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Issues in China Power Sector Reform: Generator Dispatch

Discussion Paper

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Acronyms

CFD	Contracts for differences
CO_2	Carbon dioxide
FIT	Feed-in tariff
kW	Kilowatt
kWh	Kilowatt-hour
MEP	Ministry of Environmental Protection
MW	Megawatt
MWh	Megawatt-hour
NEA	National Energy Administration
NDRC	National Development and Reform Commission
NO_x	Nitrogen oxides
PM	Particulate matter
SERC	State Electricity Regulatory Commission
SO_2	Sulfur dioxide

Introduction[1]

Generator dispatch has been a major obstacle to meeting China's clean energy, air quality, and economic goals. In most provinces, grid companies dispatch power plants to enable each generator to achieve its annually allocated number of operating hours. This is very different from the rest of the world. In many other countries, system operators typically seek to minimize short-run costs, ideally including the social cost of emissions, based on a "merit order" approach.[2] No other major country has annual planning of generator hours.

There are four main reasons why dispatch reform is crucial to meeting China's power sector goals. The current approach to dispatch:

- Is a major reason for current high levels of curtailment of wind, solar, and hydroelectric energy and is an obstacle to integrating higher penetrations of wind and solar energy onto the grid;
- Results in more frequent use of less efficient coal-fired power plants, even when more efficient ones are available, resulting in excessive fuel use and higher emissions;
- Distorts investment decisions, contributing to over-investment in (typically coal-fired) baseload power plants and under-investment in peaking capacity and more flexible power plants (particularly natural gas);
- Lowers efficiency of emission control equipment, causing more air pollution, especially nitrogen oxides (NO_x), a precursor to ambient ozone and fine particulates ($PM_{2.5}$).

In short, the provision of electricity services in China is both more expensive and environmentally damaging than it would be with merit order dispatch.

Recent policy pronouncements regarding electricity reforms represent a major step forward in improving dispatch. However, there are still a number of important questions that have yet to be addressed. This paper is intended for policymakers, to help them frame the issues and develop workable solutions to them. We start with a review of the historical context for dispatch in China, then take a look at how dispatch has been treated in recent policies and reform proposals, and finish by identifying key gaps, remaining questions, and potential near-term strategies for reforming dispatch.

We highlight issues in four areas that need to be addressed as China transitions toward more efficient dispatch: (1) generator compensation, (2) dispatch order determination, (3) reconciliation of "planned," "priority," and "market" generation, and (4) the political economy of cross-provincial exchange. We argue that, regardless of how rapidly wholesale markets are developed and what form they take, in the

[1] Friedrich Kahrl of Energy + Environmental Economics (E3) and RAP and Max Dupuy and Wang Xuan of RAP authored this paper.

[2] Several RAP reports are available on this subject, in both English and Chinese, including our recommendations regarding dispatch reform in the context of China's overall power sector challenges, our technical primer on system operations in China, and a survey of relevant international experience.

near term China's policymakers should seek to move toward a merit order approach to dispatch in all provinces.

Historical Context

During much of China's modern history the benefits of merit order dispatch were not immediately obvious. Many provinces were chronically short of power in all hours of the year; most provinces only had two generation resources—coal and hydropower—and coal generator output was scheduled around expected hydropower output; and differences in efficiency among coal generators were relatively small.

In an effort to ensure adequate investment in new generation, the government set tariffs for thermal generators on a yuan-per-kilowatt-hour (kWh) basis, given an assumed minimum number of operating hours. In this way, their investment cost recovery was tied directly to their kWh output, which gave them a strong incentive to minimize unplanned outages. To ensure that all thermal generators had a fair chance at earning their return on investment, operating hours were allocated evenly across all generators of a given type through an annual planning process.

In the 2000s, new generation resources came online—nuclear, wind, natural gas—and new coal plants yielded significant efficiency improvements. As these shifts occurred, the shortcomings of the planned approach to dispatch became clearer. For instance, efficient coal generating units were being operated a similar number of hours as older, less efficient ones. Electricity reforms launched in 2002 attempted to address these shortcomings, but reform pilots were discontinued and reforms were put on hold, partly in response to a surge in electricity demand growth.

The next attempt to reform generator dispatch was through a generation rights trading (发电权交易) system which began in Jiangsu in 2006 and then expanded to other provinces. This system allowed more efficient generators to purchase dispatch "rights" from less efficient generators. Generator rights trading has had some success in improving dispatch of thermal generators, but has been limited in scope (to thermal generation) and scale (as a share of total thermal generation).[3] In 2007, the National Development and Reform Commission (NDRC), State Electricity Regulatory Commission (SERC), and Ministry of Environmental Protection (MEP) began piloting an alternative approach—"energy-efficient" dispatch (节能调度) based on a preset dispatch order—in five provinces. In 2010, energy-efficient dispatch was expanded to cover the remaining provinces within the Southern Grid region. Although it is still the basis for dispatch in pilot provinces, the extent to which energy-efficient dispatch has been fully implemented varies among these provinces, and it has not been extended nationwide as originally envisioned.

[3] Between 2007 and 2011, for instance, the volume of traded power was equivalent to between 2% and 5% of total thermal generation. See Kahrl, F., & Wang, X. (2014). *Integrating Renewable Energy Into Power Systems in China: A Technical Primer—Power System Operations*. Beijing: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/document/download/id/7459

In 2007, the NDRC also issued a requirement that grid companies purchase all output from renewable energy resources, subject to grid security constraints.[4] This policy applied to all provinces, regardless of dispatch system. That wind and solar curtailment rates remain high suggests that this policy has had limited success.

Across these different reform strategies, the primary obstacle for dispatch reforms has been generator compensation—how to reconcile the revenue realignment between generators that will operate more and those that will operate less under a more efficient system of dispatch.

Recent Policy and Reform Announcements

In recent months, there have been a number of major policy and legislative announcements signaling strong intent and political will to reform dispatch. These include:

- Document 9, *Opinions on Deepening Electricity Reforms* (关于进一步深化电力体制改革的若干意见; March 2015), which stipulates that:
  - "Very low emissions units should generate more electricity through direct trading and scientific dispatch." (Article 5)[5]
- Document 518, *Improving Operation and Utilization of Clean Energy* (关于改善电力运行调节促进清洁能源多发满发的指导意见; March 2015), which stipulates that:
  - In preparing annual provincial electricity balance plans (年度电力电量平衡方案), provincial planning agencies should "implement the mandatory renewable procurement system, ensuring procurement of all renewable energy within grid security constraints" (Article 1), and "establish a principle that all new demand should be met with either within-province or imported clean energy, rewarding coal generators that balance clean energy." (Article 3)[6]
  - In their annual plans for cross-border import-export schedules (年度跨省区送受电计划), State Grid and Southern Grid should "increase transmission capacity utilization, increase grid flexibility, plan for both clean energy and supporting generation, prioritize clean

[4] *Regulatory Measures for Grid Company Mandatory Procurement of Renewable Energy* (电网企业全额收购可再生能源电量监管办法). Retrieved from http://www.gov.cn/flfg/2007-08/01/content_702636.htm

[5] "超低排放机组通过直接交易和科学调度多发电." See http://www.ne21.com/news/show-64828.html

[6] "各省（区、市）政府主管部门组织编制本地区年度电力电量平衡方案时，应采取措施落实可再生能源发电全额保障性收购制度，在保障电网安全稳定的前提下，全额安排可再生能源发电," and "各省（区、市）政府主管部门在统筹平衡年度电力电量时，新增用电需求原则上优先用于安排清洁能源发电和消纳区外清洁能源，以及奖励为保障清洁能源多发满发而调峰的煤电机组发电." See http://www.sdpc.gov.cn/gzdt/201503/t20150323_668207.html

energy in cross-border power exchange, and clarify clean energy's share of that exchange." (Article 6)[7]

- The revised Air Law (大气污染防治法; August 2015), which requires that, "Clean energy be given priority in electricity dispatch." (Article 42)[8]
- The US-China Joint Presidential Statement on Climate Change, issued in September 2015, in which China commits to "promote green power dispatch, giving priority, in distribution and dispatching, to renewable power generation and fossil fuel power generation of higher efficiency and lower emission levels."[9]
- Document 2554, *Pilots for Local Consumption of Renewable Energy* (关于可再生能源就近消纳试点的意见; October 2015), calls for the creation of a system of generation priority rights for renewable generators and a compensation mechanism for coal-fired generators that balances renewable energy (Article 3).[10] The pilots will be established in Gansu and Inner Mongolia, which both have large amounts of renewable resources and investment.
- Document 2752, *Notice on Supporting Electricity Reform Documents* (关于印发电力体制改革配套文件的通知; November 2015), describes how a system of priority dispatch for clean energy should be implemented (Attachments 2 and 4 of Document 2752), launches provincial pilots for wholesale generation markets (Attachment 2), and provides instructions for how non-pilot provinces should gradually transition from planned operating hours to a more market-based approach (Attachment 4).[11]
- Document 625, *Measures for Guaranteed Full Purchase of Renewable Energy Allocation* (可再生能源发电全额保障性收购管理办法，发改能源 [2016] 625 号; March 2016), again emphasizes generation priority rights for renewable generators and outlines new compensation for curtailment.

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[7] "政府主管部门在组织国家电网公司、南方电网公司制定年度跨省区送受电计划时，应切实贯彻国家能源战略和政策，充分利用现有输电通道，增加电网调度灵活性，统筹考虑配套电源和清洁能源，优先安排清洁能源送出并明确送电比例，提高输电的稳定性和安全性. " See http://www.sdpc.gov.cn/gzdt/201503/t20150323_668207.html

[8] "电力调度应当优先安排清洁能源发电上网." See http://news.xinhuanet.com/legal/2015-08/30/c_128180129.htm

[9] See: Dupuy, M. (2015, September 25). *Obama-Xi Joint Presidential Statement on Climate Change Promises Much-Needed Reform of Generator Dispatch in China* [Blog post]. Beijing: Regulatory Assistance Project. Retrieved from http://www.raponline.org/featured-work/obama-xi-joint-presidential-statement-on-climate-change-promises-much-needed-reform-of-generator-dispatch-in

[10] "**通**过**建立**优**先**发电权，**提出可再生能源**发电**的年度安排原**则，实**施**优**先**发电权**交易**，**并在**调**度中落**实，**努力**实现规**划内的可再生能源全**额**保障性收**购。**建立利益**补偿**机制**，**鼓励燃煤**发电对**可再生能源**发电进**行**调节." See http://www.ndrc.gov.cn/fzgggz/jjyx/zhdt/201510/W020151019538057210325.pdf

[11] Attachment 2 is titled *Opinions on Advancing the Creation of Electricity Markets (*关于推进电力市场建设的实施意见); Attachment 4 is titled *Opinions on Implementing an Orderly Liberalization of Electricity Generation and Consumption Planning* (关于有序放开发用电计划的实施意见). Both documents are available at http://www.sdpc.gov.cn/zcfb/zcfbtz/201511/t20151130_760016.html.

In sum, these documents mandate priority dispatch for clean generation, create institutions to prioritize dispatch for clean generation, and encourage grid companies to dispatch more efficient and lower emissions thermal generators before less efficient ones. None of these policies are entirely new; they follow earlier efforts that were never fully implemented or enforced. For instance, as described in the previous section, China has had a regulation requiring mandatory purchase of renewable energy since 2007.

There are, however, significant new elements in the current round of electricity reforms. In particular, the creation of wholesale markets, on a larger scale in market pilot provinces and on a smaller scale in "non-pilot" provinces, will represent a significant change in China's electricity sector. Market pilot provinces will be granted some degree of latitude in developing market designs, but will need to hew to a basic standardized format. This basic format, proposed by the National Energy Administration (NEA) in December 2015, includes longer-term forward markets and a short-term energy balancing mechanism (e.g., a spot market).[12]

Provinces that are not participating in market pilots are expected to more gradually introduce competition in generation and scale back generator operating-hour planning through direct access programs.[13] Generators that are approved to participate in these programs can sign contracts directly with eligible industrial customers, with contracted output no longer counted in the operating-hour planning process. In these provinces, the share of competitively procured generation is expected to increase gradually over time, eventually expanding to fully competitive generation and retail segments.

Both the market pilot and non-pilot provinces are required to implement a system of "priority procurement and generation" (优先购电发电). On the procurement side, this system is intended to guarantee reliable electricity service to "public interest" (公益性) customers, including critical service facilities (e.g., hospitals) but also including residential users. Priority customers are to be served by non-market generation.[14] On the generation side, this system is intended to ensure priority dispatch for clean energy, dispatchable generation needed for reliability, and combined heat and power for heating needs. For clean power, priority dispatch only applies to generation that is built "within plan" (规划内); clean energy that is procured through bilateral contracts is considered outside of plan. How this system of priority procurement and generation will be implemented remains an open question.

[12] For more, see: National Energy Administration. (2015, December). *Basic Rules for Electricity Market Operations* (电力市场运营基本规则). Retrieved from http://zfxxgk.nea.gov.cn/auto92/201512/t20151201_1989.htm

[13] Whereas market pilots are governed by Attachment 2 of Document 2752, non-pilot provinces are governed by Attachment 4.

[14] Attachment 4 of Document 2752 states: "Capacity and energy for priority procurement will be provided by all 'public use' generators, with retail and on-grid prices set by the government" (优先购 电对应的电力电量由所有公用发电机组共同承担，相应的销售电 价、上网电价均执行政府定价). It does not define which generators are "public use." We assume that this includes all central-scale generation that is not privately contracted.

Key Gaps, Remaining Questions, and Potential Near-Term Strategies for Dispatch Reform

The policy pronouncements and proposed reforms leave a number of questions related to dispatch reform unanswered. In particular, moving toward economic (and lower-emission) dispatch will require addressing four interrelated questions:

- How should generator compensation issues be addressed?
- How should dispatch order be determined?
- How can "planned" and "market" generation be reconciled in dispatch?
- How can cross-border power exchange be efficiently increased?

The focus of these questions will be different in provinces that are selected to participate in market pilots and those that are not, but they are relevant in both contexts.

How Should Generator Compensation Issues Be Addressed?

Generator compensation has been a longstanding obstacle to dispatch reform in China, and changing compensation mechanisms, for coal generators in particular, is likely to be a precondition for more efficient dispatch.[15] Coal generators in China are compensated under a fixed yuan-per-kWh tariff, benchmarked against the cost of an efficient new unit. Because generator profits (or losses) are based on how much they generate, there is a strong incentive for generators to oppose reductions in operating hours that might accompany dispatch reforms.

The political and economic context for reforming generator compensation is now shifting, in light of growing overcapacity in coal-fired generation. This overcapacity stems from continued weaknesses in China's electricity planning and generation approval processes and sharply falling growth in electricity demand.[16] Approval is not closely tied to any resource adequacy planning process on a provincial or national level, and investments in new generation resources are often made without reference to whether the resource is actually needed for resource adequacy. Slowing demand growth is not being reflected in investment decisions and more coal-fired capacity is being built than is needed for reliability purposes. Given planned generator operating hours, growing overcapacity in coal-fired generation increasingly puts downward pressure on operating hours for *all* generation.

An important challenge is devising an approach to generation compensation that 1) supports dispatch reforms; 2) compensates generators that are needed for reliability; 3) encourages those generators that are *not* needed to shut down; and 4) sends the right signals for new investment in flexible resources

[15] See, for instance, Kahrl, F., Williams, J.H., & Hu, J. (2013). The Political Economy of Electricity Dispatch Reform in China. *Energy Policy*, 53, 361-369.

[16] Kahrl, F. (2016, February). *Coal-Fired Generation Overcapacity in China*. Beijing: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/document/download/id/8038

such as gas-fired generation and energy storage. Meeting all of these challenges will not be possible without concurrent reform of China's electricity planning and generation approval processes.

Reform documents to date do not clearly deal with coal generator opposition to dispatch reforms. Priority dispatch for clean energy will put further downward pressure on operating hours for coal-fired generators. Documents 518 and 2554 indicate that coal generators should be compensated for balancing renewable energy, but do not specify the scope of compensation (e.g., variable cost impacts only or also opportunity costs) or how they should be compensated. Document 9 calls for dispatch priority for more efficient and lower-emission thermal generation. However, none of the documents specify how this should be achieved for "non-market" generators.

Provinces that <u>are not</u> participating in market pilots. Proposed reforms have thus far not addressed the realignment of revenues and profits across generators that will occur under a shift to more efficient dispatch. In the non-market provinces, in the near term there are two main approaches to addressing generation compensation issues:

- *Enhancing and expanding generation rights trading*. Under this approach, government agencies maintain existing generator tariff designs, but enhance and expand generation rights trading, overcoming previous shortcomings in trading through improvements in design of "rights markets," such as must-offer requirements, price floors, and shorter trade windows (e.g., hourly). In addition, whereas rights trading was historically often limited to a subset of coal-fired generators, the scope of rights trading would be expanded to include all generators, as proposed in Attachment 4 of Document 2752. A precondition would be well-implemented priority generation rights for renewable generators. Note that, under such a precondition, unless generation hours are over-allocated to renewables, renewable generators would be unlikely to sell generation hours.
- *Splitting benchmark tariffs into a two-part price*: In this case, government agencies focus on generator tariff redesign rather than generation rights trading. They separate the current "energy-only" benchmark price for coal and natural gas generation into a two-part price, with separate payments for capacity and energy. Capacity payments would be tied to generator availability, with penalties for noncompliance with availability rules. They can be structured in different ways (e.g., flat yuan/kW payments each month, tiered yuan/kWh payments for operating hour ranges, etc.). They can be incorporated into contracts of different lengths (e.g., one-year, five-year), and reevaluated regularly on the basis of reliability need. They should be linked to resource adequacy planning, so that only generators needed for reliability receive a capacity payment. In periods of excess capacity, as is currently the case, generators that are eligible to receive a capacity payment would be determined administratively (e.g., by technology or vintage) or through an auction. Energy payments can be linked to a common fuel price index, and set at levels that compensate additional costs incurred through load-following operations.

Provinces that <u>are</u> participating in market pilots. The transition to true market-based pricing will be challenging. A number of thermal generators will likely be designated as priority generators, to meet

"priority procurement" needs. These generators will have government-determined tariffs, but they will also likely have lower capacity factors because of the low load factors of the customers they serve (e.g., residential customers). How their tariffs can be set to encourage the "right" investment—gas-fired generation may be more economical for low-capacity factor generation, for instance—is an open question. For the remaining ("market") generators, a challenge facing the pilots will be to ensure that market revenues can adequately support generation needed for reliability purposes: given overcapacity, market-determined prices are likely to be very low. As seen in other countries, this challenge grows larger with increasing penetrations of solar, wind, and hydropower generation. There is also the challenge of ensuring adequate competition and mitigating market power, which can be an issue even in the presence of general overcapacity.

How Should Dispatch Order Be Determined?

Provinces that <u>are not</u> participating in market pilots: These provinces will need to determine a new basis for how units should be committed and dispatched, at the very least so that they can implement a system of priority dispatch for clean energy. Ideally, they would move toward merit order dispatch, on the basis of marginal costs. However, in non-market provinces grid companies lack information about what these costs are. Thus, in practice, there are three near-term options for determining dispatch order that would approximate merit order dispatch, each of which is compatible with a particular approach to generator compensation:

- *Preset dispatch order.* Government agencies set a dispatch order, based on cost proxies (e.g., heat rates), emissions proxies (e.g., emissions rates), and policy priorities. This approach is similar to energy-efficient dispatch. (Under energy-efficient dispatch, system operators may have access to remotely-sensed information on generator heat rates and emissions rates for use as cost proxies, but generators do not explicitly provide cost information to system operators.) It is most compatible with a two-part pricing approach to generator compensation.
- *Cost basis*. On a regular (e.g., quarterly) basis, generators provide cost information, including heat rate curves, fuel, and other operating costs, and verifiable emission rates to regulators or system operators. This additional information will allow for improvements on the preset dispatch order approach, resulting in additional system cost and emission reductions. System operators optimize unit commitment and dispatch around these costs. This approach is also most compatible with a two-part pricing approach to generator compensation.
- *Trade basis (generation rights trading).* The power exchanges (交易机构) that facilitate generation rights trading provide dispatch order to system operators, based on generation rights trades. This approach is most compatible with generation rights trading.

Provinces that <u>are</u> participating in market pilots. These provinces have a number of potential market tools for determining dispatch order, though there are still questions about how it will be determined in practice. Two key issues include: (1) how bilateral contracts are reconciled with a merit order dispatch, discussed in the next section; and (2) how environmental costs are incorporated into dispatch.

The second of these issues requires a new approach to the control and pricing of emissions—NO_x, PM, sulfur dioxide (SO_2), and carbon dioxide ($CO_{2]}$). Currently, coal generators are required to install SO_2, NO_x, and PM control equipment, but pay relatively small fees for residual emissions. This may result in situations where SO_2, NO_x, and PM fees are too low to encourage changes in dispatch order necessary to meet air quality targets. Addressing this problem requires raising pollution fees, creating and expanding SO_2 and NO_x cap-and-trade systems, or implementing an emissions cost "adder" administered by the system operator. For CO_2, the emissions trading schemes that are under development in China may allow for incorporation of some emissions costs into dispatch. Because of their potentially significant impact on system operations and investment, CO_2 pricing mechanisms should be integrated into thinking on market designs.

How Will Market and Planned Generation Be Reconciled in Dispatch?

The reform documents envision a transition from the current planned operating-hour approach to dispatch to wholesale generation markets, although this will take different paths and occur on different timescales in market pilot and non-pilot provinces. In all provinces, there will be up to three categories of generation operating at the same time:

1. Market generation, with output determined by a combination of forward and spot markets;
2. Priority generation, with output determined by planning agencies; and
3. Non-priority planned generation, with output (operating hours) determined through the traditional annual planning process.

In provinces that are participating in market pilots, most generation may be categories (1) and (2); in non-pilot provinces, they may be categories (2) and (3), with a smaller share of category (1). In both instances, renewable generators are encouraged to participate in forward markets.

The introduction of bilateral contracts and the co-existence of market, priority, and planned generation raises an important question for dispatch: How will system operators reconcile and prioritize different kinds of contracts with dispatch decisions, subject to transmission congestion and reliability constraints? In market pilot provinces, the NEA's proposed market model provides for "contracts for differences" (CFDs) and a secondary market that allows for flexibility between financial arrangements and the physical operation of the electricity system. However, the details of how this will be done are not immediately clear from NEA's draft document.

In provinces that are not participating in market pilots, the issue is how to integrate bilateral market (i.e., direct access) generation into the system of planned and priority dispatch. If the bilateral market remains small, the most straightforward approach is to treat contracted generation as "must-take." As the market becomes larger (e.g., greater than a few percent of demand), this approach creates the potential for conflict among generators, and between the market and government policy goals. In a given hour, for instance, the amount of planned and priority generation plus bilaterally contracted generation may exceed demand, requiring that generation resources be curtailed.

This issue of how to reconcile *financial* contracts with the *physical* operation of the electricity system arose in the context of electricity industry restructuring in the US and Europe in the 1980s and 1990s.[17] A consensus emerged that it is societally beneficial (i.e., welfare-enhancing) for system operators to dispatch the physical system according to short-run costs, rather than based on the length and type of contract.

The standard approach to resolving differences between contracted and dispatched quantities is through the use of a power pool and bilateral CFDs. With this approach, all buyers, including those with contracts, buy their power directly from the power pool (e.g., an exchange), paying pool prices. Generators are paid from the pool, also at pool prices. If the pool price (P_{POOL}) is higher than the contract price ($P_{CONTRACT}$), generators pay buyers the quantity in the contract multiplied by the difference in price ($Q_{CONTRACT}$ * [$P_{POOL} - P_{CONTRACT}$]). If the pool price is lower, buyers pay generators the difference ($Q_{CONTRACT}$ * [$P_{CONTRACT} - P_{POOL}$]). Depending on the nature of the contract, this reconciliation can take place on different timelines (e.g., hourly, weekly, monthly, annually). What this means is that dispatch is optimized economically, while the financial obligations of buyers and sellers under bilateral contracts are preserved. CFDs are, in effect, a hedge against the volatility of market prices.

CFDs are a component of NEA's draft market design for market pilot provinces. However, it is unclear from the NEA's proposal whether system operators would use this kind of "CFD plus power pool" model alongside a security constrained economic dispatch, or whether they would attempt to enforce bilateral contracts in dispatch. In the former case, using a merit order dispatch, there may be no need to maintain the system of priority dispatch for generation that already has low marginal costs (e.g., hydropower, wind, solar).

In provinces that are not participating in market pilots, developing a settlement mechanism to reconcile these kinds of differences is complicated by two main issues: (1) the current lack of mechanisms for generation cost discovery, and (2) the lack of a system for curtailment compensation for non-dispatchable generators that receive feed-in tariffs (FITs). (Document 625 calls for a new system of curtailment compensation, but the details have yet to be worked out.) Addressing the first issue requires a cost proxy for settlement, given that the proposed power exchanges (交易机构) will, in principle, not have information on contract costs. For this, a reasonable approach might be to use the appropriate default tariff for each unit (e.g., for coal units, the benchmark tariff).

Addressing the second issue requires a more systematic approach to dealing with FITs for renewable energy. With the current approach, renewable generators are only paid for the power that they sell to the grid, with the cost of curtailment absorbed by renewable generators. The payment they receive is based on the benchmark coal tariff, with the difference between the FIT and benchmark price paid separately. This approach may lead to higher costs under marginal cost dispatch (see appendix for details), but higher total costs because FITs must be kept higher to cover the cost of curtailment. A

[17] Joskow, P. L., & Schmalensee, R. (1985). *Markets for Power: An Analysis of Electrical Utility Deregulation*. Cambridge, MA: The MIT Press.; Fox-Penner, P. (1997). *Electricity Utility Restructuring: A Guide to the Competitive Era*. Vienna, VA: Public Utilities Reports, Inc.; Rothwell, G., & Gomez, T. (2003). *Electricity Economics: Regulation and Degregulation*. Piscataway, NJ: IEEE Press.

better approach would be to set the FIT more closely in line with estimated costs, and to pay generators for curtailment up to a specified limit.

A numerical example illustrating how market and planned systems can be reconciled in a system of marginal cost dispatch is provided in the appendix.

How Can Cross-Border Power Exchange Be Efficiently Increased?

Most of the power exchange across regions and provinces in China is "point-to-grid" (点对网) instead of "grid-to-grid" (网对网). Point-to-grid exchange refers to an individual power plant connected via a single transmission line with another balancing area. In China, these "cross-border" units have historically had dispatch priority, based on a multi-level dispatch hierarchy.[18] Grid-to-grid exchange refers to two synchronous balancing areas exchanging power based on cost differences between them. Given low grid-to-grid exchange levels, and large amounts of renewable curtailment, there are likely large differences in marginal generating costs across provinces in China, even where sufficient transmission capacity exists between them.

Previous reform and policy efforts attempted to address these generation cost discrepancies. This was the goal of two pilot regional power pools in the early 2000s, which were abandoned due to difficulties in allocating benefits and costs among provinces.[19] It was also partly a goal of trading mechanisms enabled through trading centers (交易中心), established within grid companies beginning in 2006, which were intended to facilitate power exports from surplus to scarcity provinces. These trading mechanisms were ultimately ineffective in encouraging convergence in dispatch across provinces.[20]

Improving mechanisms for cross-border power exchange has been a central theme in reform documents thus far. Document 9, for instance, calls on government agencies to oversee the creation of market mechanisms that facilitate medium- and long-term contracts for power exchange and the sharing of operating reserves among provinces. Accompanying Document 962, *Notice on Improving Pricing Mechanisms for Cross-Border Power Exchange* (关于完善跨省跨区电能交易价格形成机制有关问题的通知), calls for voluntary long-term contracts between sellers and buyers in different provinces, allowing contracts that were previously set by the central government (e.g., for Three Gorges power) to be renegotiated.

However, the reform documents thus far do not address a number of key underlying obstacles to efficient cross-border exchange:

[18] Cross-border units are scheduled by national or regional grid companies. National and regional grid companies have scheduling priority over provincial and sub-provincial grid companies. Provincial grid companies thus schedule around cross-border units.

[19] See Kahrl & Wang, 2014, for a more detailed description.

[20] Kahrl & Wang, 2014.

- *Mechanisms for shorter-term least-cost exchange and benefit-cost allocation*. How can provincial grid companies be encouraged to import when the marginal cost of imports is less than within-province generation, when they have historically not done so?
- *Retail price disparities between provinces*. How can greater cross-border exchange be reconciled with policy-driven differences in retail prices among provinces?
- *Dispatch hierarchy*. How can provincial dispatch accommodate voluntary cross-border transactions? Can this be done within the existing dispatch hierarchy or should the hierarchy be changed?
- *Price regulation*. Which organization should regulate cross-border exchange (e.g., market monitoring), and how?

Addressing generator compensation, discussed earlier, is also a key part of the solution to benefit-cost allocation questions. Currently, provincial grid companies will choose to operate more expensive generation rather than import power to increase operating hours for in-province generators and contribute to meeting their annual targets.

Variations of these questions have long been areas of policy and regulatory discussion in the US. Historically, utilities often coordinated to exchange power on a longer-term (e.g., months) or shorter-term (e.g., days or hours) basis, for reliability and economic reasons. In this practice, known as economic (or "economy") exchange, one utility would import from another when its marginal generation costs ("system lambdas") were higher than those of the other utility. The cost savings from these exchanges were typically split 50/50 between utilities. In some areas this practice continues, though in others wholesale markets have made it obsolete. Economy exchange transactions were and continue to be regulated by the Federal Energy Regulatory Commission.

Under economy exchange, multiple utilities have to coordinate import and export schedules across their balancing areas, often with high transactions costs. Centralized regional dispatch, alternatively, is a single security-constrained economic dispatch across multiple balancing areas. With the evolution of wholesale markets for generation and with increasing levels of variable wind and solar generation, both the US and Europe have experienced a shift toward larger balancing areas and more centralized regional dispatch. Notable developments include the establishment of a five-minute voluntary energy imbalance market, consisting of the California ISO and a handful of utilities in the western United States, continued expansion of wholesale markets organized under regional transmission organizations in the central and eastern United States, and day-ahead market coupling in Western Europe.

With a longer-term goal of more centralized regional dispatch, in the near term the main priority for policymakers and regulators in China should be on narrowing the gap between marginal generation costs across different provinces. For grid companies which, in the near term, are still tasked with serving the majority of demand,[21] this will be more along the lines of economy exchange in the US. Convergence

[21] Attachment 4 of Document 2752 indicates that grid companies will be responsible for procurement, on the basis of annual electricity balances (电力企业应根据年度电力电量平衡方案协商签 订购售电合同).

in dispatch through greater coordination in operations among provincial grid companies will reduce overall costs, emissions, and renewable energy curtailment, and will improve reliability.

There are several near-term options for improving the efficiency of cross-border exchange in China, differing primarily in which organizations are involved and how prices are set. For grid companies, which will likely be responsible for the majority of cross-border exchange in the nearer term, three potential near-term options include:

- *Economy exchange*. Grid companies bilaterally negotiate import/export schedules; if grid companies do not have information on marginal generation costs, economy exchange could instead be based on a regulated cost proxy, with prices set or approved by the NDRC.[22] This exchange is largely grid-company-to-grid-company.
- *Inter-provincial balancing market*. Power exchange organizations expand their existing trading platforms to facilitate longer- and shorter-term bilateral transactions between generators and provincial grid companies, with greater regulatory oversight of market design and pricing. This exchange is directly between generators and grid companies.
- *Power pool model*. Provincial grid companies submit hourly (or sub-hourly) supply and demand quantity and price schedules to their regional grid company, which develops a security-constrained economic dispatch for the region and sends dispatch instructions to provincial system operators. This option is a first step toward a centralized regional dispatch, which should be a longer-term goal.

Addressing generator compensation issues is a precondition for enabling any of these options. Additionally, they all require stronger regulatory oversight both in the design of transaction mechanisms and in the oversight of transactions to prevent the exercise of market power. Lastly, cross-border power exchange is known to create transfers between provinces and among generators, grid companies, and customers. Explicitly recognizing the political economy of cross-border exchange, and developing strategies to address it, is a useful starting point for reforms.

Conclusion

In summary, dispatch reforms are a key element of China's energy, climate, air quality, and economic goals. Although there have been important steps to address current shortcomings in dispatch, a number of key obstacles remain—particularly in how coal-fired generators are compensated. Addressing these issues will be critical for moving toward truly "green" dispatch.

[22] When the marginal unit is not a coal- or gas-fired unit, the marginal generating resource will most likely have some of its output curtailed. In other instances, the marginal unit will likely be a coal- or gas-fired unit.

Appendix: Reconciling Market and Planned Generation in Marginal Cost Dispatch

Basic Assumptions

Consider a system that has 2,500 MW of available generation in a given hour, described in Table 1.

Unit	Type	Available Capacity (MW)	Marginal Cost (yuan/MWh)	Contract Status
1	Coal	600	300	Short-term
2	Coal	300	325	Long-term
3	Coal	600	350	Planned
4	Wind	400	20	Planned
5	Hydro	600	15	Planned

Table 1: 2,500 MW System

Assume that loads A and B pay units 1 and 2 exactly at marginal cost. The remaining generation is paid through a combination of benchmark, FIT, and cost-based prices. The benchmark price for coal includes levelized fixed costs for simplicity.

Unit	Type	Price
1	Coal	Contract price = 350 yuan/MWh
2	Coal	Contract price = 375 yuan/MWh
3	Coal	Benchmark price = 425 yuan/kWh
4	Wind	FIT = 425 yuan/kWh + 75 yuan/kWh renewable premium
5	Hydro	Cost-based price = 250 yuan/kWh

Table 2: Prices by Generating Unit

This system has 1,700 MW of demand in that hour, with 900 of it contracted to loads A and B.

Load	Demand (MW)	Contract Status
A	600	Contract with unit 1
B	300	Contract with unit 2
C	800	Public (no contracts)

Table 3: Demand and Contract Status

Dispatch

a. Contract

Table 4 shows dispatch under "contract dispatch," where the system operator dispatches generation in order of the length of contracts. Unit 2, which has a long-term contract, is dispatched first. Unit 1, with a short-term contract, is dispatched second. The remaining units are assumed to be dispatched in order of marginal costs. In this case, half of the wind unit's output is curtailed. Total cost in that hour is 290,500 yuan.

Unit	Type	Available Capacity (MW)	Dispatched Capacity (MW)	Total Marginal Cost (yuan)
2	Coal	300	300	97,500
1	Coal	600	600	180,000
4	Hydro	600	600	9,000
5	Wind	400	200	4,000
3	Coal	600	0	0
Totals		2,500	1,700	290,500

Table 4: Contract Dispatch

b. Marginal Cost

Table 5 shows dispatch under marginal cost dispatch, where units are dispatched according to marginal cost regardless of their contract status. In this case, all of the wind plant's output is consumed, and Unit 2 (long-term contract) is only dispatched for 100 MW.

Unit	Type	Available Capacity (MW)	Dispatched Capacity (MW)	Total Marginal Cost (yuan)
5	Hydro	600	600	9,000
4	Wind	400	400	8,000
1	Coal	600	600	180,000
2	Coal	300	100	32,500
3	Coal	600	0	0
Totals		2,500	1,700	229,500

Table 5: Marginal Cost Dispatch

In this example, marginal cost dispatch produces a 61,000 yuan lower (marginal) cost solution than contract dispatch. These cost savings result from running the lower-cost Unit 4 (wind) more and the higher-cost Unit 2 (coal) less.

Settlement

Actual payments to different market participants (settlement) will be different than marginal costs, and depend on pricing.

a. Contract Dispatch

Under contract dispatch, loads A and B will pay the contracted amount to units 1 and 2, plus the renewable energy premium for the wind unit. The amount paid to the wind unit will depend on the extent to which curtailment is compensated. If curtailment is compensated and included in the premium, the total premium payment to the wind generator will be 115,000 yuan (200 MW * 425 yuan/MWh + 400 MW * 75 yuan/MWh), with 85,000 yuan paying for lost base revenues and 30,000 yuan paying the full cost of the renewable premium. If curtailment is uncompensated, the total premium payment to the wind generator will be 15,000 yuan (200 MW * 75 yuan/MWh).

As noted in the main text, if the FIT is near costs, limiting payment to the wind generator in this hour to 100,000 yuan (base revenues of 85,000 yuan = 200 MW * 425 MW plus the 15,000 premium) will result in the wind unit collecting half of its anticipated revenues. This approach is unlikely to support wind development.

With compensated curtailment, loads pay the amounts shown in Table 6. The price for loads A and B is their contract price. The price for load C is the capacity-weighted average price of the remaining generation (wind and hydro). Wind premiums are assumed to be made on a pro rata load basis. Total cost is 672,500 yuan.

Load	Demand (MW)	Price (yuan/MWh)	Base Payment (yuan)	Wind Premium (yuan)	Total (yuan)
A	600	350	210,000	40,588	250,588
B	300	375	112,500	20,294	132,794
C	800	294	235,000	54,118	289,118
Total	1,700		557,500	115,000	672,500

Table 6: Payments Under Contract Dispatch

b. Marginal Cost Dispatch

With a pool and CFDs, loads pay the average pool price for generation. Generators are assumed to be paid the benchmark or cost-based tariff. This results in an average pool price of 363 yuan/MWh(= 617,500/1700), as shown in Table 7.

Unit	Type	Dispatch (MW)	Pool Price (yuan/MWh)	Pool Cost (yuan)
5	Hydro	600	250	150,000
4	Wind	400	425	170,000
1	Coal	600	425	255,000
2	Coal	100	425	42,500
3	Coal	0	350	0
Totals		1,700	363	617,500

Table 7: Pool Prices and Cost

Adding the wind premium, Table 8 shows payments for load to the pool (base payment) and total payments. The wind premium could be paid by the pool or through another mechanism.

Load	Demand (MW)	Price (yuan/MWh)	Base Payment (yuan)	Wind Premium (yuan)	Total (yuan)
A	600	363	217,941	10,588	228,529
B	300	363	108,971	5,294	114,265
C	800	363	290,588	14,118	304,706
Total	1,700		617,500	30,000	647,500

Table 8: Payments Under Marginal Cost Dispatch (Pool)

There is now a discrepancy between contracted and pool amounts. For instance, load A has a contract to buy 600 MW from Unit 1 for 350 yuan/MWh, but is paying 363 yuan/MWh to the pool. To settle these differences, different approaches to CFDs could be used. For instance, if the difference is based on the benchmark price, Unit 1 pays the difference between the benchmark tariff and contract price 45,000 yuan (= [425 - 350] * 600) to load A, and Unit 2 pays 5,000 yuan (= [425 - 375] * 100) to load B. Unit 1 has no change in net income. Unit 2 earns 5,000 yuan (= [375 - 325] * 100 - 5,000), which is 10,000 less than the 15,000 yuan (= [375 - 325] * 300) it would have made under contract dispatch. Load A and B pay a total of 183,529 yuan (= 228,529 – 45,000) and 109,625 (= 114,265 - 5,000), respectively, both less than their contracts.

Alternative approaches that would allocate more surplus to generators would use either the pool price or a negotiated value in between the pool price and benchmark price as the basis for the CFDs. The contracts might also separate out fixed costs, in which case contracted units would be largely indifferent to whether they are dispatched.