/ywfl/dlny/201809/t20180903_130326.htm

[30] For example, see PJM. (2020). *PJM Manual 15: Cost development guidelines*. https://www.pjm.com/~/media/documents/manuals/m15.ashx

participants (and other stakeholders) that market regulatory processes are fairly and comprehensively implemented. It would be very useful for promoting transparency and efficient market outcomes for the Guangdong market committee and relevant authorities to publish such a document. We note that the May 2019 draft rules on market regulation[31] do not specifically mention the term "reference price" (although they do mention a general requirement for monitoring the costs of market participants). Accordingly, we suggest that it would be useful for the regional authorities to issue a new policy statement that emphasizes the importance of reference prices, specifies their use in market power mitigation and requires publication of a more detailed document on methodology. Moreover, specific provisions requiring the third-party monitoring organization to periodically audit the calculation of reference prices would be useful. The monitoring organization and the market operation organization should report publicly on the quality and accuracy of the calculation of reference prices in reflecting generator operating costs and identify areas for improvement.

One issue to consider in the development of reference levels is the calculation of reference levels for storage resources, including reservoir hydro. The storage capability means that reservoir hydropower can choose when to generate, and this raises the issue of opportunity costs. In U.S. RTOs, reference levels for storage resources may include consideration of opportunity costs and also the costs of pumping to refill reservoirs and so on.[32]

Market Monitoring

The May 2019 regulations include a brief article that sets out the role of an independent third-party monitoring organization and states that the organization will be responsible for preparing "work reports … including but not limited to analysis of market operations, assessment of market efficiency and effectiveness of market risk prevention, suggestions for rational modification of market rules, identification of clues regarding market rule violations and suggestion for rectifying [these violations]." This outline of responsibilities is useful but ideally should be expanded to include an assessment of a broader range of outcomes associated with the spot market rules, including matters that fall under the responsibility of the dispatch organizations. In particular, third-party reporting on the efficiency of dispatch outcomes and the way in which they relate to reference levels and market bids is an important topic on which the third-party organization could report. In addition, we suggest that the third-party organization should publish its reports. (The regulations simply say that the reports should be submitted to the Southern Energy Regulatory Bureau.)

[31] National Energy Board Southern Authority. (2019). Notice of the Southern Energy Regulatory Bureau on soliciting opinions on the implementation measures and supervisory guidelines for the supporting supervision of the Southern (starting in Guangdong) power spot market (Southern Supervision Market Letter No. 78). South China Energy Regulatory Office of the National Energy Administration. http://nfj.nea.gov.cn/adminContent/initViewContent.do?pk=402881e569d686de016a8fef7c19007d

[32] For example, see PJM, 2020. See also Shelton, N. (2019). *Opportunity costs for energy storage resources*. New York ISO. https://www.nyiso.com/documents/20142/7007643/ESR%20Opportunity%20Cost%20-%20061119.pdf/41cf3cfe-1a28-b738-8e18-d26f1b901a3e

In the U.S., FERC requires that each RTO must "provide the MMU [Market Monitoring Unit] complete access to the [RTO] databases of market information."[33] Confidentiality provisions in RTO rules typically prevent public disclosure of information attributable to individual market participants, although the independent MMU is required to report to the RTO and FERC confidential information and data points relevant to the MMU's mandate. In addition, the independent MMUs typically report on issues relevant to their mandate using data that is sufficiently aggregated so that individual market participants are not identifiable.

Each U.S. RTO has specific rules stipulating that the independent market monitor has detailed access to data and information, including regarding both system and market operations. For example, in one RTO, the governing rules state that the independent MMU will have access to detailed information and data, including, but not limited to:[34]

- Full data on all individual offers or bids in markets.
- All data on individual export interchange transaction bids and import interchange transaction offers.
- "Actual commitment and dispatch of [generation and other] resources."
- Locational marginal prices and market clearing prices at all nodes for every period.
- Detailed balancing area operational data.
- "Conditions or events both inside and outside the SPP Balancing Authority Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold."
- "Information regarding transmission services and rights, including the estimating and posting of Available Transfer Capability or Available Flowgate Capability … the operation and maintenance of the transmission system."
- "Information regarding the nature and extent of transmission congestion."[35]

Guangdong's 2019 regulations also require the electricity market operating agency to play a major role in market monitoring and to publish periodic reports. This is a very good provision, but similarly the scope of these reports should ideally be expanded to cover topics such as the efficiency of system operations outcomes.

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[33] Federal Energy Regulatory Commission (FERC). (2008). *Wholesale competition in regions with organized electric markers* (Order 719). https://ferc.gov/sites/default/files/2020-06/OrderNo.719.pdf

[34] Southwest Power Pool (SPP). (2020). *Market protocols: SPP integrated marketplace, revision 75, SPP Tariff, Section 8.1.4.2*. https://www.spp.org/spp-documents-filings

[35] Southwest Power Pool (SPP). (2020). *Market protocols, Section 8.1.12.3*. SPP rules further stipulate that market participants must retain all relevant data and information (including the list cited here) "for a minimum of three years and will promptly provide any such Data and Information to the Market Monitor upon request."

Market Power Screens

Guangdong's market operation organization published a calculation of the Herfindahl-Hirschman Index (HHI) — a metric regarding the degree of ownership concentration — for generators in the province during the October 2019 spot market trial. The HHI was between 1,300 and 1,400 for all suppliers and around 1,900-2,100 among suppliers that cleared the market. In China, HHI values between 1,000 and 1,800 are considered to reflect moderate concentration (低集中寡占型), with values below 1,000 considered competitive (竞争型) and above 1,800 considered noncompetitive (高寡占型).[36] These relatively high levels of market concentration in Guangdong reflect a dominant supplier, which is a provincially owned enterprise. We note that, in the U.S. context, such a dominant supplier may not pass the screens required by FERC for horizontal market power (nor the more sensitive specific market power screens administered by the RTOs) and thus would not be allowed "market-based rate" authorization — meaning that the supplier would be required to offer into the market according to its reference levels.[37]

In any case, the HHI does not account for transmission constraints and real-time fluctuations in supply and demand, which can affect opportunities to exercise market power, and thus is of limited usefulness in monitoring the exercise of market power in real time. The Guangdong regulations recognize this and set out requirements for more sophisticated market screens, including "conduct and impact" tests. We suggest that, as in the case of the U.S. RTOs, a much more detailed specification regarding how these screens — as well as very specific mitigation procedures — should be published. For example, U.S. RTOs state specific thresholds for market screens to apply to different parts of the grid, with suppliers located in more frequently constrained areas often being subject to stricter thresholds.[38]

d. Harmonizing Medium- and Long-Term Contracts and Spot Markets

It is impossible to precisely forecast actual (spot) system conditions for a given hour months or years in the future because these conditions depend on the weather and other variable factors. Ideally, from a social point of view, investors in power system resources, such as power plants, should be able to enter into long-term contracts to manage the risk of the investment but *without* locking in the actual amount of power they will sell during a particular month, day or hour in the

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[36] Guangdong Power Exchange Center. (2019). *Guangdong 2019 annual electricity market report*. http://news.bjx.com.cn/html/20200227/1048396.shtml

[37] See Federal Energy Regulatory Commission (FERC). (n.d.) *Horizontal market power*. https://www.ferc.gov/industries/electric/gen-info/mbr/market-power/horizontal.asp. See also Wenner, A., & Lankford, A. C. (2019). Major reforms to FERC market-based rate program include new data collection requirements. *Mondaq*. https://www.mondaq.com/unitedstates/Energy-and-Natural-Resources/835598/Major-Reforms-To-FERC-Market-Based-Rate-Program-Include-New-Data-Collection-Requirements

[38] For example, see Midcontinent Independent System Operator. (2020). *FERC electric tariff, Sections 64 and 65*. https://www.misoenergy.org/legal/tariff/. Also see FERC. (2014). *Price formation in organized wholesale electricity markets: Staff analysis of energy offer mitigation in RTO and ISO markets*. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf

future. Internationally, this is why the power sectors of many countries feature financial contracting. This includes contracts for difference (CfDs) in which contract participants agree to make up the difference between a contracted spot market price in a future period and the spot market price that actually emerges in that period. An important aspect of financial contracting is that the contracts do not directly affect short-term operational (dispatch) decisions; that is, the system operator dispatches according to economic dispatch principles, and the system operator is typically not even aware of the existence of most long-term contracts. This contrasts with physical contracts. For the purposes of the discussion in this paper, we will use the term "physical contracts" to mean contracts that (1) specify operating hours for a given period and (2) are referred to by system operators (dispatchers) as the system operators make hour-by-hour and day-by-day dispatch decisions.

Financial contracts harmonize well with spot markets and support efficient outcomes. An important and desirable function of financial contracting is to allow market participants to hedge against the risk of fluctuating short-term (spot) prices. For instance, hydropower output may vary significantly from year to year, and coal and natural gas prices fluctuate monthly and even daily. Meanwhile, electricity demand and wind and solar generation vary over timescales ranging from years to seconds. Longer-term contracting (whether for periods of many years or a single month) should be flexible and not interfere with real-time economic dispatch of all resources, given that the conditions that determine real-time economic dispatch (such as the exact level of demand or amount of unplanned generator outages that will emerge for a particular hour) are not known with certitude at the time of contract signing. It is worth repeating and emphasizing a key point: system reliability does *not* require physical contracts that allocate hours of operation months in advance. In fact, this kind of approach raises costs, lowers system efficiency and hampers integration of variable renewable generation.

The combination of a financial approach to contracts with spot markets can facilitate real-time economic dispatch — the least-cost operation of the electricity system — by incentivizing (1) suppliers to offer all of their available capacity into day-ahead and real-time energy markets at their marginal cost and (2) buyers to bid in their best estimate of forecasted demand that accurately reflects their willingness to pay.

In China, national policy statements on contracting[39] and Guangdong's market design rules[40] both emphasize that the existing physical approach to contracting (the aforementioned MLT contracts) will transition to financial CfDs. This transition from physical to financial contracts will help remove barriers to economic dispatch and support least-cost outcomes in the spot market. However, this transition will require more detailed policy and regulatory rules to facilitate rational contracting models and harmonization with the spot market. It may also require a change in

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[39] For example, see NEA. (2019). *Advancing electricity spot market implementation*. http://www.nea.gov.cn/2019-03/08/c_137878845.htm

[40] National Energy Board Southern Authority. (2018). Notice of the Southern Energy Regulatory Bureau, Guangdong Provincial Economic and Information Technology Commission, Guangdong Provincial Development and Reform Commission on soliciting opinions on the Southern (starting from Guangdong) electricity spot market series rules. South China Energy Regulatory Office of the National Energy Administration. http://nfj.nea.gov.cn/adminContent/initViewContent.do?pk=402881e56579be6301658d7123c2001a

industry mindset and practices.

Guangdong's MLT contract market (中长期交易市场) for thermal generation contracts includes annual bilateral contracts (双边协商交易) and annual and monthly auctions (集中竞争交易) for energy. In 2019, energy contracted through the MLT contract market accounted for 30% of total provincial electricity consumption and 46% of within-province generation.[41]

When the MLT markets began operation in 2016, Guangdong did not have a separate transmission and distribution (T&D) tariff.[42] MLT contracts were transacted as a reduction (or increase) in the catalogue (administratively set) retail price (目录电价) and the generation tariff (上网电价). This has been known as the price-difference model (价差模式).[43] Although the Guangdong Development and Reform Commission (DRC) has reportedly developed a separate T&D tariff, MLT contracts are still largely based on the price-difference model.

MLT contracts have typically been settled on a monthly basis, with deviations from contracted amounts calculated monthly and charged or credited using administratively set prices. During the October 2019 (weeklong) spot market trial, MLT contracts were ostensibly treated as CfDs. Contracted amounts were converted, for purposes of settlement only, from monthly to hourly quantities using disaggregation curves (分解曲线). Day-ahead schedules were determined using supply bids and dispatch center load forecasts. Deviations between the day-ahead schedules and actual generation and consumption were settled at real-time energy market prices.

In Guangdong's October spot market trial operation period (highlighted in Figure 2)[44], generators do not appear to have been bidding at marginal cost in the day-ahead and real-time energy markets. *Average* day-ahead clearing prices (251 yuan/MWh) and real-time market clearing prices (241 yuan/MWh) appear to have been at reasonable levels. In many hours, market prices were, however, at the price floor (70 yuan/MWh), which is below the operating costs of coal and natural gas units.[45] For instance, an efficient coal unit with a net heat rate (供电煤耗) of 300 kgce/MWh and delivered coal costs between 500 and 1,000 yuan/tce should have an operating cost range of at least 150 and 300 yuan/MWh.

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[41] Guangdong Power Exchange Center. (2019). *Guangdong 2019 annual electricity market report.* http://news.bjx.com.cn/html/20200227/1048396.shtml

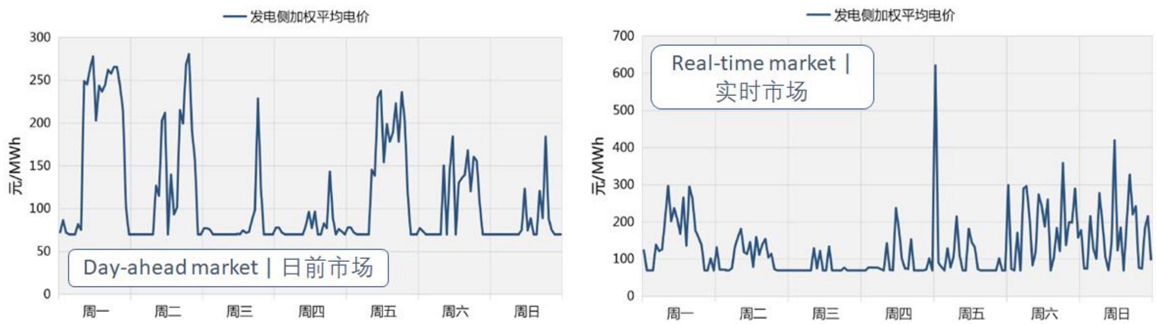
[42] The establishment of the Guangdong power exchange center in March 2016 marked the creation of a formalized GD MLT market. However, MLT-style contracts existed before this. The earliest power direct trading was in 2006 and was expanded in 2013-2014, just before the issuance of Document #9 in 2015, which gave a big push for market competition and formalization of the MLT market. See Chen, H., & Li, Z. (2016). *Correct understanding of Guangdong power market trading rules: The history and current situation of Guangdong power market*. http://shupeidian.bjx.com.cn/news/20161115/788876.shtml]

[43] This approach maintains the T&D tariff at current levels. For instance, a customer with a 0.65 yuan/kWh retail price and a generator with a 0.45 yuan/kWh generation tariff might negotiate a -0.05 yuan/kWh tariff reduction. The customer would pay the grid company 0.60 yuan/kWh, the grid company would pay the generator 0.40 yuan/kWh, and the grid company would still collect 0.20 yuan/kWh in T&D revenues.

[44] Guangdong Power Exchange Center, 2019.

[45] Guangdong Power Exchange Center, 2019.

Figure 2. Day-ahead and real-time market prices during Guangdong's October trial spot market operations



Source: Guangdong Power Exchange Center. (2019). *Guangdong 2019 annual electricity market report*. Note that figures show generation-weighted locational marginal hourly prices from Monday to Sunday; units are in yuan/MWh.

According to published interviews with market participants, generators that bid lower than operating cost in the October spot market trial cited two considerations: (1) their concerns over being shut down or decommitted ("staying on," 保开机), given the long start times for coal units and (2) concerns over losing operating hours ("maintaining hours," 保电量).[46] The latter is perhaps not surprising, given the historical links between generators' operating hours and profit and the short (one-week) time frame of the trial operation. Concerns about maintaining hours are at odds with the fundamental logic of electricity markets. A well-designed market gives each generator incentive to operate when it is economic to do so. Similarly, a well-designed market will discourage generators from simply maximizing operating hours or generation.

Generator behavior during the October 2019 trials illustrate the potential obstacles of transitioning from the historical approach to contracting, where generators expected that contracts would translate into physical operation, to financial contracts, where contracts and physical operations are disconnected. Looking forward, it is important that dispatch centers *not* dispatch according to MLT contracts. The 2018 regulations make reasonably clear that the dispatch centers are not supposed to do so, and indeed, the dispatch centers may very well be following the regulations. However, it may be that generators *perceive* or *expect* that MLT contracts are physical, perhaps due to details of contract terms and conditions. The NDRC developed a model contract (for national use) in May 2019 to provide a reference for the design of MLT contract terms and conditions. This model contract is designed for physical power transactions in a wholesale market that does not have spot market settlement, rather than settled through a physical spot market.[47] (The Guangdong Power Exchange reportedly has its own model contract, although it does not appear to be publicly

[46] Chen, X. (2019). *A shameful spot market pilot*. Caixin Global. https://m.weekly.caixin.com/m/2019-12-07/101491698.html

[47] The NDRC's model contract explicitly notes that "the basis for settlement between two contracted parties is physical metered energy." In the model contract, settlement is based on metered generation and consumption, contract deviations measured on a monthly or annual basis, and penalties for deviations determined by buyers and sellers in the contract. See NRDC. (2019). *Letter on encouraging use of Model MLT contract.*

available.)

In addition, power exchanges assess MLT contract markets in terms of contract completion rates (完成率), or the amount of electricity generated and consumed relative to what was initially contracted, and deviation rates (偏差率), or the difference between a buyer's contracted consumption and actual consumption. The use of contract completion rates risks giving market participants the misimpression that their contracts are physical rather than financial. The use of deviation rates risk giving loads the misimpression that they should seek to minimize deviations from disaggregated contract amounts to avoid penalties.

Transitioning existing contracts to CfDs with spot market settlement may not require significant changes in contract terms and conditions. The disaggregation curves provide an approach to translating contract quantities into hourly quantities for settlement, which can facilitate financial contracting as long as sellers and buyers understand that contract quantities are not physical, that is, are not tied to monthly or annual metered generation or load (see Example 1).

Example 1: Financial contracting using disaggregation curves

A buyer and seller clear a 4,000 MWh monthly contract for May through the Guangdong Power Exchange, with a clearing price of 350 yuan/MWh. The contract is disaggregated into on-peak and off-peak periods, with an eight-hour on-peak window and an on-peak/off-peak ratio of 2, which translates to 8.1 MWh/h on-peak and 4.0 MWh/h off-peak (8 hrs × 8.1 MWh/h + 16 hrs × 4.0 MWh/h = 129 MWh/day).

During the hour of 15:00 (on-peak) on May 10, the buyer has forecasted demand of 10 MWh/h in the day-ahead market and 11 MWh/h metered demand. Day-ahead and real-time (average hourly) market clearing prices are 250 yuan/MWh and 300 yuan/MWh, respectively. The seller (generator) had an above-market offer and is not committed in the day-ahead market on May 10.

The buyer pays the Power Exchange 2,800 yuan/h (= 250 yuan/MWh × 10 MWh/h + 300 yuan/MWh × 1 MWh/h). The Power Exchange does not make payments to the generator because it did not clear the market. The buyer pays the seller 806 yuan/h (= 8.1 MWh/h × [350 yuan/MWh – 250 yuan/MWh]).

The buyer's final settlement is 3,606 yuan/h (= 2,800 yuan/h + 806 yuan/h) or 328 yuan/MWh. The seller's final settlement is 806 yuan/h, which is also the seller's net income because the generator does not have operating costs.

After the May contract is finalized, then over the course of May, the buyer and seller should be agnostic as to whether the buyer actually consumes 4,000 MWh or the seller actually generates 4,000 MWh. The buyer will pay the seller 1.4 million yuan (= 350 yuan/MWh × 4,000 MWh) regardless. The CfD allows the buyer to manage the risk of high spot market prices and allows the seller to manage the risk of low spot market prices.

However, if sellers or buyers expect that contracts *are* physical, suppliers are likely to bid below marginal cost to ensure that they clear the market. If suppliers bid below cost, it will lead to uneconomic dispatch, with higher cost generators operating even though lower cost generation is available. When a large portion of suppliers offer at the offer floor (what is typically called self-scheduling in the U.S. context), the dispatch center may struggle to determine economic dispatch (i.e., determine the merit order). The dispatch center could rely on reference prices (as discussed in section 2c) to determine a reasonable merit order, but if those are not yet in place, the dispatch center may resort to administratively dispatching in a noneconomic manner. This kind of noneconomic self-scheduling of fossil-fuel-fired generation becomes a larger challenge as more variable renewable generation is added to the electricity system.

Even if MLT contracts are no longer physical *and* generators fully understand this, there may be other reasons for a disconnect between bids and marginal costs. In particular, generators may have motivations *other* than the profits that they may earn from the market. These nonmarket motivations could include the following:

- Generators have an incentive to consider their annual generation (in kWh) total because annual generation has been a key metric for evaluating generation companies (including by SASAC).[48] With the shift to spot markets and financial contracting, new financial metrics should supplant the use of annual generation as a proxy for profitability. This would help to remove an incentive for generators to bid below marginal cost.
- Local officials may encourage power plant managers to maximize hours of operation because hours of operation (or coal consumption) are relevant to GDP figures, and local officials are evaluated, in part, on GDP outcomes in their jurisdiction.

In addition, it may be useful to expand industry education and training that builds trust in the market. The spot market trials do not appear to have engendered this trust yet, and more significant efforts to build trust may be needed. It may be that the "maintaining hours" mentality of generators derives from lack of trust and expectation that the spot market pilot may disappear and that the industry may revert to historical pricing and dispatch practices. To cite a more specific possible issue: for coal units with relatively long start times, incentivizing economic bidding in the day-ahead market may require building trust in the accuracy of the unit commitment software.

Since the early 1990s, the Southern Grid region has had significant power exchange between provinces. Power exchange expanded and became more formalized in the early 2000s as part of the West-East Power Transfer (西电东送 | xidian dongsong) policy framework. These transfers are primarily exports from resource-rich Yunnan, Guizhou and Guangxi provinces to load centers in Guangdong, though Guangdong is also a net exporter to Hainan, Hong Kong and Macau. All of the power transfer from Yunnan to Guangdong is via direct current (DC) lines, whereas power transfer from Guizhou and Guangxi is through a mix of DC and alternating current (AC) lines.[49] In 2019, Guangdong had 39.4 GW of import capability and imported 30% of its total electricity consumption.[50]

National policy statements call for Guangdong's provincial spot market to be the first step in the

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[48] SASAC is responsible for evaluating the financial performance of state-owned generators, particularly its ability to earn return on equity. Since generators have traditionally covered both fixed and variable costs from a per-kWh on-grid tariff that is set annually, SASAC focused on annual generation output as a key metric.

[49] Guangdong had five DC interconnections with Yunnan, eight AC and three DC interconnection with Guizhou and Guangxi, and one DC connection with State Grid in 2019. Guangdong Power Exchange Center, 2019.

[50] Guangdong Power Exchange Center, 2019.

development of a regional electricity market covering the Southern Grid region. Now that Guangdong's spot market is preparing to move past the trial stage and commence official operations, government agencies, the trading organization and market participants are considering how to deepen existing interprovincial coordination, how to design a Southern Grid regional market and how to transition from the Guangdong spot market to this regional market design. This is an important set of issues and promises significant benefits for the region, including reduced costs and emissions for the region as a whole. One of the most important potential near-term benefits of a regional Southern Grid market will be in using spot market prices to optimize regional operations, particularly with relation to seasonal hydropower patterns. Over the longer term, a regional market will also be crucial in balancing higher penetrations of wind and solar energy across a broad geographic footprint.

Drawing on the perspective of U.S. experience with regional markets, a good way of framing the goal for the Southern Grid region is to aim for the establishment of a regional transmission organization (RTO).[51] Following the pattern of U.S. RTOs, a Southern Grid RTO would be designed with several features, including:

- A unified and efficient approach to transmission cost allocation for the region, with a single set of regional rules for allocating the cost of existing and new transmission infrastructure across provinces throughout the region.
- A unified regional transmission planning process that identifies transmission investments that are needed for reliability and economics and to meet policy goals.
- A single regional system operator and market operator overseeing a single regional spot market that, consistent with Guangdong's spot market design, would have:
    - Financially binding, nodal day-ahead energy markets with security-constrained unit commitment.
    - Nodal real-time energy markets with five-minute security-constrained economic dispatch and settlement.
    - Markets for frequency regulation (secondary control) and operating (tertiary control) reserves that are co-optimized with day-ahead and real-time energy procurement.
    - Operating timelines and markets that enable market-to-market coordination with State Grid Company markets to the north.

This RTO-style approach would have several significant benefits for the Southern Grid region. Unified Southern Grid RTO energy and AS markets would extend across the Southern Grid region, meaning that, when there is no congestion on the transmission system, the entire region would have a single day-ahead and real-time energy market price, with only minor differences in price due to marginal transmission losses. Nodal market prices and regional transmission planning would help to guide new resource development throughout the region and help to integrate renewable

[51] In the U.S., the terms "RTO" and "ISO" are now used virtually synonymously to refer to regional market footprints.

energy, leading to lower long-run costs. The RTO approach would also alleviate barriers to cross-provincial trading associated with China's current approaches to interprovincial transmission pricing and interprovincial trade. Many studies in the U.S. context have found substantial benefits associated with RTO markets in comparison to smaller balancing areas.[52]

In a transition to an RTO, the Southern Grid region faces two questions: (1) In the immediate near term (2020-2021), how can generators in other provinces more actively participate in Guangdong's spot market without expanding the market institutions and software to other provinces? (2) In the coming years, how can the China Southern Grid region establish unified regional institutions and implement a full RTO?

A Southern Grid RTO would feature unified regional economic dispatch and a regional decision-making approach to new transmission additions. Although implementation of a Southern Grid RTO would produce substantial net benefits overall,[53] this will nevertheless have different effects on producers and consumers in different provinces within the region. Existing generation and transmission tariffs and retail tariffs in China were often designed to reflect regional development priorities, suggesting that moving toward an efficient regional market could lead to significant transfers. Anticipating and potentially mitigating these transfers may be something that policymakers should consider, but transfers are best addressed ex-post through out-of-market mechanisms rather than through the market. A regional market will reveal some generation units as uneconomic. It is best to let these units retire as soon as possible (in an orderly fashion, subject to reasonable reliability considerations). Any compensation offered to these generation units that retire before the end of their normal accounting life should be offered in a way that does *not* prolong the operational life of the generation unit. For example, it would be much better to provide a compensation payment to the owner after retirement, rather than compensating the owner by allowing an uneconomic generator to continue to operate.

Allocation of the Cost of Regional Transmission Infrastructure

One of the important and beneficial facets of a transition to a Southern Grid RTO would be changes to who pays for regional transmission infrastructure and changes to how the charges are designed. Currently, importing provinces pay a yuan/kWh transmission price for each kWh imported, and this transmission price is intended to cover the full cost (or most of the cost) of interprovincial transmission lines. This approach does not reflect the underlying costs of transmission utilization and creates a barrier to beneficial electricity trade among provinces. It also acts as a barrier to dispatching the entire regional grid on economic dispatch principles.

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52 Hurlbut et al., 2015. For a summary of several studies on this topic, see Pfeifenberger, J., Chang, J., & Oates, D. L. (2016). *Senate Bill 350 Study, Volume XII: Review of existing regional market impact studies*. California ISO. https://www.caiso.com/Documents/SB350Study-Volume12ReviewofExistingStudies.pdf

53 Abhyankar, N., Lin, J., Liu, X., & Sifuentes, F. (2020). Economic and environmental benefits of market-based power-system reform in China: A case study of the Southern Grid system. *Resources, Conservation and Recycling, 153*. https://www.sciencedirect.com/science/article/pii/S0921344919304641

Consider the case of a particular hour or day where (1) hydro generation capacity is available in Yunnan at an operating cost that is below that of thermal generation capacity located in Guangdong and (2) ample transmission capacity is available to facilitate increased power flows from Yunnan and Guangdong. In this case, reducing production from the Guangdong thermal generators in favor of the Yunnan hydro generators would provide positive net benefits (i.e., cost savings) for the region. However, the per-kWh transmission charge can make the import of Yunnan power *appear* more expensive than that of the thermal power, even when there is plenty of transmission capacity available. This misrepresentation of the hydro generation import cost can cause the costly thermal generators to be dispatched and hydro generation to be curtailed, even though the principle of regional economic dispatch indicates that, in this case, the thermal generators should not be dispatched and the hydro generation should not be curtailed.[54] The central problem is that it is inefficient to recover full interprovincial transmission costs on the basis of a price for each kWh transmitted. The full cost of interprovincial transmission should be recovered in another way that avoids discouraging the use of transmission capacity when it is available.[55]

An RTO-style approach would involve:

- Recognizing regional transmission as beneficial to the RTO region as a whole.[56]
- Allocating these regional transmission costs to *all* provincial grid companies (and ultimately to all demand) in the RTO region on a monthly or annual basis (as opposed to a per-kWh transaction basis).[57]

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[54] Curtailment would happen, for example, if the hydro facility is run-of-river or if it has a reservoir that is already at capacity and must be spilled. In cases where the reservoir is not at capacity, the misrepresentation of costs that the text describes may not cause curtailment but can cause hydro to be operated inefficiently.

[55] Managing transmission congestion is a related consideration. Often, transmission capacity is limited or congested. It is economically rational to implement transmission congestion pricing on a per-kWh transaction basis, but revenue from this economically rational congestion pricing will not typically be sufficient to recover all transmission costs. See Madrigal, M., & Stoft, S. (2011). *Transmission expansion for renewable energy scale-up: Emerging lessons and recommendations.* World Bank Group. https://www.esmap.org/sites/default/files/esmap-files/Transmission-Expansion-and-RE_0.pdf

[56] To be slightly more specific, the RTO-style approach would classify transmission assets within the RTO as either deep assets that benefit the whole region or shallow assets that benefit specific beneficiaries. Most interprovincial assets would likely be deep. In this discussion, we consider regional transmission assets to be deep. See Madrigal & Stoft, 2011.

[57] FERC. (2011). Transmission planning and cost allocation by transmission owning and operating public utilities (Order 1000). https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf. For additional discussion, see Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (Ed.). (2020). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

Government agencies would then work together with RTO management to establish rules to allocate regional transmission costs to provincial transmission companies. Each provincial transmission company would receive a monthly allocation. This could be calculated on the basis of the company's coincident peak (MW) consumption in each month. It could also be done on the basis of the company's monthly total energy (MWh) consumption (i.e., total energy consumption from any source, regardless of where in the Southern Grid region the source is located).[58] In this way, the allocation of regional transmission costs would no longer be done in a way that obscures the relative operating costs of different generation resources located in different provinces. This would mean that allocation and recovery of transmission costs would now be separate from the economic dispatch of the regional grid.

Under this RTO-style approach, regional transmission costs would be incorporated into the allowed transmission cost (transmission revenue requirement) of each provincial grid company. These costs would then be recouped in the transmission and distribution prices that the provincial grid company applies to all customers. Provincial governments could continue to have the responsibility for setting and designing these transmission and distribution prices with central government approval, as is currently the case.[59]

Example 2: Transmission pricing and incremental costs

Consider a situation where the marginal cost of generation in Guangdong is 350 yuan/MWh, Yunnan has available hydropower and there is 200 MW of unused interprovincial transmission capacity available. The hydropower facility is willing to sell at a price greater than 260 yuan/MWh. Following the current approach in China of allocating regional transmission costs to a uniform (non-time-varying) per-kWh charge imported, the transmission charge is 100 yuan/MWh.

If a transaction to import Yunnan hydropower into Guangdong must pay the 100 yuan/MWh transmission charge, the transaction will be uneconomic from the point of view of the parties to the transaction (260 yuan/MWh + 100 yuan/MWh > 350 yuan/MWh) and will not be transacted. The incremental cost of supplying the 200 MW that could have been imported from Yunnan will be 70,000 yuan/h (= 200 MW × 350 yuan/MWh).

However, if the transaction is not charged for transmission (or is charged less than 90 yuan/MWh), the transaction will be economic (260 yuan/MWh < 350 yuan/MWh). The incremental cost of supplying the 200 MW will be 52,000 yuan/h.

The scenario where the transaction is not charged for transmission will lower total system costs by 18,000 yuan/h. The 20,000 yuan/h (= 200 MW × 100 yuan/MWh) difference in transmission revenues can be recovered through an alternative annual allocation to provincial grid companies (which would in turn be passed on to end users), as described in the main text.

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58 There may be political reasons to negotiate different monthly burdens (i.e., responsibilities for the fraction of interprovincial transmission costs) across the provincial grid companies than the burdens that would be derived from these rules. Again, the key point is that this should not be calculated based on the level of kWhs imported in the month in question.

59 There are many considerations for efficient design of these retail prices, but that subject is beyond the scope of this paper. See, for example, Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Next Steps Toward Regional Market Expansion

Among U.S. RTO markets, the California Independent System Operator (CAISO) provides a reference point worth considering for the Southern Grid region in terms of issues around the transition to an RTO. The CAISO has historically been the only ISO/RTO market in the western U.S. Meanwhile, neighboring regions in the western U.S. have been a patchwork of relatively small balancing areas, most of which are separately operated and planned by vertically integrated electric utilities. In order to start capturing the efficiency gains associated with better regional integration and to build confidence and trust among the region's utilities, CAISO and several of these utilities have taken steps in the direction of what may ultimately become an RTO for the western U.S.

In 2014, as a first step, CAISO began expanding its real-time market to utilities in neighboring regions, creating a structure known as the energy imbalance market (EIM). The Western EIM is voluntary, meaning that utilities could join or leave at any time and can select the units that they wish to allow the CAISO to dispatch. The CAISO only uses available transmission capacity for dispatch, and utilities still have responsibility for hour-ahead scheduling and procuring and deploying reserves. From the first two participants in 2014, the Western EIM has grown to nine members and is expected to add 11 more members by 2022.[60] The region is now discussing a similar expansion of CAISO's day-ahead market to the region. Although these steps have fallen short of unlocking the benefits of a full RTO, they have moved the region in that direction and significantly improved the efficiency of regional system operation. The EIM can be viewed as an initial step in the creation of a more comprehensive regional market.

In the western United States, before implementation of EIM, a persistent divergence between CAISO market prices and prices at regional bilateral trading hubs outside the CAISO (Figure 3)[61] provided a clear indication of inefficiencies. Rising amounts of variable renewable generation throughout the western United States threatened to make the regional inefficiencies worse and bolstered the rationale for implementing an EIM and eventually a western RTO.[62]

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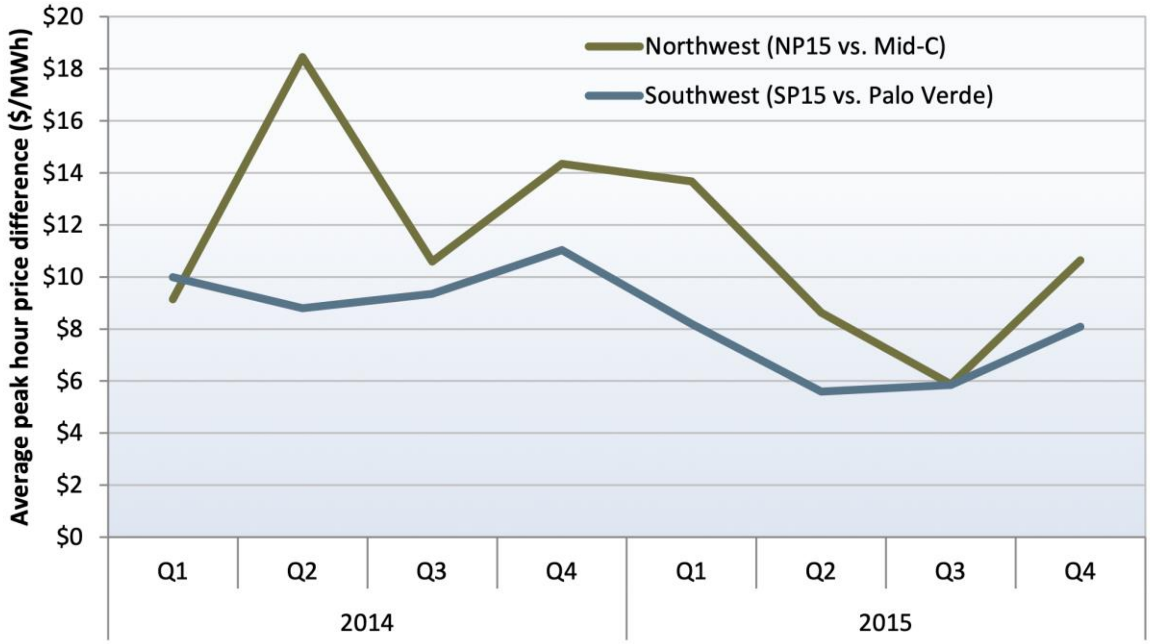
[60] For more on the Western EIM, see Western Energy Imbalance Market (https://www.westerneim.com/pages/default.aspx).

[61] CAISO. (2016). *2015 Annual Report on Market Issues & Performance*.
https://caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

[62] Energy and Environmental Economics. (2013). *PacifiCorp-ISO energy imbalance market benefits*.
https://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

Figure 3. Average peak hour price differences between CAISO Market (NP15 Zone) and Northwestern U.S. Trading Hub (Mid-C) and CAISO Market (SP-15 Zone) and Southwest U.S. Trading Hub (SP15 Zone), 2014-2015



Source: CAISO. (2016). *2015 Annual Report on Market Issues & Performance*.[63]

For the Southern Grid, this incremental strategy may also be an effective way to transition to a regional market. Under an EIM-like structure, a regional dispatch center would extend Guangdong's real-time energy market dispatch software to the entire region, ideally but not necessarily extending the full network model and nodal prices to the entire region. China Southern Grid would be the EIM system operator. Scheduling coordinators in other provinces would submit day-ahead and hour-ahead schedules and economic offers to the regional dispatch center, and the regional dispatch center would dispatch units across the Southern Grid region based on these schedules and offers. An EIM could be compatible with one or more provincial day-ahead markets, if scheduling is well coordinated. Although an EIM is limited to real-time dispatch and available transmission capacity, EIM prices can provide signals for market participants to improve their day-ahead and hour-ahead scheduling practices and can be a bridge to regional security-constrained unit commitment in a regional day-ahead market. For instance, in the Western EIM in the U.S., participants have changed their unit commitment practices to take better advantage of low-cost solar generation in California during the middle of the day.[64]

The advantage of using an EIM as a next step would be to build confidence in the benefits of a

[63] Figure 3 is licensed with permission from the California ISO. Any statements, conclusions, summaries or other commentaries expressed herein do not reflect the opinions or endorsement of the California ISO.

[64] Based on personal communication with EIM participants.

regional market. The Western EIM required approximately two years to establish, including time for extending the CAISO's modeling software, development and documentation of rules and training for market participants.[65]

Additional Considerations for a Southern Grid RTO

Regional transmission planning. Interprovincial transmission planning in the Southern Grid region is already done by a regional organization: the China Southern Grid Company. In a market environment, the transmission planning process will, however, need to become more open and transparent to provide market participants with information so that they can make rational decisions regarding investments in generation and other resources. Additionally, as a regional market takes shape and as the region's resource mix changes, transmission planning methods will need to adapt. Potential changes include the changing economics of the transmission network; implications of variable generation for transmission economics, including the role of LMPs in efficient siting; and the importance of LMPs for congestion management.

Coordination with other markets. Coordination among ISO/RTO markets has been a weakness in the U.S. For the Southern, Central, Northwest and Eastern Grids in China, it will be important to have a basic, coordinated common market design among regional markets, joint transmission planning and cost allocation and coordinated operations. Although designs can evolve over time, U.S. experience suggests that it is important to begin thinking about market-to-market coordination issues early in the process of RTO development.

Toward a Southern Grid RTO: Summing Up

To recap, we suggest that creating a Southern Grid regional transmission organization is the best approach to the national government's requirement that the Southern Grid create a regional spot market, starting with Guangdong. A Southern Grid RTO would include:

- A unified regional set of rules for allocating regional transmission costs to provincial grid companies across the region.
- An approach to transmission charges that does not obscures the relative operating costs of different generation resources located in different provinces.
- A unified regional transmission planning process that identifies transmission investments that are needed for reliability and economics and to meet policy goals.
- A single regional system operator and market operator overseeing a single regional spot market.

A regional RTO would bring many benefits and ameliorate long-standing problems in the region. To move toward formation of a Southern Grid RTO, there are several worthwhile interim measures

[65] Initial discussions between the CAISO and PacifiCorp on the EIM began in late 2012. In March 2013, the CAISO and PacifiCorp released a study on the potential benefits and costs of an EIM. The EIM became operational in November 2014.

that may be somewhat easier to implement, could capture some (but not all) of the benefits of regional integration and can serve as stepping-stones to a full RTO. In addition, several of the foundations needed for an RTO require nearer-term steps.

We have several suggestions for possible interim measures and interim steps to consider:

- Develop rules for allocating regional transmission costs to provincial grid companies (not on an import-export transaction basis) across the region.
- Once the Guangdong spot market is fully operational, begin to develop the software upgrades and market rule changes to enable Guangdong's real-time energy market to be extended to other provinces in the Southern Grid region. The real-time market could be extended even if other RTO functions are not yet in place.
- Begin considering the design of a regional day-ahead market, including unit commitment processes, AS procurement and other market rules.
- Develop an open and transparent transmission planning process that supports investment decision-making by resources and loads and incorporates economic evaluation of transmission projects. This planning process would include publicly available planning criteria (reliability, economic, policy) that guide transmission investment decisions. U.S. RTO transmission plans may be a useful reference, although U.S. transmission planning and investment practices have many shortcomings and are continuing to evolve.[66]
- Begin to develop the governance structures and dispute resolution mechanisms needed to facilitate and sustain a regional market.

We note that a 2020 policy statement from NDRC calls for unified national trading systems by 2025, focusing on the role of the trading organizations.[67] We suggest that an additional policy statement regarding regional unified spot market formation would be useful, specifying roles and time lines not only for the trading organizations but also roles and time lines for dispatch organizations and regional officials — and specifying how they must all work together in these tasks. This would help smooth the road to a Southern Grid RTO.

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[66] See, for example, ISO New England (n.d.) *Regional system plan*. https://www.iso-ne.com/system-planning/system-plans-studies/rsp/. See also Pfeifenberger, J., & Chang, J. (2016*). Well-planned electric transmission saves customer costs: Improved transmission planning is key to the transition to a carbon-constrained future*. The Brattle Group. https://hepg.hks.harvard.edu/files/hepg/files/wires_brattle_report_transmissionplanning_june2016.pdf; and Eto, J. (2017). *Planning electric transmission lines: A review of recent regional transmission plans*. Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory. https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf

[67] NDRC & NEA (2020). *Notice on pushing independent operation of power exchange centers*. https://www.ndrc.gov.cn/xxgk/zcfb/tz/202002/t20200224_1221078.html

3. Conclusion

This paper has discussed the design and implementation of electricity markets in the context of a broader power sector reform effort, with the assumption that this effort is being undertaken to support the goals of an energy revolution, cost reduction, emission reduction, integration of VRE resources and reliability (as set out in various policy statements). These are challenges that policymakers around the world are also facing. The Southern Grid region has made great strides — including in the design of Guangdong's spot market pilot — and has the potential to become a model for the country and the world in these areas.

Market design in the Southern Grid region will undoubtedly be an ongoing process of debate and revision to market rules, as it has been in other countries. In international discussion, it has been clear that the best way to view markets is to consider them as tools that should be designed to meet government policy objectives, including goals for efficiency, emissions reductions and reliability. When markets are not delivering outcomes in line with policy objectives, it is necessary to modify the market rules and regulations. Markets cannot meet these goals alone, and they need to be closely coordinated with various planning processes — including planning processes for transmission and demand-side resources.

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