IMPLICATIONS OF ENERGY SPOT MARKETS IN CHINA

FINDING THE RIGHT MARKET MECHANISMS TO ADDRESS THE TECHNICAL, ECONOMIC, AND POLITICAL IMPACTS OF CHINA'S MARKET REFORM

BY RUOSIDA LIN AND DAN WETZEL

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China is in the process of introducing electricity spot markets, which could greatly improve power plant dispatch, reducing costs and CO_2 emissions. Compared with China's dispatch protocol before the 2015 electricity market reforms, some research shows market dispatch could reduce costs and emissions by up to 8% today, growing to 12% savings by 2035.[1] Power markets will substantially change how generators operate and are paid, and ultimately help determine which resources are essential to economically meet electricity demand. Electricity spot market pilots in select provinces are underway, and regulators are concerned about how their market designs will impact generators: how will their economics change, how might this effect GDP and jobs, and how do we manage these changes? Understanding these impacts is key to managing stakeholders and finding a politically feasible, balanced way to institute these reforms. Without this, reforms may meet with strong resistance, delay or halt implementation, or force regulators to make concessions that sacrifice cost and emissions reductions.

We believe rigorous, independent analysis enables regulators to evaluate market designs for their appropriateness in their province and select the right political mechanisms to manage the transition. This is why Rocky Mountain Institute (RMI) along with experts from China's electric utility think tanks have developed a modeling tool that provides a rough estimate of which generators will exit the market and what the resulting market prices for generators will be under a specific market design. This analysis, conducted on a representative sample of generators in China's northern regions, is an example of the types of analysis provincial regulators might find useful in setting up their electricity spot markets, allowing them to assess different market design scenarios to decide which is best suited for their province. Below are the main insights from the analysis, including the key outcomes from the simulated energy spot market implementation and resulting recommendations for electricity spot market designs suited to the modeled situation:

- **The test area can reduce costs and emissions by 3.6% and 4.4% respectively,** largely driven by increased renewable integration and utilizing more efficient power plants. While these reductions are unto themselves substantial, totaling 627 million RMB and 2.12 million tons annually, this is ultimately a conservative estimate assuming no technical changes to power plant operation or interprovincial exchange. Furthermore, markets are a foundation for cost minimization in the future, especially as more renewables are added in line with China's latest installation targets. Other analyses have demonstrated up to 12% annual cost and emissions reductions systemwide in China by 2035.[2]

- Wholesale electricity prices decrease from current state-set prices due to overcapacity. These prices are too low to keep all current generators profitable and will **pressure nonessential generators to exit the market.** After these plants exit, prices rise to levels that cover the going-forward costs of remaining generators, around 370 RMB/MWh, only 11.2 RMB/MWh below the benchmark prices of the year we simulated. Even with generator exit, the current reliability standards of the grid can be met. Only small price reductions are passed to customers, an estimated 0.01 RMB/kWh, although it is expected that competition in electricity markets will make generation more efficient, and will, in turn, further pass cost reductions on to customer rates.

- Combined heat and power (CHP) represents too great a share of the test area's generation (81% of installed capacity) to be exempt from market dispatch, as is the current protocol in many ongoing market reforms. **CHP must participate in market dispatch, even when meeting heat obligations** to place economic pressure on CHP to reduce minimum run rates, thereby enabling cost and emissions reductions to grow beyond the 4% reductions expected from dispatch reform alone. Furthermore, by not having CHP participate in energy spot markets, market prices cannot be set during many hours in heating season, undermining a sustainable market environment.

- **Shifting to market dispatch does not require additional thermal power plant flexibility;** all dispatch efficiencies can be achieved using existing assets without violating any technical constraints, including minimum run rates and ramping rates. Contrary to common perception, market dispatch actually reduces fleetwide ramping by improving generator scheduling, and keeps the number of startups and shutdowns consistent with current dispatch. Ramping, startups, and shutdowns, however, are now concentrated among a few generators, instead of being spread evenly across the fleet as is done under current dispatch.

While these results are derived from rigorous dispatch, unit commitment, and market modeling, the exact quantitative outcomes are subject to many uncertainties. Therefore, this report identifies and explains the general phenomena that undergird the northern regions' specific results, which we hope can be helpful to market designers in all regions in China. We also discuss how this kind of analysis can be used to support regulator decision-making, serving as a starting point to determine appropriate market rules, remediation mechanisms, and transition mechanisms needed to facilitate China's market implementation.

1 CONTEXT AND OBJECTIVES

CONTEXT AND OBJECTIVES

China is in the process of deregulating its power sector and implementing wholesale power markets, an effort taken up most recently in 2015 to reduce rising costs to customers and support a more efficient, less polluting, more reliable power system.

Market reforms aim to achieve these outcomes by improving dispatch, the process of choosing which generators to use to meet demand. China previously employed an equal allocation dispatch system, where generators of the same type are dispatched for roughly the same number of hours, regardless of their efficiency or marginal cost. By switching to market-based dispatch, as is used in much of the rest of the world, the lowest marginal-cost generation is utilized first, and higher marginal-cost generation is only used as demand increases. Therefore, the shift to market-based dispatch will result in both cost and emissions reductions, since both efficient generators and renewables (that have close to zero-marginal cost) will see greater utilization. In turn, some of these cost savings can be passed on to customers in the form of lower retail electricity rates.

China has already made great progress, implementing mid-to-long-term direct power purchases in most provinces, which has led to reduced electricity prices. But electricity spot markets, which will play a key role in improving dispatch efficiency, are still in their early phases. China has eight provincial-level electricity spot market pilots, each selected to develop markets that are suited to different regional challenges and resource mixes. Collectively, these pilots will ideally prove out market designs that can overcome the biggest challenges posed to China's power system: rationalizing electricity pricing, integrating high amounts of seasonal hydro and remote variable renewable energy (VRE), and alleviating the overcapacity situation in coal basin provinces.

There remains an ongoing debate as to what market design is best for which regions. This question is important. It shows that policymakers are aware that markets are a design choice, developed to address specific technical, political, and financial challenges faced by the places they are implemented, and that there is no one-size-fits-all "ideal" market design.

In designing these pilots, market designers must consider more than just which market mechanisms will solve these challenges at least cost. To be effective, any design must also grapple with how generators and other stakeholders will respond to these markets: Will there be political resistance? Do the rules reward the right behaviors and penalize noncompliance? Are there opportunities for market actors to collude and thus render the market ineffective? Potential stakeholder reactions need to be acknowledged and proactively managed in the market design to avoid market failures similar to those seen in other countries during their deregulation process. Particularly potent is the question of how revenues change for existing generators, which have the most to gain or lose in this market transformation and therefore could play an important role in either enabling or undermining market reforms.

This question is one focus of RMI's China program, which has developed an economic dispatch, market-equilibrium model with the ability to test different market scenarios, the Market Optimization Simulation Tool (MOST). **MOST helps to identify not only how specific market designs correspond to price and emission reductions, but also how the economics of individual power plants shift under different market rules.** This model and its resulting findings can then be used by policymakers and market operators to identify the right political or market mechanisms necessary to mitigate stakeholder opposition while preserving the positive effects of competition: cost reduction and reinforcing efficient dispatch

In this context, the objectives of this report are to:

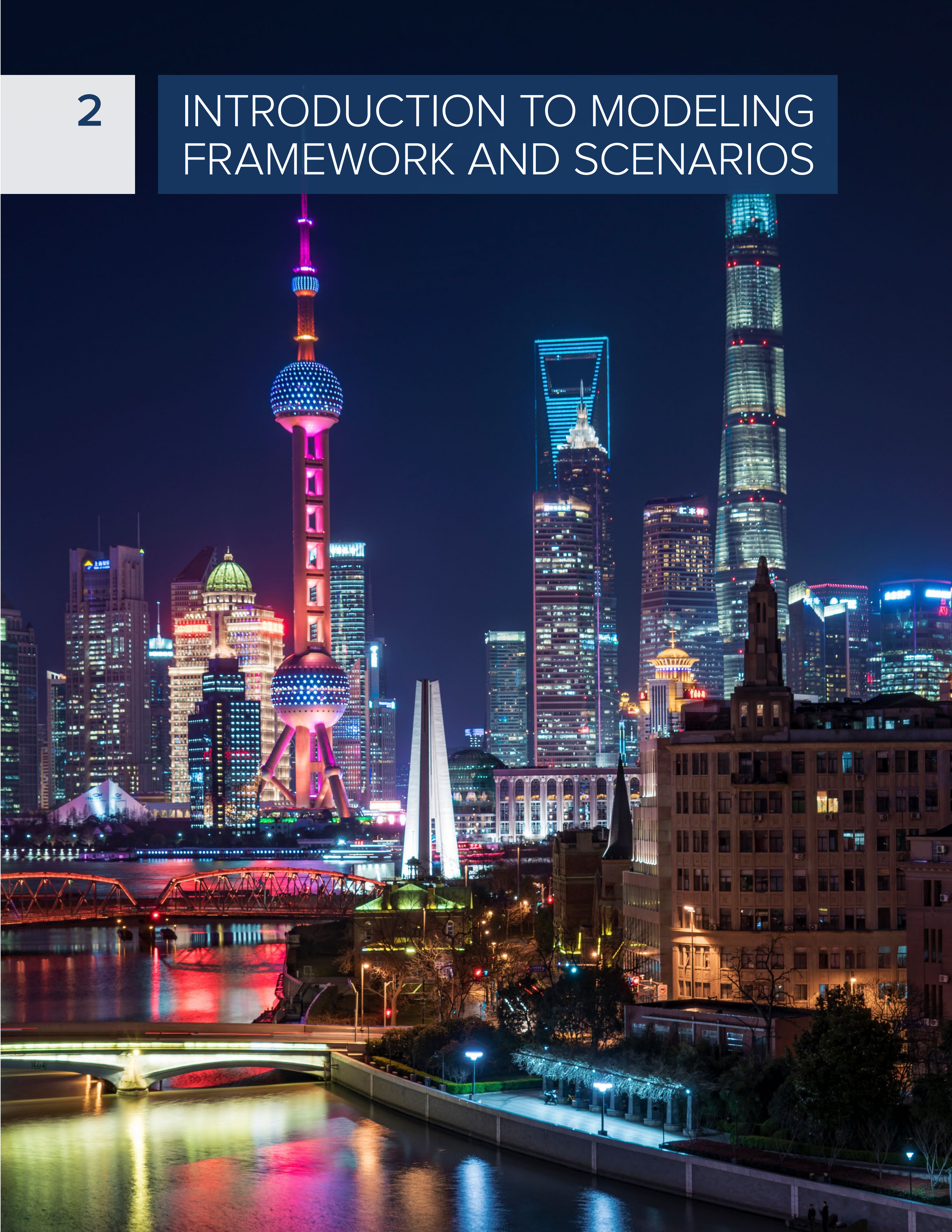
- Introduce a standard analytical approach for evaluating the efficacy of different electricity spot market designs to address the unique challenges faced in different regions, and understand the impacts of those market designs on the economics of individual generators.

- Utilize a representative test case from China's northern regions to apply this analytical approach, and demonstrate the efficacy of this modeling approach.

- Identify important market design insights—based on these results—that are relevant to northern regions and potentially applicable in other Chinese provinces.

Although this report is only a preliminary look into designing markets suited to the local context, RMI believes these tools bring sufficient depth to provide meaningful market reform recommendations and provide a methodology to back up market designs. Through further collaboration with provincial governments, the model can be tailored to each province's specific need and conditions, therefore ensuring a robust design and providing smooth implementation of markets that meet provincial goals, helping these provinces become leaders in China's energy revolution.

2 INTRODUCTION TO MODELING FRAMEWORK AND SCENARIOS



INTRODUCTION TO MODELING FRAMEWORK AND SCENARIOS

2.1 GENERAL MODEL DESCRIPTION

The MOST model is a security-constrained, economic dispatch, market-equilibrium model. This type of model considers the technical limitations of the grid and all generators and uses the generators' operating costs to determine the least-cost operating schedules to meet demand for every hour of the year. The MOST model also has a market-equilibrium component, which estimates the expected market prices and payments to each generator under different market design scenarios.

Model Structure:

The model aims to minimize electricity production costs while abiding by all safety constraints.[i] It considers the safety and reliability constraints of the grid and the generators to produce an hourly unit commitment for all generators over a single year (8,760 hours). The **constraints and constants** used in this model represent current stated operational conditions for the grid and generators, and include hourly regional electrical demand curves, seasonal heat supply requirements, renewable resource curves, generator unit operational parameters (e.g., ramp rates, startup times, minimum run rates), grid structure and transmission capacity limits, and reserve requirements.

Inputs:

Generator bids are the primary input to determine economic dispatch. Each unit submits a segmented bid curve, giving a price for each output level, broken into segments representing 10% of that unit's nameplate capacity. Bids are cost based, considering only the short-run marginal costs associated with energy production. We factor in rent-seeking bidding behavior only during hours of high demand. Generator costs were determined using a separate generator cost model, which considers generator age, capacity, technology type, coal costs, and expected heat rates. Different **market design** settings can be applied to a given model run by adjusting which units are subjected to market-based dispatch, the conditions under which generators may be paid at non-market-based prices, and how generators bid to reflect different bidding behaviors promulgated by a different market design. Across all market designs, MOST employs a standard energy spot market design with a uniform clearing price mechanism, which is the foundation of most major electricity spot markets around the world.

Outputs:

After MOST calculates the hourly unit commitments, it calculates the economics, providing outputs on operating costs and market payments at the system and individual generator level, each units' profitability, and carbon emissions. Generator costs included in the model are marginal costs (based on the units' hourly output, which could be different from its bidding price), startup and shutdown costs, fixed operation costs, financial costs, depreciation, taxes, and surcharges.

Market revenues are dependent on the market design settings, and are calculated using the resulting market prices for each hour and the scheduled dispatch for each generator. The units' profitability will consider both power and heat supply revenues. Profitability is calculated over the course of the entire operation year for each plant by subtracting total costs from total revenues. Emissions are calculated using emissions factors multiplied by plants' coal consumption.

The model structure and input parameter settings are described in more detail in the Technical Appendix of this report.

[i] In modeling speak, it is a mixed integer-linear program with a standard cost-minimization objective function.

2.2 SITUATION IN CHINA'S NORTHERN REGIONS

This analysis uses a data set from China's northern regions as a test case, since it experiences a broad mix of dispatch challenges representative of the dispatch challenges China faces as a whole, including generation overcapacity, renewable curtailment, and low flexibility of its coal plants. A particular challenge in the northern regions is that combined heat and power (CHP) plants must consider residential, industrial, and commercial heating needs when being dispatched, further increasing their inflexibility, particularly in winter.

The simulation test case uses a representative portion of China's northern regions that has 57.6 TWh of annual consumption and a peak demand of around 10,000 MW. The generation fleet has about 20,000 MW of installed capacity, including 2% solar, 24% wind, and 74% thermal generators. All the thermal plants, 55 units in total, are coal plants. Except for a few pure condensing units, the majority are all CHP units, with nameplate capacity ranging from 40 MW to 660 MW. The structure and scale of the test system is similar to that of a provincial power system in China's northern regions, in an attempt to be indicative of the results produced in current pilots.

Assumptions:

Considering data availability and model complexity, the following assumptions were used to simplify the parameters of the test case. The MOST model:

- Uses an aggregated transmission topology that is based on real grid infrastructure, where nodes are defined based on where congestion has been experienced in the past. Renewable generators on the same node are combined into one unit of capacity in the model.

- Assumes all generators bid in near their true marginal cost during most hours without scarcity, as is seen in all other energy spot markets globally that use a single clearing price. We represent generators bidding above their marginal cost only during hours of scarcity, when rent-seeking bids are able to influence market prices. These "competitive markups" are calculated based on the number of firms in the market and how much additional capacity is available during a given hour. These percentages are derived by functional forms observed in other competitive markets globally.

- Does not integrate hydro, biomass, and municipal waste generators into the market, instead directly subtracting their generation from the demand curve. The scale of these generators is very small in the test area and cannot meaningfully respond to dispatch signals.

- Simplifies heating output from CHP to be a constant throughout each segment of the heating season (early, peak, and late), and does not consider intraday heating demand fluctuations.

2.3 MARKET SCENARIOS

Using the above model settings as a basis, we developed different scenarios to evaluate using the model. These scenarios do not necessarily represent a proposed market design but were developed to make possible comparisons across different treatments. The scenarios we utilize throughout this initial analysis are:

- **Traditional dispatch:** Establishes the current situation under China's state set pricing and the current equal allocation dispatch method (called "three fairs" dispatch in China) to spread generation hours roughly even across generators.

- **Market dispatch:** Dispatchers utilize an energy spot market to determine least-cost dispatch. CHP dominates the test area's installed capacity, and therefore heating obligations need to be integrated into market-based dispatch decisions. We tested the following sub-scenarios for how to handle CHP:

1. **CHP out-of-market settlement:** CHP plants do not participate in market-based dispatch, and do not set market prices, but instead are paid out of market at their measured costs.

2. **CHP as price taker:** CHP plants do not submit bids (effectively bidding $0/MWh) for the power they must generate to meet heat demand but receive whatever the market price may be during operating hours.

3. **CHP plants bid into the market and procure generation rights during curtailment:** CHP plants bid into the market, including prices for energy below their minimum run rates, and are scheduled like any other generator. CHP plants that do not bid low enough should ramp down, but to be conservative we assume generators do not ramp down below their minimum heating levels, and instead pay renewables to ramp down on their behalf.

- **Market dispatch after market exit:** It is expected that some generators will leave the market due to low prices induced by overcapacity. We assess the resulting energy prices and dispatch after market exit.

When we discuss the overall results of implementing energy spot markets throughout the report, we are assuming a scenario in which a) markets require CHP to competitively bid into the market (CHP treatment 3), and b) unnecessary generators have already exited the market. We explain our full reasoning for the selection of this CHP treatment in Section 4.2, and why the results after market exit are representative of final market outcomes in Section 4.1.

We have maintained conservative assumptions throughout the modeling, but where practical experience from other energy spot markets gives us confidence that the modeling does not reflect expected outcomes, we discuss what expected behavior will occur, although it is not reflected fully in the modeling results.

2.4 EVALUATING SCENARIOS

To fairly assesses the efficacy of each market-based dispatch scenario, we *quantitatively* evaluate the macrolevel impacts, including system cost, price, and emissions reductions. We also assess the impacts to individual generators, including revenue, cost, and dispatch performance. This added level of granularity helps to better gauge **if markets adequately compensate generators necessary to achieve reliable operation of the grid.** It also helps gauge the political acceptability of a proposed design, because if too much generation capacity is exposed to long-run financial risk it might be a political nonstarter.

We also *qualitatively* assess how each market design puts competitive pressure on generators and system operators to reduce their costs and become more flexible. Although there are no quantitative measures for this, we evaluate to ensure:

- Generators with lower marginal prices receive greater dispatch and higher returns above marginal costs.

- Generators with higher marginal costs that do not ramp down to integrate lower-cost generators due to technical limitations bear the costs for their inflexibility.

- Market prices and dispatch decisions are not distorted by market price controls, special treatment of renewable energy (RE) or CHP, or out-of-market compensation to keep certain generators in the market. In particular, we want to ensure necessary market exit occurs and is not hindered.

We also recognize that there are many non-power-sector goals and measures that will influence the design and acceptance of any wholesale power market design: maintaining jobs, GDP, and tax revenue; sufficiently protecting the interests of state-invested power assets; and heat price and supply optimization. We briefly discuss these topics in this report and propose some mechanisms to manage these challenges. A more robust analysis is beyond the scope of this report but is an important future research topic.

2.5 ORGANIZATION OF FINDINGS

This report organizes the findings by:

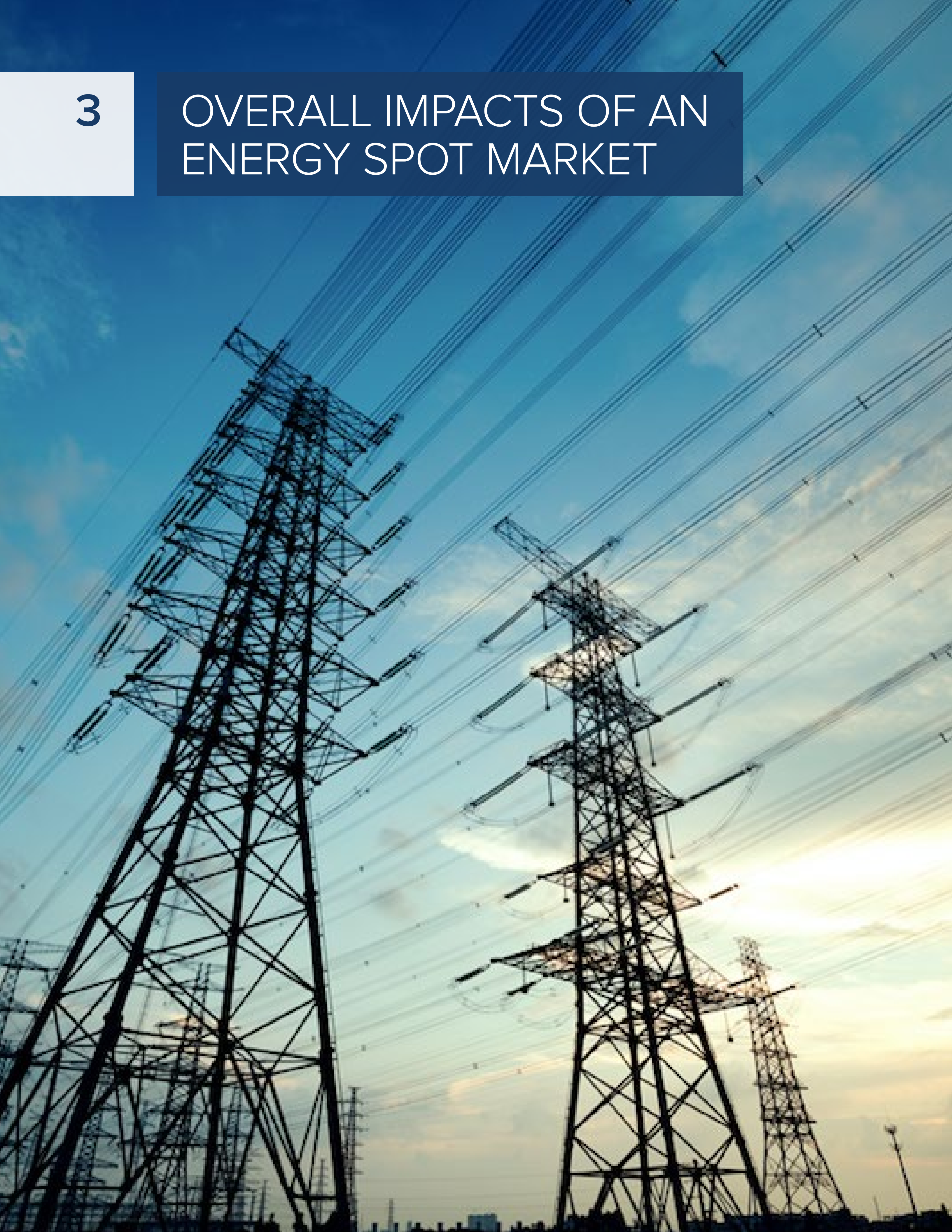
1. Reviewing the overall economic and environmental impacts of market implementation.

2. Describing the economic impacts on individual generators, in particular exploring the resulting generation market exit.

3. Examining how this design changes the operation of different power plants, in particular the test area's extensive fleet of combined heat and power plants.

4. Discussing market and political mechanisms necessary to address resistance caused by these impacts to generators.

3 OVERALL IMPACTS OF AN ENERGY SPOT MARKET



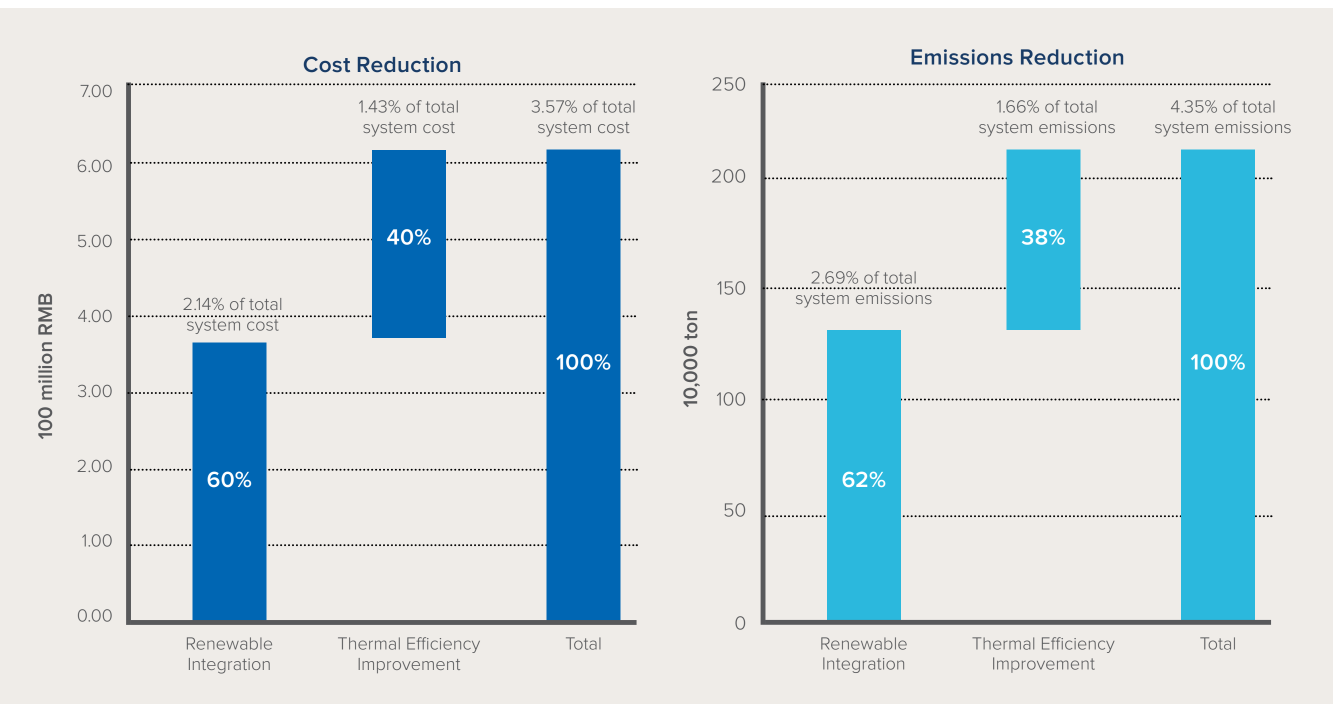
OVERALL IMPACTS OF AN ENERGY SPOT MARKET

Implementing an energy market would reduce costs by 627 million RMB (3.6% of the system's cost) and emissions by 2.12 million tons of CO_2 (4.4% of the test region's emissions) annually. If all of China saw the same CO_2 savings as this region, the country would reduce 153 MT of CO_2 per year,[ii] which is more than all but 34 countries in the world.[iii] This is still likely an underestimate of the potential savings: energy markets would put economic pressure on thermal plants to be more flexible, especially on CHP to lower its output, thereby integrating more curtailed renewables. We also do not consider the benefits of better investment choices over time caused by markets.

This decrease in system cost and emissions is driven by an increase in the utilization of both zero-marginal-cost renewables and more efficient thermal generators. Market dispatch enables the integration of 1.4 TWh of additional renewables and drops curtailment from 31% to 17% for the year of data we tested. It also drives better scheduling of generators so that generators that are already running operate at higher run rates and therefore increase their overall efficiency. There is no significant difference between total startup and shutdown costs under market dispatch compared to the current system, but the number of startups and shutdowns is more

EXHIBIT 1

Cost and Emissions Reductions after Implementing Market-Based Dispatch



[ii] Total CO2 emission of China's power sector exceed 3,476 MT in 2016, **https://www.sohu.com/a/204987810_505851**.

[iii] Country emission data, **http://www.globalcarbonatlas.org/en/CO2-emissions**.

concentrated on a few generators (see Section 5: *Changes to Generator Operation* for more detail). Exhibit 1 shows the contribution of these two drivers to overall reductions in system cost and emissions.

While cost reductions are important to system operators, policymakers have emphasized that they want to see end-users enjoy price reductions—or at least have their prices remain stable in the face of increased prices from carbon and emissions pricing measures. Accordingly, we calculated the total energy payments that would be made to generators under an energy spot market compared to the current allocation system, and assumed that any reduction in total payments to generators would be fully passed through to customers.

Our analysis showed that when an energy spot market is fully implemented—that is, fully equilibrated and competitive—in the test area, customers would see only modest price reductions. Average wholesale payments to generators could be reduced 2.9% from 0.3803 RMB/kWh to 0.3691 RMB/kWh,[iv] although some of these may have already been achieved in the mid-to-long-term markets.[v] Since only 50% of current customer rates are used to pay for generation (the remaining 50% pay for transmission and distribution and government surcharges),[vi] this reduction in energy payments would reduce customer rates by approximately 1.5%. In the long run, customer rate reduction could be much larger as generators are able to refine their cost structure and offer lower bids into the market—a trend observed in regions around the world that have previously implemented energy markets.[3]

In the short term, however, energy spot market prices would likely fall to very low levels (average wholesale payment is as low as 0.2655 RMB/kWh) since the test area is significantly over capacity, leading to generators competing for market share and suppressing market prices. While these short-term prices may be too low to adequately cover the capital (fixed) costs for generators needed for reliability,[vii] prices should rise to sustainable levels once uncompetitive generators leave the market and allow market prices to equilibrate. It's important that low prices persist for long-enough to encourage generators to exit the market. Without exit, prices may never reach levels that sustain adequate generation capacity. It may be necessary to mitigate the political impacts of market exit and low margins for generators in the short term. These measures are discussed in Section 6, and must be designed to encourage necessary market exit, not prevent it.

[iv] The state set price was 0.3803/kWh when the study started; it is currently 0.3731/kWh.

[v] Generator costs are reduced by 4%, yet generators are paid only 2.9% less under energy spot markets. This is because some of these cost savings stay with generators, especially after generators exit the market and remaining generators can seek higher returns during hours of high demand.

[vi] The power retail price in China ranges from 0.5–1.1 RMB/kWh depending on the types of customers and regions.

[vii] We consider a generator's fixed costs to be its amortized capital costs (depreciation), financing and interest, taxes, and fixed O&M.

A FEW POINTS ON MARKET FUNDAMENTALS

Market Pruning

We must stress that market exit is an expected outcome of energy markets in overcapacity grids and should not be viewed as a negative outcome. Market pruning is an essential function of the market to:

- **Keep "needed" current generators economically viable.** Under the current allocation system, many generators are claiming that they are receiving insufficient funds and are fighting to maintain their current dispatch levels. Energy markets help identify the least-competitive and most-polluting generators, and limit the money these plants receive, signaling them to exit the market. Once they exit, hours are then distributed across a smaller set of generators, at a higher price, improving those plants' economics. Without market pruning, there is a risk that all generation will sustain losses, instead of just a few inefficient plants experiencing losses.

- **Reduce prices to customers,** helping to improve the economic competitiveness of Chinese industry and supporting China's development goals.

- **Signal new investment and update generation technology.** To meet China's emissions and development goals, China needs to be replacing older, polluting generators. Markets help remove the least-effective generators and, when economic, replace them with other resources that are cleaner and cheaper.

Market Price Volatility

Price volatility in markets is an important feature to encourage generator flexibility and ensure reliability. High-priced hours encourage all generators to make their full output available, and low-priced hours encourage generators to reduce their output to true technical minima. Investors and policymakers, on the other hand, do not like market volatility, and will encourage generators to sign long-term bilateral contracts to hedge against potential price risk. We expect most generators to sign bilaterals at or slightly above average energy spot market prices, as is observed in most international markets. Therefore, although this analysis only looks at the expected market revenues directly from spot markets, this should be comparable to revenues from bilaterals and spot markets together.

4 GENERATOR-SPECIFIC IMPACTS OF AN ENERGY SPOT MARKET

GENERATOR-SPECIFIC IMPACTS OF AN ENERGY SPOT MARKET

While the net impact of implementing an energy spot market is lower overall payments to generators, these reduced payments are concentrated among the least-efficient plants—those that are unnecessary for reliable operation of the power system due to generator overcapacity. This presents a political risk if generators, already under financial duress due to low utilization, see further declining revenues. To understand this dynamic and be able to proactively manage it, it is important to evaluate the economic impacts of energy spot market implementation on a generator-by-generator basis to understand which generators remain economically viable, and which will be forced to leave the market. Specifically, we evaluate: 1) if the system maintains sufficient generation to meet reliability standards with the resulting market exit and 2) if the volume and type of generators exiting the market present an untenable political challenge. It's important that decision makers first fully understand the pure economic outcome of markets before trying to manage the political situation. Without a clear understanding of the impacts, political remediation can lack focus, be less economically efficient, and prop up a wider set of plants than is necessary.

Our analysis shows that once power markets eliminate unnecessary plants and market prices equilibrate, resulting market prices are sufficient to sustain enough generators to reliably operate the grid. But in order to reach these equilibrium prices, roughly 11% of generation capacity (15% of total thermal generation capacity) must exit the market. In the following section, we describe generator economics in an energy spot market both before and after generator exit. This comparison highlights which generators would be expected to leave the market and shows that the economics of the remaining generators are substantially improved from this market exit.

4.1 EVALUATING MARKET EXIT FOR RELIABILITY IMPACTS

Generators that are unlikely to earn enough revenues above their going-forward costs in power markets would likely exit the market. Exhibits 2 and 3 show the economic viability of the system before and after market exit respectively, indicating how much each individual generator earns from the energy market above its going-forward costs.

In Exhibit 2, any generation capacity above the break-even line (the x-axis) is receiving adequate compensation and will remain in the market. The red line indicates the current planning reserve levels required. If the capacity to the left of that line is all above the break-even line, then the market is capable of meeting the planning reserve without additional out-of-market compensation. The exhibit indicates that prior to market exit of uncompetitive generators, market prices are too low to cover the going-forward costs of 31% of generation capacity that are necessary to meet the reserve margin.

Low energy prices are a natural outcome of excess capacity, which prevents generators from bidding high during hours of high demand since other generators are available and would likely underbid them. Without these few hours where available capacity is scarce and market prices rise, generators would likely earn little above their marginal cost. This situation should be short-lived provided generators actually exit the market.

It is important that low-market prices are allowed to persist for long enough to force uncompetitive generators to make the decision to leave the market. Exhibit 3 shows that once the most inefficient, least-competitive generators have exited, average market prices should rise to sustainable levels where enough generation will cover their costs to meet reliability requirements.

EXHIBIT 2

Economic Viability Dashboard of Energy Market-Based Dispatch Under Current Oversupply Environment

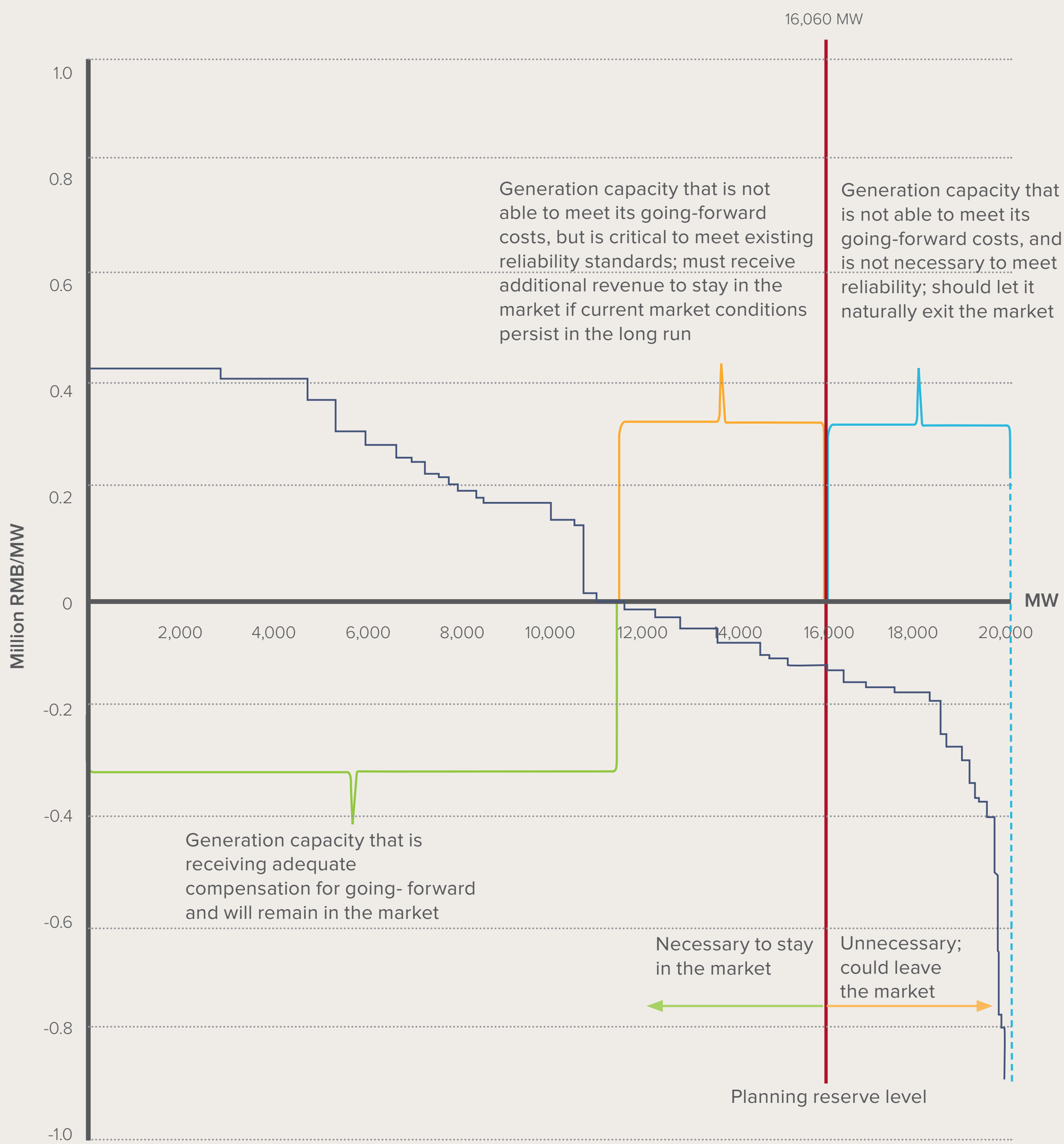
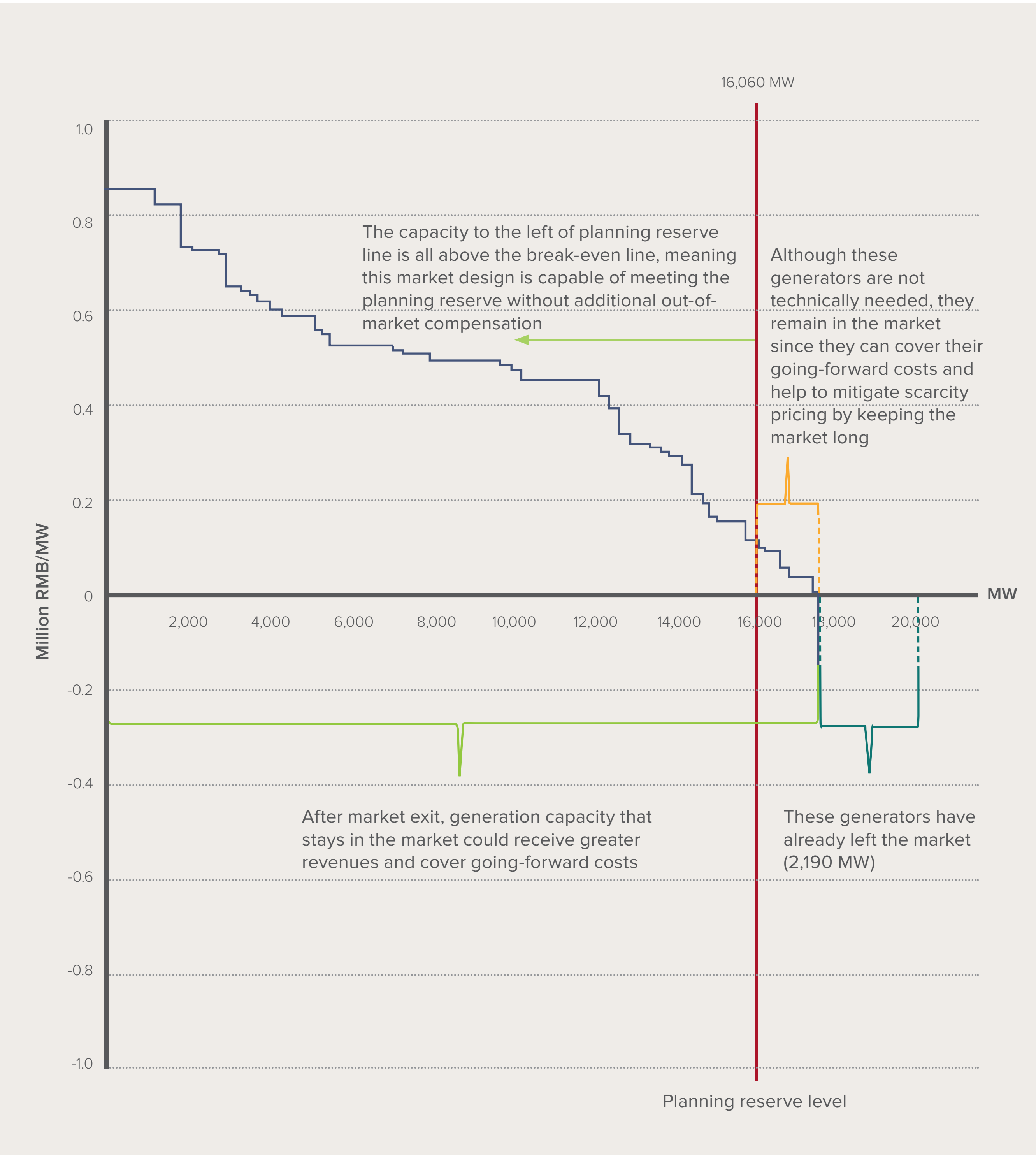


EXHIBIT 3

Economic Viability Dashboard of Energy Market-Based Dispatch After Market Exit



As seen in Exhibit 3, after the energy market has been implemented and equilibrated, roughly 17.6 GW of generation capacity remains in the market, with only 11% of existing capacity exiting. Enough capacity remains to meet the planning reserves, maintaining a 24% reserve margin, 14% more than the 10% required by current grid standards.[viii, ix]

Before market exit, all generators will endure low market prices due to oversupply for a short period. While generators receiving sufficient dispatch can endure low prices for some time, eventually even economically viable generators will run into cash flow problems. There are methods by which system operators can address this missing money problem in the short term, either through additional market mechanisms or out-of-market payments. Any mechanism employed to bridge this gap until market exit rectifies prices should avoid providing incentives that discourage market exit. Mechanisms that could help during this implementation period, and even some mechanisms to help encourage and expedite market exit, are discussed in Section 6.

[viii] All renewable capacity in China does not count toward meeting a province's planning reserve margin, and accordingly we assume the same in this analysis. This is incredibly conservative, essentially assuming no solar and wind will be operating during peak demand hours. This assumption adds substantial cost to the system in the long run by requiring more dispatchable generation than necessary. It also threatens market prices rising to sustainable levels, because if wind and solar are operating during peak hours, then scarcity doesn't exist in the market, and participants can't bid at levels essential for raising average market prices. The recommended treatment for this problem is to assign a capacity credit to wind and solar in this region. A capacity credit is applied to variable or intermittently available generation, measured by the probable adjusted portion of that generation's capacity that can be expected to be available for the system during the peak hours of demand. In most markets, renewables are assigned a capacity credit as solar and wind are consistently available at some level during system peaks. For example, In August 2019, California assigned solar and wind 41% and 27% capacity credits respectively.
http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

[ix] Additional capacity remaining in the market beyond the reserve margin may seem economically inefficient, but it is due to the "lumpiness" of power sector assets, and that a single unit necessary to meet the reserve margin large enough to create excess capacity. Any marginal plant with capacity exceeding the reserve margin and that can remain economic also indicates that this additional capacity serves an important function in hedging against market power concentration and preventing generators within the reserve margin from being able to drive up prices too easily.

4.2 EVALUATING GENERATOR-SPECIFIC IMPACTS

Exhibits 4 and 5 show generators' costs and expected revenues—and therefore also profitability—by unit type once the test area implements an energy spot market. For each generator type there are two columns: the first column indicates their total expected market revenues, the second, their total costs (both amortized across the average unit of capacity [MW] for that type of plant). For the cost bars, solid colors indicate short-run O&M costs (or going-forward costs) that must be covered in the short term for the plant to continue operating. Striped bars indicate other capital and financing costs that do not need to be covered in the near term to keep that unit operating but that need to eventually be recovered to foster healthy power sector investment.[x] In the initial phases of energy spot market implementation, as long as the revenue bars are higher than the solid-colored cost bars, the generator is not under threat of market exit, even if the revenue stack doesn't currently cover the generators' full capital costs (striped bar).

Exhibit 4 shows the economic situation for generators by type prior to any generators exiting the market. Small CHP and condensing coal units will be under the most economic pressure to exit the market. Small, inefficient CHP units (<100 MW) have high marginal costs, and therefore are infrequently dispatched beyond what is required to meet their heating obligations. Under the scenario where CHP participates in the market, small CHP also must suffer losses from generating at prices below their marginal costs in order to meet heating obligations. Pure condensing 300 MW coal units are also seldom dispatched. Although their electrical efficiency is better than many of the CHP plants of over 100 MW, CHP plants are able to discount their heating payment from their marginal cost, therefore undercutting pure condensing plants in the market. These two sets of plants are the least necessary for the economic, reliable operation of the grid, and should naturally exit. Transition schemes to handle unnecessary generation retirement should focus on these plants.

The shift in generator revenues after some generators exit the market is shown in Exhibit 5. All units remaining in the market have significantly improved economics as a result of market prices rising and revenues being spread across a smaller subset of generators. After market exit, not only do all remaining generators cover their going-forward

[x] The definition of going-forward costs is relatively standard, containing only the short-run costs associated with keeping the plant open from year to year (fuel, variable O&M, taxes, and fixed O&M). Principal (depreciation) and financing payments are considered part of longer-term costs, assuming those can be refinanced or written off in bankruptcy, and under any circumstance the asset will still be operated to recuperate as much revenue as possible. To calculate the long-term fixed costs for each plant, we have amortized the principal and financing costs associated with each plant according to standard depreciation timelines for Chinese power sector assets. Fully depreciated plants will have no associated long-term fixed costs. We have calculated which plants are fully depreciated using typical depreciation periods associated with that generation type. When discussing which plants cover their full amortized costs, we include any fully depreciated plants that cover their going-forward costs in this category. It should be noted that many of the plants that do exit the market are the older, inefficient plants that are fully depreciated because they cannot outcompete more efficient plants for dispatch, meaning they cannot cover even their going-forward costs from year to year. This conclusion is worth noting, since it is different than the expectation from some industry experts in China, who assume fully depreciated plants will outcompete efficient ones. This may stem from expected treatment of loan repayment in China, where state-owned assets are typically paid at set prices to virtually eliminate default risk and are expected to bid in such that they can assure repayment.

EXHIBIT 4

Levelized Revenue and Cost by Generator Type Before Market Exit

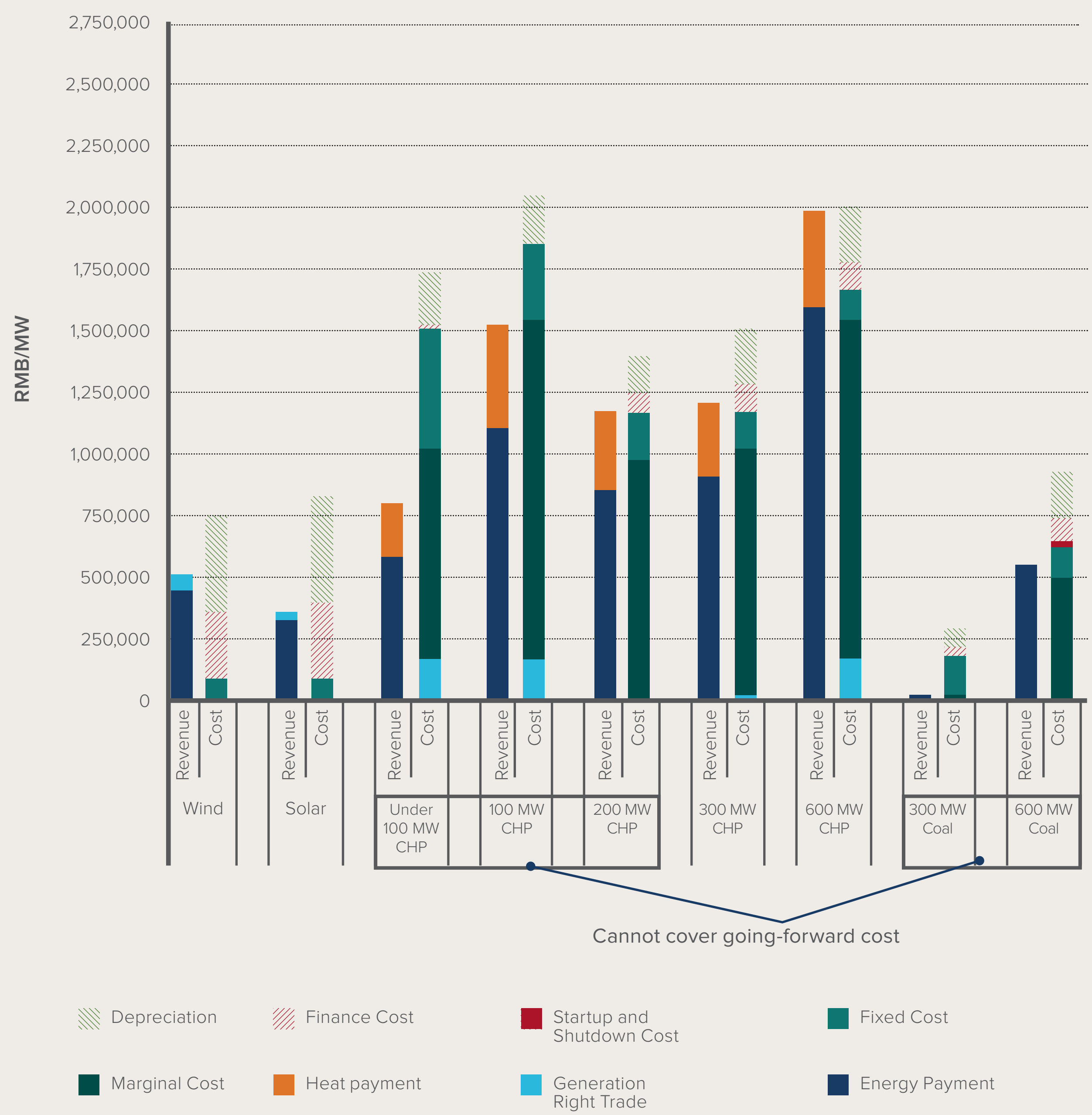
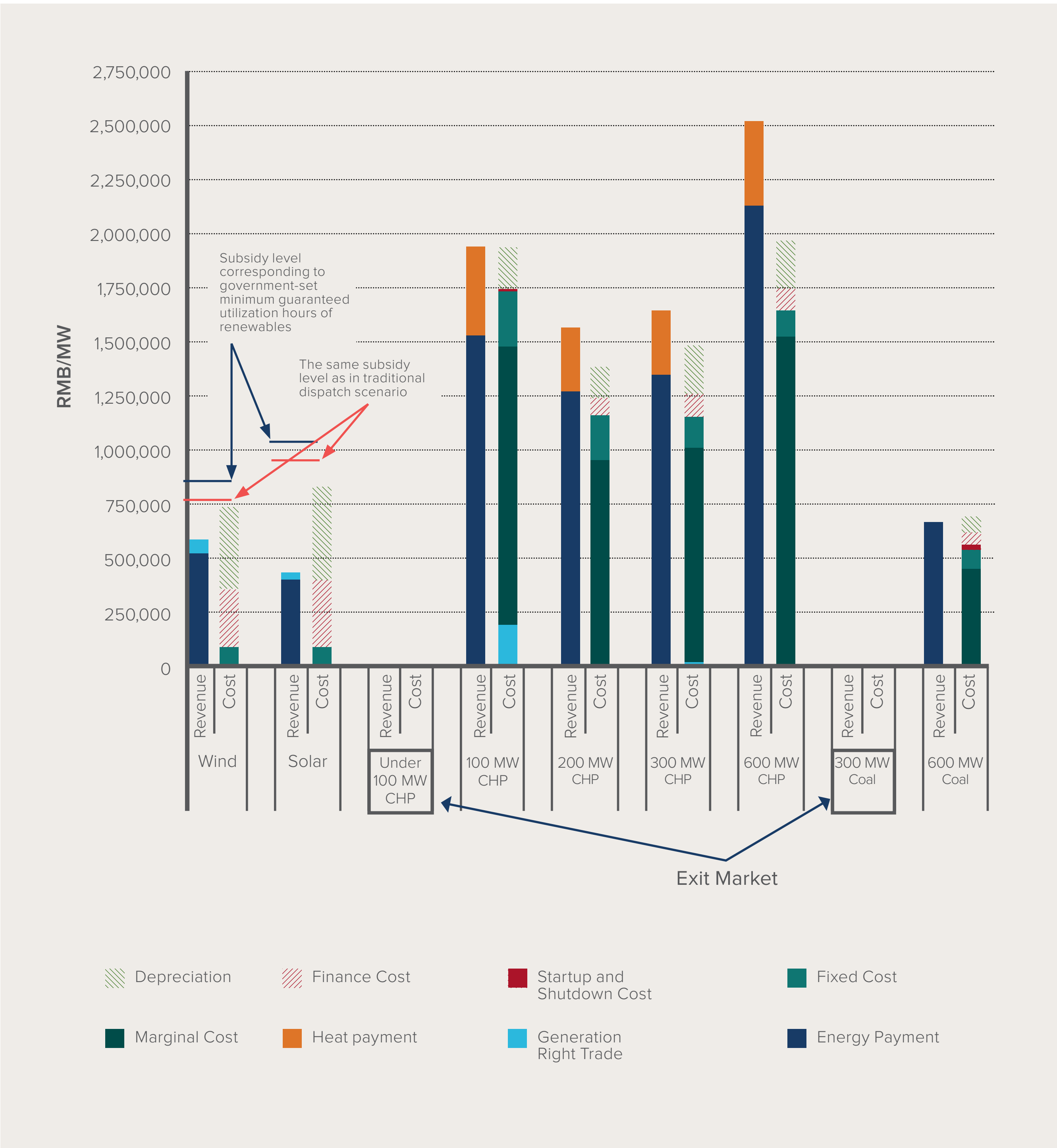


EXHIBIT 5

Levelized Revenue and Cost by Generator Type After Market Exit



costs, all but 19% of thermal generation capacity can fully cover their annualized capital costs with market revenue alone, with a good portion of that 19% being a single large 600 MW pure condensing coal plant. This 19% of thermal capacity receives less dispatch compared to other plants, either due to lower efficiency levels or lower heat sales—requiring plants to submit higher electricity market bids that reflect their marginal costs not covered by heat sales.

These generators will stay in the market despite not covering their full amortized costs, because they are already built and will persist in the market as long as they can cover their going-forward costs. It is not uncommon for markets to have 19% of plants not covering their full amortized costs in a year. In international experience, plants are not expected to earn full returns on capital every year. Instead, certain years have higher prices due to extreme weather, capacity retirement, etc., and therefore create higher returns, making up for lower returns in other years.[4]

With 19% of generators experiencing this uncertainty, it will send a market signal to investors that new thermal capacity is currently unneeded in the test region. While large CHP plants are among the most competitive plants in the test area, the expected hurdle rates for recovering the cost of new CHP are not met by current market prices and the expected dispatch for a new CHP plant. This appears to remain true in the future, as target-driven new RE installation will continue to drive inefficient plants away from the market. Furthermore, there are few regions remaining that require substantial heat load that could economically justify the construction of new CHP. In order to achieve China's national commitment for emissions reductions and to minimize future stranding of coal assets, this outcome for new coal investment is appropriate.

Wind and solar also earn more after market exit due to higher prices and higher integration. Although market revenues alone cannot meet renewables' full annualized capital costs, existing solar and wind subsidies will enable them to fully cover their capital costs. With greater utilization of renewables, there is concern about how this may impact the renewable subsidy fund, which is already estimated to be running a 100 billion RMB gap.[5] We discuss methods to handle subsidy payments to existing wind and solar plants during market implementation in the callout box *Coordinating Renewable Subsidies with Power Market Reforms.*

New wind and solar plants will increasingly rely on market revenue alone to cover their full capital costs, which under current market conditions means reduced new investment, an outcome that is out of step with China's wind and solar installation targets. At their current subsidy price points and curtailment rates, we would not expect generation companies to invest in new renewables on their own.[xi] Instead, government targets and the renewable portfolio standards will continue to be necessary to encourage a minimum level of new RE installation. But once curtailment is reduced, renewables could be competitive compared to other generation, and we could expect market demand to drive new renewables beyond government requirements. Market implementation will likely play a major role in reducing the remaining curtailment, as shown in this report. In fact, if curtailment were eliminated in the test region, recent price points for new wind and solar projects in China would make it possible for new projects to rely solely on market prices to cover their capital costs, alleviating the need for government subsidies.

[xi] Renewables capacity will not be built unless there is a contract in place that guarantees complete offtake at a price—known as a power purchase agreement (PPA)—that meets the generation companies' own internal hurdle rate.

POTENTIAL COST SAVINGS FOR CHP FROM LOWERING MINIMUM RUN RATES

Costs shown in Exhibits 4 and 5 in light blue represent costs that are incurred by CHP during periods of curtailment when CHP avoids being ramped down by either accepting 0 RMB/MWh real-time market prices or buying back generation rights in a secondary market (described in Section 5.1). During the heating season, CHP is not dispatched by the market, but instead produces electricity according to minimum heating requirements. In the CHP market integration scenario, CHP still submits bids to the market during these must-run conditions, with their bids being based on their incremental marginal costs to dispatch additional electricity. When CHP plants are not dispatched by the market, but still must run to meet their heating obligation, they offer low prices in real-time markets or purchase generation rights from generators that were dispatched but can more easily ramp down, in most cases renewables. This generation rights trading approach is similar to the approach taken in the current Dongbei ancillary services pilot. But, whereas in the ancillary services pilot all generators not ramping down pay generators that do ramp down, under this market design inflexible generators pay renewables or more flexible generators to not operate. While these payments/forgone revenues are minimal, they play an important role in putting pressure on thermal plants to be more flexible, which is discussed further in Section 5.1. Generators selling energy at 0 RMB/MWh or buying these generation rights have this in their cost stack; those generators buying replacement energy at 0 RMB/MWh or selling their generation rights have these gains represented in their revenue stack.

COORDINATING RENEWABLE SUBSIDIES WITH POWER MARKET REFORMS

Increased renewable integration from market reforms would further the financial burden on the renewable energy fund and could create perverse incentives to limit the amount of RE integration during market reforms. While renewable developers will inherently want their full generation to receive the subsidy, that stance could sacrifice full integration, which would cost generators substantial additional revenue and perpetuate the new capacity permitting ban in curtailment regions.

We propose two approaches that could meet the need to not grow the subsidy pool too much, while still ensuring renewables meet their expected IRRs:

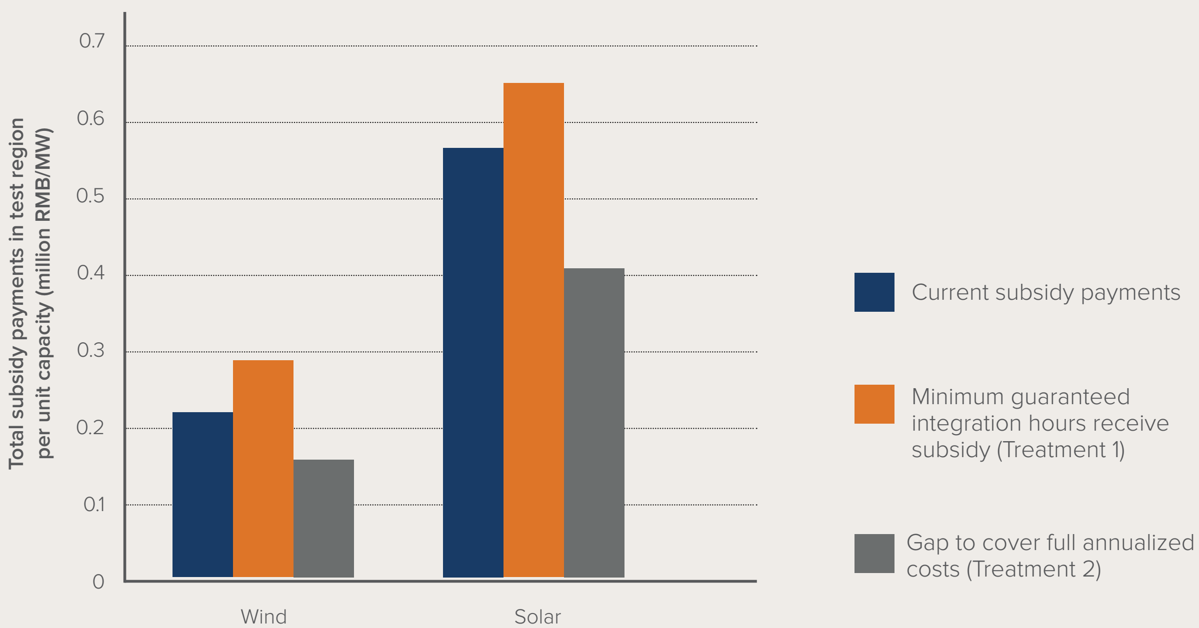
1. Renewable generators receive the subsidy for all hours within their guaranteed integration volume; any excess hours are paid the market price

2. The subsidy price is adjusted to ensure any gap between their full annualized cost and market revenue is completely covered

The first model would be preferred by generators as it would increase the total subsidy revenue

EXHIBIT 6

Total Subsidy Obligation Under Different Treatment



they receive before reforms and also increase their market revenues. This model would also be less disruptive to investors and would maintain investor confidence in China's renewable energy industry. The second model could enable a reduction in overall subsidy payments due to energy spot market reforms, which might bolster government support for market implementation. This could also result in lifting freezes on renewable interconnection and an increase in future years' wind and solar capacity targets. A hybrid model could exist, where savings on total subsidy payments are shared between the renewable energy fund and generators in order to balance political objectives and maintain investor confidence.

In the test region, the second subsidy treatment would reduce total subsidy payments to wind and solar by 29% and 28%, respectively, as compared with the traditional dispatch scenario. The annual revenue gaps to cover full annualized costs for wind and solar in an energy spot market are 0.157 million RMB/MW and 0.41 million RMB/MW, respectively—far below the subsidy amount paid in the traditional dispatch scenario (the annual subsidies for wind and solar are 0.22 million RMB/MW and 0.567 million RMB/MW). They are also lower than the subsidy corresponding to government-set minimum guaranteed utilization hours of renewables, which are 0.287 million RMB/MW for wind and 0.65 million RMB/MW for solar of the test area when the study started.[xii]

HOW DO ENERGY SPOT MARKETS COUPLE WITH EXISTING MARKET PILOTS?

China already has implemented several market pilots: ancillary service (AS) markets and direct power purchase markets. These markets have already produced substantial cost and emissions reductions, but energy spot markets should be seen as a complementary and necessary addition to these pilots, since they expand the scope of and further increase the benefits from these existing markets and help discover the real price for these services.

China's AS markets were designed to incentivize more flexible operation from generators accustomed to baseload dispatch. The current wholesale rates set for these generators also assume baseload operation, and therefore do not reflect the costs incurred when generators have to ramp. AS markets will need to adapt when energy spot markets are implemented to avoid double-paying for this flexibility, since marginal bids will, in part, reflect the cost of flexible operation. The most prominent of China's current **AS markets** is a "deep ramping" or "peak regulation" market. This market has current thermal generators bid in prices at which they are willing to ramp down below their minimum run rates to incorporate renewables that might otherwise be curtailed. This has already revealed substantial flexibility from CHP plants, and has already achieved 1.9% emissions reductions in the test area. Adding energy spot markets can further reduce emissions by an additional 2.5%, and also helps identify what flexibility should be provided gratis

[xii] These are calculated based on the wind and solar feed-in tarriff (0.54 RMB/kWh for wind generators in category III wind resource area, 0.88 RMB/kWh for solar generators in catalog II solar resource area, **http://www.sdpc.gov.cn/gzdt/201512/t20151224_768582.html)**, government-set benchmark price (0.3803 RMB/kWh), and minimum guaranteed utilization hours of renewables (1,800 hours for wind and 1,300 hours for solar, **http://news.bjx.com.cn/html/20170418/820862-2.shtml)**.

to the grid and what needs to be paid for. Energy spot markets further the emissions reductions by further reducing curtailment (0.8% points) and by optimizing dispatch outside of curtailment situations (1.7% points). Although a small amount of the decrease in curtailment can be attributed to a divergence between theory and practice (e.g., the model not considering imperfect information, unexpected outages, dispatcher judgment, etc.), the majority is from better scheduling: meeting demand with less units in operation, meaning there are fewer situations in which minimum run rates trigger curtailment. The majority of emissions (and cost) reductions (38% beyond the current AS market) come from reallocating hours from inefficient thermal plants to efficient ones, since the ancillary service market is only employed during periods of curtailment. Energy spot markets would also reduce the number of instances AS markets would be necessary, since fewer generators would be scheduled to be on in the first place. Energy spot markets also put pressure on generators to become more flexible without additional payments. If generators are not able to ramp down, they risk being dispatched in the market at prices well below their short-run marginal cost. For these reasons, energy spot markets help refine the AS market, only paying for services that generators actually incur additional costs to provide.

China's ongoing **direct power purchase (DPP) reforms**, have already reduced prices for end users (e.g., DPP price in portions of China's northern regions fell by an average of 0.03 RMB/kWh to 0.04 RMB/kWh). But these price reductions are not realized through system optimization since the current DPP dispatch is not based on least-marginal cost, but rather on contract volume. This presents a short-term challenge to DPP markets, where older, inefficient generators that have paid off their fixed costs can offer lower contract prices, thereby earning more dispatch. Without a spot market, retailers and other generators cannot identify cheaper energy resources to fulfill these contracts, which reduces the amount dispatch optimization can reduce costs and emissions. This, in turn, also limits how much price reduction will be seen in these markets. This is why energy spot markets must be operated in parallel with DPP markets to help fully realize optimized dispatch and discover the true market equilibrium prices for electricity.

We do not explicitly calculate how much additional cost, emissions, and price reductions can be achieved by adding energy spot markets to existing DPP markets, since the DPP market is still in flux, changing every month. But it is expected that cost and emissions reductions will be substantial, while further price reductions will depend on the province, with those experiencing an overcapacity situation seeing more substantial reductions.

5 CHANGES TO GENERATOR OPERATION

CHANGES TO GENERATOR OPERATION

Generators will face a new paradigm of operation under market-based dispatch, changing how generators are scheduled, how they respond to dispatchers, and how they manage their plant operations. These changes are less significant than is often anticipated with market reforms. No upgrades to existing plants are required to meet the types of flexible operation promulgated by market-based dispatch. All dispatch conducted in the model is well within the technical limits of existing grid assets. While no new flexibility is required, market reforms ought to incentivize flexibility, either increasing revenues to more flexible plants or penalizing inflexible plants. In the following section, we review how generator operation changes under market-based dispatch, discuss the right market structure that ensure adequate economic pressure is applied to the least-flexible generators, and discuss the expected changes in operation that will precipitate from generators over time. Given that CHP is a major cause of the northern regions' existing inflexibility, we discuss at length how to integrate CHP into markets, then touch on how hour-to-hour ramping and startups/shutdowns change for all thermal generators.

5.1 INTEGRATING CHP INTO ENERGY SPOT MARKETS

The test region requires significant heating in the winter and year-round heat supply for industrial processes: over 81% of thermal capacity is CHP; nearly 60% of total capacity. In the winter, CHP self-schedules based on its heating obligations, which can account for all the generation needed to meet demand during some hours. By accepting these units as must-run units (as is common practice in the rest of the world where CHP represents a smaller portion of the generation fleet), the effectiveness of energy markets in China would be compromised by failing to:

- Fully optimize dispatch by using least-cost electricity generation;
- Use markets to set wholesale electricity prices at sustainable levels; and
- Put economic pressure on CHP plants to ramp down more aggressively to avoid wind and solar curtailment.

In this section, we describe three options for how to treat CHP and other must-run units in a market-based system to ensure optimized dispatch, fair compensation, and the right incentives to encourage flexible operations. CHP can either:

1. Submit dispatch schedules and receive an administratively set, **out-of-market** price for all hours generated.
2. Submit dispatch schedules and become a **price taker**, receiving whatever the market price may be during operating hours.
3. Submit **market bids** and follow market-based dispatch, and bid below marginal costs during curtailment periods to avoid getting ramped down.

Option 3 is the most practical for the test area. Each of these CHP treatments, the rationale for our recommendation, and their resulting market outcomes are described below.

CHP MARKET INTEGRATION SCENARIOS

1. **Out-of-market** compensation is commonly used in regions where there are few must-run generators and they have a critical role for system security and public health. Under this model, CHP plants dispatch according to their heating schedules that are set by the plant and local heating authorities. Any electricity generation resulting from these heating requirements are paid at cost-based prices (current benchmark prices under this

EXHIBIT 7

Market Outcomes of Different CHP Treatments

model) that are audited and agreed to in advance by regulators.[xiii] This model does not fit China's northern regions because in winter months, almost all generation would be paid at prices outside of the market and would not be dispatched based on a least-cost basis. Setting cost-based pricing is a struggle in other electricity markets globally, and often results in overpayment and no competitive pressure for generators to reduce their costs.[6] In fact, generators are not exposed to price risk at all: even at their minimum run rate they are covering their costs. This encourages generators to overinflate their heating requirements to sell more electricity, a behavior that is likely already happening in China. Furthermore, this model does not address curtailment and does not encourage greater generator flexibility because generators have no exposure to losses at or below their minimum run rate.

2. **Price-taker** compensation is a common model employed to integrate self-scheduled units into the market. These generators are still allowed to define their schedule, but they are paid at whatever market prices are during those hours. A price-taker treatment allows the market to set prices and optimize dispatch, with the exception of times when CHP is at its minimum run rate, when it gets priority dispatch. A price-taker treatment also creates economic pressure for CHP to ramp down as low as technically feasible during moments of curtailment. When low-marginal-cost renewables are being curtailed, the market is clearing at 0 RMB/MWh. All CHP plants generating during this time will be bearing prices that do not cover their operating costs. Therefore, CHP will ramp down as low as technically possible while still maintaining its heat output requirements. This has been observed in Denmark, where CHP is treated as a price taker. Danish CHP plants have become much more efficient with their heat provision and have found ways to lower their minimum run rates to become more economically competitive and better integrate Denmark's high percentage of wind.

   One challenge under a "price-taker" scenario in the test area is the lack of market price formation. During the winter, CHP is often the marginal generator, and when it is, it means there is no generator to set the market clearing price. All other generation resources during these hours are renewables, which have a near-zero marginal cost. This means during any hours where minimum run rates and renewable outputs exceed demand, market prices will be near 0 RMB/MWh or negative. Nearly 2,200 hours per year would be priced at 0 RMB/MWh, which would deflate market prices to unsustainable levels. While there are ways to manage this situation, it frequently relies on using administrative means to set prices during these hours, resulting in market price distortion that may undermine market efficiency.

3. Having CHP submit **market bids** becomes a logical next step, where all electrical dispatch is determined by bids, regardless of heating and other must-run requirements. During periods when all CHP plants are at their minimum run rates and excess renewables are available, we expect CHP plants to bid below their marginal costs to avoid getting ramped down. Gradually CHP plants should reduce their minimum run

[xiii] Out-of-market integration is used for renewables in some regions where wind, solar, hydro, and geothermal are sometimes paid at administratively set prices and integrated as a must-take. Renewable resources often do not require special integration plans, since they are often lower marginal-cost resources and should naturally be prioritized in markets. But in this scenario, for consistency, wind and solar resources are still paid at the current benchmark prices. This is consistent with China's current approach to market exemptions, where solar, wind, run-of-river hydro, and CHP are all exempt from market dispatch.

rates, finding ways to ramp down instead of suffering a loss generating at submarginal cost market prices (the current ancillary service market demonstrates that many CHP plants can indeed ramp down and still meet their heating demand). This CHP treatment should achieve the objectives of full cost optimization, accurate price formation, and increasing CHP flexibility. This requires CHP bilateral contracts to include provisions where anytime CHP is dispatched at submarginal cost market prices, then the CHP plant bears this loss and cannot pass it on to the customer.

One concern is that CHP plants may bid lower than necessary to avoid getting ramped down, or not bid low enough and be left dispatching below their heating requirements. This could undermine markets by depressing market prices or disrupting heat supply, respectively. Therefore, in the initial phases of the market we recommend a **"buy-back"** provision, where generators that are not scheduled above their minimum output requirements can buy rights to generate from other generators that were cleared in the market. This buyback would only occur when electricity demand drops below the total of all generation from minimum run rates and available renewables.[xiv] This would allow CHP plants to not violate their heating requirements despite mis-bidding, but still obligate them to bear the cost of not being able to ramp down. This and other transition mechanisms are discussed more in Section 6.2.

STRUCTURING THE "BUY-BACK" SECONDARY MARKET

The secondary buy-back market can be structured in many ways, depending on how energy markets evolve in China. The most common is having a two-clearing market, where the day-ahead market schedules generators (and pays them for the hours they are scheduled), then in day-of markets generators buy and sell their scheduled hours or additional, unscheduled megawatt-hours to meet real-time conditions or must-run obligations. Under this model, CHP plants could bid low for their full minimum output level in the day-ahead market, secure full dispatch at their minimum run-rate, and then in real-time buy cheaper replacement energy to the extent they are able to ramp down. This model is similar to decremental bidding in two-step clearing markets.

A secondary generation rights swap could also evolve, similar to other markets currently operating in China. Generators can sell their scheduled hours to other generators that bid to acquire those hours. The current ancillary service pilot functions in a similar way, but instead of CHP plants purchasing these generation rights from renewables or more flexible thermal plants, the AS pilot requires all generators, including renewables, to pay CHP facilities that ramp down. We believe switching to the model proposed will

[xiv] This assumes a bidding behavior where CHP plants bid near their marginal cost for energy segments above their minimum run rate, and then bid at a substantially lower price for hours below their minimum output level. This bidding practice should reflect their willingness to sell electricity for substantially lower prices (or free) to avoid getting dispatched below their minimum output level and having to buy back rights. This behavior would result in all generators getting cleared at their minimum run rate (all priced at marginal cost) before the market begins to cut into their minimum run rates (substantially discounted prices). Given the experience in China's AS market, generators are technically able to ramp down, and with the presence of this penalty, we can expect plants most capable of ramping down to bid higher prices, reflecting their greater unwillingness to lose money by being not cleared in the markets. This would result in the most flexible generators being turned down first, and they would not buy back those generation hours. Thus, the calculations in this model represent a worst-case scenario, where there is no flexibility, and generators would have to buy back at the highest buy-back price (the last dispatched unit's marginal price). Even under these conditions, buyback represents a small impact to generator economics, about 2.4% of total costs.

ultimately create more CHP flexibility and not put undue economic burden on renewables to reduce their own curtailment, which could hinder more renewables from being added to the system.

Both of these structures help discover the true cost of inflexible CHP to the system. This value is useful for CHP plant owners to determine when it is economically beneficial to retrofit their CHP to become more flexible. Common retrofit options include installing bypass steam valves, hot water storage, and even electric boilers to absorb otherwise curtailed wind, an option already available in many of China's AS market pilots.[7]

Overall results using the market bids model

The economics shown for the overall model results in Sections 3 and 4 reflect using the market bidding treatment. CHP would need to underbid or buy back 2,441 hours annually in the test area under current technical requirements. CHP plants would need to underbid or buy back 1.5 million MWh to maintain their current heating loads, representing 3.4% of CHP's total generation. This cost does not substantially undermine CHP economics: CHP plants remaining in the market can afford this buyback, and those that cannot were uneconomic before implementing a buy-back system. Furthermore, the improved price formation in the market bid scenario results in much higher market prices during heating season (72% higher market prices than the price-taker scenario and 140% higher taking into consideration competitive bidding after market exit), and therefore CHP is much better off in this scenario, even with these buybacks.

While much of the CHP treatment design focuses on incentivizing downward ramp capability of CHP, **we assume no ramping below stated minimum run rates in the modeling**. We chose this conservative treatment because 1) results predicated on minimum heating rates that change could undermine the other findings, and 2) we wanted to assess if the maximum buy-back payments required to preserve existing heat output levels would jeopardize CHP's ability to cover going-forward costs. We determined that the buyback did not impede CHP's ability to economically meet heat demand: full generation rights buyback (the more expensive of the two buy-back scenarios) still allowed remaining CHP plants to cover their going-forward costs, typically exceeding them by 35%.

Both Dongbei's AS pilot and the experience in Denmark have proven that CHP plants can reduce their minimum run rates for limited periods of time and still maintain acceptable heat provision. Therefore, it can be expected that curtailment rates could drop even further to near 0%, where only a few hours of curtailment would occur from transmission constraints. In addition to integrating more low-cost renewables, system costs would be reduced even further by having the most inefficient, expensive CHP ramp down first, or paying CHP facilities more capable of ramping down to ramp down instead (effectively "buying back" from more flexible CHP).

Security of heat supply concerns with CHP retirement

The resulting market scenario does have some small CHP plants exiting the market, responsible for providing 18% of system heat supply. This raises concerns about whether those retiring plants will be

[xv] Most small CHP units are older units and are likely the first CHP units built within cities. Since then, larger CHP facilities have come on line and should, in most cases, be able to serve the heat loads previously met by these small CHP plants. This would require only small changes in operation levels and investments in interconnecting heat distribution systems. Rural areas typically use coal boilers and other on-site combustion of heating fuels, not CHP. Thus, it is reasonable to assume that most small CHP plants will be in urban areas with additional CHP plants within range to interconnect their heating systems.

leaving some heating needs unmet. We expect most small CHP facilities that are being closed are within a short distance from other larger, more efficient heating plants and could feasibly be interconnected.[xv]

Conducting the exact modeling of which CHP plants are or are not redundant is not possible without using a specific province and having the relevant information. Therefore, we cannot determine if the units that are receiving market signals to exit are critical or not to meet local heat demand. If it is determined that the exit of these CHP plants threatens the security of residential heat supply and cannot be met by using another CHP source, some out-of-market mechanism must be used to cover the going-forward cost of that heating plant.

ADVICE TO REGULATORS WHEN EVALUATING CHP HEATING REQUIREMENTS

Determining if heating demand cannot be met by other means is a challenge to regulators, who will likely receive many petitions to not shutter these plants even if they are uneconomic. Regulators and financers need to put clear guidelines in place that require generation companies and municipalities to demonstrate: 1) their stated minimum run rates are not inflated, and 2) their heating demand cannot be more efficiently met through other heat provision sources (including electric, biomass, efficiency, or other CHP). This policy should extend to CHP plants at risk of retirement, condensing plants retrofitting to CHP units to avoid mandated closure, and any new plants proposed to meet incremental heat demand.

While the market integration of CHP treatment described above should help with the overstatement of heating demand, other methods can be deployed to make sure heating efficiency is improved to reduce minimum run rates and heating demand. Those include:

- monitoring return heating fluid temperatures to expose overheating
- requiring heating system efficiency audits, including pipe inspections for excessive leaking and subpar insulation
- building efficiency and envelope assessments to identify where customer heat loss is not up to code, or where customers are opening windows due to overheating

Where heating is required but CHP would be economically stranded because of minimal electricity demand, alternative heating options may be the most economic decision. This is especially true as more renewables are added to the system and increase the number of hours with low electricity prices. Regulators should require heating companies to demonstrate that they have explored all alternative heating options, including end-user efficiency and renewable heating. Denmark has found retrofits to existing CHP systems as the most economic option, adding electric hot water tanks within CHP systems. An effective heat supply alternative are district-level geothermal heat pumps, which use a combination of electricity and the ground as a thermal sink/source to provide climate control, even cooling, something that will become increasingly important as the planet warms. And with appropriate storage components these efficient heat pumps could also help integrate VREs in the future.

5.2 INTER-HOUR RAMPING

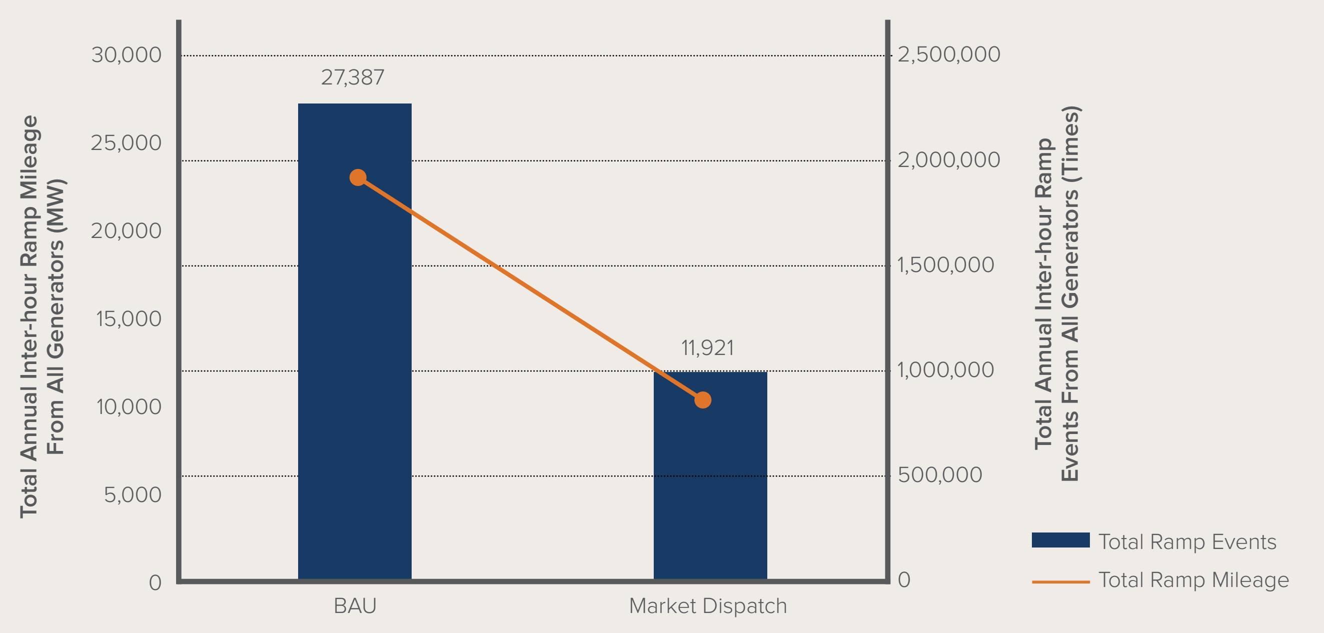
The common perception is that market-based dispatch, especially when increasing the level of renewable integration, greatly increases the amount of flexibility required of thermal plants, and that those plants must be retrofit to meet these increased needs for flexibility. In reality, the switch to a more optimized scheduling process decreases the total amount of ramping required of plants, both the number of ramping events required and the overall amount of ramping, called ramp mileage (the sum of every plant's delta in output levels between consecutive hours summed across the entire year).[xvi] Even with market exit, the system can meet all flexibility required with no retrofits to current plants, and does not require any modification to the plants' current ramping specifications.

Markets reduce inter-hour ramping

Markets reduce the need for two major types of flexibility: ramp events and ramp mileage.

EXHIBIT 8

The Ramping Comparison Between Market and Current Dispatch



[xvi] Ramping is defined as the number of times a generator changes its output level. Ramp mileage is how much a generator's output changes between each time period over a single ramping period. Both are important indicators for the increased costs of flexibility. Anytime a generator changes its output level (a ramp event), even within its technical limits, wear and tear is increased due to thermal stressing caused by temperature swings, regardless of how big the change. It also increases the likelihood of a generator tripping offline. The ramp mileage of a plant also indicates how much cost is added due to flexible operation.

Ramp Events: The current equal-allocation dispatch protocol causes the generator fleet to have nearly 2.3 times more ramp events than under market dispatch (shown in Exhibit 8). Market dispatch reduces ramp events by concentrating the ramping among a few generators, instead of spreading this responsibility evenly across all generators. So instead of having each generator ramp a little, a few generators will ramp much more, potentially reducing the total wear-and-tear costs incurred across the entire fleet, a market benefit not quantified in this report.

Ramp Mileage: Although the demand curves and renewable output used in both scenarios are the same (meaning the ramp mileage required to meet demand is the same in each), the ramp mileage required in the market dispatch scenario is only 44% of that in the current situation. This is largely driven by the lack of optimization between when startups and shutdowns are conducted and when other ramping activity is required. In the current dispatch, startups and shutdowns are scheduled to evenly split operating hours across all different generators. This means there are times when a generator is ramping down to turn off, despite the overall generator fleet needing to ramp up to meet increasing demand. Under market-based dispatch, the startup and shutdown schedules are coordinated with other ramping needs. Generators are only turned off when they are unneeded and during periods when the whole system is ramping downward. While some of this reduction is likely due to differences between theoretical modeling and actual dispatch (e.g., forced outages or maintenance schedules may add ramping not captured in this model), the theoretical decrease is so substantial that even accounting for incidentals, ramp mileage is expected to decrease.

Ramping is concentrated among a handful of generators

Under current equal allocation dispatch, ramping is spread out across the whole generation fleet. Under market dispatch, marginal units are dispatched much more frequently for ramping purposes, forcing them to become more flexible. In the simulation region, 600 MW CHP plants and 600 MW condensing plants see increased instances of ramping (Exhibit 9), largely because smaller, more expensive units are frequently shut down as they are not required to meet demand. 600 MW plants are almost always on and available to ramp, and can provide a much wider range of ramping.

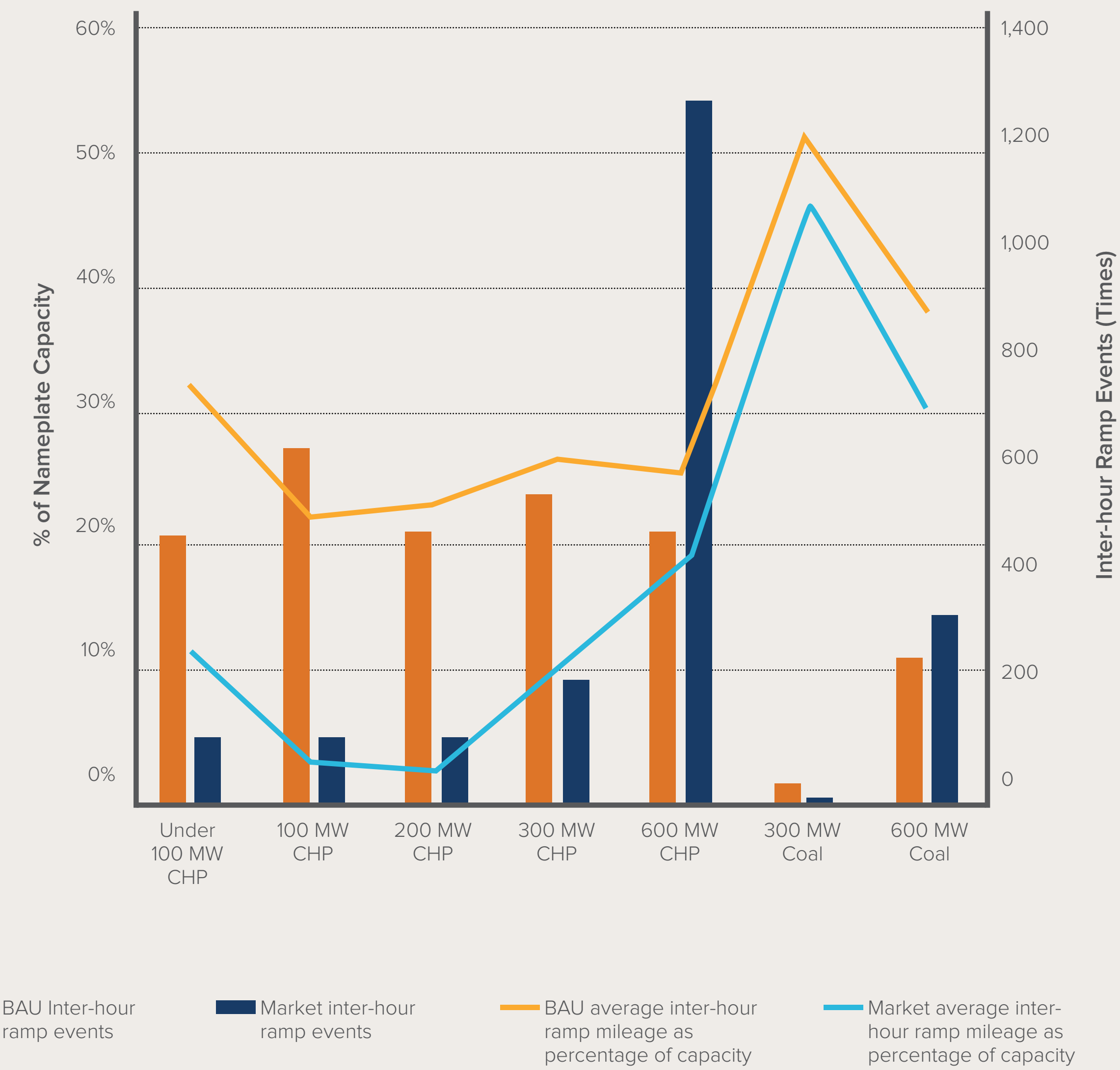
Despite concentrating the ramping among a few units, the average ramp mileage during a ramping period is reduced for all generator classes (Exhibit 9), due to improved scheduling of ramp periods. This is mostly reduced by eliminating unnecessary startups and shutdowns, and when those startups occur, those generators are usually only ramped to just above their minimum run rate to minimize the usage of the most expensive generation on the system.

Markets naturally put economic pressure to create more flexibility

There is a perception that generators should be paid more for generating flexibly under market-based dispatch. This perception needs to be challenged for two reasons: 1) efficient market dispatch reduces overall ramping, and 2) ramping within a generator's specification for ramping does not significantly increase generator costs. Often this perception is due to a lack of experience operating under a market-based dispatch regime, where marginal generators are ramping every hour, infrequently maintaining a steady-state output. This requires operational changes and plant operators to become accustomed to this new regime. Energy markets, especially when dispatched at subhour timescales, help force generators to understand how to extract this available flexibility and reflect that mode of operation in their energy bids.

EXHIBIT 9

The Ramping Comparison by Generation Types



While this analysis assumes no improvements to the ramping specifications of any plant, we expect generator flexibility will improve after market implementation. Many international markets have seen generators increasingly be capable of operating flexibly, updating their stated ramp rates.[8] This is because energy markets force generators to not only compete on marginal costs, but also compete on flexibility and ability to follow a dispatch signal. Otherwise they risk losing energy dispatch.

In most markets, generators submit binding constraints to dispatchers to consider when determining market-based dispatch. Important specifications are ramp rate (delta in megawatt output over a certain period of time), minimum output level, startup and shutdown times, and how long a generator must be on after a startup. Initially after market implementation in other regions, many generators tried to use these specifications to avoid costly ramping and startups/shutdowns, but those able and willing to provide more flexibility actually received more dispatch in energy markets.[9] The optimization considers the generator's specification and if the uptime and ramping limitations increase the overall cost of dispatching that generator, generators with slightly better ramp rates may receive dispatch even if they have slightly higher marginal costs.[10] Thus, many plants on the margin will begin to naturally explore ways to improve their flexibility when energy markets are implemented without additional payment. We do not quantify this benefit in this analysis but many retrofit incentive programs could be eliminated by shifting the motivation to retrofit to generators.

Adding ancillary service markets would help optimize for cheapest flexibility resources

Marginal generators are not necessarily the most flexible units and may not actually be the most cost-effective selection for providing that flexibility. This is why ancillary service markets operate alongside almost all energy markets internationally: to help identify the true cost of providing these ramping services (among other services for security) and to help select the least-cost resources to provide these services.[xvii]

Ancillary service markets should be co-optimized with energy markets, because it helps identify the overall least-cost means to provide energy, flexibility, and reliability to the electricity system. There are frequently moments where a generator that can provide cheaper energy should actually sell less into the energy market because it can provide lower-cost ancillary services. Instead, a slightly more expensive generator should provide energy, because its cost to provide ancillary services is substantially higher than the other generator. Although this results in slightly higher system energy costs, it reduces the whole cost of the system by lowering ancillary service costs substantially.

5.3 STARTUPS/SHUTDOWNS AND OPERATING SETPOINTS

Another common concern is that energy markets will cause units to start up and shut down more frequently. This analysis observed roughly the same number of startups and shutdowns under current dispatch (90 times annually) and market dispatch (94 times annually). But these startups were previously spread evenly across all generators, while under

[xvii] Flexibility incurs additional costs to generators in the form of increased wear and tear, increased forced outage rate of a plant, operating at less efficient output levels, opportunity costs incurred by reserving room to ramp up instead of selling the plant's full output in the energy market, and more. These costs are factored into the ancillary service bids offered into ancillary service markets, with the exact mix of costs bid in depending on the service they are competing to provide. Most markets regulate what costs are allowed to be factored into ancillary service bids, especially when the market for those services are not fully competitive and cost-based bids must be used.

market-based dispatch they are concentrated within marginal generators. Which generators are subjected to these frequent startups and shutdowns is highly dependent on whether or not heating requirements for CHP are in effect. It is worth noting that the conclusions around startup and shutdown are highly dependent on the system analyzed; in a system with less CHP we would expect further optimization of startups and shutdowns, since less units are constrained on for heating purposes.

As shown in Exhibit 10, after implementing market-based dispatch, startups and shutdowns concentrate within condensing units, primarily the 600 MW generators. This is primarily during the heating season, when most of the demand can be met using the CHP plants that are already on. When additional generation is needed, 600 MW condensing plants, the next most efficient in the lineup, start up, and once they are no longer needed, they shut down once again. During heating season, 600 MW condensing units are used infrequently; therefore, most startups are cold startups, creating more wear and tear on generators than if they shut down for only short periods (known as warm or hot starts).[xviii] Outside of the heating season, 600 MW condensing units experience less frequent startups and shutdowns, staying on to provide bulk power for longer periods of time. Although the frequency of condensing units turning on and off is significantly increased, it is still within a reasonable level when compared to international market experience.[11]

While the model result indicates no change in startups and shutdowns, we believe that in reality, market implementation will reduce the number of startups and shutdowns. CHP will likely lower its minimum heating must-run levels to avoid market buybacks as discussed in Section 5.1. This would mean more 600 MW condensing units could stay on line instead of jumping on and off the system frequently.

Exhibit 10 also shows the number of hours that each generator type is operating at a given output level as a percentage of its nameplate capacity. As expected, larger, more efficient plants frequently operate at or near their nameplate capacity, while less efficient plants spend more time turned off. When heating requirements are in effect, less-efficient CHP plants operate near their minimum run rates, and only the most efficient CHP plants are ramped up during times of increased demand. Outside of the heating season, 600 MW condensing units are typically operating at or near their nameplate capacity, providing some relief from the costs incurred by the frequent startups and shutdowns.

Managing startup costs

Plants on the margin will incur more startup costs than other plants. This was part of the reason for spreading the number of startups evenly across all generators in the current equal allocation dispatch mechanism, making sure the total cost of annual startups was fairly amortized into the state set price for energy. Under market dispatch, the costs for startups and shutdowns need to be compensated differently and factored into dispatch decisions.

Startup and shutdown costs are typically handled one of two ways:

1. Generators submit cost-based bids for their startup and shutdown costs, and the least-cost

[xviii] Hot, warm, and cold starts are defined using the following criteria: Hot startup is a startup event in which the unit was offline for 24 hours or less before starting to combust fossil fuels; warm startup is a startup event in which the unit was offline for 25–119 hours before starting to combust fossil fuels; cold startup is a startup event in which the unit was offline for 120 hours or more before starting to combust fossil fuels. **https://www.epa.gov/sites/production/files/2015-11/documents/matsstartstsd.pdf**

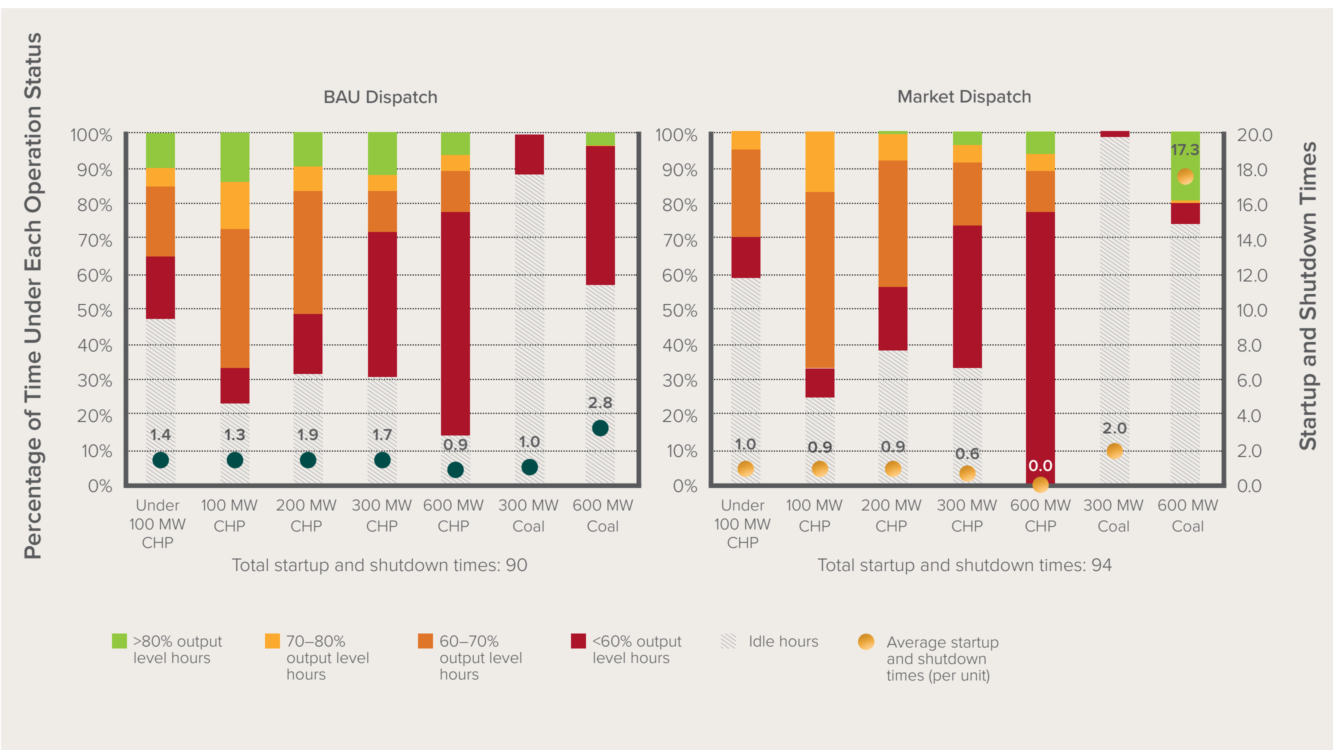
dispatch and scheduling optimization considers these costs when generating schedules. Any time units are requested to start up and shut down, they are paid these regulated, cost-controlled payments.

2. Generators factor startup costs into their bid prices or scheduling. In the presence of physical scheduling, generators are expected to know how much these costs are and perform this optimization on their own. In full market-based dispatch, generators can bid accordingly to avoid startup or shutdown.

Like with flexibility, high startup costs, long startup time requirements, and long uptime requirements submitted to dispatchers can factor into which plants receive dispatch. Dispatching a plant according to its operational requirements could negate its lower marginal cost, if the total cost is lower by

EXHIBIT 10

Operation Status Changes Caused by Market Dispatch



dispatching a higher marginal cost plant with lower startup cost and requirements. Accordingly, plants have an incentive to decrease the time and costs associated with startup and shutdown to increase their competitiveness in the market.

After plants optimize their startup procedures, it could result in 600 MW condensing units performing startups less often than the model results, since they are not necessarily the best candidates to provide such service in reality. Initially, 600 MW condensing units take this role solely due to the model assumptions, where current stated costs for generator startup are roughly uniform across China's fleet. However, once the market operates for a while, generators will refine their startup bids and specifications, and other more flexible generators may end up starting up to meet these short time span, infrequent demand spikes. For instance, generators that are old and nearing retirement might find it more profitable to bid into the market with low startup and shutdown costs and receive additional dispatch beyond what their energy bids alone would warrant. This strategy allows them to maximize their profits by providing this flexibility, and when this added wear and tear eventually causes the generator to break, then they simply retire the plant.

6 MANAGING CHALLENGES

MANAGING CHALLENGES

While the benefits of implementing energy spot markets are clear, we expect there to be resistance from local governments and generator companies due to changes to their operation and revenue, and the potential of plants having to close. The major challenges identified in this analysis are:

- Generators adapting their operations to a market-based system, particularly CHP;

- Generators enduring low market prices during the pre-market exit period; and

- Managing the stranded capital and unemployment associated with necessary market exit.

These challenges need to be met with reasonable compromise and transition mechanisms that ameliorate concerns and reduce resistance toward market reform. Otherwise these theoretically ideal market designs will never see implementation, and the cost and emissions benefits will not be realized. In the following section we highlight some possibilities on how to manage these challenges and how to determine which compromises are acceptable and which fundamentally jeopardize the function of these markets. While the topic of managing the politics of transitioning to a market-based electricity system is too broad to be covered fully in this report, we focus on those that could be used to manage the major challenges identified in this analysis.

- **Employ transition mechanisms** that minimize the financial impact to generators while still subjecting them to market-based dispatch so they are forced to adapt their operational and business strategies, but in a low-risk environment. **Revenue guarantee contracts,** which keep current payment to each generator the same, regardless of how much they are dispatched, are an important vehicle to manage this in the short term.

- **Gradually increase generator exposure to operational changes,** initially by limiting the amount of ramping and startups/shutdowns, then gradually expose generators to more market forces or regulatory measures to increase flexibility. This is particularly true for **CHP minimum run rates**, which need to be subjected to market pressure at the start of market pilots to make market prices equilibrate in regions with high heat supply obligations.

- **Facilitate market exit, do not hinder it.** Market exit is necessary to form sustainable market prices; propping up unneeded generators will undermine markets. But for generators pushed to exit, appropriate mechanisms to **manage stranded capital and unemployment** should be employed to minimize resistance.

6.1 TRANSITION MECHANISMS

Generators, dispatchers, and customers need to adapt to participate in markets; they need to change their operation and business models and make decisions about what parts of their portfolio remain viable under markets and which need to be eliminated. This learning takes time. Implementing markets should include a transition period that leaves sufficient time for generators and dispatchers to learn how to operate in this new paradigm. It is also important to create "forced learning" situations in which generators are *required* to adapt their mode of operation as opposed to opting in to operational changes.

While a common instinct may be to gradually submit generators to market-based dispatch, or even submit them to market pricing first, these models do not pressure generators to change their operation, and therefore just delay the need to force generators to shift to new dispatch modes, elongating the resistance period.

Employ virtual revenue guarantees to lessen financial impact to generators

One mechanism that has been employed successfully in other market transitions internationally is a revenue guarantee, in which current payment levels from existing contracts are fixed for a given period of time while markets are implemented. Generators will begin to submit their marginal cost bids to determine dispatch, market payments will be made to the generators that clear the market, and any difference between market payments and contract payments will be made whole. So, while generator dispatch changes, generator revenues do not.

This structure could result in generators not actively competing in markets for more dispatch, since they will get paid the same way regardless of dispatch. Therefore, it is important that revenue contracts be treated like virtual contracts, where any time market prices are cheaper than a generator's marginal cost, the market will automatically dispatch the cheaper resource, and the contracted generator will automatically purchase that cheaper energy from the market instead of generating itself. This allows the contracted generator to still get paid its full contract rate and keep any amount above the market price or its marginal cost, while those generators receiving more dispatch will earn the difference between the market price and their marginal cost. This system means any cost reductions achieved from dispatch optimization will be split between the generators. This encourages generators to bid into the markets at their true marginal costs, thereby giving a clearer picture of what market dispatch will be once markets are fully implemented. This model begins to expose generators to market-based dispatch, helping them understand how to respond to more real-time dispatching instructions, how often they will need to ramp or shutdown/startup, and how they will schedule their fuel shipments and labor differently.

Set a clear transition period

Revenue guarantees need to have a defined, limited tenure so that market prices eventually put economic pressure on those generators to change their operation and exit the market. These periods should be defined at the beginning of the implementation period, and strict limitations on when extensions are provided (for technical challenges only). The duration of these revenue guarantees can vary per generator type, allowing more sensitive assets, like small CHP plants, more time to find alternatives for heat provision and pay off any additional capital costs incurred by installing these alternatives. Tiering out the end dates of different assets' revenue guarantee periods is a better alternative than subjecting only some generators to market dispatch in the early days of the pilot. Withholding some generators from the market means the initial pilot does not give a representative picture of what the real dispatch and resulting prices will be.

Use shadow markets to practice before real market operation

Prior to full implementation, many market transitions have employed a shadow market, or a simulated market. Generators still dispatch according to the current protocol, but submit bids to the market, and receive limitation on what their dispatch would have been under those grid conditions. These simulations are helpful throughout the implementation process and should proceed any change in the market rules during the transition to help all parties familiarize themselves with the new process.

Methods to manage market transitions are numerous and need to be fit for the region and political context in which they are being implemented. These methods substantiate a more involved discussion than is allowed here. For a more detailed discussion on mechanisms suited to China's current transition, see RMI's ***Transition Pathways for China's Power Market Implementation report (Chinese only)***.

6.2 GENERATOR OPERATIONAL SHIFTS

Changing how plants are operated is a challenge and takes time, but the greater challenge is often the pushback from plant operators, who cite technical limitations as a reason why they cannot change their operation. These technical limits are frequently not rigorously derived, but instead are industry heuristics, developed when plants often operated at steady outputs throughout the day. After market implementation, it is found that many plants can safely operate well outside their previously stated technical limits without retrofit, which is only realized when it is economically beneficial to operate in this fashion.[xix, 12]

As discussed before, markets should apply pressure to generators to become more flexible at least cost, either by compensating flexibility or penalizing inflexibility. Whether to force generators to become more flexible (penalties) or reward their flexibility (compensation) depends on how critical their flexibility is to market function and how certain market designers are that technical limits can be revised. The more critical the flexibility and the more certain that additional flexible capability exists, the more penalties should be employed.

In the test area, sufficient ramping, startup, and shutdown capability exists today, so generators do not need to be forced to reevaluate their current specifications in the short term. It is sufficient for those plants to determine if adjusting those setpoints will result in more dispatch, and when the time comes, updating the current ancillary services market could further incentivize flexible dispatch from these generators. CHP minimum run rates do need to be subjected to penalizing forces during the initial market implementation, since business-as-usual operation would prevent markets from forming sustainable prices and substantially reduce the benefits of optimized dispatch.

Subjecting CHP to economic pressure is a major political challenge. CHP minimum run rates are not subjected to grid company review and are set by different regulatory authorities than those overseeing the grid company. Given this, it is expected that any pressure to lower minimum output levels would be met with strong opposition that would be difficult to counter. Ancillary service pilots, like those in Dongbei, have demonstrated that minimum run rates can be lowered but have set an expectation that CHP plants should be paid to ramp below their minimum run rates.

This compensation only works if all plants are in fact at their verified minimum run rate. Otherwise it encourages plants to set their technical minima higher than necessary, and then be compensated for any time they ramp down below 50% of their nameplate capacity. But given the precedence in several regions of paying for downward ramping service, it may be too difficult to shift directly to a mechanism that penalizes CHP inflexibility.[xx] Therefore, we propose two methodologies to facilitate the transition to a more market-integrated model of operating CHP: 1)

[xix] As an example, after market implementation in certain regions of the US, coal plants found it economically beneficial to alter operations to be able to turn on and off more easily and operate below 40% output. In order to operate in this way, plants required significant procedural updates (e.g., greater frequency of inspections, better definition in standard operating procedures for ramping periods) but required only limited hardware modifications. The economic viability of any deeper retrofits to further enhance flexibility are highly dependent on the market context of the plant, particularly the prevalence of scarcity pricing, the compensation available in ancillary service markets, and the existing flexibility in that region's fleet.

[xx] Market pilot regions should be cautious adopting the current deep ramping ancillary service market design. Setting precedent by paying for thermal generators to ramp down could increase the political resistance to moving to energy spot markets.

continuing the current ancillary service model but verifying minimum run rates, or 2) submitting CHP to market dispatch, but placing caps on how low deep ramping will be required, similar to those in the ancillary service pilot.

Evolve the current AS market to fit energy markets

The current ancillary service pilot must include some evaluation of true setpoints to avoid overpaying CHP for this downward ramping capability. This requires evaluating:

- the necessity and efficiency of the current heating levels (discussed in the callout box *Advice to Regulators on Evaluating Heating Minimum Run Rates*); and

- the interrelation of minimum electricity output achievable at its minimum heating level (i.e., CHP backpressure constant).

The backpressure constant can be evaluated through an audit of generator operation and benchmarking the result against other similar classes of CHP. These benchmarks then become the starting point at which CHP is eligible to be paid for additional downward ramping.

The current ancillary service pilot should also allow other generators, particularly renewables, to participate in this ramp-down market. Under the renewable energy law, renewables are also guaranteed full offtake. If both are ramping down from their promised dispatch, both should be able to bid competitively to provide that service to make this a comprehensive market that does not favor one technology over another.

Integrate CHP into markets, but gradually remove protections

Under the market bid mechanism proposed in Section 5.1, generator bidding behavior is likely to be unpredictable in the early phase and could undermine markets. Therefore, we propose a few measures to help guide generator bids and avoid putting too much economic pressure on plants before they have time to adapt to these incentives:

- Bids for segments under minimum run rates must be within 10%–20% of cost-verified marginal costs at their minimum run rates. This prevents overly aggressive underbidding.

- Limit how low CHP can be scheduled by the market or place a cap on how much a single generator is obligated to buy back in a single curtailment period. This could be 40% of a plant's nameplate capacity as is used in the ancillary service pilot.

- Allow generators to use 10 MW or less energy segments below their minimum run rate, allowing for more granular pricing of different levels of downward ramping.

These settings can be adjusted once the pilot has been operated for a while and generators understand how much they can ramp down. Throughout the process, generators should be allowed to update their stated technical specifications with dispatch centers.

As generators begin to implement these changes to technical operation, there will be mistakes. As the transition occurs, dispatchers may look to schedule higher reserve margins during periods when generators ramp down below minimum run rates, ramp over longer periods and ranges, or start up and shut down with greater frequency. This will help mitigate the increased chances of an outage caused by the increased chances of generators tripping offline or not being able to precisely follow these dispatch signals during this transition period. Providing training for these generators on how to manage these technical evolutions will also greatly speed up the transition and cause less hiccups along the way.

6.3 MANAGING MARKET EXIT

Policymakers need to come to terms with the implication that market reform means market exit in overcapacity provinces. Still, market exit presents a political challenge for many provinces, where it is untenable to have large employers go out of business and state-owned assets stranded. The initial reaction would be to find other payment means to keep these generators in business. But this undermines the point of market reforms, and would result in sustaining losses to all generators by keeping market prices low due to overcapacity.

Thus, policymakers should first assess what the likely market exit will be, and then identify mechanisms to manage any stranded capital and manage the transition of the labor force to new industries. It should be highlighted that reoptimizing dispatch presents no risk to provincial GDP and minimal impact to tax revenues since it merely shuffles the generation around between other plants.

There are two ways to manage plants identified as “at risk” for closure: mothballing or closure and decommission. In either case, the labor displacement caused by these decisions must be handled.

Mothball unnecessary plants that may be needed in the future

Mothballing a plant allows a plant that is currently unnecessary to be brought back on line in future years if demand increases. Mothballing minimizes ongoing costs while keeping the plant available to reenter the market. It also guards against the risk of having to build a new asset to meet demand. Given most Chinese plants are still rather new and have reasonable efficiency standards, mothballing is cheaper than having to build another asset and then potentially have that one stranded in the future as well.

Mothballing is also a helpful approach when the future of electricity demand is very uncertain, like it would be during China’s market rollout. As markets roll out, regions that have low market prices may see demand grow higher and faster than expected, as other provinces increase imports (and therefore see accelerated market exit). First movers on market reforms may see multiple phases where plants jump in and out of markets as the overall system and market equilibrium settles out. Additionally, after the market equilibrates, certain regions may see systemically lower electricity prices, encouraging industry to shift to those locations, creating greater growth in the long term. While mothballing incurs small additional costs, it is a very low-cost hedge during this transition period. Additionally, while mothballed plants are not bidding into markets and therefore not limiting moments of scarcity, they do serve an important role in keeping speculative bidding in check, because it is still relatively easy for these plants to reenter the market should prices rise to levels where the mothballed plants would be economic.

Decommission plants unnecessary in light of future capacity targets

If there is no anticipation of future utilization of these plants, it is best to cut losses and take advantage of China's generous coal retirement efforts. These policies allow plants to trade generation rights away for the next three years, be greenlighted for additional renewable energy permits, or use the land for five years following the closure of the plant.

But as the scale and type of market exit evolves, so must the mechanisms to handle this stranded capital. For instance, the current retirement package may be too expensive if many plants are exiting, or perhaps insufficient to encourage the exit of large, new plants that have a lot of unpaid capital. Therefore, these approaches need to be adapted to the situation at hand, and how responsibility for this retirement should be shared between financers, industry, and policymakers needs to be considered. Policymakers have to balance the environmental, health, and economic imperatives of accelerating the transition to low-cost renewable and efficient generation with doing so at least cost. At the same time, early retirement of existing plants sends signals to investors that new construction of power assets is high risk and could stunt the investment necessary to deploy new renewables. Approaches to balancing these two imperatives and mechanisms to ease capital destruction for asset owners are presented in greater detail in RMI's ***Managing the Coal Capital Transition report.***

Find least-cost pathways to justly transition labor force

Perhaps the most challenging aspect of the market exit is managing the unemployed work force from these plants, which in large plants in China could exceed 1,000 employees, often in regions with little other industry in which to redeploy these workers. There is little in the way of best practices on how to manage these transitions, and each locale needs to find its own pathway for this transition. Most approaches consist of some financial aid and retraining for employees or their families, but often do little beyond that and retraining sees mixed success.

One effective approach to understand local reemployment options is to conduct a mapping exercise, identifying what other growing industries in the region offer similar pay and require similar skillsets. Then from there providing targeted retraining programs that focus on transitioning workers to industries with the most need and least retraining required to minimize the cost, transition time, and failure rate of such programs. Additional research must be done in this area to identify applicable solutions in the Chinese context.

7 FURTHER USAGE AND IMPROVEMENT OF THIS STUDY

FURTHER USAGE AND IMPROVEMENT OF THIS STUDY

While this test case yielded results that will be helpful to China's northern regions, the framework and model used to conduct this analysis can be used by all provinces to evaluate their proposed market designs. As demonstrated, market analysis identifying impacts at the system level and impacts to individual players can be key in an iterative market design and approval process, and can help regulators and market designers align on the right market mechanisms to tackle their region's specific challenges. RMI hopes to make this tool available to different entities to use in some of the following applications:

- Evaluating major market design features (e.g., gross pool vs. net pool, CHP and RE integration rules)
- Comparing different market designs proposed by various entities (grid companies, etc.)
- Identifying potential risks and sources of political resistance
- Designing remediation mechanisms
- Running "shadow" or practice market simulations to train generators

The study uses a rigorous model that is described in greater detail in the appendix of this report. In building this model we identified several areas to improve our simulation to increase its veracity and usefulness to users, including:

- Adding locational marginal pricing
- Integrating with heat supply system analysis
- Including demand response and elastic power demand
- Incorporating the influence of long-term bilateral contracts on spot market results

RMI plans to continue to develop this functionality in partnership with other provinces and regions that may use this framework and tool.

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